ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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License No.:	NPF-47
Report No.:	50-458/97-19
Licensee:	Entergy Operations, Inc.
Facility:	River Bend Station
Location:	5485 U.S. Highway 61 St. Francisville, Louisiana
Dates:	November 30, 1997, through January 10, 1998
Inspectors:	G. D. Replogle, Senior Resident Inspector
Approved By:	E. E. Collins, Chief, Project Branch C Division of Reactor Projects
Attachment:	Supplemental Information

EXECUTIVE SUMMARY

River Bend Station
NRC Inspection Report 50-458/97-19

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The conduct of operations was generally professional and safety-conscious (Section O1.1).

- The separation criteria between a temporary cable and an uncovered safety-related cable tray was not maintained consistent with the Updated Final Safety Analysis Report and plant procedures (Section O2.2).

- A nuclear equipment operator trainee demonstrated excellent attention to detail during a diesel generator surveillance. While looking for fluid discharge on the cylinder head test valves, the operator noticed oil residue on piping adjacent to the number eight cylinder (versus the cylinder head test valve itself, Section M1.2).

- Operations and Maintenance personnel were not effective in maintaining the postaccident sampling system (PASS). The PASS was out of service for approximately 50 percent of the time during the past 10 months. Repairs were often not performed in a timely manner, and the overall material condition of the system was poor (Section M8.1).

- A shift technical advisor failed to consider the Technical Specifications Limiting Conditions for Operability when determining operability for emergency core cooling system minimum flow valve instruments (Section E8.1).

Maintenance

- Maintenance activities were generally completed thoroughly and professionally (Section M1.1).

- On-line risk assessments were not always thorough. In one instance operators assumed that a delay in placing standby service water pumps in service would not adversely affect the availability of the standby service water pumps or the associated diesel generators without fully understanding equipment response. In another case, the potential consequences associated with a freeze seal failure were not properly considered in the risk assessment (Section M1.3).

- While overall plant material condition was good, there were notable equipment and system performance problems. The inspector noted material condition concerns involving excessive main generator hydrogen leakage, an inoperable PASS, an inoperable suppression pool pumpback pump, a degraded control rod drive pump, a

failed containment isolation damper, and air entrapment in the instrument sensing lines to safety-related instruments. Conversely, spent fuel cooling Pump 1B and the suppression pool cleanup mode of the alternate decay heat removal system were repaired and returned to service (Section M2.1).

Engineering

- The diesel generator system engineers promptly and effectively evaluated the significance of fuel oil discharge coming from a diesel generator cylinder. The prompt assessment helped to minimize the out of service time for the diesel generator (Section M1.2).

- Engineers did not assess in a timely manner the significance of exceeding the flammability threshold for hydrogen concentration at the seal oil detrainment tank vent. Consequently, the flammability threshold was exceeded before safety issues were thoroughly evaluated (Section E2.1).

- Corrective actions to address air entrapment in reactor core isolation cooling minimum flow valve instrument lines (January 1997) were not comprehensive and did not prevent recurrence. Subsequently, one high pressure core spray and two residual heat removal system minimum flow valves malfunctioned for the same or similar causes (air entrapment in the instrument lines, Section E8.1).

Plant Support

- Housekeeping was considered good (Section O2.1).

- During routine tours, the inspectors noted that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the Primary Access Point were appropriately performed (Section S1.1).

Report Details

Summary of Plant Status

At the beginning of this inspection period, the plant was in Operational Mode 1 at 100 percent reactor power. On December 20, 1997, power was reduced to approximately 60 percent in support of planned maintenance on reactor feedwater pumps. At the conclusion of the work on December 21 reactor power was returned to 100 percent, where it essentially remained for the remainder of the reporting period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. The conduct of operations was generally professional and safety-conscious.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors walked down accessible portions of the following safety-related systems:

- High Pressure Core Spray (HPCS)
- Diesel Generators (DGs) I and II and HPCS
- Residual Heat Removal (RHR), Trains A, B, and C
- Reactor Core Isolation Cooling (RCIC)
- Division I, II, and III Switchgear and Battery Rooms

The systems were found to be properly aligned for the plant conditions and in good material condition. A few minor housekeeping issues were identified but, overall, housekeeping was good. One problem associated with electrical separation of safety-related and nonsafety-related cables is discussed in Section O2.2.

O2.2 Separation of Temporary Cables

b. Observations and Findings

On December 4, 1997, while touring the auxiliary building, the inspector identified that an extension cord was draped over the top of uncovered division II Cable Tray 1TX817B. Procedure ADM-0073, "Temporary Installation Guidelines," Revision 2, Step 5.2, requires that temporary installations adhere to design separation criteria specified on Drawing EE-34ZE. Drawing EE-34ZE, "Standard Details for Separation Requirements," Revision 7,

identified the separation requirements for "free air cables to trays" as one foot. Additionally, the one foot separation requirement was specified in the Updated Final Safety Analysis Report, Section 8.3.1.4.2. In response to the inspector's concern, the temporary cable was promptly re-routed and the problem was documented on Condition Report (CR) 97-2080.

The inspector further noted that CR 97-1610, dated September 1997, was previously initiated to address similar concerns. In that CR, Quality Assurance personnel toured the facility to inspect compliance with cable separation requirements. The Quality Assurance inspectors identified eight instances where cable separation requirements were not met. Corrective actions planned or taken in response to CR 97-1610 included: (1) training plant personnel on cable separation requirements (complete); and (2) changing Procedure ADM-0073, to clarify the separation requirements (planned).

The inspector considered the most recent instance of a cable separation infraction to be repetitive. Corrective actions for previous occurrences were not fully effective at preventing recurrence. The failure to maintain cable separation in accordance with Procedure ADM-0073 is a violation of 10 CFR Part 50, Appendix B, Criterion V (50-458/9719-01).

c. Conclusions

One violation was identified for the failure to comply with procedural cable separation requirements.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707)

The inspectors observed portions of the following maintenance and surveillance activities (except as noted below):

- STP-309-0202, "Division II Diesel Generator Operability Test," Revision 18E (documentation review)
- STP-309-0201, "Division 1 Diesel Generator Operability Test," Revision 16C
- Maintenance Activity Item (MAI) 302635, Replacement of Service Water Valve SWP-V-70

- MAI 341613, Replacement of Service Water Valve SWP-V-69
- MAI 314783, Division I Service Water Cooling Tower Inspection (documentation review)
- MAI 314938, Division II Service Water Cooling Tower Inspection (documentation review)
- STP-403-7301, "Containment Purge System Isolation Valve Leak Rate Test," Revision 1 (documentation review)

b. Observations and Findings

The performance of maintenance generally was thorough and professional. Exceptional performance demonstrated during the Division II DG surveillance is discussed in Section M1.2. Concerns related to less than thorough on-line risk assessments is addressed in Section M1.3, while the failure of a containment isolation damper is discussed in Section M1.4.

M1.2 Division II DG Operability Test

a. Inspection Scope (61726)

Fuel oil sprayed out of the Division II, Cylinder 8 head test valve during the air roll portion of the DG operability surveillance. The inspector performed followup to this licensee observation.

b. Observations and Findings

Licensee Actions: While looking for fluid discharge on the cylinder head test valves, a nuclear equipment operator (NEO) trainee noticed oil residue on piping adjacent to the Cylinder 8 (versus the cylinder head test valve itself). The NEO was concerned because oil discharge could be an indicator of cylinder damage.

In response to the finding, operators declared the DG inoperable and entered the Technical Specification (TS) ACTION Statement. Subsequently, DG system engineers identified the substance as fuel oil and contacted the vendor for additional guidance. The engineers determined that an unloaded DG run on November 20, 1997 (troubleshooting for a different problem), had resulted in leaving a small amount of unburned fuel in the cylinder. Per the vendor, this was not an uncommon finding following an unloaded run and the additional amount of fuel oil in the cylinder did not adversely impact the operability of the DG. As a precautionary measure, a compression test was satisfactorily completed on the DG prior to returning the unit to service later that day.

NRC Assessment: The NEO trainee demonstrated excellent attention to detail when he found oil residue on piping adjacent to Cylinder 8, as his actions exceeded the procedure's inspection requirements.

In response to the finding, system engineers demonstrated effective problem resolution capabilities (including good utilization of the DG vendor) and promptly evaluated the significance of the oil discharge. The accomplishment of the compression test, as added assurance of their conclusions, demonstrated a good safety focus. The prompt work by the engineers helped to minimize the out of service time for the DG.

c. Conclusions

An NEO trainee demonstrated excellent attention to detail in identifying oil discharge coming from the Division II DG, Cylinder 8. Additionally, engineering promptly and effectively assessed the significance of the problem and conservatively performed testing to verify their conclusions.

M1.3 Risk Assessments for On-Line Maintenance

a. Inspection Scope (62707)

The inspectors observed the licensee's risk assessments in support of on-line maintenance activities.

b. Observations and Findings

Background: The licensee performs a substantial amount of work on-line (versus during an outage). The Maintenance Rule (10 CFR 50.65(a)(3)) states, in part:

> "In performing monitoring and preventative maintenance activities, an assessment of the total plant equipment that is out of service should be taken into account to determine the overall effect on performance of safety functions."

To meet the intent of the above, maintenance is controlled via the "On-Line Maintenance Guidelines," Revision 3. These guidelines specify the use of a "blended approach," when assessing the potential risk of maintenance. The blended approach consists of quantitative as well as qualitative aspects of risk assessments. Risk is evaluated quantitatively via the equipment out of service (EOOS) computer, which provides numerical values for "instantaneous" as well as "cumulative" risk (which are then compared to predetermined acceptance criteria). Due, in part, to limitations with the EOOS computer model, engineering judgement is also utilized to qualitatively evaluate risk.

The Maintenance Guidelines stipulate that equipment may be considered "available" in the EOOS computer program when it is capable of performing its safety function, even when it is tagged out of service or declared inoperable. The guidelines stress, however, that conservative and safe operation must be the foremost consideration when making a determination involving availability of plant equipment.

Standby Service Water (SSW) Tower Inspections: The inspector identified that the licensee had not appropriately considered risk for work on the SSW cooling tower.

The licensee performed visual inspections of the SSW cooling tower (one safety-related division at a time). To ensure the personal safety of the workers, the licensee had placed the service water pumps in the "pull-to-lock" position, declared the service water division and its associated DG inoperable, and entered the applicable TS ACTION Statements. However, the equipment was considered available (in the EOOS program) because the service water pumps could be started in a short period of time. Operators estimated that evacuation of the SSW cooling tower and starting of the SSW pumps would take approximately 3-4 minutes.

The inspectors contacted a DG system engineering supervisor and inquired how long a DG could operate without service water. The supervisor stated that the DG vendor had demonstrated that a DG could operate for approximately 2 minutes (while fully loaded) before failure might be experienced. Without the load of the SSW pumps, however, the DG could operate for an additional unknown period of time.

Based on the above, the inspector concluded that the licensee's action were inconsistent with the recommendations contained in the "On-Line Maintenance Guidelines." Specifically, the licensee did not have reasonable assurance that the DG (which powers the SSW pumps during events that include a loss of offsite power) was capable of performing its safety function. This issue demonstrated poor attention to detail when assessing overall plant risk for this job.

Service Water Valve Replacements: The inspector observed the on-line replacement of four SSW valves (service water isolation valves to the Division I HVK chillers). The inspectors noted that the train of SSW and its associated DG were unavailable in the EOOS program and this resulted in a risk level at the upper administrative limit for "acceptable risk." Additionally, the work required the use of two freeze seals to isolate the valves from the SSW system (6-inch diameter lines). This method of isolation, in itself, had the potential for causing an additional event (loss of freeze seals and flooding of the control building).

The contingency actions associated with the potential loss of freeze seals included: (1) installation of blind flanges over the open valve bodies; and (2) isolation of the normal service water header to Division I components. While the contingency actions seemed

appropriate for the work, the EOOS computer model did not have the capability to evaluate the potential risk associated with a loss of freeze seal event. The risk significant aspects included:

- Isolation of normal service water to the safety-related loads (normal service water is a risk significant system).

- Flooding of the control building. Divisions I and II switchgear are located on the same floor of the control building. The licensee's generic flooding analysis considered minimal flooding (approximately 120 gpm), which did not approach the flow rate that could be expected from a freeze seal failure.

The inspector considered the use of freeze seals to constitute some unquantifiable additional risk with this job. Since the quantified risk (per the EOOS program) was already at the administrative limit, the qualitative evaluation for the job was not well focussed on safety and did not appear to provide additional value to the risk assessment process.

c. Conclusions

On-line risk evaluation assessments were not always thorough. In one instance operators assumed that a delay in placing SSW pumps in service would not adversely affect the availability of SSW pumps and Dgs without fully understanding equipment response. In another case, the potential consequences associated with a freeze seal failure were not properly considered in the risk assessment.

M1.4 Containment Purge Damper (HVR-AOV-165) Found Inoperable

a. Inspection Scope (61726)

Containment purge Damper HVR-AOV-165 failed during local leak rate testing (LLRT). The inspector performed followup to this licensee observation.

b. Observations and Findings

Background: HVR-AOV-165 is a 36-inch diameter butterfly valve (damper) located in the containment purge system and is the outboard containment isolation damper. The unit is air-operated to open, spring to close, but is also equipped with a separate hydraulic actuator to manually open the damper during maintenance. For manual operation, a skid mounted petcock valve is closed and the hydraulic actuator is manually pumped to open the damper. For damper closure, the petcock valve is opened, which releases the hydraulic lock and permits the actuator to retract. Drawing 410318 requires that the petcock be at least one turn open when the damper was operated in the pneumatic mode (the safety-related mode).

The inspector noted that closure of the petcock, alone, will not necessarily render a damper inoperable. The hydraulic actuator would also have to be manually operated (jacked) at least one time before the actuator piston would extend and affect damper closure.

Damper Failure: During the performance of Procedure STP-403-7301, "Containment Purge System Isolation Valve Leak Rate Test," Revision 1, on January 8, 1998, leakage through Damper HVR-AOV-165 was in excess of the capacity of the leak rate monitor (2000 sccm). Further examination revealed that the maintenance actuator petcock valve was out of position (closed) and the actuator was partially extended (preventing the damper from reaching the full closed position). Operators promptly declared the damper inoperable and completed the ACTIONS required by TSs. The petcock was then opened and the damper was observed to go to the fully closed position. The LLRT was then successfully performed.

In response to the finding the licensee checked the position of the petcocks on the other similar dampers in the system. The petcock for the penetration's inboard damper (HVR-AOV-123) was found open. However, the petcocks for the containment isolation dampers on the ventilation portion of the system (HVR-AOV-128 and HVR-AOV-166) were found closed. A maintenance supervisor opened the petcocks for the containment ventilation dampers and reported that no damper movement was observed. The LLRT for that penetration was subsequently performed without event.

At the close of the inspection, the licensee had not determined the root cause of the damper failure or the length of time that the damper may have been inoperable. However, the previous LLRT for Damper HVR-AOV-165 was successfully completed approximately 90 days prior to the damper failure. As such, the damper had not been inoperable for more than 90 days. This is considered an unresolved item pending further NRC review of the licensee's root cause evaluation (50-456/9719-02).

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Review of Material Condition During Plant Tours

a. Inspection Scope (62707)

During this inspection period, the inspectors conducted routine plant tours to evaluate plant material condition.

b. Observations and Findings

- **Main Generator Hydrogen Leakage:** Main generator hydrogen leakage was considered excessive. The identified leakage pathway was through the collector

end generator seal and out the roof vent. A further worsening of this condition could require a plant shutdown to support repairs. A detailed discussion is provided in Section E2.1 of this report.

- **PASS:** The PASS was found inoperable on November 12, 1997, when two system fuses blew during a surveillance. Repairs on the system were completed on December 11, 1997. However, extensive work was still planned to inspect and repair air-operated valve actuators that may have been damaged due to water intrusion into the system. PASS has been unavailable approximately 50 percent over the past year and, overall, material condition was considered poor (see Section M8.1).

- **Suppression Pool Pumpback Pump DFR-P5B:** The subject pump failed inservice testing on December 22, 1997, and remained out of service for the remainder of the inspection period. Pump DFR-P5B is one of four pumps provided to pump emergency core cooling system (ECCS) leakage from the auxiliary building sump back to the suppression pool during a design basis event. The loss of the pump leaves one train of the suppression pool pumpback system in a degraded condition (each train consists of two pumps).

- **Control Rod Drive Pump 1A:** The subject pump was experiencing higher than normal vibration, which was believed to be caused by a damaged coupling. The licensee considered the pump degraded but operable. The pump may be utilized during emergency operating procedure implementation for manual control rod movement and as a backup source of primary coolant.

- **Containment Isolation Damper HVR-AOV-165:** The damper was found inoperable during a surveillance on January 8, 1997. Although corrective actions to restore the damper were prompt, the length of time that the condition existed was not known (see Section M1.4).

- **ECCS and RCIC Flow-Transmitters:** Air entrapment was identified as a generic problem in the instrument sensing lines for the ECCS and RCIC flow transmitters. This resulted in the misoperation of the HPCS, RHR B and C minimum flow valves. Additionally, the generic ramifications of the problem were not yet fully investigated (see Section E8.1).

Material condition improvements included:

- **Spent fuel pool cooling (SFC) Pump 1B:** The SFC Pump 1B was repaired recently (new impeller) and returned to service. The pump had been in a degraded condition for approximately one year. The recent repairs restored the original design margin to the pump.

- **Alternate Decay Heat Removal (ADHR), Suppression Pool Cleanup (SPC) Mode:** The SPC mode of ADHR was repaired and returned to service this inspection period. Suppression pool clarity has steadily improved since the system was restored.

c. Conclusions

While overall plant material condition was good, there were notable equipment and system performance problems. The inspector noted material condition concerns with main generator hydrogen leakage, the PASS, suppression pool pumpback Pump DFR-P5B, control rod drive Pump 1A, containment isolation Damper HVR-AOV-165, and ECCS and RCIC flow instruments. Conversely, SPC Pump 1B and the SPC mode of the ADHR system were repaired and returned to service.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 Poor Availability for the PASS

a. Inspection Scope (61726)

The inspector reviewed maintenance records associated with the PASS.

b. Observations and Findings

Background: Out-of-service time for the PASS is administratively controlled via "Operations Policy 6," which states, in part:

> "The Pass System shall be given the same level of attention as a 30 day LCO [Limiting Condition for Operability]. This will ensure the appropriate level of management oversight for restoring the system to an operable status..."
>
> "For 30 day LCOs, a daily assessment SHALL be made. Information should be obtained at the morning meeting to ensure an action plan is in place and satisfactory progress is being made to clear the LCO in a timely manner."

Additionally, the "On-Line Maintenance Guidelines," Revision 2, states, in part:

> "Out of service time should be minimized for system outages. No more than 50% of the Technical Specification allowable out of service time should be scheduled for a system outage."

Failure to Minimize PASS Unavailability: The inspector identified that Maintenance and Operations personnel did not meet management expectations with regard to

accomplishing maintenance in less than half the administrative LCO and ensuring that satisfactory progress was made to clear the administrative LCO in a timely manner.

The inspector observed that the PASS failed a monthly surveillance, due to blown fuses (shorted limit switch), and remained inoperable from November 12 through December 11, 1997 (29 days). During this period, there were long periods of time where the PASS was not worked. For example, between November 12 and November 20 little or no maintenance was performed on the PASS. Likewise, between November 23 and November 30, no maintenance was accomplished.

Poor Availability History: The inspector also observed that the PASS was inoperable for approximately 50 percent of the past 10 months. Additionally, material condition was considered poor and long-standing equipment problems were not fixed in a timely manner. For example:

- In March 1997, water was found in the PASS control cabinet and was determined to be caused by leakage past Check Valve D24-VF010 (boundary valve between the nitrogen supply and the demineralized water tank). Water leaked past the valve, into the air lines for multiple air-operated valves, and entered the valve actuators. When the air-operated valves were repositioned, the actuators were vented and water sprayed inside the PASS panel.

  NOTE: A normally closed manual isolation valve (D24-VF012) was in the nitrogen line adjacent to Valve D24-VF010. The manual valve was opened during surveillances (only). It was during this time that leakage traveled past Valve D24-VF010 and into the nitrogen lines.

  Initially, the licensee believed that sediment prevented Valve D24-VF010 from seating properly and flushed the valve (a small amount of corrosion products was observed during the flush). The valve was considered operational even though minimal postmaintenance testing was performed and no actions were taken to address the source of the sediment.

- On May 9 the PASS failed due to a faulty sample needle. The licensee attempted to return PASS to service on June 12.

- On June 12 leakage past three valves (in series, including D24-VF010) allowed leakage out of the reactor coolant system and into the PASS nitrogen lines. The nitrogen supply system relief valve lifted and sprayed the PASS area with contaminated water. Shortly thereafter, MAI 312853 was initiated to repair the leaky valves. However, the licensee returned the PASS to service on July 12 without repairing Valve D24-VF010.

- On September 11 power was lost to the PASS control cabinet when water sprayed the circuitry (due to leakage past Valve D24-VF010). The PASS was returned to service on October 13 without effecting repairs to Valve D24-VF010.

- On November 20, after the most recent PASS failure, Valve D24-VF010 was finally repaired. Maintenance craftsmen reported that the valve was not seating properly. The valve seats were lapped and the valve reassembled.

Due to water intrusion into the nitrogen lines, the licensee was concerned that the reliability of some of the air operated valves could be compromised. An extended PASS outage was scheduled to start January 12, 1998, to inspect some of these valves.

c. Conclusions

The high PASS unavailability was indicative of ineffective maintenance. The PASS was taken out of service and often not worked in a timely manner. The amount of time taken to return the PASS to service (approximately 30 days in all cases) was considered excessive when considering the actual work accomplished.

The inspector concluded that the failure to maintain the PASS system operable, to a reasonable extent, was a violation of TS 5.5.3. This TS requires the licensee to have provisions for maintenance of sampling and analysis equipment sufficient to ensure the capability to obtain and analyze various samples under accident conditions. These provisions were inadequate (VIO 50-458/9719-03).

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Excessive Main Generator Hydrogen Leakage

a. Inspection Scope (37551)

The inspectors observed Engineering's involvement addressing excessive main generator hydrogen leakage.

b. Observations and Findings

NRC Inspection Report 97-17 discussed excessive main generator hydrogen leakage. Leakage was approximately four times normal at the close of the previous inspection period (2.5 percent concentration of hydrogen in air at the seal oil detrainment tank vent). During this inspection period, the hydrogen leakage worsened and exceeded the 4.0 percent flammability threshold on December 17, 1997. On the following day,

hydrogen leakage increased and the concentration approached 6.0 percent, before positive actions were taken to reduce the leakage.

In response to the problem, management directed operations to reduce hydrogen pressure in the main generator (within design allowables), which resulted in a significant reduction in the effluent hydrogen concentration. At the close of the inspection period, the effluent concentration was approximately 3 percent and appeared to be slowly worsening. Continued degradation of the problem could result in a plant shutdown to effect repairs.

The inspector observed that Engineering had identified the excessive main generator leakage shortly after startup and had been actively trending the effluent concentration, but had not appropriately evaluated the safety consequences of the leakage before the flammability limit was exceeded. Furthermore, senior plant managers were not adequately informed of the magnitude of the problem until it was too late to avoid exceeding the flammability threshold. Engineers had demonstrated a poor safety focus in their failure to recognize the significance of the issue and accomplish an appropriate engineering evaluation in a timely manner.

c. Conclusions

Engineering did not evaluate in a timely manner the significance of exceeding the flammability threshold for hydrogen concentration (measured at the seal oil detrainment tank vent). Consequently, the flammability threshold was exceeded before safety issues were thoroughly evaluated.

E8 Miscellaneous Engineering Issues (37551)

E8.1 (Closed) Unresolved Item (URI) 50-458/9717-05: air in HPCS flow-meter instrument lines caused minimum flow valve malfunction. During the performance of inservice testing on the HPCS system (November 11, 1997), the minimum flow valve failed to open when the test return valve was closed. Additionally, later in the surveillance, the minimum flow valve unexpectedly closed when the HPCS suction was swapped from the suppression pool to the condensate storage tank. In both instances the valve closure resulted in "dead-heading" the HPCS pump. An operator manually opened the minimum flow valve after each misoperation. In response to the malfunction, HPCS was declared inoperable and operators entered the TS ACTION Statement.

During troubleshooting, air was found in the HPCS flow transmitter instrument sensing lines. The Rosemont flow transmitter provides an input to the minimum flow valve control circuits. Since the trip setpoint (minimum of 710 gpm per TSs) corresponds to a very small differential pressure across the flow meter (6 inches water column), a small amount of air in the lines could have a significant impact on the instrument setpoint. At the close of the inspection period, the licensee had not demonstrated that the instrument setpoint had remained within a range permitted by TSs.

During subsequent reviews, the licensee determined that the control logic had reset itself after each misoperation and, had the operator not repositioned the valve, the valve would have automatically repositioned to the open position in a short time (10 to 15 seconds). As such, the licensee did not believe that the pump could have been damaged by the valve misoperations. Nonetheless, as a minimum, the condition represented a significant distraction to the operators.

Additional Events: During this inspection period, additional operational problems were experienced with two other ECCS minimum flow valves:

- On December 11, prior to the operation of RHR C, the RHR C pump minimum flow valve was found closed (it should have been open in the standby lineup).

- On December 12, 1997, after securing the RHR B pump, an operator attempted to open the pump's minimum flow valve (the normal standby position) but the valve unexpectedly cycled closed. After making a second attempt at opening the valve, the valve remained open.

The licensee vented the instrument lines for the two RHR minimum flow valves and observed relatively large amounts of air coming from the vents. As a precautionary measure, the remaining ECCS minimum flow valve instrument lines were vented. Varying amounts of air were observed coming from all of the vents.

> NOTE: Since the instrument lines are isolated during instrument calibration, air in the lines would not be apparent during the evolution.

Licensee's Cause Determination: The licensee concluded that air had likely accumulated in the instrument lines over a long period of time. The instrument lines utilize high point vents (versus the preferred installation where the instrument lines are routed with a continuous upward slope from the instrument to the process tap). Additionally, there were no provisions for venting the lines periodically to preclude adverse affects from air entrapment.

The licensee had not determined all of the corrective actions necessary to address the air entrapment problem by the close of the inspection period. More than one hundred other safety-related instruments utilize high point vents in the instrument's sensing lines, but none were believed to be as sensitive to air entrapment as the flow measuring instruments. At the close of the inspection period the licensee was still evaluating the necessity of venting other instrument sensing lines.

Historical Problems: The inspector noted one recent instance of a similar problem. Air was found in the RCIC minimum flow valve instrument lines in January 1997.

The RCIC minimum flow valve instrumentation problems were first observed in January 1993 (CR 93-0022A). When the HPCS system was placed in service (with RCIC in a

standby status) the RCIC minimum flow valve control logic failed. Since the anomaly did not appear to render the RCIC system inoperable when RCIC was in service, the licensee was not overly concerned with the condition. Engineers continued to troubleshoot the problem for approximately 4 years. On December 31, 1996, the CR was closed without correcting the condition.

On January 23, 1997, at the request of engineering, maintenance workers vented the RCIC minimum flow valve instrument sensing lines and found a substantial amount of air. This condition, coupled with HPCS induced pressure transients (through a common suction line), caused the flow instruments to cycle rapidly and fail. Venting the lines appeared to resolve the long-standing RCIC problem. No CR was written to document the condition and no actions were taken to vent other instrument lines with high point vents. At the time, engineers did not recall having a similar problem with other instruments so they assumed that a generic problem did not exist.

The following related issues were documented on CRs.

- On October 26, 1994, the SSW flow indication was erratic. Further investigation found air in the instrument sensing lines (CR 94-1396).

- On August 30, 1991, the indication from the HVK Chiller 1A flow transmitter was higher than normal when the chiller was not in service. Further investigation found air trapped in the instrument sensing lines (CR 91-0379).

- On October 25, 1987, HPCS instruments were reading erratically. The instrument lines were filled and vented to resolve the problem.

Prior to the most recent events, River Bend Station engineers had believed that the design of the instrument lines precluded the need for periodic venting, even after system draining. The lines are equipped with a loop seal that inhibits the movement of air from the process line to the instrument lines.

NRC Identified Issues and Assessments:

Venting Recommendations: The inspector identified that the licensee did not implement original recommendations for periodic venting of instrument lines with high point vents. In a Stone and Webster document entitled "High Point Vents," dated September 23, 1982, the following information was provided to River Bend Station:

> "Within the industry, it is understood that high points are undesirable; when they do occur, they must be vented . . ."
>
> "Anticipated Venting Frequency
>
> 1. Required prior to every calibration.

2. From a history of venting during calibration, a maintenance schedule could be developed, if required, on a case-by-case basis.

3. When the instruments disagree."

The inspector requested that the licensee provide evidence that the above recommendations were implemented. No such evidence was provided to the inspector.

Design: The inspector observed that the licensee's installation of flow metering instruments did not appear to conform with GE design requirements. GE Design Specification 22A3137AA, Section 4.2.4.2, states, in part:

> "Installation and arrangement of differential head meters shall conform with the recommendations defined in Chapter II - II of "Fluid Meters" for . . . orifice and venturi type devices . . . In no case shall the requirements of this specification be violated without specific GE Engineering approval."

"Fluid Meters" recommends, in part, the following:

- For connecting the primary element to the secondary element, 1/2-inch tubing and fittings are recommended.

  Contrary to this recommendation, 3/8-inch tubing was utilized for portions of the instrument lines.

- Differential pressure measuring gages should be installed in accordance with the specific instructions furnished by the manufacturer of the instrument.

  The Rosemont vendor manual states that high point vents in liquid instrument sensing lines should be avoided.

  Contrary to this recommendation, Rosemont differential pressure flow transmitters were installed with high points in the instrument lines.

At the close of the inspection period, the licensee had not found where approval to deviate from the above recommendations was provided from GE. Further NRC review will be necessary to evaluate the apparent failure to: (1) abide by the GE design specification; and (2) follow the Stone and Webster venting recommendations. This is considered an inspector followup item pending further NRC review of these issues (IFI 50-458/9719-04).

Corrective Actions: Air in the sensing lines has been a historical problem at River Bend Station. Although most CRs were documented several years ago, the licensee missed a more recent opportunity to identify this common mode problem when air was identified in the RCIC minimum flow valve instrument lines in January 1997. Engineering actions in

response to that event were not comprehensive and did not prevent recurrence. More specifically, engineers did not document the problem on a CR, which ultimately resulted in circumventing the licensee's corrective action process. As a result, the cause of the condition was not identified and the potential generic impact of the problem was not properly considered. The failure to take appropriate actions in response to air entrapment in the RCIC minimum flow valve instrument lines (a significant condition adverse to quality) is a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-458/9719-05).

In addition to the above, the licensee has repeatedly missed opportunities to correct the generic misconception that lines with high point vents don't have to be vented. Even when problems periodically occurred, corrective actions were limited to the instruments directly affected and generic applicability was not properly addressed.

Weak Operability Determination: The inspector observed that, when the HPCS and RHR C minimum flow valve problems were experienced, operators promptly declared the valves inoperable and entered the appropriate TS ACTION Statements. However, when the same problem was observed with RHR B, the valve was not declared inoperable and the TS ACTION was not entered.

An operations shift superintendent determined that the RHR B minimum flow valve was operable based on a generic operability determination performed by a shift technical advisor (STA). The inspector interviewed the STA to discuss the document and identified that the STA had not properly considered the TS LCO for instrument operability. For example, TS 3.3.5.1 requires, in part, that the RHR B minimum flow valve close at a setpoint greater than 900 gpm - a setpoint less than 900 gpm would require the licensee to call the instrument inoperable. Furthermore, the STA did not have a clear understanding of how the condition (air in the instrument lines) could affect the instrument setpoint, potentially affecting instrument operability. The STA indicated that he did not believe that the condition would have resulted in damage to an ECCS pump, but admitted that he did not consider the operability requirements for the flow instruments themselves.

Since corrective measures were promptly taken to vent the RHR B minimum flow valve, the safety consequences of the oversight were negligible. However, the inspector considered the failure to consider TS operability requirements when making an operability determination to be an example of poor attention to detail when making operability calls.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours the inspector noted that the security officers were alert at their posts, security boundaries were being maintained properly, and screening processes at the Primary Access Point were performed well.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 15, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. P. Dimmette, General Manager, Plant Operations
M. A. Dietrich, Director, Quality Programs
D. T. Dormady, Manager, System Engineering
T. O. Hildebrandt, Manager, Maintenance
P. W. Chapman, Superintendent, Chemistry
H. B. Hutchens, Superintendent, Plant Security
D. N. Lorfing, Supervisor, Licensing
J. R. McGaha, Vice President-Operations
M. G. McHugh, Licensing Engineer III
W. P. O'Malley, Manager, Operations
D. L. Pace, Director, Design Engineering
A. D. Wells, Superintendent, Radiation Control

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support

ITEMS OPENED AND CLOSED

Opened

50-458/9719-01	VIO	Failure to Follow Procedures Addressing Electrical Separation Criteria
50-458/9719-02	URI	Failure of Containment Isolation Damper HVR-AOV-165
50-458/9719-03	VIO	Failure to Maintain PASS Operable
50-458/9719-04	IFI	Failure to Comply with GE Design Recommendations and Architect Engineers Venting Recommendations for Instrument Sensing Lines
50-458/9719-05	VIO	Failure to Take Adequate Corrective Actions to Address Air in Instrument Sensing Lines

Closed

50-458/9717-05	URI	Air in HPCS Instrument Line Causes Minimum Flow Valve Malfunction

LIST OF ACRONYMS USED

ADHR	alternate decay heat removal
CFR	Code of Federal Regulations
CR	condition report
ECCS	emergency core cooling system
EOOS	equipment out of service computer
DG	diesel generator
HPCS	high pressure core spray
IFI	inspector followup item
LCO	limiting condition for operability
LLRT	local leak rate testing
MAI	maintenance activity item
NEO	Nuclear Equipment Operator
NRC	U.S. Nuclear Regulatory Commission
PASS	postaccident sampling system
RCIC	reactor core isolation cooling
RHR	residual heat removal
SFC	spent fuel cooling
SPC	suppression pool cleanup
SSW	standby service water
STA	shift technical advisor
TS	Technical Specification
URI	unresolved item
VIO	violation