U.S. NUCLEAR REGULATORY COMMISSION

REGION III

REPORT NO. 50-461/96003

FACILITY
Clinton Power Station

License No. NPF-62

LICENSEE
Illinois Power Company
500 South 27th Street
Decatur, IL 62525

DATES
from March 26 through May 10, 1996

INSPECTORS
M. J. Miller, Senior Resident Inspector
K. K. Stoedter, Resident Inspector
D. R. McNeil, Reactor Operations Assessment Representative
D. V. Pickett, Project Manager
N. Shah, Radiation Protection Inspector
D. R. Desaulniers, Human Factors Inspector
P. C. Goodman, Human Factors Inspector
J. E. Foster, Senior Emergency Preparedness Analyst
R. D. Jickling, Emergency Preparedness Analyst
R. A. Langstaff, Regional Inspector

APPROVED BY

Richard J. Miller for
Brent Clayton, Chief
Reactor Projects Branch 5

5-24-96
Date

AREAS INSPECTED

A routine, unannounced inspection of operations, engineering, maintenance, and plant support was performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and for certain previously identified items. Special inspections were performed in the areas of Improved Technical Specification implementation and human performance. Temporary Instruction TI 2515/130 was closed based on the results of this inspection.

Results: One violation was identified in the areas inspected.

Executive Summary

Plant Operations

- Although restart activities were accomplished in a controlled manner, several examples of poor communications were identified during the power ascension.
- The failure to maintain a broad understanding of plant conditions during restart activities resulted in two entries into the controlled entry area of the power to flow map.

Maintenance

- Poor preparation for on-line maintenance resulted in using additional limiting condition for operation time for accomplishing tasks that could have been resolved as part of the planning process.
- Inattention to detail and procedural weaknesses contributed to the failure to remove a fuel injector setting jack from the 12 cylinder engine on the emergency diesel generator. This was a violation of NRC requirements.

Engineering

- Implementation of the Improved Technical Specification (ITS) was performed effectively in accordance with the approved NRC safety evaluation.
- While engineering documented an oil leak on the reactor core isolation cooling system, they failed to determine the cause of the leak until it was identified by the inspectors.
- The initiation of condition reports for equipment deficiencies was inconsistent. While several equipment problems were documented, three feedwater transients were not recorded via the condition report process.
- Expediency resulted in a poor engineering evaluation explaining the loss of the rod control and information system on April 9, 1996.

Plant Support

- Poor communications of re-engineering initiatives resulted in confusion among the radiation protection staff.
- The gaseous and liquid radioactive waste program was effective in monitoring effluent releases.
- Performance during the emergency preparedness exercise was very good and demonstrated the licensee's ability to effectively implement their onsite emergency plans.

Safety Assessment/Quality Verification

- The failure to identify and effectively address adverse trends in human performance, due to a reluctance to document problems, was considered a weaknesses in the licensee's corrective action program.

Summary of Open Items

Violation: identified in Section 2.2

DETAILS

1.0 OPERATIONS

NRC Inspection Procedure 71707 was used in the performance of an inspection of ongoing plant operations. During the inspection period the plant experienced a scram due to maintenance activities in the switchyard (see Inspection Report 96004). Evolutions related to the reactor restart were timely and well managed; however, several problems were encountered because of communications. For example, a feedwater transient was not documented in the control room logs until an operator was questioned by the inspector. In addition, a nuclear engineer was not timely in communicating two entries into the controlled entry region of the power to flow map.

1.1 Restart Operations were Well Controlled

Activities associated with restarting the unit, following the April 9 scram, demonstrated good attention to detail and sensitivity to crucial evolutions.

During the pull to criticality reactor operators were properly focused on the control rod moves and resultant changes in source range indications. Once critical, the operators maintained an appropriate startup rate and remained focused on changing power levels and ranging the intermediate range nuclear instrumentation. All remaining control room activities were performed by other operators. Control room distractions were kept to a minimum throughout the evolution.

The inspectors observed an operator asking for guidance prior to synchronizing the generator to the grid. Although the individual had been properly trained and had performed the activity on the simulator, this was the first time this operator had performed the activity on the unit. The inspectors consider the operator's actions to be positive since he was willing to ask questions rather than proceed with uncertainty.

1.2 Problems Encountered During Power Ascension

On April 14, the inspectors observed several problems during the power ascension. Some of the problems were caused by poor communications while others were caused by poor planning.

The shift technical advisor informed the inspector of a feedwater transient which occurred during the midnight shift when operators were unable to place the "B" turbine driven feedwater pump on three element control. This resulted in reactor water level lowering by approximately 10 inches; level went from 35 inches to 25 inches. Although the day shift operators were aware of the event, there was no log entry to document the transient. A late log entry was made after the inspector questioned the operator. Later on the swing shift another feedwater transient occurred when operators again attempted to place the "B" turbine driven feedwater pump on three element control. The problem was later determined to be caused by a failed relay.

Another communication problem, involving procedure revisions, was identified by the shift supervisor. In this instances, the procedure the reactor operators were using to pull rods did not contain a current procedure advance change (PAC). In this case, the version in use was more conservative then the new revision and caused no operational concern. A notice, placed in the shift supervisors mail, was used to inform operations when a PAC was issued. However, due to startup activities, the shift supervisor did not have time to read the mail and was unaware that the PAC had been issued. A condition report was written to address the programmatic problem.

Contrary to licensee management's statement that all operators had been briefed on and understood the cause of the April 9 scram, the inspectors determined that this was not the case. The inspector observed a licensee person leaning on the switchyard control panel and bumping the plastic protective cover off of the reserve auxiliary transformer (RAT) input supply switcher. The inspectors questioned the operators to determine if leaning on the control panels was considered an acceptable practice. During this discussion, the inspectors determined that not all the operators understood that the loss of the RAT had resulted in the April 9 scram. The inspectors discussed this issue with senior operations management. Additionally, the individual observed leaning of the switchyard control panel was counselled on the inappropriateness of this practice.

The failure to maintain a broad perspective of operational activities resulted in two entries into the controlled entry region of the power to flow map. Prior to upshifting reactor recirculation (RR) pumps, the nuclear engineer became concerned over the low position of the boiling boundary in the core since this increased the potential for instability during RR pump upshifts. Reactor power was approximately 35 percent and just below the controlled entry region of the power to flow map when operators started pulling rods in attempt to raise the boiling boundary (at the engineers request). After reactor power to flow conditions were solidly in the controlled entry region, the nuclear engineer informed the operators and instructed them to drive rods in until an exit from the area was accomplished. While it was good that the nuclear engineer was concerned about the boiling boundary, he should have anticipated the entry into the controlled region and provided timely input to avoid the area.

Once clear of the region, the decision was made to upshift the RR pumps. A control room briefing addressed completing the task expeditiously and the need to watch for instability during the upshift process. A decision was made to raise power to 40 percent and maintain the rod line just below 70 percent which was the bottom boundary of the controlled entry region. It appears that as power increased, the power did not exactly track the mathematically derived rod line and a second entry into the controlled entry region occurred.

As the inspector entered the computer room to check progress of the power increase, he noted the second entry into the controlled entry region. The inspector questioned why the nuclear engineer hadn't identified the problem and informed the operators since the operator's indication did not show entry into the region. The nuclear engineer informed the operators that the controlled entry area had been entered. Power was then raised to 45 percent by increasing flow and the area was exited.

Although the operators followed procedures and exited the controlled entry regions promptly each time, preplanning could have avoided both entries. Even with the lack of foresight, better diligence on the part of the nuclear engineer could have identified each entry sooner.

No violations or deviations were identified in this area.

2.0 MAINTENANCE

NRC Inspection Procedures 62703 and 61726 were used to perform an inspection of maintenance and testing activities. The use of limiting condition of operation time allowances to resolve issues which should have been addressed during the maintenance planning process was considered a weakness. During the Division II emergency diesel generator outage, an injector setting jack was left on the diesel due to inattention to detail and a failure to follow procedures. This resulted in the diesel generator tripping during post maintenance testing. The inspectors considered this another example of a lack of attention to detail.

2.1 Poor Preparations for On Line Maintenance

On April 2, at approximately 5:00 a.m., the Division II diesel generator was taken out of service to perform preventative maintenance. Scaffold building promptly followed the initial tag out and was progressing well. However, at 8:00 a.m. the inspectors noted the scaffolding was being disassembled and replaced with sturdier tube and knuckle scaffolding which provided better support for equipment rigging. Although the licensee indicated the original scaffolding could have met their needs and that the change only improved working conditions, the decision should have been made during planning for the activity and not during an LCO.

During relay testing for the diesel, the inspectors noted that the required software for testing the relays had not been loaded on the diagnostic equipment nor prestage of use by the technicians performing the testing. Technicians experienced difficulty in trying to locate a copy of the test program since most of the disks around the computer station were poorly labeled. The technicians resorted to scanning many disks before finding the program. Once the software was installed and running properly, several failed attempts were made to test the first relay. The technician eventually identified and corrected loose cable connections between the computer and the test equipment. Although the test equipment was used only a few weeks prior to perform Division III relay testing, it was not functional at the start of the Division II outage. The inspectors consider the failure to have the required test equipment prestaged and functional, prior to starting on-line maintenance activities, a weakness in the licensees approach to on-line maintenance.

2.2 Failure to Follow Procedure Results in Overspeed of Diesel Generator

The Division II emergency diesel generator (EDG) tripped due to an overspeed condition on April 4, 1996. Although there was no damage to the diesel, the licensee determined that poor sensitivity to first time evolutions contributed to this event. Specifically, this was the first time that the lash adjuster check was performed in conjunction with the injector rack check. While the lack of sensitivity may have contributed to the event, the inspector noted that checking the injector rack settings was a routine maintenance activity of minor complexity. In addition, maintenance personnel involved in this event were very experienced in EDG maintenance practices.

The apparent lack of attention in following the maintenance procedures for safety related equipment was a concern. Maintenance personnel performed checks of both the lash and injector rack adjustments in accordance with CPS 8207.06, "Emergency Diesel Engine Scheduled Maintenance." Upon completion of the steps associated with setting the injector racks, maintenance personnel removed the injector setting jack from the 16 cylinder engine but failed to remove the injector setting jack from the governor linkage of the 12 cylinder engine. By leaving the jack installed, the governor was held in a full throttle condition which then caused the overspeed condition when the EDG was started.

The licensee's review of CPS 8207.06 determined some procedural weaknesses. While the procedure and its associated checklist governed the activity, an appendix provided the guidance for making adjustments to the racks. When the signoff was made for the injector racks being set (within the checklist), the signoff referenced the steps in the governing procedure which included the removal of the governor jack. No specific signoff was provided to verify that the jack was removed. Although the procedure may have been cumbersome, it would work as written. The failure to remove the setting jack in accordance with the procedure is a violation of Technical Specification 5.4.1, "Administrative Controls," (50-461/96003-01(DRP)). The licensee planned to address the procedural concerns as part of the corrective actions to this event.

Both a condition report and a fact finding meeting were initiated to determine the facts surrounding the event. The inspectors review of the fact finding results identified one weakness. Although the lack of sensitivity to first time evolutions was considered a major contributor to the event, none of the actions developed to prevent recurrence addressed this lack of sensitivity. The inadequate sensitivity to first time evolutions demonstrated during this event was similar to the actions associated with the switchyard work which resulted in a reactor scram on April 9. Also, the failure to identify actions to address possible human performance problems was considered an additional example of a concern identified during our recent human performance inspection (see Section 5 for details).

One violation was identified.

3.0 ENGINEERING

NRC Inspection Procedure 37551 was used to perform an onsite inspection of the engineering function. While implementation of the improved technical specifications (ITS) was good, the identification and documentation of equipment problems needed improvement.

3.1 Improved TS Inspection

During the current inspection period, an inspection of the implementation of the ITS was conducted. The inspectors used the guidance provided in Temporary Instruction 2515/130, Improved Standard Technical Specification Implementation Audits, to perform the inspection. Several technical specifications (TS) were selected and followed from the old TS to their final disposition in the ITS, ITS Bases, Operational Requirements Manual (ORM), or the Updated Final Safety Analysis Report (UFSAR). The selected specifications included a cross-section of specifications where surveillance requirements were increased, decreased, deleted or combined with other surveillance requirements. In each instance it was determined that the licensee had completed the TS to ITS revision in accordance with its previously approved NRC safety evaluation (SE).

Procedures controlling the revision of the ORM, TS Bases, and UFSAR were reviewed and were determined to be adequate to control the revision process for these documents. Revisions to the ORM that allowed deletion of requirements were reviewed, including the accompanying safety reviews (10 CFR 50.59 reviews). In each case it was determined the revisions and safety reviews were performed in accordance with station procedures. Several surveillance procedures associated with the old TS and carried through to the ITS and ORM were reviewed and found to have been revised to reflect the new requirements of the ITS and ORM. Operations and training personnel were interviewed to determine the level of confidence and competence operators had in the ITS prior to adoption of the ITS. In all cases operators and trainers appeared to be prepared for the adoption of the ITS prior to actual implementation. The inspectors found no discrepancies or errors while conducting this inspection.

3.2 Weak Review of Material Condition Oil Leak

The inspectors noted that an oil leak had been identified with a maintenance work request written in February 1996 for the reactor core isolation cooling (RCIC) system; however, the obvious cause of the leak was not identified nor promptly addressed. On April 3, the inspectors observed that a gasket for the pump outboard bearing cover was deformed due to apparent over torquing. This caused the gasket to extrude out of the sealing area between the cover plate and the bearing housing. Holes cut in the gasket for the cover plate bolts were visible outside the cover plate. Along the top edge of the cover plate, the gasket appeared to be misaligned with little gasket material visible. The inboard bearing housing gasket appeared to be over torqued also.

The licensee determined that the leakage would not substantially increase and therefore the pump was considered operable. A RCIC outage was planned to install new gaskets however, on April 9, the plant tripped before the work could begin. A gasket made of thinner material was replaced during the forced outage using torque values to ensure proper crush.

The crushed area of the removed .125 inch thick Buna-N gasket clearly showed that the gasket had extruded to the point that no gasket material was present in the sealing area of two bolts; this resulted in the leak path. The licensee determined that the existing gasket was the proper part; however, the hardness of the gasket was not correct. The licensee could not determine if the gasket had been over torqued during installation or whether the bolts had been subsequently tightened in an attempt to stop the leakage. The previous work packages did not provide mechanics torque specifications.

The inspectors consider the failure to question the condition of the gasket and the operability of the RCIC pump to demonstrate a weak questioning attitude on the part of engineering. Additionally, the over-torquing of the bearing housing bolts to reduce the existing oil leak is considered a poor work practice.

3.3 Weak Engineering Review of Equipment Problem Following the Scram

Following the reactor scram on April 9, engineering was tasked with evaluating several issues associated with the event. In most cases, the engineering reviews were good. However, an evaluation of the rod control and information system (RC&IS) performance problems was not technically based. (The RC&IS problems were documented in inspection report 50-461/96004.) In their discussions with the licensee, the inspectors determined that the evaluation had been performed quickly to meet time constraints of completing the post trip review process. The licensee stated that expediency may have contributed to the overall poor quality of the evaluation.

The original evaluation indicated that a reduction in voltage caused the RC&IS system to change from quickly updating the core display information to a very slow update. Since the display system was digital and controlled by a clock, this explanation could not be justified. In addition, the evaluation was focused on the equipment itself and did not look at how the event progression affected the RC&IS. Specifically, the loss of power to the display was based on operator observation but did not agree with the actual transitions to the electrical system alignment during the event.

3.4 Inconsistent Initiation of Condition Reports for Equipment Concerns

During the inspection period, the inspectors identified that the initiation of condition reports (CRs) to document equipment deficiencies was inconsistent among plant engineering. Specifically, three feedwater transients occurred during the inspection period which were not documented in CRs.

The first two feedwater transients (on pump B) happened during the reactor startup as discussed in Section 1.2. In addition, reactor feed pump "A" experienced a transient on April 23, 1996. As part of the follow-up to the April 23 occurrence, the respective engineer documented his review of the transient in a report to the shift supervisor on April 26, 1996. Although the cause of the event was unable to be determined, the report was thorough and documented appropriate recommendations for troubleshooting the feed pump problem. As of May 8, 1996, it appeared that CRs had not been initiated to document any of the feed pump transients. The inspectors considered the initiation of a CR for these items to be essential to track the individual occurrences and trend any similarities (the third was similar to a transient in February 1995). It was also not apparent that the February 1995 was documented in a CR. This issue was discussed with engineering management and no other concerns were identified.

No violations or deviations were identified.

4.0 PLANT SUPPORT (71750, 82301, 83750 and 84750)

NRC inspection procedures (IP) 71750, 82301, 83750, and 84650 were used to perform an inspection of plant support activities. The licensee continued to experience communication problems regarding the implementation of radiation protection (RP) reengineering project initiatives which has resulted in some confusion among workers. Overall, the liquid and gaseous radwaste programs appeared to be effectively implemented. One weakness was identified concerning management oversight of the area and process radiation (AR/PR) monitoring system. The level of performance in emergency preparedness was considered excellent.

4.1 RADIATION PROTECTION

4.1.1 Poor Communication of RP Reengineering Project Initiatives

In discussions with the radiation protection manager (RPM) and radiation protection technicians (RPTs), the inspectors determined that the implementation of program improvements resulted in confusion among the RPTs. It appeared that these changes were not effectively communicated to the staff. Examples of these problems included:

- In 1994, the licensee changed the restricted (i.e., locked) high radiation area (RHRA) access policy to allow workers with electronic dosimetry (EDs) to enter these areas without RP coverage. However, not all RPTs were not aware of this change.

Additionally, local posting for RHRAs still required RP coverage before entry. In one case, an RPT who had observed a worker with an ED enter an RHRA without RP coverage, initiated a condition report thinking that the entry violated station procedures.

- The licensee recently implemented a reference point radiological survey program consisting of weekly surveys performed at designated reference points, with more detailed general area surveys performed every six weeks. However, a recent audit identified new areas of contamination that had been missed during the weekly surveys. The licensee determined that inadequate training was given to the RPTs concerning how to perform the reference point surveys, resulting in the contaminated areas being missed.

- The licensee changed their policy to allow lead RPTs to modify an RWP under certain circumstances to reflect changes in radiological conditions. However, many RPTs were confused about under which circumstances they were allowed to modify RWPs.

The inspectors discussed with the RPM the licensee's expectations for properly implementing program changes. The RPM subsequently issued written guidance clarifying the program changes. The inspectors verified that the program changes were consistent with industry practice and NRC requirements.

4.2 GASEOUS AND LIQUID RADIOACTIVE WASTE PROGRAM

4.2.1 Effluent Releases and Monitoring was Good

The activity of gaseous effluent released since 1994 has remained low, with about 3 curies released to date in 1996. The licensee continued implementing a policy of no routine liquid releases. The licensee had identified several minor typographical and reporting errors in the 1994 annual release report and planned to issue a corrected report.

The inspectors verified that doses associated with these gaseous releases were ALARA and below regulatory limits. The dose totals were calculated using the methodology described in the Offsite Dose Calculational Manual (ODCM). This methodology was reviewed by the inspectors via a confirmatory calculation; no problems were identified. Changes made to the ODCM were consistent with 10 CFR Part 20 and had been appropriately documented. The inspectors also reviewed the operation and maintenance of the post accident sampling system (PASS) and observed chemistry technicians collecting a sample; no problems were identified.

Initial and subsequent calibration, channel functional tests, and setpoint records of the effluent release monitors were reviewed. No significant problems were identified and the associated procedures were technically sound. During tours, the inspectors verified that effluent monitors were in good operating condition and that alarm setpoints were determined in accordance with the ODCM.

Through discussions with plant engineers (PEs) and the performance of plant tours, the inspectors verified that the liquid and gaseous radwaste processing systems were consistent with the UFSAR. All of the plant engineers interviewed were knowledgeable of their systems. Additionally, during their tours, the inspectors verified no unmonitored release pathways existed.

Overall, the liquid and gaseous radwaste programs appeared to be effectively implemented. No significant problems were identified in station audits of the gaseous and liquid radwaste programs.

4.2.2 Control Room Ventilation (VC) and Standby Gas Treatment (VG) Systems

The inspectors reviewed the VC and VG systems. During tours and discussions with the PEs, no operational problems were identified and the systems appeared consistent with the UFSAR. A review of performance and testing data did not identify any values exceeding technical specification (TS) criteria, but did identify a declining trend in the "B" VG and "B" VC charcoal filters penetration test results. This trend was recognized by the PEs.

4.2.3 Weaknesses in Management Oversight of the Area Radiation/Process Radiation (AR/PR) Control Console

The inspectors reviewed the status of the area radiation/process radiation (AR/PR) monitoring system, as described in the UFSAR. Although the AR/PR monitors were verified operable, some problems were identified with the control room console for the AR/PR system.

This console was one of two redundant, independent consoles (the other was at the RP access desk) which provided alarm and status indications for the AR/PR monitors and were intended to provide control room operators early indication of possible plant transients (per NUREG-0737 and regulatory guide (RG) 1.97). The licensee had disabled the control room console annunciator in 1991 owing to frequent, nuisance alarms which distracted the operators. These alarms resulted from any change in status (maintenance, surveillance, failure, etc.) of an individual monitor.

The 10 CFR part 50.59 safety evaluation report (SER), that was performed when the annunciator was disabled, concluded that it did not constitute an unreviewed safety question, because of the redundant RP console. However, this conclusion was based on RP continually manning this console and notifying control room operators of any actual change in plant conditions. The licensee also planned a revision to the UFSAR to reflect the disabling of the control room console. The inspectors reviewed the licensee SER against NUREG-0737 and RG 1.97; no problems were identified.

The inspectors verified that since the disabling of the control room console, the RP console had been continually manned and that operators were kept informed of plant conditions. They also identified that the UFSAR had not been completely revised nor was RP management aware of the SER requirements in a proposal to not continuously man the RP access area.

Management oversight of the AR/PR system appeared weak, specifically regarding the licensee's failure to revise the UFSAR and to recognize the requirements of the SER in the RP proposal. The licensee indicated that they would revise the UFSAR and that the RP area would remain continually manned.

4.3 Emergency Preparedness Exercise

An announced, daytime exercise of the licensee's emergency plan was conducted on April 24, 1996. The exercise scope was modified to utility-only, as State and local offsite agencies were responding to local severe weather damage. The exercise tested the capability to respond to a severe accident scenario with the potential for a large release of radioactive material. Exercise results demonstrated that onsite emergency plans were appropriate and the licensee was capable of implementing them.

4.3.1 Control Room Simulator (CRS)

Overall performance in the CRS was excellent. The operators responded well to simulated plant conditions and effectively controlled the various transients. Operator decorum was professional and "repeat backs" of important information were very effective.

Operator actions in responding to the simulated accident were appropriate. Abnormal and emergency operating procedures were used effectively. CRS personnel efficiently coordinated operation of equipment with the various site teams.

Communications with outside organizations and other station personnel were good and contained the appropriate information. The CRS shift supervisor declared appropriate Unusual Event and Alert emergency classifications within 15 minutes of the symptoms being displayed in the CRS. State, local, and NRC notifications were made in a timely manner and met NRC requirements. The CRS crew made plant announcements of declared emergency classifications and hazardous plant conditions in a timely manner. The announcements also provided the reasons why the emergency classifications were declared in an effort to update personnel of current plant conditions.

A formal declaration of the Notice of Unusual Event was made audibly in the CRS in order to keep the operators apprised of all plant conditions. In addition, the assistant shift supervisor frequently briefed the crew, providing updates on plant conditions and event mitigation strategy. While it was unclear that a briefing of the General Emergency declaration was held, the lack of a briefing had no impact on overall CRS performance.

4.3.2 Technical Support Center (TSC)

Overall TSC performance was very good. The facility was activated within thirty minutes following the Alert announcement. Transfer of command and control was effective and smoothly accomplished. Later transfer of control to the Emergency Operations Facility was also effective and smooth.

TSC members correctly identified and classified the Site Area Emergency and General Emergency entry conditions in a timely manner. Personnel were cognizant of field activities and changing plant conditions throughout the exercise and priorities were reconsidered as needed. Any changes were appropriately communicated to other personnel within the TSC.

Status and trending boards were kept current. A status board was well utilized to track and follow actions of in-plant teams. Changes in plant conditions were logged on the critical parameter status board. An "X" was used on the critical parameter status board to communicate "White Data" (unreliable information). A reformatted critical parameters board had been placed in the TSC since the last inspection (a matching board was also placed in the EOF). In addition, sound reduction material was added to reduce the amount of background noise present in the TSC. These modifications worked well.

4.3.3 Operations Support Center (OSC) and In-plant Teams

Overall, the performance in the OSC was good. Cooperation between departments was effective and response team communications contained the proper information needed to respond to the event.

The OSC was activated within approximately 30 minutes. The facility was rapidly set up and equipment was appropriately checked. Staffing of the facility was more than sufficient, with more than 50 persons participating.

The OSC Supervisor provided exceptional coordination and control of the facility. Team formation and priorities were well coordinated and effectively tracked on the status boards. Superior use of the available resources status board was observed.

Noise and congestion in the OSC were managed adequately. There was some congestion with persons continually moving back and forth from the management area through a narrow bottleneck to the briefing/debriefing area.

A lack of communications was identified in two areas. Facility briefings were infrequent in the OSC, and TSC briefings were not heard in the OSC. However, OSC response team briefings and debriefings were effective. CRS, TSC, and OSC communications were not adequately coordinated for directing OSC response team #13. The team was directed to close the reserve auxiliary transformer 4160 volt feed by the CRS (normally teams are controlled by the OSC). This was not known to OSC personnel until the team reported (via telephone) to the OSC. This was the only instance where inadequate coordination was observed.

Communications with the OSC and CRS by response team #13 were exemplary. The team's electricians verified by phone and radio their directions each time they were redirected to perform additional tasks. Additionally, the team maintained good awareness of potential radiological conditions while performing activities both inside and outside the plant. The team Radiation Protection (RP) technician called the OSC for plant radiation levels and appropriate routes to reach assigned work areas. Dose levels and optimal low dose routes were considered.

4.3.4 Emergency Operations Facility (EOF)

The EOF was declared operational after the Site Area Emergency declaration. The facility activation procedure was observed to be effectively used during activation. Procedures and checklists were extensively utilized throughout the exercise.

Overall performance in the EOF was exemplary. Following EOF activation, the Emergency Manager and members of his staff functioned effectively as a team in terms of internal and external communications. In addition, the engineering group performed detailed reviews of methods to restore electrical busses and reduce hydrogen buildup in order to mitigate the event.

Status boards were very well maintained. An emergency planning zone map indicated the protective action recommendation provided to the State. As plant conditions worsened and fission products accumulated in the containment, protective actions were properly upgraded to the maximum provided in procedures. The decision to start manning the backup EOF when scenario conditions threatened EOF habitability was also considered positive.

Dose assessment and field team coordination activities were performed in a very effective manner. Numerous dose assessments were performed prior to the release of radioactive materials in order to anticipate release consequences.

A simulated NRC team of four individuals participated in the EOF, portraying the roles of an onsite team. The simulation of an NRC team made the scenario more realistic and was considered a positive attribute. The simulated NRC team was properly briefed on arrival.

4.3.5 Exercise Control and Critiques

The scenario was sufficiently challenging, and was designed to support offsite exercise objectives. A sufficient number of personnel were available to control the exercise. No significant examples of drill observers prompting participants to initiate actions were identified. The inspectors attended critiques in each of the licensee's facilities and found that the critiques were performed in an acceptable manner. The licensee's self-evaluation of the exercise closely matched that of the inspectors.

No violations or deviations were identified.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

5.1 Corrective Action Program for Human Performance

NRC Inspection Procedures 92720 and 40500 were used to evaluate the licensee's activities related to the identification and resolution of human performance related events. The licensee's effectiveness to fully evaluate human performance issues was weak. For example, the inspectors found that many personnel were reluctant to report human performance related concerns. Root cause analyses were often inadequate in depth and scope. Corrective actions were not always developed for the human performance issues identified and were frequently limited to the immediate personnel or program involved in the event investigated. Lastly, trending activities did not effectively support the licensee's ability to determine if corrective actions had been successful. Collectively these weaknesses caused the licensee to be vulnerable to a failure to identify and effectively address adverse trends in human performance.

5.1.1 Problem Identification

Knowledge of the condition report (CR) process as a means of reporting problems was good. Every individual that the inspectors interviewed was aware of the CR process and most had used the process at least once. Most of the interviewees were comfortable writing CRs for equipment deficiencies. In contrast, many operators and technicians expressed some reluctance to write a CR which discussed human performance problems because it may negatively reflect on an individual or group.

Many members of the plant staff held the opinion that personnel errors would generally result in a CR because such errors tended to be self-revealing. While many CRs were written for these types of events, the inspectors were concerned that the reluctance demonstrated by members of the staff may result in CRs not being written to identify non-consequential, near-miss events. In addition, work practices and conditions that are known precursors to significant events may not be identified. The inspectors did not identify any specific instances of a failure to report conditions due a reluctance to use the CR process. However, the failure to write CRs for such conditions may result in the loss of predictive indicators for human performance problems and thereby impair CPS's human performance trending capabilities.

Other plant staff felt as though it was often quicker and easier to resolve issues outside of the CR process. By solving problems within the respective department, rather than writing a CR, the ability to identify issues that crossed organizational boundaries was diminished. The lessons learned from such intra-departmental initiatives were often not communicated to other departments on site. Because a CR was not written, the means of monitoring the implementation and effectiveness of the corrective actions was also affected. The ability to trend these deficiencies was also lost.

The reluctance of some plant staff to write CRs was previously identified in Nuclear Assessment Audit Report Q38-95-04. Given the results of interviews conducted during this inspection, it was concluded that this issue was not yet fully resolved.

5.1.2 Root Cause Assessments

A number of CR packages were reviewed to determine the effectiveness of the respective root cause assessments (RCAs). The inspectors found that a lack of clear expectations and minimum standards for performing RCAs did not exist. A lack of refresher training contributed to inconsistent implementation of formal root cause analysis tools. Because of this, the depth of many RCAs was often inadequate. Many RCAs did not identify potential contributors to the event and the consideration of similar events was often omitted. In addition, RCAs often were not documented in a manner which allowed the Corrective Action Review Board (CARB) to independently assess the adequacy of the analyses. Collectively, these weaknesses impacted the licensee's ability to perform RCAs which consistently identify the root causes of reported conditions or events.

To aid in determining the level of analysis needed when performing RCAs, CPS 1016.01 refers to the "CPS Help Guide To Root Cause Analysis." However, the procedure itself does not set minimum standards for conducting RCAs. The inspectors determined from interviews that the personnel performing RCAs were aware of the CPS guidance for performing RCAs, but there was little evidence that they actively implemented the outlined techniques when performing RCAs. A lack of refresher training, and inconsistent levels of initial training, also contributed to the varied levels of analysis for many root cause evaluations.

The CARB also appeared to send mixed signals as to what level of analysis was expected for RCAs. Various members of the CARB, and personnel responsible for performing RCAs, indicated that root cause analysis implied a rigorous assessment that would typically require 15-40 hours. However, the CARB did not always require that level of analysis despite assigning a root cause assessment. Although a less in-depth assessment may have been appropriate for many cases the level of analysis necessary was not clearly communicated to the evaluators. As a result, some evaluators appeared to be determining the level of effort to apply to assessments independent of the CARB's direction.

Unclear expectations for RCAs also affected the work of the CARB. Because the level of analysis was not clearly communicated, many RCAs were rejected by the CARB or returned to the evaluator for additional information. The inspectors evaluation of RCAs also determined that many analyses were often not documented in a manner that would allow the

CARB, or other members of the staff, to verify that the depth and scope of the analysis was adequate. For example, information concerning the RCA methods used to perform the assessment and the bases for root cause determinations were seldom included in responses to CRs. The inspectors were concerned that this lack of information within RCAs may result in the CARB being unable to identify CRs that receive a less in-depth analysis than the CARB originally intended.

The assessment of contributing causes and the consideration of similar events or trends were common weaknesses in the RCAs evaluated. Two CRs reviewed during the inspection concerned the failure to initiate a CR for conditions that the Nuclear Assessment Department (NAD) considered adverse to quality. A review of the RCAs for these CRs determined that the evaluator failed to directly address why the personnel involved did not write a CR. Similarly, CR 1-96-01-021 was written to document a lack of sensitivity to verifying the certification of personnel qualified to perform surveillance on the area radiation/process radiation monitors. However, the RCA did not address the reasons behind this apparent lack of sensitivity. By not addressing these types of issues, the inspectors were concerned that information important to the development of effective corrective actions may be lost.

5.1.3 Corrective Actions

Corrective actions for CRs were evaluated to determine their overall effectiveness. While most corrective actions generally addressed the major root causes, the root cause/corrective action process was weak in specifying corrective actions for contributing or causal factors. Those actions pertinent to personnel errors were commonly limited to the individual involved with the issue and rarely addressed any broader human performance implications; this limited scope addressed the individual problem but failed to correct the system which allowed the failure to occur.

Special efforts to correct deficiencies identified as trends were limited. An example of one effort was the recently completed corrective action plan related to safety tagging. The corrective actions from this plan had a broad generic view but also concluded that there was no reason to expect that the problems have all been resolved from a generic perspective. There was also a lack of measures of success (in terms of objectives and evaluation criteria) for CRs that covered several issues or those that represented trends. It appeared the measure of success was based more on timeliness rather than the contents of the response.

Communications of specific CR corrective actions to working level personnel was adequate. It was also noted that responsibilities, proposed corrective actions, and action dates were clearly assigned.

5.1.4 Trending

The licensee's current trending program does not effectively support the ability to trend the causes of human performance problems. The knowledge of the trending program (by CARB and the staff) was also lacking which made it difficult for members of these groups to fully utilize previous trending information.

The trending program system administrator assigned both a problem code and a cause code to each CR. Problem codes were used to provide information concerning the problem described in the CR; Cause codes were used to differentiate each RCA into one of 19 categories. The inspectors thoroughly reviewed the licensee's use of cause codes and were concerned that the current trending program only allowed one cause code for each CR. A portion of the CRs reviewed during the inspection identified either multiple root causes or one root cause and many contributing causes. Because of the current trending program configuration, the system administrator had to judge which cause was most important and then assign the respective cause code. Other root cause information was lost unless the system administrator entered appropriate words in the additional remarks section. Since the licensee was unable to assign cause codes for the supplementary causes this information was not available for trending purposes.

"Work practice" was frequently used as a cause code in the CRs evaluated by the inspectors. However, more specific cause codes which may have explained why work practice problems contributed to the event were not assigned as codes even though they were available. The initiation of a broad cause code versus a more specific code created the potential to mask human performance issues in other areas such as "procedures," "communications," or "supervisory methods."

Some CARB members and root cause evaluators were unfamiliar with the methodologies used in the trending program. Recently, when new CRs were provided to the CARB, and to the root cause evaluators, a list of similar event CRs was attached to assist in identifying adverse trends. However, the listing did not identify the sort criteria used to generate the list. Consequently, it was difficult for the users of this information to determine if the list of related CRs adequately addresses the scope of the RCA. The lack of familiarity with the trending program among root cause evaluators contributed to root causes being written in a manner such that they could not be coded consistently and reliably.

Some of the individuals interviewed expressed continued uncertainty with respect to the threshold for reporting problems. The licensee's Corrective Action Trend Analysis Report for 1995 suggested that an increase in fourth quarter CRs could have been attributed to renewed management emphasis on a low reporting threshold. The inspectors were concerned that variations in CR initiation that occur with intermittent emphasis on reporting threshold may obscure actual trends and adversely affect the ability of CPS personnel to detect these trends.

The concerns described above were discussed with the trending program system administrator. The licensee was evaluating the possible use of multiple cause codes at the conclusion of the inspection.

5.1.5 **Observation of CARB Meeting**

During the CARB meeting on April 11, 1996, six CRs that concerned a reactor scram on April 9, 1996, were reviewed. While the CRs addressed several specific hardware or technical specification related concerns, none specifically addressed the human performance problems that initiated the event (switchyard maintenance). The inspectors later determined that the licensee was addressing the human performance concerns as part of CR 96-04-019, "Notification of Unusual Event." Although the inspectors understood that actions were initiated to evaluate specific human performance issues, the failure to identify the human performance concerns in a CR will result in inadequate management attention to the human performance issues. The development of lessons learned and the effective tracking of any potential corrective actions will also be compromised since only one cause code will be assigned to track this CR.

The CARB exhibited a questioning attitude concerning the CRs discussed at the April 11, 1996, meeting. However, the review of CR 1-96-02-078 illustrated weaknesses throughout the corrective action program, and in particular, was an example of a failure of the CARB to substantively address the relationship between personnel perceptions, problem reporting, and plant management policies as identified in the CR.

The inspectors reviewed CR 1-96-02-078, "OCA Maintenance Injury Trend," and identified three specific issues:

-There was a reluctance to report problems since the accident investigation process was perceived as a process where people are singled out for blame.

-Interviews performed as part of the CR review indicated a belief that the management policy on site goals contributed to the failure to report the accidents.

-The root cause investigation failed to address the above perceptions and beliefs. Also, the basis explaining why corrective actions were not needed was omitted.

The CARB failed to discuss the information concerning the personnel perceptions and beliefs that were potential contributors to the failure to report injuries. As a result the CARB failed to address why this information was not adequately addressed in the RCA and corrective actions and missed an opportunity to identify information which may have warranted additional CPS management attention.

6.0 REVIEW OF UFSAR COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

6.1 Review of Spent Fuel Pool Practices and Current Licensing Basis

As part of the NRCs follow-up actions to generic concerns associated with the design and operation of spent fuel pools, the inspectors reviewed the design and licensing basis for the spent fuel storage pool at the Clinton Power Station (CPS). A review of licensing documents was performed in order to identify the current licensing basis along with any operating restrictions and limitations. The inspectors also examined surveillance procedures, administrative procedures, and system operating procedures to ensure that specific technical specification requirements and other pertinent aspects of the licensing basis were appropriately controlled.

No apparent discrepancies between the licensing basis as described in the UFSAR and current CPS practices were identified. Procedures appeared to be in place to ensure compliance with the current licensing basis requirements and commitments. The inspectors noted that, although not required by procedure, a cycle-specific heat load calculation for the spent fuel pool was performed for each refueling outage in order to ensure that fuel pool heat loads did not exceed the USAR limits. The inspectors reviewed these calculations and no concerns were identified.

7.0 PERSONS CONTACTED AND MANAGEMENT MEETINGS

7.1 Management Meeting Held To Discuss Reactor Scram Event

Clinton Power Station management visited Region III management on May 6, 1996. The purpose of the meeting was to discuss the root causes and corrective actions associated with a reactor scram which occurred on April 9, 1996. Details of the reactor scram event were discussed in Inspection Report 50-461/96004.

7.2 Exit Meeting

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on May 10, 1996, the inspectors met with licensee representatives (denoted below) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

W. Connell, Vice President
R. Morgenstern, Manager - Clinton Power Station
D. Thompson, Manager - Nuclear Station Engineering Department
J. Palchak, Manager - Nuclear Training and Support

M. Lyon, Director - Licensing
D. Morris, Director - Radiation Protection
A. Mueller, Director - Plant Maintenance
K. Moore, Director - Plant Operations
M. Stickney, Supervisor - Regulatory Interface