U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/92006(DRP)

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

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

Facility Name: Duane Arnold Energy Center

Inspection At: Palo, Iowa

Inspection Conducted: March 13 through April 28, 1992

Inspectors: M. Parker
C. Miller
G. O'Dwyer

Approved: R. L. Hague, Chief, Reactor Projects Section 3C — 4/30/92, Date

Inspection Summary:

Inspection on March 13 through April 28, 1992 (Report No. 50-331/92006(DRP))

Areas Inspected: Routine, unannounced inspection by resident and regional inspectors of license event reports followup; followup of events; operational safety; maintenance; surveillance; refueling activities; temporary instruction 2515/113 - decay heat removal; and report review.

Results: An executive summary follows:

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EXECUTIVE SUMMARY

Operations

The plant remained in shutdown for refueling outage No. 11 nearly the entire period. Operators commenced the reactor startup and pulled rods to criticality on April 24, 1992. The turbine generator was connected to the grid on April 26, 1992, ending a 59 day outage. The reactor was at 35% power at the close of the inspection period.

- Problems with tagouts resulted in a personnel contamination due to inadequate system draindown. Section 5.

- The fire brigade took aggressive action to extinguish a brush fire adjacent to the switchyard. Section 3.

- Two reportable events occurred, resulting in two PCIS isolations. Section 3.

- Operator training for the implementation of nuclear generation division procedures 103.2 and 103.3 was inadequate. An open item in Section 4 was issued to track this.

Radiological Controls

- Several room and personnel contaminations resulted from tagging and draining problems. Section 5.a.

Maintenance/Surveillance

- Outage activities appeared well coordinated, with appropriate emphasis placed on outage risk management and work control. Section 5.c.

- Four Main Steam Isolation valves failed local leak rate as-found testing, indicating a continuing trend of poor performance. Section 5.a.

- Special Test Procedure 174, "Cardox Demonstration Test for the Cable Spreading Room", was performed twice prior to achieving satisfactory control room habitability results. The tests were well coordinated. Section 6.

- Past operability of some features of safety busses 1A3 and 1A4 are in question after testing and troubleshooting found several problems. An unresolved item was opened to pursue this issue. Section 5.b.

Engineering and Tech Support

- Engineering support during refueling outage No. 11 was key in resolving several important emergent issues. Section 7.

Safety Assessment/Quality Verification

The licensee has been very aggressive in addressing risk management issues. The licensee's program provides a defense in depth approach. Shutdown risk management program and procedures were found to be well established and implemented.

DETAILS

1. Persons Contacted

*R. Anderson, Assistant Operations Supervisor
*R. Anderson, Senior Outage Project Manager
*R. Baldyga, Supervisor, Maintenance Engineering
*B. Bernier, Supervisor, Mechanical Engineering
*P. Bessette, Supervisor, Regulatory Communications
J. Bjorseth, Assistant Operations Supervisor
*D. Blair, Group Leader, Internal Audits, Quality Assurance
*D. Boone, Supervisor, Health Physics
*C. Bleau, Supervisor, Systems Engineering
*T. Browning, Supervisor, Nuclear Licensing
D. Church, Supervisor, Quality Assurance
J. Edom, Supervisor, Reactor and Computer Performance
*G. Ellis, Senior Outage Project Manager
*M. Flasch, Manager, Design Engineering
*J. Franz, Vice President Nuclear
T. Gordon, Supervisor, Electrical Maintenance
*R. Hannen, Outage Manager
P. Hansen, System Engineer
M. Huting, Supervisor, Quality Control
*J. Loehrlein, Coordinator Professional Development
*L. Mattes, Corrective Action Coordinator
*M. McDermott, Maintenance Superintendent
R. McGee, Technical Support Specialist
C. Mick, Operations Supervisor
*W. Miller, Supervising Engineer, Special Projects
*K. Peveler, Manager, Corporate Quality Assurance
*J. Probst, Technical Support Engineer
K. Putnam, Supervisor, Technical Support
*D. Robinson, Nuclear Licensing Specialist
*A. Roderick, Supervisor, Testing and Surveillance
B. Schenkelberg, Fire Protection Coordinator
P. Serra, Manager, Emergency Preparedness
N. Sikka, Supervisor, Electrical Engineering
*W. Simmons, Outage Closeout Manager
*T. Sims, Nuclear Licensing Specialist
*S. Swails, Manager, Nuclear Training
*J. Thorsteinson, Assistant Plant Superintendent, Operations Support
*G. Van Middlesworth, Assistant Plant Superintendent, Operations and Maintenance
T. Wilkerson, Radiation Protection Manager
*D. Wilson, Plant Superintendent, Nuclear
K. Young, Assistant Plant Superintendent

U. S. Nuclear Regulatory Commission (NRC)

*C. Miller, Resident Inspector
*M. Parker, Senior Resident Inspector
G. O'Dwyer, Reactor Inspector

In addition, the inspectors interviewed other licensee personnel including operations shift supervisors, control room operators, engineering personnel, and contractor personnel (representing the Licensee).

*Denotes those present at the exit interview on April 28, 1992.

2. <u>Licensee Event Reports Followup (92700) (90712)</u>

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with technical specifications.

a. <u>(Closed) Licensee Event Report (LER) 90-004 (331/90004-LL): Momentary Spike on Local Power Range Monitor Results in Automatic Scram During Reactor Startup.</u> On April 1, 1990, during a reactor startup, a momentary increase in indicated flux on Average Power Range Monitor (APRM) channels "C" and "D", to greater than 15 percent of rated power, resulted in an automatic reactor scram from approximately eight percent thermal power. Plant equipment functioned as designed with no equipment failures observed. The APRM scram signal was generated by Local Power Range Monitor (LPRM) 32-09C, which feeds output signals to both APRM channels "C" and "D". The APRM channels feed opposite sides of the Reactor Protection System (RPS) logic. Of the eighty LPRM flux signals, forty provide shared inputs to APRM channels on both sides of the RPS logic and have the potential to cause a full scram from an individual LPRM signal.

The licensee's immediate corrective actions included bypassing the affected LPRM and hanging a warning tag on the LPRM. The licensee determined that the most probable cause of the LPRM spike was metallic particles formed in the detector, which shorted the anode to the cathode. GE SIL 500 "LPRM Spiking" contained recommendations for reducing LPRM spiking due to metallic particles and other causes. The licensee documented in letter DAEC-89-0767 a review of SIL 500. The letter also described procedure modifications to implement some SIL recommendations, e.g., PPDI-17 "LPRM Trending"; General Maintenance Procedure (GMP)-TEST-034 "LPRM Life Cycle Testing" and the LPRM Preventive Maintenance Action Request program. The licensee documented in the LER, as long term corrective actions, that an investigation of LPRM strings with weak performance would be accomplished and industry experience with LPRM spikes would be collected. Telephonic inquiries and a Nuclear Network query resulted in limited industry information of little benefit to DAEC in addressing LPRM spiking. A November 20, 1991 letter (NG-91-3439, from the Supervisor of Systems Engineering to the Assistant Plant

Superintendent - Operations and Maintenance) documented that the improved reliability and performance of the voltage regulators to be installed under Design Change Package (DCP)-1523 negated the need to install new LPRM amplifier cards. This letter also stated that bypassing APRMs and improved maintenance procedures negated the need for any other LPRM modifications. The Safety Evaluation for UFSAR Change Notice 91-21 documented the licensee's determination that no unreviewed safety question existed when APRM's were bypassed during startup and operation. This letter (NG-91-3439) also stated, "LPRM spikes are only of concern at low power levels since higher power levels eliminate the problem, because of the averaging effect of the input going to the associated APRMs". Section 4.1.2 of NRC Modified Operational Safety Team Inspection (OSTI) Report (50-331/91017) documented that the NRC team was concerned because the licensee had left two APRM channels in bypass during the entire current operating cycle (approximately one year). This and other concerns of the team were documented in that report and are being followed as an unresolved item (50-331/91017-05). Since the industry inquiries, measures to prevent LPRM spiking and the analyses of the LPRM performance as described in LER 90-004 have been accomplished in a satisfactory manner this LER is closed.

b. <u>(Closed) Licensee Event Report (LER) 91-007 (331/91007-LL): Inadvertent Inboard High Pressure Coolant Injection Steamline Isolation Due to Personnel Error While Installing Relay Block.</u> This LER documented that on August 6, 1991, while the reactor was operating at 100 percent power, a Primary Containment Isolation System (PCIS) actuation occurred due to a personnel error. During monthly Surveillance testing, while installing a relay contact block, a station technician inadvertently caused the relay contact finger to momentarily engage the fixed contact which caused the inboard high pressure coolant injection (HPCI) steamline isolation valve to shut. During the same surveillance test, one of the two HPCI high steam flow sensing switches would not actuate properly. As required by Technical Specifications (TS), the associated steamline isolation valve was closed and the HPCI system was declared inoperable. TS required demonstration of reactor core isolation cooling (RCIC), low pressure coolant injection (LPCI), automatic depressurization system (ADS), and core spray (CS) immediately following discovery of HPCI inoperability. During the performance of RCIC operability, the RCIC turbine tripped on overspeed, which was found to be due to both speed sensors being broken. On August 6, 1991, as required by the licensee's emergency plan, an Unusual Event was declared due to both the HPCI and RCIC systems being inoperable. Following successful repair to the HPCI system sensing switch, and a successful surveillance proving operability of the HPCI unit; the licensee declared the HPCI system operable and exited the Unusual Event after three hours and twenty one minutes. The RCIC speed sensors were replaced and following successful testing, RCIC was declared operable on August 7, 1991.

The cause of the inadvertent HPCI PCIS isolation was personnel error. Personnel were reminded of the care necessary for the size selection and installation of relay blocks. Similar relay blocks have been installed successfully several times per week since then with no repeat occurrences. The cause of the HPCI high steam flow differential pressure switch not functioning was the failure of an internal subcomponent microswitch which was replaced. No additional corrective actions for the switch were necessary. The cause of the RCIC speed control failure was lack of sufficient warning to personnel of the presence of speed sensors under the turbine insulation pad. The pad was stenciled with warnings to personnel of the sensitive equipment beneath. Station personnel were reminded that climbing on or over equipment may have detrimental effects and should be avoided. The location of a contaminated area step-off pad at the RCIC turbine area may have caused personnel to step on the turbine during performance of maintenance. An additional step-off pad was located to facilitate access and egress from the contaminated area. Based on these corrective actions, this LER is closed.

c. <u>(Closed) Licensee Event Report (LER) 91-009 (91009-LL): Reactor Water Cleanup System Isolation Due to a Blown Fuse in the Power Supply Unit.</u> This LER documented that on August 15, 1991, while the reactor was operating at 100 percent power, a PCIS actuation occurred when the Reactor Water Cleanup (RWCU) System isolated as required by design due to a sensed high differential flow in the RWCU system. Operators inspected the RWCU pump and heat exchanger rooms and found no steam leaks. All automatic actions associated with the Group V isolation were verified.

The cause of the isolation was a blown fuse in the power supply for the square root converter which provided an input to the high differential flow isolation logic. The root cause of the blown fuse was a bent positioning clip that resulted in inadvertent contact with the cable connector. The exact cause and time for the square root converter not being flush within its cabinet and the positioning clip being bent upward are unknown. The positioning clip was bent down slightly and the fuse was replaced. The instruments were verified to be operating satisfactorily, and the RWCU system was returned to service the same day. A review of plant history revealed no previous problems associated with the positioning clip. Based on these corrective actions, this LER is closed.

No violations or deviations were identified in this area.

3. <u>Followup of Events (93702)</u>

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements, and that corrective actions would prevent future recurrence. The specific events are as follows:

April 5, 1992 -	Fire Outside Switchyard in Owner Controlled Area
April 8, 1992 -	Engineered Safety Features Actuation (PCIS Group III Isolation - Drywell) due to spurious actuation
April 16, 1992 -	Engineered Safety Features Actuation (PCIS Groups II thru V Isolation) and Emergency Diesel Start during modification acceptance testing due to failure of Essential Bus 1A4 to fast transfer (See Section 5.b for additional details)
April 18, 1992 -	Engineered Safety Features Actuation (LPCI Signal) due to spurious actuation (subsequently retracted on April 24, 1992)
April 22, 1992 -	Emergency Diesel Generator Automatic start during modification acceptance testing (determined by licensee not to be a reportable event)

Fire Outside Switchyard

On April 5, 1992, a small brush fire adjacent to the switchyard, was reported by security to the control room. The fire brigade responded immediately. Initial reports suggested that the fire was caused by a local farmer burning the adjacent field; however, the fire brigade reported that the fire appeared to be caused by an underground cable igniting the brush.

The fire brigade and an operator at the scene took aggressive action to extinguish the fire. The local fire department was also dispatched to assist in extinguishing the brush fire.

Although adequate measures were taken to extinguish the fire, several minor deficiencies were noted with availability of emergency equipment to respond to a brush fire outside the protected area but within the owner controlled area (i.e., availability of fire hydrant, shovels, and trailer hitch for brigade response on operations truck). Some confusion was also noted in the control room as to energization of the underground cable, as this 36kv power line is not mimicked in the CR since the breakers are not controlled from the CR. The load dispatcher was also not able to assist with necessary information.

The licensee has taken action to address most of these issues, including providing better drawings identifying offsite power distribution lines.

No violations or deviations were identified in this area.

4. Operational Safety Verification (71707) (71710)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of the reactor building and turbine building 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. It was observed that the Plant Superintendent, Assistant Plant Superintendent of Operations, and the Operations Supervisor were well informed of the overall status of the plant and that they made frequent visits to the control room and regularly toured the plant. The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the high pressure coolant injection (HPCI) system to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verifying that instrumentation was properly valved, functioning, and calibrated.

a. Safety Evaluation and Applicability Review Procedures

The inspectors reviewed training and implementation of new Nuclear Generation Division (NGD) procedures NGD-103.2, "Safety Evaluation Applicability Review Process", and NGD-103.3, "Safety Evaluation Process". The licensee issued these procedures in an effort to standardize across the division the process used to address 10 CFR 50.59 requirements regarding plant equipment and procedure changes. The inspectors found that the training given to plant personnel was a good effort to raise awareness to problem areas and to emphasize effective tools available in the safety evaluation and applicability review process. However, when the inspectors reviewed implementation of the procedures in the plant, they found that most operators were not aware that the new procedures had been implemented. Operators tend to use the applicability review process frequently for temporary procedure changes and temporary modifications, and could have benefitted from training on what level of review and documentation was expected in these areas. Not only was this training not given, but alternate means of training to meet the intended level of familiarity with the 103.2 and 103.3 procedures were not specified, conducted, or documented for the operations department. The inspectors brought this problem to the attention of operations supervision at the beginning of April when the procedures first went into effect. Some action was then taken to qualify operators on the new procedures, but this process was still not complete at the end of the report period. This item is considered an open item (331/92006-01(DRP)) pending licensee action to ensure nuclear generation division wide training and implementation of procedures involving the 10 CFR 50.59 process has been completed.

b. Reactor Startup

On April 24, 1992, the licensee commenced a reactor startup from the refueling outage which commenced on February 27, 1992. The reactor was declared critical on April 24, 1992, with a 98 second period and moderator temperature at 177°F. The generator was synchronized to the grid on April 26, 1992, thus concluding a 59 day refueling outage.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

No violations, or deviations were identified in this area.

5. Monthly Maintenance Observation (62703)

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

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety related equipment maintenance which may affect system performance.

Portions of the following maintenance activities were observed/reviewed:

HPCI Pump repairs

"A" CRD Pump repair

4160 Volt Bus refurbishment

"A" Reactor Recirculation Pump Seal repair

MSIV repairs

ESW and RHRSW Strainer repairs

"B" ESW Pump replacement

Feedwater Check Valve modifications

Primary Safety Relief Valve replacements

HPCI Outboard Steam Isolation Valve repairs

Following completion of maintenance on the HPCI and Control Rod Drive systems, the inspectors verified that these systems had been returned to service properly.

a. Main Steam Isolation Valves (MSIVs)

Immediately following the plant shutdown for the refueling outage, local leak rate testing (LLRT) was performed on all containment isolation valves, including Main Steam Isolation Valves (MSIVs). Initial scope of the refueling outage had included overhaul of two MSIVs; however, LLRT test results identified that four MSIVs had exceeded their LLRT test acceptance values. In addition to the four valves, one additional valve had experienced a packing leak due to a galled stem during the operating cycle. The scope of the outage was modified to include the additional three MSIVs. This maintenance activity, therefore, became the critical path throughout the outage. Extensive machining was required during the overhaul of the MSIVs to correct previous modifications that were made to the MSIVs during the last refueling outage. Following the repairs, the MSIVs were successfully leak rate tested. Review of LLRT test results and modifications to MSIVs will be followed up by a regional specialist as part of previous concerns with MSIVs.

b. Safety Bus Fast Transfer

Modification acceptance testing (MATs) of the "K" 161KV supply breaker to the startup transformer required a test of the auto transfer feature of the 4160V safety buses 1A3 and 1A4. This test required opening the "J" and "K" breakers, and ensuring a fast transfer (several cycles) of 1A3 and 1A4 from the startup to the standby transformer occurs. During the test when "J" and "K" breakers were opened, only bus 1A3 fast transferred to the standby transformer. Bus 1A4 switched to the standby transformer with a slow transfer (4 seconds). Troubleshooting efforts revealed that three of four conductors of a control cable affecting 1A4 trip logic were stripped of their insulation in a cable run from 1A4 to the "J" breaker (161KV supply to the startup transformer) in the switchyard. This was very similar to the failure found earlier in the outage on a control cable for trip logic on the 1A3 bus, which had caused an inadvertent closure of a supply breaker to 1A3.

The licensee is not yet aware of the details of the cable failure. The inspectors questioned the licensee about the past operability of the fast transfer features of the 4160V safety buses between the time of cable failure and failure of the MATs testing for the "K" breaker. Initial questioning made the inspectors doubt whether adequate testing of this feature had been performed in the past. This item is considered unresolved (331/92006-02(DRP)) pending licensee and NRC review into previous maintenance and testing history of the 4160 volt safety busses.

c. Refueling Outage

The licensee commenced refueling outage No. 11 on February 27, 1992. The outage management organization had been in effect full time prior to the outage, planning work scope, risk management, schedules, and resources. This is the first outage where that organization has been set up well in advance with full time staffing. As a result, the inspectors noticed improvement in the attention given to timely packages, well planned schedules, and risk management issues.

Major activities worked during the outage included refueling, control rod drive and control rod blade replacements, high pressure turbine repairs, HPCI pump overhaul, 4160 volt bus insulation repairs, "A" reactor recirculation pump seal repair, MSIV repairs, cooling tower repairs, main condenser cleaning, copper piping joint repairs, large motor overhauls for "A" circulating water pump, "B" condensate pump, "B" reactor feed pump, and replacement of "B" ESW pump and "B" condensate pump.

Modifications installed this outage included adding a second supply breaker for the startup transformer, scram reduction modifications on the turbine generator, torus hard pipe vent installation, feedwater system reliability enhancements, MSIV nitrogen piping replacements, reactor protective system (RPS) power supply changes, electrohydraulic control changes, Phase 4 detailed control room design review (DCRDR) changes, and reactor water level indication modifications.

During refueling outage No. 10, the licensee had experienced significant problems with controlling contractors in order to assure quality work performance, as documented in inspection report 50-331/90017(DRP). In an effort to address this problem, the licensee instituted several initiatives this outage. One important initiative was the formation of project teams led by experienced Iowa Electric personnel for major or difficult outage tasks. This allowed direct oversight of contractor personnel by individuals who were experienced with specific plant equipment as well as with plant procedures and requirements. Another initiative involved offering incentives to entice craft to stay the length of the outage and reduce absenteeism. The effort was successful in reducing absenteeism by 7%, and helpful in keeping workers on site as long as needed, thus improving worker continuity and effectiveness. Overall control of the outage activities and craft appeared good.

Some problems with maintenance and construction activities developed during the period. These include tagout errors and several draining errors which resulted in personnel and room contaminations, an incident of cutting the wrong pipe while repairing a leaking rack isolation valve for reactor vessel narrow range level transmitter LT4560, a tagout cleared on a valve whose bonnet was removed from the system, and rework required on some components, such as Automatic Depressurization System Nitrogen Accumulator check valve V-14-14, and control rod drive 10-27. Management involvement to resolve problem issues appeared adequate in most cases, and certainly increased from the involvement seen during refueling outage No. 10. The inspectors will continue to follow the licensee's efforts in resolving tagout control and work deficiencies identified during the outage.

Engineering involvement during the outage was key in resolving certain emergent problems in a timely fashion. Issues such as cable spreading room Cardox initiation, high energy line break evaluations, reactor vessel water level instrumentation, and the general service water pipe break were handled expediously with a high degree of management review and oversight.

Overall, the inspectors noted increased attention to work control, risk management, and scheduling priorities during refueling outage No. 11. In addition, management attention appeared focused not only on scheduling but also on problem resolution and quality. The ultimate results of this effort will be born out after startup.

No violations, or deviations were identified in this area.

6. <u>Monthly Surveillance Observation (61726)</u>

The inspectors observed technical specifications required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following test activities:

STP-41A127	-	RPS MG Set and Alternate Power Source EPA Functional Test/Calibration
STP-43B001	-	Nuclear Instrument Response to Control Rod Motion and Control Rod Coupling Check
STP-44A002	-	SBLC System Manual Initiation, Explosion Valve Test, Explosion Charge Check, and Relief Valve Test
STP-45E001-CY	-	RCIC System Cyclic Operability Test
STP-46D004	-	Manual Opening and Exercising of the four ADS and two LLS Relief Valves
STP-46G022	-	Non Nuclear Heat Class 1 System Leakage Test
STP-48A001	-	Standby Diesel Generators Monthly Operability Test
STP-49A001	-	Refueling Interlocks Functional Testing
NS55001	-	CRD Function Testing
SpTP-174	-	Cardox Demonstration Test for the Cable Spreading Room

Cardox System Actuation

Background: On September I9, 1990, the licensee inadvertently actuated the cable spreading room Cardox system during surveillance testing. This actuation resulted in carbon dioxide (CO_2) intrusion into the control room (CR) through a direct ventilation path into the CR toilet area and through cable penetrations. Based on this event, the NRC, in an August 2, I991, letter, requested additional information regarding DAEC's control room habitability evaluation.

Iowa Electric letter NG-91-3284 to the NRC described the history of the modifications to the Cardox system, evaluated the September 1990 event, and detailed corrective actions to be taken to prevent Cardox actuation from affecting CR habitability. Through design change package (DCP)I511 the licensee made modifications to the cable spreading room exhaust damper operation, cable spreading room exhaust vent registers, CR toilet area ventilation, and other areas prior to performing a test to evaluate CO_2 intrusion into the CR and CO_2 concentration in the cable spreading room.

Results: The inspectors observed preparations for and performance of Special Test Procedure (SpTP) 174, "Cardox Demonstration Test for the Cable Spreading Room". Although the licensee was not expecting significant CO_2 leakage into the CR, they put sufficient controls in place to ensure personnel were protected prior to start of the test. Two senior reactor operators donned air packs in the control room in anticipation of possible CO_2 inleakage. Portable CO_2 and O_2 monitors were used in the CR and in other areas adjacent to the cable spreading room. A wintergreen scent was added to the tank discharge to alert personnel to the presence of CO_2.

The test involved manually initiating the Cardox system and monitoring CO_2 concentrations at six different locations in the cable spreading room as well as monitoring for CO_2 inleakage and O_2 levels in the CR. CO_2 levels in the cable spreading room reached the 50% concentration requirement within three and one-half minutes. However, the influx of CO_2 was much greater than the exhaust of air, which pressurized the cable spreading room to a maximum of about 14 inches water gauge (wg) above the CR. This caused significant leakage of CO_2 into the CR through penetration seals which were not designed to withstand that amount of differential pressure. As a result, O_2 levels in the CR decreased below 20% several minutes after the test had started. Operators expeditiously evacuated the CR except for the two SRO qualified operators in air packs who maintained the minimum CR manning requirements. At that point, the test conductor secured the test and operators began purging the control room to restore normal O_2 concentrations. The minimum O_2 concentrations recorded in the CR were 15% at floor level and about 18.5% at the four foot level. The test was secured before the full "soak" time in the cable spreading room was accomplished, but CO_2 levels did remain above 50% for about seven minutes.

The inspectors noted that the overall conduct of the test was well coordinated, and corrective actions to restore the control room habitability were good. A few minor exceptions are noted below. The briefing before the test did not clearly detail who would be in air packs at what time. This led to confusion right before the start of the test and led to the safety person outside of the control room not having donned an air pack. This was a procedural requirement which would have saved time had the safety person been needed to rescue someone in a low O_2 environment. The safety person did have an air pack available. Toxicity limits of CO_2 were not well understood or explained, and the personnel protective actions were based strictly on O_2 concentrations. Temporary ventilation equipment used to help purge the CR was set up quickly, but used a gasoline engine powered fan in the hallway outside the CR. This posed a breathing hazard to the personnel outside the CR. Despite these problems, operators restored the CR and cable spreading room quickly; and no personnel injuries or breathing problems occurred.

Subsequent to the special test, the licensee put a project team together to resolve the CR habitability problems noted in the test. The team, led by system engineering, met several times to determine how to bring cable spreading room pressure down during a Cardox actuation and prevent penetration seals from leaking excessively.

The outcome of the project team's recommendations was to again modify the cable spreading room exhaust vent damper closing time to approximately 4 minutes and 45 seconds after initiation of CO_2. In addition, a temporary ventilation path was installed, and sized to maintain the cable spreading room pressure to 1" water gauge (wg). These changes were installed under a temporary modification. The intent of these temporary modifications was to reduce the overpressurization of the cable spreading room from I4" wg to 1" wg, and to ultimately reduce or eliminate infiltration of CO_2 into the control room.

On April 5, 1992, the licensee performed a second CO_2 discharge test under Revision 1 to SpTP-174 to determine the effectiveness of the temporary modifications, installed to prevent overpressurization. The test was performed as described above for the first discharge test. However, as a result of significant CO_2 intrusion and reduction of O_2 in the CR, the licensee took added precautions to address personnel safety, including additional monitoring of CO_2 and O_2 levels in the CR and other potentially affected areas. The test was found to be well planned and executed. Personnel were well briefed and knowledgeable of their test responsibilities and emergency actions.

The temporary modifications performed prior to the test were found to be successful in reducing the pressure in the cable spreading room. The peak pressure was reduced from approximately 14" wg to 4.5" wg. As a result, the CR experienced only a slight reduction of O_2 from an average of 2I.0% to 20.5%. The licensee's lower O_2 limit was 19.5%. The additional vent path also caused a small reduction of CO_2 over the previous test from 53% to 50%.

Although the main purpose of the test was to verify CR habitability during and following a CO_2 discharge in the cable spreading room, it was necessary for the test to demonstrate adequate CO_2 concentration in the cable spreading room as a result of the temporary modifications and those performed under DCP-15I1.

The licensee initially demonstrated conformance to National Fire Protection Association (NFPA) requirements during acceptance testing in January 1974. NFPA 12-1973, Section 2523, requires the CO_2 concentration to be at least 30% after two minutes and a 50% concentration to be achieved within 7 minutes after Cardox initiation. Although the licensee is committed to the 1973 edition of the NFPA, the 1989 edition requires a soak time of 20 minutes following the Cardox initiation. The test was performed to determine conformance with the later version of the NFPA code.

In reviewing the test results, the licensee's temporary modifications were not only successful in reducing the CO_2 concentrations in the CR, but confirmed that the concentration of CO_2 was maintained at 50% for the duration of a 20 minute soak time. During the injection of Cardox, a 30% concentration of CO_2 was achieved in 2 minutes and a 50% concentration of CO_2 was achieved in 4 minutes. These results appear to meet NFPA requirements for deep seated fires. However, it does not fully conform to the USFAR and Fire Protection SER, June 1978, values of

3 minutes and 20 seconds. The licensee intends to update the USFAR to correct these values in the next annual submittal. While the test demonstrated adequate CR habitability and fire protection capability of the cable spreading room, the licensee will continue to evaluate permanent modifications while retaining the temporary modifications utilized to prevent cable spreading room overpressurization.

No violations or deviations were identified in this area.

7. <u>Refueling Activities (60710)</u>

The inspectors observed refueling procedures and activities throughout the period, including fuel offload, control rod replacement, fuel reload, and core verification activities. During the review, the inspectors verified the acceptability of personnel qualifications, procedure quality and adherence, fuel transfer safety practices including refueling interlocks, and core verification practices.

The fuel moving crews, composed of General Electric bridge operators and Iowa Electric personnel, worked well together. Sufficient controls were in place during grappling, ungrappling, and moving the fuel to ensure safe handling and assembly. At one point the operators astutely noted by the refuel bridge "Z" position indicator, that a fuel bundle was not seated correctly. Followup with a camera revealed that the fuel support piece for position 22-15 had become dislocated. The reactor engineer then modified the refuel plan, and reload continued until the operators were ready to reset the fuel support piece. Operators had difficulty in resetting the fuel support piece due to the fuel in the proximity of the piece, but eventually seated it, and reloaded the fuel without further problems.

The main problem experienced on the refuel floor was with the refueling bridge. Maintenance personnel started overhaul of the bridge late in the last cycle, leaving little time for adequate overhaul activities. The bridge malfunctioned several times during the outage, delaying the fuel movement and risking breakdown with a bundle suspended. Some problems were related to the high humidity conditions on the refuel floor caused by ventilation being secured. The licensee also experienced some trouble with material control on the refuel floor. In one instance a rag was dropped into the spent fuel pool and was lost in the fuel pool cooling skimmers.

Twenty control rod drives were replaced this outage as part of a normal preventive maintenance program. One of these drives had to be changed out again when its rod failed to couple to the drive. The cause of the failure has not been determined. The licensee changed out thirty two control rod blades, 14 due to exposure and 18 for installation of stellite free blades for source term reduction.

Overall, the refuel floor activities appeared well organized and well coordinated with other outage activities. Risk management issues concerning core offload and reload are discussed in Section 8.

No violations or deviations were identified in this area.

8. Temporary Instruction 2515/113 - Reliable Decay Heat Removal During Outages (2515/113)

Pursuant to NRC Temporary Instruction 2515/113, the inspectors reviewed plant programs and procedures for the Duane Arnold facility to determine if the licensee has implemented adequate controls to ensure that plant configurations and operations, during reactor plant outages, are sufficient to maintain the continued removal of decay heat from the reactor.

The objective of this inspection was to review licensee activities during a plant outage which have the potential for contributing significantly to a loss of capability to remove decay heat from the reactor, and to provide this information to the Office of Nuclear Reactor Regulation for further review.

Prior to commencement of the outage, the inspectors reviewed the licensee's program and procedures established to address Outage Risk Management. Review of the licensee's risk management program identified that the licensee has been very aggressive in addressing risk management issues. The licensee's program provides a defense in depth approach and exceeds those requirements provided in technical specifications. Licensee representatives were found to be active participants in industry working groups to provide industry guidelines to address shutdown risk management.

Outage Risk Management Guideline, OMG-7, provides specific attributes to address shutdown safety issues, including decay heat removal capability, inventory control, electrical support systems, reactivity control guidelines, and containment control. The licensee's insights into these issues were based on a review of industry experience and analytical insights.

In addition to the specific attributes provided in OMG-7, the licensee broke down the Outage Milestone Schedule into six distinct phases to evaluate overall shutdown risk.

PHASE 1: Generator Off-line to Refueling Cavity Flooded (start core offload)

PHASE 2: Start Core Offload to Install Fuel Pool Gates for Recirculation Decontamination

PHASE 3: Fuel Pool Gates Installed for Decontamination to Cavity Reflooded and Gates Removed

PHASE 4: Core Off-load with Cavity Flooded

PHASE 5: Start Core Reload to Start Containment and Hydro Testing Window

PHASE 6: Begin Testing to Mode Switch to Startup

The licensee evaluated each of these distinct milestones against the guidelines of OMG-7 to ensure that the defense in depth approach was being maintained for decay heat removal, inventory control, and electrical power. This resulted in the licensee identifying "higher risk evolutions" and providing a listing of insights and suggestions for managing overall shutdown risk during the refueling outage.

a. Decay Heat Removal

Integrated Plant Operating Instruction (IPOI) 8, "Outage and Refueling Operations", and OMG-7 provide specific instructions requiring both loops of reactor heat removal (RHR) to be available, with at least one loop of RHR in the shutdown cooling mode. This action is required until alternate decay heat removal methods are able to maintain reactor coolant below 212°F. The operating loop of RHR in the shutdown cooling mode is also required to have its associated diesel generator available to ensure a reliable source of backup power. When in a cold shutdown condition, with irradiated fuel in the vessel and forced circulation becomes unavailable, reactor water level is required to be maintained at greater than 214 inches to ensure natural circulation is occurring.

In addition, Abnormal Operating Procedure (AOP)-149 and OMG-7 provide specific instructions to plant operators upon loss of shutdown cooling. The AOP provides alternate cooling methods that can be employed for a given set of conditions during the outage. This procedure was developed from a technical basis and considers initial level of decay heat, time to boil, initial water level inventory, and contingency plans for decay heat removal.

b. Supply and Distribution of Electrical Power

OMG-7 specifies that the standby diesel generator (SBDG) should be available to support risk management systems:

- RHR loop being utilized for shutdown cooling.
- Core spray loop being utilized for emergency makeup.
- Standby gas treatment (SBGT) and standby filter unit (SFU) being utilized for secondary containment requirements.
- ESW, RHRSW, and river water supply loops being utilized to shutdown cooling.

In addition, IPOI-8 requires at least one offsite power source to be available to the emergency busses and one SBDG to be operable with its associated SBGT system train and control room ventilation system (SFU) operable. The procedure also provides restrictions to switchyard access when either the startup or standby transformers are removed from service for maintenance. Review of licensee correspondence noted that several letters were generated to address nonstandard electrical lineups. Specific action was taken on several occasions to minimize risk during the outage. In one occasion, the licensee suspended all activities in the DAEC switchyard and control room panel 1C08 when a refueling outage risk assessment indicated that the greatest period of risk involved during the outage was the loss of offsite power during the time when fuel was unloaded and the fuel pool gates were installed for chemical decontamination.

During the refueling outage, the inspectors noted only two occasions in which the licensee deviated from scheduled outage risk management guidelines. In both occasions, the licensee was unable to proceed with the original outage risk evaluation as planned. In each occasion, the licensee's Outage Management Organization thoroughly evaluated the risk involved, including the involvement of Analysis Engineering which had previously performed probability risk analysis (PRA) for outage activities, including calculation of time to boil. Both deviations were reviewed and approved by outage and plant management before work proceeded.

Also during the outage, the inspectors observed two occasions where unplanned loss of shutdown cooling occurred. In both occasions operators were knowledgeable of the current status of the core, including time to boil and vessel inventory. In both occasions, vessel inventory was adequate to ensure natural circulation was occurring. On the first occasion, shutdown cooling was lost for 36 minutes with a 2°F heatup. In this instance, the licensee calculated time to boil at approximately 11 hours, and could have taken action to restore shutdown cooling in a shorter duration if deemed necessary. On the second occasion, RHRSW was lost for 9 minutes with no noticeable heatup occurring.

The licensee took effective measures to disseminate key information to all plant employees on the current status of the outage and, more importantly, reactor status. Included as part of this information was the status of key safety related equipment supporting shutdown cooling, vessel inventory, time to boil, and electrical power, including normal and backup power. This information was discussed in many different forms, including: daily outage meetings, daily outage reports, The "DAEC Dispatch" newsletter, shutdown safety assessment sheets, and also prominently displayed in the control room.

Overall, the inspectors found the licensee's program and procedures addressing shutdown risk and, more specifically, decay heat removal practices to be a well established program. The dedication of the Senior Outage Project Manager responsible for shutdown risk management was believed to be a positive influence on shutdown risk. This individual was cognizant of all phases of the outage and relied on extensively by operations and maintenance for scheduling system availability. This temporary instruction is closed.

9. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for February and March 1992. The inspectors confirmed that the information provided met the requirements of Technical Specifications 6.11.1.C and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. An unresolved item disclosed during the inspection is discussed in Section 5.b.

11. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspectors, and which involve some action on the part of the NRC or licensee or both. An open item disclosed during the inspection is discussed in Section 4.

12. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Section 1) on April 28, 1992, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspectors. The licensee did not identify any such documents or processes as proprietary. The licensee acknowledged the findings of the inspection.