AUGMENTED INSPECTION TEAM REPORT

U.S. NUCLEAR REGULATORY COMMISSION

QUAD CITIES UNIT 1 REACTOR SCRAM AND ASSOCIATED EQUIPMENT FAILURES

FEBRUARY 27, 1992

INSPECTION REPORT NO. 50-254/92007(DRS)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-254/92007(DRS)

Docket No. 50-254 License No. DPR-29

Licensee: Commonwealth Edison Company
1400 Opus Place
Downers Grove, IL 60515

Facility Name: Quad Cities Nuclear Power Plant, Unit 1

Inspection At: Quad Cities Site, Cordova, IL

Inspection Conducted: February 8 - 13, 1992

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Inspection Summary

Inspection on February 8 - 13, 1992 (Report No. 50-254/92007(DRS))

Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the Quad Cities Unit 1 scram and equipment failures which occurred on February 6 and 7, 1992. The review included validation of the sequence of events, the cause of the reactor scram, the failure of the HPCI stop valve, the failure of the "C" relief valve, the apparent failure of the reactor feed pumps to automatically trip at the appropriate vessel level and related operator actions, anomalies associated with the main steam line flow instruments, and evaluation of the licensee's corrective actions.

Results: No violations or deviations were identified in any of the areas inspected. No significant operational safety parameters were approached or exceeded. The AIT concluded the following:

1. The root cause could not be determined for the main steam high flow trip signal, which caused the Group I isolation that ultimately led to the reactor scram. The licensee had performed reasonable analyses and testing to determine root cause. Additional equipment to monitor for

abnormalities within the main steam high flow trip system was installed prior to Unit 1 start-up.

2. The failure of the HPCI stop valve was attributed to an inadequate maintenance work package, which was performed in February 1991. The work package was considered inadequate because it did not include as-found or as-left readings of the clearances between the poppet guide and valve poppet. After welding was performed on the poppet guide assembly, incorrect tolerances caused the valve to eventually become stuck in the open position during HPCI testing conducted on February 6, 1992.

3. The failure of the "C" Electromatic Relief Valve (ERV) was attributed to brass dust on the shorting contact bar, which was caused by main steam system vibration. The licensee determined that the dust originated from brass components near the shorting contact bar. In addition, the AIT concluded that deficient preventive maintenance for the ERVs existed. Although previous ERV failures indicated high resistance readings across the contact shorting bar, the licensee did not evaluate the possibility of adding preventive maintenance to periodically obtain resistance readings and clean the shorting bar. Also, the licensee did not pursue obtaining experience from other CECo nuclear plants that have the same type of relief valves. Preventive maintenance practices may have precluded the failure of the "C" relief valve.

4. The apparent failure of the Reactor Feed Pumps to automatically trip at the appropriate vessel level was attributed to instrument drift. Because the trip setpoint for one of the two level indicating switches had drifted from +48 inches to +53.5 inches, neither of the RFPs would have tripped automatically at the expected trip point. Operator actions manually tripped the RFPs before reaching the respective trip settings; however, if manual actions had not been taken the pumps would have automatically tripped at +53.5 inches.

5. Anomalies associated with the "B", "C", and "D" main steam line flow indicators, were attributed to a faulty power supply and square root converters. These instruments are for indication only and are different from the transmitters that provide the reactor protection shutdown. The control room flow indicators had "Off Normal Instruments" or ONI stickers on the front, which meant that maintenance was needed to repair previously identified problems of false flow indications. These erroneous flow indications occurred again after the MSIVs were closed during this event and resulted in personnel being sent into the plant to look for steam leaks that didn't exist. The AIT was concerned the operator's attention was diverted because of indicators that needed repair.

The team concluded that the operators performed well in mitigating the consequences of the reactor scram and Group I isolation.

1.0 Introduction

1.1 Event Summary

On February 7, 1992, at 2:01 a.m., the Unit 1 reactor scrammed from 100 percent power after an erroneous main steam line high flow signal apparently caused the main steam isolation valves (MSIV) to close automatically. During the event, the high pressure coolant injection (HPCI) system was out of service and in day 1 of a 14 day Limiting Condition for Operation (LCO).

Immediately following the main steam isolation and reactor scram, the control room operators manually tripped the "B" reactor feed pump (RFP) prior to the expected trip setpoint of +48 inches. The "A" RFP was also tripped by operators after reactor water level exceeded the RFP trip setpoint of +48 inches. The "C" RFP automatically started and was also tripped by operators. To lower reactor pressure, the operators opened the "B" electromatic relief valve (ERV). Once pressure dropped to an acceptable level, the "B" ERV was closed. The reactor core isolation cooling (RCIC) system was also manually initiated to control reactor pressure. The operators attempted to open the "C" ERV; however, the valve did not respond. The "B" ERV was again opened to control pressure.

During the event, the "B", "C", and "D" main steam line flow indicators indicated a small amount of steam flow with the MSIVs closed. A team of personnel was sent into the plant to inspect for steam leaks. When no leaks were identified, seven of the eight MSIVs were reopened. The "B" inboard MSIV was left closed due to a continued concern with the "B" main steam line flow indication.

At 3:17 a.m., the reactor scram was reset and at 4:00 a.m. the RCIC pump was taken off line.

1.2 Augmented Inspection Team Formation

Subsequent to the reporting of this event, Region III managers determined that an Augmented Inspection Team (AIT) was warranted to gather information on the causes, conditions, and circumstances relevant to several equipment failures associated with the reactor scram. On Friday, February 7, 1992, an AIT was formed consisting of the following personnel:

Team Leader: S. D. Burgess, Team Leader, RIII - Maintenance and Outages Section

Team Members:
- F. L. Brush, RIII - Resident Inspector, Clinton Power Station
- F. P. Paulitz, NRR - Instrument & Control Systems Branch
- R. M. Pulsifer, NRR - Division of Reactor Projects, PD III-2
- D. E. Roth, RIII - Observer
- H. A. Walker, RIII - Maintenance and Outages Section

The team arrived on site during the morning of February 8, 1992. In parallel with formation of the AIT, RIII issued a Confirmatory Action Letter (CAL) on February 7, 1992, which confirmed certain actions in support of the team and established conditions required to be met prior to the restart of the plant (Attachment 1).

1.3 AIT Charter

A charter was formulated for the AIT and transmitted from T. O. Martin to S. D. Burgess on February 7, 1992, with copies to appropriate EDO, NRR, AEOD, and RIII personnel(Attachment 2).

The AIT was terminated on Thursday, February 13, 1992.

2.0 Description of the Event

2.1 Sequence of Events

At the AIT's request, a chronology of events related to the scram on February 7, 1992, was assembled by the licensee. The chronology, which included operator actions, was verified to be accurate by AIT personnel by review of operating logs and interviews with licensee operating personnel. The chronology was as follows:

NOTE: All times are in Central Standard Time.

Initial Conditions

Unit 1	820 MWe HPCI out of service (day 1 of 14)
Unit 2	Refueling outage - core unloaded Reactor water level at flange

Time	Event Description
01:59	Center desk nuclear station operator (NSO) leaves control room.
02:01:06	Reactor scram, Group I isolation (MSIV closure)
02:01:09	Group II and III trip.
02:01:53	"B" RFP manually tripped by Unit 2 NSO. NSO resumed duties on Unit 2 by direction of Shift Control Room Engineer (SCRE).
02:02	Center desk NSO enters control room. SCRE initiated entry into abnormal procedure QGA 100.
02:02:53	Reactor water level indicates +48 inches on the "A" and "B" Yarway instruments. GEMAC level indicates +56 inches.

02:03	Shift engineer (SE) enters control room. Reactor water level: GEMAC = +56 inches, Yarways >50 inches.
02:03:46	"A" RFP manually tripped by Unit 1 NSO.
02:03:46	"C" RFP automatically comes on. RFP standby position was not deselected.
02:03:48	"C" RFP turned off.
02:05:52	Reactor pressure at 1041 psig.
02:06	Extra NSO opens "B" ERV to lower reactor pressure.
02:07	Extra NSO places residual heat removal (RHR) in torus cooling mode.
02:08:09	Reactor water cleanup blowdown flow established.
02:10	Communications center senior reactor operator (SRO) notifies the Assistant Superintendent of Operations (ASO) of event.
02:12	Shift foreman dispatched to inspect for steam break by SE. SE sent equipment attendants (EAs) to RHR to inspect immediately, nothing found. SE sent instrument maintenance foreman to check main steam line flow differential pressure (dP) instruments. All were consistent.
02:12:05	"A" RFP turned on.
02:14	Extra NSO closes "B" ERV.
02:19	Extra NSO placed RCIC in service to control reactor pressure.
02:29	Extra NSO attempts to open "C" ERV to control pressure. Valve did not open as indicated by position lights, acoustic monitors, steam flow, alarms, and pressure indication.
02:29:38	Extra NSO opens "B" ERV to control pressure.
02:30:36	"A" RFP turned off.
02:32	ASO contacts control room for briefing.
02:33:15	"A" RFP on. SCRE monitoring level per procedures.
02:33:17	Group II and III isolation.
02:35	"B" ERV closed.
02:53	Group I isolation reset. Area inspections show no visible indications of a steam leak.

02:58 Seven MSIV's opened by extra NSO. "B" inboard MSIV left closed due to concern with flow indication.

03:15 NRC resident notified of event.

03:17 Reactor scram reset.

03:30 ASO notified nuclear duty officer of event.

04:00 RCIC turned off. Condensate and feedwater system used for reactor level control.

04:02 Exited abnormal procedure QGA 100.

04:12 Emergency notification completed for engineered safety feature (ESF) actuations.

04:15 ASO notifies Technical Superintendent of event.

05:42 "A" RFP shutdown by Unit 1 NSO.

06:30 MSIVs closed to determine if MSIV flow obstruction existed. All MSIVs determined to be functional and isolatable.

2.2 Operator Response

The team reviewed plant logs, appropriate plant emergency and off-normal procedures, and interviewed the operating crew to determine what actions were taken in response to the event and the suitability of those actions.

On February 7, 1992, prior to the event, the operators were performing routine functions with no major evolutions or plant transients in progress. The HPCI system was in day 1 of a 14 day LCO for corrective maintenance as detailed in section 3.2.1. The initial event information noted by the operators was as follows:

- Annunciator - "Channel B Main Steam Line High Flow"
- All MSIVs indicated shut
- Reactor scram

At 2:01:06 a.m. on February 7, 1992, an automatic reactor scram occurred when the MSIVs closed on a main steam line high flow signal. Almost immediately, the Unit 2 NSO removed the "B" RFP from service after reactor vessel level, which had reached a minimum of -20 inches below instrument zero, started to increase. This was a normal action for the operators since the feedwater regulating valves had a history of seat leakage when fully closed. The SCRE initiated entry into Quad Cities General Abnormal Procedure QGA 100, "RPV Control," because reactor water level had decreased below +8 inches during the event. The following procedures were used as a result of the entry in QGA 100:

- Quad Cities Operating Procedure QCOP 3200-9, "Condensate/Feedwater"

- Quad Cities Operating Procedure QCOP 1300-2, "RCIC System Manual Start-Up" (Injection/Pressure Control)

- Quad Cities General Procedure QGP 2-3, "Reactor Scram"

After the shift engineer directed recovery operations, the Unit 1 NSO removed the "A" RFP from service after reactor water level exceeded the RFP trip setpoint of +48 inches. The "C" RFP automatically started because the operator failed to place the "C" RFP switch in the "OFF" position before securing the "A" RFP. Additional information on this action is contained in section 3.2.3 of this report. The extra NSO opened the "B" ERV to control reactor pressure and also placed RHR in torus cooling. At 2:12:05 the "A" RFP was placed in service. After pressure had decreased, the "B" ERV was closed and the RCIC pump was placed into service to control reactor pressure; however, the RCIC pump was not used to inject water into the reactor vessel.

As pressure again began to increase, the "C" ERV failed to respond when an operator attempted to open it. A detailed discussion of this failure is contained in section 3.2.2. Immediately, the operator opened the "B" ERV. The "A" RFP was then secured for three minutes to control reactor water level. Again, after pressure had decreased, the Unit 1 NSO closed the "B" ERV.

Early in the event the SCRE requested that IM personnel check the MSIV high flow sensors. After checks were made, the IMs reported that there were no apparent problems. The operator also noticed anomalies with the "B", "C", and "D" main steam line flow indications. Because these instruments indicated a small amount of flow when the MSIVs were closed, a team of personnel was sent into the plant to inspect for signs of a steam leak. No leaks were identified and seven of the MSIVs were reopened. The "B" inboard MSIV was left closed due to a continued concern with the "B" main steam line flow indication. Further discussion of these anomalies is contained in section 3.2.4.

At 3:17 a.m., the reactor scram was reset and at 4:00 a.m. the RCIC pump was taken off line and procedure QGA 100 was exited. The shift engineer also reviewed Quad Cities Abnormal Procedure QGA 200, "Primary Containment Control," during the event and determined that plant conditions did not require entry into that procedure.

Based on review of this event and operator interviews, the team determined that the operators performed well in responding to the plant transient. Their actions were prudent and conservative, placing the plant in a stable condition in a very short time.

3.0 Inspection Results

3.1 The Cause of the Reactor Scram

The cause of the Group I isolation signal, which resulted in the closure of the MSIVs, and ultimately in the reactor scram, could not be determined. When the reactor scrammed, only the "B" Channel High Steam Flow annunciator was the reactor scrammed, only the "B" Channel High Steam Flow annunciator was received in the control room. No alarms were received for the "A" Channel High Steam Flow, the A and B Group I isolation annunciators, High Steam Flow or Group I Isolation computer point alarms nor any other Group I isolation alarms.

The Group I isolation signal comes from Barton Model 27B differential pressure indicating switches (DPIS), four of which are connected to each flow element with a flow element on each of the four main steam lines. These 16 DPISs are located in the RHR room in the southeast corner of the reactor building basement. Eight of the switches are on panel 2201-10 sections A and B and eight are on section C. In order to achieve a full Group I isolation, one of the eight DPISs in each channel must actuate, which will cause the MSIVs to close and scram the reactor.

The licensee speculated that the Group I isolation was caused by a spurious actuation of the DPISs, possibly by personnel bumping the racks or instruments since this had occurred in the past. The security card readers and radiation protection control records indicated only three personnel could have been in the area of the racks when the plant scrammed; however, interviews with these personnel indicated that they were not in the immediate area of the instruments when the event took place.

The licensee performed a functional check and calibration of the trip circuitry. One DPIS was replaced and all indications and inputs to annunciators and computer points worked correctly.

To determine whether bumping of these instruments or racks could have caused the reactor scram, the licensee conducted a special test that pressurized the DPISs to a pressure differential close to the trip setpoint. The torus bulk head door and rack enclosure door were slammed. The impulse sensing lines, racks, and instruments were bumped for trip susceptibility. No alarms were received for high steam flow or Group I isolation as the result of the special test.

The licensee also checked several of the flow check valves in the sensing lines and determined that there was no blockage. Walkdowns of the sensing lines and the electrical wiring from the instrument racks to the circuit fuses and trip relays (102 A through D) in the control room panels were performed but no abnormalities were identified.

The AIT team inspected the instrument racks to determine the degree of protection of the instruments on the racks from accidental bumping. The probability of bumping these instruments or a rack when passing from the torus area to the stairwell in that southeast RHR corner room is remote. The rack containing instruments A through H is located next to a wall with space between the instruments and the stairway. There is a wire mesh barrier over the top of the rack and on the side of the stairway between the instruments with a door for access to the racks. The other rack is 90 degrees around the corner, also against the wall, and it has a wire mesh barrier above it. Personnel must pass in front of rack section A and B before getting to section C.

During the exit, the licensee committed to monitor the eight main steam flow sensing lines with pressure transducers whose output will be recorded to determine if there are any process fluid disturbances. The four DPIS' input contacts to each of the four sub-channel trip logic relays will also be monitored and recorded to pinpoint which set is actuating. This monitoring is intended to help identify the source of the signal that caused the MSIV isolation on February 7, 1992. The monitoring equipment was in place prior to start up from this event.

The licensee also proposed a long term modification to the main steam line high flow detection system. The digital Barton DPIS instruments will be replaced with an analog system. Unlike the present DPISs, the functional check of this new equipment would be made from an area not subject to radiation. This modification is projected to be more reliable as well as reduce exposure to personnel.

3.2 Equipment Failures or Malfunctions

3.2.1 Failure of HPCI Stop Valve

During quarterly HPCI pump tests the HPCI steam stop valve successfully operated a number of times from April 1991, until February 6, 1992, when the valve failed to close during post modification testing of the remote HPCI turbine trip pushbutton. Unsuccessful attempts were made to close the valve; however, the valve was eventually closed by applying an external force.

The HPCI turbine steam stop valve is a poppet type, hydraulically positioned shut-off valve designed to close quickly on the following trip signals: HPCI turbine overspeed, high reactor water level, low HPCI booster pump suction pressure, high HPCI turbine exhaust pressure, remote HPCI turbine trip pushbutton, and local manual trip lever.

Following the failure and to allow for further troubleshooting, maintenance personnel attempted to disconnect the actuator from the poppet stem. The valve bonnet was then removed to facilitate inspection of the poppet. The outside of the poppet and the inside of the poppet guide, which was welded to the bonnet, were severely galled. This interference prevented the valve from stroking.

The AIT determined that the root cause of the valve failure was an inadequate maintenance work package that was completed in February 1991. The work package was inadequate, because it did not include as-found or as-left readings of the clearances between the poppet guide and valve poppet after welding was performed on the poppet guide assembly. The welding caused the guide to become oval shaped and to lose perpendicularity with the bonnet, which allowed the poppet to come into contact with the guide after the valve was reassembled and resulted in fretting of both metal surfaces when the valve was operated. The valve stuck open during the HPCI test that was conducted on February 6, 1992.

The licensee repaired the Unit 1 poppet assembly in accordance with vendor recommendations using the poppet guide and valve bonnet from the Unit 2 HPCI valve. During inspection of the Unit 2 stop valve, indications of contact between poppet and poppet guide were noted. Measurements indicated that the poppet guide was perpendicular to the bonnet but the guide was slightly out of round. In 1988, cracks were also repaired on the poppet guide to bonnet weld similar to the weld repair on the Unit 1 valve. The work package had instructed maintenance personnel to take as-found measurements on the poppet guide's position in relation to the bonnet. However, there were no instructions to measure the concentricity of the guide. The licensee planned to replace or repair the Unit 1 poppet guide and install it in the Unit 2 HPCI stop valve.

3.2.2 Failure of "C" Electromatic Relief Valve

During cool down from the Unit 1 reactor scram on February 7, 1992, pressure control was accomplished by manually initiating the RCIC system and opening the ERVs, as needed, to avoid reaching the automatic pressure relief set points. As pressure rose initially, ERV "B" was opened and, after pressure dropped to an acceptable level, the valve was closed. After a short period, as pressure began to rise again, the control switch for ERV "C" was placed in the open position; however, the valve did not respond. The "B" valve was then opened a second time to control the pressure.

The ERV is a six inch solenoid actuated pressure relief valve, which may be operated, when desired, by closing a switch that allows 125 volts DC to actuate the operating solenoid. Automatic pressure relief is accomplished by using a pressure sensing element to control the solenoid. A cut out switch (contact shorting bar) is built into the solenoid assembly to increase coil resistance in order to reduce the solenoid current when the solenoid is actuated and in the holding position. The Unit 1 plant has five pressure relief valves that are used to prevent over pressurization of the main steam system. The "A" relief valve is a dual purpose valve manufactured by Target Rock and the other four valves, "B", "C", "D" and "E", are ERVs manufactured by Dresser Industries.

During troubleshooting, two unsuccessful attempts were made to actuate the valve from the control room. After the cover for the solenoid was removed, the valve opened on the first attempt. On subsequent attempts the valve appeared to open and close normally. The cover and internal components were carefully examined along with the plunger and other moving parts of the solenoid; the results were inconclusive. Electrical connections were tight and electrical measurements indicated that the valve solenoid coil was normal. The resistance reading across the cut out switch terminals was 182 ohms, which was very high compared to the normal resistance of less than 1 ohm. The licensee concluded that the high resistance across the cut out switch contacts caused the failure of the solenoid valve on ERV "C" to operate on demand.

An inspection of the "C" cut out switch, indicated a tarnish build up on the contact points. An analysis of the material indicated that the tarnish most likely was caused by the loose dust found in the enclosure which vaporized during contact arcing. The origin of the dust appeared to be wear from moving brass parts located inside the actuator. After cleaning, the moving parts of the four Unit 1 ERVs were lubricated with a graphite based lubricant to reduce friction and wear.

The AIT agreed with the licensee that the failure of the "C" ERV was attributed to brass dust on the contact shorting bar; however, the team also concluded that deficient preventive maintenance (PM) for the ERVs existed. Maintenance history indicated that Unit 1 ERVs had failed to open 12 times since 1975. Four of these failures, including the most recent, were attributed to problems with the cut out switch; however, it was difficult to determine if the failure mechanism was the same as the February 7, 1992 failure. One of the failures indicated a high electrical resistance across the cut out switch contacts but none of the previous failures indicated tarnish or other build up on the switch contact surfaces. Although electrical PM tasks were in place as required by the EQ requirements and vendor recommendations, the licensee did not evaluate the possibility of adding PM to periodically obtain resistance readings and clean the cut out switch. Also, the same type of relief valves are used at the licensee's Dresden Station, but the licensee had not evaluated Dresden's experience with the valves for applicability to Quad Cities. Dresden's PM program included obtaining resistance readings and lubricating certain brass components in the valve actuator. Dresden had not noticed any dust in their valve actuators, nor failures of the ERVs due to high resistance across the cut out switch.

The "C" ERV cut out switch was replaced and the solenoid was cleaned, reassembled and tested. The valve stroked properly after work was completed. The licensee checked resistance readings on the remaining Unit 1 ERVs and all were below eight ohms. The ERVs were then cleaned and tested. As-left resistance measurements across the cut out switches for all four ERVs was less than one ohm. All four ERVs stroked properly after the cleaning and tests.

The team reviewed maintenance history dating back to 1986 for the "A" Target Rock relief valve. No significant failure trends or excessive repetitive failures were noted.

Licensee personnel stated that there were no existing mechanical PM tasks in place for the ERVs; however, some types of mechanical PM were being performed. For example, the ERV pilot valve internals were changed each time a unit outage occurred in order to prevent inadvertent opening of the ERVs due to excessive leakage through the pilot valves. A review of maintenance history verified the pilot valve replacement.

The environmental qualifications (EQ) for the ERVs' qualified life of 40 years was based on drywell temperatures of 150 degrees. Information supplied by the licensee indicated that temperatures as high as 176 degrees had been recorded in 1991 in the vicinity of the ERVs. Licensee personnel stated that they thought that the temperature issue had been previously noted and evaluated, however, the previous evaluation could not be located. Engineering did a brief analysis of the temperature concern and determined that the equipment would still be qualified for 40 years at temperatures as high as 187 degrees. A copy of this preliminary analysis was provided to the NRC inspector. The licensee committed to providing the NRC the final analysis, complete with appropriate calculations, within ten days of the exit.

3.2.3 Failure of the Reactor Feed Pumps to Automatically Trip at the Appropriate Vessel Level

The Unit 1 NSO tripped the "A" RFP after the "A" Yarway reactor water level indication exceeded +50 inches since the feed pumps were expected to trip at +48 inches. Once the "A" RFP was tripped, the "C" reactor feed pump automatically started because it was in the STANDBY position. The Unit 1 NSO then immediately secured the "C" RFP. The Unit 1 NSO stated that he remembered seeing the Unit 2 NSO place the "C" standby feed pump selector switch in the OFF position but did not check the switch before securing the "A" RFP.

The RFPs are motor driven centrifugal pumps that supply water to the reactor vessel. The "A" and "B" RFPs were in service with the "C" RFP in STANDBY when the Unit 1 reactor tripped. Forty-three seconds after the scram, the Unit 2 NSO removed the "B" RFP from service per procedure QOP 3200-5, "Reactor Feed Pump Shutdown." The procedure required the "C" standby reactor feed pump selector switch be placed in the OFF position when removing a feed pump from service to prevent an inadvertent start of the standby pump. The switch was then placed back in STANDBY after the "B" pump was stopped since the "A" feed pump was still in service. The "B" Yarway reactor water level instrumentation indicated +48 inches, which was the setpoint for the main turbine and RFP automatic trip.

As level continued to increase, the setpoint (+48 inches) for the "A" RFP trip was passed, but the "A" pump did not trip. This did not result in a safety concern because the operator tripped the pump at >50 inches. It was subsequently determined that the setpoint for the "A" RFP had drifted and the "A" RFP would have tripped at +53.5 inches. The main turbine vendor recommended that the trip level be set at +60 inches to prevent turbine damage due to carryover of water associated with high reactor vessel water level in a transient. There is no credit taken for safety in the FSAR nor any setpoint or surveillance in the Technical Specification for these Yarway level indication transmitter switches. However, the drifting indicates that more frequent calibrations should be performed to ensure that the RFPs trip at the expected level. To assure the accuracy of the RFP trip setpoint, the licensee committed to calibrating these instruments on a quarterly basis instead of the current refueling cycle basis.

The licensee performed an as-found calibration check of the "A" and "B" Yarway level indication transmitter switches (LITS 59 A&B) that should have initiated the +48 inch trip signal. Both LITS signals are required to trip the RFPs. The "A" LITS trip setpoint was +53.5 inches. The "B" LITS setpoint was +48 inches. The operators stated that the reactor water level observed on the Yarway indicators never exceeded +52 inches. If the operator had not stopped the "A" RFP at >50 inches, the RFPs would have automatically tripped when the reactor vessel water level reached +53.5 inches, which is 5.5 inches above the design trip point. The "A" LITS was recalibrated to +48 inches and a functional test was satisfactorily performed on the trip circuit.

The Yarway LITS instruments have had a history of drifting as evidenced by the calibration and maintenance records for these instruments from October 9, 1989, through February 8, 1992. Calibration history of the "A" Yarway LITS showed that the instrument had drifted both low and high three out of four of the last calibrations (including the post-scram calibration). The "B" Yarway LITS had drifted low twice before being replaced in November 1989.

3.2.4 Anomalies Associated with the Main Steam Line Flow Instruments

During this event, when the MSIVs were closed, the operator reported some indication of main steam line flow on the control room board indicators 1-640-23A, B, C, D. (These instruments are for indication only and are different from the transmitters that provide the reactor protection shutdown.) Flow of 0.5 million pounds per hour (MPH) was observed on the "A" flow indicator (FI) and the "B" FI indication was observed to be bouncing up and down. These erratic flow changes were also seen on the total steam flow recorder after the trip. The recorder displayed spikes ranging from 0.0 MPH to 2.5 MPH.

The "B", "C" and "D" main steam line flow indicators in the control room had "Off Normal Instrument" or ONI stickers on the front of the indicator meaning that maintenance was needed to repair previous problems noted with flow indications. Although there was no indication of high temperature or high radiation in the main steam line area, these control room indications provided questionable data to the operator during this event. These erroneous flow readings resulted in personnel being sent into the plant to investigate potential steam leaks that didn't exist.

The AIT reviewed the open maintenance work requests corresponding to the ONI stickers for these flow instruments. The "B" flow indicator had two open work requests and the "C" and "D" each had one. These work requests were in various stages of completion and dealt with measured flow when no flow existed on "B", "C" and "D", and erratic flow indication on the "B" indicator. One of the work requests required work to be done on the Foxboro square root converters that supplied input to the four main steam high flow indicators and total steam flow for the recorder used during this event. These same problems were observed by operators during the event on February 7, 1992. Unit 2 also had an ONI on the "C" main steam flow indicator with similar problems as found on the Unit 1 indicators. See section 3.2.4.1 for further discussion of the licensee's ONI program.

The licensee performed troubleshooting on the instruments and determined that the Foxboro square root converters needed to be replaced on all instruments, and the flow transmitter and power supply needed to be replaced on the "B" instrument. These square root converters provided a signal for indication only and not for the MSIV Group I isolation circuitry. Because these square root converters were no longer available from the manufacturer, converters from Unit 2 (in a refueling outage) were used. The licensee stated that an alternate converter or a new design would be examined for the Unit 2 instruments.

The team reviewed the maintenance and calibration history for the flow indicators and determined that outstanding work requests existed for these problems and were the reason for the ONI tags.

3.2.4.1 Off Normal Instruments

The AIT determined that the licensee needed to ensure timely corrective action of ONIs to ensure that instruments needing repair do not divert the operator's attention or impact the operator's response to plant transients.

The instruments and equipment in the control room that are operating off-normal are tracked on the ONI list and governed by procedure QAP 300-34, "Off-Normal Instruments and Equipment," Revision 4.

The licensee currently logs ONIs manually and on a computer list. When all of the data is on the computer the official log for ONIs will be a Total Job Management (TJM) report to be kept in the control room. QAP 300-34 required that operations categorize these items into Category I or II depending upon importance and route for assignment of work request and resolution.

QAP 300-34 stated that on a monthly basis the SCRE shall notify an Operating Engineer on ONI items that have been active longer than two weeks in order to ensure timely repairs on instruments that can be repaired. A copy of an audit report dated December 21, 1991, indicated that there were 110 ONIs meeting this criteria. At the time of the reactor scram, there were 84 ONI items. Of the 84 open ONIs, none were Regulatory Guide 1.97 instrumentation, three were safety-related, and five could be used as Emergency Operating Procedure (EOP) equipment. The team determined that, in all cases, adequate and redundant means were available to provide the necessary input.

The AIT reviewed all of the control room ONIs and concluded that no safety significant problems existed. However, several ONIs have been outstanding for a long time. One-safety related ONI corresponded to a work request written in April 1988. Another safety-related ONI, initiated in October 1991, for a closed indication light for Recirculation Pump A suction valve, was repaired in February 1992, by tightening a loose wire for the bulb.

Overall, the AIT considered the ONI process to be weak. The resident inspectors have been following this issue for several months and the licensee was slowly working off the backlog of open items; however, greater emphasis is needed to ensure that ONIs are addressed and resolved in a timely manner. The licensee stated at the exit meeting that work had been completed on an additional 25 to 30 ONIs on Unit 1 since February 7, 1992.

3.2.5 Other Less Significant Equipment Failures

The team interviewed operators and reviewed the active out-of-service list and the ONI list and determined that there was no indication of other significant equipment problems with safety related or balance of plant equipment that could have interfered with the ability of the operators to safely operate the plant. A review of the sequence of events computer data showed that the "B" ERV was cycling open and closed; however, other data in the control room adequately showed that the "B" ERV did not cycle but operated correctly. This problem was traced to a loosely mounted acoustic monitor that resulted in false ERV position input for the sequence of events data recorder. All other acoustic monitors were found securely attached.

4.0 Conclusions

After completing the AIT Charter, the team was able to make the following conclusions:

1. The root cause could not be determined for the main steam high flow trip signal, which caused the Group I isolation that ultimately led to the reactor scram. The licensee had performed reasonable analyses and testing to determine root cause. Additional monitoring equipment to monitor for abnormalities within the main steam high flow trip system was installed prior to Unit 1 start-up.

2. The failure of the HPCI stop valve was attributed to an inadequate maintenance work package, which was performed in February 1991. The work package was considered inadequate because it did not include as-found or as-left readings of the clearances between the poppet guide and valve poppet. After welding was performed on the poppet guide assembly, incorrect tolerances caused the valve to eventually become stuck in the open position during HPCI testing conducted on February 6, 1992.

3. The failure of the "C" Electromatic Relief Valve (ERV) was attributed to brass dust on the shorting contact bar, which was caused by main steam system vibration. The licensee determined that the dust originated from brass components near the contact shorting bar. In addition, the AIT concluded that deficient preventive maintenance for the ERVs existed. Although previous ERV failures indicated high resistance readings across the contact shorting bar, the licensee did not evaluate the possibility of adding preventive maintenance to periodically obtain resistance readings and clean the shorting bar. Also, the licensee did not pursue obtaining experience from other CECo nuclear plants that have the same type of relief valves. Preventive maintenance practices may have precluded the failure of the "C" relief valve.

4. The apparent failure of the Reactor Feed Pumps to automatically trip at the appropriate vessel level was attributed to instrument drift. Because the trip setpoint for one of the two level indicating switches had drifted from +48 inches to +53.5 inches, neither of the RFPs would have tripped automatically at the expected trip point. Operator actions manually tripped the RFPs before reaching the respective trip settings; however, if manual actions had not been taken the pumps would have automatically tripped at +53.5 inches.

5. Anomalies associated with the "B", "C", and "D" main steam line flow indicators, were attributed to a faulty power supply and square root converters. The control room flow indicators had "Off Normal Instruments" or ONI stickers on the front, which meant that maintenance was needed to repair previously identified problems of false flow indications. These erroneous flow indications occurred again after the MSIVs were closed during this event and resulted in personnel being sent into the plant to look for steam leaks that didn't exist. The AIT was concerned the operator's attention was diverted because of indicators that needed repair.

6. Operators performed well in mitigating the consequences of the reactor scram and Group I isolation.

7. The licensee's recovery from this event was thorough. Corrective actions to address each of the equipment failures or anomalies were considered adequate and corrective actions to prevent recurrence were reasonable and complete.

5.0 Exit Interview

The team met with licensee representatives (denoted in attachment 3) in a public exit meeting on February 13, 1992, and summarized the purpose, AIT charter items, and findings of the inspection. The team discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the team during the inspection. The licensee did not identify any such documents or processes as proprietary.