U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-461/91023(DRP)

Docket No. 50-461 License No. NPF-62

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

Facility Name: Clinton Power Station

Inspection At: Clinton Site, Clinton, Illinois

Inspection Conducted: November 19 - December 30, 1991

Inspectors: P. G. Brochman
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Reactor Projects Section 3B

1/30/92
Date

Inspection Summary:

Inspection from November 19 - December 30, 1991 (Report No. 50-461/91023(DRP))

Areas Inspected: Routine, unannounced safety inspection by resident and region based inspectors of licensee actions on: previous inspection findings, event follow-up, operational safety, maintenance/surveillance observations, surveillance program review, measuring and test equipment, maintenance management discussions, freon leak, emergency preparedness drill oversight and training exercises, security control of explosives and vital area keys, licensee review of environs surrounding the site, 10 CFR Part 21 programs, receipt inspection activities, and licensee event reports.

Results: Of the six areas inspected, no violations or deviations were identified in five areas; one violation was identified in the remaining area: (failure to identify and correct significant conditions adverse to quality - paragraph 7.d(2)). The inoperability of the fission product monitor was of minimal safety significance; however, managements failure to correct this longstanding problem was of concern. Three unresolved items were also identified. The first item involved two channels of a containment and reactor vessel isolation control system (paragraph 3.b (3)). The second item involved the inadvertent release of freon inside the control building (paragraph 4.e). The third item involved the loss of control of vital area keys (paragraph 6.b).

The following is a summary of the licensee's performance during this inspection period:

Plant Operations

- The operators manually scramm d the reactor when core flow decreased into the power-to-flow instability region due to a equipment malfunction. No reactor power oscillations were observed and the operator response was very good.

- Managements response to problems encountered with the rod control and nuclear instrument systems during the startup were prudent and conservative. Managements response to the thermal degradation of a switchyard component were also prudent and conservative and permitted repair of the component before a plant transient occurred.

- Operator detection of a problem with both instrument channels of a containment and reactor vessel isolation control system (CRVICS) function was good. Operations department management's understanding of the relationship between the failure of a nonsafety-related fan and the two inoperable CRVICS channels was weak. This problem affected other CRVICS instrument channels. (URI 461/91023-01(DRP))

Maintenance/Surveillance

- A review of the calibration and traceability of the measuring and test equipment installed in the licensee's new receipt inspection facility did not identify any problems.

- Approximately 100 pounds of refrigerant was released inside the control building when maintenance personnel cut into a chiller vent line. No impact on plant operations resulted. Concerns with the presence of freon in the vent line was under review by the licensee. (URI 461/91023-02(DRP))

- The inspector's review of the surveillance program indicated that it was a program strength.

Emergency Preparedness

- Poor management oversight of a drill simulation led to the injury of a drill controller. Several areas for improvement were identified in the licensee's review of this event.

Security

- Contrary to the licensee's policy, explosives were brought inside the protected area as part of an emergency preparedness drill simulation. The licensee did not understand that black powder was an explosive.

- An auxiliary operator lost a key ring which contained a vital area key and did not notify operations management in a timely manner. Apparently, the one hour notification to the NRC was not made within the required time period. Additional problems with operators taking keys out of the protected area were discovered during investigation of this event. The licensee's response to this event was overly conservative. This overly conservative response resulted in new safety questions being raised. The licensee reversed its decision and reissued the keys after the inspectors raised questions. (URI 461/91023-03(DRSS)).

Safety Assessment and Quality Verification

- The licensee's program to evaluate 10 CFR Part 21 reports was reviewed and no weaknesses were noted.

- Two weaknesses were identified with the use of the qualified supplier list (QSL) during observations of receipt inspections.

- A review of Licensee Event Report 461/91005 and other records indicated that longstanding equipment problems and poor understanding of the interrelationship between movement of the filter paper and operability of the drywell fission product monitor resulted in the monitor having been inoperable multiple instances over the last several years. Managements attention to this problem has still not prevented the preventative maintenance task from being performed at too long a period. (NV4 461/91023-04(DRP)).

DETAILS

1. Persons Contacted

Illinois Power Company (IP)

*J. Perry, Vice President
*J. Cook, Manager - Clinton Power Station (CPS)
*J. Miller, Manager - Nuclear Station Engineering Department (NSED)
R. Wyatt, Manager - Quality Assurance
*F. Spangenberg, III, Manager - Licensing and Safety
*R. Morgenstern, Manager - Scheduling and Outage Management
*J. Palchak, Manager - Nuclear Planning and Support
*D. Miller, Director - Plant Radiation Protection
P. Yocum, Director - Plant Operations
*S. Rasor, Director - Plant Maintenance
R. Phares, Director - Licensing
*K. Moore, Director - Plant Technical
W. Bousquet, Director - Plant Support Services
*C. Elsasser, Director - Planning & Scheduling
*S. Hall, Director - Nuclear Program Assessment

The inspector also contacted and interviewed other licensee and contractor personnel during the course of this inspection.

* Denoted those present during the exit interview on December 30, 1991.

2. Action On Previous Inspection Findings (92702)

a. (Closed) Unresolved Item (461/89034-04(DRS)): Drain flow tests not being conducted as required by the licensee's commitment to the National Fire Protection Association Standard Number 13. A NRC review was conducted on the licensee's safety evaluation of this issue, including procedures and related documentation, the licensee's Updated Safety Analysis Report, and the plant Safety Evaluation Report (NUREG 0853). The NRC concluded that the licensee has established adequate alternate controls and administrative procedures to minimize the potential for any obstruction in the fire protection suppression supply system. This review was documented in a NRC memorandum from J. A. Zwolinski to H. J. Miller, dated November 18, 1991. Based on this review, this issue is considered closed.

b. (Closed) Unresolved Item (461/90001-01(DRP)): Adequacy of 10 CFR 50.59 reviews of alternate decay heat removal methods. In February 1990, the inspectors identified questions relating to the licensee's practice, during shutdown operations, of utilizing nonsafety-related systems to transfer decay heat from the reactor core to the ultimate heat sink. These practices have typically been required to accomplish maintenance on certain systems during outages. The licensee also used combinations of systems, in which some were safety-related and others were not (i.e., some would be available following a loss of offsite power and others would not).

Technical assistance was requested from the NRC Office of Nuclear Reactor Regulation (NRR) on this issue. NRR's evaluation of this issue was contained in a memorandum from J. A. Zwolinski to E. G. Greenman, dated November 18, 1991. Based on NRR's ongoing shutdown risk program, NRR did not make a plant specific resolution on this issue, but has deferred resolution of this issue pending issuance of generic requirements from the shutdown risk program.

However, NRR has provided guidance that a licensee should not utilize nonsafety-related methods of decay heat removal for unlimited time periods during normal circumstances. The licensee has planned its outage activities to minimize the length of time that only nonsafety-related methods of decay heat removal are to be utilized. Based on the NRR review and the licensee's actions, this item is considered closed. Further review of this topic will be covered under NRR's shutdown risk program.

c. The licensee contacted the inspectors to inform the NRC of a decision to delay one of the corrective actions described in the licensee's response to Inspection Report 461/89030(DRP), Paragraph 3.6.3.a. This issue was an example of the licensee "working around" problems rather than resolving them. The specific issue related to spurious isolation of the reactor water cleanup (RWCU) system. In their response to the inspection report, documented in a letter from J. S. Perry to A. B. Davis, dated February 28, 1990, (U-601615) Attachment B, Section XX.B(2), the licensee committed to implementing modifications to eliminate the spurious RWCU isolations. This modification was scheduled to be implemented by the end of the third refueling outage (RF-3) in May 1992.

However, the licensee had requested that the completion of the modification be deferred until the end of RF-4 (December 1993). This was based on management establishing a lower priority for this change and due to the high dose rates in the main steam tunnel, which would be reduced by the chemical decontamination scheduled for RF-4. There have not been any spurious isolations of the RWCU system in three years nor have there been any problems with the flow isolation being bypassed for more than one hour. The inspectors and NRC management concluded that the licensee's actions were acceptable.

d. The licensee contacted the inspectors to inform the NRC of a decision to delay one of the corrective actions described in the licensee's response to Confirmatory Action Letter CAL-RIII-89-016 (461/89C16-01). Their response was documented in a letter from D. L. Holtzscher to A. B. Davis, dated June 30, 1989. Attachment "A", corrective action (6), of the response letter, specified that a vibration monitoring system for the reactor recirculation (RR) pumps would be installed during RF-3. The licensee had previously installed eight sensors on the RR pumps and motors under temporary modification 90-31. The sensors will be converted to permanent modification RRF015 after permanent cabling and conduit are installed in the drywell. This permanent modification will be rescheduled to be completed by RF-4. Also, additional sensors will be installed as part of a second temporary modification during RF-3. Since the temporary modifications allow for the acquisition of vibration monitoring data, the inspectors and NRC management concluded that the intent of the CAL was met and that the licensee's actions were acceptable.

e. The licensee contacted the inspectors to inform the NRC of a decision to delay one of the corrective actions described in the licensee's response to Open Item 461/88028-03(DRP). This issue related to implementation of corrective actions for a failure of the 345 kV circuit switcher for the reserve auxiliary transformer (RAT). The open item had been reviewed and closed in Inspection Report 461/90028(DRP). The licensee has developed a modification to the circuit switcher, based on manufacture recommendations, that was scheduled to be installed in RF-3. The licensee has decided to defer the modification until RF-4 when the reactor core will be completely off-loaded. This will minimize the potential risk during the refueling outage when the RAT would be deenergized. The licensee has continued to perform thermographic monitoring of the circuit switcher for evidence of deterioration. The inspectors and NRC management concluded that the licensee's actions were acceptable.

f. The licensee contacted the inspectors to inform the NRC of a decision to delay one of the corrective actions described in the licensee's response to Notice of Violation 461/90027-01(DRS). This issue relates to improvements in the licensee's design control program. The licensee was making substantial revisions to eight procedures dealing with the design change process. In their response to the Notice documented in a letter from F. A. Spangenberg, III to A. B. Davis, dated April 5, 1991, (U-601822), the licensee committed to complete the corrective actions by December 31, 1991. The licensee requested that completion of the procedure revisions and training be completed by February 29, 1992. The revised procedures were in the final review and approval process. The inspectors and NRC management concluded that the licensee's actions were acceptable.

No violations or deviations were identified.

3. Plant Operations

The unit began the report period shut down for Forced Outage 15 (see inspection report 461/91020(DRP)). The unit was started up at 1:49 a.m. on November 19, 1991, and the generator was synchronized to the grid at 10:40 p.m., on the same day (see paragraph 3.b(1)). The unit operated at power levels up to 100% until 8:03 a.m. on November 27, 1991, when the generator was taken off-line to perform maintenance on the main generator disconnect switch (see paragraph 3.b(2)). The reactor remained critical at 15% power and the generator was re-synchronized at 6:50 p.m., on the same day. The unit operated at power levels up to 100% until 4:02 a.m. on December 22, 1991, when the plant was manually scrammed due to a malfunctioning reactor recirculation system flow control valve (see paragraph 3.a). The unit was started up at 9:55 a.m. on December 26, 1991, and the generator was synchronized to the grid at 7:23 p.m. on the same day. The unit operated at power levels up 100% for the rest of the report period.

a. Onsite Event Follow-up (93702)

The inspectors performed onsite follow-up activities for an event which occurred during December 1991. This follow-up included reviews of operating logs, procedures, condition reports, licensee event reports (where available), and interviews with licensee personnel. For the event, the inspectors developed a chronology; reviewed the functioning of safety systems required by plant conditions; and reviewed licensee actions to verify consistency with procedures, license conditions, and the nature of the event. Additionally, the inspectors verified that the licensee's investigation had identified the root cause of equipment malfunctions and/or personnel errors and that the licensee had taken appropriate corrective actions prior to restarting the unit. Details of the event and the licensee's corrective actions developed through the inspectors follow-up are provided below:

Manual Reactor Scram Following Recirculation Flow Instability

At 12:35 a.m. on December 22, 1991, reactor power was being reduced to 70 percent by decreasing core flow using the reactor recirculation flow control valves (FCVs). The FCV was a remotely controlled, hydraulically operated valve. Power was being reduced in preparation for surveillance testing and corrective maintenance on the main steam system. At 3:40 a.m. the 'B' FCV started to oscillate between 24 and 29 percent open. Reactor power was at approximately 63 percent when core flow dropped to 40.2 million pounds mass per hour (Mlbm/hr). At 4:00 a.m. the reactor operator tripped the FCV's hydraulic power unit (HPU) to lock out the FCV; however, the valve continued to change position. Core flow dropped to 37.8 Mlbm/hr. This was just inside the reactor core instability region on the power-to-flow map. As required by operating procedures, the reactor operator manually scrammed the reactor from approximately 62.5 percent power at 4:02 a.m.. The reactor operators did not observe any core power oscillations during the period that the power-to-flow ratio was inside the instability region. The inspectors verified this by review of Average Power Range Monitor (APRM) strip charts. All systems performed as required following the scram.

The licensee determined that the "B" FCV linear variable differential transducer (LVDT) had failed. The LVDT was used to provide valve position indication. This generated false feedback signals and caused the valve to operate erratically. Possible degradation was also noted on the "A" and "B" FCV linear variable transducers (LVT). The LVTs were used to provide a valve velocity signal. The LVT and LVDT on both FCVs were replaced along with the "pig tail" (the electrical connector) for the "B" FCV LVDT.

The licensee also determined that at least one of three solenoid operated hydraulic valves on the "B" FCV's HPU was not functioning properly. This allowed the FCV to change position after it was locked out. These valves were replaced along with the shuttle valve on the HPU. The plant was started up at 9:55 a.m. on December 26, 1991, and synchronized to the grid at 7:23 p.m. on the same day. The inspectors will perform further reviews of this event, in a subsequent report, after the licensee event report (LER) is issued.

b. Operational Safety (71707)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during November and

December 1991. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, and attentive to changes in those conditions, and that they took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. Tours of the lake screen house and the auxiliary, containment, control, diesel, fuel handling, rad-waste, and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors verified by observation and direct interviews that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection controls. The inspectors also witnessed portions of the radioactive waste system control associated with rad-waste shipments and barreling.

The observed facility operations were verified to be in accordance with the requirements established under Technical Specifications, Title 10 of the *Code of Federal Regulations*, and administrative procedures.

(1) Reactor Startup

At 1:49 a.m. on November 19, 1991, the licensee commenced a reactor startup. During withdrawal of control rod 36-53, at notch 32, problems occurred with the rod control and information system (RC&IS). The continuous withdrawal and in-timer skip lights were flashing alternately. RC&IS had applied a block to prevent control rod withdrawal. At 6:20 a.m., operations department management decided to insert all the control rods pending completion of troubleshooting on RC&IS, to ensure an adequate shutdown margin. This was a conservative decision.

Following troubleshooting and discussions with the reactor vendor (General Electric), the licensee decided the problem was caused by a small ripple in the "B" RC&IS power supply voltage. When control rods were continuously withdrawn, the voltage ripple would cause delays in logic signals that were sent from the "A" train to the "B" train of RC&IS. When the delay got longer than 400 milliseconds, a disagreement signal was generated and a control rod withdrawal block was imposed. As a temporary fix, the licensee determined that stopping the control rod withdrawal and deselecting and then reselecting the control rod would clear the problem. The licensee was monitoring the power supply's voltage and was attempting to obtain a replacement. The startup was resumed at 9:40 a.m. on the same day and the reactor was taken critical at 12:30 p.m. The generator was synchronized to the grid at 10:40 p.m. A normal power escalation was initiated.

In accordance with plant startup procedures, power escalation was halted at 35% to verify that core thermal limits were within acceptable values. At 7:20 a.m. on November 20, 1991, traversing incore probes (TIP) drive "C" was stuck and the core monitoring (P-1) report could not be generated as required by technical specifications. At 11:45 a.m., operations management directed that reactor power be reduced to less than 25% to ensure that the plant would be in compliance with technical specifications by 5:38 p.m. The power reduction was completed by 1:45 p.m.

By 3:00 p.m. the "C" TIP drive had been repaired. Power was subsequently raised to 35% and thermal limits were verified and power range monitor gains adjusted. The remainder of the power escalation was normal and the unit was taken to 100%. The RC&IS power supply was replaced during the reactor shutdown on December 22, 1991. The inspectors concluded that the actions by licensee management were prudent and conservative.

(2) <u>Overheating On The Main Generator Disconnect Switch</u>

Following the unit startup on November 20, 1991, the licensee's reliability engineering group performed thermography of switchyard components. This was a routine task that was part of the licensee's program to improve equipment reliability. The thermography detected that the "C" phase connection of the main generator, motor operated disconnect switch (4508) was hotter than the "A" and "B" phases. The licensee began monitoring this temperature twice a day and by November 26 the "C" phase was reading 170 °F. This was over 100 °F hotter than the other phases and a plot of the temperature showed it was rising at a rate of 7 - 8 °F/day. A visual examination of the switch indicated that the "C" phase was not fully closed and that the faces of the stationary contact were not vertical.

The licensee contacted the vendor and was informed that the switch could withstand temperatures up to 300 °F. As a prudent action, the licensee decided to take the generator off line and repair the switch. The licensee began reducing power at 5:50 p.m. on November 26 and opened the generator output breaker at 8:03 a.m. on November 27. The reactor remained critical at 15% power. The contacts were adjusted and the disconnect switch was cycled, to verify proper operation. After completing the repairs, the generator was synchronized to the grid at 6:50 p.m..

Thermography measurements taken after the repairs showed that all three phases were within 15 °F of each other. The inspectors concluded that the actions by licensee management were prudent and conservative.

(3) <u>Inoperable Containment And Reactor Vessel Isolation Control System (CRVICS) Due To Failure Of Nonsafety-Related Fan</u>

At 9:30 a.m. on December 12, 1991, control room operators noted a trend on the equipment areas' ambient temperature chart recorder. The problem was in the "B" RWCU system heat exchanger (HX) room. The "?" RWCU HX was not in service at the time. Inspection by the auxiliary operators revealed that the shaft of the fan for the room cooler had sheared. The fan and room cooler were nonsafety-related. One of the CRVICS isolation signals for the RWCU system was equipment area high delta temperature. This delta temperature was created by measuring the supply and discharge temperatures of the chilled water that flowed through the room cooler. If a RWCU line in this room were to break, the steam issuing from the pipe would transfer some of its heat to the chilled water via the room cooler. This would cause the discharge temperature to rise and would generate an isolation signal when the differential temperature got too large. With the fan failed, air was not blown across the room cooler and negligible heat transfer would take place. With negligible heat transfer, the discharge temperature of the water would not rise, rendering both instrument delta temperature channels inoperable. The inspectors thought the control room operators did an excellent job in detecting this problem considering the small change that was noted on the back-panel chart recorder.

Technical Specification 3.3.2, Action c.1, required that with one of the two channels inoperable that the channel should be placed in a tripped condition within one hour. Action c.2 required that with both channels inoperable, place at least one channel in the tripped condition and take the action required by Table 3.3.2-1, Action 27. This required that the affected isolation valves be closed within one hour and the system declared inoperable.

Operations department personnel were unsure which technical specification was applicable and contacted the licensing and safety department for assistance. By 11:30 a.m., a consensus had been reached that the failure of the fan made both channels of the equipment area high delta temperature isolation signals inoperable and that action c.2 should be followed. The "B" RWCU HX was isolated satisfying the technical specification. However, this action may not have been completed within one hour of determining that the fan was inoperable. During this evaluation the licensee attempted to determine when the fan had failed by reviewing the chart recorder. The equipment area ambient temperature recorder indicated that the temperature had started to rise at approximately 9:00 a.m.. However, a review of the equipment area delta temperature recorder appeared to indicate that the fan had failed at approximately 6:00 a.m..

Additional review by the licensee has indicated that the nexus between the nonsafety-related fan being inoperable and both channels of delta temperature being inoperable was not understood by their staff. It was noted that several other instances had occurred when the fan had been out of service for several days and the technical specifications were not complied with. The licensee was conducting an investigation to evaluate what other instances had occurred when technical specifications were not complied with. Additionally, other CRVICS delta temperature monitoring instrument channels were being evaluated to see if this problem was also applicable.

Further review of these issues and root causes of the event will be completed after the LER is issued and will be tracked as an unresolved item (461/91023-01(DRP)).

No violations or deviations were identified. One unresolved item was identified.

4. Maintenance/Surveillance (61726 & 62703)

a. Maintenance/Surveillance Observations

Station maintenance and surveillance activities of the safety-related systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications.

9080.01 Diesel Generator Monthly Surveillance

The following items were considered during this review: the limiting conditions for operation were met while affected components or systems were removed from and restored to service; approvals were obtained prior to initiating work or testing; quality control records were maintained; parts and materials used were properly certified; radiological and fire prevention controls were accomplished in accordance with approved procedures; maintenance and testing were accomplished by qualified personnel; test instrumentation was within its calibration interval; functional testing and/or calibrations were performed prior to returning components or systems to services; test results conformed with Technical Specifications and procedural requirements and were reviewed by personnel other than the individual directing the test; any deficiencies identified during the testing were properly documented, reviewed, and resolved by appropriate management personnel; work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

During performance of the diesel surveillance the inspectors observed that the lubricating oil temperatures were at 175 °F. The inspectors contacted the system engineer to review the manufacture's recommendations for the lubricating oil's maximum working temperature. The inspectors were informed that the lubricating oil was rated for 165 - 210 °F. The normal working ranges, action and alert temperatures recommended by the manufacture were incorporated into [illegible] generator log sheets. The inspectors had no further concerns on this issue.

b. <u>Surveillance Program Review</u>

The inspectors reviewed the licensee's surveillance testing program as implemented by the following procedures: Clinton Power Station (CPS) 1011.00, "Surveillance Testing Program"; CPS 1011.02, "Implementation and Control of Surveillance Testing"; CPS 1011.05, "CPS Surveillance Guidelines"; and CPS 1011.06, "Routine Surveillance Tracking and Scheduling". The inspectors reviewed various completed surveillance procedures, the weekly surveillance activities schedule, the overall testing schedule, and the method by which changes to the program were implemented. The inspectors also interviewed various personnel in the operations and maintenance departments on their responsibilities in implementing these programs.

The program appeared to be very comprehensive. Personnel had good knowledge of the program requirements. The tracking system for regularly scheduled surveillance activities was easy to use. The process to implement changes to test requirements caused by technical specification (TS) updates was good. However, the licensee's performance in accomplishing non-routine surveillances generated by TS limiting conditions for operation has not been as good, with two instances of missed surveillance this past year. The inspectors consider the licensee's surveillance program to be a performance strength.

c. <u>Maintenance Management Discussions</u>

The inspectors reviewed the performance of the maintenance department with its management. Issues that were discussed included staffing levels, training, quality of work product, procedural compliance, and control of growth of refueling outage scope. Staffing levels have been increased during last year to meet department goals and craft personnel were considered well qualified. The increase in personnel had allowed the licensee to continue to reduce the corrective maintenance backlog to less than 2.5 months. Additional training to improve the skills of supervisory personnel were scheduled in 1992. The quality of work by maintenance personnel had been excellent and had exceeded managements expectations. Rework rates have been very low with only isolated recurring problems. Maintenance and engineering personnel were working closer together to resolve many of the nagging equipment problems. Maintenance management had consistently expressed its high expectations to craft personnel on procedural compliance. During the previous outage the increase in the number of maintenance work requests, over the original scope of work, exceeded original estimates. The scope for the next refueling outage had been defined. Management had revised the administrative programs and policies to better control contractor activities and generation of new work requests.

d. Review of Receipt Inspection Facility Measuring And Test Equipment

The inspectors reviewed the procedural controls for the calibration of measuring and test equipment (M&TE) used for material receipt inspections and commercial dedication. Clinton Power Station (CPS) procedure No. 1012.01, revision 7, "Control of Measuring and Test Equipment" and CPS No. 1512.01, revision 13, "Calibration and Control of Measuring and Test Equipment," described the necessary controls for the calibration of equipment routinely used and stored in areas away from the calibration laboratory. The calibration requirements for the new equipment have not been specifically determined. However, when determined, they will be governed by CPS No. 1512.01. The inspectors did not identify any concerns.

e. Refrigerant Release Inside the Power Block

At 9:00 a.m. on November 21, 1991, mechanical maintenance personnel were installing an additional vent and isolation valve on the refrigerant vent line for chilled water (WO) system chiller "C". When the mechanic cut into the vent line, approximately 100 pounds of R-500 refrigerant (freon) was released into the 702 elevation of the control building. The mechanics notified the main control room and evacuated the area. At 9:15 a.m. maintenance personnel were directed to remove the vent cap on the end of the vent line, which was outside the power block, in an attempt to vent off any remaining refrigerant. By 9:30 a.m. the licensee's HAZMAT (hazardous material response) team was assembled and at 9:40 a.m. they entered the area and covered and secured the breach. The isolation valves for the five chillers were tightened shut and the freon purge fans were started. The air was sampled and declared safe at 9:47 a.m. The licensee initiated an investigation and conducted a critique the next day.

The line that was being worked on was the WO "C" chiller connection to a vent header common to all five chillers located in the 702 elevation of the control building. A charging header and a separate vent header were connected to all five chillers and ran from the control building through the radwaste building to a manifold on its exterior wall. The purpose of these two headers was to allow the licensee to charge and discharge refrigerant into the chillers from tanker trucks, due to the large size of the chillers. The "C" chiller had been taken out of service for overhaul under Maintenance Work Request (MWR) D23129. Adding the isolation and vent valve was a modification to the system. The modification had been previously approved, but work requests to install it had not been generated. The modification was added to the existing MWR after the work was started. The MWR was resubmitted to the operations department for approval again and no changes were made to the tagout for this job, even though the work boundary had changed. The addition of these valves had previously been completed on two other chillers, using the same methodology and similar isolation boundaries.

The licensee has developed two hypotheses for the presence of freon in the vent line. The first was that the isolation valves on the "E" chiller leaking by and pressurizing the vent header. The tagout used to isolate the system did not ensure that the line was vented. When the mechanic cut into it, the freon was released. This was contrary to the licensee safety tagging procedure.

The second hypothesis was that liquid freon was trapped in a low point in the charging header. When the vent line was cut, the freon boiled away. Since the pressure of liquid freon could not have been anticipated, the event was unavoidable. Corrective actions taken by the licensee included: training for maintenance personnel on tagout boundaries and single failure criteria for pressurized and energized systems, developing modifications to relocate the suction of the freon purge fan closer to floor level and to move the control switch to a higher elevation of the control building, reminding all personnel of requirements to follow main control room announcements, obtaining portable freon detection equipment, and conducting periodic hazardous material emergency response drills.

Five other concerns were identified. First, that personnel reentered the affected area after the order had been given to evacuate it. The personnel were checking to ensure that everyone had evacuated; however, they were not wearing protective equipment nor had the atmosphere monitored to assure it was not life threatening. This was of particular concern because one of the individuals was the site safety supervisor. Second, the control switch for the freon purge fans was located in the same area as the chillers, creating the possibility that it might become inaccessible after a major refrigerant release. Also, the control room operators were not familiar with this purge system nor the location of the control switch. Third, the licensee's monitoring instruments were designed to detect very small freon leaks and were saturated by the large quantity of freon in the air. Fourth, the HAZMAT team had never before performed a drill on this type of accident. A large scale freon release had never been included in any of the licensee's emergency preparedness drills. Fifth, communications between the control room, security, the HAZMAT team, and the on-scene commander were initially confused. The inspectors discussed these concerns and their root causes with licensee management. Further review of these issues and root causes of the event will be completed in a subsequent report and will be tracked as an unresolved item (461/91023-02(DRP)).

No violations or deviations were identified. One unresolved item was identified.

5. Emergency Preparedness (71707)

a. Poor Oversight Of Drill Simulation Results In Personnel Injury

On November 14, 1991, a drill controller was injured while performing a drill simulation. The controller received second degree burns to his hand while igniting a small quantity of black powder (3-4 grams) which had been distributed into two old boots. The intent of this drill simulation was to produce smoke from these two boots which was to "represent an individual that was vaporized by electrocution, while working near the emergency reserve auxiliary transformer."

The inspector attended the licensee's critique and reviewed the report (critique LS-91-0010). During the critique, numerous issues were identified that included: 1) the substitution of black powder occurred on the day of the drill due to the unavailability of dry ice; 2) the details of the simulation of the vaporized individual were not written down and reviewed by other organizations, but were only outlined at the controllers briefing the day before the drill; 3) the safety department was not consulted about the use of black powder; 4) no personal protective equipment was utilized by the individual igniting the powder; 5) the simulation was a home-made device rather than a commercially available simulation; 6) this technique had never been tested before; and 7) communication of the injury and the transportation of the individual to an offsite hospital were not made to the shift supervisor in a timely manner.

The principal conclusions drawn by the inspectors were:

1) a questioning attitude needs to be maintained by management at all times; 2) scenario details for event simulations need to be reviewed for their impact on personnel safety; 3) last minute changes to drill scenarios should be very carefully reviewed and fully discussed with all involved departments; 4) personnel protective equipment should [illegible]sed during hazardous simulations; and 5) the use o[illegible] [illegible]me-made devices versus commercially available simulations should be closely examined. The inspectors discussed these conclusions with licensee management. The licensee was reviewing these aspects of its emergency preparedness program. A further review of the security aspects of this event are discussed in paragraph 6.a below.

b. Inspector Participation In Emergency Response Drill

On December 11, 1991, the inspectors participated in a licensee integrated emergency response facility drill. The inspectors played the roles they would perform had a limited NRC site team been dispatched to the site. The inspectors worked with licensee personnel who played the roles of other NRC personnel. The inspectors provided comments during the post-drill critiques. No problems were observed during the performance of the drill.

No violations or deviations were identified.

6. Security

a. Introduction Of Explosives Into The Protected Area

On November 14, 1991, emergency preparedness personnel contacted the security management to obtain permission to bring a small quantity of black powder inside the protected area. This material was to be used in a drill simulation. The purpose of the simulation and problems that resulted from the use of the black powder were discussed in paragraph 5.a above.

Security management stated the black powder had been inspected [illegible] the security force when it was brought onsite and that there was no malicious or malevolent intent to threaten the plant. Security management stated that black powder was an incendiary ingredient and not an explosive device; therefore, it was not considered contraband. The licensee has defined "contraband" in procedure CPS No. 1032.02, "Security Access Control," Paragraph 2.2.15, as including firearms, ammunition, explosives, incendiary devices, and other items that may be used for radiological sabotage.

The inspectors contacted the U.S. Treasury Department, Bureau of Alcohol, Tobacco, and Firearms, to verify the licensee's position that black powder was not an explosive. However, the inspectors were informed that black powder was an explosive.[1] The inspector communicated this information to the licen se and the licensee subsequently issued a memorandum which stated that black powder was to be considered an explosive and that explosives shall not be permitted inside the protected area. Exceptions to that rule would require approval of the Manager-CPS.

In reviewing the relevant procedure, CPS 1032.02, the inspectors noted that the procedure was ambiguous and confusing in relating contraband to prohibited items and in not providing approved exceptions to the prohibition on importing explosives into the protected area. This exception would be necessary due to the fact that certain items such as security force bulk ammunition stocks or the standby liquid control system squib valves were routinely brought into the protected area. The inspector discussed these concerns with security management and was informed that CPS 1032.02 was under review and that changes would be forthcoming. The inspectors reviewed this event with NRC Region III security management and concluded that no violations occurred.

b. Loss Of Control Of Security Keys

At 11:40 p.m. on November 27, 1991, an auxiliary operator noticed that he had lost a key ring that contained security keys for vital areas. He immediately began a search for the keys but did not report the loss to the Staff Assistant Shift Supervisor (SASS) until 1:00 a.m. on November 28, 1991. The SASS notified the Security Liaison supervisor at 1:24 a.m. The key ring was located at 2:10 a.m. on November 28, 1991. There was no obvious compromise of security measures noted. Security immediately notified the NRC upon being informed of the lost key. A follow-up call was made to the NRC when the key was located. Apparently the keys were know to be lost at 11:40 p.m. However, the call to the NRC was not made until 1:24 a.m. and the one hour reporting requirement of 10 CFR 73.71(b)(1) did not appear to be met.

Also, during investigation of this event, the licensee discovered that the auxiliary operators were routinely leaving the protected area, as part of their normal

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[1] *Organized Crime Control Act of 1970, Title XI*, Public Law 91-452, §1102(a) (1970), 84 Stat. 952-959, 18 U.S.C., §1102, Chapter 40, §841(d), Importation, Manufacture, Distribution and Storage of Explosive Materials

duties, with this key ring still in their possession. This was contrary to CPS procedure 1701.58, "Key and Core Control" and the Physical Security Plan. The licensee's corrective actions included: removal of vital area keys from the operator's key ring, briefing the operating crews on the requirements for key control, changed the cores of the vital area locks, and including formal training on this matter in the 1992 operator requalification program.

Subsequent to the licensee's decision to remove the vital area keys from the key rings, the inspectors questioned operations management if this was the most prudent course of action. This was based upon the need for the auxiliary operators to be able to go anywhere in the plant to respond to an emergency, combined with the failure of the card reader system, such as might happen on a loss of electrical power. The licensing and safety staff researched this issue and determined that in response to a prior industry event, the licensee had committed to the NRC to provide the auxiliary operators with vital area keys. As new corrective action, the licensee has reissued the keys and added a metal tag, similar to that used on identification badges, to ensure that the key rings will not be removed from the protected area.

Further review of these issues and root causes of the event will be completed by Region III security inspectors. This issue will be tracked as an unresolved item (461/91023-03(DRSS)).

No violations or deviations were identified. One unresolved item was identified.

7. <u>Safety Assessment And Quality Verification</u>

a. <u>Review Of Licensee Program To Evaluate Changes To The Environs Around Licensed Reactor Facilities, Temporary Instruction (TI) 2515/112</u>

This TI requested that the inspectors determine if the licensee had implemented a program to periodically review, identify, and evaluate changes in hazards and demography within proximity of the plant, to determine their effect on the safety of the plant. It also requested that the inspectors determine if the licensee has updated the Final Safety Analysis Report (FSAR) to reflect changes in the licensing basis in these two areas.

The inspectors reviewed the licensee's program and determined that the licensee did not presently have a program in place to review changes to the environs around the plant for impact on the plant.

Additionally, the licensee has not revised its Updated Safety Analysis Report (USAR) to incorporate changes in the licensing basis to reflect changes to offsite conditions. However, the licensee was developing a program to accomplish these tasks as part of its corrective actions in response to an issue identified in Inspection Report 461/91007(DRP). Unrelated to this TI, the inspectors had identified an offsite hazard, at a local chemical facility, that was not analyzed in the USAR. Resolution of this issue was being tracked by Unresolved Item (461/91007-01(DRP)).

b. Review Of Licensee's 10 CFR Part 21 Program

An inspection of the licensee's 10 CFR Part 21 reporting program was performed to determine if existing procedures and controls were adequate to ensure the reporting of applicable defects and noncompliance and if implementation of the procedures and controls were in compliance with the licensee's program. The licensee's 10 CFR Part 21 program was implemented by licensing and safety department (L&S) procedure L.4, revision 3, "Evaluation and Reporting of 10 CFR 21 Defects and Noncompliance." The procedure contained the requirements for reporting defects or compliance issues, preliminary assessment to determine potential reportability, a committee to evaluate each reported item, and the transmittal of the results of the evaluations to the responsible officer for action including reporting to the NRC. The procedure also delineated the requirements for posting the appropriate federal regulations, record keeping, and the content of written reports to the NRC. The procedure adequately addressed the requirements contained in 10 CFR Part 21.

Two administrative weaknesses were identified in the implementation of procedure L.4. The first was the lack of documentation of the progress of the evaluations that determined the site specific applicability of 10 CFR Part 21 notifications, sent by vendors or other licensees. (These were called external notifications by the licensee.) Some of the external notifications required extensive engineering evaluations before a determination of site specific applicability was made. External notifications were not administratively controlled by procedure L.4 until the determination of site specific applicability had been made. However, the evaluations were personally monitored by the responsible L&S engineer on an informal basis. The licensee planned to revise procedure L.4 to require documentation of the progress of external notification evaluations.

The second weakness concerned the lack of documentation of the progress of the preliminary assessment to determine if a 10 CFR Part 21 report was required. After a potential 10 CFR Part 21 issue was identified, (from either an external notification or onsite identification) a preliminary assessment was required by procedure L.4. Procedure L.4 stated that the preliminary assessment was intended to be a rapid recommendation of reportability which should nominally take one week. Several of the preliminary assessments required several weeks. Documenting the progress of the preliminary assessment was not required by procedure L.4. However, the progress of the assessments was personally monitored by the responsible L&S engineer on an informal basis. Procedure L.4 has been revised to require documentation of the progress of the preliminary assessments. Procedure L.4 was under final review and approval at the end of the report period.

c. Use Of The Qualified Supplier List For Receipt Inspections

During observation of receipt inspection activities, a weakness was identified concerning the use of an uncontrolled copy of the qualified supplier list (QSL). When questioned, the quality assurance (QA) inspector performing the receipt inspection stated that since the uncontrolled copies were updated monthly from the single controlled copy and were usually very accurate, there was no need to consult the controlled copy. Additionally, due to the small number of personnel involved in receipt inspections, any changes to the QSL were widely know to the QA inspectors. The controlled copy of the QSL was updated when required and was reprinted quarterly. The supplier in question was on the QSL. No other weaknesses were identified.

This approach did not seem appropriate and the inspectors discussed it with QA management. As corrective action, the QA Audit Supervisor directed that an additional, controlled copy of the QSL be distributed for use in the receipt inspection area. Additionally, all of the receipt inspectors were reminded that information in the uncontrolled copies of the QSL must be verified.

d. Licensee Event Report (LER) Follow-Up (90712 & 92700)

(1) LER 461/91004 - RCIC Isolation Due To Transmitter Failure

This LER described an event on August 19, 1991, in which a spurious isolation of the reactor core isolation cooling system (RCIC) occurred. The licensee attributed the isolation to the failure of differential flow transmitter 1E31-N083B. The licensee believed that the loss of fill fluid from the high side of the differential transmitter had caused the failure. The failed transmitter was Rosemount Model 1153, Series DB5. The licensee intended to decontaminate the transmitter and return it to Rosemount for additional analysis.

On December 13, 1991, the inspectors inquired if any results had been obtained from Rosemount. Licensee personnel stated that the transmitter had not been shipped to Rosemount. This was due to the inability to decontaminate the transmitter bellows. The remaining corrective actions, described in the LER, have been completed. The licensee had previously implemented a program to evaluate Rosemount transmitters for loss of fill fluid, in response to NRC Bulletin No. 90-01. Based on those actions, and since the corrective actions described in the LER have been completed, this LER is considered closed.

(2) LER 461/91005 - Inoperable Fission Product Monitor

This LER described an event on October 15, 1991, in which the filter paper for the drywell fission product monitor (FPM) (1E31-P002) was not advancing. The FPM was part of the reactor coolant system leak detection system. The FPM samples air from the drywell and passes it through a moving filter paper. The paper then passes in front of a scintillation detector where any particulate radioactivity would be detected. If the filter paper was not moving then the detector was not measuring the current radioactivity in the drywell and the FPM was effectively inoperable. The filter paper was on a roll that was 60 feet long. At the normal speed of advance, there was a 20 day supply of paper in the FPM. Preventative maintenance (PM) task PCILDW001 replaced the paper and was scheduled on a nominal 14 day period.

When maintenance technicians performed PCILDW001 on October 15, they found that the paper had not advanced at all since the PM had been previously performed on October 3, 1991. The FPM did not contain any external indication that the filter paper was moving. The technicians inspected the drive mechanism and inspected for loose components. None were found. This was one of the corrective actions from LER 461/90009, dated April 27, 1990. The technicians also notified the shift supervisor and the alternate grab sample requirement of Technical Specification 3.4.3.1 was initiated. The technicians did adjust the capstan tensioner, which appeared to correct the problem. There was only minimal information in the vendor manual on adjusting the capstan tensioner.

Technical Specification 3.4.3.1.a requires that the reactor coolant leakage detection system drywell atmosphere particulate radioactivity monitoring system shall be operable in Operational Conditions 1, 2, and 3 (power operations, startup, and hot standby, respectively). The action statement for this technical specification requires that with this monitor inoperable that grab samples of the drywell atmosphere be obtained and analyzed at least once per 24 hours; and this action may continue for up to 30 days. Otherwise be in cold shutdown within the 36 hours. The failure of the filter paper to move from October 3 to 15, 1991, rendered the FPM portion of the reactor coolant leakage detection system inoperable and was a violation of Technical Specification 3.4.3.1.

The inspectors reviewed the equipment history of the FPM and noted that there have been multiple problems with it over the last four years and that it has had extremely low reliability. There have been two previous LERs that dealt with an inoperable FPM due to the filter paper not moving, 461/90009 and 461/88005. In LER 88005, dated February 1988, there was a clear understanding that if the paper was not moving then the FPM was inoperable. The paper advances at 1.5 inches per hour, in the slow speed. The FPM was normally run in the slow speed. With 60 feet of paper in each roll this equates to a capacity of 20 days. In several of the equipment history entries for PM PCILDW001 it was noted that the paper was jammed or not moving. In other cases the length of time between performance of the PMs was greater than 20 days and the paper supply was not noted to be exhausted. This would not be possible unless the paper had not been moving. The inspectors noted at least 7 instances in the last 18 months. In all of these cases, the FPM was apparently inoperable, yet these facts were not recognized. Consequently, the technical specification action statement was not entered.

The performance of the PM at an interval of greater than 20 days and the lack of clear guidance in the PM on the consequences of finding the filter paper not moving indicate that the design of the FPM was not clearly understood by the engineering and maintenance organizations that created the PM. The critical nature of the moving filter paper and its nexus to FPM operability was inconsistently understood for the last four years. The inspectors discussed these concerns with maintenance department management. Management agreed that the PM did not provide clear enough guidance and that personnel did not understand the significance of stuck filter paper. Management also stated that the maintenance shops have considerable flexibility in scheduling PMs that have a periodicity of less than 30 days; and that considering the critical nature of the timing of this task, it should have been performed as a surveillance procedure rather than a PM task. The surveillance program has much tighter controls on periodicity. In the interim the PM has been revised to provide clear guidance to maintenance personnel on finding that the paper has not been moving.

10 CFR Part 50, Appendix B, Criterion XVI, requires that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, and defective material and equipment, are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The multiple instances of unmoving filter paper that have occurred since February 16, 1988, have resulted in the failure of the FPM which affected the reactor coolant leakage detection system's ability to monitor leakage and were significant conditions adverse to quality. These adverse conditions were not identified nor were they corrected and have resulted in operation of the facility contrary to the requirements of technical specifications. The failure to identify that the FPM had been inoperable on numerous occasions and the failure to correct these long standing problems is a violation of 10 CFR Part 50, Appendix B, Criterion XVI (461/91023-04(DRP). The NRC is requesting that the licensee's response to this violation address both the failure of the corrective action program to resolve this matter and efforts that will be taken to improve the reliability of the FPM.

The inspectors met with the licensee's engineering staff to review initiatives that have been started to improve the reliability of the FPM. The inspectors were informed that the engineering department has been working on fixes to the FPM problem for some time. This fact was not well understood by many plant personnel. These ranged from modifying the FPM, to relocate the scintillation detector, to obtaining a new FPM. Some of the outstanding technical issues that still remain involve seismic qualification and equipment sensitivity requirements contained in Regulatory Guide 1.45. The inspectors were informed that this effort was scheduled to be completed by May 10, 1992. Consequently, the NRC has requested that the licensee supplement its response to the notice of violation by June 1, 1992, with the actions it intends to take to improve the reliability of the FPM.

Finally, the day after the end of this report period, the inspectors were contacted by maintenance management and informed that once again PM PCILDW001 had not been performed within 20 days; although this time the paper had been moving and had run out. This error was attributed to the flexibility in PM scheduling. The inspectors expressed serious concern that this event should happen again so soon, especially with the attention being focused on this issue by management and independent review efforts (i.e., the supplement to the human performance enhancement system (HPES) evaluation 91-022, dated December 10, 1991). However, in this instance, no technical specifications were violated. This was due to the fact that the alternate grab samples were being taken continuously, as a compensatory measure.

No deviations were identified; however, one violation was identified.

8. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Three unresolved items disclosed during the inspection are discussed in paragraphs 3.b(3), 4.e, and 6.b.

9. Exit Interview

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on December 30, 1991. The inspectors summarized the purpose and scope of the inspection and the findings. The inspectors also discussed the likely informational content of the inspection report, with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.