U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Facility:	Sequoyah Nuclear Plant, Unit 1 & 2
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Dates:	September 19 through November 2, 1996
Inspectors:	M. Shannon, Senior Resident Inspector D. Starkey, Resident Inspector P. Kellogg, Reactor Inspector, RII
Approved by:	M. Lesser, Chief Projects Branch 6 Division of Reactor Projects

Enclosure 1

EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327, 328/96-13

This special inspection was conducted to review the events associated with the reactor shutdown and subsequent manual tripping of Unit 2 on October 11, 1996. Equipment failures and/or complications included excessive reactor coolant pump seal leakage which caused the need for an immediate reactor shutdown; a turbine runback due to failed turbine impulse pressure switches, which caused the need for a manual reactor trip; a failed main feedwater isolation valve to close; inadequate auxiliary feedwater control; and a water hammer in the steam dump system which caused damage to piping and hangers.

In addition, this special inspection was conducted to review issues associated with inadequate maintenance on a reactor trip breaker (RTB) and the subsequent replacement of the Unit 2 RTB "B" with the spare breaker. The P-4 function was found to have been inoperable greater than allowed by Technical Specifications.

The following apparent violations and findings are associated with the October 11 reactor trip event:

- An apparent violation was identified for the failure to identify the cause of the main feedwater isolation valve (MFIV) motor brake failures and to take adequate corrective actions for the water intrusion into the brake assembly. A weakness was identified in the licensee's repeat failure tracking/trending programs associated with Work Requests (WR) and Problem Evaluation Reports (PER) to identify repeat MFIV equipment failures.

- An apparent violation was identified for the failure to take adequate corrective actions to prevent further flexible conduit damage on the MFIVs.

- An apparent violation was identified for failure to implement corrective actions related to previously identified deficiencies related to ASCO solenoid valves.

- An apparent violation was identified for the failure to implement adequate corrective actions associated with the fire system actuation in June 1996.

- A positive observation was made in that the shift manager provided good oversight for the unit 2 downpower and appropriately ordered the tripping of the unit when the unanticipated turbine runback occurred. Operator performance was good in controlling the event and responding to the abnormal plant conditions during the event.

- A positive observation was identified in that the operators appropriately isolated the auxiliary feedwater (AFW) system to prevent

an uncontrolled cooldown of the reactor coolant system (RCS). This required timely management approval due to lacking procedural guidance in the emergency operating procedures.

- A weakness was identified following a water hammer event that severely damaged the piping supports and cracked the steam dump to main steam line weld in the discharge line for SD-111. There have been previous piping support damage events associated with the steam dump system and the licensee had not identified the root cause.
- A weakness was identified in that the licensee failed to identify the malfunctioning steam dump drain tank level switch, causing the steam dump lines to not drain properly. The operator rounds sheet lacked adequate guidance regarding the steam dump drain tank level controls.
- A weakness was identified in that the assistant unit operators failed to identify the damaged piping supports following the reactor trip (8.5 hours), although required to monitor the steam dump valves once per shift, in addition to normal roving tours of the building.
- A negative observation was made concerning the water intrusion into a single zone actuation fire detector, which resulted in the July 1996, deluge actuation.
- A weakness in the licensee's training program was identified in that the operators lacked knowledge in the functioning of the turbine impulse pressure switch circuitry.
- A negative observation was identified concerning the failure of two non-safety related and non-independent switches, which resulted in the inability of operators to reset an AFW actuation signal.
- A weakness was identified for the maintenance practice of using RTV sealant, which could result in acetic acid intrusion into the brake assembly, which in turn could cause damage to the MFIV brake assembly.
- A negative observation was made in that the motor to brake assembly gasket was missing.
- A negative observation was noted regarding a poor maintenance practice which permitted a dust cover to be left in the exhaust port of a solenoid valve following maintenance activities.
- A negative observation was made due to the improper setting of the air supply regulator for the reactor coolant pump (RCP) seal leakoff isolation valve.
- A negative observation was made concerning the wrong instruments being referenced in an abnormal procedure.

The following apparent violations and findings are associated with the inoperable P-4 function due to reactor trip breaker maintenance.

- An apparent violation was identified when an inoperable reactor trip breaker was in service for greater than the time allowed in the Technical Specification (TS) Limiting Condition for Operation (LCO).

- An apparent violation was identified when reactor trip breaker maintenance procedure sections were performed out of sequence. A second example of this apparent violation was identified regarding the maintenance procedure which did not provide cautions or adequate instructions regarding the reassembly of the reactor trip breaker auxiliary contact linkage assembly following lubrication.

- An apparent violation was identified for failure to perform an operability/reportability determination as required by SSP-3.4. The lack of action by the event critique team and technical support personnel to report the inoperability of the reactor trip breaker led to this problems.

- A weakness was identified in the thoroughness of the root cause determination process regarding the reactor trip breaker event critique.

- A positive observation was identified when operations stressed the need to remove a potentially faulty reactor trip breaker (RTB) from service and in not allowing troubleshooting of the breaker while still in service.

- A negative observation was noted when maintenance failed to ensure that Quality Control (QC) personnel would be available as necessary during a reactor trip breaker refurbishment.

- A negative observation was identified when engineering "dummied" a signal to a computer alarm circuit prior to determining the cause for the signal.

Report Details

I. Reactor Trip of October 11, 1996

A. Operational Aspects

1. Inspection Scope (71707)

On October 11, 1996 at 8:27 a.m., due to a turbine runback, Unit 2 was manually tripped. Several problems were encountered prior to and during recovery efforts. The inspector observed the unit shutdown, reactor trip, unit cooldown, and placing of RCS on shutdown cooling.

2. Observations and Findings

On October 11, 1996, at 3:12 a.m., Unit 2 experienced a higher than normal seal leakoff on the #4 RCP seal #2 of approximately 1.5 gpm. The seal leakoff for the #1 seal dropped to .6 gpm (normally 3.0 gpm). Plant shutdown is required, per abnormal operating procedure, within 8 hours when #2 seal leakoff exceeds .5 gpm. A controlled plant shutdown was initiated at 5:22 a.m. At 8:24 a.m., the ICS computers both failed; however, this appeared to only affect computer data points and recorder inputs. Power was reduced to approximately 50% and one operating feedpump was stopped. At this point, a main turbine runback automatically initiated at 200% per minute, all unisolated main steam dumps went open as designed, and rod control began inserting rods at a high rate. The Shift Manager directed that the reactor be manually tripped.

Following the trip, operators had some difficulty controlling cooldown. The RCS reached the low Tave setpoint (550 degrees F) and the feedwater isolation signal was actuated. The #3 feedwater regulating valve indicated in the mid position (limit switch problem only) and the #4 feedwater isolation valve failed "open" and its MCR indication was lost. During the unit trip recovery procedure steps, the operators attempted to take manual control of the AFW pump flow control valves, but were unable to reset the AFW actuation signal. A decision, by the Operations Manager, Operations Superintendent, Shift Manager and Unit Supervisor, was made to place the motor driven AFW pumps in pull-to-lock and to close the isolation valves on the turbine driven AFW pump. Tave dropped to approximately 538 degrees F and the low-low Tave setpoint (540

degrees F) was reached which locked out the steam dumps. In addition, the operators were required by procedure to initiate emergency boration due to being below 540 degrees F. Steam generator levels were maintained as required and approximately 450 gallons of borated water was injected into the RCS during the event.

A controlled cooldown of the RCS commenced at approximately 4:15 p.m. on October 11. Initially, operators had trouble controlling the cooldown rate due to sporadic operation of steam dump valve SD-111. Steam dump valve SD-111 had to be isolated and cooldown of the RCS was successfully continued. Mode 4 was entered at 8:58 p.m., and RHR was placed in the shutdown cooling mode at approximately 12:16 a.m., on October 12.

The inspectors observed operator actions during the controlled shutdown, the trip, the cooldown and while placing RHR in service. The operators performed well with appropriate supervisory oversight by shift management and site management. Routine status briefings were held, which the inspectors considered to be beneficial to the control room staff and for the control of the event and the event related activities.

The various equipment problems resulted in challenges to the operators. These individual equipment problems are discussed in the following sections of this report.

3. Conclusions

Operator performance was good in controlling the event and responding to the abnormal plant conditions. The Shift Manager provided good oversight for the Unit 2 downpower and appropriately ordered the tripping of the unit (within 10 seconds) when the unanticipated turbine runback occurred. These are considered to be a positive observations.

There were several equipment failures that complicated operator recovery actions which indicate continued plant equipment reliability problems, for both safety related and non-safety related equipment.

B. Steam Dump Water Hammer Damage

1. Inspection Scope (71707, 62707, and 37551)

When operators attempted to start the RCS cooldown, operation of the steam dump valve was erratic and resulted in a higher than desired cooldown rate or no cooldown rate at all. The affected steam dump valve was isolated and cooldown proceeded with no further problems. The inspector reviewed the operation of the steam dump valves during the event and walked down the steam dump system.

2. Observations and Findings

During the turbine runback, the inspector observed that all of the steam dump valves opened (indicator lights in MCR). There were no indications in the control room or reports from the turbine building to indicate

that the steam dumps were not operating properly. Later in the day, when the operators went to the "pressure mode" of steam dump operation, steam dump SD-111 exhibited erratic operation and after a couple of attempts, the operators stopped using the affected steam dump. Cooldown of the RCS was then continued by using two other steam dumps in the "pressure mode." Following plant cooldown, SD-111 was found to have a broken feedback arm, which apparently caused the erratic action during the initial cooldown. It could not be determined how the feedback arm became broken.

Reports from the turbine building indicated piping damage and support damage associated with SD-111. The inspector walked down the steam dump system and noted significant misalignment of the SD-111 piping and severe damage to the piping supports. During the walkdown, the inspector also noted minor water hammer (noise with no pipe movement) occurring on three isolated steam dump lines, which indicated that the lines were partially full of water. Additional inspections by the licensee noted crack indications on the outside diameter of the main steam line weld to the steam dump transition piping. The crack indications were at the 12 o'clock and 6 o'clock positions and measured approximately 1 7/8 inch long by 1/2 deep and 7/8 inch long by 1/2 inch deep respectively. The main steam line piping thickness is nominally 1-1/4 inches thick and did not have any reported through wall leakage.

During subsequent review, the licensee identified a failed level switch on the steam dump drain tank. The failed switch prevented the tank from draining and due to the common SD drain piping system arrangement, potentially all of the steam dump exhaust lines to the condenser were partially full of water prior to the event. There had been leakage past four of the steam dump valves, SD-103, SD-104, SD-105 and SD-109, since the last outage and two valves had been isolated (SD-103 and SD-104) due to more significant leakage. These conditions would have provided a sufficient amount of water to partially fill all of the steam dump exhaust lines.

Further review noted a history of prior system structural and component problems. The piping supports for SD-107 were damaged during a previous event in 1993. During a recent walkdown of the steam dump system, the inspectors had noted that SD-103 had a broken support strut. A work request had been written. In addition, following disassembly of SD-103, the licensee found that the valve had a broken valve stem and the stem shield plate was cracked and a piece of the shield plate was missing. The SD-107 support damage, the SD-103 broken strut, and the damage SD-103 valve internals and stem, appeared to be indicators of system operational problems and/or previous water hammer events.

The operator rounds sheet directed the operator to inspect various steam lines and moisture traps associated with the steam dump system but did not require the assistant unit operators to take routine readings on the steam dump drain tank level. Routine readings on this tank could have identified the failure of the level switch.

The inspector also noted that the damaged SD-111 supports were not identified until 5:00 p.m., on October 11. The runback and subsequent reactor trip took place at 8:30 a.m., at which time the rapid opening of the steam dumps took place and the damage to the piping supports was thought to have occurred. However, the roving assistant unit operators did not identify the damaged system, although required to verify operability of the steam dump valves once per shift.

Following the event the licensee repaired the cracked main steam line, replaced the damaged steam dump piping and supports, repaired the leaking steam dump valves and repaired the faulted steam dump tank level switch. In addition, the licensee performed inspections of the unit 1 and Unit 2 steam dump lines and the Unit 1 steam dump drain tank and its operation and did not identify any additional problems. The licensee has also inspected the main condenser internals for damage with no problems identified.

In addition to the apparent water hammer damage to the steam dump piping, during the event, the plant manager observed secondary water hammer indications, with various reliefs lifting and directed that the turbine building be evacuated of non-essential personnel.

3. Conclusions

The licensee failed to identify the malfunctioning steam dump drain tank level switch, which resulted in the steam dump lines not draining properly. The operator rounds sheet lacked adequate guidance regarding the steam dump drain tank level controls and is considered to be a weakness.

Assistant unit operators failed to identify the damaged piping supports following the reactor trip (8.5 hours), although required to monitor the steam dump valves once per shift, in addition to normal roving tours of the building. This is considered to be a weakness.

A water hammer event, in the discharge line for SD-111, severely damaged the piping supports and cracked the steam dump to main steam line weld. There have been previous piping support damage events associated with the steam dump system. The failure to identify and correct the cause is considered to be a weakness.

C. Main Feedwater Isolation Valve Failure

1. Inspection Scope (62707, 40500, and 37551)

Following the reactor trip, the low Tave (550 degrees F) setpoint was reached and a feedwater isolation signal was generated. Following the actuation, the operators noted that the main feedwater isolation valve (2-MVOP-003-0100-B) for steam generator 4 had lost position indication. The inspector reviewed the equipment problems related to the failure of the main feedwater isolation valve to close.

2. Observations and Findings

The feedwater isolation signal automatically initiated as expected on a normal reactor trip. The remaining feedwater pump was tripped, the feedwater regulating valves automatically closed and three of the four main feedwater isolation valves closed. The number three main feedwater regulating valve experienced a limit switch problem and indicated mid-position; however, it was verified in the closed position. The number four main feedwater isolation valve, however, did not close and was found to be full open. The breaker for the valve was found tripped on overcurrent. However, the line was isolated by the feedwater regulating valve, and also, the feedwater pump had been tripped by the feedwater isolation signal.

During the subsequent investigation, the licensee identified that the motor brake was partially full of water. The water had caused the motor brake to rust and prevented operation of the motor operator, however, the valve could be operated manually. The motor was disassembled and found to have a melted rotor and damaged windings, due to sustained locked rotor conditions. Thermal overloads are not available for motor protection during a main feedwater isolation actuation signal, which, in this example, resulted in motor destruction.

The valve and operator are located in a high temperature environment (>120 degrees F) and discussions indicated that the valve was periodically being wetted down during operation of the steam generator wet layup system due to system leaks. None of the other MFIVs on either unit were located such that this condition was a problem and the area temperature should not have affected valve reliability. However, the licensee discovered that the brake was not designed to be waterproof and therefore this model of brake was susceptible to this mode of failure if used in an environment that could cause moisture intrusion. The licensee also noted that the brakes are used in areas where incidental moisture intrusion was possible.

A review of the equipment history found previous failures of 2-MVOP-003-0100-B.

- On January 20, 1989, a PER was written to address the action plan associated with the motor failure of 2-MVOP-003-0100-B. It noted that the brake assembly was found to be rusted and locked in position and the motor had failed. It also noted that the valve brakes were not qualified or required to be waterproof, indicating that the licensee understood the failure mechanism/root cause at that time.

- On September 8, 1990, the valve failed to close on a feedwater isolation signal and the breaker was found tripped. Inspection of the brake assembly noted a collapse of the air gap adjustment and rust obscuring the physical location of the air gap match point.

The mechanics identified the root cause of the failure as incorrect assembly of the air gap adjusting nuts and stop nuts on the brake adjustment plate. In addition, the documentation noted that, "The brake mechanism was of a type which we do not normally have to deal" and with foreman and general foreman approval "further information from vendors manuals would be needed prior to disassembly of brake unit for inspection and/or repairs."

- In September 1994, a work request was initiated to repair a damaged brake flexible conduit. Water was found in the brake compartment and the motor brake was found to be highly corroded. The brake assembly was replaced.

- On April 6, 1995, the valve failed to close and the work request noted that the valve thermaled out when given a closed signal. The mechanics noted that the motor amps went high during the valve stroke and smoke came out of the motor casing.

  The mechanics identified the root cause of the failure as intermittently grounded motor brake leads and the motor brake was replaced. Discussions with the mechanics indicated that the old brake was full of rust, however, this was not identified in the work package.

Various work packages identified occurrences of flexible conduit damage since 1989. There were approximately 20 instances of flexible conduit damage on Unit 2 main feedwater isolation valves, with 8 instances of damage on 2-MVOP-003-0100-B.

On October 15, 1996, the inspector observed the testing of the Dings Motor Brake in its as-found condition. Initial observation of the air gap, which was to be set at .035 inches, indicated that no gap existed. The brake was energized and no apparent movement of the pressure plate was observed. A torque wrench was then used to attempt to rotate the brake, however, the brake would not rotate with 250 ft.lbs of torque applied. The brake air gap was adjusted to .035 inches and when power was then applied to the brake, the pressure plate moved and the brake rotated freely. Power was then removed from the brake and it was turned at 50 ft-lbs as required. With the brake in a condition where it released at 50 ft-lbs, even if the brake failed to release, the motor would be able to overcome the brake friction and to operate the valve as required.

Based on the rust lines within the brake assembly, it appeared that the water was leaking into the brake assembly through the damaged flexible conduit. The manufacturer's technical representative assisted in the disassembly of the motor brake. He noted that no rust should be present in the brake assembly and that the rust had caused the loss of air gap and resulted in brake failure. He also noted that a gasket on the brake housing was missing; however, the gasket had not been required by Limitorque. He also noted that the brake had been sealed using RTV and informed the licensee that acetate from the RTV curing process could

cause damage to the brake assembly. The licensee was not aware that a motor gasket was needed and that RTV (acetate) could cause a problem. However, neither of these conditions appeared to contribute to the previous brake failures.

The previous root cause determinations for the brake failures were inadequate. In 1989, 1990, and 1994 there was a significant amount of rust in the brake assembly; however, the cause and overall effect of the rust were not addressed. In 1995, the grounded leads were identified as the failure mechanism; however, the inspector concluded that this could not be the root cause because even if the brake failed to release, it still should have operated. The motor is rated with 250 ft-lbs of starting capacity while the brake is set for 50 ft-lbs. Grounded/shorted leads would have caused a loss of the power source fuses, in order to make the brake inoperable; however, the fuses did not fail. The failure to develop an adequate root cause, led to the failure to identify and correct the water induced failure of the brake assembly. The failure to identify and correct the root cause of the brake failure, is considered to be an apparent violation of the licensee's corrective action program as required by 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and as required by SSP-3.4 (EEI 50-327, 328/96-13-01).

Following the October 11 failure, the licensee determined that the root cause for the failures of the brake assembly was an inadequate specification of design requirements for this component. The feedwater isolation investigation team documented that "A component that could withstand incidental moisture intrusion would have prevented this condition."

The equipment work history noted repeated occurrences of flexible conduit damage in Unit 2. This led to the multiple water intrusions into the brake assembly and the subsequent failures. After repeated repairs of the flexible conduit for MFIV MVOP-003-0100-B in 1990, the work history noted "suspect that it makes a good stepping place for climbing in the area." In addition to the water intrusion, in 1995 the wiring was found grounded which affected the environmental qualification of the assembly. The failure to take adequate corrective actions to prevent continued damage to the flexible conduits, is considered to be an apparent violation of the licensee's corrective action program as required by 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and as required by SSP-3.4 (EEI 50-327, 328/96-13-02).

The licensee and the inspectors noted that the work history and the previous PER history had identified the repeat failures of the MFIV brake and flexible conduits. However, the licensee's trending programs, for repeat failures of WRs and/or PERs, did not identify the repeat failures of the MFIV brake or the MFIV flexible conduits. This was a missed opportunity to identify and correct a repeating adverse condition.

3. Conclusions

The failure to identify the cause of the brake failures and to take adequate corrective actions for the water intrusion is considered to be an apparent violation.

The failure to take adequate corrective actions to prevent further flexible conduit damage is considered to be an apparent violation.

The use of RTV could result in acetic acid intrusion into the brake assembly, which in turn could cause damage to the brake assembly. The previous use of RTV to seal up the brake assembly is considered to be a weakness.

The manufacturer's technical representative noted that the motor to brake assembly gasket was missing and should be installed. The missing gasket is considered to be a negative observation.

The failure of the licensee's repeat failure tracking/trending programs, associated with WRs and PERs, to identify repeating equipment failures on the MFIVs is considered to be a weakness.

D. Failure of RCP Seal Leakoff Isolation Valve

1. Inspection Scope (62707 and 37551)

The initial abnormal plant indication which resulted in the shutdown of Unit 2 was RCP low seal leakoff flow. The inspector reviewed the root causes which led to the low seal leakoff flow indication.

2. Observations and Findings

On October 11, Unit 2 received indications of # 4 RCP # 1 seal low leakoff flow, # 2 seal high leakoff flow and seal return line standpipe alarms. Based on these indications, operators concluded that the # 2 seal had failed (excessive leakoff) and they commenced a shutdown of the unit as required by AOP-R.04, Reactor Coolant Pump Malfunctions, Revision 5. Subsequent licensee investigation revealed that, rather than a failure of # 2 seal, the # 1 seal leakoff isolation valve, 2-FCV-62-48, had failed closed and blocked leakoff flow.

Valve 2-FCV-62-48, is a pneumatic air-to-close, spring-to-open valve and is normally open during plant operation. It was not classified as an EQ valve or as a safety-related valve, however, it was classified as Quality Related, which places it in the licensee's Appendix B program. The inspectors reviewed the piping diagrams associated with the RCP seal leakoff lines and isolation valves. The diagrams noted that the downstream side of the # 1 seal leakoff isolation valve has a system design rating of 200 psig. The low pressure design rating of the downstream piping would dictate that this valve would be important to safety and would be required to close on a RCP seal failure event to prevent an unisolatable RCS leak inside containment.

The licensee's investigation noted that the ASCO solenoid valve contained Buna-N rubber o-ring seals which failed due to temperature age hardening and thus permitted air to escape past the seals and to be vented to the diaphragm of the pneumatic valve. Additionally, other problems that contributed to the failure of the valve were noted:

- Upon removal of the exhaust port tubing, a piece of foreign material was found in the port which caused partial blockage of the exhaust port. The material was determined to be a plastic dust cover which had apparently been left in the exhaust port following previous maintenance.

- The as-found regulator output pressure was 76 psig (the required value was 50 psig). While this increased pressure was not believed to have caused the failure of the solenoid (120 psig design rating), it did exceed the pressure rating of the air operated isolation valve, 2-FCV-62-48.

It appeared that the higher pressure provided additional air to leak past the failed "O" rings and the vent plug did not allow the air to leak out of the exhaust port. This apparently caused a pressure buildup in the ASCO valve which caused the seal leakoff isolation valve to go closed. The failure to remove the dust cover from the ASCO prior to installation and the failure to properly set the supply air regulator are considered to be poor maintenance practices and are identified as a negative observation.

The licensee concluded that the root cause of the ASCO solenoid failure was temperature age hardening of the Buna-N o-rings in the solenoid which allowed air to leak past the o-rings and pressurize the valve diaphragm. This solenoid was installed in October 1990 and had been in service for six years and it was also installed in an area where temperatures could be as high as 150 degrees F. Buna-N elastomers installed in solenoids in this environment (approximately 150-160 degrees F) have a service life of less than one year. The solenoid vendor indicated that the Buna-N upper temperature limit is 125 degrees F.

NRC IE Bulletin 78-14, Deterioration of Buna-N Components in ASCO Solenoids and Generic Letter (GL) 91-15, Operating Experience Feedback Report, Solenoid-Operated Valve Problems at United States Reactors, characterized the industry problems associated with the solenoid valves. The GL addressed many failure modes including thermal aging and the need for replacement or refurbishment of resilient parts. The GL did not require a written response, however, the NRC expectation was that utilities would review the report and apply the information as appropriate to avoid similar problems. In late 1993, TVA developed an action plan to address the issues identified in Generic Letter (GL) 91-15, and the NRC recommendation. The licensee could find no evidence to indicate that the action plan was ever implemented. The licensee noted that implementation of the action plan that was developed in response to GL 91-15 could have prevented the solenoid valve failure.

In addition, the licensee noted that a previous PER had been initiated to address repeat failures of solenoid valves due to the elastomer material (Buna-N) becoming hard and brittle due to being in an area with elevated temperature (>140 degrees F). However, the scope of condition for resolution was narrowly focused in that only secondary side systems were evaluated for a thermal degradation issue which was also applicable to primary and safety-related systems. The failure to implement corrective actions for previously identified deficiencies related to ASCO solenoid valves is considered to be an apparent violation of the licensee's corrective action program as required by 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, and as required by SSP-3.4 (EEI 50-327, 328/96-13-03).

During the review, it was noted that the seal leakoff valve fails open on a loss of power or a loss of containment control system air pressure. For a RCP seal failure, this valve must remain closed or the downstream seal leakoff low pressure piping could be damaged. It was not clear whether the accident analysis considered the open condition of the seal leakoff valve following a seal failure event. This is considered to be an unresolved item (URI-327, 328/96-13-04).

3. Conclusions

The inspectors concluded that the ASCO solenoid failed due to temperature aging of the Buna-N seals. An apparent violation was identified for failure to implement corrective actions for ASCO solenoid failures.

A negative observation was noted regarding a poor maintenance practice which permitted a dust cover to be left in the exhaust port of a solenoid valve following maintenance activities and the failure to properly set the air supply regulator to the proper setting.

E. Turbine Runback and Engineering Support

1. Inspection Scope (37551)

When the operator stopped one of the two operating feedwater pumps, the plant experienced a turbine runback. The plant was below the runback setpoint of 80% turbine load and a runback should not have occurred. The inspector reviewed the equipment problems related to the turbine runback.

2. Observations and Findings

The plant shutdown proceeded to approximately 50%, at which point one of two operating feedwater pumps was procedurally required to be removed from service. When the operator tripped the feedwater pump, the plant experienced a main turbine runback, all of the steam dumps opened and the bank D control rods were automatically driven into the core.

A turbine runback signal is initiated on a main feedwater pump trip with turbine power above 80%. Main turbine power was approximately 50% and the turbine runback was not expected. There is a total of nine pressure instruments, located in the turbine building, associated with turbine impulse pressure. Two were safety related pressure transmitters (PT 1-72 and PT 1-73) that supply signals to reactor control and interlock circuits. One pressure transmitter (PT 47-13) supplies a signal for turbine impulse control. Two pressure switches (PS 1-81 and PS 1-82) provide a pressure setpoint actuation for AMSAC. Two pressure switches (PS 47-13A and PS 47-13D) provide inputs to the heater drain tank turbine runback circuit. The last two pressure switches (PS 47-13B and PS 47-13E) provide inputs to the loss of main feedwater pump turbine runback and AFW actuation circuits.

After the event, the associated pressure switches were inspected by the licensee. Pressure switches (PS 47-13B and PS 47-13E), which develop the two out of two actuation signal for the turbine runback, were partially filled with water. In addition, one of the pressure switches used in the heater drain tank turbine runback circuit, was also found partially filled with water. The water had corroded the switches, causing them to become stuck and they erroneously indicated power above 80%. This sealed in the turbine runback signal as well as an AFW actuation signal. The licensee determined that the water had leaked into a common junction panel above the pressure switches and then leaked into the individual pressure switch enclosures. The source of the water appeared to be from a fire system deluge actuation, caused by a failed fire detector in July 1996. The water from the actuation entered the top of various junction boxes and then drained down the wiring into the switch enclosures. During further investigation of the water intrusion, the licensee identified 18 additional instruments affected by the fire system actuation. Ten instruments, that provide secondary plant control functions, were repaired prior to plant startup.

Following the fire system actuation in July 1996, the licensee did not adequately evaluate the consequences of the deluge actuation and soaking down of plant equipment. This led to the subsequent failure of the impulse pressure switches. The failed switches caused a turbine runback and sealed in an AFW actuation signal. In addition, the switches could have failed in a position that would have prevented a turbine runback and blocked the associated AFW actuation signal. The licensee's corrective action process, as implemented by station procedure SSP-3.4, Corrective Action, Appendix H, requires an extent of condition review in order to bound the problem. However, following the deluge actuation, the PER corrective actions did not adequately bound the adverse conditions, in that they did not identify the adverse condition of the turbine impulse switches. This is considered to be an apparent violation (EEI 50-327, 328/96-13-05).

All of the associated impulse pressure switches, on both units, were inspected and the three sticking pressure switches were replaced (to date, one awaiting parts). The licensee had previous problems with the operation of these pressure switches resulting in a turbine runback:

Engineering "dummied" a signal to a computer alarm circuit prior to determining the cause for the signal. This is considered to be a negative observation.

B. Unit 2 Reactor Trip Breaker Maintenance

1. Inspection Scope (62707)

The inspectors reviewed the activities related to refurbishing the spare RTB and the subsequent replacement of the Unit 2 RTB "B" with the spare refurbished RTB.

2. Findings and Observations

On September 19, 1996, with Unit 2 at 100% power, RTB "B" was replaced with a refurbished spare RTB. Due to a malfunction of auxiliary contacts and subsequent insistence of Operations management, the rebuilt RTB was removed and the original breaker was reinstalled. Upon inspection of the removed refurbished RTB it was determined that linkage control to the auxiliary contacts had not been reconnected during the breaker refurbishment activities.

The following is the sequence of events related to the refurbishment of the spare RTB.

- On September 13, 1996 (Friday), maintenance personnel began refurbishment of the spare RTB in accordance with Maintenance Instruction (MI) 10.9.1, Reactor Trip Breaker Type DB50 Inspection Associated with System 99, Revision 16. Procedure Section 6.2.6, Breaker Auxiliary Switch Inspection and Test, was completed on this date.

- On September 14, 1996 (Saturday), maintenance personnel requested QC support in order to complete the remaining lubrication activities in Section 6.4. Since it was the weekend and no QC inspectors were on site, maintenance requested that a QC inspector be called in; however, the request was denied.

  Maintenance supervision determined that it was acceptable to proceed with the steps of MI-10.9.1, which did not require QC support. They determined that activities involved with lubrication would not affect those maintenance activities already completed on the breaker and they made a decision to proceed with Section 7.0, Post Performance Activities, and to perform the lubrication activities of Section 6 when QC was available on Monday.

- On September 15, 1996 (Sunday), work continued on the post performance activities of Section 7.

- On September 16, 1996 (Monday), with QC support, maintenance personnel began performance of the remaining steps in MI-10.9.1.

Sections 6.4 through 6.7. These activities included inspection and lubrication of the inertia latch which required removal of one end of a link to the auxiliary contact linkage assembly. During the reassembly of the linkage assembly, neither the QC inspector nor maintenance personnel noticed that a portion of the linkage had not been reconnected. Following the lubrication of the inertia latch, subsequent steps of Section 6 required that the breaker be opened/closed several times during which maintenance personnel did not notice the disconnected linkage. MI-10.9.1 was completed with the linkage still disconnected.

- On September 19, 1996 (Thursday), the refurbished RTB was installed in Unit 2.

The inspector reviewed MI-10.9.1 and the RTB refurbishment activities and had the following observations.

- MI-10.9.1, Section 6, contained a "NOTE" which permitted steps within Section 6 to be performed out of sequence. This "NOTE" only applied to Section 6 and did not intend that Section 7 be completed prior to Section 6. If Section 6 had been completed prior to Section 7, the Post Maintenance Test (PMT) of Section 7 may have identified the linkage reassembly errors made in Section 6.

  Technical Specification 6.8.1.a requires, in part, that procedures shall be established, implemented, and maintained covering the activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A, including procedures for performing maintenance. Procedure MI-10.9.1, did not authorize personnel to perform procedure "sections" out of sequence. The failure to follow procedure MI-10.9.1 is considered to be example one of an apparent violation of TS 6.8.1.a (EEI 50-328/96-13-08).

- MI-10.9.1 was written such that the auxiliary contacts were tested in Section 6.2.6. Later, in Section 6.4.1 of the procedure, the auxiliary contact linkage assembly was disconnected from the inertia latch to allow lubrication of the inertia latch. After the performance of Section 6.4.1, there was no further check or test of the auxiliary contacts to ensure the linkage was intact prior to returning the RTB to service. Additionally, there was no guidance in the procedure to caution that the linkage could become disconnected during the inertia latch disassembly process.

  The inspector also reviewed MI-10.9.1 to determine if there had been any recent procedure revisions which had changed the method of inertia latch lubrication. The inspector noted that Revision 13, dated July 29, 1994, was changed such that the inertia latch was removed for inspection and lubrication. Prior to Revision 13, the latch had been lubricated without removal of the latch. Revisions 14 and 15 also required removal of the inertia latch as did Revision 16 under which this most recent RTB inspection was

performed. The inspector concluded that Revision 13 to procedure MI-10.9.1 did not adequately address the evolution of removing the inertia latch in that it did not consider appropriate precautions regarding reinstallation of the inertia latch to ensure proper reassembly.

Procedure MI-10.9.1 was inadequate in that it did not provide precautions or adequate instructions regarding the disassembly/reassembly of the reactor trip breaker auxiliary contacts linkage assembly during lubrication. The failure to provide an adequate MI-10.9.1 procedure is considered to be an additional example of an apparent violation of TS 6.8.1.a (EEI 50-328/96-13-08).

- The licensee did not adequately plan the refurbishment of the RTB to recognize the need for weekend QC support. The absence of QC support started a chain of events which led maintenance supervision to make an inappropriate decision to perform the Post Performance Activities, Section 7 of MI-10.9.1, without first completing Section 6.

- Neither the maintenance person performing the reassembly of the linkage nor the person performing the "2nd check" noticed that the linkage was disconnected. After several strokes of the breaker during bench testing and with the breaker mechanism apparently functioning normally, maintenance personnel did not notice the disconnected linkage.

- The inspector reviewed the licensee's corrective action plans and concluded that the licensee had completed corrective actions to revise MI-10.9.1. The procedure revision included moving the auxiliary contact check and test to the end of the procedure to a place where all partial disassembly of the breaker has been completed. Additionally, a caution note was added to the step requiring removal of the inertia latch to ensure that the auxiliary contact linkage was connected following lubrication of the inertia latch. The procedure revision contained clarification as to the meaning of working steps out of sequence and to which sections this applied. The licensee visually verified that the remaining RTBs contained correctly assembled linkages. Management expectations were also expressed to personnel that, to the extent practical, extra effort should be extended to ensure components are properly reassembled and will perform their required function.

3. Conclusions

The inspector concluded that the MI-10.9.1 procedural "NOTE" permitting steps to be performed out of sequence did not permit the "performance" section and the "testing" section to be performed out of sequence. The failure to follow a procedure guidance is considered to be an apparent violation.

The inspector concluded that procedure MI-10.9.1 was inadequate in that it did not provide cautions regarding the reassembly of the auxiliary contact linkage assembly following lubrication. The use of an inadequate procedure is considered to be an apparent violation.

The inspector concluded that, during the planning for the RTB refurbishment, Maintenance failed to ensure that QC personnel would be available when required by the procedure. This issue is considered to be a negative observation.

C. Licensee Self-Assessment Activities (40500)

1. Inspection Scope (40500)

The licensee performed a root cause investigation to determine corrective actions associated with the reactor trip breaker event. The inspectors reviewed the Event Critique Report and its associated corrective actions.

2. Observations and Findings

The inspectors reviewed the licensee's Event Critique Report which addressed the problems identified in PER No. SQ962451PER related to failure of the auxiliary contacts in the refurbished RTB breaker. The licensee concluded that "...the root cause of this event was inadequate skills and knowledge resulting from inadequate training. Specifically, the training associated with the DB-50 breakers did not adequately address the mechanical linkage between the inertia latch and the auxiliary contacts. Further, the procedure (MI-10.9.1) did not identify the possibility of linkage disengagement while removing the inertia latch. Additionally, the Westinghouse vendor manual does not adequately address this mechanical linkage...."

The inspectors concluded that the licensee's event critique accurately described the lack of training and knowledge which were most probably due to vendor manual deficiencies regarding inertia latch lubrication. However, the inspectors concluded that the event critique was not thorough in that it (1) did not address operability of the refurbished RTB, (2) did not address the functions of the auxiliary contacts which were disabled, and (3) did not address the effect of a revision to MI-10.9.1 (July 29, 1994) which changed the method of lubricating the inertia latch.

3. Conclusions

The inspectors concluded that the failure of the RTB Event Critique to discuss (1) RTB operability, (2) the function of the auxiliary contacts, and (3) the revision to the maintenance procedure, represented a weakness in the thoroughness of the root cause determination process.

D. Failure to Perform an Operability/Reportability Determination

1. Inspection Scope (40500)

Following removal of the refurbished reactor trip breaker on September 19, 1996, the licensee identified that the linkage for the auxiliary contacts had not been reconnected properly. The operations Shift Manager and the PER event critique team questioned the function of the contacts due to concerns with the operability of the reactor trip breaker. In addition, the Management Review Committee (MRC) reviewed the PER and noted that the reactor trip breaker issue potentially affected reportability. The inspectors followed up on the function of the disconnected contacts.

2. Observations and Findings

Following identification of problems identified with the reactor trip breaker, the Shift Manager expressed concerns regarding the proper functioning of other RTB auxiliary contacts. His concerns led to an addendum to the initial PER and he also expressed to the operation's representative on the RTB event critique team the need to evaluate the disconnected contacts.

The MRC met on September 20, 1996 and determined that the PER condition could potentially affect reportability and appropriately checked the potentially reportable block on the PER form. This action required that the PER be hand carried to Operations so that Appendix E of SSP- 3.4, Corrective Actions, could be implemented. Appendix E details the requirements for performing an operability/reportability determination. As of approximately two weeks later the PER was not returned to Operations and the subsequent operability/reportability determination was not performed until questioned by the inspectors. The failure to perform the operability/reportability determination is an apparent violation of NRC requirements (EEI 50 328/96-13-09).

In addition, as follow up on the Shift Manager's concerns, the review team questioned the function of the disconnected auxiliary contacts in order to determine if the contacts affected the operability of the reactor trip breaker. During the week following the RTB malfunction, technical support completed its review of the function of the disconnected auxiliary contacts and supplied a memo to the event critique team. The memo noted that the disconnected auxiliary contacts affected the turbine trip and feedwater isolation outputs from the reactor trip breaker.

NRC discussions with an event critique team member indicated that the team understood that the disconnected auxiliary contacts affected P-4; and therefore, affected the operability of the reactor trip breaker. This information was thought to be common knowledge, however, neither technical support or the event critique team formally reported the inoperability of the RTB to appropriate levels of management. The lack

however, the previous event was not due to water intrusion into the pressure switch enclosures.

The licensee's review also noted that the fire system detector had failed (in July) due to water intrusion into the detector. The water had leaked into the detector, possibly due to overflow from the gland sealing steam system.

During a review of control diagrams and alarm response procedures associated with the turbine runback, the inspector noted that alarm response procedure, 2-AR-M2-A-B-1, Turbine Runback, did not identify the same instruments for the alarm inputs as depicted on control diagram CCD No.1, 2-47 W610-47-2. Although inconsistent, this error would not affect operator actions associated with the turbine runback alarm.

3. Conclusions

The failure to implement adequate corrective actions associated with the fire system actuation is considered to be an apparent violation.

The water intrusion into a single zone actuation fire detector, which resulted in the deluge actuation, is considered to be a negative observation.

Inconsistencies in the control diagrams and the abnormal procedures is considered to be a negative observation.

F. AFW Actuation Signal Sealed In

1. Inspection Scope

During recovery actions the operators could not reset the AFW actuation signal and could not take manual control of the AFW system. This contributed to reaching a low-low Tave condition. The inspector reviewed the circuitry associated with the AFW actuation and the operator's response to the loss of AFW control.

2. Observations and Findings

While performing the reactor trip recovery steps in the emergency response procedures, the operators had difficulty in controlling the cooldown of the RCS. This led to dropping below the low-low Tave setpoint of 540 degrees F which resulted in a main feedwater isolation signal and also required the operators to emergency borate the RCS. Because of the operators quick response to abnormal plant conditions, Tave only dropped to 538 degrees F. However, the operators had to control the steam generator level by fully opening/closing the AFW isolation valves (cannot be throttled).

The operators had difficulty in controlling RCS cooldown because the AFW actuation signal was sealed in and they were unable to take manual control of the motor driven AFW system flow control valves or to take

manual speed control of the turbine driven AFW pump. Operators, with management approval, disabled the AFW pumps by placing the motor driven AFW motors in pull-to-lock and by closing the turbine driven AFW pump discharge isolation valves. This resulted in all three AFW pumps being technically inoperable with TS 3.7.1.2 LCO actions preventing any mode change and also requiring immediate initiation of corrective actions to return one pump to operable status. Following the reactor trip, the operators maintained adequate steam generator water levels (>10% in all four SGs) by operating the turbine driven AFW pump discharge isolation valves and maintained acceptable RCS temperature conditions (approximate 545 degrees F).

The operators were unable to reset the AFW actuation signal because the signal was sealed in by the failed impulse pressure switches. A review of the wiring diagrams noted that with a main feedwater pump trip above 80% turbine power, the AFW system receives an automatic actuation signal. Since the impulse pressure switches were stuck, the signal was sealed in and could not be reset by the operators. During the event, the operators were unaware of the interlock between the turbine runback and the locked in AFW actuation signal. At 10:44 a.m., following discovery by the licensee of the failed switches, a lead was lifted in the impulse pressure switch circuitry and the operators were then able to reset the AFW actuation signal, which allowed normal control of the AFW system.

Further review noted that if the operators had reset the main feedwater pump after it was manually tripped, then the turbine runback would have reset automatically and the AFW actuation could have been manually reset. However, this was not proceduralized and the operators did not understand the operation of the runback circuitry and did not reset the main feedwater pump. Discussions indicated that a turbine runback, due to impulse pressure switch problems, had occurred before and the inspector concluded that knowledge of the circuitry should have been available based on the previous event. The lack of knowledge appeared to be a deficiency in classroom training and in simulator scenarios.

The AFW actuation signal following a main feedwater pump trip is designed to compensate for a loss of feedwater. It is not safety related and not subjected to any separation requirements. In this case a common mode failure occurred due to a lack of separation. It does not appear to provide a safety function but rather assists the unit in maintaining steam generator levels and preventing a reactor trip following a feedwater pump trip at high power levels. The licensee was reviewing the continued need for the circuitry as designed and is considering potential modifications to the circuitry which would allow for manual resetting of the (main feedwater pump trip/turbine power >80%) AFW actuation following a reactor trip.

Mitigating actions are required for a reactor trip, a steam line break inside containment, a steamline break outside containment, and a SG tube rupture. Operators are required to take manual control of the AFW system (UFSAR assumption within 10 minutes) to ensure that the plant can

meet the analysis for the above listed events. The UFSAR Section 10.4.7.2.3, Safety Evaluation, states, "The AFW system is automatically initiated by redundant, coincident logic to preclude loss of function due to a single failure." However, based on the system failure due to water intrusion, it does not appear that the system was properly designed to preclude a loss of function with a single failure. This issue is identified as an Unresolved Item pending further NRC review. (URI 50-327, 328/96-13-06).

3. Conclusions

The operators lacked knowledge in the functioning of the turbine impulse pressure switch circuitry and this lack of knowledge indicated a weakness in the licensee's training program, considering the previous problems with this circuit.

The operators appropriately isolated the AFW system to prevent an uncontrolled cooldown of the RCS. This is considered to be a positive observation.

The failure of two non-safety related and non-independent switches resulted in the inability of operators to reset an AFW actuation signal. This could have led to an RCS overcooling event or could have affected plant safety during one of several events discussed in the safety analysis and its design is an unresolved item.

II. Inoperable Reactor Trip Breaker

A. Operational Aspects

1. Inspection Scope (71707)

On September 19, 1996, a refurbished RTB was placed in service. The breaker had position indication problems that caused alarms in the control room and the RTB was subsequently removed. A PER was initiated and a root cause investigation was performed. Following completion of the root cause investigation, the inspectors reviewed the facts surrounding the event. The NRC review found that the breaker had been inoperable and the licensee had exceeded an LCO required shutdown.

2. Observations and Findings

At 9:29 a.m., on September 19, 1996, the licensee entered TS 3.3.1, Action 12 for installation of the refurbished breaker in the RTB "B" cubicle. Testing was performed to ensure that the breaker functioned properly. The breaker opened and closed as required; however, when the bypass breaker was cycled, the "computer alarm rod deviation NIS power range tilts" annunciator went into alarm and cleared. This occurred several times during the testing process. At 10:48 a.m., the testing was complete, the refurbished reactor trip breaker was considered to be operable, the bypass breaker was opened, and the rod deviation alarm came in and stayed in alarm. Discussions with operations indicated that

the operators were concerned that the alarm was associated with the reactor trip breaker, but were unable to confirm the relationship.

At 11:30 a.m., engineering personnel confirmed that the computer rod deviation alarm was due to an input from RTB "B", which was erroneously indicating that RTB "B" was not closed. The operator logs noted that the most likely cause for the alarm was due to a malfunction of an auxiliary contact in RTB "B". Discussions with operations indicated that the operators were concerned that if one contact was malfunctioning that other contacts in the breaker could also be malfunctioning and they wanted the breaker removed.

At 1:28 p.m., engineering "dummied" the computer signal to the Integrated Computer System (ICS) computer so that the input to the rod bank deviation circuit would indicate a closed signal from RTB "B". This cleared the "Tilt" alarm which reduced the surveillance frequency requirements for operators taking rod position readings. At this time, the breaker was considered to be operable based on the completed breaker operability surveillance; however, the surveillance only checked the operation of the breaker and did not verify the breaker position output signals to the computer or to the P-4 circuits.

Discussions with operations noted that engineering and maintenance wanted to troubleshoot RTB "B" in its closed position and were reluctant to remove RTB "B" and to replace it with the original breaker. Operations insisted on not troubleshooting the breaker and asked for removal of the potentially faulted breaker. The Operations Manager was called to the site for a staff meeting to discuss the various options. The Operations Manager agreed with the Shift Manager that the breaker needed to be replaced and that no troubleshooting would be performed while the breaker was in service.

At 5:45 p.m., the breaker replacement was initiated and at 6:34 p.m., RTB "B" replacement was completed. When the faulted breaker was opened, the licensee determined that a linkage that operated two of three sets of breaker position contacts, was not connected. Following completion of the licensee's root cause investigation, the inspectors noted that the licensee still did not appear to know the function of the disconnected contacts. The inspectors reviewed the logic diagrams and believed that the contacts supplied the P-4 permissive function which provides a turbine trip, feedwater isolation, and steam dump arming signal following a reactor trip and was based on the position of the reactor trip breaker.

Discussions with the licensee's compliance personnel noted that the turbine trip associated with the RTB had been reviewed and evaluated for operability. Compliance personnel stated that the turbine trip was not taken credit for in the accident analysis; therefore, the RTB "B" was considered to be operable. The inspector noted that the turbine trip function, following a reactor trip, provides protection for an overcooling event on the RCS and, in addition, is part of the P-4

circuit which is a TS required function with a 6-hour LCO for shutdown to hot shutdown, if the circuit is not functional.

In response to questions by the inspectors, the licensee reviewed the functions of the disconnected contacts and determined that the contacts supplied signals for reactor trip alarm, high steam flow interrupt, a computer point for the rod deviation program, <u>turbine trip, feedwater isolation (which provides feedwater isolation coincident with a low Tave signal, maintains a feedwater isolation, turbine trip, and trip of main feedwater pumps signals after a steam generator high level trip), and allows blocking of the safety injection signal after a SI so that the SI signal can be reset</u>. The above underlined signals are part of the P-4 circuitry required to be operable by TS. The inspectors noted that the inoperable P-4 circuitry exceeded the TS requirements for shutdown (6 hours). The failure to follow TS 3.3.1.22.G, Action 14, requirements is considered to be an apparent violation (EEI 50-327, 328/96-13-07). Due to the failure of the contacts, the breaker was inoperable from the time it was installed (9:29 a.m.) until it was removed (6:34 p.m.).

The inspectors noted that the "A" train RTB would have been able to actuate the turbine trip and feedwater isolation signals. However, blocking of the SI signal would have been prohibited by the faulty reactor trip breaker. Following an SI, due to the failure of the RTB P-4 contacts, the operators would have been required to manually isolate all of the SI actuated components, which would have complicated recovery actions.

On November 4, 1996, licensee staff was still convinced that the turbine trip contacts from the reactor trip breaker were not part of the P-4 circuitry. However, following additional questions and review of the 18 month surveillance SI-IFT-099-0P4.0, Periodic Verification of P-4 Interlock Function From Reactor Trip Breakers, Revision 1, the plant staff agreed with the inspectors that the turbine trip in question was part of the P-4 circuitry.

3. <u>Conclusions</u>

Operations did a good job in stressing the need to get the potentially faulted RTB out of service and in not allowing troubleshooting of the breaker while still in service. This is considered to be a positive observation.

The inoperable RTB was in service for greater than the allowed TS LCO time period and this is considered to be an apparent violation of NRC requirements.

The plant staff did not realize that the turbine trip contacts on the reactor trip breaker were part of the P-4 circuitry and this is considered to be a weakness.

of action by the critique team and technical support personnel to report the inoperability of the RTB is considered to be a weakness.

3. Conclusions

The failure to perform an operability/reportability determination as required by SSP-3.4 is considered to be an apparent violation.

The lack of action by the event critique team and technical support personnel to report the inoperability of the reactor trip breaker is considered to be a weakness.

III. Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 5, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials would be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

*Adney, R., Site Vice President
*Beasley, J., Acting Site Quality Manager
*Bryant, L., Outage Manager
*Burzynski, M., Engineering & Materials Manager
Driscoll, D., Training Manager
*Fecht, M., Nuclear Assurance & Licensing Manager
Fink, F., Business and Work Performance Manager
*Flippo, T., Site Support Manager
*Harrington, W., Acting Maintenance Manager
*Herron, J., Plant Manager
Kent, C., Radcon/Chemistry Manager
Lagergren, B., Operations Manager
Rausch, R. Maintenance and Modifications Manager
Reynolds, J., Operations Superintendent
*Rupert, J., Engineering and Support Services Manager
*Shell, R., Manager of Licensing and Industry Affairs
Skarzinski, M., Technical Support Manager
*Smith, J., Licensing Supervisor
Summy, J., Assistant Plant Manager
Symonds, J. Modifications Manager

* Attended exit interview

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls In Identifying, Resolving, & Preventing Problems
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-327, 328/96-13-01	EEI	Failure to correct repetitive problems (water intrusion) with the MFIV #4 MOV brake assembly (Section I.C.2).
50-327, 328/96-13-02	EEI	Failure to implement adequate corrective actions to prevent repetitive damage to the MFIV flexible conduits (Section I.C.2).
50-327, 328/96-13-03	EEI	Failure to implement adequate corrective actions to address ASCO solenoid valve elastomer aging (Section I.D.2).
50-327, 328/96-13-04	URI	Evaluate the adequacy of the fail open design of the RCP seal leakoff isolation valve, which is needed to mitigate the consequences of a RCP seal failure (Section I.D.2).
50-327, 328/96-13-05	EEI	Failure to perform an adequate extent of condition review required by SSP-3.4 for deluge event which resulted in the impulse pressure switch failures (Section I.E.2).
50-327, 328/96-13-06	URI	Evaluate the adequacy of design of the turbine impulse AFW actuation circuitry which the UFSAR required to be independent to prevent a common mode failure (Section I.F.2).
50-327, 328/96-13-07	EEI	Failure to Follow TS 3.3.1.22.G, Action 14 (Section II.A.2).

50-327, 328/96-13-08	EEI	Failure to Follow Procedure MI10.9.1 and Failure to Provide an Adequate MI-10.9.1 Procedure (Section II.B.2).
50-327, 328/96-13-09	EEI	Failure to Perform an Operability/Reportability Determination (Section II.D.2).

factors in arriving at the appropriate severity level will be dependent on the circumstances of the violation. However, if a licensee refuses to correct a minor violation within a reasonable time such that it willfully continues, the violation should be categorized at least at a Severity Level IV.

D. Violations of Reporting Requirements

The NRC expects licensees to provide complete, accurate, and timely information and reports. Accordingly, unless otherwise categorized in the Supplements, the severity level of a violation involving the failure to make a required report to the NRC will be based upon the significance of and the circumstances surrounding the matter that should have been reported. However, the severity level of an untimely report, in contrast to no report, may be reduced depending on the circumstances surrounding the matter. A licensee will not normally be cited for a failure to report a condition or event unless the licensee was actually aware of the condition or event that it failed to report. A licensee will, on the other hand, normally be cited for a failure to report a condition or event if the licensee knew of the information to be reported, but did not recognize that it was required to make a report.

V. Predecisional Enforcement Conferences

Whenever the NRC has learned of the existence of a potential violation for which escalated enforcement action appears to be warranted, or recurring nonconformance on the part of a vendor, the NRC may provide an opportunity for a predecisional enforcement conference with the licensee, vendor, or other person before taking enforcement action. The purpose of the conference is to obtain information that will assist the NRC in determining the appropriate enforcement action, such as: (1) A common understanding of facts, root causes and missed opportunities associated with the apparent violations, (2) a common understanding of corrective action taken or planned, and (3) a common understanding of the significance of issues and the need for lasting comprehensive corrective action.

If the NRC concludes that it has sufficient information to make an informed enforcement decision, a conference will not normally be held unless the licensee requests it. However, an opportunity for a conference will normally be provided before issuing an order based on a violation of the rule on Deliberate Misconduct or a civil penalty to an unlicensed person. If a conference is not held, the licensee will normally be requested to provide a written response to an inspection report, if issued, as to the licensee's views on the apparent violations and their root causes and a description of planned or implemented corrective action.

During the predecisional enforcement conference, the licensee, vendor, or other persons will be given an opportunity to provide information consistent with the purpose of the conference, including an explanation to the NRC of the immediate corrective actions (if any) that were taken following identification of the potential violation or nonconformance and the long-term comprehensive actions that were taken or will be taken to prevent recurrence. Licensees, vendors, or other persons will be told when a meeting is a predecisional enforcement conference.

A predecisional enforcement conference is a meeting between the NRC and the licensee. Conferences are normally held in the regional offices and are not normally open to public observation. However, a trial program is being conducted to open approximately 25 percent of all eligible conferences for public observation, i.e., every fourth eligible conference involving one of three categories of licensees (reactor, hospital, and other materials licensees) will be open to the public. Conferences will not normally be open to the public if the enforcement action being contemplated:

(1) Would be taken against an individual, or if the action, though not taken against an individual, turns on whether an individual has committed wrongdoing;

(2) Involves significant personnel failures where the NRC has requested that the individual(s) involved be present at the conference;

(3) Is based on the findings of an NRC Office of Investigations report; or

(4) Involves safeguards information, Privacy Act information, or information which could be considered proprietary;

In addition, conferences will not normally be open to the public if:

(5) The conference involves medical misadministrations or overexposures and the conference cannot be conducted without disclosing the exposed individual's name; or

(6) The conference will be conducted by telephone or the conference will be conducted at a relatively small licensee's facility.

Notwithstanding meeting any of these criteria, a conference may still be open if the conference involves issues related to an ongoing adjudicatory proceeding with one or more intervenors or where the evidentiary basis for the conference is a matter of public record, such as an adjudicatory decision by the Department of Labor. In addition, with the approval of the Executive Director for Operations, conferences will not be open to the public where good cause has been shown after balancing the benefit of the public observation against the potential impact on the agency's enforcement action in a particular case.

As soon as it is determined that a conference will be open to public observation, the NRC will notify the licensee that the conference will be open to public observation as part of the agency's trial program. Consistent with the agency's policy on open meetings, "Staff Meetings Open to Public," published September 20, 1994 (59 FR 48340), the NRC intends to announce open conferences normally at least 10 working days in advance of conferences through (1) notices posted in the Public Document Room, (2) a toll-free telephone recording at 800–952–9674, and (3) a toll-free electronic bulletin board at 800–952–9676. In addition, the NRC will also issue a press release and notify appropriate State liaison officers that a predecisional enforcement conference has been scheduled and that it is open to public observation.

The public attending open conferences under the trial program may observe but not participate in the conference. It is noted that the purpose of conducting open conferences under the trial program is not to maximize public attendance, but rather to determine whether providing the public with opportunities to be informed of NRC activities is compatible with the NRC's ability to exercise its regulatory and safety responsibilities. Therefore, members of the public will be allowed access to the NRC regional offices to attend open enforcement conferences in accordance with the "Standard Operating Procedures For Providing Security Support For NRC Hearings And Meetings," published November 1, 1991 (56 FR 56251). These procedures provide that visitors may be subject to personnel screening, that signs, banners, posters, etc., not larger than 18" be permitted, and that disruptive persons may be removed.

Members of the public attending open conferences will be reminded that (1) the apparent violations discussed at predecisional enforcement conferences are subject to further review and may be subject to change prior to any resulting enforcement action and (2) the statements of views or expressions of opinion made by NRC employees at predecisional enforcement conferences, or the lack thereof, are not intended to represent final determinations or beliefs.

Persons attending open conferences will be provided an opportunity to submit written comments concerning the trial program anonymously to the regional office. These comments will be subsequently forwarded to the Director of the Office of Enforcement for review and consideration.

When needed to protect the public health and safety or common defense and security, escalated enforcement action, such as the issuance of an immediately effective order, will be taken before the conference. In these cases, a conference may be held after the escalated enforcement action is taken.

VI. Enforcement Actions

This section describes the enforcement sanctions available to the NRC and specifies the conditions under which each may be used. The basic enforcement sanctions are Notices of Violation, civil penalties, and orders of various types. As discussed further in Section VI.D, related administrative actions such as Notices of Nonconformance, Notices of Deviation, Confirmatory Action Letters, Letters of Reprimand, and Demands for Information are used to supplement the enforcement program. In selecting the enforcement sanctions or administrative actions, the NRC will consider enforcement actions taken by other Federal or State regulatory bodies having concurrent jurisdiction, such as in transportation matters. Usually, whenever a violation of NRC requirements of more than a minor concern is identified, enforcement action is taken. The nature and extent of the enforcement action is intended to reflect the seriousness of the violation involved. For the vast majority of violations, a Notice of Violation or a Notice of Nonconformance is the normal action.

A. Notice of Violation

A Notice of Violation is a written notice setting forth one or more violations of a legally binding requirement. The Notice of Violation normally requires the recipient to provide a written statement describing (1) the reasons for the violation or, if contested, the basis for disputing the violation; (2) corrective steps that have been taken and the results achieved; (3) corrective steps that will be taken to prevent recurrence; and (4) the date when full compliance will be achieved. The NRC may waive all or portions of a written response to the extent relevant information has already been provided to the NRC in writing or documented in an NRC inspection report. The NRC may require responses to Notices of Violation to be under oath. Normally, responses under oath will be required only in connection with Severity Level I, II, or III violations or orders.

The NRC uses the Notice of Violation as the usual method for formalizing the existence of a violation. Issuance of a Notice of Violation is normally the only enforcement action taken, except in cases where the criteria for issuance of civil penalties and orders, as set forth in Sections VI.B and VI.C, respectively, are met. However, special circumstances regarding the violation findings may warrant discretion being exercised such that the NRC refrains from issuing a Notice of Violation. (See Section VII.B, "Mitigation of Enforcement Sanctions.") In addition, licensees are not ordinarily cited for violations resulting from matters not within their control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Generally, however, licensees are held responsible for the acts of their employees. Accordingly, this policy should not be construed to excuse personnel errors.

B. Civil Penalty

A civil penalty is a monetary penalty that may be imposed for violation of (1) certain specified licensing provisions of the Atomic Energy Act or supplementary NRC rules or orders; (2) any requirement for which a license may be revoked; or (3) reporting requirements under section 206 of the Energy Reorganization Act. Civil penalties are designed to deter future violations both by the involved licensee as well as by other licensees conducting similar activities and to emphasize the need for licensees to identify violations and take prompt comprehensive corrective action.

Civil penalties are considered for Severity Level III violations. In addition, civil penalties will normally be assessed for Severity Level I and II violations and knowing and conscious violations of the reporting requirements of section 206 of the Energy Reorganization Act.

Civil penalties are used to encourage prompt identification and prompt and comprehensive correction of violations, to emphasize compliance in a manner that deters future violations, and to serve to focus licensees' attention on violations of significant regulatory concern.

Although management involvement, direct or indirect, in a violation may lead to an increase in the civil penalty, the lack of management involvement may not be used to mitigate a civil penalty. Allowing mitigation in the latter case could encourage the lack of management involvement in licensed activities and a decrease in protection of the public health and safety.

1. Base Civil Penalty

The NRC imposes different levels of penalties for different severity level violations and different classes of licensees, vendors, and other persons. Tables 1A and 1B show the base civil penalties for various reactor, fuel cycle, materials, and vendor programs. (Civil penalties issued to individuals are determined on a case-by-case basis.) The structure of these tables generally takes into account the gravity of the violation as a primary consideration and the ability to pay as a secondary consideration. Generally, operations involving greater nuclear material inventories and greater potential consequences to the public and licensee employees receive higher civil penalties. Regarding the secondary factor of ability of various classes of licensees to pay the civil penalties, it is not the NRC's intention that the economic impact of a civil penalty be so severe that it puts a licensee out of business (orders, rather than civil penalties, are used when the intent is to suspend or terminate licensed activities) or adversely affects a licensee's ability to safely conduct licensed activities. The deterrent effect of civil penalties is best served when the amounts of the penalties take into account a licensee's ability to pay. In determining the amount of civil penalties for licensees for whom the tables do not reflect the ability to pay or the gravity of the violation, the NRC will consider as necessary an increase or decrease on a case-by-case basis. Normally, if a licensee can demonstrate financial hardship, the NRC will consider payments over time, including interest, rather than reducing the amount of the civil penalty. However, where a licensee claims financial hardship, the licensee will normally be required to address why it has sufficient resources to safely conduct licensed activities and pay license and inspection fees.

2. Civil Penalty Assessment

In an effort to (1) emphasize the importance of adherence to requirements and (2) reinforce prompt self-identification of problems and root causes and prompt and comprehensive correction of violations, the NRC reviews each proposed civil penalty on its own merits and, after considering all relevant circumstances, may adjust the base civil penalties shown in Table 1A and 1B for Severity Level I, II, and III violations as described below.