ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.: 50-313; 50-368
License Nos.: DPR-51; NPF-6

Report No.: 50-313/96-06; 50-368/96-06

Licensee: Entergy Operations, Inc.

Facility: Arkansas Nuclear One, Units 1 and 2

Location: Junction of Hwy. 64W and Hwy. 333 South
Russellville, Arkansas

Dates: August 18 through September 28, 1996

Inspectors: J. Melfi, Acting Senior Resident Inspector
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Approved By: Elmo E. Collins, Chief, Project Branch C
Division of Reactor Projects

ATTACHMENTS: Partial List of Persons Contacted
List of Inspection Procedures Used
List of Items Opened and Closed
List of Acronyms
Reactor Coolant System (RCS) General Reference Points
Effects of Fuel Oil Water Intrusion on Emergency
Diesel Generator (EDG) Performance

EXECUTIVE SUMMARY

Arkansas Nuclear One, Units 1 and 2
NRC Inspection Report 50-313/96-06; 50-368/96-06

This routine announced inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an announced inspection by a regional project inspector.

Operations

- A defective electrical fuse combined with breaker charging springs vibration caused loss of an electrical bus leading to a Unit 1 reactor trip. Operator response was well controlled. Plant response was as designed, except for Reactor Coolant Pump C oil pumps and main feedwater. Emergency feedwater actuated and functioned as designed (Section O1.1).

- A reactor water level perturbation while in reduced inventory was caused by the inadvertent introduction of air into the reactor coolant system. Operator response was prompt and effective. The method of purging a decay heat removal containment penetration for local leak rate testing was beyond the test boundaries. This is a violation (Section O1.2).

Maintenance

- While welding on a pressurizer safety valve tailpipe, a small hydrogen burn occurred. Procedures for sampling and purging lines of explosive gases were not followed. This is a violation. The licensee performed thorough inspections and evaluations of the event and concluded that no plant equipment was damaged (Section M4.1).

- On May 27, 1996, the licensee detected water in diesel fuel oil tanks. The licensee performed an evaluation of the impact of the water on emergency diesel performance and concluded that the emergency diesel was capable of performing the design function based on the quantity and location of the water and sediment. The evaluation was conservative (Section M8.1).

Engineering

- The proposed modifications to the main feedwater pump control circuitry adequately addressed the concerns noted in NRC Inspection Report 50-313/96-19; 50-368/96-19 (Section E1.2).

- The inspectors reviewed the modification package for the atmospheric dump valves and concluded that the proposed modification was satisfactory. The inspectors noted a potential weakness in the scope of documents reviewed in the safety evaluation process. The licensee appropriately evaluated the potential weakness (Section E3.1).

- The licensee found a significant increase in biological growth in both units' intake structures, which has affected service water pump discharge strainers and leakage assumptions for the emergency cooling pond. This item will be followed up on in a future inspection (Section E8.1).

Plant Support

- A health physics technician exhibited a good questioning attitude when he identified that a worker had poured water down a reactor coolant pump oil fill funnel, which was disconnected from the pump. The technician took appropriate action to bring this issue to the attention of proper personnel (Section R4.1).

Report Details

Summary of Plant Status

At the beginning of the inspection period, Unit 1 was operating at 100 percent power and remained at full power until a reactor trip occurred at 12:10 p.m. on September 12, 1996, (See Section O1.1). Unit 1 was in a forced outage until 10:20 a.m. on September 14 when the licensee entered Refueling Outage 1R13, which had been scheduled to begin at 12 a.m. on September 17. Unit 1 remained shut down for the remainder of the inspection period.

Unit 2 operated at 98 percent power throughout the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors reviewed ongoing plant operations. In general, the conduct of operations was professional and safety conscious; specific events and noteworthy observations are detailed below.

O1.2 Reactor Trip

a. Inspection Scope (71707, 93702)

Inspectors reviewed the circumstances associated with the September 12, 1996, Unit 1 reactor trip to assess the licensee's determination of the cause, assess plant response, and assess the corrective actions taken by the licensee. Inspectors observed operator immediate recovery actions.

b. Observations and Findings

At approximately 12:10 p.m., the licensee was removing the Startup 2 electrical power supply feeder breaker in Electrical Bus H1 from service as part of an electrical tagout for a plant design change on the Startup 2 transformer. When the breaker reached the bottom of the cabinet, the breaker springs unexpectedly discharged. Reactor Coolant Pumps (RCP) A and C electrical power supply breakers, also located in Bus H1, opened causing an automatic reactor protection system trip.

Inspectors entered the control room shortly after the trip and found that operator immediate recovery actions were proper and well controlled.

The licensee determined that the undervoltage relay to Bus H1 had actuated and caused the loss of Bus H1. The licensee further determined that a fuse in the undervoltage relay circuit had intermittent electrical continuity. The fuse was located in the same breaker cubicle as the Startup 2 breaker and had failed due to the vibration in the breaker cubicle when the springs discharged. Further investigation

determined that this fuse had a poor solder joint connecting the fuse element to the end caps. The fuse apparently dated to initial plant construction. The licensee believed that the age of the fuse and solder joint quality contributed to its failure. The licensee replaced the defective fuse and other fuses of similar age in protective relay circuitry with newer fuses.

Plant equipment responded as designed with two exceptions. RCP C lube oil pumps and main feedwater (MFW) Block Valve B did not function as designed. When RCP C tripped, its high pressure lube oil pumps did not automatically start. Approximately 6 minutes after the plant trip, operators started the oil pumps. The oil pumps had not started because the speed amplifying circuit had failed. The licensee planned to replace this circuit during the refueling outage.

The MFW block valves are designed to fast close on a reactor trip, but MFW Block Valve B, CV-2675, remained open. Accordingly, MFW system logic would not permit MFW Pump B to supply Once-Through Steam Generator (OTSG) B and a low water level in the steam generator resulted. The emergency feedwater system actuated and restored water level as designed. The failure of the MFW block valve to go closed was a blown capacitor in the dual speed clutch circuit. The licensee replaced the capacitor and planned to develop a periodic replacement schedule for this capacitor.

c. Conclusions

The vibration of breaker springs discharging and a defective plant fuse caused loss of an electrical bus leading to a reactor trip. The operator's performance after the trip was well controlled. Plant response was as designed except for RCP C oil pumps and MFW Block Valve B. The emergency feedwater system functioned as designed. The inspectors concluded that the licensee's conclusions and corrective actions were appropriate.

O1.2 Reactor Level Perturbation During Reduced Inventory

a. Inspection Scope (71707)

On September 18, 1996, while the reactor coolant system (RCS) was in reduced inventory, indicated RCS level increased approximately 0.70 feet due to service air being introduced into the RCS. The inspector reviewed the circumstances of the RCS level anomaly to determine the sequence of events and the cause of the anomaly.

The inspectors interviewed personnel involved with the event and reviewed the following procedures:

- Procedure 1104.048, "Hot Spot Flushing"

- Procedure 1103.011, "Draining and N_2 Blanketing of the RCS"
- Procedure 1305.018, "Local Leak Rate Testing - Type C"
- Procedure 1300.143, "Control of Infrequently Performed Tests or Evolutions"

b. Observations and Findings

System Description

A sketch of the system is included in Attachment 2. The RCS consists of the reactor vessel, two vertical OTSGs, four RCPs, a pressurizer, and interconnecting piping. In each heat transport loop, there is a hot leg pipe connecting the reactor vessel to the top of each OTSG, piping from the bottom of OTSG to the RCPs bowl, then piping from the RCP to the reactor vessel. The piping from the bottom of the OTSG rises approximately 35 feet to the suction of the RCPs. There is a connection on this line to the letdown system. There are four cold legs and two hot legs which penetrate the reactor vessel at the same elevation. The RCP bowl elevation is 372.3 feet.

Initial Conditions

The RCS was in reduced inventory with a stable level indication of 371.5 feet. The licensee was draining the cold legs in preparation to install nozzle dams on the OTSGs, but the water was not entirely drained and the water level was above the OTSG bowl. The drainage path from the cold legs used a drain off of the normal letdown line. The RCP seal vents, reactor vessel head, and OTSG were opened.

Sequence of Events

The licensee was using the same drain to remove water from the primary side of the OTSG and to remove water used in performing a hot spot flush of the letdown heat exchangers. The purpose of the flush was to reduce dose rates in the immediate vicinity of the letdown heat exchangers.

The auxiliary operators had finished flushing water through the line and had reduced radiation levels in the letdown heat exchanger room. Following this evolution, the operator was preparing to drain the letdown line penetration from the reactor building to perform a local leak rate test (LLRT). The operators used service air to purge the penetration. Shortly thereafter, control room operators observed RCS level indication change from 371.5 to 372.2 feet. Control room operators began preparations to drain the RCS to reduce water level since their level indications showed a 0.7 foot increase. Control room operators also began questioning, via radio, what the source of the water was. The auxiliary operator heard air pass through the letdown line and also heard, through his radio, control room operators asking about the increase in level. The auxiliary operator promptly directed another auxiliary operator to secure service air. The indicated RCS level gradually returned to 371.5 feet.

Procedure 1104.048 did not explicitly include or exclude the use of service air as part of the flush. Procedure 1305.018 did imply that the use of service air was allowed. Neither procedure contained any caution about using service air in this configuration. This approach had been discussed during the infrequently performed tests or evolutions brief in the control room, but was not questioned.

Procedure 1305.018, "Local Leak Rate Testing, Type C," Step 10.2.5, specifies to vent and drain the system inside the LLRT boundaries. This procedure did not preclude the use of service air to purge the lines. In this event, the vent path was beyond the LLRT boundaries. This resulted in air introduction into the reactor coolant system during reduced inventory. Reactor water level indication was adversely affected. This is a violation of procedures required by Technical Specification (TS) 6.8.1 (50-313/9606-01).

The inspectors found, because of the configuration of the RCS, that the maximum RCS level increase would have been limited to approximately 0.7 feet. Beyond that indicated level, additional venting capacity would have been available. For this occurrence, the decay heat removal (DHR) capability was not reduced. In assessing the amount of water which would have to be removed before DHR would be lost, the inspectors found that accurate level would have been restored before losing a DHR pump. The licensee planned to revise procedures to add a caution regarding the use of air in this plant configuration. At the end of the inspection period, the licensee had not completed their root cause determination.

c. Conclusions

Control room operators had an unexpected level increase during reduced inventory conditions caused by the introduction of service air into the RCS. Operators were prepared to remove water inventory based on these indications. The procedure in use did not have procedural cautions about the use of service air, and the letdown system was vented and drained beyond the LLRT boundaries. This is a violation. Operator response was prompt and effective in stopping this event.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- Job Order (JO) 00953454, "HPI Suction Relief (PSV -1242) Refurbishment"

- JO 00952693, "Replacing Foxboro Transmitters with Rosemont for 2PT 1423-2"

b. Observations and Findings

The inspectors found the work performed under these activities generally to be professional and thorough and performed with the JOs present and in active use. Technicians appeared experienced and knowledgeable of their assigned tasks.

M1.2 Unit 2 Relay Failure in Trip Circuit Breakers (TCBs)

a. Inspection Scope (92902)

The inspectors reviewed the corrective actions to address slow response times for two of eight TCBs.

b. Observations and Findings

On August 10, 1996, while performing the monthly Plant Protection System (PPS) Channel A test, the time response of two of the eight TCBs exceeded their operability criteria. Unit 2 has eight circuit breakers, which are in two trains of circuit breakers for the four channels of the PPS. While performing the monthly tests, TCBs 4 and 8 showed response times of 161 and 268 milliseconds, respectively, which is above the operability limit of 120 milliseconds. The other six TCBs had response times between 41 and 44 milliseconds. The licensee initiated JO 00953055 and Condition Report (CR) 2-96-0225 on this failure of the TCBs to meet their response time.

The licensee found that Relay K4, which was common to both of these TCBs, was responding slowly. Tests showed that the relay, when energizing, had time delays of less than 25 milliseconds. However, the time delays when de-energizing were between 2600 and 7000 milliseconds. The licensee replaced the relay and bench tested the old relay in an attempt to duplicate the results. During these bench tests, the relay degraded further and would not rotate the required 30°.

These normally energized alternating current relays are Potter-Brumfield MDR relays, which were qualified by ABB Combustion Engineering for use in the PPS. A similar failure had occurred on August 28, 1995, on another channel, Relay K2.

All four PPS relays had been installed at approximately the same time and had Lot Code 9412. The licensee determined that the relay shafts were binding. The specific cause of the relay binding has not been determined as of the end of the inspection period. The licensee replaced the relays with that lot code with new relays.

The licensee sent the relay for failure analysis. The licensee noted that industry has had previous problems with MDR relays, such as varnish outgassing and pole shading coils coming loose. These relay failures were not attributed to these causes.

M1.3 Failure of DHR Pump B Bearing

On September 15, 1996, as the RCS was being cooled down, the inboard bearing temperature to the DHR Pump B increased, accompanied by motor current spikes.

a. Inspection Scope (62707, 92902)

The inspectors reviewed the sequence of events surrounding this pump bearing temperature transient and the licensee's corrective actions for this failure.

b. Observations and Findings

On September 15, the inboard bearing temperature to DHR Pump B increased from 125°F to 175°F over approximately 6 minutes, accompanied by motor current spikes. The motor current and bearing temperature then returned to normal and remained normal. Inspection by an operator revealed that the oil appeared discolored, also indicating that the oil temperature had increased.

The licensee took oil samples and did not find abnormal metallic wear products in the oil. Bearing vibration readings were normal. The licensee then replaced the bearing oil and ran the pump for 6 hours. The licensee attempted to duplicate the failure by causing another thermal transient, which did not duplicate the results. The licensee also satisfactorily completed the routine flow and vibrations surveillance tests on the pump.

The licensee initiated CR 1-96-0356 to document this event. Based on the apparent satisfactory performance of the pump, the licensee declared the pump operable and continued to monitor the pump. The licensee's initial cause for the observed conditions was that this radial bearing had hung up during thermal growth on the shaft and then moved to a new position.

The licensee decided to inspect the bearing to verify pump reliability. The licensee found that this bearing was wiped and that there was some damage to the shaft. At the end of the inspection period, the licensee planned to replace the bearing and the shaft and then declare the pump operable.

M1.4 Failure of Control Room Radiation Monitor

a. Inspection Scope (62707, 92902)

The inspector reviewed the licensee's response to actuations of control room radiation Monitor 2-RITS-875-1.

b. Observations and Findings

During this inspection period, control room radiation Monitor 2-RITS-8750-1 spiked high once and drifted high twice. Three CRs were initiated relating to these occurrences. The CRs are C-96-0208, C-96-0217, and C-96-0231 dated September 3, 6, and 15, 1996, respectively. The first two resulted in a control room isolation actuation, and operators isolated the control room for the third instance before the monitor reached the setpoint.

For the first two instances, the licensee replaced the detector twice and the power supply using JO 00953554. For the third failure, the licensee rebuilt the connection from the detector. The licensee concluded that the connector was the root problem because of the lack of spurious actuations after the connector was rebuilt.

The licensee reviewed these failures for the maintenance rule requirements to see if they needed to perform more maintenance on the system. The requirements are to be placed in Category A if there are two failures in one refueling cycle. The licensee classified these experiences as one failure for maintenance rule purposes.

M1.5 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspector observed all or portions of the following surveillance activities:

- Procedure 1304.106, "Unit 1 Green Channel Low Pressure Injection Flow 18-Month Surveillances"
- Procedure 1306.017, "Unit 1 Main Steam Safety Valve Test"
- Procedure 2304.101, "Unit 2 Excores Safety Channel B Test"
- Procedure 1309.013, "Unit 1 Service Water Flow Test"

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All surveillances observed were performed with the surveillance and JOs present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors also noted management's oversight during the main steam safety valve test.

M1.6 Conclusions on Conduct of Maintenance

The maintenance and surveillance activities were accomplished according to work instructions. The licensee's actions with the Unit 2 TCB, Unit 1 DHR bearing, and the control room radiation monitor were appropriate.

M4 Maintenance Staff Knowledge and Performance

M4.1 Unit 1 - Hydrogen Burn During RCS Welding Activity

a. Inspection Scope (93702)

The inspectors conducted interviews with personnel involved and reviewed the following procedures and instructions:

- Procedure 1102.010, "Plant Shutdown and Cooldown"
- Procedure 5120.119, "Control of Plant Welding"
- Procedure 1003.006, "Control of Ignition Sources"
- Construction Work Package 94-5030/946520-5
- JO 00946520
- Procedure 1103.011, "Draining and Nitrogen Blanketing the Reactor Coolant System"
- Procedure 1402.018, "Unit 1 Pressurizer Relief Valves (PSV-1001 and PSV-1002) Removal"

b. Observations and Findings

On September 21, 1996, at 3:45 p.m., while completing welding on a common 10-inch electromatic relief and pressurizer relief valve tailpipe, the tailpipe shook while a second welding pass was being completed on the pipe. The tailpipes from Pressurizer Relief Valves PSV-1001 and -1002 and Electromatic Relief Valve PSV-1000 direct steam to a 10-inch pipe connected to the quench tank. The quench tank contains water to cool and condense the steam. Following the noise, the contract welder decided to complete a third welding pass and subsequently exited the area.

The licensee investigated the occurrence and found the temporary cover (taped bag) over the disconnected tailpipe flange for Pressurizer Relief Valve PSV-1002 blown off. The licensee concluded that welding caused a hydrogen burn to occur which

shook the pipe, created the loud noise, and blew the temporary cover off the pipe. As a result of the event, the licensee stopped all welding activities on the RCS and inspected the systems for damage. No damage was found.

After the event, the licensee sampled the common 10-inch pipe and the tailpipes for hydrogen and found hydrogen in concentrations near the lower explosive limit of 4 percent. The licensee believed that the hydrogen had entered the quench tank water when the operators opened Electromatic Relief Valve PSV-1000 during the cooldown of the RCS following the September 12 reactor trip. Hydrogen gas eventually came out of the solution and collected in the tailpipes. The heat generated through the weld passes ignited the hydrogen. The tailpipes were not sampled or purged before welding.

Through interviews and a review of operational logs, the inspectors were unable to identify any other possible cause of the event. The licensee also conducted an inspection of the associated pipe hangers to determine if a failed hanger may have shaken the pipe and confirmed there were no pipe hanger failures. Further, quench tank level trends from the plant computer indicated approximately a 3000 gallon level spike at approximately 3:46 p.m. The inspectors concluded that the pressure spike created by the hydrogen burn indicated on quench tank level instruments as a level spike. Therefore, the inspectors concluded that a hydrogen burn had occurred as a result of the welding activity.

The inspectors found on Form 1003.006A, "Ignition Source Permit," that the welder's supervisor had marked the block for containers purged of flammable vapors as "Not Applicable" before the welding started. The block was marked "Not Applicable" because the contract supervisor did not recognize that the pipe may be a source of hydrogen. Further, the supervisor and the welder thought that operations told them that the lines were previously flushed and purged when, in fact, they were not.

Procedure 1003.006, Step 5.1.1, requires the cognizant supervisor to determine the fire and explosion precautions necessary for the safe performance of work. For the welding performed on the lines leading to the quench tank, the cognizant supervisor failed to ensure that hydrogen was identified and purged from the common tailpipe to prevent the hydrogen burn during the welding activity and is a TS 6.8.1.f violation (50-313/9606-02).

Information Notices (IN) 82-28, "Hydrogen Explosion While Grinding in the Vicinity of Drained and Opened Reactor Coolant System," and 94-53, "Hydrogen Gas Burn Inside Pressurizer During Welding," provided opportunities for the licensee to address this issue. For IN 82-28, the licensee included precautions in maintenance procedures for reactor coolant makeup and injection systems to eliminate hydrogen as an explosive hazard. The inspectors reviewed the list of maintenance procedures and confirmed the precautions were included as necessary. Procedure 1402.018 was included in this list and contained a precaution to sample the pressurizer but not

the tailpipes because the tailpipes were not considered part of the RCS while Pressurizer Relief Valve PSV-1002 was being removed for testing. The licensee initiated Plant Impact Evaluation 94-0232 to evaluate IN 94-53 and concluded that they had adequate programmatic and procedural instructions for the performance of hot work in explosive environments.

At the close of the inspection period, the licensee was performing a root cause evaluation for CR 1-96-0403, which was initiated to document the event. The proposed corrective actions for this CR had not been completed. The licensee's interim corrective actions included a briefing to each maintenance crew of industrial fire hazards regarding detection and elimination of explosive gases prior to welding, the INs, and emphasis of the ignition source permit requirements.

M4.2 Conclusions

The inspectors concluded that the procedural instructions, precautions, and ignition source permit were adequate steps to identify and remove hydrogen from the system, but these procedure steps were not adequately implemented by the craft. This is a violation.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Unresolved Item (URI) 50-313(368)/9604-04: Degradation of Diesel Fuel Oil System

This URI was opened subsequent to the licensee's May 27, 1996, identification that the water content in Units 1 and 2 emergency diesel generator (EDG) fuel oil storage tanks exceeded TS limits. Both diesel generators in Unit 1 and one generator in Unit 2 were affected. The issue was discussed in Section 8 of NRC Inspection Report 50-313/96-04; 50-368/96-04. The issue was unresolved pending NRC review of the actual impact of the condition on EDG operability. During this inspection period, the inspectors reviewed a qualitative analysis regarding the operability of the Unit 1 EDGs. The analysis concluded that, despite the water content in the fuel, the EDGs remained capable of performing their intended safety function. The inspectors found the licensee had sufficient basis to support its conclusion. The licensee demonstrated that the water content in the Unit 1 EDG B day tank would not have exceeded TS limits. The Unit 1 EDG A remained fully functional in that it ran fully loaded for 2 hours with no adverse effects and that the Unit 2 EDG A with water content was within manufacturer's specifications. The licensee's analysis is provided as Attachment 3.

The root cause of the water contamination was an improper sampling technique on the 185,000 bulk fuel oil storage tank. The sample point was procedurally specified to be from the top of a filter located in the line between the bulk storage tank and

the individual EDG fuel oil storage tanks. This sample point was not representative of water content at the bottom of the tank. The sample point should have been designated at the bottom of the tank where water accumulates.

In NRC Inspection Report 50-313/96-04; 50-368/96-04, Section 8, the inspectors concluded that Procedure 1618.010, Revision 12, "Sampling Unit 1 Diesel Fuel," was not appropriate to the circumstances in that it did not specify a sample point to adequately assess water content in the bulk oil storage tank. The inadequate procedure constitutes a violation of 10 CFR Part 50, Appendix B, Criterion V. This licensee-identified and corrected violation is a noncited violation in accordance with Section VII.B.1 of the NRC's Enforcement Policy.

Corrective actions undertaken as a result of the water fouling of the fuel oil included straining, cleaning, inspecting the bulk oil tank, increasing the height of the outlet orifice in the bulk oil tank to provide additional margin before water and sediment can carry over, revising procedures to properly sample the bulk oil tank, and draining from the bottom of the tank quarterly to remove accumulated water and sediment. The inspectors considered these corrective actions appropriate.

Based on the above, this URI and corresponding Licensee Event Report (LER) 96-006 are considered closed.

M8.2 (Closed) LER 50-313/96-006: EDGs Inoperable Due to Excessive Water in the Fuel Oil System. This LER is closed in paragraph M8.1.

III. Engineering

E1 Conduct of Engineering

E1.1 Unit 2 - Grease on the Outside of Containment Wall

a. Inspection Scope (37551)

During a tour of the lower south electrical penetration room, the inspectors observed grease on the containment building wall above Electrical Penetration 2E-36.

b. Observations and Findings

The licensee initiated CR 2-96-0261 to document the deficiency. The licensee found that Containment Tendon 21H15 had leaked grease to the outside of the wall. The grease lubricates the tendon to aid in expansion and contraction as the containment building heats up and cools down. The licensee has tracked the leakage since 1992 and has determined that a 5 percent grease packing void, equivalent to approximately 11 gallons of grease, was acceptable. Engineering

Calculation 95-E-0060-01 indicated that approximately .75 gallons of grease has been collected between August 1992 and July 1995 and the tendon remains operable.

c. Conclusions

The inspectors concluded that the licensee appropriately identified and monitored the leakage.

E1.2 Design Change Package (DCP) 93-1013 DCP, Revision 14, Trip Hardening of MFW Pump Control System

a. Inspection scope (92903)

On May 19, 1996, Unit 1 experienced a reactor trip with complications that was initiated by a single failure in the main feedwater pump turbine (MFPT) control system. One complication was that the feedwater system could not respond to posttrip demand signals due to an inadvertent lock of the MFPT control system from valid integrated control system (ICS) demand signals. This revision to DCP 93-1013 was designed as corrective action for those May 19 failures. The inspection focused on the adequacy of those corrective actions and the 10 CFR 50.59 evaluation performed to ensure the modification did not constitute an unreviewed safety question.

b. Observations and Findings

The failure of the MFPT control system associated with the May 19 event is fully documented in NRC Inspection Report 50-313/96-19; 50-368/96-19.

The licensee determined the initiating cause of the event was an electric short of a speed sensor that was common to both power supplies of the low pressure electrohydraulic control controllers. This fault to ground on the speed sensor degraded the voltage of the power supplies, causing the low pressure electrohydraulic control to react to the low voltage condition. This caused a degradation of control oil pressure and a subsequent prompt reduction in feedpump speed and output. The reduced output resulted in insufficient primary to secondary heat removal and the reactor tripped on high pressure.

To prevent recurrence, this modification will install fusing between the power supplies and external devices which share the power supplies with the critical components. The licensee designed the modification in consultation with the vendor and identified four digital speed monitors and 10 transmitters that could affect the power supplies. The inspectors reviewed the intended fusing scheme and found it to be an appropriate means of protecting the critical power supplies.

Above 50 percent power, the feedwater system is split such that one feedwater pump feeds one OTSG. The feedwater system is designed with logic such that, if one feedwater pump trips, a crossover valve will open to allow the affected feedwater header to be supplied from the opposite feedwater pump. During the May 19 event, MFP A went to minimum speed and output due to the degradation in control oil pressure, but did not trip. Accordingly, the logic was not satisfied to open the crossover valve. Had MFP A tripped, the reactor trip may not have occurred as was demonstrated by an MFP A trip on June 22, 1996, without a reactor trip. As corrective action, this modification equips the MFPT control system with a low pressure trip. The inspectors found that the incorporation of this MFPT control system trip should enable the plant to withstand a transient induced by a degradation of MFPT control oil pressure without causing a reactor trip.

In the May 19 event, MFP B was also lost when it tripped on high pressure after it failed to respond to rapidly decreasing ICS demand. It failed to respond because the control system inadvertently transferred to "diagnostic manual" mode where it is disassociated from ICS input. This transfer was designed to occur upon invalid ICS demand signals, but the MFPT control system sensed a valid ICS demand signal as invalid because of excessive electronic noise in the ICS signal. This modification attempts to correct the undesirable noise by changing the ICS demand from a voltage to a current signal. The demand signal from the ICS to the MFPT control system is a 0 to 10 VDC signal. A signal is developed in the ICS from a -10 to +10 VDC signal. A signal limiter was installed on the demand module because the system did not respond well to negative voltages. The licensee determined that the signal limiter module was not intended to be used as a final output device. Used in this application, a ringing effect occurs at the extremes of the output range. This ringing noise was suspected to be the cause of the inadvertent transfer to the "diagnostic manual" mode of operation. To reduce the noise to a minimum, this modification replaced the signal limiter with a voltage to current (E/I) converter.

In discussions with engineering, the inspectors found that, although this modification is expected to correct the noise concern, the "diagnostic manual" logic that was defeated after the May 19 event will not be reinstituted at this time. After some operating experience is gained with the new current signal driver, it may be reinstituted at a later time.

c. <u>Conclusions</u>

The inspectors concluded that the proposed modifications adequately addressed the concerns developed in NRC Inspection Report 50-313/96-19; 50-368/96-19. The inspector concluded that the licensee had sufficient basis for determining that the proposed modifications do not constitute an unreviewed safety position.

E3 Engineering Procedures and Documentation

E3.1 DCP 95-1015: Atmospheric Dump Valve (ADV) Replacement

a. Inspection Scope (37551)

The inspector reviewed the description of change and 10 CFR 50.59 evaluation associated with DCP 95-1015 to ensure the modification did not constitute an unreviewed safety question.

b. Observations and Findings

The Unit 1 ADVs have had a history of experiencing thermal binding, which precludes automatic operation. Repairs were attempted in Refueling Outage 1R12 but were unsuccessful. During the previous operating cycle, instructions were provided to operators to "work around" the condition by fully opening the ADVs and then throttling the ADV block valves to control steam pressure.

The licensee indicated that the overall design basis for the ADVs is to provide an alternate means of pressure control and heat removal from the steam generators in the event that the turbine bypass valves cannot be used. The main steam safety valves are credited as the safety-related means of secondary system heat removal. The ADVs are credited as being manually operated to achieve alternate shutdown prescribed by 10 CFR Part 50, Appendix R.

To correct the thermal binding concern, the current ADVs, which are angle globe valves, are being replaced with straight globe valves. The new valves are also physically relocated to a new platform to improve access for manual operation or maintenance. The modification made no functional change to the system for normal operation.

The inspectors reviewed the description of change and corresponding 10 CFR 50.59 evaluation and found that the licensee had adequate basis for determining that the change did not constitute an unreviewed safety question. However, in the process of evaluation, the inspectors identified a vulnerability in the licensee's design change process. The inspectors found that, in a supplemental safety evaluation (SSE) for the ANO Units 1 and 2 Station Blackout (SBO) Rule (10 CFR 50.63) dated October 24, 1991, the ADVs are relied upon for DHR during an SBO event. In the SSE, the staff concluded that, following an SBO event and upon the loss of compressed air, the licensee will be able to manually operate the ADVs for DHR.

The inspectors did not consider that the modification would adversely affect this functional requirement but was concerned that the DCP did not address this current licensing basis commitment.

The inspectors found that Procedure 1000.131, Revision 2, "10 CFR 50.59 Program," requires that Safety Analysis Report documents be reviewed to ensure that statements therein remain valid as a result of the proposed activity. Safety Evaluation Reports are defined as SAR documents; however, only those Safety Evaluation Reports that support the original operating license and subsequent amendments are included in the definition. Accordingly, the supplemental safety evaluation supporting the SBO rule would not be included in the licensee's search of SAR documents.

The licensee indicated that other management controls have been established to maintain the licensing basis that has been established through docket correspondence such as the SBO rule. In this instance, the licensee indicated that the licensing basis requirement of the ADVs to be manually operated following an SBO would be reviewed as part of the overall design change development in accordance with Procedure 6010.001, "DCP Development," Revision 7. The inspectors found the procedure did provide guidelines to preparers to consider "licensing correspondence" as part of design basis considerations, but the procedure did not require any documentation of findings.

For this modification, the preparer indicated that there was no relationship to regulatory commitments, regulations, or programs affected by this modification. There was no evidence to suggest that the licensing basis requirement to have the ADVs be operable manually for an SBO scenario was identified in the development of this DCP.

Further, Procedure 6010.001 provides guidelines for developers to consider station programs affected by the modification. The programs designated that are required to be addressed include Appendix R, Appendix J, Seismic II/I, and Environmental Qualification; but SBO is not addressed.

In reviewing the Updated Safety Analysis Report (USAR) as part of the design change review, the inspectors found that the USAR had not been updated to reflect the addition of the SBO diesel to comply with the SBO rule (10 CFR 50.63). The licensee indicated that the reason the USAR did not reflect the blackout diesel was that the DCP that installed it had not yet been formally closed. The licensee provided a draft USAR amendment that addressed the incorporation of the blackout diesel into station design. The inspectors found that the licensee did not intend to address the addition of the SBO diesel in the accident analysis section of Chapter 14 of the USAR, where loss of electric power is discussed. The licensee initially responded by indicating that the loss of all alternating current was not an original licensing basis accident. The inspectors indicated that, if paragraph 14.1.2.8.4, "Results of Complete Loss of All Unit AC Power," was not revised to reflect the addition of the blackout diesel, the USAR would not describe current plant configuration. The licensee responded that they would update paragraph 14.1.2.8.4 and indicated they would do so as part of Amendment 14 to the Unit 1 USAR.

c. Conclusions

The inspectors concluded the licensee had adequate basis to support its determination that the proposed modification did not constitute an unreviewed safety question. The inspectors concluded that the licensee was vulnerable to missing regulatory requirements which might be affected by station modifications due to the loose guidelines provided by Procedure 6010.001. The licensee indicated the inspector's observations and conclusions were valid and indicated they intended to enhance Procedure 6010.001 as part of an Entergy, Inc. system-wide revision of the procedure. The inspectors concluded that the licensee's intended Amendment 14 to the USAR would not have fully reflected current plant design in that paragraph 14.1.2.8.4, "Results of Complete Loss of All AC Power," was not to be updated to reflect the incorporation of the blackout diesel into system configuration.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Open) URI 50-313/9606-04, "High dP Across SW Pump Strainers"

This item was opened since the licensee had two CRs within 2 weeks that affected service water (SW) pump operability due to high dP across SW pump strainers. This occurred during routine surveillance tests when the water supply source was changed to the pump and debris may have been stirred up. Since a potential exists to stir up debris in the bays when pump water sources are changed, the inspectors needed to determine if there was a common mode failure occurring for the SW system. This item was delayed until the outage to see how much debris was in the SW bays.

a. Inspection Scope (37551, 92903)

The scope of this inspection was to determine the extent of debris in the Unit 1 SW bays. During this inspection, the original concern has expanded due to the as-found condition in the bays. Since this item was opened, Unit 2 also had indications of high dPs when switching water sources and two Unit 1 sluice gates exceeded their specified leakage criteria. The inspectors will status the findings of the Unit 1 SW bay and the Unit 2 SW bay inspections.

b. Observations and Findings

The following are relevant CRs generated on the SW system by the end of the inspection period:

Date	CR Number	Pump	Condition
7/15/96	1-96-0245	P-4C	High dP observed (18 psid) when switching from lake to the emergency cooling pond (ECP).
7/29/96	1-96-0266	P-4B	High dP observed (11 psid) when switching from lake to ECP. Also, Pump P-4A was affected since sluice gate was open between SW bays.
8/8/96	2-96-0214	2P-4C	During performance of the surveillance test, the lake sluice gate would not open from the control room.
9/18/96	2-96-0254	2P-4A	High dP observed (10 psid) when switching from ECP to lake.
9/22/96	C-96-0245	ALL	Excessive leakage (>103 gpm) observed on sluice gate affecting allowable leakage on both units.
9/20/96	1-96-0383	P-4A	High dP observed (12 psid) when switching from ECP to lake.
9/27/96	2-96-0266	2P-4B 2P-4C	Following SW Bay B cleaning, pump suction was changed back from ECP to lake. At the time of event, Pump 2P-4C had a high bay level and the sluice gate to the lake was opened.

SW System Description

For both units, the SW system provides cooling for equipment essential for safe operation and shutdown of the plant. During normal operation, the water supply is from the Dardanelle reservoir. An alternate supply of water can be obtained from the ECP. Each unit has two independent flow paths to furnish water to safety-related equipment. There are three SW pumps to supply these flow paths, with one pump as a swing pump. Each bay can be isolated and use the ECP as the water source. After taking suction from their respective bays, the pumps send the water through a discharge filter. Clogging of the filter can render a flow path inoperable due to a reduction in SW flow to safety-related components.

For Unit 1, SW Pumps A and C can take suction from the lake or the ECP. Pump B can take suction from either SW Bays A or C or the ECP. These bays can be isolated from each other and the lake depending on opening and closing of various sluice

gates. Directly in front of SW Bays A and C are Circulating Water Bays B and C, which have trash racks, traveling screens, and the circulating water pumps.

For Unit 2, SW Pumps A, B, and C can take suction from the lake or the ECP. These bays have no direct connection between them and can be isolated from the lake by closing their respective sluice gates. Directly in front of the SW bays is a common forebay, which has trash racks and traveling screens.

For both units, the design basis for the ECP inventory is to supply one unit to cold shutdown while the other unit has a loss-of-coolant accident, coincident with a loss of the lake as a suction source. Included in this inventory are assumptions for sluice gate leakage from the SW bays back into the lake and leakage for valves which are the interface of nonsafety-related systems with SW. The Final Safety Analysis Report (FSAR) values are for 75 gpm of total leakage based on an engineering calculation of 89 gpm.

Previously, both intake structures have seen evidence of biological fouling of zebra mussels, asiatic clams, etc; however, the amount of growth seen was minor. During the refueling outage, the licensee found a significant infestation of both units' intake structures.

Unit 1 As-Found Intake Structure Bay Condition

Zebra mussels, silt, and other debris were found in all three SW bays and the amount was significantly more than the last inspection during April 1995. The zebra mussels were dead in the SW bays, except for the lake inlet into the SW bay, which had live zebra mussels. The SW bay biocide injection the plant uses was not effective in this area since this is before the biocide injection point.

Significant amounts of live zebra mussels, asiatic clams, and other biological life were in the untreated circulating water bays on the walls and other surfaces of the bays. Circulating Water Bay B was last cleaned in April 1995 and Circulating Water Bay C was last cleaned in April 1996. Since Bay B had not been cleaned as recently as Bay C, the amount of zebra mussels in Bay B was significantly more than Bay C. The zebra mussels in Bay B were bigger and approximately 2 to 4 inches thick on surfaces in Bay B. Zebra mussels in Bay C were smaller, with a maximum thickness of approximately 1 inch, and Bay C had some bare surfaces.

The licensee also tested the leakage out of the sluice gates back into the lake from SW Bays A and C (Sluice Gates 1 and 2) and found that the leakage out of these sluice gates was 103 gpm and 41 gpm, respectively. This leakage was due to clams interfering with the guides and seat of the sluice gates. The leakage amount from these two sluice gates was approximately double the FSAR limits and greater than the 10 gpm leakage assumed. The licensee is evaluating this as-found condition.

Unit 2 As-Found Intake Structure Bay Condition

Due to the as-found condition of the Unit 1 bays, concerns with sluice gate leakage, and high dP alarms, when switching suction sources for Unit 2, the licensee decided to inspect Unit 2 SW bays and the forebay with divers.

The licensee found some dead clams and debris within the SW bays but not to the same extent as the Unit 1 bays. The licensee also found that the sluice gate surfaces were clean. The licensee removed debris from the SW bays and, at the end of the inspection period, was intending to clean the forebay walls.

Licensee's Actions

At the end of the inspection report period, the licensee had cleaned the Units 1 and 2 SW bays and had cleaned the Unit 1 circulating water bays. The licensee is still evaluating the effects the zebra mussels had on both units intake structures and has not developed long-term plans to address the growth they are currently seeing.

c. Conclusions

Based on the cleaning of the Units 1 and 2 SW bays, there was not an immediate safety concern. The growth of zebra mussels has affected the closing of two Unit 1 SW sluice gates, which exceeded the ECP leakage FSAR limits. This item will remain unresolved pending review of the licensee's evaluation for ECP leakage, the effects of the zebra mussels on the discharge filters, and review of the licensee's long-term actions.

IV. Plant Support

R4 Staff Knowledge and Performance

R4.1 Unit 1 - Water Poured Down RCP Oil Fill Funnel

a. Inspection Scope (71750, 92904)

On September 25, 1996, a health physics technician observed a worker pouring approximately 5 gallons of water from an air conditioning unit down the oil fill funnel for the RCP motor. The technician questioned the individual and found that the worker thought the funnel was used for a floor drain. The technician proceeded to the lower elevation and found that the tubing from the oil funnel was not connected to the RCP oil fill reservoir. The technician found that water poured on the top of the RCP motor housing. The individual left the area before the technician returned. CR 1-96-0432 was initiated to document the event.

b. Observations and Findings

The licensee covered oil fill funnels for all four RCPs and secured the covers with tie wraps to prevent this incident from recurring. The licensee inspected all of the empty RCP oil reservoirs for water and confirmed no water was present. The licensee stated that the oil fill funnels and tubing were installed under Plant Change JO 00803593 to allow addition of oil to the pumps in an area with low radiation (outside the bio-shield) during normal plant operation. Pump maintenance procedures and JOs permitted the funnel tubes to be disconnected. Procedure 1015.036, "Containment Building Closeout," Attachment B, "Closeout Items Guide," required the electricians check that RCP motor oil addition funnels were clean and ready for use during containment closeout. The inspectors believed this instruction could be improved by including explicit instructions to reconnect the tubing. The licensee initiated refueling task under Job Request 920333 to check the tubing for tightness and kinks. The inspectors concluded that the initiated task was acceptable.

c. Conclusions

The inspectors concluded that the health physics technician exhibited a good questioning attitude in identifying the discrepancy. At the close of the inspection period, the CR root cause and the proposed corrective actions have not been completed; but, the licensee's immediate corrective actions were acceptable.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Edington, General Manager
R. Fuller, Unit 1 Operations Manager
M. Harris, Unit 2 Maintenance Manager
R. Lane, Director, Design Engineering
D. Lomax, Manager, Engineering Programs
D. Mims, Director, Licensing
T. Mitchell, Unit 2 System Engineering Manager
R. Partridge, Acting Chemistry Superintendent
S. Pyle, Licensing Specialist
M. Smith, Supervisor, Licensing
R. Starkey, Unit 1 System Engineering Manager
M. Stroud, Electrical Instrumentation and Control Design Manager
C. Turk, Manager, Mechanical, Civil, and Structural Design
C. Zimmerman, Unit 1 Plant Manager

NRC

J. Melfi, Resident Inspector
T. Reis, Project Engineer

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support
IP 93702: Prompt Onsite Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-313/9606-01	VIO	Reactor Level Perturbation During Reduced Inventory
50-313/9606-02	VIO	Hydrogen Burn During RCS Welding Activity
50-313(368)/9604-04	URI	Degradation of Diesel Fuel Oil System

Closed

50-313(368)/96-006	LER	EDGs Inoperable Due to Excessive Water in the Fuel Oil System

Discussed

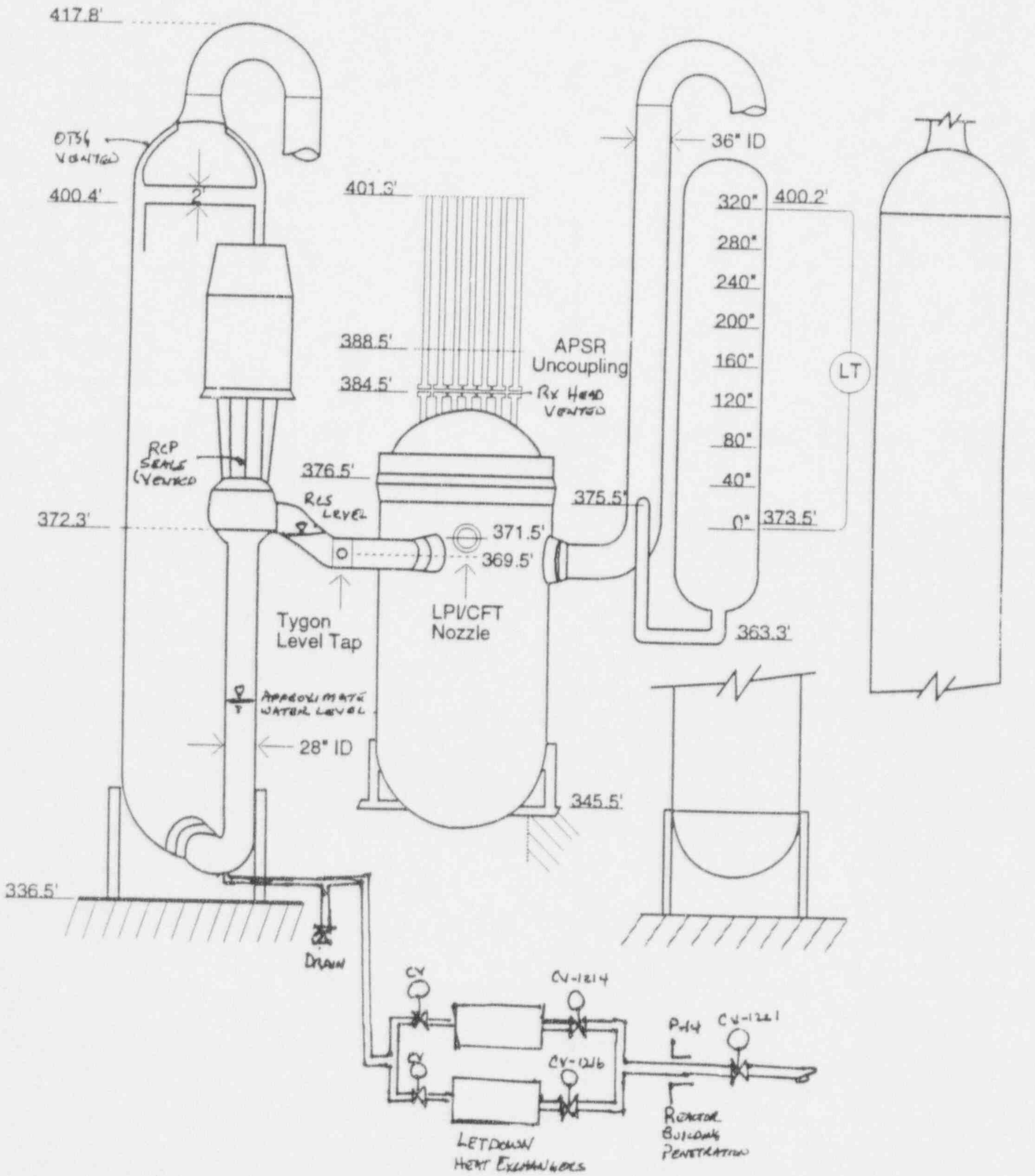
50-313/9606-04	URI	High dp across SW pump strainers

LIST OF ACRONYMS USED

ADV	atmospheric dump valve
CR	condition report
DCP	design change package
DHR	decay heat removal
ECP	emergency cooling pond
EDG	emergency diesel generator
FSAR	Final Safety Analysis Report
ICS	integrated control system
IN	information notice
JO	job order
LER	licensee event report
LLRT	local leak rate test
MFPT	main feedwater pump turbine
MFW	main feedwater
OTSG	once-through steam generator
PPS	plant protection system
RCP	reactor coolant pump
RCS	reactor coolant system
SBO	station blackout
SW	service water
TCB	trip circuit breaker
TS	Technical Specification
URI	unresolved item
USAR	Updated Safety Analysis Report

ATTACHMENT 2

GENERAL REFERENCE POINTS



Effects of Fuel Oil Water Intrusion on EDG Performance

A qualitative analysis has been performed by ANO of the potential effect of water found in the diesel fuel oil system on the ability of the EDGs to perform their design function. The water was discovered during the monthly EDG surveillance test on May 27, 1996. (ref. LER 50-313/96-006-00 dated June 26, 1996)

The analysis assumed that the entire volume of water drained from or passed through the system from the time of the initial sample until the tanks were returned to within specifications contained the percentage of water and sediment indicated in the results of the initial sample. That amount of water was then assumed to be transferred to the applicable fuel oil day tank (T-30A, B) and the resultant concentration's affect on the ability of the associated EDG to perform its design function was evaluated.

On May 27, the K4A EDG was declared inoperable after a sample taken from EDG fuel oil storage tank T-57A indicated a high water/sediment content. K4B was run for approximately 10 minutes after K4A was declared inoperable. After the run, EDG fuel oil storage tank (T-57B) was sampled. The results of that sample indicated a water/sediment content of 0.3%. After draining 50 gallons of fuel oil from the tank, a subsequent sample indicated 0.0% water/sediment. To assess the potential effects of this condition, it was conservatively assumed that the entire 50 gallons contained 0.3% water/sediment and that amount of water would be transferred to T-30B during an EDG run. (Sampling of this tank showed no water was actually present) The resultant water/sediment concentration in T-30B was calculated to be 0.05%, which is within the manufacturers and the Technical Specifications' operability limits. Therefore, it can be concluded that K4B remained capable of performing its design function if called upon to do so while there was water in its fuel oil system.

K4A was running at the time of the initial sample, which indicated a water/sediment concentration of 1.4%. During the surveillance run, K4A consumed approximately 400 gallons of fuel oil. Another 6 gallons of fuel oil was drained before a sample indicated 0.0% water/sediment. Conservatively assuming the entire 406 gallons of fuel oil contained 1.4% water/sediment and that all of the water/sediment was transferred to T-30A, that tank would contain 2.07% water/sediment, rendering K4A inoperable. However, the functionality of K4A was proven in that it successfully ran fully loaded for its entire surveillance run and samples from T-30A showed no water/sediment content.

The sample points are located in tank low points where water/sediment tends to concentrate. The sampling location is indicative of the worst case fuel oil water/sediment content of the tank and therefore provides a conservative early indication of any water intrusion. When the sample results exceeded the limit listed in the surveillance requirement, the applicable EDG was conservatively declared inoperable even though in the case of K4A, the EDG was running fully loaded at the time. A subsequent check of cylinder temperatures and injector condition and functioning revealed no problems. These were checks that were recommended by the vendor to determine if moisture in the fuel oil had any impact on the ability of the EDG to perform its intended function. Additionally, the vendor recommended checking the skid mounted fuel oil filters for evidence of water/sediment. Neither EDG showed any indication of water/sediment in the engine fuel filter and none of the samples taken indicated any water/sediment in the day tanks. (By inference, no water/sediment was indicated in the transfer piping between the storage tanks and the day tanks since there was never any indication of water/sediment in the day tank. This is particularly true of K4A as the day tank

was totally replenished at least once during the EDG run without any indication of moisture in the day tank.) Thus the evidence indicates the quantity and location of water/sediment in the tanks was such that both EDGs were capable of performing their design function.

In retrospect, conservative actions were taken based on the best information available and the assumption that the samples were representative of the respective tanks' entire contents at the time of the sample. The sample locations provided early indication of a developing problem, as intended, and the samples taken did not satisfy surveillance requirements. However, in the case of K4B, even with the conservative assumptions that the 50 gallons drained from the tank had 0.3% moisture, which could not have been the case, and the entire 50 gallons were transferred to the day tank, which is also unlikely, the day tank would still have met the water/sediment surveillance requirement. That, coupled with no indication of water/sediment in the day tanks in the samples taken, is strong evidence the ability of K4B to perform its design function was never impaired throughout this event. In the case of K4A, its ability to run fully loaded while this condition existed without any degraded indications; no water/sediment indications in the day tank, transfer piping, or fuel filter; and restoration of the storage tank to in-specification conditions after draining only six gallons from the tank constitute strong evidence that K4A's ability to perform its design function was not impaired during this event. It can be concluded from the above information that the water actually present in the EDG fuel oil system was limited to a small quantity at the bottom of the tanks and in the sample lines which was not sufficient to prevent the EDGs from performing their design function.