U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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License No:	DPR-49
Report No:	50-331/98013(DRP)
Licensee:	Alliant, IES Utilities Inc. 200 First Street S.E. P. O. Box 351 Cedar Rapids, IA 52406-0351
Facility:	Duane Arnold Energy Center
Location:	Palo, Iowa
Dates:	September 5 through October 13, 1998
Inspectors:	P. Prescott, Senior Resident Inspector M. Kurth, Resident Inspector
Approved by:	R. D. Lanksbury, Chief Reactor Projects Branch 5

EXECUTIVE SUMMARY

Duane Arnold Energy Center
NRC Inspection Report 50-331/98013(DRP)

This inspection report included resident inspectors' evaluation of aspects of licensee operations, maintenance, engineering, and plant support.

Operations

- Operating crews exhibited the appropriate working knowledge of plant equipment and instruments when questioned by inspectors. Effective discussions regarding the status of plant equipment, planned maintenance, and testing were noted during shift turnovers (Section O1.1).

- Operators began the September 12 and 13, 1998, planned downpower for the control rod sequence exchange by inserting the proper grouping of control rods. However, they were inserted in reverse order. The operations shift manager appropriately stopped control rod movement and discussed the issue with the reactor engineer. The licensee concluded that reactor safety was not compromised. Corrective actions were initiated to provide clear expectations to operating crews to ensure error-free reactivity management control. The crew continued the control rod adjustments without error (Section O1.1).

- The inspectors identified two instances in which licensee personnel did not document operability determinations on action requests involving equipment problems. These instances involved difficulty in maintaining back-pressure in the appropriate band during standby liquid control (SBLC) pump testing and wall thinning on essential service water piping. After additional review, the inspectors concluded that the equipment remained operable. Licensee management was reviewing the inspectors' concerns regarding the documentation (Section 03.1).

Maintenance

- In general, surveillance testing and maintenance activities were conducted in an acceptable manner. Electrical technicians showed good attention-to-detail during preventive maintenance activities on the high pressure coolant injection (HPCI) motor control center in the identification of a potentially defective breaker. The licensee decided to correct an SBLC throttling valve problem by replacing the valve with one better suited for the purpose of throttling flow (Section M1.1).

Engineering

- The inspectors concluded that the licensee adequately addressed the potential for a waterhammer event in the HPCI steam turbine exhaust line. Specific actions included a modification, maintenance activities, additional testing, and a change in the way the system is operated (Section E1.2).

- The licensee appropriately declared the reactor water cleanup inlet inboard isolation valve inoperable when it exceeded its Technical Specification required closing time of 20 seconds. Further analysis by engineering personnel concluded that the 20.06-second closure time was well within the time for the valve to perform its intended function. The licensee properly initiated corrective actions to document changes to the surveillance testing procedure, Updated Final Safety Analysis Report, and in-service testing program data (Section E1.3).

- During the last two refueling outages, main steam safety valves and main steam relief valves experienced several failures to pass the as-found testing for setpoint requirements of the limiting safety system setting. This was considered a non-cited violation for failure to take adequate corrective action to prevent recurrence (Section E8.2).

Plant Support

- The licensee appropriately removed radiologically contaminated debris that blocked the pathway of an emergency exit door identified by the inspectors. Also, the inspectors were concerned that the emergency door pathway was roped off as a contamination area boundary, which could inhibit workers from exiting the area in an emergency. The licensee appropriately explained that workers had been instructed to cross contamination boundaries in an emergency, if necessary, for personal safety (Section R1.1).

- Overall, licensee personnel performance in the practice emergency plan exercises was good. No significant weaknesses were noted. The emergency response facilities were in good material condition (Section P1.1).

Report Details

Summary of Plant Status

The plant began this inspection period at 100 percent power. On September 12 through 13 and October 10 through 11, 1998, power was reduced to approximately 85 percent for several hours for control rod sequence exchange and main turbine valve testing. The plant was operated at approximately 100 percent power for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (71707)

The inspectors followed the guidance of Inspection Procedure 71707 and conducted frequent reviews of plant operations. This included observing routine control room activities, reviewing system tagouts, attending shift turnovers and crew briefings. The inspectors observed the September 12 and 13, 1998, planned downpower for the control rod sequence exchange and main turbine valve testing.

b. Observations and Findings

The conduct of operations was professional. The inspectors observed various shift turnovers and noted effective discussions regarding the status of plant equipment, planned testing, and maintenance. Operating crews exhibited the appropriate working knowledge of plant equipment and instruments when questioned by inspectors.

On September 12 and 13, 1998, the operators performed a planned downpower for the control rod sequence exchange and main turbine valve testing. The operating crew initiated the control rod adjustment by inserting the proper grouping of control rods from positions 10 to 08; however, the insertion order was in reverse. The operations shift manager stopped control rod movement and discussed the issue with the reactor engineer, who was in the control room during the evolution. They agreed that the expectation was for operators to insert the control rods in accordance with the control rod adjustment sheet following a "left to right" pattern. Instead, operators had followed a "right to left" pattern. The licensee acknowledged that some confusion may exist regarding the proper control rod adjustment pattern since operating crews had been trained to insert control rods in a "right to left" pattern for unplanned downpowers and also insert control rods in a "left to right" pattern for a planned control rod sequence exchange.

The operations shift manager discussed expectations with the operating crew that the proper "left to right" control rod insert pattern was to be followed. The crew continued the control rod adjustment without error.

Although the initial control rod group was inserted in the reverse order, the licensee and the inspectors concluded that safety was not compromised. The inspectors reviewed previous control rod adjustment data and did not identify discrepancies with control rod adjustment patterns; therefore, this was an isolated example. The licensee initiated Action Request (AR) 982482 for operations and reactor engineering personnel to review expectations and procedures regarding control rod adjustments to ensure error-free reactivity management control. In the interim, reactor engineers verbally committed to clarify expectations to operating crews during pre-job briefs for evolutions involving control rod manipulations.

c. Conclusions

Operating crews exhibited the appropriate working knowledge of plant equipment and instruments when questioned by inspectors. Effective discussions regarding the status of plant equipment, planned maintenance, and testing were noted during shift turnovers. Although the September 12 and 13, 1998, downpower began with the operating crew inserting the first grouping of control rods in reverse order, the overall evolution was performed adequately and without compromising safety. The licensee initiated corrective actions to provide clear expectations to operating crews regarding control rod manipulations.

O2 Operational Status of Facilities and Equipment

O2.1 General Plant Tours and System Walkdowns (71707)

The inspectors followed the guidance of Inspection Procedure 71707 in walking down accessible portions of several systems. The systems chosen based on maintenance work activities and risk significance were:

- High pressure coolant injection system (HPCI)
- Reactor core isolation cooling (RCIC)

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies of debris in contaminated areas were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

O3 Operations Procedures and Documentation

O3.1 Documentation of Initial Operability Determinations

a. Inspection Scope (71707)

The inspectors reviewed the adequacy of initial operability determinations related to action requests (ARs) involving the standby liquid control (SBLC) system and essential service water piping to the reactor core isolation cooling (RCIC) system. The inspectors discussed present operability with the onshift operators, responsible system engineers, and licensing personnel.

b. Observations and Findings

On September 7, 1998, the inspectors observed performance of Surveillance Test Procedure (STP) -3.1.7-01, "Standby Liquid Control Pump Operability Test." The surveillance test verified adequate pump flow at operating pressure. Operators throttled a valve on the pump discharge to maintain a back-pressure between 1150-1190 psig. However, operators could not maintain pressure within the required band. The suspected problem was that the valve used was a gate valve rather than a globe valve, which is normally used for throttling applications. The surveillance test was subsequently performed successfully on the third attempt, when operators managed to maintain the pressure long enough within procedural requirements.

The inspectors discussed with the licensee the fact that no initial operability determination was documented on the AR. Onshift operations management involved with the surveillance test stated continued operability had been based on the last successful surveillance test of the "A" SBLC pump. The licensee did not require a justification for operability unless the component was actually considered inoperable. The inspectors questioned licensee management how others (e.g., system engineers and managers) would know the reason for continued operability of a component was justified.

Verification of operability was supplemented by continuous and ongoing processes, such as surveillance tests. Generic Letter 91-18, "Resolution Of Degraded And Nonconforming Conditions And Operability," stated that when verification indicated a potential deficiency of loss of quality, licensees should make a prompt determination of operability. Without adequate documentation of the process, there could be a potential to miss making a prompt and collectively adequate decision on continued operability of the system.

The inspectors also discussed with licensing personnel another AR generated during the inspection report period on wall thinning detected in essential service water (ESW) piping to the RCIC room cooler. The AR stated, "An engineering evaluation has determined that the worst case locations should be replaced at the next availability." The inspectors questioned what "at the next availability" specifically meant. A meeting with the engineers involved in the analysis and licensing personnel showed that an analysis had been completed and catastrophic failure was not an immediate concern. Replacement of the piping was originally identified a week prior to the last refueling outage. An outage scope change was processed and denied. The basis for this decision was that the work could be done online. However, a planned RCIC work window passed without the work being done. The piping was in the process of a re-evaluation and work was scheduled to be performed in November 1998. The inspectors reviewed the licensee's evaluation and noted there was sufficient margin in wall thickness. This was not considered an immediate safety concern. Licensing management was reviewing the value of documenting the initial operability determination to the AR process.

c. Conclusions

The inspectors identified two instances in which licensee personnel did not document operability determinations on action requests involving equipment problems. These instances involved difficulty in maintaining back-pressure in the appropriate band during standby liquid control (SBLC) pump testing and wall thinning on essential service water piping. After additional review, the inspectors concluded that the equipment remained operable. Licensee management was reviewing the inspectors' concerns regarding the documentation.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (40500 and 71707)

During the inspection period, the inspectors reviewed multiple licensee self-assessment activities, including:

- Quality Assurance Quarterly Debrief Meeting
- Safety Committee Meeting

The meetings covered various areas including engineering, maintenance, plant support, and operations activities. The meetings addressed procedure reviews, program weaknesses, performance trends, and self-assessment activities. The inspectors noted effective discussions between board members and individuals that represented various disciplines.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-331/96011-02: Average power range monitor (APRM) 15 percent trip function inoperable during core alterations. On October 26, 1996, the APRM 15 percent scram setpoint was rendered inoperable when the local power range monitors (LPRMs) were replaced. The cause of the event was a failure to bypass the 24 LPRMs when they were replaced on October 21, 1996. Since the selector switches were left in "operate," this caused the APRMs to indicate a neutron power level lower than actual. As a result, the APRM neutron flux 15 percent power trip function was inoperable.

Upon identification of this issue, the licensee promptly stopped moving fuel, verified all control rods were full in, and requested further evaluation. The root cause was determined to be an inadequate procedure for LPRM replacement. Refueling procedure (RFP)-504, "LPRM Replacement," Revision 2, did not contain instructions to bypass LPRMs. The licensee's corrective actions included; revising RFP-504 and other associated procedures to check selector switch position, and emphasis of this event during training for appropriate personnel. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707 and 61726)

The inspectors observed all or portions of the surveillance test activities and work requests listed below. The applicable surveillance test or work package documentation was reviewed. The inspectors focused on risk-significant work and surveillance test activities. Specific tests and work requests observed are listed below:

b. Observations and Findings

The inspectors determined that, in general, the work associated with these activities was conducted in a professional and thorough manner. Technicians were knowledgeable of their assigned tasks and work document requirements. Specific tests and work requests observed are listed below along with inspector comments where applicable:

Maintenance Activities

- A38632: Reactor vessel wide range level (anticipated transient without scram [ATWS], Groups 1 and 5); replace "O"-ring leaking from high side of valve manifold
- A36191: Reactor building equipment drain sump heat exchanger; add inlet and outlet connections and isolation valves to allow flushing
- A29214: "A" emergency diesel generator cooling water pump; replace leaking mechanical seal
- A50389: HPCI steam flow orifice FO-02205; Relocate to proper line
- 1106006: HPCI redundant shutoff to condensate storage tank, MO-2316 circuit breaker; clean and inspect, and replace control power breaker
- 1106008: HPCI injection valve MO-2312 circuit breaker; clean and inspect
- 1105808: SSA-1 seismic monitor functional test

Surveillance Test Activities

- STP 3.1.7-01: "SBLC Pump Operability Test"
- STP 3.3.6.1-10: "Reactor Lo-Lo Water Level (ATWS-Reactor Protection Trip/All Rods In Trip/Reactor Water Cleanup Isolation) and Lo-Lo-Lo Water Level (Main Steam Line Isolation Trip) Channel Calibration"

- STP 3.7.7-01: "Bypass Valves Test"

The inspectors noted that during the circuit breaker preventive maintenance (PM) activity (1106006), the electrical technicians demonstrated good attention-to-detail. The electrical technicians identified that the control circuit breaker for HPCI redundant shutoff valve to the condensate storage tank, MO-2316, had poor fit-up along the two halves of the casing. No spare circuit breaker was in stock; however, the licensee had performed PMs on a spare breaker in the same motor control center (MCC) and used it as a replacement. The licensee was pursuing with the breaker vendor the cause of the bulging along the joint of the circuit breaker.

During performance of the "A" SBLC pump flow-rate surveillance test, it was noted that the proper back pressure could not be maintained using the normal throttling valve, within procedural guidelines. The inspectors noted during a review of the potential operability concern (see Section O3.1), that Action Requests (ARs) had been written in January 1997 (AR97009) and January 1998 (AR98051), on throttling problems with the valve. The licensee determined the modification to replace the valve with one designed for throttling purposes was not cost-effective. The AR that documented this recent throttling problem (AR982475) recommended that the AR be closed with no action. However, the licensee later decided to replace the valve with one more suited for throttling purposes.

c. Conclusions

In general, surveillance testing and maintenance were conducted in an acceptable manner. Electrical technicians showed good attention-to-detail during PMs on the HPCI MCC in the identification of a potentially defective breaker. The licensee decided to correct an SBLC throttling valve problem by replacing the valve with one better suited for the purpose of throttling flow.

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551)

The inspectors evaluated engineering involvement in resolution of emergent material condition problems and other routine activities. The inspectors reviewed areas such as operability evaluations, root cause analyses, safety committees, and self assessments. The effectiveness of the licensee's controls for the identification, resolution, and prevention of problems was also examined.

E1.2 Re-evaluation of Need to Complete Task Interface Agreement (TIA) 96-254

a. Inspection Scope (37551)

The inspectors reviewed the necessity for the Office of Nuclear Reactor Regulation (NRR) to complete an evaluation on the potential for waterhammer in the HPCI steam exhaust line which could affect operability of the system. The safety evaluation for the exhaust line modification, the revised engineering analysis for the formation and effect of a water slug on the piping, applicable maintenance records, and previous documentation between NRC and the licensee on this issue were reviewed. Additionally, the inspectors walked down the HPCI piping.

b. Observations and Findings

Pre-modification Discussion

In December 1995, the licensee drained a significant amount of water from the HPCI steam turbine exhaust line. Water had siphoned from the torus after securing the HPCI system and had been captured between isolation swing check valve V22-0016 and plug lift check valve V22-0017. This was due to vacuum conditions created by steam condensation following HPCI operation. There are vacuum breakers that open upon sufficient vacuum in the exhaust line to allow water in the vertical exhaust line leg to drain to the torus. However, this system feature may not prevent water from entering the exhaust line initially. If valve V22-0017 did not promptly close following turbine operation, the 58-foot length of 16-inch diameter pipe between the check valves would provide additional vacuum to draw water into the exhaust line from the torus and water could be drawn into the section of pipe between the two valves. The design of valve V22-0017 was such that a dam existed that would not allow water in the bottom half of the horizontal pipe between the two valves to drain out to the torus, even when V22-0017 was open. Chemical analysis of the water drained from the exhaust line supported the conclusion that the water came from the torus. The licensee declared the HPCI system inoperable pending resolution.

The licensee's preliminary operability determination concluded that the water in the line would not prevent the HPCI system from fulfilling its safety function and the HPCI system was declared operable. The inspectors were concerned with several assumptions made in the initial operability evaluation that involved water slug formation and velocity. In August 1996, Region III submitted the subject TIA for NRR review. The TIA was requested due to the resident inspectors' concern that, under certain operating conditions of the HPCI system, a stagnant volume of water could form in the steam turbine exhaust line to the torus between valves V22-0016 and V22-0017. There was the potential, during actuation of the HPCI system, for the sudden inflow of steam into the exhaust line to cause the water remaining in the line to form a water slug and create a waterhammer impact on the piping.

Post-modification Discussion

Subsequently, the licensee performed a modification in October 1996 to the exhaust line piping and refurbished the valves. The inspectors reviewed the adequacy of the

modification and the safety evaluation that supported the operability of the system assuming a volume of water trapped between the two check valves that were now three feet apart. The evaluation determined the initial slug length was reduced to 1.9 feet. The slug would then pass through the downstream transition of the piping diameter from 16 inches to 20 inches. This transition occurs 10 feet downstream from V22-0017. About 6 feet downstream of the 20-inch diameter piping, the evaluation determined the slug would start to disperse. There was an additional three feet of piping to the first pipe bend. Therefore, the hydraulic loads imparted on the elbow would be minimal. Also, since the valves were refurbished, there would be less likelihood of water collecting between the two valves. The valves were also now checked on a two-year cycle by nonintrusive testing to ensure the valves are seating properly. In addition, the licensee implemented a vendor Service Information Letter (SIL) 480, which provided a softer HPCI system startup transient. Steam admission was accomplished in the same time span, but in a more linear fashion through recommended governor adjustments. The inspectors retracted the request for NRR to complete TIA 96-254.

c. Conclusions

The inspectors concluded that the licensee adequately addressed the potential for a waterhammer event in the HPCI steam turbine exhaust line. Specific actions included a modification, maintenance activities, additional testing, and a change in the way the system is operated

E1.3 Calculational Review for Acceptable Reactor Water Cleanup Containment Isolation Valve Closure Time

a. Inspection Scope (37551)

The inspectors reviewed calculations for the reactor water cleanup inboard containment isolation valve, MO-2700. The review was initiated following the failure of MO-2700 to close within its in-service testing program time limit during surveillance testing. The inspectors also reviewed applicable portions of the Technical Specification (TS) and the Updated Final Safety Analysis Report (UFSAR).

b. Observations and Findings

On September 15, 1998, operations personnel performed STP 3.6.1.3-02, "Primary Containment Isolation System (PCIS) and American Society of Mechanical Engineers (ASME) Valve Functional Test," Revision 0. While performing Section 7.5, "Reactor Water Cleanup (RWCU) Valves," operators determined that the RWCU inlet inboard isolation valve, MO-2700, failed to close within its in-service testing program time of 20 seconds. The valve closure was 20.06 seconds. Operations personnel immediately isolated and de-energized MO-2700 in accordance with TS and declared the valve inoperable.

The 20-second closing stroke time was derived from Section 7.3.1.1.1.7 of the UFSAR. The UFSAR described closure times for various automatic isolation valves to prevent the reactor water level from falling below the top of the active fuel as a result of a break of the line that the valve isolated. The UFSAR used the standard closing rate of

12 inches per minute to meet isolation requirements. The RWCU supply line was 4 inches; therefore, its UFSAR design closure time was 20 seconds. Action Request 982483 was initiated for engineering personnel to evaluate the operability of MO-2700 further.

Engineering personnel calculated that 201 seconds were needed for the reactor water level to drop 119.5 inches from the low-low set point to the top of the active fuel. The normal reactor water level is 191 inches above the top of the active fuel; therefore, a conservative reactor water level was used to achieve the 201-second time frame. Also, engineering personnel reviewed environmental qualification (EQ) requirements for the reactor building with the valve's increased closure time. Engineering calculations demonstrated that the increased closure time from 20 seconds to 20.06 seconds was insignificant regarding EQ requirements. The licensee declared MO-2700 operable based on the calculations. The inspectors reviewed the calculations and identified no discrepancies. The licensee initiated AR982483.01 to formally document the operability determination, safety evaluation, and to track document changes to the UFSAR, in-service testing program data, and STP.

c. Conclusions

The licensee appropriately declared the RWCU inlet inboard isolation valve inoperable when it exceeded its TS required closure time of 20 seconds during surveillance testing. Further analysis by engineering personnel concluded that the 20.06-second closure time was well within the time for the valve to perform its intended function. The licensee properly initiated an AR to document the changes to the STP, UFSAR, and in-service testing program data.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Licensee Event Report (LER) 50-331/96-007-00: Failure of main steam relief valves and main steam safety valve to meet TS setpoints. This event was initially reported as a voluntary LER. The licensee, after additional review of industry reporting practices, determined this was reportable as a common cause failure pursuant to 10 CFR 50.73(a)(2)(vii), "Licensee Event Report System." The corrective actions for this voluntary LER were reviewed in the supplemental LER detailed below. This item is closed.

E8.2 (Closed) LER 50-331/96-007-01: Failure of three main steam relief valves (MSRVs) and one main steam safety valve (MSSV) to meet Technical Specifications setpoints (+/- 1 percent). On November 27, 1996, as-found testing was completed for the MSRVs and MSSVs removed during refueling outage (RFO)-14. Four of the eight valves failed to meet the setpoint requirements of the limiting safety system setting. The MSSVs and MSRV pilot valve were replaced with valves that were previously set pressure tested. Prior to this event, the setpoint test methodology had been improved to account for differences between the MSSVs' installed ambient conditions and the test conditions. The effectiveness of that corrective action in reducing the setpoint drift was reviewed after receipt of RFO-15 test results. Expanded setpoint tolerances (+1,-3 percent) were requested and granted for the Improved Technical Specifications (ITS). Results of the

as-found testing completed on May 2, 1998, for the valves removed during RFO-15 indicated that four MSRVs and one MSSV failed these new setpoint criteria.

The licensee initiated actions through additional analyses, to further expand the tolerances to +/-3 percent, which was the range of an industry initiative to expand the tolerances as described in licensing topical report NEDC-31753P. This corrective action was reported in LER 98-004-00, which documented the RFO-15 failures. This failure to implement adequate corrective actions to prevent meeting setpoint requirements of the limiting safety system settings for the MSSVs and MSRVs was considered a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," (50-331/98013-01(DRP)). However, this licensee-identified and nonrepetitive violation is considered a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. The licensee's proposed corrective action of expanding the tolerances recommended by the licensing topical report appeared adequate. This item is closed.

E8.2 (Closed) Inspection Followup Item 50-331/96011-06: Residual heat removal (RHR) check valve chattering. On November 24, 1996, the licensee identified that the "A" RHR loop injection check valve, V20-0082 was chattering. This issue was made an inspection followup item to review the licensee's subsequent detailed testing and operability evaluation. Testing indicated that as differential pressure (dp) decreased across the valve, due to check valve leakage, the valve would begin chattering. Chattering also decreased following power reductions. The chattering was attributed to the check valve being capable of swinging more freely due to maintenance performed during RFO-14. It was suspected that the pressure spikes caused by the recirculation pump were exciting the V20-0082 disc such that turbulence caused by the recirculation pump flow was causing the disc to impact the seat. Engineering personnel developed a temporary modification to increase the dp across the check valve in order to collect data at various pressures. Discussions between licensee engineering personnel and the valve vendor indicated the chattering should not damage the valve.

The operability evaluation appeared adequate. From an isolation perspective, the valve was exempt from Appendix J testing. Downstream of the check valve a normally closed isolation valve existed. Piping between the valves was rated for full system pressure. The isolation valve was required to open for low pressure coolant injection and shutdown cooling modes of RHR. This was a situation that was part of the design and licensing basis such that a failure of the check valve was adequately accommodated. Both core spray systems would be available for injection. The shutdown cooling mode of RHR was not safety-related and there were alternate methods of removing post-operation reactor core heat.

The maintenance history was also reviewed. Recent maintenance history indicated that the valve was overhauled every third operating cycle. Check valve V20-0082 tended to slowly degrade over time due to its service conditions; however, the valve had not degraded to an unacceptable level nor was it expected to degrade to an unacceptable level over the current cycle per the licensee's operability determination. The licensee had performed a local leak-rate test every refueling outage to trend check valve performance. A modification was in the prefabrication stage to connect the piping between the isolation valve and check valve of both trains of RHR injection to the

recirculation pump discharge piping to the RHR suction line from the suction side of the recirculation pump piping. This modification was designed to create a constant dp across the check valves. The inspectors reviewed the safety evaluation and work package. Also, the modification was discussed with the designated project engineer. No problems were noted. The modification was planned to be completed by the end of October 1998. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Daily Radiological Work Practices

a. Inspection Scope (71750)

The inspectors observed radiological worker practices during various maintenance activities detailed in this inspection report and also monitored radiological practices during daily plant tours.

b. Observations and Findings

Appropriate radiation practices were observed during maintenance activities. Overall, radiation postings were appropriate for plant conditions. On September 7, 1998, the inspectors identified that the emergency exit door located on the refuel floor was blocked by debris and the pathway to the door was roped off as a contamination area. The debris consisted of several tools and a contaminated laundry bag. The contamination boundary was extended to include the emergency exit door pathway to support fuel pin shipment activities. The inspectors were concerned that an emergency exit pathway that was blocked and roped off as a contaminated area could inhibit workers from exiting the floor.

Radiation protection personnel were informed and appropriately responded by removing the debris from the door pathway. Also, the licensee explained that workers had been instructed to cross through contamination boundaries during emergency conditions, if necessary, for personal safety. Workers would be surveyed for contamination later in a designated area onsite. Radiation protection personnel initiated AR 982344 to document the concern and corrective actions taken. The inspectors were satisfied with the licensee's corrective actions.

c. Conclusions

Radiological practices observed during maintenance activities were adequate. The licensee appropriately removed radiologically contaminated debris that blocked the pathway of an emergency exit door identified by the inspectors. Also the inspectors were concerned that the emergency door pathway was roped off as a contamination area boundary that could inhibit workers from exiting the area in an emergency. The

licensee appropriately explained that workers had been instructed to cross contamination boundaries in an emergency, if necessary, for personal safety.

P1 Conduct of Emergency Preparedness Activities

P1.1 Emergency Preparedness Dress Rehearsal Drills

a. Inspection Scope (71750)

The inspectors observed the emergency preparedness dress rehearsal drills in preparation for the October 21, 1998, NRC evaluated exercise. The initial dress rehearsal drill was conducted on September 10, 1998. A remedial drill was held on October 1, 1998. The inspectors observed portions of both drills and the pre-drill brief. Operations personnel were observed in the simulator. The inspectors toured the facilities and observed licensee personnel performance during the drills in the technical support center (TSC), operational support center (OSC) and emergency operations facility (EOF).

b. Observations and Findings

The inspectors observed the first drill at the simulator. The inspectors observed good command and control by the operations shift supervisor (OSS) and good three-way communications by the onshift operations personnel. Notifications to state and NRC were timely. Key plant parameters were monitored and proper followup actions were conducted. Crew briefs were given at adequate intervals and gave direction on upcoming priorities. The inspectors observed one minor detractor in otherwise good performance by the operators. The OSS continued to try alternate methods of rod insertion rather than begin to individually vent the HCUs. The TSC personnel subsequently suggested using the final method to insert the control rods.

The inspectors observed licensee personnel during the second drill in the TSC, OSC and EOF. Each facility was well maintained and in an excellent operational state of readiness. Current copies of the Emergency Plan and Emergency Plan Implementing Procedures and appropriate forms were present in each facility, as required. Licensee personnel in the TSC conducted the drill in a professional manner. No weaknesses were identified. The operating shift manager and OSS maintained their oversite role during the drill. Frequent crew briefs were held to provide the operating crew with the current plant status and to provide direction for the roles and responsibilities of each crew member. Operating crew members were attentive to instrumentation and controls during the drill.

c. Conclusions

Overall, licensee personnel performance in the practice emergency plan exercises was good. No significant weaknesses were noted. The emergency response facilities were in good material condition.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 13,1998. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Franz, Vice President Nuclear
G. Van Middlesworth, Plant Manager
R. Anderson, Manager, Outage and Support
J. Bjorseth, Maintenance Superintendent
D. Curtland, Operations Manager
R. Hite, Manager, Radiation Protection
M. McDermott, Manager, Engineering
K. Peveler, Manager, Regulatory Performance

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92901:	Followup - Operations
IP 92903:	Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-331/98013-01	NCV	failure to implement adequate corrective actions to prevent meeting setpoint requirements of the limiting safety system settings for the MSSVs and MSRVs

Closed

50-331/96-007-00	LER	Failure of three main steam relief valves and one main steam safety valve
50-331/96-007-01	LER	Failure of three main steam relief valves and one main steam safety valve
50-331/96011-06	IFI	Residual heat removal check valve chattering
50-331/96011-02	VIO	Average power range monitor 15 percent trip function inoperable during core alterations
50-331/98013-01	NCV	failure to implement adequate corrective actions to prevent meeting setpoint requirements of the limiting safety system settings for the MSSVs and MSRVs

Discussed

None

LIST OF ACRONYMS USED

APRM	Average Power Range Monitor
AR	Action Request
ATWS	Anticipated Transient Without Scram
CFR	Code of Federal Regulations
CRD	Control Rod Drive
DAEC	Duane Arnold Energy Center
dp	Differential Pressure
DRP	Division of Reactor Projects
EOF	Emergency Operations Facility
EQ	Environmental Qualification
ESW	Essential Service Water
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
IFI	Inspection followup item
IP	Inspection Procedure
IR	Inspection Report
LER	Licensee Event Report
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
MCC	Motor Control Center
MSRV	Main steam Relief Valve
MSSV	Main steam Safety Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OSC	Operations Support Center
OSS	Operation Shift Supervisor
PCIS	Primary Containment Isolation System
PM	Preventive Maintenance
PSIG	Pounds per Square Inch Gauge
RCIC	Reactor Core Isolation Cooling
RFO	Refuel Outage
RFP	Refuel Procedure
RHR	Residual Heat Removal
RWCU	Reactor Water Cleanup
SBLC	Standby Liquid Control
SIL	Service Information Letter
STP	Surveillance Test Procedure
TIA	Task Interface Agreement
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
VIO	Violation