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

Report Nos.: 50-321/90-25 and 50-366/90-25

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

Docket Nos.: 50-321 and 50-366 License Nos.: DPR-57 and NPF-5

Facility Name: Hatch Nuclear Plant

Inspection Conducted: November 18 - December 15, 1990

Inspectors: S. E. Sparks for 1/8/91
Leonard D. Wert, Jr., Sr. Resident Inspector Date Signed

S. E. Sparks for 1/8/91
Randall A. Musser, Resident Inspector Date Signed

Approved by: Ken E. Brockman 1/8/91
Ken E. Brockman, Chief, Projects Section 3B Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations, maintenance activities, surveillance testing, allegation followup, inadequate fire protection program implementation procedures, and review of open items.

Results: Two non-cited violations were identified and reviewed during the inspection:

Licensee identified NCV 90-25-01: Incorrect Revision to FHA Resulting in Inadequate Fire Protection Program Implementation Procedures. (paragraph 6)

NRC identified NCV 90-25-02: Failure to Properly Report Loss of the ENS. (paragraph 2.b)

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *C. Coggin, Training and Emergency Preparedness Manager
   D. Davis, Plant Administration Manager
   *D. Edge, Nuclear Security Manager
   *P. Fornel, Maintenance Manager
   *O. Fraser, Safety Audit and Engineering Review Supervisor
   G. Goode, Engineering Support Manager
   M. Googe, Outages and Planning Manager
   *J. Hammonds, Regulatory Compliance Supervisor
   *J. Lewis, Operations Manager
   C. Moore, Assistant General Manager - Plant Support
   D. Read, Assistant General Manager - Plant Operations
   *H. Sumner, General Manager - Nuclear Plant
   *S. Tipps, Nuclear Safety and Compliance Manager
   R. Zavadoski, Health Physics and Chemistry Manager

   Other licensee employees contacted included technicians, operators, mechanics, security force members and staff personnel.

   NRC Resident Inspectors

   *L. Wert
   *R. Musser

   NRC management/officials on site during inspection period:

   K. Jabbour, Hatch NRR Project Manager
   D. Hood, alternate Hatch NRR Project Manager
   D. Matthews, Director, NRR PD II-3

   *Attended exit interview

   Acronyms and initials used throughout this report are listed in the last paragraph.

2. Plant Operations (71707)

   a. Operational Status

      Both units operated at power during the entire reporting period. At the end of the report period Unit Two had operated at power continuously for over 260 days. The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification logs, LCO logs and equipment clearance records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, I&C, and NSAC personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the Safety Parameter Display system were monitored. Control Room observations also included ECCS system lineups, containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls. Numerous informal discussions were conducted with the operators and their supervisors. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's administrative procedures. The complement of licensed personnel on each shift met or exceeded the requirements of TS.

Several safety-related equipment clearances that were active were reviewed to confirm that they were properly prepared and executed. Applicable circuit breakers, switches, and valves were walked down to verify that clearance tags were in place and legible and that equipment was properly positioned. Equipment clearance program requirements are specified in licensee procedure 30AC-OPS-001-0S, "Control of Equipment Clearances and Tags." No major discrepancies were identified.

Selected portions of the containment isolation lineup were reviewed to confirm that the lineup was correct. The review involved verification of proper valve positioning, verification that motor and air-operated valves were not mechanically blocked and that power was available (unless blocking or power removal was required), and inspection of piping upstream of the valves for leakage or leakage paths.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Reactor Buildings
Station Yard Zone within the Protected Area
Turbine Building
Intake Building
Diesel Generator Building
Fire Pump Building

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

On November 26, 1990, the inspector noted that a security guard temporarily stationed at the CR door to control access during modification work on the security system (a major system upgrade is in progress and the card reader was out of service) was not rigorously verifying all security badges with the access list to ensure each individual was permitted CR access. This was discussed with security management onsite and the problem was promptly corrected. All personnel requesting access were screened against the access list as required. The inspectors observed strict and thorough adherence to this practice during the remainder of the modification work which rendered the CR reader inoperable. This case is considered an isolated instance. The inspectors have noted a significant amount of planning and coordination effort has been made by security personnel to ensure the system upgrade is completed without a reduction in site security.

During this inspection period, one of the inspectors, along with several NRR personnel and the Region II Hatch project engineer, attended a 1 1/2 day session conducted by the licensee to provide fundamental EOP indoctrination. The session included one day of classroom lecture addressing each major portion of the EOP and several hours of demonstrations of EOP utilization by a training crew in the simulator. All participants regarded the session as extremely beneficial and worthwhile.

The inspectors reviewed a sampling of issues on which Discrepancy Cards had been submitted to verify that the licensees' corrective action program was performing as expected. The resolution of several issues involving the Unit One Fission Product Monitoring System was reviewed. Several of the problems were followed daily by the inspectors as they were resolved while others were examined after resolution had been initiated. On November 27, 1990, the Unit One FPM Noble Gas Sampler Vacuum Pump was found tripped. DC 1-90-7507 was submitted which addressed the vacuum pump problem. Additionally, DC 1-90-7507 was written to address the fact that the HI/LO flow annunciator had not been received in the CR when the pump tripped. The failure of the alarm is apparently due to a system design problem in that flow from another sample pump is sufficient to keep the alarm from actuating. The malfunctioning pump motor was replaced and tested on November 28, 1990, in accordance with MWO 1-90-7703. SOR 1-90-296 was initiated to address the flow alarm problems. The inspectors concluded that corrective actions addressing these issues were prompt and thorough.

On December 4, 1990, during observation of CR activities, the inspector noted that the operators failed to follow procedures during resetting of a locked recirculation pump scoop tube. The operators were utilizing an alarm response procedure which directed the operators to refer to the resetting the scoop tube section of 34SO-B31-001-1S: Reactor Recirculation System. Section 7.3.2 of this procedure required both recirculation pump speed control switches to be placed in manual. This step was not performed. The inspector questioned whether the procedural guidance was correct or if the operator simply failed to adhere to the procedure. After reviewing the issue, operations management informed the inspector that the procedure would be changed. There was no reason to place both switches in manual during this evolution. Additionally, potentially confusing guidance in the ARP will also be revised. The inspectors consider this case to be an example of failure to follow procedure brought about by a less than adequate procedure. The operator, well aware of how to complete the evolution, failed to question the apparent conflict within the procedural guidance. The evolution was performed safely, without any complications, and in the manner which the procedure should have specified. Enforcement action is not appropriate.

b. Failure to Properly Report Loss of the ENS (71707) (93702)

On December 12, 1990, the site experienced a loss of communications event. The problem was initiated at approximately 2:15 p.m. when the land line telephone system trunk line to Baxley was cut about five miles south of the site by a back hoe operator. This was not known during the initial portion of the event but was determined at a later time.

At approximately 2:35 p.m., an NRC Region II inspector (onsite as part of an ALARA team inspection) informed the licensee that the residents office ENS phone was not functioning. He was not aware of any other communications problems at that time. The CR operators immediately identified that the ENS phone in the CR was also not operable. Licensee EP personnel onsite investigated the magnitude of the problem, and when ENN problems were identified, they coordinated contact with local agencies through standby means. At about 2:50 p.m., EP informed the SOS that the ENS, ENN, and Bell lines (land lines) were apparently inoperable. Due to some misunderstanding by onsite personnel, it was believed that the Bell lines were not lost. The microwave system had remained operable and calls had been successfully made to Vidalia by several personnel who had upgraded phone lines which utilized the microwave system. The SOS and NSAC manager indicated that, consistent with longstanding practice and existing plant procedure, the ENN or ENS outage was not reportable to the NRC as long as the backup Bell line capability was available. However, during this time, the microwave system was being utilized to conduct long distance phone calls.

Toombs County and Appling County were expeditiously contacted by civil defense radio and informed of the ENN problem. Site EP personnel and corporate EP contacted both the Tattnall and Jeff Davis EMAS by phone. These agencies were also contacted via GEMA and their ENN system because of initial problems in contacting these counties by radio. Subsequently, it was determined the Tattnall county EMA had not been reached from Hatch by civil defense radio because their antenna had been removed from service. The Jeff Davis EMA was not manned at the time and the 24-hour contact (Hazlehurst Police Department) did not respond to the radio. Once contacted by phone, both of these agencies' radio systems were manned and operable. As of 3 :1 Hatch EP personnel had confirmed by mobile radio telephone that all counties were aware of the issue and monitoring their radios.

At about 3:50 p.m., it became clear that the back-up Bell lines were unavailable. At that time NSAC personnel felt that 10 CFR 50.72 (b)(1)(v) required a report. At 4:10 p.m., the SOS utilized the microwave system to inform the NRC Operations Center of the event. By 8:30 p.m. that day, all phone lines had been repaired and the ENS, ENN and Bell phone restored to operability.

The inspectors primary concern in this issue is that Operations Shift personnel did not realize the full magnitude of this loss of communications. Procedural guidance did not provide adequate directions to fully assess the scope of the problem once it was identified. Dayshift EP personnel were extensively involved in the resolution process. Due to a misunderstanding, the Bell line inoperability was not identified until later in the incident.

Another concern is that the reporting requirements of 10 CFR 50.72 (b)(1)(v) apparently were not met. The ENS was known to be inoperable for a period of about 90 minutes without a 50.72 notification being made. This was because NSAC and operations onshift personnel had interpreted 50.72 (b)(1)(v) to require a report only if the backup (Bell) system was also inoperable. This interpretation had been made by applying judgement and assessing a simple loss of ENS as not being a "major loss of communications capability," even though the ENS is specifically listed as an example. It should be noted that the microwave system, radio system, and several mobile telephones were available for use at all times during the incident.

Discussions were held with regional management and EP personnel on the issue. NRR personnel familiar with the requirements of 50.72 were also contacted. It was confirmed that loss of the ENS is, in itself, a reportable event. On December 17, the licensee issued a standby order containing guidance to CR personnel on how to assess a loss of communication event. While this document will ensure future communications issues are more promptly and thoroughly followed up, the guidance still did not require a 50.72 report on loss of the ENS. On December 18, the inspectors informed NSAC personnel that losses of the ENS are reportable as indicated in 50.72 (b)(1)(v). Management indicated procedures would be promptly changed to reflect this requirement.

The failure to report the loss of the ENS within an hour is a violation of 50.72 (b)(1)(v). This violation was apparently caused by a long standing interpretation by the licensee that only a loss of the ENS along with a loss of its backup system would be reportable.

This NRC-identified violation is not being cited because the criteria specified is Section V.A. of the Enforcement Policy were satisfied. NCV 90-25-02: Failure to Properly Report Loss of ENS will be utilized to track this issue.

Violation 90-18-02: Failure to Report an ESF Actuation, was issued in October 1990 and addressed the failure to report inadvertent ES actuations. This issue also involved a failure to correctly interpret the requirements of 50.72. The corrective action for that violation was primarily to revise all guidance to ensure the reporting of all ES actuations. This corrective action, which appeared adequate at the time, would not be expected to prevent the most recent violation from occurring.

One NCV was identified.

3. Surveillance Testing (61726)

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

The following surveillances were reviewed and witnessed in whole or in part:

(1) 34SV-R43-005-2S: EDG '1B' Semi Annual Test

(2) 34SV-E51-002-1S: RCIC Pump Operability Test

(3) 34SV-R43-001-2S: EDG '2A' Monthly Test

4. Maintenance Activities (62703)

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify; proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

The following maintenance item was reviewed and witnessed in part:

MWO 1-90-7476: Investigate/Repair '1A' EDG Jacket Coolant Inleakage problem IAW 52PM-R43-015-0S.

No violations or deviations were identified.

5. Allegation Followup

During this report period, the inspectors investigated a recent allegation. The allegation involved "poor looking welds on a stainless steel pipe in the reactor building". The inspectors located a pipe which was most probably the subject pipe, based on the brief description provided. The pipe was stainless steel, of the diameter specified, and was located just inside an access door to the RB. The inspectors determined that this pipe was part of the RB roof drain system. The pipe conveys the drainage collected from the individual roof drain lines to the yard drain system.

Based on two separate inspectors observations, the welds did not appear to be "poor" in appearance. The inspectors asked onsite welding engineering personnel if any work had recently been perform[illegible] on the welds on this pipe. The licensee's response, and furt[illegible]gation into maintenance involving this pipe, indicated that no [illegible] performed on this pipe recentl[illegible]

Inspection Report 50-321,366/89-02 (Maintenance Team Inspection) contains a discussion of poor welding inspection practices involving a patch on a portion of this pipe which had been welded on in 1985. The inspection team closely examined the licensee's weld inspection program and its implementation. NCV 50-366/89-02-08 addressed the isolated case of failure to follow welding acceptance criteria involving the patch. No additional concerns of any type other than "poor looking welds" were involved in this allegation.

The inspectors concluded that no further investigation into this allegation is required.

6. Inadequate Fire Protection Program Implementation Procedures (64704, 92700)

The inspectors reviewed Special Report 50-366/1990-003: Fire-Rated Assemblies Inoperable without an Hourly Fire Watch Maintained Results in Special Report, as required by Fire Hazards Analysis. The report was submitted on November 15, 1990, and addressed a condition in which two Unit Two fire doors were inoperable without the required hourly fire watch being maintained. The event occurred due to inadequate review of a recent change to the FHA which resulted in incorrect procedural guidance concerning fire door compensatory measures.

Appendix B of the Hatch Nuclear Plant FHA contains the fire protection equipment operating and surveillance requirements. Operating Requirement 1.1.1 specifies that the fire-rated assemblies and sealing devices in fire-rated assembly penetrations separating safety-related fire areas or separating portions of redundant systems important to safe shutdown within a fire area shall be operable. Tables 1.1.-1 and 1.1-2 list the Unit One and Unit Two fire doors. Action Statements 1.1.1.a and 1.1.1.b contain compensatory and reporting requirements.

In July 1989, a change was made to Appendix B of the FHA (as a result of site initiated Document Change Request (DoCR) 89-04) which revised these tables and the requirements of Section 1.1.1. The change added asterisks to the listing of fire doors to designate the doors to which the requirements of Section 1.1.1 applied. Intentions were to eliminate unnecessary surveillances and to facilitate implementation of the requirements by CR operators.

On October 24, 1990, in response to a concern raised by plant SAER personnel (as a result of a scheduled SAER audit), it was determined that fire doors 2C05 and 2C05a had been inoperable for over five days without the required fire watch. These doors are located on the inside/outside of a wall between the Unit Two oil storage room and the working floor of the control building. Additional review indicated that Tables 1.1-1 and 1.1-2 did not properly annotate all appendix B fire doors. Fire doors 2C05 and 2C05a were two examples of several doors which were not marked by asterisks and should have been. On November 1, 1990, Operating Order OO-02-1090S was issued. It required all fire doors in Tables 1.1.-1 and 1.1-2, whether asterisked or not, to be treated as Appendix B doors. The resident inspectors were informed of this issue at that time.

The inspector's major concern in this issue is the apparent inadequate review utilized during the DoCR process which permitted the Appendix B requirements to be incorrectly revised. This concern was discussed with NSAC personnel onsite and at the corporate office. The incorrect revision resulted in the possibility that various fire doors could be inoperable without the proper compensatory actions. This situation existed from July to November 1989. The licensees' Special Report states that about 60 percent of the fire doors had been removed from the Appendix B, Section 1.1.1 requirements without adequate justification. The licensees corrective actions, once the issue was identified, were both prompt and comprehensive;

- Special Report 50-366/1990-003 was submitted addressing the issue. FHA Appendix B, Section 1.1.1, Action Statement b requires a report be submitted if fire-rated assemblies or sealing devices are not restored to operable status within 14 days. In the specific case of fire doors 2C05 and 2C05a, they were blocked open for a total of six days. While the requirements of Action Statement a of Section 1.1.1 were not met (compensatory action requirements for inoperable fire doors were not taken) a special report was not specifically required by the FHA regarding this issue.

- An Operating Order was issued on November 1, which required all fire doors to be treated as Appendix B doors. This action prevented the existing inadequate procedure guidance of Appendix B from causing additional fire doors to be inoperable without proper actions.

- Revision 6B of the FHA will be issued prior to the end of January 1991. It will correctly identify all fire doors subject to Appendix B, Section 1.1.1 requirements.

- A sampling of all DoCRs which affected the FHA over the last 3 years will be reviewed to ensure no other problems exist due to improper revisions.

- By January 11, 1991, procedures will require an architect/engineer review of any future FHA Appendix B DoCRs prior to PRB submittal. This is a significant action since the A/E is aware of all the aspects and assumptions of the FHA in its entirety. In the past, while FHA revisions were reviewed by the PRB and other personnel, the A/E did not perform a review.

In 1986, Hatch TS were revised consistent with GL-86-10. The fire protection surveillance and operability requirements were removed from the TS and placed in Appendix B of the FHA, which is part of the FSAR. The TS were revised concerning the review of changes to the protection program/procedures and the submittal of Special Reports for fire protection equipment and surveillance requirements. TS require written procedures be established, implemented and maintained covering activities including Fire Protection Program implementation. It is implicit in these requirements that the procedures be adequate. This licensee-identified violation is not being cited because criteria specified in sections V.G. of the NRC Enforcement Policy were satisfied. NCV 90-25-01: Incorrect Revision to FHA Resulting in Inadequate Fire Protection Program Implementation Procedures will be utilized to follow this issue.

One NCV was identified.

7. Inspection of Open Items (92700) (90712) (92701)

The following items were reviewed using licensee reports, inspection, record review, and discussions with licensee personnel, as appropriate:

a. (Closed) LER 321/89-15: Diesel Generator 1B Inoperable Due to Installation of Incorrect Part. In October 1989, during surveillance testing, the 1B EDG was discovered to be inoperable due to the installation of an incorrect model of circulating lubricating oil pump. This had resulted in a lubricating oil hydraulic lock on the number two cylinder. An incorrect model number had been assigned to the warehouse number for the standby lubricating oil pump. The installed pump developed more discharge head than the specified model of pump and, consequently, continuously pumped oil into the upper crankcase. The LER listed a contributing cause as a less than adequate functional test. Although an FT was completed (verify no oil flowing into the crankcase), the oil flow was very slow and difficult to detect. Corrective actions included verifying that the other four EDGs' had the correct model pump installed and assigning the model its own stock number and warehouse location.

   52PM-R43-016-0S: Diesel Generator Lube Oil Pumps Major Inspection/Overhaul was revised to provide a more thorough post pump repair/replacement functional test. The process used by Quality Control regarding material receipt inspections was enhanced. Based on these corrective actions, this LER is closed.

b. (Closed) LER 321/90-05: Safety Relief Valves Experience Setpoint Drift Due to Corrosion Induced Bonding

On March 29, 1990, while Unit One was in the refuel mode, the results of off-site testing of safety relief valves (SRVs) were received by site engineering. Of the eleven SRV pilot valves bench tested at Wyle Laboratories, six exhibited setpoint drifts in excess of the +/- 3 % tolerance specified in the ASME Boiler and Pressure Vessel Code, Section XI, IWV-3512. The highest setpoint drift was for SRV 1B21-F013B, which lifted 12.90 % above the nameplate actuation pressure. The majority of the remaining SRVs lifted at approximately 3-4 % greater than nameplate actuation pressure. In addition, nine of eleven SRV pilot valves bench tested at Wyle failed to lift within the TS 2.2.A specified setpoint of +/- 1 % of nameplate pressure. This LER was determined to be not reportable under 10 CFR 50.73, and was submitted voluntarily due to potential interest to the industry.

The licensee's SRVs are manufactured by Target Rock Company, and have had a history of setpoint drift due to corrosion induced bonding of the pilot valve disc with the seat. The utility is in cooperation with the BWROG to resolve the SRV setpoint drift issue. The BWROG had identified PH13-8Mo as a disc material which had the potential to be less susceptible to forming a corrosive bond to the Stellite-6 seat. Of the six SRVs which demonstrated excessive setpoint drift, three had PH13-8Mo discs. Based on inservice data as of November 1989, the BWROG reached the conclusion that the PH13-8Mo discs were not providing the improved setpoint drift performance originally expected. The data obtained by Plant Hatch supported this conclusion.

The licensee's safety assessment was performed by GE, and demonstrated that Plant Hatch has sufficient margin for over-pressure protection and can tolerate up to a 200 psi drift in SRV setpoint. In addition, the licensee conservatively assumed all eleven SRVs lifted at +9 % above nameplate pressure. The resulting pressure transient would be limited to approximately 1300 psig, which is less than the design limit of 1375 psig. The root cause of the event was corrosion induced bonding of the pilot valve disc and seat. The licensee's corrective actions included refurbishing all SRVs to bring lift pressures within a +/- 1 % tolerance, and continued cooperation with the BWROG to resolve the SRV setpoint drift issue. The licensee's actions were satisfactory, and as such LER 321/90-05 is closed.

c. (Closed) LER 321/89-17: Personnel Error Results in Incorrect Liquid Radwaste Discharge Monitor Setpoint. This LER involved the licensee's identification of incorrect discharge monitor setpoints caused by utilizing incorrect monitor efficiency factors. Inspection Report 50-321,366/90-03 documents a review of this issue and corrective actions conducted by a regional health physics inspector. NCV 50-321,366/90-03-02 was identified addressing this issue. Based on the detailed review documented in Inspection Report 90-03, this item is closed.

d. (Open) LER 366/89-07: Safety Relief Valves with PH13-8Mo Pilot Valve Discs Experience Setpoint Drift

On September 26, 1989, while Unit Two was in the refuel mode, results of off-site testing of safety relief valves (SRVs) were received by site engineering. Of the eleven SRV pilot valves tested at Wyle Laboratories, four exhibited setpoint drifts in excess of +/- 3 % tolerance specified in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, IWV-3512. Specifically, SRVs 2B21-F013C, G, H, and K lifted at 3.58 %, 5.50 %, 10.54 %, and 9.18 % above their respective nameplate set pressures. In addition, as noted on Deficiency Card No. 2-89-2954, all eleven SRV pilot valves bench tested at Wyle failed to lift within the TS 3.4.2.1 setpoint of +/- 1 % of nameplate pressure. This LER was determined to be not reportable under 10 CFR 50.73, and was submitted voluntarily due to potential interest to the industry.

The licensee's actions were similar to that performed for LER 321/90-05, which addressed the same issue of SRV setpoint drift. However, a supplemental report has not been issued, as indicated in the LER and, therefore, this LER remains open.

8. Exit Interview (30703)

The inspection scope and findings were summarized on December 19, 1990, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Description and Reference
50-321,366/90-25-01	NCV-Incorrect Revision to FHA Resulting in Inadequate FPP Implementation Procedures. (paragraph 6)
50-321,366/90-25-02	NCV-Failure to Properly Report ENS Inoperability. (paragraph 2b)

9. Acronyms and Abbreviations

A/E - Architect/Engineer
ARP - Alarm Response Procedure
BWROG- Boiling Water Reactor Owners Group
CR - Control Room
DC - Discrepancy Card
DoCR - Document Change Request
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EMA - Emergency Management Agency
ENN - Emergency Notification Network
ENS - Emergency Notification System
EP - Emergency Planning
EOP - Emergency Operating Procedures
ESF - Engineered Safety Feature
FHA - Fire Hazards Analysis
FPP - Fire Protection Program
FPM - Fission Product Monitor
FT - Functional Test
GE - General Electric
GL - Generic Letter
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MWO - Maintenance Work Order
NCV - Non-cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PD - Project Directorate
PRB - Plant Review Board
RCIC - Reactor Core Isolation and Cooling
SAER - Safety Audit and Engineering Review
SOR - Significant Occurrence Report
SOS - Superintendent On Shift (Operations)
SRV - Safety Relief Valve
TS - Technical Specifications
URI - Unresolved Item