U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	50-461/99010(DRP)
Licensee:	Illinois Power Company
Facility:	Clinton Power Station
Location:	Route 54 West Clinton, IL 61727
Dates:	April 22 - June 10, 1999
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EXECUTIVE SUMMARY

Clinton Power Station
NRC Inspection Report 50-461/99010(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support related to restart activities during the transition from Mode 4 to 100 percent power operations. The report covers a 7-week period of inspection.

Operations

- Plant operators methodically and cautiously conducted plant restart activities and, in most cases, exhibited conservative decision-making when challenging situations were encountered. For example, operators manually scrammed the plant after a startup feedwater flow control valve malfunctioned and stopped their approach to criticality when unusual reactor period readings were observed (Sections O1.14 and O1.15).

- While overall operator performance during the plant restart was acceptable, NRC inspectors identified several instances where plant management's expectations for the conduct of operations were not clearly understood by all operators, occasions where suspect plant conditions were either not recognized or were not thoroughly evaluated by the operators, and instances where procedural requirements were not followed (Sections O1.2, O1.5, O1.10, and M1.2).

- The inspectors determined that management expectations for documenting unexpected annunciators were vague and not completely understood by operations personnel (Section O1.5).

- The failure of operators to recognize that conditions existed which required entry into Technical Specification (TS) limiting condition for operations on three occasions was indicative of the need to improve operators' knowledge of TS requirements. One Non-Cited Violation with three examples was identified associated with this issue (Section O1.9).

- The inspectors determined that operations personnel did not understand management expectations for control room supervisor oversight during changes in reactivity (Section O1.10).

- The inspectors determined that operations personnel exhibited a conservative safety focus in deciding to insert the control rods following an unexplained period indication. However, engineering support to operations was poor during this event in that the abnormal period meter indications were not explained and the fact that the reactor was critical was either not recognized or not effectively communicated to the operators (Section O1.14).

- Operators reacted well to challenges encountered during the failure of valve 1FW004 on two occasions. However, the licensee did not identify and correct the root causes of the first valve failure which resulted in an unnecessary challenge to operators during restart activities when the valve failed a second time. This was indicative of a need to improve the effectiveness of the corrective action program (Section O1.15).

- The inspectors identified one Non-Cited Violation for the failure to implement a tagout while administratively controlling TS equipment (Section M1.2).

Maintenance

- The inspectors determined that maintenance activities conducted by the Fix-It-Now (FIN) team continued to unnecessarily challenge main control room operators in that FIN team personnel started two work activities without first notifying operations personnel, and the work activities caused unexpected annunciators to alarm in the main control room. Inspector prompting was necessary to ensure FIN team-related human performance deficiencies were entered into the corrective action program (Section O1.6).

- The licensee encountered problems during plant restart activities with source range monitor (SRM) surveillance tests, SRM channel checks, SRM calibrations, SRM and intermediate range monitor overlap, and intermediate range monitor correlation. Based on these issues, the inspectors concluded that improvements were needed in the licensee's nuclear instrument surveillance and calibration programs (Section M1.2).

- The inspectors identified one Non-Cited Violation for the failure to conduct a 20-minute maintenance run on the reactor core isolation cooling system turbine at greater than 1500 revolutions per minute as required by the licensee's procedure (Section M1.3).

- The inspectors determined that a violation occurred involving an inadequate procedure for establishing the proper air gap on the motor bearing for shutdown service water Pump 1SX01PB. The licensee appropriately identified the cause of the failure and implemented corrective actions which should preclude recurrence. The violation was not cited (Section M1.4).

- During turbine testing, inspector prompting was necessary to ensure that operations personnel did not proceed until lamp test results were understood, that prerequisites were completed, and that acceptance criteria were met (Section M1.5).

Engineering

- Following the inspectors' questions, reactor engineers decided to revise an estimated critical position calculation (ECP) to account for an approximate 75 degree reduction in moderator temperature from the value used in the original calculation. The inspectors determined that the applicable procedure was vague in that it did not clearly state what a significant moderator temperature change was and, in turn, when a new ECP calculation was required (Section E1.1).

- Engineering personnel generally provided sufficient information to demonstrate compliance with TS surveillance test requirements. However, the information provided as part of an engineering operability evaluation for the jet pump, which was accepted by operators, was not sufficient to support the operability determination. This indicated a need for improvement in engineering personnel's rigor in performing operability evaluations and in operator's questioning attitude (Section E1.2).

- The failure of engineering personnel to provide timely and/or adequate resolution of several technical issues encountered during plant restart activities unnecessarily challenged operations personnel and indicated that engineering staff support to operations needed to be improved (Section E4.1).

Report Details

Summary of Plant Status

The licensee transitioned from Mode 4 to Mode 1 operations during the inspection period. Mode 2 was initially entered on May 2, 1999. Mode 1 was entered on May 25. The main generator was synchronized to the grid on May 27. On June 3rd, 100 percent power was achieved. Major equipment issues which delayed plant restart involved bearing damage on the Division II shutdown service water (SX) pump, rod control and information system (RC&IS) deficiencies, fluctuating reactor period indications, source range monitor (SRM) and intermediate range monitor (IRM) calibration adjustments, reactor core isolation cooling (RCIC) system control problems, RCIC differential pressure concerns, a manual reactor scram on May 14 due to feedwater oscillations, and a plant shutdown on May 19 following additional feedwater oscillations.

I. Operations

01 Conduct of Operations

The inspectors provided near continuous monitoring of main control room (MCR) activities between April 24 and May 27, 1999. The inspectors continuously observed evolutions conducted before the initial plant start-up from the extended outage, three subsequent plant shutdown and startup evolutions, and activities as plant power was increased to approximately 30 percent. The inspectors also observed selected plant evolutions between 30 and 100 percent power.

The inspectors observed all or portions of activities conducted in accordance with the following procedures:

Procedure 1401.00, "Conduct of Operations"
Procedure 3001.01, "Preparation for Startup and Approach to Critical"
Procedure 3002.01, "Heatup and Pressurization"
Procedure 3004.01, "Turbine Startup and Synchronization"
Procedure 3006.01, "Unit Shutdown"

Plant operators methodically and cautiously conducted plant restart activities and, in most cases, exhibited conservative decision-making when challenging situations were encountered. For example, operators manually scrammed the plant after a startup feedwater flow control valve malfunctioned and stopped their approach to criticality when unusual reactor period readings were observed.

While overall operator performance during the plant restart was acceptable, NRC inspectors identified several instances where plant management's expectations for the conduct of operations were not clearly understood by all operators, occasions where suspect plant conditions were either not recognized or were not thoroughly evaluated by the operators, and instances where procedural requirements were not followed. Specific activities observed are described below.

O1.1 Operator Response to Main Control Room Annunciators

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed operations personnel respond to MCR annunciators.

b. Observations and Findings

The inspectors observed that operations personnel appropriately responded to plant annunciators. Alarming conditions were acknowledged in a timely manner and effectively communicated to MCR personnel. The appropriate annunciator response procedure was referenced following each annunciation of a MCR alarm. Nevertheless, three exceptions to the normal operational practices were observed.

- On April 26, the inspectors observed the annunciation of a trouble alarm on local panel 1PL022J. Operations personnel appropriately dispatched chemistry personnel to assess the alarming condition. After approximately 30 minutes, the trouble alarm cleared; however, a report was not made to the MCR regarding the reasons for the alarming condition or the actions taken to restore the condition to normal. The inspectors questioned the control room supervisor (CRS) 30 minutes after the alarm had cleared to determine what actions were taken to address the alarming condition. The CRS stated that a report had not been made to the MCR. The inspectors again questioned operations personnel 30 minutes after the initial question to determine why the alarm had cleared. Operations personnel again stated that no report had been made to the MCR. At the second prompting by the inspectors, operations personnel contacted chemistry personnel and determined the cause of the initial alarming condition and the actions taken to restore the discrepant condition to normal.

- On April 29, the inspectors observed that the CRS allowed a fission product monitor alarm to remain flashing. The CRS had determined that due to plant conditions, the fission product monitor repeatedly alarmed causing a distraction for MCR personnel. Because of the distraction, the CRS authorized the reactor operators (ROs) to leave the annunciator flashing. The inspectors determined that the plant mode of operation did not require the fission product monitor to be operable.

  The inspectors reviewed Procedure 1401.15, "Alarm and Transient Response," and determined that nuisance alarms were to be tracked in accordance with Procedure 1406.01, "Annunciator Tracking Program." Procedure 1406.01 specified that annunciators which are a distraction to operations personnel and provide no meaningful data may be disabled. The inspectors determined that operations personnel had not disabled the fission product monitor alarm. After discussing the concern with the inspectors, operations personnel determined that the fission product monitor alarm should have been disabled and the status of the alarm tracked in the annunciator out-of-service program. Following the inspectors observation, operations personnel improved the control and tracking of annunciators that caused nuisance alarms.

- On May 4, the reactor recirculation (RR) flow control valve, hydraulic equipment redundant subloop inoperable annunciator alarmed in the MCR. Because of a pre-existing condition, the annunciator window did not flash which resulted in a delay in operations personnel being able to identify the alarming condition. The inspectors questioned work management personnel on the status of correcting the deficiency. Work management personnel responded that the licensee was below the goal for MCR deficiencies and the discrepancy would be repaired within the allowed time frame for correcting a MCR deficiency. The inspectors observed that the inoperable flashing annunciator window had introduced an unnecessary operator challenge. Following a discussion with operations personnel, the shift manager (SM) contacted the Fix-It-Now (FIN) team and the discrepancy was corrected on May 6.

c. Conclusions

Operators generally responded in accordance with procedures to alarming MCR annunciators.

O1.2 Operator Awareness and Response to Main Control Room Indications

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed operations personnel monitor MCR indications.

b. Observations and Findings

Main control room personnel typically recognized or were aware of degraded plant indications. When questioned by the inspectors, operations personnel were normally knowledgeable of the reasons and corrective actions for suspect parameters being monitored from the MCR. The inspectors observed operations personnel conduct several MCR panel walkdowns each shift. Discrepant indications were identified and promptly entered into the corrective action program. Nevertheless, several exceptions to the normal operational practices were observed.

- On April 26, 1999, the D area non-licensed operator (NLO) reported that oil from the seal oil vacuum pump had spilled onto the floor. Operations personnel secured the pump and checked the annunciator response procedure for guidance; however, they did not observe that the MCR indication for hydrogen was off scale high until prompted by the shift monitor.

- On April 27, the inspectors observed that the Volts-amps-reactive (VAR) meter for the reserve auxiliary transformer (RAT) static VAR compensator (SVC) and the VAR meter for the emergency reserve auxiliary transformer (ERAT) SVC provided different displays for similar conditions. Although both meters were identical and displayed from -30 to +30 on a vertical scale with 0 at the mid point, the indicating bar for the RAT SVC extended up from the bottom (or -30) while the indicating bar for the ERAT SVC extended up or down from 0. The inspectors determined that the two meters had been set-up differently during installation and calibration.

  Based on discussions with the ROs and the SM, the inspectors identified general knowledge weakness regarding how the meters functioned. The inspectors discussed the condition with the Director of Operations who acknowledged the error in the meter displays. An action request was written to correct the RAT SVC meter display. Additionally, condition report (CR) 1-99-04-368 was written to address the adequacy of operator training on the SVC modification instrumentation, the training for any other modifications that had been installed, and the indications for the RAT and ERAT VAR meters on the MCR simulator.

- On May 13, the A RO questioned the B RO on the status of a flashing fire protection annunciator. The B RO did not know that a fire protection surveillance had been completed 45 minutes earlier and that the flashing annunciator could be reset.

- On May 25, the inspectors observed a turbine oil lift pump switch in the pull-to-lock (PTL) position. When the inspectors inquired about the switch position, the SM did not know why the turbine lift pump was in PTL with the turbine running at 1800 rpm. The SM stated that the pump had probably been in PTL before the turbine was spun to prevent the turbine from coming off the jacking gear. However, the SM did not take any actions to direct the CRS to determine why the switch was out-of-position and correct the switch position. Following shift turnover, a crew briefing, and panel walkdowns, the B RO identified the out-of-position turbine lift pump switch and placed the switch in the proper position for the plant condition.

- On May 26, the inspectors observed that both of the control room differential pressure indications were pegged high and that the makeup flow for the non-operating train of control room ventilation was indicating approximately 800 standard-cubic-feet-per-minute. The inspectors discussed the indications with the on-shift ROs and the CRS and were informed that an action request had been written for the makeup flow indication. None of the MCR operators were knowledgeable about the differential pressure indications. In response to the inspectors' question, the ROs contacted the system manager and learned that the indication was normal. The system engineer also stated that an engineering change notice was being processed to change the indicator face such that normal operation of the control room ventilation system will not result in a pegged indication.

- On June 2, the inspectors observed that the Division I secondary containment differential pressure indication was reading downscale and did not appear to be responding. The inspectors questioned the CRS about the indication. The CRS was initially unaware of the indication even though he had just completed a panel walkdown with the oncoming CRS. After questioning by the inspectors, the CRS initiated an action request to correct the indication.

c. <u>Conclusions</u>

The inspectors concluded that operators' recognition and questioning of suspect indications had improved from the performance previously observed in this area. However, the several instances where operators either did not recognize or question suspect indications which were identified by the inspectors is indicative of the need to further improve performance in this area.

O1.3 Conduct of Main Control Room Briefings

The inspectors observed that briefings for plant evolutions were of good quality in that they included a discussion of the expected plant response, assignments, industry experience, and mitigating actions for potential but not expected events. On occasion, briefings commenced without the full MCR personnel compliment being present. Specifically, on May 12, personnel involved in RCIC testing arrived late, on May 16, a senior management representative or shift monitor was not present for the day shift brief for a reactor start-up, and on May 19, a shutdown brief was commenced without the SM's presence.

O1.4 Communications Within the Main Control Room and between the Main Control Room and Field Operators

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed the communications within the MCR and between the MCR and field operators.

b. Observations and Findings

In general, the inspectors observed frequent and proper use of three-way communication techniques during face-to-face discussions in the MCR. However, the inspectors observed several instances of communications within the MCR that were vague and lacked specificity. For example, operations personnel used phrases such as; "I'll give you a tweak," "You'll give me a tweak," "Correct" --- "We're going to need to adjust it," "Aye" --- "Another low flow steam test," No acknowledgment --- "Check that out," No acknowledgment --- "I'm going to bump the valve again," "Bumping the valve."

Early in the inspection period, the inspectors determined that operations personnel frequently did not use three-way communication techniques when directing activities outside the MCR. The inspectors determined that the use of three-way communications in directing field operators improved following discussions with the inspectors during the first and second week of the inspection.

On April 27, the inspectors observed personnel in the MCR shouting into the sound powered phone headset in order for personnel in the emergency diesel generator (EDG) space to hear directions. The inspectors determined that the shouting in the at-the-control area of the MCR created a distraction to operations personnel. In response to the observation, the licensee provided a copy of CR 1-98-07-159, dated July 14, 1998, which identified that non-qualified sound powered headsets were being used in the EDG rooms. The corrective actions described in CR 1-98-07-159 consisted of determining the correct sound powered headset for the EDG spaces and submitting a request for purchase. As of May 5, 1999, the licensee had not initiated a purchase order to procure appropriate sound power phone headsets for the EDG spaces. On May 6, operations personnel approved the purchase order for the appropriate sound powered phone headsets.

c. Conclusions

In general, operators effectively communicated among themselves and while directing field activities during the plant restart activities.

O1.5 Log Keeping

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed operations personnel maintain records of plant activities.

b. Observations and Findings

The MCR journal typically described activities which occurred during each shift. The inspectors determined that Procedure 1401.05, "Operator Logs and Records," did not provide guidance on documenting alarming annunciators. However, Section 8.2.1.4 of Procedure 1401.15, "Alarm and Transient Response," required operations personnel to log significant annunciators and actions taken in response to the alarming conditions. The inspectors questioned operations personnel to determine which annunciators were considered significant. In response, some operations personnel stated that any unexpected annunciator was significant and should be documented in the MCR journal, while other operations personnel stated that they were unaware of any expectation to document unexpected annunciators in the MCR journal.

The inspectors observed that on three occasions, operations personnel did not document unexpected annunciators in the MCR journal. Specifically, on May 5, the inspectors observed that the RAT SVC trouble alarm annunciated following the start of condensate booster pump A, but the alarm was not documented in the MCR journal. On May 13, the licensee informed the inspectors that action requests (ARs) F01172 and F01173 had been initiated on April 30, 1999, to correct spurious thyristor alarms on the RAT and ERAT SVCs. The inspectors also questioned if the main control room deficiency (MCRD) list referenced ARs F01172 and F01173. On May 13, 1999, the licensee informed the inspectors that the ARs would be added to the MCRD list. On May 8, three EDG ventilation trouble alarms unexpectedly annunciated and were not recorded in the MCR journal. On May 13, 1999, the glycol tank low alarm annunciated and was not recorded in the MCR journal. Plant management stated that these alarms were not considered significant and that, while plant procedures did not specifically require that unexpected alarms be recorded in the MCR journal, the operators did not meet their expectation to record unexpected alarms in the journal. Management further stated that an initiative to determine how best to communicate their expectations to operators was being pursued.

c. Conclusions

The inspectors determined that management expectations for documenting unexpected annunciators were vague and not completely understood by operations personnel.

O1.6 Impact of Plant Activities on Operational Activities within the Main Control Room

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed the impact of plant activities on operational activities within the MCR.

b. Observations and Findings

Previous issues concerning the impact of FIN team activities on operations personnel have been documented in NRC Inspection Reports 50-461/99005 and 50-461/99011. During this inspection, operations personnel were normally aware of plant activities with the potential to impact MCR activities. However, three noteworthy examples of operators being unaware of FIN team activities during the plant restart activities were noted.

- On April 26, 1999, electrical maintenance personnel were unable to re-close generator output breaker 4506. It was identified during a subsequent review by operations personnel that a generator back-feed lineup had resulted in the deenergization of the generator synch check relays which provided the close permissive to the main generator output breaker. The inspectors determined that the licensee did not initiate a CR for the event. On April 27, the inspectors discussed the issue with operations management. Following the discussion, operations personnel initiated CR 1-99-04-375. Additionally, Procedure 3501.01C001, "Generator Backfeed Checklist," was revised to include a step to prepare and place a caution tag on the MCR generator output breaker switches when a generator back-feed lineup is used. Operations personnel were also briefed on the need to initiate CRs following the identification of unexpected plant conditions.

- On May 10, the inspectors observed operations personnel respond to unexpected filter demineralizer trouble alarm 5000-2C. The CRS informed the inspectors that FIN personnel had started a maintenance activity on the filter demineralizers and had not informed the MCR that the work had resumed. The CRS stated that he had communicated to the FIN team senior reactor operator (SRO) the need to ensure that MCR personnel were kept appraised of maintenance activities. The inspectors questioned the CRS to determine if a CR or behavioral observation document would be initiated to trend the deficiency. The CRS stated that a document would be initiated if the problem occurred again. When questioned by the inspectors on the frequency of unexpected annunciators caused by FIN team personnel, the CRS stated that FIN team personnel had caused an unexpected annunciator the previous day during a maintenance activity. The inspectors discussed the lack of trending information with operations management. In response to the discussion, operations personnel initiated CR 1-99-05-101 to provide trend data relative to the performance of FIN team personnel.

- On May 16, FIN team personnel entered the switchyard which caused an unexpected alarm in the MCR. Operations personnel subsequently determined that FIN team personnel had received permission from the FIN team SRO to enter the switchyard to replace a gaitronics speaker without notifying the MCR.

This is of concern since personnel entered the switchyard area without adhering to warning signs which require MCR notification. The inspectors questioned the CRS and SM to determine if a CR was going to be initiated. Initially, operations personnel responded by stating that the issue had been discussed with the FIN team SRO. Subsequent to the inspectors questioning, on May 19, operations personnel ensured that the FIN team initiated CR 1-99-05-166 to review and trend deficiencies in FIN team performance.

c. Conclusions

The inspectors determined that, while there was improvement in operators' awareness of FIN team activities, the occasional lack of coordination of FIN team activities with MCR personnel continued to present an unnecessary challenge to operations personnel.

O1.7 Professional Atmosphere in the Main Control Room

The inspectors observed that operations personnel generally effectively restricted MCR access to minimize distractions during plant restart activities. For example, during control rod withdrawals, the licensee staged an additional person outside the MCR to restrict access. Additionally, signs were posted outside the MCR to require personnel to discuss MCR business with the work control supervisor before entering the MCR. The inspectors also observed the CRS request that personnel cease potentially distracting conversations within the at-the-controls area of the MCR and resume them elsewhere. However, the inspectors observed that off-shift operations personnel routinely entered the MCR without the permission of the CRS during plant transients. For example, following a trip of reactor water cleanup (RT) pump B, several operations personnel proceeded directly to the at-the-controls area of the MCR without the CRS having requested their assistance. In this instance, the CRS directed an extra RO to suspend RCIC testing which was in progress when the pump tripped, but did not suspend other distracting evolutions during the same period. As a result, alarms associated with off-gas panel maintenance activities unnecessarily distracted the operators as they attempted to diagnose and assess why the RT pump had tripped. The inspectors concluded that improvement was made in reducing operator distractions but that distractions occurred which could have been avoided during the restart activities.

O1.8 Shift and Relief Turnovers

a. Inspection Scope (71707, 71711, 71715)

The inspectors observed operations personnel conduct shift and relief turnovers.

b. Observations and Findings

The inspectors observed that operators involved in shift and relief turnovers communicated the appropriate amount of information before completing the turnover process. The inspectors observed frequent discussions between operations personnel on the status of plant equipment.

The inspectors observed management personnel re-enforce expectations during shift turnover meetings. Specifically, operations personnel were prompted to discuss abnormal system status as plant conditions changed. The inspectors observed improvement in turnover briefs following the re-enforcement of expectations. However, the inspectors had the following observations.

- On May 1, 1999, operations personnel identified that the "A" RR pump lower thrust bearing temperature was higher than the upper thrust bearing temperature during an evolution governed by Procedure 9000.01D001, "Control Room Surveillance Log-Mode 1, 2, and 3." Operations personnel reviewed Step 4.8 of Procedure 3302.01, "Reactor Recirculation," and determined that the high lower bearing temperature was possibly due to a dropped upper wear ring. Engineering personnel were contacted for assistance as directed by Procedure 3302.01.

  On May 2, another operations crew identified that the thrust bearing temperatures on the "A" RR pump were indicative of a dropped wear ring. Operations personnel contacted the engineering department for further evaluation and were informed that the "A" RR pump bearing temperatures had been determined to be acceptable on the previous day. The operations crew was also informed that dropped wear rings were not a concern when the RR pumps were operating in slow speed and reactor pressure was low.

  The inspectors questioned operations personnel to determine why a log entry regarding the bearing temperatures was not made in the MCR journal, and to question why this information had not been discussed during shift turnover. The inspectors were informed that, while engineering personnel verbally notified the crew that the lower bearing temperature was not a concern, an engineering evaluation had not been written. Engineering personnel subsequently documented their decision. With regards to operator performance, the Director of Operations stated that a log entry was not made and the information was not provided during shift turnover due to an oversight by the operations crew. Counseling on the need to effectively communicate important equipment information was subsequently provided to the operating crews.

- On May 9, the B RO left the MCR to participate in a RCIC testing brief in the technical support center. Even though the brief lasted for over 1 hour, no temporary relief was designated. Following the departure of the B RO, the extra RO arrived in the MCR and was informed by the CRS that he would be needed to help in the at-the-controls area of the MCR by answering telephones and assisting when needed. The inspectors observed that a temporary relief turnover had not occurred. When questioned by the inspectors, MCR personnel stated that the B RO was not required to be present by plant procedures. The inspectors discussed the issue with the SM. The SM stated that the crew had not meet his expectations in that he had provided specific instructions to the crew to ensure a temporary relief turnover was provided for the B RO before the RCIC brief. Poor temporary relief turnovers of the B RO with an extra RO had been recently identified by the licensee in CR 1-99-04-299 dated April 23, 1999.

c. <u>Conclusions</u>

The inspectors determined that overall, the conduct of shift and relief turnovers had improved.

O1.9 Use of Technical Specifications

a. Inspection Scope (71707, 71711, 71715)

The inspectors assessed the use of Technical Specification (TS) by operations personnel.

b. Observations and Findings

In general, the inspectors observed frequent use of TSs in the MCR. Additionally, in most instances, at least two independent assessments of activities affecting the implementation of TS requirements were conducted. When operators recognized that TS limiting condition for operations (LCOs) were not met, they followed administrative procedures which required that the conditions that led to the LCO not being met and the time required to perform the required actions associated with the LCOs be documented in the MCR journal. Even though the inspectors noted improvements in operators' use of TSs, three occasions were identified where operators failed to recognize that conditions existed which required entry into TS LCOs and failed to document these occurrences in the MCR journal.

- On April 28, 1999, at 10:46 a.m., the Division II SX pump was declared inoperable due to oil sample results indicating a bearing failure. The loss of SX impacted cooling for Division II switchgear and the Division II diesel generator. Technical Specification LCO 3.8.2.a requires one qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem to be operable. Technical Specification LCO 3.8.2.b requires one diesel generator capable of supplying one division of the Division 1 or 2 onsite Class 1E AC electrical power distribution subsystem to be operable. Operations personnel recognized that conditions existed for entry into TS LCO 3.8.2.b. but did not recognize that entry into TS LCO 3.8.2.a was also required until after the inspectors questioned them. The licensee initiated CR 1-99-05-025 to address the failure of operators to recognize that conditions existed for entry into T.S. LCO 3.8.2.a. The inspectors determined that the required actions were the same for both TS LCOs and that these actions were met. However, operations personnel failed to log in the MCR journal the entry into TS LCO 3.8.2.a. Operations management personnel stated that this issue would be used as a lessons learned for future training on TS implementation.

  Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978. Section 1 of Appendix A to RG 1.33 recommends that licensees develop administrative procedures for equipment control and log entries. Section 8.1.8 of Procedure 1405.03, "Evaluating and Tracking Improved Technical Specifications Limiting Condition of Operation/Operational Requirements Manual (LCO/ORM) Operational Requirements (OR) Actions and Offsite Dose Calculation Manual (ODCM) OR Remedial Requirements," an administrative procedure for equipment control and log entries, stated that operations personnel were to make an entry in the MCR journal identifying the conditions that existed for entry into a TS LCO, the required actions, and the required completion times for the actions. The inspectors determined that the failure to make the appropriate entry in the MCR journal for the entry into TS LCO 3.8.2.a was a violation of TS 5.4.1.a. However, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-461/99010-01)**. This violation is in the licensee's corrective action program as CR 1-99-05-025. and CR 1-99-05-248.

- On May 19, during a review of the MCR journal, the inspectors identified that the RCIC system was not declared inoperable during high pressure RCIC system testing. Operations personnel informed the inspectors that Step 6.5 of Procedure 9054.01, "Reactor Core Isolation Cooling," required that the RCIC system be declared inoperable if both test valves from the RCIC storage tank (1E51-FO22 and 1E51-FO59) were not fully shut. However, the operating crew was unsure if the previous crew had opened both test valves during the RCIC test. The inspectors reviewed the copy of Procedure 9054.01 used during the high pressure RCIC system testing and identified that operations personnel had opened both test return valves without declaring the RCIC system inoperable. Technical Specification LCO 3.5.3 states that the RCIC system shall be operable and the required actions if RCIC is inoperable are to verify that the High Pressure Core Spray system is operable within one hour and restore the RCIC system to operable within 14 days. The inspectors determined that these required actions were met; however, operators failed to log the entry into LCO 3.5.3 which was a second example of a violation of TS 5.4.1.a. This example also met the criteria for a Non-Cited Violation and is in the licensee's corrective action program as CR 1-99-05-153.

- During the morning of May 27, the inspectors observed operations personnel preparing to conduct an EDG jacket water heat exchanger performance test. The testing involved reducing SX flow to the heat exchanger to approximately 25 percent of the design flow. The inspectors questioned operations personnel to determine the impact of the reduced SX flow on EDG operability. The CRS and SM stated that operations and engineering personnel had previously reviewed the heat exchanger performance test and determined that the EDG would remain operable because the EDG load for the test was 100 percent and no increase in jacket water temperature was expected following any postulated accident.

  During the afternoon of May 27, the inspectors observed that operations personnel were implementing the actions prescribed in Section 8.7 of Procedure 2700.15, "Division 1Diesel Generator Jacket Water Cooler Heat Exchanger Performance Covered by NRC Generic Letter 89-13." The test required operators to slowly throttle valve 1SX005A, SX inlet to the EDG heat exchanger, as necessary, to reduce flow through the heat exchanger and increase jacket water temperature above the temperature control valve set point. At the time, the EDG was operating at approximately 93 percent of full load.

  The inspectors questioned the SM and CRS to determine if the EDG was operable with cooling flow to the heat exchanger manually reduced to control jacket water temperature at a load less than 100 percent. In response to the inspectors question, operations personnel declared the Division I EDG inoperable and implemented the appropriate TS requirements within the allowed completion time. Additionally, the SM directed that engineering personnel complete an evaluation on the impact of reducing SX flow to the EDG heat exchanger during performance testing. The inspectors determined that operations personnel did not fully question the validity of conducting the heat exchanger performance test at a load of less than 100 percent.

Engineering personnel subsequently determined that reducing SX flow for testing to approximately 25 percent of the design flow would not impact the operability of the EDG in that: (1) operations personnel were available to take manual actions to open the SX heat exchanger inlet valve during the test, and (2) informal calculations for the lake temperature and actual EDG load for the test indicated that the jacket water temperature would not have increased above the design limits for jacket water. The inspectors reviewed the calculations and determined that the EDG remained operable for the plant conditions present during the heat exchanger performance test.

- On May 28, during a review of the MCR journal, the inspectors determined that operations personnel had placed inoperable local power range monitors (LPRMs) in service without declaring the associated average power range monitor (APRM) channel inoperable. Operations personnel stated that the LPRMs were placed in service for testing to demonstrate operability and that if the APRM indication was affected, the associated APRM would be declared inoperable until the required adjustments were completed. Additionally, during rod scram time testing, operations personnel placed inoperable LPRMs in service to check the detector response while withdrawing control rods. Following the withdrawal of the control rod, operations personnel returned the inoperable LPRM to the bypassed position.

The inspectors questioned the SM to determine why the associated APRMs were not declared inoperable when placing an inoperable LPRM in service. Following the inspectors' questioning, operations personnel determined that the affected APRMs should have been declared inoperable. The inspectors determined that the TS required actions did not need to be implemented in that the allowed 48-hour outage time had not been exceeded. The licensee suspended reactivity manipulations and power ascension until crew briefs on the issue could be conducted. This was a third example of the failure of operators to log in the MCR journal the entry into a TS LCO as required by Procedure 9054.01. This example of a violation of TS 5.4.1.a also met the criteria for a Non-Cited Violation and is in the licensee's corrective action program as CR 1-99-05-248.

c. Conclusions

The failure of operators to recognize that conditions existed which required entry into TS LCOs on three occasions was indicative of the need to improve operators' knowledge of TS requirements. One Non-Cited Violation with three examples was identified associated with this issue.

O1.10 Control Room Supervisor Oversight

a. Inspection Scope (71707, 71711, 71715)

The inspectors assessed the effectiveness of MCR oversight provided by the CRS.

b. Observations and Findings

Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in RG 1.33, Revision 2, Appendix A, dated February 1978. Section 2 of Appendix A to RG 1.33 recommends that general plant operating procedures be established. Section 8.2.6 of Procedure 1401.01, "Operating Philosophy," a general plant operating procedure, specified that before performing a planned reactivity change, ensure the CRS is directly supervising the reactivity change.

On April 28, 1999, the inspectors observed an SRO, other than the CRS, directly supervising control rod withdrawals during exercising of the control rod drive mechanisms. The inspectors determined that while the procedural requirements were not met as written, the intent of the procedure was fulfilled in that an SRO was specifically tasked with monitoring and supervising the reactivity change. On April 29, following discussions with the inspectors, the licensee initiated CR 1-99-04-392 to document that the CRS was not directly supervising the reactivity change. Additionally, the licensee revised Procedure 1401.01 to specify that an SRO under the direction of the CRS could monitor reactivity changes.

On May 9, the inspectors observed ROs adjusting the reactor water cleanup system (RT) reject flow rate on three occasions without informing the CRS of the evolution. While the evolution progressed, the inspectors determined that the CRS was not cognizant of the change in RT reject rate. When questioned by the inspectors, the CRS stated that the adjustment in RT reject rate had an impact on reactivity, but that he did not know if it should be considered a planned reactivity evolution which required direct supervision. The inspectors also discussed the issue with the SM and Director of Operations Support. Neither individual could specify whether or not adjusting RT was a planned reactivity evolution which required direct supervision. Procedure 1401.01 did not describe examples of specific reactivity evolutions.

On May 10, 1999, the Assistant Plant Manager and Director of Operations stated that at a minimum, for minor reactivity changes such as the adjustment of RT reject rate while in the intermediate range, the ROs were expected to inform the CRS before the evolution so that the CRS would be aware of the activity.

On June 8, the Director of Operations informed the inspectors that it was not his expectation that the CRS be informed of each change in RT reject rate while in the intermediate range. Additionally, he stated that if the CRS provided direction to maintain reactor vessel level within a specified band, no further communication relative to actions taken to maintain vessel level was needed between the ROs and the CRS during the remainder of the operating shift. On June 10, the Director of Operations stated that while the RT adjustment could impact reactivity, it was not the intent of Procedure 1401.01 to require direct CRS oversight of routine plant activities to maintain steady state reactor conditions. Additionally, CR1-99-06-085 was initiated and Procedure 1401.01 was in the process of being revised to distinguish between significant and minor reactivity changes. Nevertheless, the inspectors determined that operations personnel did not understand the management expectations for CRS oversight during small changes in reactivity.

c. Conclusions

The inspectors determined that operations personnel did not understand management expectations for control room supervisor oversight during changes in reactivity

O1.11 Effectiveness of Shift Monitors and Management Observers

a. Inspection Scope (71707, 71711, 71715)

The inspectors assessed the effectiveness of shift monitors and management observers.

b. Observations and Findings

On May 16, 1999, the senior management member and shift monitor were not present for the reactor start-up brief. Additionally, neither individual was present for the rod withdrawal to criticality. When questioned by the inspectors, the SM stated that he had discussed with the Assistant Plant Manager the necessity of having the senior management member present in the MCR for the reactor start-up and decided that the senior management member did not need to observe the reactor start-up because the crew had been involved in a reactor start-up previously. Additionally, the SM stated that the presence of the senior management member could be waived with management approval. The inspectors also observed that on one occasion, the SM left the at-the-controls area of the MCR for 9 minutes (9:52 to 10:01 a.m.). During this interval, rod withdrawals for criticality continued.

The inspectors reviewed Procedure 1401.11, "Planning and Control of Evolutions," and determined the following:

- The purpose of the senior management representative was to advise the SM of conditions that may indicate the need to suspend any special evolution.
- A special evolution is an evolution that is seldom performed or not specifically covered by existing operating procedures, and without additional planning and controls, could result in undesirable consequences. Examples of special evolutions include startup, shutdown, and fuel movement (significant reactivity changes).
- During the review of planned activities, operations services is responsible for identifying activities that are considered special evolutions. During the planning for a special evolution, operations management shall evaluate if a management representative should be present during the special evolution and pre-briefing.

The inspectors determined that at least two of the eight designated senior management members were on-site during the reactor start-up (assistant plant manager and engineering manager). Additionally, the restart briefing package for the control rod pull to criticality required the management representative to be present. The inspectors determined that Procedure 1401.11 did not specify the criteria or level of management involvement for deciding when senior management participation was no longer required for a special evolution. The inspectors also determined that had senior management been present, the issue involving the incorrect moderator temperature for the estimated critical position determination may have been avoided (See Section E1.1).

On May 19, the inspectors questioned operations personnel to determine which activities on the startup schedule required senior management to be present during the pre-brief and evolution. In response, an SM stated that any evolution/brief specified on the startup scheduled required senior management to be present at the brief and during the evolution. Additionally, the SM stated that operations management could waive the requirement per Procedure 1401.11.

On May 22, the inspectors again observed that senior management was not present during rod withdrawals to criticality. The inspectors determined that the crew conducting the startup was the same crew which had been involved in the May 3, 1999, fluctuating period and criticality event. On May 25, the inspectors were informed by personnel involved with the development of the restart schedule that briefs specified on the restart schedule did not require senior management oversight.

On May 28, the inspectors observed that senior management was not present for a brief on scram time testing. The scram testing brief was an activity specified on the restart schedule. The inspectors determined that had senior management been present, the issue on the implementation of TS for placing inoperable LPRMs in service (see Section M1.2) may have been avoided.

c. Conclusions

The inspectors determined that while shift monitors normally were attentive to MCR activities and provided the appropriate feedback to the operating crew, management expectations for when additional senior management oversight was necessary were not understood by operations personnel.

O1.12 Procedural Use and Peer Checks

The inspectors continued to observe frequent use of plant procedures. Additionally, operations personnel continued to perform peer checks of exceptional quality in the MCR. Specifically, peer checks were conducted with the procedure in active use, when independent verification of switch manipulations was required, and during discussions of the expected plant response and annunciators before beginning an evolution.

O1.13 Non Licensed Operator Tours

The inspectors accompanied several non-licensed operators (NLOs) on tours of plant spaces. The NLOs were knowledgeable of the equipment within the assigned areas.

O1.14 Failure to Recognize Criticality Due to Fluctuating Reactor Period

a. Inspection Scope (71711, 37551)

The inspectors assessed the licensee's critique and corrective actions following the failure of the MCR team to recognize criticality due to a fluctuating reactor period on May 3, 1999.

b. Observations and Findings

On May 3, 1999, while withdrawing control rods to criticality, unexpected SRM and reactor period readings were observed by operations personnel. The licensee initiated CR 1-99-05-016 to prompt a review of the event. The sequence of events was as follows:

May 3, 1999

2:45 p.m.	Control Rod 32-53 withdrawn from notch 18 to 20. The reactor period fluctuated between 300 and 999 seconds and decayed to infinity within 2-3 minutes.
2:49 p.m.	Control Rod 32-53 withdrawn from notch 20 to 22. The reactor period initially indicated 150 seconds, decayed to 300 seconds, and then oscillated between 300 and 999 seconds. The oscillating condition existed for approximately 10 minutes.
2:50 - 3:03 p.m.	SRM indication increased to $1X10^5$ counts. The reactor engineer (RE) informed operations personnel that the estimated reactor period was 300 seconds. SRM A indicated 2-4 times higher than SRMs B, C, and D. The SRO stated that the core was not critical because a stable reactor period had not been achieved as required by Procedure 3001.01, "Preparation for Startup and Approach to Critical."
3:04 p.m.	Control Rod 32-53 inserted from notch 22 to 20.
3:05 - 3:06 p.m.	Control Rod 32-53 inserted from notch 20 to 12.

May 4, 1999

2:01 a.m.	Operations personnel commenced insertion of all control rods to the full in position.
5:17 a.m.	All control rods fully inserted.

On May 4, the licensee conducted a critique to discuss the issues associated with the May 3 event. During the critique, operations personnel and the RE described the event and the approach to criticality. Based on the discussion at the critique, it became apparent that:

- the individual crew members had not communicated concerns to the entire shift,
- the SM and CRS were not involved in resolution of the unusual reactor period indications before and after withdrawing control rod 32-53 from notch 18,
- the RE was not surprised by the unusual SRM and period indications; however, the ROs and SRO were concerned with the unusual period indication,

- the MCR crew did not understand the limitations associated with the period indication,

- the plant procedures needed revision in order to provide a bank rod withdrawal pattern and a method for manually determining reactor period, and

- the simulator did not model the actual behavior of the reactor.

The inspectors reviewed the SRM strip charts following the event and determined that approximately 3 SRM count doublings had occurred with no control rod motion between 2:49 and 3:04 p.m. Specifically, all four channels of SRMs indicated at least a decade increase in source counts. Because of the source count increase, the inspectors questioned operations personnel to determine if the reactor had reached criticality during the May 3 reactor startup. In response to the inspectors question, the licensee determined that the reactor had achieved criticality and responded as expected for a long period of approximately 350 seconds. The inspectors and licensee determined that poor communications between control room personnel as criticality was approached contributed to personnel not understanding the response of the reactor and plant indications.

The inspectors questioned why the simulator had not been upgraded to model the actual plant operating characteristics for startup. In response, the licensee provided a copy of a training seminar on cycle 7 characteristics. The inspectors determined that the difference in core design for the current operating cycle from that of previous operating cycles had been discussed; however, the seminar did not include a discussion of the period fluctuations and SRM response.

In mid-1997, the licensee identified the need for a simulator upgrade during a review of INPO SOER 96-2, "Design and Operating Considerations for Reactor Cores," issued November 26, 1996. On October 8, 1997, the licensee developed a proposal to upgrade the simulator core model prior to restart from refueling outage 7. On December 8, 1997, the licensee approved a purchase requisition to upgrade the simulator in early 1998. The licensee subsequently deferred upgrade of the simulator in late 1998 to early 1999. During the capital budget review for 1999, senior management restricted expenditures to only those items that were required to startup the unit or were associated with a regulatory commitment. Since, in the licensee's judgement, the simulator upgrade did not fall into either category, the upgrade project was deferred to the year 2000. Nevertheless, the licensee stated that had the new core model been obtained, it would not have been installed in the simulator to facilitate training prior to plant startup.

Engineering personnel determined that the SRM channels were set at the upper limit of the threshold curve. Setting the SRMs at the upper threshold resulted in a decrease in the neutron signal associated with the neutron pulses with energy levels that exceeded the upper threshold. Engineering personnel also determined that saturation of the SRMs compressed the count rate at higher flux levels. Since the reactor period signal was derived from the count rate, the compression caused a longer indicated reactor period.

Corrective actions involved adjusting the upper threshold settings, calibrating SRM A, and adjusting the lower threshold setting for SRMs A and D. Additional corrective actions included briefing the operating crews on the event, revising the briefing package to include additional industry events, revising Procedure 3001.01 to provide guidance on alternate reactor period determinations, and modifying the rod withdrawal sequence. The inspectors determined that the licensee's corrective actions for the fluctuating reactor period indication were effective.

c. Conclusions

The inspectors determined that operations personnel exhibited a conservative safety focus in deciding to insert the control rods following an unexplained period indication. However, engineering support to operations was poor during this event in that the abnormal period meter indications were not explained and the fact that the reactor was critical was either not recognized or not effectively communicated to the operators.

O1.15 Reactor Scram and Reactor Shutdown Due to Oscillating Feedwater Flow

a. inspection Scope (93702)

The inspectors evaluated the licensee's response to malfunctions of startup level control valve 1FW004 on May 14 and May 19, 1999.

b. Observations and Findings

On May 14, a reactor scram occurred when feedwater flow fluctuated due to the malfunction of valve 1FW004. The following sequence of events occurred:

Initial Conditions	MODE 2, reactor power 87 megawatts thermal (3 percent), reactor pressure 935 psig, reactor vessel level 30-39 inches, motor-driven reactor feed pump (MDRFP) in service with valve 1FW004 regulating feedwater flow and RCIC testing in progress.
7:30 a.m.	Reactor operator observes reactor vessel level increasing. Operations personnel attempt to control level using feedwater inlet shutoff valve 1B21-F065.
7:51 a.m.	Annunciators for a level 8 reactor vessel water level, turbine trip, and MDRFP trip alarmed in the MCR.
7:52 a.m.	Reactor operators inserted a reactor scram by placing the reactor mode switch in the shutdown position.
7:54 a.m.	Reactor operators secured the RCIC turbine to reduce steam loading.
8:36 a.m.	Reactor operators established a cooldown rate of approximately 70°F per hour.
8:43 a.m.	Reactor operators reset the reactor scram.
9:02 a.m.	Operations personnel shut the MDRFP discharge valve 1FW005.

9:42 a.m. Operations personnel exited the scram off-normal procedure.

The inspectors observed operations personnel from their initial attempt to control reactor vessel level through exit of the scram off-normal procedure. The CRS provided frequent updates during the event to ensure MCR personnel were kept informed of the event progression and recovery actions. Before conducting the briefs, the CRS went to the various teams in the MCR to determine the status of activities in lieu of personnel periodically updating the CRS as major milestones within evolutions were completed. The inspectors determined that in general, the CRS was not kept informed of the status of activities until the assigned action was completed. For example, at:

- 8:12 a.m., the CRS directed personnel to maintain reactor pressure between 850-500 psig. At 550 psig, personnel shut the main steam isolation valves and then informed the CRS of the actions taken.

- 8:33 a.m., the CRS directed the A RO to ensure the RT system was not in the cool down mode. The A RO informed the CRS that RT was not in the cool down mode. Within 15 seconds, the A RO realized that RT was in the cool down mode and secured the lineup without informing the CRS.

- 8:41 a.m., the field supervisor reported that an inspection of valve 1FW004 revealed physical damage. The CRS was not aware that an inspection of the valve was in progress.

- 8:48 a.m., the CRS informed the MCR operators that preparations were being made to isolate the MDRFP and the 1FW004 valve. At 8:52 a.m., personnel from the field requested that the A RO lock-out the MDRFP. The A RO subsequently locked-out the MDRFP without first informing the CRS.

The inspectors reviewed the post-trip report and identified that the licensee had concluded that the probable direct cause of the event was failure of valve 1FW004. The post-trip report included the anomalies which occurred during the event and the corrective actions to be implemented before initiating a plant start-up. Corrective actions implemented by the licensee included: testing valve 1FW004, adjusting SRM D, validating the calibration of reactor vessel level instruments, monitoring of valve 1FW004, and initiating CR 1-99-05-127. However, the specific failure mechanism of valve 1FW004 was not described in the post-trip report. Additionally, the cause of the valve failure was not determined before restarting the plant.

On May 19, while operators attempted to increase reactor power, valve 1FW004 malfunctioned again. Operators were able to control reactor vessel level and avoided a high level scram. The following sequence of events occurred:

Initial conditions MODE 2, reactor power 115 megawatts thermal (4 percent), reactor pressure 936 psig, reactor vessel level 35 inches, MDRFP in service with the startup level control valve 1FW004 regulating feedwater flow, and RCIC testing in progress.

1:47 a.m. Vessel level indication spiked while valving in a temporary reactor pressure gauge for RCIC testing. Valve 1FW004 correctly responded to the level indication.

3:57 a.m.	Valve 1FW004 hydraulic trouble annunciator alarmed in the MCR.
4:00 a.m.	Valve 1FW004 hydraulic trouble annunciator cleared.
4:07 a.m.	Reactor water level reached an indicated level of 40 inches on the narrow range level instrument.
4:10 a.m.	Operations personnel increased the RT reject rate to 92 gpm to maintain reactor vessel level.
4:24 a.m.	Operations field supervisor reported that valve 1FW004 was 10 percent open.
5:15 a.m.	Following a crew brief, operations personnel made preparations to shut down the plant.
6:34 a.m.	Operation personnel inserted a manual scram by placing the reactor mode switch in the shutdown position.
6:35 a.m.	Motor-driven reactor feed pump was shut down.
6:38 a.m.	Operations personnel attempted to locally close valve 1FW004. When the lower knob was taken to on, the valve opened instead of closing as expected.
7:03 a.m.	Operations personnel reset the reactor scram.

The inspectors observed operations personnel conduct the plant shutdown. No deficiencies were observed during the reactor plant shutdown.

The licensee determined that the probable direct cause of the event was the failure of valve 1FW004 to respond and control reactor water level. However, the post-trip report did not describe the failure mechanism of the valve. During the facility review group (FRG) meeting on May 19, FRG personnel disapproved the post-trip report because the licensee's post-trip review did not:

- adequately address the problem with the full core display not indicating the numeric position of the control rods for approximately 30 seconds,
- identify if the level transient before the event was an expected occurrence and if corrective actions were necessary,
- determine if the AR written to address the failure of valve 1FW004 would direct an investigation to determine if a hardware or procedure issue existed with local operation of the valve,
- result in obtaining the information from a post-trip critique before submitting the report to the FRG for approval,

- address whether or not the issues associated with valve 1FW004 constituted a repeat problem or evaluate any contingencies needed for restart.

The inspectors determined that the FRG appropriately disapproved and criticized the line organization's review of the May 19 event. Following the FRG disapproval, the line organization conducted additional evaluations of the event and reconvened the FRG on May 21, to discuss the FRG's concerns. Each of the issues described above was resolved during the FRG meeting. Specifically:

- the full core display operated as designed following a scram of the reactor and CR 1-99-05-162 was initiated to resolve the difference in indications between the MCR and the simulator MCR,

- the initial level transient was due to a hydraulic impact while valving in a temporary pressure gauge for RCIC testing. Condition Report 1-99-05-161 was initiated to prompt a review and revision to procedures for placing instruments in service,

- Procedure 3103.01, "Feedwater," was revised to provide the correct instructions for local operation of valve 1FW004,

- a post-trip critique was conducted on May 19, 1999, and the information from this critique factored into the post-trip report.

- an evaluation of the failure mechanisms for valve 1FW004 was conducted.

The licensee identified that a combination of the following issues resulted in the failure of the 1FW004 valve: (1) the solenoid valve block for valve 1FW004 had been incorrectly assembled in March 1999, (2) the seats were degraded based on the results of the vendor inspection, (3) the high contaminants found in the actuator oil were due to erosion and pitting of the valve seats, and (4) the scram on May 14 and the transient on May 19 had similar causes. Corrective actions included refurbishment of the solenoid block by the vendor, replacement of the actuator oil, replacement of the amplifier card, full inspection of the valve internals, installation of monitoring equipment, and revision to the preventative maintenance program to include vendor recommendations for the valve. These actions effectively addressed the problems with valve 1FW004 and the valve operated as designed during the subsequent plant startup.

c. <u>Conclusions</u>

Operators reacted well to challenges encountered during the failure of valve 1FW004 on two occasions. However, the licensee did not identify and correct the root causes of the first valve failure which resulted in an unnecessary challenge to operators during restart activities when the valve failed a second time. This was indicative of a need to improve the effectiveness of the corrective action program.

O2 Operational Status of Facilities and Equipment

O2.1 Verification of System Configuration

The inspectors conducted walkdowns to determine if selected engineered safety feature systems had been configured in accordance with plant procedures. The inspectors determined that the RCIC, EDG, high pressure core spray, and automatic depressurization systems were aligned in accordance with the respective system operating procedures. Minor deficiencies identified during the walkdown involving nomenclature issues were entered into the corrective action system by the licensee.

The inspectors randomly selected eight primary containment manual isolation valves for comparison to Procedure 9061.01D001, "Primary Containment Integrity Verification Data Sheet," requirements for implementation of TS surveillances 3.6.1.3.2 and 3.6.1.3.3. The TS required that the licensee verify that primary containment isolation manual valves that are required to be closed are closed. No discrepancies were identified.

O2.2 Walkdown of Plant Spaces

The inspectors performed a walkdown of all accessible plant spaces before restart of the facility to ensure transient materials had been removed following the completion of the extended shutdown.

The inspectors conducted an inspection of the drywell with no significant concerns identified. Minor deficiencies were corrected by the licensee before the inspectors exited the drywell. The inspectors identified several minor discrepancies during walkthroughs of plant spaces outside the drywell. The majority of the discrepancies involved improper storage of ladders and trash/objects which were not removed following maintenance activities. The licensee corrected each of the deficiencies. The inspectors determined that the licensee had made adequate preparations for returning plant spaces to an operational mode.

O2.3 Rod Control and Information System (RC&IS) Deficiencies

On May 3, 1999, during the initial attempt to withdraw control rods in the gang mode, the RC&IS inoperable annunciator alarmed. Operations personnel reviewed Procedure 5006.03, "Alarm Panel 5006 Annunciators-Row 3," and determined that the withdraw block and insert block on the operator control module was not lit as specified in the procedure. Because the expected indications did not exist, operations personnel declared the rod pattern controller inoperable, entered the applicable TS, and initiated CR 1-99-05-004. Engineering personnel, with the assistance of the vendor, determined that the RC&IS deficiency was limited to the gang mode of the RC&IS. In response, the licensee exited the TS for the rod pattern controller and modified the startup procedure to use single rod withdrawal in lieu of the gang mode of RC&IS. The licensee planned to conduct troubleshooting and repairs to the rod gang mode of RC&IS before using the system for gang rod motion. The inspectors determined that the licencee appropriately resolved the deficiency associated with the rod gang portion of the RC&IS.

O5 Operator Training and Qualification

O5.1 Instant Senior Reactor Operator Qualifications

During discussions with a recently licensed SRO, the inspectors determined that the training program did not require tours of plant areas for instant licenses (when an SRO license is obtained by an individual who was not previously licensed, it is called an instant license). The inspectors determined that at least one instant SRO had never entered the drywell at the Clinton facility.

In response to the observation, operations management stated that a revision to the training program requirements would be made to ensure that instant senior reactor operators (SROs) toured plant spaces before completing the qualification process.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

The inspectors observed all or portions of the following activities:

Procedure 9431.13,"SRM Channel Calibration"
Procedure 8528.01,"SSW Pumps A and B Motor Maintenance"
Procedure 9431.14,"IRM Channel Calibration"
Procedure 3310.01,"Reactor Core Isolation Cooling"
Procedure 3808.01,"RCIC Turbine Overspeed Trip Test"
Procedure 9813.01,"Control Rod Scram Time Testing"
Procedure 2206.01,"Core Flow Calibration"

Specific observations pertaining to each of these activities are described below.

M1.2 Surveillance Testing for Nuclear Instrumentation Monitors

a. Inspection Scope (61726, 62707)

The inspectors observed and reviewed the results of surveillance testing for nuclear instrumentation including source range monitors (SRMs), intermediate range monitors (IRMs), and average power range monitors (APRMs).

b. Observations and Findings

Incomplete surveillance test for source range monitor

On May 4, 1999, the inspectors and the licensee independently identified that the last TS surveillance test for SRM A was only partially completed. Specifically, Procedure 9431.13, "SRM Channel Calibration," which implements the TS surveillance test requirements, was partially completed on May 13, 1998. Work management personnel incorrectly entered the partial completion of Procedure 9413.13 into the surveillance test database which reset the next performance date to November 14, 1999. The last acceptable test for SRM A was March 13,1997, which corresponded to a late date of January 29, 1999. Consequently, SRM A was inoperable between January 30, 1999, and May 4, 1999.

Technical Specification 3.3.1.2, "Source Range Monitor Instrumentation," requires a minimum of two operable SRM instrument channels with the plant in Mode 4. The licensee subsequently determined that between April 1 and 3, 1999, three channels of SRM instrumentation had been inoperable. The inspectors determined that the licensee fortuitously met the required TS actions associated with the condition in that all control rods remained inserted and the reactor mode switch was in the shutdown position.

The licensee determined that the partial surveillance test had been incorrectly entered into the surveillance test data base by a contractor who had temporarily filled the surveillance test coordinator position between June 1 and July 1, 1998. When the permanent surveillance test coordinator resumed the position, he conducted a 100 percent review of surveillance tests completed after June 1, 1998. As a result of the review, the licensee initiated CR 1-98-11-265 to document 12 errors which occurred during the time frame the contractor was acting as the surveillance test coordinator. Because the contractor entered a completion date of May 13, 1998, the partially competed surveillance test on SRM A was not identified during the permanent surveillance test coordinators's assessment.

Short term corrective actions included initiation of CR 1-99-05-023, a review of completed SRM surveillance tests to ensure they were completed when required, and a 100 percent review of surveillance tests completed between April 1 and June 1, 1998.

Source range monitor channel checks

On May 3, during the reactor startup, operations personnel observed that the indicated power level on SRM A was 3 to 4 times greater than the power level indicated on SRMs B, C, and D. Operations personnel performed a qualitative assessment; however, quantitative acceptance criteria for TS channel checks were not available for all instruments. The inspectors conferred with personnel in the NRC's Office of Nuclear Reactor Regulation and determined that the TS requirements for channel checks were met by qualitatively assessing the affected instruments. Operations personnel initiated CR 1-99-05-040 to prompt an evaluation of how the licensee performed channel checks including a review of the need to develop quantitative acceptance criteria.

Source range monitor to intermediate range monitor overlap

During the May 3 reactor start-up, operations personnel did not observe adequate overlap between the SRM and IRM indications. In response to the difficulty in obtaining proper overlap, the licensee adjusted the low threshold discriminator setting for SRMs A and D. The licensee also increased the gain setting on IRMs B and E to increase the detector sensitivity. The inspectors determined that the licensee's methodology for adjusting the SRM instrument settings was appropriate in that the changes ensured proper overlap with the IRMs and maintained a minimum count rate of 3 counts per second.

On May 6, the licensee returned a tripped IRM instrument to service in order to perform surveillance testing. Operations personnel invoked the provisions of TS 3.0.5 and Operational Requirements Manual (ORM) 1.2.5 which allowed inoperable equipment to be returned to service under administrative controls to demonstrate operability. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. Section 1 of Appendix A to RG 1.33 recommended establishing administrative procedures for equipment control. Section 6.8 of Procedure 1014.01, "Safety Tagging," a procedure for equipment control, specified that the tagging procedure be used to provide administrative control for components positioned to comply with TS. In this case, a caution tag or danger tag shall be used. The inspectors determined that operations personnel did not control the operation of the IRMs with a caution tag or danger tag following the invocation of TS 3.0.5. The inspectors concluded that the failure to initiate a tagout for administratively controlling equipment pursuant to TS 3.0.5 was a violation of TS 5.4.1.a. However, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-461/99010-02)**. This violation is in the licensee's corrective action program as CR 1-99-06-088.

Intermediate range monitor correlation

On May 7 at 1:30 p.m., operations personnel were unable to obtain correlation for IRMs B and E between ranges 6 and 7. The licensee initiated CR 1-99-05-082 to prompt a review of the issue. The licensee initially determined that the IRMs remained operable in Range 6 but were inoperable in Range 7. The inspectors questioned the SM to determine if an operability determination had been conducted for the degraded but operable IRMs. The SM stated that the need for an operability determination had not been recognized and directed personnel to prepare the required documentation. The licensee approved the operability determination on May 8 at 3:00 a.m. Had the inspectors not prompted the licensee, the operability determination most-likely would not have been completed within the required 24 hours.

Following review by contractors, the vendor, maintenance personnel, and engineering personnel, the licensee determined that Procedure 9431.14, "IRM Channel Calibration," specified erroneous acceptance criteria for adjusting IRMs to obtain proper range correlation. The licensee revised Procedure 9431.14, adjusted IRMs B and E, and continued with power ascension. The inspectors determined that the licensee's assessment of the issue was appropriate.

c. <u>Conclusions</u>

The licensee encountered problems during plant restart activities with SRM surveillance tests, SRM channel checks, SRM and IRM overlap, and IRM correlation. Based on these issues, the inspectors concluded that improvements were needed in the licensee's nuclear instrument surveillance and calibration programs.

M1.3 <u>Reactor Core Isolation Cooling System Testing</u>

a. <u>Inspection Scope (37551, 61726, 62707)</u>

The inspectors observed the licensee test the RCIC system and evaluated the resolution of identified deficiencies.

b. Observations and Findings

On May 9, 1999, operations personnel attempted to operate the RCIC system for a specified period of time (referred to as a maintenance run) in accordance with Procedure 3310.01, "Reactor Core Isolation Cooling." During the attempted maintenance run, operations personnel identified that the turbine governor valve was not operating as expected after placing the turbine steam supply shutoff valve, 1E51-FO45, in the open position. Due to the operators' inability to control RCIC flow, the system was promptly secured. The MCR journal indicated that the RCIC turbine was operated for a total of 26 minutes between 0 - 700 rpm during 3 separate attempts to conduct the maintenance run.

On May 10, operations personnel successfully completed RCIC turbine overspeed testing in accordance with Procedure 3808.01, "RCIC Turbine Overspeed Trip Test." However, the inspectors identified that operations personnel had not completed the RCIC maintenance run at 1500 rpm for 20 minutes or until the oil level was no longer visible as required by Section 8.2.1.8.e of Procedure 3310.01. During a discussion between engineering and operations personnel at the pre-job brief for overspeed testing, the licensee determined that the 20 minute maintenance run at greater than 1500 rpm was no longer required because the 3 attempted runs at less than 700 rpm had ensured the oil system was full.

On May 11, the inspectors questioned operations personnel to determine if a procedure revision was made to change the RCIC turbine maintenance run requirements or if an engineering evaluation had been prepared to provide a technical justification for not implementing the procedural requirements. In response, the licensee initiated CR 1-99-05-182 for failing to fully complete the RCIC maintenance run.

Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A to RG 1.33. Section 9 of Appendix A of Regulatory Guide 1.33 recommends that the licensee have procedures for performing maintenance activities. The inspectors determined that the failure to conduct the 20 minute RCIC maintenance run as required by Procedure 3310.01, a procedure for performing a specific maintenance activity, was a violation of TS 5.4.1.a. However, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-461/99010-03)**. This violation is in the licensee's corrective action program as CR 1-99-05-182.

On May 13, the licensee conducted additional testing and identified that the RCIC system was unable to deliver 600 gpm to the reactor as described in Section 5.4.6 of the Updated Safety Analysis Report and Section 3.5.3 of the TS Bases when vessel pressure was between 165 and 1215 psia. Instead, the RCIC system was only able to deliver the required flow at a vessel pressure between 165 and 1123.7 psia. In response to this issue, the licensee contacted General Electric and was informed that the upper end of the vessel pressure band was overly conservative. As a result, the licensee completed a safety screening and evaluation to reduce the reactor vessel pressure band from 165-1215 psia to 165-1103 psia. No concerns were identified during the inspectors' review of the safety screening and evaluation.

On May 17, the inspectors discussed the resolution of the RCIC problems described above with engineering personnel and were informed that the inability to control RCIC flow on May 9 was due to a procedure problem. The inspectors were also informed that the procedural problem had been corrected. The inspectors reviewed a controlled copy of Procedure 3310.01 on May 19, and determined that changes had not been made to correct the procedure deficiency. However, changes were made to Procedure 3808.01, "RCIC Turbine Overspeed Trip Test." The inspectors questioned engineering and procedure writing personnel to determine why Procedure 3808.01 was changed but Procedure 3310.01 had not been changed. Procedure writing personnel informed the inspectors that Procedure 3310.01 was not changed due to an oversight by operations and engineering personnel and that a CR would be initiated to document this issue. Procedure 3310.01 was in the process of being revised at the conclusion of the inspection.

c. Conclusions

The inspectors identified one Non-Cited Violation for the failure to conduct a 20 minute maintenance run on the RCIC system turbine at greater than 1500 rpm.

M1.4 Failure of Division II Shutdown Service Water Pump

a. Inspection Scope (62707)

On April 28, 1999, engineering personnel determined that an oil sample for SX pump 1SX01PB had foreign material. The inspectors assessed the licensee's review of and corrective actions for the degraded condition.

b. Observations and Findings

On April 28, 1999, via routine sampling, the licensee identified foreign materials in the SX pump 1SX01PB motor bearing oil. The licensee initiated AR F05473 and CR 1-99-04-348 to prompt an investigation and correction of the degraded condition.

Based on the results of the investigation, the licensee determined that the motor upper bearing had been worn into an egg-shaped pattern. The air gap between the motor armature shaft and the inner diameter of the bearing was 0.039 inches, whereas the allowable clearance was 0.007 inches. The licensee further determined that the pump motor had been overhauled in January 1999, and that the upper bearing had not been properly installed. Specifically, the motor bearing should have been installed such that the air gap between the stator and the armature were constant from the bottom to the top of the motor to ensure the armature was placed at the stator's magnetic center. Because the stator was not located in the magnetic center, a side-loading force was applied on the bearing which caused the bearing wear discovered upon disassembly of the top end of the motor.

Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities recommended in Appendix A to RG 1.33. Section 9 of Appendix A to RG 1.33 recommends that the licensee have procedures for performing maintenance activities. Contrary to the above, Procedure 6528.01, "SSW Pumps A and B Motor Maintenance," a procedure for performing a specific maintenance activity, was inadequate in that it did not contain instructions for verifying the air gap between the armature shaft and inner diameter of the SX pump motor bearing. This licensee identified and corrected Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-461/99010-04)**. The violation is in the licensee's corrective action program as CR 1-99-04-348.

Corrective actions included machining and installing a new bearing to ensure the proper motor air gap, revising the maintenance procedure for SX pump bearing work to include instructions on maintaining the proper air gap during motor reassembly, and inspecting SX pump 1SX01PA for upper bearing wear.

c. Conclusions

One Non-Cited Violation was identified which involved an inadequate procedure for establishing the proper air gap on the SX pump 1SX01PB motor bearing. The licensee appropriately identified the cause of the failure and implemented corrective actions which should preclude recurrence.

M1.5 Main Turbine On-Line Tests

a. Inspection Scope (62707, 61726)

The inspectors observed operations department personnel conducting on-line tests of the main turbine in accordance with Procedure 3812.01, "Turbine On Line Tests."

b. Observations and Findings

On May 25,1999, shortly before shift turnover from the day to night shift, the ROs observed that six buttons or lights did not illuminate when the LAMP TEST button was pushed during Step 5.7 of Procedure 3812.01, "Turbine On Line Tests." Step 5.7 required the ROs to: "Perform a satisfactory lamp test of P870-54C. If light(s) burned out notify the SM/CRS before performing section 8.0." The ROs informed the CRS of the observed condition who subsequently informed the SM. Neither the ROs or shift management knew whether the buttons and/or lights should light up during the lamp test. Additionally, the procedure did not provide acceptance criteria for a "satisfactory lamp test." Operations personnel contacted control and instrumentation personnel for information on the lights and completed a walkthrough of Section 8.0.

After the walkthrough, the ROs informed the CRS and SM that all of the lights required to be monitored in Section 8.0 had operated during the lamp test. As a result, the CRS and SM decided to allow the ROs to continue with the test per the procedure. The inspectors questioned how the ROs could comply with Step 8.1.1, which required that only the NORMAL and RESET lights be energized and that the remaining lights in the ELECTRICAL TEST GROUP be de-energized, if the ROs could not verify that a light was de-energized since the light was burned out. The CRS stopped the test until the issue with the proper status of the six lights/buttons was resolved.

After shift turnover, the evening shift ROs did not affirm that all prerequisites had been re-established before commencing testing. The ROs completed Section 8.1, "Electrical Trip Test," without stationing an operator at panel 1PA06J (to reset annunciators and to report any abnormal alarms) as required by Step 5.8 of the prerequisites. The night shift ROs were unaware of the requirement until the inspectors questioned if they had stationed an operator to reset the annunciators tripped during the test.

After completing Section 8.4, "Mechanical Trip Piston Test," the ROs were in the process of signing off the corresponding portion of the test as satisfactory until the inspectors identified to the ROs that the sequence of illuminating lights was contrary to the required sequence. The ROs agreed that the sequence was incorrect and completed the test with a note referring to the wrong light sequence. The inspectors informed the CRS, the SM, and the Director of Operations of the ROs failure to identify the incorrect sequence. The Director of Operations ensured that a condition report was generated to capture the problems with the testing and the failure to meet the test acceptance criteria. This activity is not safety-related work and therefore, the failure to follow procedural requirements in this case is not a violation of NRC requirements.

c. Conclusions

During turbine testing, inspector prompting was necessary to ensure that operations personnel did not proceed until lamp test results were understood, that prerequisites were completed, and that acceptance criteria were met.

III. Engineering

E1 Conduct of Engineering

E1.1 Review of Estimated Critical Position Determinations

a. Inspection Scope (37551)

The inspectors reviewed estimated critical position (ECP) determinations prepared by RE personnel.

b. Observations and Findings

On April 30, 1999, the inspectors were provided with a copy of the ECP to be used during the initial reactor startup on May 4. The inspectors reviewed the licensee's ECP determination and concluded that the ECP was calculated in accordance with Procedure 2202.04, "Estimated Critical Position Determination."

During a subsequent reactor startup on May 16, 1999, the inspectors reviewed the new ECP calculation completed by RE personnel. The moderator temperature estimate for the ECP calculation was 225°F. However, the inspectors determined that the actual temperature for criticality would be approximately 175°F and questioned the RE on the validity of the ECP. The RE stated that the difference in the number of rod withdrawal notches (approximately 50) between the original ECP that assumed a moderator temperature of 225 °F and an ECP that used a temperature input of 175 °F was not significant and that a new ECP did not need to be determined even though the estimated upper limit of the withdrawal range for when the reactor should be critical was lowered from Step 13 to Step 12.

Just prior to reaching criticality, the startup was suspended to allow for an inspection of RR pump B. The inspectors questioned the SM on the validity of the ECP given the large variance between the estimated temperature for the ECP and the actual temperature of criticality. Following the discussion with the inspectors, the SM directed the RE to recalculate the ECP using a value which more accurately estimated the moderator temperature at the expected time of reactor criticality. The RE selected a temperature of 150°F for the ECP determination and the actual temperature for criticality was 159°F. The inspectors determined that a new ECP would not have been conducted without the inspectors' prompting and that the difference in the ECPs for 225°F and 150°F was approximately 90 rod withdrawal notches.

The inspectors reviewed Procedure 2202.04 and Procedure 2202.04F001, "Reactor Operator Instructions for Criticality," provided by RE personnel, and noted that Procedure 2202.04F001 stated that: (1) a new ECP needed to be determined for a significant change in temperature, and (2) that if criticality was not reached at the completion of Step 13, control rods were to be reinserted in reverse order. The inspectors determined that criteria for what constituted a significant change in temperature was not specified in operating procedures or the operator instructions provided by RE personnel. In addition, Procedure 2202.04F001 incorrectly specified the acceptance criteria for the upper completion step for criticality as Step 13 instead of Step 12.

On June 15, the licensee stated that Procedure 2204.02 may need enhancing to provide guidance on when an ECP should be re-verified. However, the licensee maintained that the intent of the procedure was met in that engineering judgement was used to ensure the ECP was not significantly changed by the decrease in moderator temperature.

c. Conclusions

Following inspector questions, reactor engineers decided to revise an estimated critical position calculation to account for an approximate 75 degree reduction in moderator temperature from the value used in the original calculation. The inspectors determined that the applicable procedure was vague in that it did not clearly state what a significant moderator temperature change was and, in turn, when a new ECP calculation was required based on a moderator temperature change.

E1.2 Review of Reactor Engineering Surveillance Tests

a. Inspection Scope (61707, 71711, 37551)

The inspectors observed all or portions of reactor engineering surveillance tests involving shutdown margin determinations, thermal limits, and jet pump operability.

b. Observations and Findings

Review of shutdown margin determination

Technical Specification Surveillance Requirement 3.1.1.1 requires that the licensee demonstrate adequate shutdown margin within 4 hours after achieving criticality. The inspectors reviewed applicable TSs, Procedure 9811.01, "Shutdown Margin Determination," and the licensee's shutdown margin calculations and concluded that the licensee had complied with the TS surveillance requirement within the specified time frame.

Review of thermal limits

The inspectors reviewed the licensee's compliance with thermal limits during power ascension and after achieving 100 percent power. In all cases, the inspectors determined that the thermal limits were within the TS required values.

Review of jet pump operability surveillance test

On June 1, the inspectors reviewed MCR journal entries completed on May 31. During this review, the inspectors noted that the surveillance test performed in accordance with Procedure 9041.01, "Jet Pump Operability," was considered satisfactorily completed based on an engineering evaluation. Although the inspectors did not suspect any jet pump problems, they reviewed the engineering evaluation and determined that the evaluation was not rigorous. Specifically, RE personnel did not provide any technical analysis to support the conclusion that the pump continued to be operable. Instead, RE personnel stated that jet pump data was consistent with the data being collected in accordance with Procedure 2214.01, "Core Flow Vs. Recirculation Flow Trending."

The inspectors discussed the lack of technical information in the engineering operability evaluation with RE personnel and the Director of Operations. Both individuals agreed with the inspectors assessment that additional information was needed in the engineering evaluation to support continued operability.

On June 2, the inspectors questioned the Director of Operations to determine whether the engineering evaluation was revised to provide an improved justification for operability and to determine why the CRS accepted an engineering evaluation regarding continued TS operability which was not adequately supported. The Director of Operations informed the inspectors that the CRS knew the engineering evaluation was not thorough. However, the CRS did not ask the reactor engineer to provide any additional justification since alternate main control room indications supported continued jet pump operability. In response to this issue, RE personnel planned to supplement the engineering operability evaluation.

c. Conclusions

Engineering personnel generally provided sufficient information to demonstrate compliance with TS surveillance test requirements. However, the information provided as part of an engineering operability evaluation for the jet pump, which was accepted by operators, was not sufficient to support the operability determination. This indicated a need for improvement in engineering personnel's rigor in performing operability evaluations and in operator's questioning attitude.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineering Staff Support to Operations

a. Inspection Scope (37551)

The inspectors assessed the engineering organization's support to operations during restart activities.

b. Observations and Findings

As previously described in Sections O1.8, O1.9, O1.14, O1.15, M1.2, M1.3, and E1.2, the inspectors identified seven examples of poor engineering staff support to operations. Specifically:

- Section O1.8 described an issue where engineering personnel did not provide written documentation to operators supporting the resolution of a high RR pump seal lower bearing temperature indication.

- Section O1.9 described an issue involving EDG heat exchanger performance testing where engineering personnel did not consider the impact of conducting the test at less than 100 percent of full diesel load.

- Section O1.14 described an issue where engineering personnel did not communicate the causes of a fluctuating reactor period as criticality was approached.

- Section O1.15 described an issue where engineering personnel did not determine the cause of the startup level control valve 1FW004 failure following a reactor scram.

- Section M1.2 described an issue where engineering personnel did not provide an evaluation of why IRMs where operable in Range 6 but not in Range 7 following an unsatisfactory range correlation surveillance test.

- Section M1.3 described an issue where engineering personnel did not prepare an engineering evaluation to justify why a maintenance run on the RCIC turbine did not need to be conducted at 1500 rpm.

- Section E1.2 described an issue involving a poorly documented engineering evaluation for jet pump operability.

c. Conclusions

The failure of engineering personnel to provide timely and/or adequate resolution of several technical issues encountered during plant restart activities unnecessarily challenged operations personnel and indicated that engineering staff support to operations needed to be improved.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) IFI 50-461/97999-13: Multiple Electrical Distribution Safety Functional Inspection design concerns which have not been addressed since 1993.

The NRC's Special Evaluation Team report, dated January 2, 1998, provided an assessment of Clinton Power Station performance problems and documented that various electrical design issues and concerns identified in the electrical distribution system functional inspection had not yet been addressed. The 13 design-related issues had been documented in Engineering Work Request (EWR) # 94-00014, dated

January 11, 1994. The design issues pertained mainly to inadequate or lack of design calculations or analyses to demonstrate adequate auxiliary power and EDG system performance/design. The inspectors reviewed the items and discussed them with design engineering personnel. Six of the thirteen issues were closed and the remaining seven were placed in the corrective action program and will be completed after plant re-start. Based on a review of the licensee's actions to address 6 of the 13 issues, the inspectors concluded the licensee was giving appropriate attention to the design issues and determined that this item could be closed.

E8.2 (Closed) Temporary Instruction (TI) 2515/141: Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants.

The staff conducted an abbreviated review of Y2K activities and documentation using Temporary Instruction (TI) 2515/141 as a guide. The review effort addressed aspects of Y2K management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The reviewers used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review.

Conclusions regarding the Y2K readiness of this facility are not included in this report. The results of this review will be combined with reviews of Y2K programs at other plants in a summary report to be issued by July 31, 1999.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Plant Walkthrough of Radiological Areas (71750)

The inspectors conducted tours of the facility before and during reactor startup. No deficiencies were identified involving postings, labeling, or radiological controls.

S1 Conduct of Security and Safeguards Activities

S1.1 Walkthrough of Protected Area (71750)

The inspectors conducted a tour of the protected area during the evening hours and did not observe any deficient lighting for areas of the plant. The inspectors also determine that access to the protected area was appropriately controlled by security force members.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 10, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

H. Anagnostopoulos, Director - Plant Radiation and Chemistry
G. Baker, Manager - Quality Assurance
V. Cwietniewicz, Manager - Maintenance
J. Goldman, Manager - Work Management
P. Hinnenkamp, Assistant Plant Manager
G. Hunger, Plant Manager
W. Maguire, Director - Operations
J. McElwain - Chief Nuclear Officer
R. Phares, Manager - Nuclear Safety and Performance Improvement
J. Sipek, Director - Licensing
D. Smith, Director - Security and Emergency Planning
D. Warfel, Manager - Nuclear Station Engineering Department

INSPECTION PROCEDURES USED

IP 37551: Engineering Observations
IP 61726: Surveillance Observations
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71711: Plant Startup From Shutdown
IP 71715: Sustained Control Room and Plant Observation
IP 71750: Plant Support and Observations
IP 92903: Followup - Engineering
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-461/99010-01	NCV	Failure to recognize conditions impacting TSs and make the appropriate main control room journal entry
50-461/99010-02	NCV	Failure to implement tagout for administratively controlled equipment
50-461/99010-03	NCV	Failure to perform 20-minute reactor core isolation cooling turbine maintenance run
50-461/99010-04	NCV	Failure to provide an adequate procedure for shutdown service water pump motor maintenance

Closed

50-461/97999-13	IFI	Multiple Electrical Distribution Safety Functional Inspection design concerns which have not been addressed since 1993
50-461/99010-01	NCV	Failure to recognize conditions impacting TSs and make the appropriate main control room journal entry
50-461/99010-02	NCV	Failure to implement tagout for administratively controlled equipment
50-461/99010-03	NCV	Failure to perform 20-minute reactor core isolation cooling turbine maintenance run
50-461/99010-04	NCV	Failure to provide an adequate procedure for shutdown service water pump motor maintenance

LIST OF ACRONYMS

APRM	Average Power Range Monitor
AR	Action Request
CR	Condition Report
CRS	Control Room Supervisor
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
EM	Electrical Maintenance
ERAT	Emergency Reserve Auxilary Transformer
EWR	Engineering Work Request
FRG	Facility Review Group
IRM	Intermediate Range Monitor
LPRM	Local Power Range Monitor
MCR	Main Control Room
MCRD	Main Control Room Deficiency
MDRFP	Motor Driven Reactor Feedwater Pump
NLO	Non Licensed Operator
ORM	Operational Requirements Manual
PTL	Pull-to-Lock
RE	Reactor Engineer
RAT	Reserve Auxiliary Transformer
RC&IS	Rod Control & Information System
RCIC	Reactor Core Isolation Cooling
RG	Regulatory Guide
RHR	Residual Heat Removal
RR	Reactor Recirculation
ROs	Reactor Operators
RT	Reactor Water Cleanup
SM	Shift Manager
SR	Surveillance Requirement
SRM	Source Range Monitor
SRO	Senior Reactor Operator
SVC	Static Var Compensator
SX	Shutdown Service Water
TS	Technical Specification
VAR	Volts-amps-reactive