UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

JUL 23 1991

MEMORANDUM FOR: Chris A. VanDenburgh, Chief, Reactive Inspection Section 2
Vendor Inspection Branch
Division of Reactor Inspections and Safeguards

FROM: Luis A. Reyes, Director
Division of Reactor Projects

SUBJECT: VOGTLE SPECIAL TEAM INSPECTION - ALLEGATION FOLLOWUP TEAM DRAFT INSPECTION REPORT (INSPECTION REPORT NOS. 50-424/90-XX AND 50-425/90-XX)

This memorandum refers to the special inspection conducted on August 6 through 17, 1990, at the Vogtle Electric Generating Plant (VEGP). This inspection involved a review of several allegations regarding the safe operation of VEGP and the review of operational activities generally related to the allegations. As discussed in the inspection plan, the inspection was performed by two separate teams--an operational followup and an allegation followup team.

As decided in a meeting held in Nuclear Regulatory Commission (NRC) headquarters on September 26, 1990, the allegation followup team's findings and conclusions was not included in Inspection Report 50-424/90-19; 50-425/90-19. This information was to be withheld pending the completion of an Office of Investigation review of the allegations and the inspection team's conclusions. On January 11, 1991, Inspection Report 50-424,425/90-19 was issued which included the operational followup team findings. The remaining issues from the allegation followup team were then left in Inspection Report 90-XX, pending the completion of Ois' review of the allegations.

On July 9, 1991, a meeting was held in Region II, with members of Region II-DRP, OI, and NRR-PD3-2 and Regional management. It was determined to issue the remainder of the 50-424,425/90-19 report, except for the following issues: 1) ¶ 2.3 Missed Containment Isolation Valve Surveillance; 2) ¶ 2.4 Mode Change With Inoperable Source Range Monitor Nuclear Instrument; 3) ¶ 2.7 Reliability of Emergency Diesel Generators and their corresponding parts to the Notice of Violations.

This memorandum forwards a marked up copy of Inspection Report 50-424, 425/90-19, Supplement 1, which documents the inspection team's review and conclusions regarding the allegations as of the time of the inspection exit meeting on August 17, 1990. The report has already been reviewed by the Office of Investigation in Region II for information that might compromise their on going investigations. The information that was considered pertinent to these investigations will not be included in the issued report.

A1157

If you have any questions concerning this issue, please contact P. Skinner at Ext. 16299 or S. Vias at Ext. 15350.

Luis A. Reyes

Luis A. Reyes

Enclosures:
1. Draft Notice of Violation
2. Draft Inspection Report
   50-424,425/90-19, Supplement 1

cc w/encls:
L. Robinson, OI
D. Hood, NRR, PD3-2
S. VIAS
P. Skinner
L. Reyes
G. Jenkins

101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

~~JAN 11 1991~~

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P.O. Box 1295
Birmingham, AL 35201

DRAFT

Gentlemen:

SUBJECT: VOGTLE SPECIAL TEAM INSPECTION AND NOTICE OF VIOLATION (NRC INSPECTION REPORT NOS. 50-424/90-19 AND 50-425/90-19, Supplement 1)

This refers to the inspection conducted by an NRC Special Inspection Team on August 6 through 17, 1990. ~~The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.~~ See insert #1

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice).

~~Although the inspection concluded that the facility was operated in a safe manner in accordance with the requirements of the operating license, we are concerned that there were several operational policies and programs where weaknesses were identified. As part of your response to the violations identified in the enclosed Notice, you are also requested to address each of the weaknesses listed in the inspection summary.~~

You are required to respond to this letter and Notice and should follow the instructions specified in the enclosed Notice when preparing your response to the violations. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

Insert #1 Previous correspondence associated with this inspection was transmitted to you on January 11, 1991. As discussed in the Inspection Summary of that document, the results of the allegation followup ~~activities~~ team would be the ~~any~~ subject of separate correspondence. This report includes, in part, results of that allegation followup team.

~~Additionally, you should respond to each of the operational weaknesses identified within the report. (These weaknesses are specifically annotated in the Inspection Summary.) The response should address your analysis of the significance of the weaknesses and your actions to ensure that these operational practices do not evolve into items of non-compliance or reduce the margin of safety for the plant.~~

In accordance with Section 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96.511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

James L. Milhoan for

Stewart D. Ebneter
Regional Administrator
Region II

Enclosures:
1. Notice of Violation
2. Inspection Report 50-424/90-19; 50-425/90-19 Supplement 1

Add appropriate cc & bcc lists

SVIAS CVanDenburgh P.Skinner Heidt

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May 9, 1991

MEMORANDUM FOR: Luis A. Reyes, Director
Division of Reactor Projects
Region II

FROM: Chris A. VanDenburgh, Chief
Reactive Inspection Section - 2
Vendor Inspection Branch
Division of Reactor Inspections and Safeguards

SUBJECT: VOGTLE SPECIAL TEAM INSPECTION - ALLEGATION FOLLOWUP TEAM DRAFT INSPECTION REPORT (INSPECTION REPORT NOS. 50-424/90-xx AND 50-425/90-xx)

This memorandum refers to the special inspection conducted on August 6 through 17, 1990, at the Vogtle Electric Generating Plant (VEGP). This inspection involved a review of several allegations regarding the safe operation of VEGP and the review of operational activities generally related to the allegations. As discussed in the inspection plan, the inspection was performed by two separate teams--an operational followup and an allegation followup team. At the conclusion of the inspection, all of the inspection team's conclusions with respect to the operations and allegation followup were discussed with the members VEGP's staff identified in the enclosed draft inspection report.

As decided in a meeting held in Nuclear Regulatory Commission (NRC) headquarters on September 26, 1990, the allegation followup team's findings and conclusions have not been included in Inspection Report 424/90-19; 50-425/90-19. This information has been withheld pending the completion of an Office of Investigation review of the allegations and the inspection team's conclusions. This memorandum forwards a draft inspection report (50-424/90-xx; 50-425/90-xx) which documents the inspection team's review and conclusions regarding the allegations as of the time of the inspection exit meeting on August 17, 1990.

The areas examined during the inspection are identified in the inspection report. As discussed in Inspection Report 50-424/90-19; 50-425/90-19, the inspection team concluded that the facility was safely operated. However, the inspection identified several instances in which the VEGP was not operated in accordance with the intent of the Technical Specifications. In addition, the inspection identified several potential weaknesses in the facilities' operational policies and practices.

The inspection team's review of the allegations identified several additional weaknesses in these operational policies and practices. These are identified in the inspection summary of the enclosed draft inspection report.

Based on the results of this inspection of the allegations, certain activities appeared to be in violation of NRC requirements, as specified in the enclosed draft Notice of Violation (Notice). These violations are important because they indicate (1) a failure to implement the requirements of the Technical Specifications and administrative procedures, and (2) the failure to provide accurate information to the NRC.

As part of the response to the violations identified in the enclosed notice, VEGP should also be requested to address each of the concerns listed in the inspection summary.

Enclosures:

1. Draft Notice of Violation
2. Draft Inspection Report 50-424/90-xx; 50-425/90-xx

cc:
BKGrimes
EWBrach

NRR/DRIS JWilcox* 9/ /90	RII/DRP RAiello* 8/31/90	RII/DRP RStarkey* 8/31/90	RII/DRP MBranch* 8/31/90
RII/DRP LGarner* 9/27/90	RII/DRS MThomas* 8/31/90	NRR/DLPQ NHunemuller* 8/31/90	RII/DRS PTaylor* 8/31/90
RII/DRP RCarroll* 8/31/90	NRR/DRIS CVanDenburgh 9/ /90		

* See previous concurrences

ENCLOSURE 1

NOTICE OF VIOLATION

Georgia Power Company
Vogtle Electric Generating Plant
Units 1 and 2

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

During an NRC inspection conducted on August 6 through 17, 1990, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the violations are listed below.

A. 10 CFR Part 50.9, "Completeness and Accuracy of Information," requires that information provided to the NRC by a licensee shall be complete and accurate in all material respects.

Contrary to the above, the licensee provided inaccurate information to the inspection team on ~~three~~ four separate occasions. Although the information was provided in unsworn, oral statements, the information provided was significant to the licensing process. The information was provided by licensed operators, supervisors and management concerning information which was within their specific responsibilities. FOUR The, ~~five~~ examples were as follows. (50-424/90-~~xx-05~~ 19-12; 50-425/90-~~xx-05~~ 19-12)

1. Containment Isolation Valves: During a Unit 2 surveillance procedure, the unit shift supervisor (USS) stated, and the operations manager later confirmed, that the containment isolation valves for the hydrogen monitor system were allowed to be opened without entering the limiting condition for operation (LCO) action requirements for Technical Specification (TS) 3.6.3 because the valves received an automatic isolation signal. The inspection identified that these containment isolation valves were remotely-operated, manual valves without automatic isolation signals. (Discussed in Section 2.2.1.1 of Inspection Report 50-424/90-19; 50-425/90-19)

2. Snubber Reduction: The operations manager stated that, after the second Unit 1 refueling outage (1R2), the modifications to the snubbers were done in conjunction

INSERT #2

PAGE 2

3 ~~A)~~ Personnel Accountability: The operations manager stated that the shift superintendents (SSs) reported directly to the operations manager and that he personally prepared their performance appraisals. The inspection identified that the SSs reported to the unit superintendent (US), and that the US personally prepared the performance appraisals of the SSs. (Discussed in Section 2.~~1I~~ 8 of this inspection report)

4 ~~B)~~ TS 3.0.3 Actions: The unit superintendent indicated that there were no Operations Department actions which were anticipated or required within the first three hours of entering the action statement of TS 3.0.3. The inspection identified that the VEGP management policy and stated practice required preparations for a power reduction, including informing the load dispatcher within the first hour. (Discussed in Section 2.1.1.3 of Inspection Report 50-424/90-19; 50-425/90-19)

with preplanned system outages which were required for other preventive or corrective maintenance or testing. The inspection identified that few of the snubber modifications were done jointly with pre-planned system outages. (Discussed in Section 2.1.1.4 of Inspection Report 50-424/90-19; 50-425/90-19)

~~I. Emergency Diesel Generator (EDG) Reliability:~~ VEGP incorrectly counted the number of starts and failures of the EDGs and incorrectly represented the EDG reliability in a Region II presentation on April 9, 1990. Although the presentation was not intended to represent a specific number of successful valid tests as specified in Regulatory Guide (RG) 1.108 and TS 4.8.1.1.2a, but rather to describe the EDG maintenance test program and the EDG reliability status, the NRC was not informed of the incorrect information until the NRC asked for it during the inspection. The confirmation of action (CAL) response and Licensee Event Report (LER) 90-006 were also incorrect because they were based on the EDG start information that was compiled for the VEGP presentation in the Region II Office. (Discussed in Section 2.7 of this inspection report)

INSERT #2

This is a Severity Level IV violation (Supplement VII).

B. Technical Specification 6.7.1.a requires that written procedures be established or implemented for those activities delineated in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

Contrary to the above, two examples were identified in which the licensee failed to establish or implement the procedures for these required activities as follows: (50-424/90-~~xx-02~~ 19-13; 50-425/90-~~xx-02~~ 19-13)

1. Administrative Procedure 00150-C, "Deficiency Control," states that a deficiency card must be written if the deficiency involves safety-related components which are to be dispositioned "use-as-is/repair," or other conditions involving safety-related components which require engineering support or other technical assistance to determine if the component is deficient.

On August 17, 1990, the NRC identified that a deficiency card was not written on residual heat removal (RHR) pump #1B (a safety-related component) to document the pump's

degraded conditions which were dispositioned "use-as-is". (Discussed in Section 2.2 of this inspection report)

2. Administrative Procedure 00100-C, "Quality Assurance Records Administration," Paragraph 4.1.1.8, specifies that quality assurance (QA) records will exhibit necessary and appropriate signatures or initials and dates.

   On August 17, 1990, the NRC identified that the Unit Superintendent incorrectly initialed, dated, and signed a QA record which voided Temporary Change Procedure (TCP) 1802-C-7-90-1 to Abnormal Operating Procedure 18028-C, "Loss of Instrument Air," with the date of June 12, 1990, in lieu of the actual date (June 15, 1990) on which the document was signed. (Discussed in Section ~~2.5~~ 2.3 of this inspection report)

This is a Severity Level IV violation (Supplement I).

~~C. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective~~ Action," requires measures to be established to ensure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures are required to ensure that the cause of the condition is determined and corrective action is taken to preclude repetition.

Contrary to the above, two examples were identified in which the licensee failed to determine and implement adequate corrective actions to preclude repetition as follows: (50-424/90-~~XX-03~~ 19-14)

1. On August 17, 1990, the NRC determined that the licensee did not identify the format and normal use of the LCO status sheet as one of the causes of the event described in Licensee Event Report (LER) 90-004, "Failure To Comply With Technical Specification 3.0.4 Occurs on Entry Into Mode 6"; therefore, corrective action was not taken to preclude repetition of the failure to review LCO-required actions or remarks which may be on the back side of the LCO status sheet. (Discussed in Section 2.4 of this inspection report)

2. Technical Specifications 4.8.1.1.3 and 6.8.2 require that all valid or non-valid EDG failures be reported to the NRC in a special report within 30 days. In addition,

Operations Procedure 55038-C, "Diesel Start Log," Section 7.0, requires that all EDG failures shall be reported to the NRC in a special report.

On August 17, 1990, the NRC identified that the corrective actions taken in response to a previous notice of violation were inadequate. Inspection Report 50-424/87-57 (dated November 5, 1987) previously identified a violation of Technical Specification 4.8.1.1.3, in that, all EDG failures were not reported to the NRC in a special report. During a review of the start records for EDG #1B during the period of March 21 through June 14, 1990, the NRC identified that EDG failures had occurred which were not submitted to the NRC in a special report. In addition, the NRC identified that Operations Procedure 55038-C provided inadequate guidance to identify and classify EDG failures. (Discussed in Section 2.7 of this inspection report)

This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Georgia Power Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and, if applicable, a copy to the NRC Resident Inspector within 30 days of the date of the letter transmitting this Notice ~~of Violation (Notice)~~. This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license

should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

FOR THE NUCLEAR REGULATORY COMMISSION

Stuart D. Ebneter
Regional Administrator
Region II

? ?.
Louis Reyes

Dated at Atlanta, Georgia
this day of 1990

~~LIMITED DISTRIBUTION - Not For Public Release~~
~~DRAFT - PREDECISIONAL INFORMATION~~
REPORT DETAILS
~~ENCLOSURE 2~~

Report No.: 50-424/90-~~19~~ and 50-425/90-~~19~~, Supplement 1

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

Docket Nos.: 50-424 and 50-425 License Nos.: NPF-68 and NPF-81

Facility Name: Vogtle Electric Generating Plant, Units 1 and 2

Inspection Conducted: August 6-17, 1990

Team Members:

Ron Aiello - Resident Inspector, Vogtle
Morris Branch - Senior Resident Inspector, Watts Barr
Robert E. Carroll, Jr. - Project Engineer, DRP, Region II
Larry Garner - Senior Resident Inspector, Robinson
Neal K. Hunemuller - Licensing Examiner, NRR
Larry L. Robinson - Investigator, OI, Region II
Robert D. Starkey - Resident Inspector, Vogtle
Craig T. Tate - Investigator, OI, Region II
Peter A. Taylor - Reactor Inspector, DRS, Region II
McKenzie Thomas - Reactor Inspector, DRS, Region II
John D. Wilcox, Jr. - Operations Engineer, NRR

Team Leader: ~~Chris A. VanDenburgh, Section Chief~~
Division of Reactor Inspections and Safeguards
Office of Nuclear Reactor Regulation

Submitted ~~Approved~~ by: ______________________
~~Luis A. Reyes, Director~~ P.H.Skinner
~~Division of Reactor Projects~~ Section chief 3B
~~Region II~~

Approved by: ______________________ A. HERDT Branch Chief

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INSPECTION SUMMARY

Recent activities which have occurred at the Vogtle Electric Generating Plant (VEGP) have raised concerns within the Nuclear Regulatory Commission (NRC) as to the ability and the determination of the licensee to operate the facility in a safe and conservative manner. To address this concern, the NRC performed a special team inspection to determine if the licensee operates the facility in accordance with approved procedures and within the requirements and intent of the facility's operating license. In addition to the occurrence of specific events, NRC concerns regarding the safe operation of the facility were heightened with the receipt of several allegations relating to operational activities at VEGP. The aggregation of the facts and circumstances associated with the operational events and the allegations was viewed as a possible indicator of a non-conservative attitude on the part of the facility's operating staff which warranted the immediate initiation of special inspection activities.

Specifically, the inspection objectives were to:

1) Assess the operational philosophy, policy, procedures and practices of the facility's operating staff and management regarding operational safety.

2) Determine the technical validity and safety significance of ~~each of~~ the allegations and their impact on the safe and conservative operation of the facility.

These inspection objectives were accomplished by the use of two inspection teams--an operations followup team and an allegations followup team. The efforts of these two inspection teams were closely coordinated; however, they independently pursued the objectives outlined above.

The operations followup team monitored control room activities on a 24-hour basis in order to: (1) evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management and (2) determine if the plant was being operated in a safe and conservative manner in accordance with the facilities' operating license.

The allegations followup team verified the technical validity and safety significance of ~~each of~~ the allegations. In addition, with the assistance of the OI staff, this team interviewed members of the plant staff in order to determine (1) their personal involvement and knowledge of the specific allegations and (2) their practice and understanding of the station operational policies.

These interviews were transcribed. Although an OI investigator was assigned to the inspection team to assist during the transcribed interviews, this inspection was not an investigation into the intent of the alleged violations. NRC INVESTIGATIONS MAY BE IMPLEMENTED TO FURTHER REVIEW THESE ISSUES.

The inspection substantiated the occurrence of the specific events described in the allegations. These events resulted in two examples of violations of regulatory requirements (50-424/90-~~xx-02~~ 19-03 AND 50-425/90-~~xx-02~~ 19-03) ~~and 50-424/90-xx-03;~~ and two of the events were previously identified as non-cited violations (50-424/90-10-03 and 50-425/90-01-01). ~~However, the inspection did not substantiate that the events and violations were performed with the full knowledge of VEGP management. This conclusion was based upon a review of the licensee's records and the sworn testimony of the people involved in the events.~~

~~The inspection also identified that on several occasions responsible managers and supervisors verbally supplied inaccurate information to the inspection team during the inspection. Although the inspection team was concerned about the accuracy of the information provided, the team did not have a basis to conclude or suspect that these examples were the result of careless disregard for regulatory requirements or individual wrongdoing.~~

ADDITIONAL ~~The specific~~ observations and conclusions of the inspection team are detailed in Inspection Report 50-424/90-19; 50-425/90-19, ISSUED JANUARY 11, 1991. In addition, the bases for these previous conclusions are summarized below.

Operational Policies and Practices

NRC Inspection Report 50-424/90-19; 50-425/90-19 identified several examples in which the licensee's operational policies and practices had the potential to adversely affect the operation of the facility. The allegation followup team's review of the allegations identified THE FOLLOWING ~~several~~ additional examples in which the licensee's operational policies and practices had the potential to adversely affect the safe operation of the facility: ~~For example:~~

1) The licensee's method of conducting Plant Review Board (PRB) meetings had the potential for adversely affecting open discussions among the PRB members. This concern was based on an example in which a PRB voting member felt intimidated and feared retribution during a PRB meeting because of the presence of the general manager and the absence of dissenting opinions in the PRB meeting minutes. Continued licensee action is necessary to ensure that PRB members freely and

openly express their technical opinions and safety concerns. (Section ~~2.10~~ 2.7)

2) The licensee's practice of signing and dating quality assurance records was controlled by administrative procedures; however, there was a confirmed example in which a signature was backdated to reflect the actual date of performance. The backdating of TCP 1802-C-7-90-1 was verified and was identified as Violation 50-424/90-~~xx-02~~ 19-13; 50-425/90-~~xx-02~~ 19-13. (Section ~~2.5~~ 2.3)

3) The licensee' practice of not initiating a deficiency card (DC) during troubleshooting activities involving the questioned operability of the residual heat removal (RHR) pump prevented a documented engineering evaluation for either the nuclear service cooling water (NSCW) outlet leak or the excessive vibration on the RHR motor. The failure to implement this administrative procedure was identified as Violation 50-424/90-~~xx-02~~ 19-13. (Section 2.2)

~~4) The licensee's method of maintaining and controlling copies of completed surveillance procedures was not controlled by administrative procedures. Based on the confusion which resulted in the missed surveillance of the containment isolation valves and a review of this methodology additional attention is necessary to ensure that these procedures are appropriately controlled and used. (Section 2.3)~~

~~5) The licensee's method for identifying active and informational limiting condition for operations (LCOs) on LCO status sheets allowed continuation of the LCO required actions on the reverse side of the form. This method, in conjunction with the operator's confirmed practice of reviewing only the front side of the LCO status sheets, was one of the root causes for a non-cited violation (50-424/90-10-03) concerning a mode change which occurred with inoperable source range nuclear instruments. The failure to identify this additional root cause was identified as Violation 50-424/90-xx-03. (Section 2.4)~~

4 ~~6)~~ The licensee's method of appraising the performance of the licensed operators resulted in a potential disincentive for identifying items which may result in LERs or violations. (Section ~~2.11~~ 2.8)

Accuracy of Information

The inspection concluded that during the inspection inaccurate information was received on several occasions, from responsible managers and operators on topics well within the scope of their specific responsibility. In ~~five~~ four instances the initial information supplied was clearly incorrect or inadequately researched. The inspection team concluded that in each of these examples that licensee officials provided inaccurate, unsworn, oral statements concerning information which concerned topics well within their responsibilities.

In the ~~first three~~ two cases, the inaccurate information was significant to the inspection process. Specifically, (1) if the containment isolation valves received an automatic closure signal, and the valves could remain open without a violation of TS 3.6.3, ~~(~~(2) if the snubber modifications had been performed in conjunction with other preplanned preventive and corrective maintenance, then the voluntary entries into LCO 3.7.8 would not have been required. ~~and (3) if the NRC was accurately informed of the number of problems and failures of the Emergency Diesel Generator No. 1B which occurred during troubleshooting, then additional testing may have been required prior to the release of the confirmation of action letter.~~ The inspection team concluded that the failure to provide accurate information was a violation of the requirements of 10 CFR 50.9 concerning accuracy and completeness of information. The inspection identified Violation 50-424/90-~~xx-05~~ 19-12; 50-425/90-~~xx-05~~ 19-12 in this area and noted the following examples:

1) Containment Isolation Valves: During a Unit 1 surveillance procedure, the unit shift supervisor (USS) stated, and the operations manager later confirmed, that the containment isolation valves for the hydrogen monitor system were allowed to be opened without entering the LCO action requirements for TS 3.6.3 because the valves received an automatic isolation signal. The inspection identified that these containment isolation valves were remotely-operated, manual valves without automatic isolation signals. (Discussed in Section 2.2.1.1 of Inspection Report 50-424/90-19; 50-425/90-19)

2) Snubber Reduction: The operations manager stated that, after Unit 1 refueling outage 1R2, the modifications to the snubbers were done in conjunction with preplanned system outages which were required for other preventive or corrective maintenance or testing. The inspection identified that few of the snubber modifications were done jointly with pre-planned system outages. (Discussed in Section 2.1.1.4 of Inspection Report 50-424/90-19; 50-425/90-19)

~~3) Emergency Diesel Generator Reliability: The licensee's method of researching information for Region II presentation concerning the reliability of the emergency diesel generators (EDGs) was inadequate in that there was a lack of specific guidance concerning the EDG information desired coupled with inadequate research of the EDG starting history. This method resulted in providing incomplete and, therefore, inaccurate information to the NRC. In addition, the licensee's response to the NRC's confirmation of action letter (CAL) was based on this same inadequate research. In addition, the subsequent Licensee Event Report (LER) 90-006 was also inadequately researched. As a result of this method of investigation, the NRC was never informed of the correct operability status until this inspection. (Discussed in Section 2.7 of this inspection report)~~

3 ~~4)~~ Personnel Accountability: The operations manager stated that the shift superintendents (SSs) reported directly to the operations manager and that he personally prepared their performance appraisals. The inspection identified that the SSs reported to the unit superintendent (US), and that the US personally prepared the performance appraisals of the SSs. (Discussed in Section ~~2.11~~ 2.8 of this inspection report)

4 ~~5)~~ TS 3.0.3 Actions: The unit superintendent indicated that there were no Operations Department actions which were anticipated or required within the first three hours of entering the action statement of TS 3.0.3. The inspection identified that the VEGP management policy and stated practice required preparations for a power reduction, including informing the load dispatcher within the first hour. (Discussed in Section 2.1.1.3 of Inspection Report 50-424/90-19; 50-425/90-19)

In summary, the inspection identified ~~three~~ two violations and two inspector followup items. The violations involved: (1) a violation of 10 CFR 50.9 in that responsible licensee officials provided inaccurate information to the NRC during the inspection~~;~~ and (2) a violation of TS 6.7.1.a in that, two examples were identified of the licensee failing to implement actions in accordance with administrative procedures~~; and (3) a violation of 10 CFR 50, Appendix B, Criterion XVI, in that, two examples were identified of the licensee implementing inadequate corrective actions.~~

The inspection also identified two inspector followup items involving: (1) an unreviewed safety question concerning the use of the alternate radwaste building, and (2) the lack of operator guidance concerning the applicable limiting conditions of operation during engineered safety features actuation system sequencer outages.

INSPECTION DETAILS

1.0 INSPECTION OBJECTIVES

Recent activities which have occurred at the Vogtle Electric Generating Plant (VEGP) have raised concerns within the Nuclear Regulatory Commission (NRC) as to the ability and the determination of the licensee to operate the facility in a safe and conservative manner. To address this concern, the NRC performed a special team inspection to determine if the licensee operates the facility in accordance with approved procedures and within the requirements and intent of the facility's operating license. In addition to the occurrence of specific events, NRC concerns regarding the safe operation of the facility were heightened with the receipt of several allegations relating to operational activities at VEGP. The aggregation of the facts and circumstances associated with the operational events and the allegations was viewed as a possible indicator of a non-conservative attitude on the part of the facility's operating staff which warranted the immediate initiation of special inspection activities.

Because a non-conservative attitude or operating philosophy may represent a hazard to the health and safety of the public, a special inspection team comprising staff from the Region II Office and the Office of Nuclear Reactor Regulation (NRR), assisted by staff from the Office of Investigations (OI), was formed to determine the individual validity and collective impact of these allegations on the safe operation of the facility. The purpose of the inspection was to determine if the licensee operates the facility in a conservative and safe manner in accordance with approved procedures, and the intent and requirements of the facility's operating license. Specifically, the inspection objectives were to:

1) Assess the operational philosophy, policy, procedures, and practices of the facility's operating staff and management regarding operational safety.

2) Determine the technical validity and safety significance of each of the allegations and their impact on the safe and conservative operation of the facility.

These inspection objectives were accomplished by the use of two inspection teams--an operations followup team and an allegations followup team. The efforts of these two inspection teams were closely coordinated; however, they independently pursued the objectives outlined above.

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The operations followup team monitored control room activities on a 24-hour basis in order to: (1) evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management and (2) determine if the plant was being operated in a safe and conservative manner in accordance with the facility's operating license.

The specific inspection activities of the operations team was described in Inspection Report 50-424/90-19 and 50-425/90-19. The efforts and conclusions of the allegations followup teams are described in this inspection report. subsequent In addition, this report identifies several violations ~~and potential weaknesses~~ in the licensee's ~~operational policies, programs~~, and procedures. ~~The~~ specific details ~~and basis for the inspection team's concerns~~ are detailed in the sections that follow and in the Inspection Summary.

2.0 ALLEGATION FOLLOWUP

The inspection team reviewed several allegations for their technical validity and interviewed licensed and non-licensed personnel to determine their personal knowledge and experience regarding these issues. This portion of the inspection was performed to determine the validity and significance of the allegations. ~~Because the allegations asserted that licensed operators had violated the Technical Specifications (TS) with the knowledge of licensee management, the inspection team reviewed the circumstances and rationale for individual actions.~~

The inspection of the allegations included technical reviews of the licensee's records, logs, and interviews of the personnel involved in the alleged violations. Although a transcribed record was not required for every discussion with the licensee's staff, the inspection team conducted sworn, transcribed interviews with selected individuals in order to document (1) the individual's personal knowledge and involvement in the alleged violations and (2) the circumstances and rationale for their individual actions. Although an OI investigator was assigned to the inspection team to assist during the transcribed interviews, this inspection was not an investigation into the intent of the alleged violations. The intent aspects of the alleged activities may require further NRC investigations.

The interviews were transcribed after the technical evaluations of the allegations in order to permit a focused interview and to minimize the length and scope of the transcribed proceedings. The transcribed interviews are listed in Appendix ~~1~~ A in the order they were conducted. The sworn testimony was ~~the basis~~ on which the inspection team reached its conclusion on each of the allegations. These conclusions are presented in the material that follows (Sections 2.1 through ~~2.11~~ 2.8).

2.1 Improper Installation of FAVA System

An allegation indicated that VEGP installed and operated a radwaste microfiltration system, known as the FAVA system, without performing an adequate engineering and safety evaluation (i.e., 10 CFR 50.59). Furthermore, the material configuration, fabrication and quality of the system did not meet the guidance of Regulatory Guide (RG) 1.143 and the requirements of the American Society of Mechanical Engineer's (ASME) Code.

The FAVA system was temporarily installed for removing Niobium-95. The system was later determined to be better suited for as-low-as-reasonably-achievable considerations during refueling outage 1R2, particularly for removing Cobalt-59 and Cobalt-60. VEGP planned to replace this temporary modification with a permanent, high-quality, steel system in the future; however, the health and safety of the public may be jeopardized if a break in the system (resulting in a radioactive release to an unrestricted area) occurred in the interim.

Discussion

In February 1988, the VEGP experienced difficulty in removing colloidal Niobium-95 following a reactor shutdown for maintenance work. FAVA Control Systems (FAVA) was hired to help rectify this problem. FAVA was selected because of its experience in filtration and demineralization. The situation was corrected by installing a 0.35-micron filter system downstream of the existing vendor-supplied pre-filters. However, a large volume of radwaste was generated as the 0.35-micron filters rapidly exhibited high differential pressure and were required to be changed frequently. The need to change filters frequently also resulted in additional radiation exposure to Radwaste Department personnel.

Upon evaluation of the performance of the 0.35 micron filter system, the Radwaste Department felt that the best approach to the problem was a back-flush, pre-coat filter system. However, no operational data was available for a system of this type in this specific application. FAVA supplied a proprietary Ultra Filtration System (Model No. 5FD/E) for testing purposes in order to evaluate whether or not this was a viable and economic solution to the problem. The FAVA system was installed before the Unit 1 refueling outage and was operated under Test Procedure T-OPER-8801. The test system kept liquid effluent releases well below TS limits. On the basis of an evaluation of test results by the Radwaste, Chemistry, and Engineering Departments, a general work order was initiated to purchase a permanent system.

In the early part of 1989, a Quality Assurance (QA) Department audit identified a significant audit finding involving a programmatic breakdown in the procurement of the FAVA system and the failure to meet commitments of the Final Safety Analysis Report (FSAR). Because of that finding, the FAVA system was removed from service. In late 1989, the licensee sought to reinstall the FAVA system under a temporary modification because colloidal Cobalt-59 and Cobalt-60 had to be removed. The Plant Review Board (PRB) reviewed this temporary modification and several members expressed strong objections to it based on the previous QA audit finding.

Subsequently, a request for engineering assistance (REA) was submitted and a 10 CFR 50.59 safety evaluation was performed in late 1989. This safety evaluation did not properly address the guidance of Regulatory Guide (RG) 1.143 regarding the use of polyvinyl chloride (PVC) piping. Therefore, another safety evaluation was performed in February 1990 to address this issue--particularly with respect to radiation degradation.

The February 1990 safety evaluation specifically stated that the FAVA system did not conform to the criteria of RG 1.143. This deviation was found to be acceptable for the following reasons:

1) The design of the FAVA system had been previously evaluated and found to be adequate in the response to REA VG-9057 dated November 28, 1989 (log SG-8592).

2) The location of the FAVA microfiltration system inside a shielded, watertight vault provided adequate assurance that any system failures will be contained and would not create the potential for offsite releases of radioactivity.

3) The presence of PVC pipe in the FAVA system, although prohibited by RG 1.143, was acceptable because the radiation exposure to the plastic was within acceptable limits for up to 6 months based on the following:

   a) The amount of PVC piping used was not extensive and was contained on the FAVA filter skid.

   b) There were no reported leaks or malfunctions during the approximately 6 months that the FAVA system filter was previously in use.

   c) Since the FAVA system filter skid was located within the demineralizer vault, it would be protected from being damaged.

d) On the basis of the assumed length of time that the PVC piping would be used in a radioactive environment and the activity levels of the effluent at this stage in the liquid radwaste process, the integrated dose to the PVC piping would be well below the radiation damage threshold for PVC pipe as reported in Electric Power Research Institute (EPRI) Report NP-2129, dated November 1981 (i.e., 6.5 rad over a 6 month period versus the radiation damage threshold of 5.0×10^5 rad).

e) The PVC pipe would not be subjected to excessive pressure conditions since the maximum available inlet pressure to the filter was 80 to 100 pounds per square inch gauge (psig) which is well below the maximum allowable working pressure of 120 psig for the PVC pipe.

f) The system could be operated at design-basis conditions for 182 days before it would exceed the radiation damage threshold. However, under conditions currently existing at the plant, the expected dose to the PVC piping will less than 0.1 percent of the design basis.

Although the testimony of one of the PRB members indicated that the temperature effects on the use of PVC in the FAVA System were not adequately evaluated before the system was installed, the testimony of the corporate system engineer indicated that this was considered prior to installation, although not specifically documented in the safety evaluation.

The VEGP general manager subsequently consulted the NRC resident inspector to seek an NRC position with regard to placing this system back in service. This was supplemented by information documenting reasons why it should not be placed in service. This package was forwarded to Region II and the Office of Nuclear Reactor Regulation (NRR) for review. In March 1990, following Region II and NRR concurrence via a telephone conference, the licensee placed the FAVA system in service with the following NRC stipulations:

1) Procedures for operating the FAVA system required an operator to be in attendance for the entire length of time the system would be in operation.

2) All hoses going to and coming from the FAVA system required verification that they met the requirements of RG 1.143.

3) The cover over the FAVA system was required to be securely fastened when the system was in operation to ensure that if a

spraying leak developed, it would be contained in the concrete vault.

4) The design of the walls of the alternate radwaste building (ARB) was required to be evaluated to determine whether or not a design modification should be made to reduce the potential of wall leakage in the event that a hose leak developed and sprayed its contents on the walls.

In June 1990, in response to item 4 (above), the licensee revised Part G of the safety evaluation for the FAVA system. Part G of the safety evaluation addressed the effect that operation of the FAVA system would have on the probability of occurrence or consequences of accidents described in the FSAR. Although there was no comparable accident analysis in the FSAR that addressed the ARB accidents or the consequences of accidents in the ARB, the FSAR accident analyses (Chapters 15.7.2 and 15.7.3) did describe worst-case releases of the contents of the recycle holdup tank (HUT).

The first bounding analysis in Chapter 15.7.2 addressed the release of the entire gaseous radioactive contents of the HUT to the environment at ground level and the second bounding analysis addressed the release of the entire liquid contents of the HUT through an assumed crack in the ARB floor directly into the ground water supply. In both cases, the 10 CFR Part 100 and 10 CFR Part 20 limits were not exceeded. These criteria were consistent with criteria provided in NRC Circular 80-18, "10 CFR 50.59 Safety Evaluations for Changes to Radioactive Waste Treatment System." However, neither of these analyses addressed the potential for wall spray down and leakage through the ARB walls and the subsequent release path to the environment. Therefore, the licensee revised the safety evaluation in June 1990 to address the consequences of a hose break on the FAVA system which would result in wall spray down and potential leakage to the environment.

The inspection team's review of the revised Part G of the safety evaluation identified several erroneous assumptions with respect to the release path and the dilution volumes that could be used in the analysis of a hose break and resultant wall spray down. However, the inspection team also found that the design of the FAVA system (i.e., the use of a system cover) would prevent wall spray down and that the only potential source for wall spray down and subsequent leakage was from a hose break in another radwaste system in the ARB. Therefore, the inspection team concluded that the FAVA system safety evaluation dated June 1990, adequately addressed the temporary modification for the installation of the FAVA system; however, the inspection team's review identified an unreviewed

safety question concerning the release paths and consequences of a failure of the other radwaste systems in the ARB.

In addition, the team noted that in Supplements 3 and 4 of the Safety Evaluation Report (SER), the NRC staff reviewed and accepted the design of the ARB and specifically addressed the consequences of a hose break on a radwaste system in the ARB. However, the SER supplements addressed the effects of high airborne activities and puddling and did not address the potential for wall spray down and leakage. The ARB was installed before the plant was licensed; therefore, the NRC approved the design and use of the ARB in Supplements 3 and 4 of the SER. Thus, there was no requirement to perform another evaluation of the potential effects of hose breaks on systems other than the system being installed by the temporary modification (i.e., the FAVA system). Because the design of the FAVA system effectively prevented a wall spray down, this was not a concern that was required to be addressed by the FAVA system safety evaluation. Nevertheless, now that it has been identified, the consequences of a hose break and wall spray down in the other ARB radwaste systems must be resolved. Therefore, this issue will be followed as an inspector followup item pending further review and evaluation and is identified as:

IFI 50-424/90-~~XX-01~~ 19-14 and 50-425/90-~~XX-01~~ 19-14, "Potential Unreviewed Safety Question Regarding Spray Down of the Alternate Radwaste Building."

Conclusion

Although the FAVA system was originally installed without an adequate safety evaluation and did not meet the regulatory guidance, the inspection team concluded that the subsequent safety evaluations were acceptable for the system's use. ~~Therefore, the inspection team concluded that the allegation was not fully substantiated.~~

As a result of QA Department's significant audit finding in early 1989 involving a breakdown in procurement and failure to meet FSAR commitments, the system was removed from service. Subsequently, the FAVA system was returned to service following two safety evaluations which adequately addressed the use of PVC piping with respect to radiation degradation and pipe rupture. Therefore, these safety evaluations justified the use of the FAVA system, even though the recommendations of RG 1.143 and ASME Code requirements were not met. Although the safety evaluations did not specifically address high-temperature effects, the testimony indicated that these effects had been considered before the system was installed.

Although the safety evaluation performed in June 1990 at the request of the NRC Region II Office did not adequately evaluate the effects of a wall spray down and wall leakage to an unrestricted area, this evaluation was not required because the FAVA system has a protective cover and the use of hoses and effects of hose breaks (i.e., airborne activity and puddling) were addressed in SER Supplements 3 and 4.

Regardless of whether the safety evaluation was required to address the effects of a break in the hoses (which could result in wall spray down or leakage), the inspection team identified a new concern involving the use of the ARB because the safety evaluation inadequately addressed the potential effects of wall spray down from any other source in the ARB owing to erroneous assumptions concerning the release path and the dilution volumes. This is a potentially unreviewed safety question concerning the use of the alternate radwaste building.

2.2 Operability of the Residual Heat Removal Pump

An allegation indicated that during Unit 1 refueling outage 1R2 with residual heat removal (RHR) Train A out of service for maintenance, the Train B RHR pump experienced excessive vibration and a nuclear service cooling water (NSCW) motor cooler outlet leak. In addition, TS 3.9.8.1, "RHR and Coolant Circulation," was allegedly violated because the Operations Department chose not to declare RHR pump 1B inoperable in an effort to mitigate the impact on the critical work path.

Discussion

TS 3.9.8.1 requires at least one RHR train to be operable and in operation during Mode 6 (refueling) when the water level above the top of the reactor vessel flange is 23 feet or more. Otherwise,

> Suspend all operations involving an increase in the reactor decay heat load or a reduction in boron concentration of the reactor coolant system (RCS) and immediately initiate corrective action to return the required RHR train to operable and operating status as soon as possible and close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

The inspection team verified that during Unit 1 refueling outage 1R2 with higher than normal vibration measurements on the RHR pump 1B and a leak on the NSCW outlet of the RHR motor cooler, Operations Department personnel did not declare the pump

inoperable. This determination was made after consulting with the on-shift duty engineer from the Engineering Department and was based on the determination that the pump would fulfill its intended safety function in Mode 6. Specifically, the RHR pump was capable of removing decay heat from the partially defueled reactor core. The testimony of the individuals involved indicated that this operability determination was based on the fact that the vibration readings taken at the inservice test (IST) surveillance points did not reach the IST Alert levels and were therefore acceptable for continued service. Although the high vibration readings on the top end of the RHR pump were later determined by the vendor (Westinghouse) to be excessive, at the time of the operability evaluation, the licensee accepted these values, regardless of their magnitude, because the readings at IST test points were below the Alert levels. The testimony also indicated that, even with a leak on the NSCW outlet of the RHR motor cooler, the motor was receiving full cooling water flow and cooling would not have been immediately compromised following a complete NSCW discharge pipe break.

Furthermore, the testimony indicated that the Operations Department had implemented compensatory actions to monitor the vibration levels and NSCW leakage and ensure the continued operability of the pump by stationing an operator at the RHR pump to monitor the vibration levels and notify the control room if the vibration levels increased, thus allowing the control room to implement the actions of the limiting condition for operations (LCO).

The inspection team also noted that in event of a catastrophic failure of the RHR pump, all the required actions of TS 3.9.8.1 (i.e., closing all containment penetrations) could have been completed within the required 4 hour time period of the LCO because the LCO for TS 3.9.4, "Containment Building Penetrations," was in effect during this time period. This LCO was implemented due to the movement of irradiated fuel from the core to the spent fuel pool. The LCO required that,

> The equipment door be closed and held in place by at least four bolts; at least one door in each airlock be closed; and each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either closed by an isolation valve, blind flange, or manual valve, or be capable of being closed by an operable automatic containment ventilation isolation valve.

As a result of the implementation of TS 3.9.4, the only remaining action for the LCO of TS 3.9.8.1 would have been to close the

containment purge valve which receives an automatic closure signal and could have been isolated within the LCO action times.
During the course of this review, the inspection team found that the licensee failed to initiate a deficiency card for either the NSCW leak or the excessive vibration as required by Operations Procedure 00150-C, "Deficiency Control." This procedure requires that a deficiency card be written if the deficiency involves safety-related components which are to be dispositioned "use-as-is/repair," or other conditions involving safety-related components which require engineering support or other technical assistance to determine if the component is deficient. Failure to establish, implement, and maintain adequate operating procedures represents a violation of TS 6.7.1.a. This item is identified as:

VIO 50-424/90-~~xx-02~~ 19-13, ~~and 50-425/90-xx-02~~, "Failure To Establish or Implement Procedures for Required Activities."

Conclusion

The inspection team concluded ~~that the allegation was not fully substantiated because~~ that the Operations Department had an adequate engineering basis for accepting the operability of the RHR pump in spite of the pump's deficiencies. In addition, the team concluded that declaring the pump inoperable would not have impacted the critical work path: the LCO actions would not have been restrictive because containment (excluding ventilation) had been isolated as required by TS 3.9.4. The LCO actions would not have prevented the continuation of refueling activities because the actions to close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere would only have required closing the containment purge valve which has an automatic closure signal.

In addition, the inspection team identified that the licensee violated the station's administrative procedures by failing to initiate a deficiency card for either the NSCW outlet leak or the excessive vibration on the RHR motor as required by Operations Procedure 00150-C.

~~3.3 Missed Containment Isolation Valve Surveillance~~

~~An allegation indicated that a unit shift supervisor (USS) concealed the correct entry time for a TS LCO to prevent a forced shutdown of the unit and to prevent a 10 CFR 50.72 notification to the NRC. Furthermore, containment isolation valves (CIVs) which were missed during a surveillance test should have been declared inoperable and the immediate actions of the TS LCO should have been initiated at the time the missed surveillance was identified. In~~

addition, delaying the initiation of the deficiency card (DC) until the surveillance had been re-performed allowed the licensee to avoid the immediate actions of the LCO and allowed the unit to remain in operation and avoid the immediate NRC notification.

Discussion

The inspection team reviewed the documentation of the missed surveillance on the containment isolation valves described in Licensee Event Report (LER) 90-001 for which a non-cited violation (50-425/90-01-01) was issued. The LER identified that during the review of monthly Surveillance Procedure 14475-2, "Containment Integrity Verification-Valves Outside Containment," the licensee discovered that 39 CIVs had been overlooked and had not been tested. In addition, the valves had not been tested during the previous two monthly surveillances. Upon identification, the operating shift re-performed the complete surveillance and initiated an investigation which resulted in a deficiency card (DC) for the previously missed surveillances.

The LER indicated that the root cause of the violation was personnel error in reviewing the completed surveillance task sheet. In addition, the computer software which generated the surveillance task sheets (STS) has been modified so that it is no longer possible to inadvertently get an incomplete listing of the equipment. Even if an error similar to the one which resulted in only two valves being shown on the STS were to recur, it could only result in either all or none of the equipment being listed.
The inspection team verified that TS 3.6.1.1, "Containment Integrity," LCO action statement required restoring containment integrity within 1 hour or commencing a unit shutdown to hot standby within the next 6 hours. A shutdown required by Technical Specifications would have required that the NRC be immediately notified in accordance with 10 CFR 50.72.

The inspection team found that the CIV surveillance requirement of TS 4.6.1.1.a had been completed and approved. The surveillance procedure required verification every 31 days that all penetrations not capable of being closed by operable containment automatic isolation valves and required to be closed during accident conditions be closed by valves, blind flanges, or deactivated automatic valves secured in their normal positions. During the next shift, the oncoming shift supervisor noted that the surveillance procedure was only partially performed and that 39 of the CIVs on the surveillance procedure had been marked as "not applicable" and had not been performed.

TS 4.0.2.a requires that each surveillance requirement be performed within the specified time interval with a maximum allowable extension not to exceed 25 percent of the surveillance interval. In addition, TS 4.0.3 requires that failure to perform a surveillance requirement within the specified time interval shall constitute a failure to meet the operability requirements for an LCO. As such, the failure to perform Surveillance Requirement 4.6.1.1.a for all the CIVs within the surveillance period (i.e., 31 days plus the 25-percent extension) would have constituted an inoperable condition of the CIVs.

The oncoming USS testified that he lacked sufficient information to determine if the complete surveillance had not been performed within the surveillance frequency because he was not familiar with the circumstances under which the surveillance procedure was performed. Furthermore, he lacked sufficient information in the control room to determine if the complete surveillance procedure had been performed within the surveillance period. On the basis of his experience, the CIV surveillance was normally performed in its entirety; therefore, the potential existed that another partial surveillance procedure had verified the position of the missed CIVs. Although previously performed surveillances were filed in the control room, these records were for information only and were neither controlled nor complete.

The USS indicated that the previous two monthly surveillances on the CIVs obtained from this file were performed incompletely; however, he did not know whether surveillances on the missed CIVs had been performed completely under some other surveillance procedure. This was confirmed when the team interviewed the surveillance coordinator. Who indicated that approximately once a month the Surveillance Tracking Group identified that suspected missed surveillances were performed under different tasks.

Upon identification of the potential missed surveillances, the USS initiated an investigation to determine whether the surveillances had actually been missed and, concurrently, re-performed the surveillance within three hours. The inspection team verified that the discovery time on the deficiency card correctly reflected the time at which it was verified that the previous two surveillances had been performed incompletely.

Conclusion

On the basis of the testimony of the USS, the inspection team concluded that the allegation was not fully substantiated because

the USS did not conceal the true discovery time of the missed CIV surveillances to avoid a unit shutdown. The USS indicated that he was not pressured to keep the plant in operation or to prevent NRC notification. He stated that he had never been given any indication or instruction to do "whatever it takes" to keep the unit on line or to avoid NRC notification of unusual events. The USS did not know and could not confirm if the previous CIV surveillances had been inadequately performed and believed that the surveillance could be re-performed within the allowable outage time; therefore, his actions to initiate an investigation into the adequacy of the previous surveillance and to concurrently re-perform the CIV surveillance procedure were appropriate.

~~2.4 Mode Change With Inoperable Source Range Monitor Nuclear~~ Instrument

An allegation indicated that the operations staff allegedly knowingly violated Technical Specifications (TS) when the unit was taken from Mode 5 (cold shutdown) to Mode 6 (refueling) with a source range monitor (SRM) nuclear instrument inoperable and that the prohibited operational mode change was made in order to reduce the critical path outage time.

Discussion

The inspection team reviewed the documentation of the mode change described in Licensee Event Report (LER) 90-004 for which non-cited Violation 50-424/90-10-03 was issued. The LER indicated that TS 3.0.4 was violated on March 1, 1990, when Unit 1 entered Mode 6 from Mode 5 with an LCO for Source Range Channel 1N31 in effect to allow performance of an 18-month channel calibration. The LER indicated that the root cause for the event was personnel error by the shift superintendent.

The inspection team confirmed that TS 3.0.4 required that entry into an operational mode not be made unless the conditions for the LCO are met without reliance on the provisions of the action requirements. With one source range monitor inoperable, TS 3.9.2, "Instrumentation," could not be satisfied in Mode 6 without reliance on the action statement.

Personnel were interviewed to (1) confirm the effect on the outage schedule directly attributed to this TS violation, (2) determine whether it was known at the time of the mode change that a mode-restraining LCO was in effect, and (3) determine the extent of emphasis on schedule.

The testimony and a review of the outage schedule confirmed that there was a reduction in critical path outage time which was directly attributed to proceeding to Mode 6 before restoring the SRM to an operable status.

The testimony also indicated that the shift superintendent (SS) and the unit shift supervisor (USS) did not recognize that a mode-restraining LCO was in effect at the time of the mode change. Both the SS and USS were aware that there was an active LCO on the SRM, but neither of them had connected the LCO to the mode restriction. Contributing factors to the error were that both the SS and USS had directed their attention to a problem with the testing of the engineered safety features actuation system (ESFAS) sequencer and that the work which had been emphasized to be holding up the mode change was the decontamination of the reactor head. Upon notification that the Health Physics Department had cleared the reactor head for work, the SS granted permission to enter Mode 6.

The testimony also indicated that there was no indication of an unreasonable emphasis on the critical path schedule. Both the SS and USS indicated that they had never been given any indication or instruction to do "whatever it takes" to stay on schedule. They also indicated that they did not feel undue pressure to stay on schedule and, particularly, not if it meant compromising safety.

The SS admitted that he was initially commended for the schedule benefits; however, the violation of the Technical Specifications was not recognized at the time. The SS indicated that he had initially received some positive feedback during the morning management briefing for the shift's accomplishments and later in the briefing the TS violation was recognized and discussed. In the SS's opinion the recognition of the TS violation negated all positive feedback.

The inspection team identified an additional concern during the inspection concerning the format and use of the LCO status sheets. On the basis of interviews with the SS and USS and the review of the format of the LCO status sheets, the inspection team concluded that both the format and normal use of this form contributed to this TS violation.

The LCO status sheet, is a two-sided form; the section for required actions begins on the front and continues on the back, where the "remarks" section is located. During the testimony, both the SS and USS indicated that their usual practice, notwithstanding mode changes, was to review only the front of this form because only restorative actions were noted on the back. In this case, the mode

~~restraint was noted on the back of the form in the "remarks" section.~~

~~LER 90-004 did not identify the format and use of the LCO status sheet, as a cause of the violation; therefore, corrective actions have not yet been taken in this regard. The failure to identify and implement adequate corrective actions to preclude repetition is a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," and as such will be followed as:~~

~~VIO 50-424/90-xx-03, "Failure To Determine and implement Adequate Corrective Actions."~~

~~Conclusion~~

~~On the basis of the transcribed interviews and from its review of the outage schedule, the inspection team concluded that the allegation was not fully substantiated. The testimony indicated that the mode change was a critical path item. However, the testimony of the shift superintendent and the unit shift supervisor involved indicated that at the time of the mode change they were not aware that an LCO was in effect on the SRM and that a mode change was prohibited.~~

~~The inspection team also concluded that the corrective actions for the LER failed to identify that the format and use of the LCO status sheets, was one of the causes of the event. Therefore, the failure to implement appropriate corrective actions was found to be a violation of 10 CFR 50, Appendix. B, Criterion XVI.~~

2.3 ~~2.5~~ Backdating of Signatures

An allegation indicated that a temporary change to Abnormal Operating Procedure (AOP) 18028-C, "Loss of Instrument Air," was not approved within the 14-day requirement of TS 6.7.3.c; and that the unit superintendent intentionally incorrectly signed and dated the temporary change to indicate that the TS requirement was satisfied.

Discussion

TS 6.7.3.c requires that temporary changes to AOPs which do not involve changes to the intent of the original procedure be documented and reviewed in accordance with TS 6.7.2 and approved within 14 days of implementation. TS 6.7.2 requires that changes to AOPs be reviewed as stated in administrative procedures and approved by the Plant Review Board (PRB) and general manager. Administrative Procedure 00100-C, "Quality Assurance Records

Administration," Paragraphs 4.1.1.4 and 4.1.1.8, require that corrections to Quality Assurance records exhibit necessary and appropriate signatures, initials, and dates.

Operations Procedure 18028-C, Revision 7, provided operator actions in the event of a loss of the instrument air system. A temporary change to the procedure was initiated on May 29, 1990, to delete the references to the header isolation at 70 psig and the associated actions. This change was processed in accordance with Administrative Procedure 00052-C, "Temporary Changes to Procedures," which allowed the temporary implementation of minor changes to procedures as long as the change was approved by the PRB and signed by the general manager within 14 days of the temporary change. Therefore, Temporary Change Procedure (TCP) 1802-C-7-90-1 was required to be approved by the PRB and signed by the general manager by June 12, 1990.

The PRB tabled the TCP on June 8, 1990, (PRB meeting 90-81) and assigned action to the Operation's Department to void the TCP or revise the TCP to incorporate the PRB comments. Revision 8 to Operations Procedure 18028-C was developed to modify valve numbers and descriptions reflected in Temporary Modifications 1-90-006 and 2-90-002. This revision superseded the changes of the TCP. On June 12, 1990, the PRB approved Revision 8 (PRB meeting 90-82) and the TCP was removed from the control room copies of the procedure. On June 15, 1990, the unit superintendent lined out the operations manager's previous approval of the TCP and marked the TCP form as disapproved by the Operations Department. The date entered on the form was June 12, 1990.

On June 22, 1990, the PRB secretary initiated Deficiency Card (DC) 1-90-282 which indicated that the unit superintendent incorrectly dated the TCP with the date of June 12, 1990, rather than actual date of June 15, 1990, and DC 1-90-283 which indicated that the TCP was not processed within the required 14 days (i.e., by June 12, 1990). The resolution of these DCs, the associated PRB meeting minutes, and discussions with the operations manager and Nuclear Safety and Compliance Department staff indicated that described deficiencies were acknowledged and confirmed by the Operations Department on July 3, 1990, and attributed to personnel error. The TCP form was dated with the date on which the Operations Department decided to void the TCP and not the date on which the original was actually signed.

As part of the corrective actions for DC 1-90-282, a TCP record correction notice was initiated to correctly indicate the date on which the TCP form was processed; however, the TCP record correction notice could not be produced--one was subsequently

written on August 14, 1990. In addition, the operations manager counselled the unit superintendent and assigned him to investigate both DCs because he was the most knowledgeable of the deficiencies and the assignment served to reinforce the reprimand. The subsequent PRB meeting of June 28, 1990, (PRB meeting 90-90) determined that the 14-day TS violation addressed in DC 1-90-283 was reportable to the VEGP vice president, but not to the NRC. However, the inspection team found that the report to the VEGP vice president was not made. On August 9, 1990, the PRB (PRB meeting 90-104) confirmed that the report was required. As of August 17, 1990, the licensee had not issued the required report to the VEGP vice president; however, the licensee intended to issue the report.

With respect to the rationale for the unit superintendent's actions, the inspection team learned (during discussions with the Technical Support Manager) that the PRB secretary told the unit superintendent on June 15, 1990, that the TCP needed to be voided and a DC written for violating the 14-day requirement of TS 6.7.3. As discussed in Section 2.11 of this inspection report, Operations Department personnel are held personally accountable for violations and LERs (i.e., there is a direct impact on their bonus pay); therefore, a reportable occurrence based on this event could have adversely impacted the unit superintendent's salary.

The testimony of the unit superintendent indicated that he dated the TCP with the date (June 12, 1990) on which the PRB disapproved it and not the date on which it was actually signed (June 15, 1990). Additionally, the unit superintendent had no recollection of any discussions on June 15, 1990, regarding violation of the 14-day TS requirement. He indicated that he never considered the 14-day requirement despite his previous knowledge and training concerning this requirement and the June 12, 1990, expiration date indicated on the TCP form.

The testimony of the PRB secretary indicted that during a discussion with the unit superintendent on June 15, 1990, she identified the need to void the TCP, as well as the need to write a DC for violating the 14-day TS requirement. Therefore, the inspection team was concerned about whether the TCP was voided before or after the PRB secretary identified the need to void the TCP and initiate a DC. In order to resolve this discrepancy, the inspection team discussed the discrepancy with the PRB secretary on August 16, 1990. In addition to earlier testimony, the PRB secretary indicated that during her discussions concerning the TCP with the unit superintendent on June 15, 1990, the unit superintendent had indicated that the TCP had already been voided earlier in the day.

Conclusion

On the basis of the testimony, the inspection team concluded that backdating to avoid a violation of the 14-day TS requirement was not ~~fully substantiated. In addition, the concern that this practice was~~ a plant-wide problem. ~~was not fully substantiated~~. However, the inspection team did confirm that TCP 1802-C-7-90-1 had been dated incorrectly; this was a violation of Administrative Procedure 00100-C, "Quality Assurance Records Administration," Paragraphs 4.1.1.4 and 4.1.1.8 and will be followed as:

19-13 19-13
VIO 50-424/90-~~xx-02~~ and 50-425/90-~~xx-02~~, "Failure to Establish or Implement Procedures for Required Activities."

2.4 ~~2.6~~ Reportability of Previous Engineered Safety Features Actuation System Load Sequencer Outages

An allegation indicated that the Operations Department incorrectly used a 72-hour shutdown requirement when one of the two ESFAS load sequencers was previously inoperable. It was also indicated that VEGP had taken no action to ensure that the past occurrences were identified and reported to the NRC as required by 10 CFR 50.73, despite newly acquired information that deenergizing an ESFAS sequencer required entry into the 1 hour limiting condition for operation (LCO) action requirements of TS 3.0.3. In addition, the possibility existed that the LCO for TS 3.0.3 (i.e., 7 hours to hot standby) were exceeded when the sequencers were previously deenergized for maintenance and testing. This concern was based on (1) the lack of a specific TS for the sequencers, (2) the Operations Department historically linking the sequencer outages to the emergency diesel generator (EDG) LCO of TS 3.8.1.1.b (78 hours to hot standby), (3) a limited review of past maintenance work orders (MWOs) indicated possible sequencer deenergization; and (4) comments by the engineering staff that the sequencers had been previously deenergized.

Discussion

There are two ESFAS sequencers for each unit--one for each 4.16-kilovolt (kV) emergency bus. Each sequencer is activated by one of two conditions, undervoltage (UV) on the associated emergency bus or a respective train's safety injection (SI) signal. Upon receipt of either or both of the initiating signals, each sequencer will perform all or part of the following functions:

- Start the associated EDG.
- Stop any test sequence in progress.

- Strip the associated emergency bus of all loads (UV only).

- Close the associated EDG breaker (UV only).

- Energize the associated train's engineered safety features (ESF) loads as determined by the initiating signal.

Each ESFAS sequencer contains three levels of UV detection and system response, as well as the power supply for this UV circuitry. Four potential transformers monitor the emergency bus voltage for these three levels of degraded bus voltage (Level 1, ≤ 70 percent; Level 2, ≤ 86 percent; and Level 3, ≤ 88.5 percent) and furnish an analog signal to three sets of four bistables located in one of the five sequencer cabinets.

Level 1 is the "loss of voltage" and Level 2 is the "degraded voltage" which is referred to in TS Table 3.3-2, Items 6.d, 8.a, and 8.b. As these TS items (applicable in Modes 1 through 4) do not address the loss of all four channels in Level 1 or in Level 2 (as would be the case when the sequencer is deenergized), TS 3.0.3 would apply if such a loss were to occur. It should be noted, however, that if the sequencer were deenergized, it could not respond to a safety injection signal either. Therefore, there would be only one automatic safety injection actuation channel (i.e., associated with the unit's unaffected sequencer) and Item 1.b of TS Table 3.3-2 (6 hours to hot standby) would be the most limiting LCO.

Discussions with the operations manager, the assistant general manager-plant support, and system engineers for the ESFAS and sequencers confirmed that the Operations Department historically linked the sequencer outages to the emergency diesel generator (EDG) LCO of TS 3.8.1.1.b (78 hours to hot standby). Although the applicability of TS Table 3.3-2 and TS 3.0.3 to sequencer outages had been recently identified, past sequencer outages were not reviewed. Therefore, with the assistance of the licensee, the inspection team reviewed the completed MWOs which were performed on the sequencers on Units 1 and 2, as well as the related Instrumentation and Control (I&C), Engineering, and Operations Department surveillance tests.

The review of completed MWOs did identify several instances where the work performed would most likely require the sequencers to be deenergized; however, the associated unit was found to have not been in Modes 1, 2, 3, or 4 at the time the work was performed. Somewhat related to this concern, the review did identify two

occurrences (March 4 and June 17, 1987) where the Unit 1 Train B sequencer was inoperable during the change of sequencer controller card A (SLOT A4-3). Specifically, when the controller card was removed, both the automatic SI function and UV function for the sequencer were rendered inoperable. Because the unit was in Mode 3 (hot standby) during these two occurrences, the sequencers and the ESFAS were required to be operable per TS 3.3.2. However, the associated LCO status sheets (1-87-355, dated March 4, 1987 and 1-87-566, dated June 17, 1987) only recognized TS LCO 3.8.1.1.b as being applicable to the outage. Despite the fact that LCOs associated with TS Table 3.3-2 (Item 1.b) and TS 3.0.3 were not recognized, these TS were not violated since the system was restored within 30 minutes and 10 minutes, respectively. ~~In addition, as the unit remained in hot standby, reportability under 10 CFR 50.72 or 50.73 was not required [i.e., there was no power reduction while in a TS LCO (10 CFR 50.72) nor was the plant taken to hot standby as a result of a TS LCO (10 CFR 50.73)]~~.

Similar to the MWO review, the inspection team's review of related I&C, Engineering, and Operations Department's surveillance tests did not find any examples of the sequencers or the ESFAS being deenergized in Modes 1 through 4. Completed 18-month ESFAS channel calibrations, EDG tests, and ESFAS tests were verified as having been done in Modes 5 and 6. Completed quarterly testing of the ESFAS Auto SI K610 slave relay, which removed the automatic SI signal to the sequencer, were verified to be performed within time limits allowed by TS 3.3.2. All other sequencer testing that used installed test circuitry is automatically bypassed on an SI or UV signal.

In addition to the inspection team's review of MWOs and surveillance test procedures, the system engineers for the sequencers and ESFAS [as well as the nuclear steam supply system (NSSS) supervisor] were asked if they knew of any time in which the sequencers were deenergized in Modes 1 through 4. None of these engineers remembered any such occurrences.

A review of applicable operator training material (System Description 8b for Engineered Safety Features System Sequencers) revealed that there was no reference to ESFAS TS 3.3.2, just those for the diesel and other power sources and distributions (i.e., TS 3.8.1.1, TS 3.8.3.2, TS 3.8.2.1, TS 3.8.3.1, and TS 3.8.3.2.). This finding, along with the March 4 and June 17, 1987, occurrences discussed above, indicates that the Operations Department historically has not linked sequencer outages to the LCOs of TS 3.3.2 or TS 3.0.3. Nevertheless, discussions with the operations manager and the licenced operators on shift indicated that although no written guidance or TS interpretation existed for the

sequencers, the Operations Department staff would currently consider all applicable TS requirements, including TS 3.3.2 and 3.0.3.

Conclusion

The LCO actions of TS Table 3.3-2, "ESFAS Instrumentation," are applicable for determining the operability of ESFAS components; however, if a load sequencer is not operable, the more restrictive requirement of TS Table 3.3-2, TS 3.0.3, or the affected system LCO should be considered. Although the EDG LCO of TS 3.8.1.1.b had been used for sequencer outages in the past, the allegation's concern of possibly exceeding the LCO for TS 3.0.3 when the sequencers were previously deenergized ~~could~~ WERE not ~~be fully substantiated~~. CONFIRMED.

Because there is no specific TS for the sequencers and considering (1) their unique interaction with numerous other systems and equipment, and (2) the varying degrees in which related failures, maintenance work, and surveillances can affect the sequencers' associated functions, the inspection team concluded that additional guidance for the operators is warranted. Therefore, this issue will be followed as an inspector followup item pending further review and evaluation and is identified as:

IFI 50-424/90-~~xx-01~~ 19-15 and 50-425/90-~~xx-01~~ 19-15, "Lack of Operator Guidance Concerning the LCO Actions Applicable During ESFAS Sequencer Outages."

~~2.3 Reliability of Emergency Diesel Generators~~

~~An allegation indicated that VEGP counted the number of starts and failures of the EDGs incorrectly and misrepresented this information knowingly in (1) a verbal presentation to the NRC, (2) a formal response to the Region II confirmation of action letter (CAL), and (3) LER 90-006, Revision 0, issued following the March 20, 1990, event involving failures of the EDG #1A. In addition, it was alleged that VEGP attempted to confuse the EDG reliability issue with Revision 1, and delayed LER 90-006, Revision 1, in order to avoid drawing attention to these incorrect representations.~~

~~Discussion~~

~~The inspection team reviewed the following:~~

1) VEGP presentation in the Region II Office on April 9, 1990, concerning the site area emergency event of March 20, 1990. This presentation is identified as Enclosure 2 to the Region II meeting summary letter of May 14, 1990.

2) VEGP letter dated April 9, 1990, in response to the Region II confirmation of action letter (CAL) dated March 23, 1990.

3) LER 90-006, issued April 19, 1990, to report the site area emergency event of March 20, 1990.

These documents and the following procedures describe the EDG operability status and the licensee's program for recording EDG start information and the EDG surveillance test frequency requirements:

- Procedure 55038-C, "Diesel Start Log"
- Procedure 13145-1, "EDG Operation for Maintenance Troubleshooting or Maintenance Testing"
- Procedure 14980-1, "EDG Operability Test"

The licensee indicated in a transparency used during the Region II presentation that there were 18 successful starts on EDG #1A and 19 successful starts on EDG #1B between the loss-of-offsite-power event (March 20, 1990) and the presentation to Region II of April 9, 1990. The inspection team reviewed the EDG start logs and the detailed EDG start records completed during the performance of Surveillance Procedures 13145-1 and 14980-1. The inspection team's review of these records indicated that there were 31 EDG #1A and 29 EDG #1B attempted starts. Two of the EDG #1A and eight of the EDG #1B starts involved problems or failures. On EDG #1A there were a total of 29 successful starts and on EDG #1B there were 21 successful starts. However, there were several intermittent problems or failures during the EDG #1B start attempts. Although there were 29 successful, sequential starts on EDG #1A, the inspection team identified that there were only 12 successful, sequential starts of EDG #1B during this time period.

TS 4.8.1.1.2.a requires that each EDG be demonstrated operable in accordance with the periodicity specified in TS Table 4.8-1 by verifying that the EDG starts and assumes rated frequency and voltage in accordance with the EDG surveillance test. This surveillance test required a minimum run time of 1 hour at a designated load. The inspection team found that at the time of the presentation to the NRC, the operability test of the EDGs had been successfully demonstrated two times. In addition, the EDGs had

successfully passed four operability tests before Unit 1 entered Mode 2. Therefore, the EDGs were reliable and operable before the presentation.

The NRC Region II Office was not verbally informed of the incomplete information regarding the number of EDG starts until June 11, 1990 (approximately 2 months after the presentation). Although Revision 1 of LER 90-006, dated June 29, 1990, correctly identified the number of sequential, successful EDG starts from the end of the maintenance test program (i.e., the first successful operability test per TS 4.8.1.1.2a) until the issuance of LER 90-006, Revision 0, dated April 19, 1990, this revision (June 29, 1990) did not address the number of EDG starts that should have been cited in the presentation, in the VEGP letter in response to the CAL, and in LER 90-006, Revision 0. The correct number of sequential, successful starts for EDG #1B was 12 and not 19 as indicated in the presentation. Therefore, the NRC was not informed of the correct information in a timely manner.

The information presented to the NRC did not completely describe the problems and failures that occurred with EDG #1B. However, the testimony indicates that the general manager's intention was to demonstrate that the problems involving the immediate trip of EDGs identified during and following the March 20, 1990 event were corrected prior to Unit 1 startup. Therefore, a compilation of the total number of successful starts (i.e., a start that did not immediately trip) was an important factor in his presentation.

The testimony also indicated that the unit superintendent (US) researched the EDG starting history for the NRC presentation based on a request from the general manager. The general manager did not ask the US to prepare a complete description of the EDG starting history. Specifically, the general manager requested a summary of only the successful starts--the information concerning the EDG problems and failures was not requested. In addition, the US used the unit reactor operator logs instead of the EDG operating logs to compile the EDG starting history. The reactor operator logs did not contain a detailed description of problems or failures which occurred during the EDG starts. The US did not receive specific guidance concerning the type of EDG starts that he was requested to summarize. In addition, the testimony indicated that the original assumptions and EDG #1B start information used in the presentation were also used in the VEGP response to the CAL, and in LER 90-006 issued April 19, 1990.

The inspection team's review of the Unit 1 EDG's reliability and operability status between March 21 and June 14, 1990, raised the following additional concern. The review was performed to verify

that all EDG failures were identified and classified as either valid or non-valid and were reported to the NRC as required by TS 4.8.1.1.3 and TS 6.8.2. The inspection team discovered that the following failures during starts of EDG #1B had not been classified as valid or non-valid and, consequently, had not been reported to the NRC pursuant to TS 4.8.1.1.3 and TS 6.8.2.

EDG Start	Date	Remarks
1-90-132	3/22/90	EDG trip, high-temperature lube oil. Maintenance troubleshooting test.
1-90-134	3/23/90	EDG trip, low jacket water pressure. Maintenance troubleshooting test.
1-90-136	3/24/90	EDG intentionally stopped due to alarmed condition, high jacket water temperature. Maintenance troubleshooting test.
1-90-157	5/23/90	EDG trip, high jacket water temperature Maintenance troubleshooting test.
1-90-160 -161 -162	5/23/90	EDG trip, low turbocharger oil pressure. Maintenance troubleshooting test.
1-90-164 -165	5/23/90	EDG trip, high jacket water temperature. Maintenance troubleshooting test.

These inspection findings were discussed with the engineering support manager who agreed that these types of failures have not been reported. The licensee committed to have all EDG start records reviewed for any unreported failures.

The inspection team also found that a violation was previously identified for the failure to report all EDG failures in Inspection

~~Report 50-424/87-57 dated November 1987. Although the failure to report all EDG failures is a violation of TS 3.8.1.1.3 and TS 6.8.2, the inspection team concluded that the failure was the result of inadequate implementation of corrective actions to prevent recurrence of a violation and, as such, is a violation of 10 CFR 50 Appendix B, Criterion XVI, "Corrective Actions," and will be followed as:~~

~~VIO 50-424/90-xx-03, "Failure to Determine and Implement Adequate Corrective Actions."~~

~~Conclusion~~

~~The allegation that VEGP incorrectly counted the number of starts and failures of the EDGs and knowingly misrepresented the EDG reliability in order to mislead the NRC was partially substantiated. On the basis of the sworn testimony and its review of EDG records, the inspection team concluded that the Region II presentation was not intended to represent a specific number of successful valid tests as specified in RG 1.108 and TS 4.8.1.1.2a, but rather to describe the EDG maintenance test program and the EDG reliability status. Nevertheless, the inspection team concluded that the NRC was not informed of the incorrect information until the NRC asked for it during the inspection. The lack of specific guidance concerning the EDG information desired, coupled with inadequate research of the EDG starting history, resulted in providing incomplete and therefore inaccurate information to the NRC. The CAL response and LER 90-006 were also incorrect because they were based on the EDG start information that was compiled for the VEGP presentation in the Region II Office. The inspection team concluded that the failure to provide accurate information to the NRC was a violation of 10 CFR 50.9 requirements and will be followed as:~~

~~VIO 50-424/0-xx-05; 50-425/90-xx-05, "Failure to Provide Accurate Information to the NRC."~~

2.5 ~~2.6~~ Air Quality of Emergency Diesel Generator Starting Air System

An allegation indicated that VEGP had no basis for its conclusions regarding the air quality of the EDG starting air system and misrepresented the air quality in the licensee's written response to the CAL.

Discussion

The inspection team reviewed the maintenance records and deficiency cards associated with Unit 1 EDG starting air system. The team

noted that the maximum dewpoint reading of 50 degrees Fahrenheit was established when preoperational tests were initially performed on Unit 1 in November 1986. Dewpoint measurements were taken after this date, but not on a scheduled frequency. During the latter part of 1988, a monthly preventative maintenance (PM) schedule was established to measure the EDG starting air system dewpoint. The current PM program required checking the dewpoint monthly, cleaning the air dryer condensing units, and cleaning the fan motors. In addition, Operating Procedure 11882-1, "Outside Area Rounds," required that the EDG starting air system air receivers and air dryers be blown down on a daily basis until they were free of moisture. The inspection team verified that the plant equipment operators blew down the air systems on each shift during the performance of their rounds.

A review of the Unit 1 EDG maintenance history records indicated that the majority of the dewpoint measurements taken were within specifications. There were instances, however, when the dewpoint measurements were above specifications. These conditions were primarily attributed to problems with (1) the dewpoint measuring instruments, (2) system air dryers being out of service for extended periods of time, and (3) repressurizing the EDG air start system following maintenance.

The inspection team reviewed maintenance records associated with an internal inspection of the EDG air start system air receiver, 5-micron control air system filter inspection and replacement, and the replacement of the dewpoint measuring instrument with an EG&G analyzer. Following the loss of offsite power event of March 20, 1990, the control air system instrument lines were disconnected for maintenance troubleshooting and functional tests of Calcon sensors. The system engineers associated with this work stated that no evidence of internal moisture or corrosion was noted during inspection and calibration of the Calcon sensors or the control air system instrument lines when this equipment was disconnected for maintenance troubleshooting and testing.

<u>Conclusion</u>

The inspection team concluded that the licensee did have an adequate basis to assess the quality of the EDG starting air system. This was based primarily upon the records of the visual inspection of EDG air start system components for degradation. In addition, the PM program dewpoint readings have shown more consistency since the licensee changed over to an EG&G analyzer. The allegation that VEGP did not have a basis for their statements concerning EDG air start system quality was not ~~fully~~ ~~substantiated.~~ CONFIRMED.

Licensee Representation to NRC of D/G Air Quality is subject to further NRC investigation.

2.6 ~~2.9~~ Reportability of Previous System Outages

An allegation indicated that VEGP failed to immediately notify the NRC as required by 10 CFR 50.72 when VEGP identified that both trains of the containment fan coolers (CFCs) had been previously inoperable at the same time on Unit 1.

Discussion

The inspection team's review of plant records indicated that this condition occurred when EDG #1A was declared inoperable when tape (used when the EDG was being painted) was found on the EDG fuel rack. The tape kept the fuel injector piston from moving and injecting fuel into the EDG. With EDG #1A inoperable, the equipment associated with the Train A was also inoperable. In the process of investigating the installation of the tape, VEGP identified that this condition existed during a period when the Train B containment fan coolers were also in a degraded condition for maintenance.

During the performance of Surveillance Procedure 14623-1, Train B containment fan cooler (CFC) 1-1501-A7-003 failed to start in slow speed. LCO 1-90-560 was initiated at 0115 hours on June 19, 1990, and maintenance on the CFC was initiated. The CFC was returned to operable status on June 19, 1990, at 1415 hours. Approximately 9 hours later [on June 19, 1990, at 2359 (LCO 1-90-562)], EDG #1A was determined to be inoperable because the tape had been installed on the fuel rack. On July 17, 1990, VEGP issued LER 90-014 to identify the previously unrecognized violation of the LCO in accordance with 10 CFR 50.73.

Conclusion

Based upon the fact that VEGP did not become aware that both trains of CFCs were simultaneously inoperable until after the Train B CFC fan had been returned to service, the immediate notification requirements of 10 CFR 50.72 were not applicable. The allegation that VEGP failed to immediately notify the NRC upon discovery of the previously degraded condition of the CFCs was not ~~fully~~ ~~substantiated.~~ CONFIRMED.

2.7 ~~2.10~~ Intimidation of Plant Review Board (PRB) Members

An allegation indicated that Plant Review Board (PRB) members were allegedly intimidated and pressured by the general manager in a PRB meeting. The meeting occurred in February 1990, to determine the

acceptability of the safety analysis for the installation of the FAVA microfiltration system.

Discussion

As discussed in Section ~~2.2~~ 2.1 of this inspection report, several safety evaluations were performed for the installation of a temporary modification which installed the FAVA microfiltration system. Discussions with PRB members indicated that during the review of these safety evaluations, various PRB members had expressed reservations on several occasions concerning the acceptability of the installation of the FAVA system.

Despite these reservations, the inspection team's review of the PRB Meeting minutes associated with this temporary modification identified few instances of the PRB members documenting their dissenting opinions. Specifically, PRB meeting 90-15 (dated February 8, 1990) documented one PRB member's negative vote and dissenting opinions regarding the acceptability of exempting the temporary modification from regulatory requirements and the adequacy of the system's safety evaluation. PRB Meeting 90-28 (dated March 1, 1990) indicated that information and issues regarding the FAVA system's safety analysis were presented to the PRB and that the general manager solicited written comments and questions from other members for resolution. The only other example was in PRB meeting 90-32 (dated March 6, 1990) which identified a dissenting opinion related to the acceptability of voting on the FAVA system installation when the PRB member who raised the initial questions and concerns on the operation of the FAVA system was not present.

Discussions with the PRB members indicated that during the various PRB meetings concerning the installation of the FAVA system, the PRB members felt intimidated and pressured by the presence of the general manager at the PRB meeting. The sworn testimony confirmed that on one occasion an alternate voting member felt intimidated and feared retribution or retaliation because the general manager was present at the meeting and the PRB member knew the general manager wanted to have the temporary modification approved. However, the testimony also indicated that the PRB member did not alter his vote and felt comfortable with how he had voted. In addition, the PRB member was not aware of any occasions on which he or any other PRB member had succumbed to intimidation or feared retribution.

The inspection team verified that the general manager was informed following this meeting that several PRB members viewed his presence as intimidating. As a result, on March 1, 1990, the general

manager met with all PRB members to reiterate the member's duties and responsibilities. He specifically told the members that his presence at PRB meetings must not influence them and that alternates should be selected who would feel comfortable with this responsibility. He also addressed the difference between professional differences of opinion and safety or quality concerns, and their respective methods for resolution.

Conclusion

The inspection team concluded that in one case a PRB voting member felt intimidated and feared retribution because the general manager was present at the PRB meeting. However, this member stated that he did not change his vote in response to this pressure and the general manager met with the PRB to allay fears. Based on the testimony, the inspection team concluded that retribution did not occur. Nevertheless, this confirmed event and the absence of dissenting opinions in the PRB meeting minutes indicate that there was a potential for an adverse affect on open discussions at the meeting. The licensee needs to ensure that PRB members freely and openly express their technical opinions and safety concerns.

2.8 ~~2.11~~ Personnel Accountability

As a result of several comments and questions by the licenced operators to the inspection team, the team reviewed the method used to rate the performance of the shift superintendents and unit shift supervisors.

Discussion

The operations manager stated that the shift superintendents (SSs) reported directly to the operations manager and that he personally prepared their performance appraisals. The inspection identified that the SSs reported to the unit superintendent (US), and that the US personally prepared the performance appraisals of the SSs.

The personnel accountability system, first used in 1989, was a pay-for-performance methodology. Annual pay increases and a percentage of the Operations Department bonus were dependent on their ratings in accountability categories. Each accountability category was subdivided into performance categories. Most of the performance categories were based upon group performance. Once these are eliminated, any differential in pay will result from eight performance categories. Implementation of the plan in 1989 could result in up to an $8,000-a-year difference in bonus pay to a shift superintendent. The performance categories and their relative weights are:

• Personnel safety	4.1%
• Regulatory compliance	10.2%
• ESFAS actuation	12.2%
• Reactor trips	10.2%
• MWO performance	4.1%
• Special projects	8.2%
• Personnel development	30.6%
• Training	20.4%

Therefore, 51 percent will be associated with personnel development and training and 32.6 percent will be associated with the number of LERs, and violations [i.e., regulatory compliance (10.2 percent), ESFAS actuation (12.2 percent) and reactor trips (10.2 percent)].

Conclusion

The inspection team concluded that there was a potential disincentive for identifying items which may result in LERs or violations. In addition, the inspection team concluded that the operations manager provided incorrect or inadequately researched information to the inspection team. The inaccurate information concerned whether the operations manager personally performed the performance appraisals of shift superintendents. The information was not very important because the inspection team did not use the information as the basis for a significant inspection finding. The inspection team concluded that this failure to provide accurate information was an example of a violation of the 10CFR 50.9 requirements to provide accurate information to the NRC and will be followed as:

VIO 50-424/90-~~xx-05~~ 19-12; 50-425/90-~~xx-05~~ 19-12, "Failure to Provide Accurate Information to the NRC."

3.0 EXIT INTERVIEWS

The inspection scope and findings were summarized on August 17, 1990, with those persons indicated in Appendix 2. The inspection team described the areas inspected and discussed in detail the inspection results. The licensee made numerous dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during this inspection.

APPENDIX 3

LIST OF TRANSCRIBED INTERVIEWS

DATE	TIME	PERSON
8/14/90	904 hours	George Bockhold
	911 hours	Jim Swartzwelder
	1023 hours	Harvey Handfinger
	1026 hours	Bill Diehl
	1109 hours	Mike Horton
	1335 hours	Mike Chance
	1136 hours	Jimmy Paul Cash
	1338 hours	Dudley Carter
	1529 hours	Bruce Kaplan
	1625 hours	Greg Lee
	1800 hours	Jeff Gasser
8/15/90	906 hours	Allen Mosbaugh
	937 hours	Ernie Thornton
	1009 hours	John Gwin
	1048 hours	Steve Waldrup
	1335 hours	Jerry Bowden
	1452 hours	John Williams
	1637 hours	Carolyn Tynan
	1730 hours	John Williams

APPENDIX 2

PERSONS CONTACTED

Licensee Employees

*J. Aufdenkampe, Manager Technical Support
*G. Bockhold, Jr., General Manager Nuclear Plant
*D. Carter, Shift Superintendent
J. Bowden, Work Planning
J. Cash, Unit Superintendent
M. Chance, Senior Engineer, Engineering Support
*S. Chesnut, Technical Support
C. Coursey, Maintenance Superintendent
W. Diehl, Shift Supervisor, Operations
*G. Frederick, Safety Audit and Engineering Group Supervisor
J. Gasser, Shift Superintendent, Operations
*L. Glenn, Manager - Corporate Concerns
*D. Gustafson, Maintenance Engineering Supervisor
J. Gwin, Corporate System Engineer
*H. Handfinger, Manager Maintenance
*K. Holmes, Manager Training and Emergency Preparedness
*M. Horton, Manager Engineering Support
B. Kaplan, Senior Engineer, Engineering Support
G. Lee, Plant Engineering Supervisor, Operations
*R. LeGrand, Manager Health Physics and Chemistry
W. Lyons, Quality Concerns Coordinator
*G. McCarley, Independent Safety Engineering Group Supervisor
*C. McCoy, Vice-President, Georgia Power Company
*R. McDonald, Executive Vice-President, Georgia Power Company
*D. Moncus, Outage and Planning
*A. Mosbaugh, VEGP Staff
R. Odom, Nuclear Safety and Compliance Manager
*A. Rickman, Senior Engineer - Nuclear Safety and Compliance
*L. Russell, Independent Safety Engineering Group, SONOPCO
*M. Sheibani, Senior Engineer
*C. Stinespring, Manager Plant Administration
*S. Swanson, Outage and Planning Supervisor
*J. Swartzwelder, Manager Operations
E. Thorton, Shift Supervisor, Operations
*E. Toupin, Oglethorpe Power Corporation
C. Tynan, PRB Secretary
S. Waldrup, Planning and Scheduling Supervisor
J. Williams, Shift Superintendent, Operations

* Attended exit interview, August 16, 1990.

APPENDIX 2

PERSONS CONTACTED (continued)

NRC Employees Who Attended Exit Interview

R. Aiello, Resident Inspector - Vogtle
B. Bonser, Senior Resident Inspector - Vogtle
M. Branch, Senior Resident Inspector - Watts Bar
K. Brockman, Chief, Reactor Projects Section 3B - RII
R. Carroll, Project Engineer - RII
L. Garner, Senior Resident Inspector - Robinson
N. Hunemuller, Reactor Engineer - NRR
D. Matthews, Project Director - NRR
J. Milhoan, Deputy Regional Administrator - RII
L. Reyes, Director Division of Reactor Projects - RII
R. Starkey, Resident Inspector - Vogtle
P. Taylor, Reactor Inspector - RII
M. Thomas, Reactor Inspector - RII
C. VanDenburgh, Section Chief - NRR
J. Wilcox, Operation Engineer - NRR

APPENDIX 3

LIST OF ACRONYMS

AOP	Abnormal Operating Procedure
ARB	Alternate radwaste building
ASME	American Society of Mechanical Engineers
CAL	Confirmation of action letter
CFC	Containment Fan Cooler
CFR	Code of Federal Regulations
CIV	Containment isolation valve
DC	Deficiency card
DRP	Division of Reactor Projects
EDG	Emergency diesel generator
EPRI	Electric Power Research Institute
ESF	Engineered safety features
ESFAS	Engineered safety features actuation system
FSAR	Final Safety Analysis Report
HUT	Holdup tank
I&C	Instrumentation and controls
IFI	Inspector followup item
IST	Inservice test
kV	Kilovolt
LCO	Limiting condition for operation
LER	Licensee Event Report
MWO	Maintenance work order
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSCW	Nuclear service cooling water
NSSS	Nuclear steam supply system
OI	Office of Investigations
PM	Preventative maintenance
PRB	Plant Review Board
psig	Pounds per square inch gauge
PVC	Polyvinyl chloride
QA	Quality Assurance
RII	Region II Office
RCS	Reactor coolant system
REA	Request for engineering assistance
RG	Regulatory Guide
RHR	Residual heat removal
SER	Safety Evaluation Report
SI	Safety injection
SONOPCO	Southern Nuclear Operating Company
SRM	Source range monitor
SS	Shift superintendent
SSS	Shift support supervisor

APPENDIX 3

LIST OF ACRONYMS (continued)

STS	Surveillance task sheet
TCP	Temporary change to procedure
TS	Technical Specification
USS	Unit shift superintendent
UV	Undervoltage
VEGP	Vogtle Electric Generating Plant
VIO	Violation