ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-416/95-21

License: NPF-29

Licensee: Entergy Operations, Inc.
P.O. Box 756
Port Gibson, MS 39150

Facility Name: Grand Gulf Nuclear Station

Inspection At: Port Gibson, Mississippi

Inspection Conducted: December 3, 1995 through January 13, 1996

Inspectors: J. Tedrow, Senior Resident Inspector
C. Hughey, Resident Inspector

Approved: Gregory A. Pick for 2/20/96
P. H. Harrell, Acting Chief, Project Branch D Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite review of events, operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, and followup maintenance.

Results:

Plant Operations

- Implementation of the licensee's cold weather protection measures was not thorough, as the measures failed to identify that the open turbine building rollup doors should be closed during cold weather. This deficiency resulted in an automatic reactor feedwater pump trip and resultant plant runback (Section 2.1).

- Operator knowledge concerning the effect of operating the emergency diesel generator (EDG) load switch while the engine was secured was deficient and contributed to the unavailability of the generator for approximately 9 hours (Section 2.2).

- During a tour of the switchyard, the inspector noted that an unsecured tent was located inside the fenced area, which might become a missile

hazard during adverse weather. The licensee removed the tent and initiated an investigation into programmatic controls for switchyard activities (Section 3).

Maintenance

- Minor material condition deficiencies were observed on plant components, which indicated that the threshold for deficiency identification might not have been appropriately established (Section 3).

- The calibration procedure for the containment and drywell hydrogen analyzers was considered to be deficient for not establishing appropriate plant conditions for performing the test. This issue was identified as a violation (Section 8.1).

Engineering

- The licensee's program for monitoring and periodic replacement of Agastat relays was considered to be good (Section 6.1).

- An error in the core thermal power heat balance calculation was identified by another plant. The licensee took actions to correct the error when it was identified. This issue was identified as an unresolved item pending additional NRC review (Section 6.2).

Plant Support

- Radiological postings were found to be properly installed and generally well maintained. However, on two occasions the inspectors identified two examples of poor housekeeping practices in contaminated areas (Section 7.2).

Summary of Inspection Findings:

New Items

- Unresolved Item 416/9521-01: The issue of slightly exceeding licensed thermal power limits is unresolved pending NRC's review of the generic implications (Section 6.2).

- Violation 416/9521-02: Failure to provide appropriate procedure for calibration of the hydrogen analyzers (Section 8.1).

Closed Items

- Inspection Followup Item 416/9421-02 (Section 8.1).

DETAILS

1 PLANT STATUS

The plant began this inspection period at 100 percent power. On December 9, 1995, power was reduced momentarily to 85 percent to insert control rods for preventive maintenance. On December 16 and 17, power was again reduced to 85 percent to recover these control rods. On January 8, 1996, power was reduced to 68 percent when a reactor feedwater pump automatically tripped. Power was returned to 100 percent later that same day and essentially remained at 100 percent power to the end of this inspection period.

2 ONSITE REVIEW OF EVENTS (93702)

2.1 Reactor Feedwater Pump (RFP) Trip

On January 8, 1996, with the plant at 100 percent power, the RFP A tripped. The pump trip, in conjunction with the expected decrease in reactor vessel level to less than Level 4, caused the recirculation system flow control valves to automatically reposition to the reduced reactor power position. After the trip, the operators entered the appropriate response procedures. The repositioning of the flow control valve and power decrease caused the plant to enter the "increased awareness" region of the power/flow map. Control rods were inserted to exit this region and provide more flow margin. The inspectors determined that the operators acted appropriately and promptly after the RFP trip to stabilize the plant.

The licensee determined the cause of the trip was a frozen instrument sensing line associated with the RFP A discharge flow instrumentation. This instrument line runs between the flow element and the narrow- and wide-range transmitters on the instrument rack. The instrument rack and pump are located on the ground elevation of the turbine building, very near an outside rollup door. This door had been opened for a long period of time to provide dilution air into the turbine building to reduce the buildup of noble gases.

On the day of the pump trip, outside air temperature was well below freezing. The negative building pressure provided by the turbine building ventilation system caused this extremely cold air to flow around and near the instrument rack and freeze the fluid in the line. This resulted in a false low flow signal from the transmitter, which caused the pump minimum flow recirculation valve to open and RFP A to trip. This diversion of feedwater flow from the reactor vessel caused a decrease in vessel level to less than Level 4.

An operator was dispatched to the reactor feed pump room and observed frost on the instrument sensing line. The operator shut the rollup door for the room, and after about 10 minutes, the transmitters indicated back on scale.

Equipment Performance Instruction 04-1-03-A30-1, "Cold Weather Protection," Revision 7, specifies actions to be taken to protect equipment during cold

weather conditions. Although these rollup doors were not specifically discussed, the procedure required a tour of the outside areas to look for exposed pipes and components that may have inadequate freeze protection. The procedure requirements were completed in November 1995. Subsequent to this event, Quality Deficiency Report 0007-96 was initiated by the licensee to track corrective actions and initiate a root cause evaluation for this event.

The inspectors considered the cold weather protection procedure guidance to be poor in that the effects of the opened rollup door during extremely cold weather was not recognized. The licensee subsequently revised the procedure to specify closing of rollup doors during cold weather conditions. It appeared that the actions taken by the licensee effectively addressed this issue.

2.2 Division I EDG Overspeed Trip

On November 27, 1995, the Division I EDG tripped on an overspeed condition upon startup for a routine monthly surveillance test.

The licensee assembled an investigation team, comprised of the diesel vendor, governor service representative, and licensee onsite and offsite engineering personnel. Licensee personnel conducted troubleshooting activities to identify the cause for the overspeed trip, which included inspection of these diesel generator components: mechanical overspeed trip devices, fuel racks, electronic and hydraulic governor, and voltage regulator. The engine crankcase was inspected in accordance with advice from the vendor. No problems were identified with fuel rack binding or voltage regulator field excitation. A motor-operated potentiometer associated with the electronic governor was found in an abnormal full lower position. This potentiometer should have received an automatic reset signal to return to the normal predetermined speed position when the engine was secured.

The Division I EDG was started on November 28, with the motor-operated potentiometer in the full lower position in an attempt to recreate the overspeed trip; however, the electronic governor controlled engine speed satisfactory and prevented an overspeed trip. The EDG was started on five different occasions for troubleshooting and operated satisfactory during each start.

The diesel was declared operable on November 28 following completion of a successful surveillance test. Although the licensee did not identify the root cause for the overspeed condition, the licensee determined that the diesel was operable based upon the troubleshooting, testing, and component replacements that were performed following the event. The licensee was continuing with the development of the root cause evaluation at the end of this inspection period.

Since the overspeed trip signal is not bypassed on an emergency start, the licensee reported this event as a valid diesel failure on December 21. The

licensee decided to perform increased testing of the engine at 2 week intervals until 7 successful starts were obtained to ensure confidence in engine performance.

The inspector observed portions of the troubleshooting activities and reviewed the work packages. The inspector witnessed the tests with the motor-operated potentiometer in the full lower position and reviewed the results of all testing performed to declare the diesel operable and the subsequent diesel testing at the 2 week intervals. No deficiencies with engine performance were noted during these observations or reviews. The inspector considered the troubleshooting efforts to be satisfactory.

The licensee believed that the potentiometer had a potential to be stuck in the abnormal position because of a previous deficient condition identified with the control room handswitch used for raising and lowering diesel speed, which was found to be sticking in the lower position during the previous monthly test on October 30. However, following the identification of switch problems in October, the licensee verified that the switch was properly positioned. The switch is normally spring returned to the neutral position after use. The licensee believed the switch was stuck in a lower speed position after a previous operation. The switch was scheduled for replacement during the next Division I EDG outage and was subsequently replaced on November 28.

The inspector discussed the potential effect of the sticking of the governor control handswitch on engine operation with licensee engineering personnel. With the switch stuck in the lower position, a signal would be provided to the motor-operated potentiometer, which would lower engine speed via the electronic governor to below the predetermined speed. Licensee personnel informed the inspector that, under such conditions, the engine would not have received a ready-to-load signal (greater than 430 rpm) and, therefore, could not have automatically performed its safety function. Because of the significance of this condition, the inspector requested that licensee personnel determine how long the switch was stuck in the lower position.

The investigation determined that the governor control handswitch had been exercised approximately 9 hours before the actual overspeed trip on November 27 by an operator on the previous shift checking the status of the deficient condition. The operator who manipulated the switch did so to verify no problems but had, in fact, caused the problem. The licensee believed that the switch was left in the lower position, which continuously applied a lower signal to the motor-operated potentiometer and resulted in the potentiometer being found in the abnormal lower limit position.

The inspector interviewed the operator who had previously operated the speed control switch and reviewed the test procedure for the diesel generator. The speed control switch was operated to raise and lower the load on the generator during startup and shutdown, respectively. Upon completion of the test, the diesel was unloaded and the generator frequency was verified to be correct for the unloaded condition. The engine was operated in the unloaded condition for

5 minutes prior to stopping the engine. Based upon this information, the inspector considered it highly unlikely that the control switch would have been left in a stuck position upon securing the engine from the previous test.

From discussions with the operators, the inspector learned that the switch had also been exercised on November 20, approximately 1 week prior to the overspeed trip, after a request by maintenance planning personnel to verify the switch was sticking. The inspector interviewed this operator who stated he was confident that the switch had been left in the neutral position following the operation and described to the inspector the checks he had made to verify the switch was in the neutral position. The operator who positioned the switch on November 26 did not make the same verification of switch position after he was finished.

After learning of prior switch manipulations, which the licensee's investigation did not identify, the inspector requested that licensee personnel reinterview the operators to determine if the switch had been repositioned at some other time. This action was completed on December 11, with no other manipulations identified. Based upon this information, the inspector concluded that the switch was most likely left in the stuck position on November 26, approximately 9 hours prior to the overspeed trip event. The inspector considered the initial investigation of this issue to be deficient for not identifying the previous switch manipulations. The licensee took action to counsel the investigator and required him to reperform the operator interviews.

Since the Division II EDG was available during this time and the Technical Specifications (TS) allowed an out-of-service time of 72 hours for one inoperable EDG, no TS violations occurred. Since the switch was spring return to neutral, it was not included in any operating procedures or switch lineups to verify the position. Nonetheless, the malfunctioning switch made the Division I EDG inoperable, unknown to control room personnel, for 9 hours. Licensee management attributed this problem to a general knowledge deficiency among the operations staff.

The licensee addressed the knowledge deficiency by performing on-shift training to operating personnel describing the event, impact of load switch operation, and the operation of the reset circuit. Information tags were placed on the switches immediately following identification of the potential effect of switch operation while the engine is secured. The tags were subsequently replaced with placards on the main control board near the switches prohibiting switch operation unless the engine was running. Licensee personnel were in the process of reviewing the control board for similar switches and were revising the operating instruction to provide cautions and limitations on operation of the EDG switches.

The inspector searched the maintenance history for this switch and discovered one additional case where the same switch for the Division II EDG experienced a similar sticking problem in November 1993. That switch was repaired shortly

after identification of the problem. As a result of this information, the licensee was considering a periodic replacement schedule for these types of switches.

Based on the reviews performed by the inspector, once the problem with the switch was identified, appropriate actions were taken by the licensee to correct the deficient condition.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Unsecured Structure in the Main Switchyard

On December 22, 1995, the inspector accompanied a nonlicensed operator conducting routine rounds in the main switchyard. The inspector observed an unsecured portable tent/garage within the fenced area around the switchyard. The tent was constructed of a strong plastic material with metal rods used to support the structure. The inspector discussed his concerns about the possibility of strong winds carrying this tent into switchyard breakers and other equipment with the on-shift operations shift supervisor immediately after the rounds were completed. The inspectors considered the practice of allowing unsecured items being left in the switchyard to be poor.

The tent was removed from the area the next day since plant personnel had to request that the offsite maintenance organization remove it. A contractor had stored equipment in the tent during recent switchyard maintenance activities but had not been removed. The licensee initiated an investigation into programmatic controls over switchyard maintenance activities and logistical relationships among plant staff, the company overseeing the transmission switchyard, and contractors performing switchyard maintenance activities. The licensee stated that procedural changes would be made to ensure that appropriate controls were maintained for the switchyard.

3.2 Poor Material Condition of Plant Components

During a plant tour, the inspector observed several minor material condition discrepancies associated with the Train A drywell purge compressor. The inspector observed an oil leak from the compressor, debris on the compressor skid under the coupling guard, and two old packing leaks causing general corrosion on service water cooling valves for the compressor. The inspector did not identify similar deficiencies on the Train B drywell purge compressor, which was located in a more frequented area. The inspector discussed these deficiencies with licensee personnel who checked and determined that the deficient items had not already been identified for correction.

After a surveillance test of the Division II EDG, the inspector observed some minor oil leaks on the engine. Following operation, the test procedure required that the operator check the engine for leaks. The inspector discussed his observations with the operator who had identified leaks in different locations and noted two of the leaks identified by the inspector were not noted by the operator. The inspector checked the Division I EDG and

noted similar leaks. The inspector discussed these deficiencies with a control room supervisor who checked and determined that the leaks identified by the inspector had not been previously identified by the licensee as needing repair.

The inspector discussed these observations with licensee management. Since these discrepancies were all minor in nature, the inspector considered that they did not affect the ability of the components to perform their intended safety function. However, management's ongoing initiative to improve the material condition of the plant was apparently not effective in establishing the desired threshold for deficiency identification.

4 MAINTENANCE OBSERVATIONS (62703)

During this inspection period, the inspectors observed portions of the maintenance activities listed below. The observations included a review of the following maintenance work orders (MWO):

- MWOs 155840 and 155835: Replacement of calibration and reagent gas regulators and check valves for the Train A containment and drywell hydrogen analyzers

- MWOs 155839 and 155841: Replacement of calibration and reagent gas regulators and check valves for the Train B containment and drywell hydrogen analyzers

The inspector found that these activities were performed in accordance with the work instructions provided and that appropriate postmaintenance testing had been performed. No notable strengths or weaknesses were observed by the inspectors.

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the performance of portions of the surveillance tests listed below:

- Procedure 06-IC-1E61-Q-1004, "Containment and Drywell Hydrogen Analyzer (PAM) Calibration"

- Procedure 06-OP-1P75-M-0002, "Standby Diesel Generator (SDG) 12 Functional Test"

The inspectors concluded that the licensee performed these surveillance tests in accordance with established procedures. No significant strengths or weaknesses were observed by the inspectors.

6 ONSITE ENGINEERING (37551)

6.1 Agastat Relay Monitoring and Replacement Program

After the failure of a 125-Vdc Agastat relay associated the Division I EDG output breaker on October 3, 1995, the licensee initiated an investigation into the cause of this and other similar relay failures (see NRC Inspection Report 50-416/95-16 for more details). The inspectors reviewed the results of this investigation and the overall program for replacement of Agastat relays.

A total of 1645 Agastat relays are installed in the plant and are divided into 4 groups: (1) relays installed in Class 1E equipment that fall under the environmental qualification program; (2) safety-related, normally-energized relays; (3) safety-related, normally-deenergized relays; and (4) all nonsafety-related relays. Groups 1 and 2, a total of about 870 relays, are periodically replaced based on environmental conditions. Group 3 relays are considered to have a service life of 40 years and Group 4 relays have no existing replacement program. In addition, existing surveillance and testing activities should identify any failed relays in any of the groups.

The relay installed in the Division I EDG output breaker that failed was in Group 3. This safety-related, normally-deenergized relay, was located in a mild environment and had an expected service life of 40 years; therefore, this relay was not in the periodic replacement program. It should be noted that this relay is only energized during parallel operations of the EDG to offsite power. Further, the failure of this relay would not have prevented energizing the Division I bus from an offsite or emergency source.

The investigation stated that the vendor published relay failure rate was 1E-6 failures/hour. For a population of about 870 relays (Groups 1 and 2), the failure rate would be about 7 relays per 12 month period. The failure history indicated that there were 3 failures in Groups 1 and 2 over the 12 month period, which was within the expected failure rate.

The licensee was conducting a review of all Group 4 relays to identify normally-energized relays in "trip critical" and "trip sensitive" circuits for inclusion in the replacement program.

The inspectors consider the monitoring and replacement program for Agastat relays to be effective.

6.2 Nonconservative Thermal Power Calculation

On December 4, 1995, in response to an industry notification of an error in the calculation of core thermal power at another boiling water reactor, licensee personnel discovered a similar error in the core thermal power calculation for the Grand Gulf plant. Specifically, the error failed to account for flow to the reactor vessel through the control rod drive system purge supply to the recirculation pump seals and into the vessel. Since the control rod drive water supply to the recirculation pump seals is located

upstream of the system flow element, this flow was not accounted for in the heat balance calculation. The licensee performed manual heat balance calculations and determined that with this additional flow, core thermal power was higher than indicated by approximately 0.8 MWt (0.02 percent power).

The licensee immediately issued directives to operating personnel to limit core thermal power to 3832 MWt, which was below the licensed 100 percent power limit of 3833 MWt. A fixed bias was added to the computer point for control rod drive system flow input to the heat balance calculation to account for the identified nonconservative values. Since the plant was operated at full power by referencing the 8-hour average core thermal power, licensee personnel determined that the plant had operated in the past slightly in excess of the licensed thermal power limit of 3833 MWt, which is specified in License Condition 2.C.(1).

The inspector reviewed the corrective actions, which included the order to limit thermal power to 3832 MWt, and the subsequent revision to the heat balance calculation to account for the error. The licensee reviewed operating and engineering procedures to ensure that the control rod drive flow used in heat balance calculations was controlled and documented and that heat balance calculations included all potential flowpaths for water addition to the reactor vessel. Methods for controlling changes to heat balance inputs were also being reviewed.

Since the safety analysis assumed a power level of 102 percent for transient and accident analysis, the licensee determined that this deficiency had no significant impact on safety. The licensee issued Licensee Event Report 95-13 to report the violation of this license condition. The inspectors consider this matter an unresolved item pending NRC's review of this generic issue to determine what regulatory action should be taken in response to this event and followup of the event report (416/9521-01).

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Security Observations

The inspectors periodically observed security practices to verify that security officers implemented the Security Plan in accordance with site procedures. Search equipment at the access control points was appropriately maintained, vital area portals were kept locked and alarmed, and personnel in the protected area were properly badged. The inspectors identified no deficiencies in this area.

7.2 Radiological Control Activities

During plant tours, the inspectors checked selected high radiation area doors required to be locked and found them to be appropriately controlled. Radiological postings were also checked and verified to be in accordance with licensee procedures.

The inspectors found that radiological areas were properly posted and generally well maintained. On two occasions, however, the inspectors observed poor contamination control practices and housekeeping in contaminated areas. In the hot machine shop, unsecured electrical cords and air samplers were lying across contaminated area boundaries and a significant amount of trash was on the floor inside the boundaries. No one was working in these areas at the time. The inspector passed these observations on to on-shift health physics supervision for immediate correction.

During a routine tour of containment, the inspector observed rags and discarded protective clothing in a contaminated area around the control rod hydraulic control units. It appeared to the inspector that these items had been used to contain liquid that had been vented from the units during control rod recovery operations, which had been completed for some time. These items were also discussed with health physics supervision who immediately corrected the condition.

8 FOLLOWUP - MAINTENANCE (92902)

8.1 (Closed) Inspection Followup Item 416/9421-02: Resolution of the Engineering Evaluation on the Hydrogen Analyzers

The inspector met with licensee personnel to discuss this item and observed a calibration test of the Channel B hydrogen analyzers on November 20, 1995. Licensee personnel informed the inspector that the flow fluctuations, observed during the testing, were caused by hard to adjust needle throttle valves. During the performance of the calibration, the inspector observed that the valves could be throttled and flow rates stabilized, although with some difficulty. The inspector verified that the as-found reagent gas values were consistent with the previously performed as-left calibration values.

As a further check, the inspector reviewed calibration records of the analyzers for the first quarter of 1995. The inspector noted that the initial as-found values for reagent gas flow (15 cc/min and 22 cc/min) were significantly lower than the previous calibration as-left values (34 cc/min) for the Channel A drywell hydrogen analyzer for two calibrations. The initial as-found values were also significantly higher (40 cc/min and 50 cc/min versus 31 cc/min) for two previous calibrations of the Channel B containment hydrogen analyzer. Since changes in reagent gas flow rate could affect the ability of the analyzer to accurately indicate hydrogen concentration, the inspector questioned licensee personnel on the effect of this flow variation on the capability of the analyzers to detect hydrogen.

The inspector reviewed Sections 6.2.5.2 and 7.5.1.2.8.3 of the Safety Analysis Report, which described the design, purpose, and capabilities of the containment and drywell hydrogen analyzers. These units provide indication of hydrogen concentration to the control room and are utilized by the operations staff following an accident to manually initiate the hydrogen recombiners to maintain containment hydrogen concentration below 4 percent. The hydrogen analyzers are automatically activated upon a loss-of-coolant accident to

immediately provide an indication of hydrogen concentration. Figure 6.2-18 of the Updated Final Safety Analysis Report depicts calculated hydrogen concentrations inside containment following an accident and shows a maximum concentration of approximately 9 percent, 28 days following the accident, if no recombiners are started. The hydrogen concentration reaches 4 percent after 6 days.

Procedure EP-3, "Containment Control," contains steps requiring operators to initiate or secure the hydrogen igniters and recombiners based upon values of the hydrogen concentrations in containment and the drywell to prevent an inadvertent explosion if the components are started in too high a hydrogen/oxygen environment. If hydrogen analyzers are not available, then grab samples are taken.

Licensee engineering personnel determined that an analyzer accuracy of 2 percent, based upon the ability to read the indication in the control room, was required to provide sufficient margin before exceeding any explosive limits. If insufficient reagent gas flow was available to the analyzer, then full recombination of any hydrogen present in the analyzer may not occur and the analyzer would indicate a nonconservative, low hydrogen concentration. Excessive reagent gas flow will also introduce an error in the analyzer indication by affecting sample flow but this effect would be much less pronounced.

After being informed of the inspectors concern, the licensee performed a review of calibration records for the hydrogen analyzers. Although the electronic portion of the analyzer calibrations showed no signs of drifting, the Channel A containment hydrogen analyzer exhibited excessive lower as-found reagent gas flow rates than as-left from the previous calibrations on 6 occasions since February 1993 and the Channel A drywell hydrogen analyzer exhibited 9 such discrepancies during the same time period. The Channel B train of hydrogen analyzers exhibited occasional increases in reagent gas flow rates. The licensee determined that, based upon the amount of drift observed on the Channel B hydrogen analyzers, no operability concern existed. However, the drift on the Train A analyzer would have adversely affected analyzer indication above 3 percent hydrogen concentrations.

A material nonconformance report, dated December 11, 1995, was generated by the licensee to document the drifting problems. The data indicated a random drifting of reagent gas flow and, therefore, licensee personnel were unable to establish a drift rate. Licensee personnel conservatively assumed that an analyzer was inaccurate for the entire period from the previous calibration. From a review of the data, the licensee determined that both trains of analyzers were never inoperable at the same time in excess of 7 days nor was a single channel inoperable for 30 days, which is the limits specified in TS 3.3.3.1.

A monthly periodic calibration is normally performed; however, the licensee initiated a weekly check of reagent gas flow to establish a drift rate for the analyzer indication. On December 12, the Train A containment analyzer reagent

gas flow was found to be low and was adjusted. Work packages were generated to replace components inside the analyzers that could affect the flow rates. Regulators for controlling reagent gas and calibration gas pressure were replaced. In addition, check valves in these systems were replaced. Subsequent weekly checks of the analyzer reagent gas flow showed little deviation from previously set values. The licensee planned to continue the weekly checks until analyzer reliability can be established.

From discussions with the system engineer and a review of the Procedure 06-IC-1E61-Q-1004, "Containment and Drywell Hydrogen Analyzer (PAM) Calibration," the inspector determined that the surveillance procedure required technicians to check reagent gas flow prior to the analyzer calibration and make an adjustment if necessary to the previous calibration value. The system engineer informed the inspector that this procedure requirement had been instituted since November 1992. The inspector considered this direction to be improper since this action had the result of masking a deficiency with the ability of the analyzers to maintain accuracy for the entire monthly calibration frequency. In addition, the inspector noted that the directions provided to the technicians constituted preconditioning of the test. A change in calibration frequency to quarterly occurred in March 1995, when the new improved TS were implemented. Since calibration records indicated no adverse trend in the ability of the analyzer to maintain its accuracy for this period of time, the prudence of changing the calibration frequency was not questioned.

The inspector considered the calibration procedure for the containment and drywell hydrogen analyzers to be inadequate in that an adjustment was being made to the reagent gas flow prior to obtaining as-found calibration data. This is a violation of TS 5.4.1.a for an inadequate procedure (416/9521-02).

The licensee implemented a temporary change to the procedure to address the calibration instructions deficiency identified by the inspector.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

D. Bost, Director, Nuclear Plant Engineering
*C. Bottemiller, Superintendent, Plant Licensing
*C. Ellsaesser, Manager, Performance and System Engineering (Acting)
W. Deck, Security Superintendent
*M. Dietrich, Manager, Training
J. Dimmette, Manager, Operations
C. Dugger, Manager, Outage Maintenance and Work Control
*C. Hayes, Director, Quality Assurance
*C. Hutchinson, Vice President, Nuclear Operations
*A. Khanifar, Manager, Materials, Purchasing and Contracts
*M. McDowell, Operations Superintendent
M. Meisner, Director, Nuclear Safety and Regulatory Affairs
R. Moomaw, Manager, Plant Maintenance
A. Morgan, Manager, Emergency Preparedness
*D. Pace, General Manager, Plant Operations
T. Tankersley, Radiation Control Superintendent

The inspectors contacted other licensee personnel during this inspection.

*Denotes personnel who attended exit interview.

2 EXIT MEETING

The inspectors conducted an exit meeting on January 22, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this inspection report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.