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

Report Nos.: 50-338/92-17 and 50-339/92-17

Licensee: Virginia Electric & Power Company
5000 Dominion Boulevard
Glen Allen, VA 23060

Docket Nos.: 50-338 and 50-339 License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: July 19 - August 15, 1992

Inspectors: A. Ruff For 9-11-92
M.S. Lesser, Senior Resident Inspector Date Signed

A. Ruff For 9-11-92
D.R. Taylor, Resident Inspector Date Signed

Accompanying Inspector: A.B. Ruff

Approved by: P. Fredrickson 9/11/92
P.E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: operations, maintenance, surveillances, engineered safety feature walkdown, design changes and modifications, operational event followup, licensee event report followup, and action on previous inspection findings. Inspections of licensee backshift activities were conducted on the following days: July 20, 30 and August 7.

Results:

In the area of operations, one non-cited violation was identified involving the failure to have annunciator response procedures for the post-accident hydrogen recombiners (para. 7).

In the area of operations, one non-cited violation was identified involving an inadequate procedure which contributed to the failure to properly reset the air ejector exhaust valves following a unit safety injection (para. 4.c).

In the area of technical support, an unresolved item was identified involving a cracked safety injection system vent weld. The same weld cracked in 1991 and the inspectors considered that the licensee's 1991 corrective action was weak. Further, this event appears to be related to chronic pressure spikes in the system during pump starts as a result of non-condensible gases which come out of solution (para. 5.b).

In the area of operations, the licensee's response to an electrical fire was a strength. Immediate action was effective, the emergency plan was properly implemented, the effects of inoperable equipment were thoroughly reviewed and repairs were conducted in a timely manner (para. 4.a).

In the area of technical support, a strength was identified regarding the licensee's contingency plan for replacement of several 2-IV vital battery cells. The licensee is trending suspect cells to identify signs of impending failure (para. 6.a).

In the area of technical support, the new steam generators were delivered to the site. The licensee performed a receipt inspection and transported them to the steam generator storage facility (para. 8).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager, Operations and Maintenance
J. Hayes, Superintendent of Operations
*D. Heacock, Superintendent, Station Engineering
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
W. Matthews, Superintendent, Maintenance
J. O'Hanlon, Vice President, Nuclear Operations
D. Roberts, Supervisor, Station Nuclear Safety
*R. Saunders, Assistant Vice President, Nuclear Operations
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Outage and Planning
B. Shriver, Acting Station Manager, Nuclear Safety and Licensing
J. Smith, Manager, Quality Assurance
A. Stafford, Superintendent, Radiological Protection

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

NRC Resident Inspectors

*M. Lesser, Senior Resident Inspector
D. Taylor, Resident Inspector
A. Ruff, Project Engineer

*Attended exit interview

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

2. Plant Status

Unit 1 operated for most of the inspection period at 95 percent power. Power was reduced to 90 percent on one occasion to repair leaking condenser tubes. At the end of the inspection period, the licensee had identified a pin hole leak on a three inch class 3 steam line. A soft patch was placed on the flaw and the licensee initiated actions to request NRC approval for a temporary non-code repair.

Unit 2 commenced the inspection period operating at 100 percent power. A reactor trip and safety injection occurred on August 6 when the C MSTV failed closed (see para. 3). The unit started up on August 7 and following power ascent, operated at 100 percent for the duration of the period.

3. Followup of Operational Events (93702)

A UE was declared on July 29 due to an electrical fire in the intake structure switchgear building. Inspector followup is documented in paragraph 4.a. On August 6, Unit 2 automatically tripped and safety injected from 100 percent power on high steam flow coincident with low steam pressure on the A and B steam lines. This was a result of the C MSTV failing closed. A UE was declared based on the non-spurious SI initiation. Proper notifications were made. The results of additional followup are in paragraph 4 and 5.

4. Operational Safety Verification (71707)

The inspectors conducted frequent visits to the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operational safety and compliance with TS and to maintain awareness of the overall operation of the facility. Instrumentation and ECCS lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. Deviation reports were reviewed to assure that potential safety concerns were properly addressed and reported. Selected reports were followed to ensure that appropriate management attention and corrective action was applied.

a. Unusual Event Due to Fire

The licensee declared a UE on July 29 at 4:25 am due to a fire lasting longer than 10 minutes. An electrical fire occurred in the non-safety related 1G1-1N 480V motor control center and was detected by control room operators when the feeder breaker tripped at 4:06 am. The motor control center is located in the intake structure switchgear building outside the protected area. Responders used CO_2 to extinguish the fire at 4:31 am. The UE was terminated at 4:53 am.

Severe fire damage occurred in the circuit breaker cubicle for 1-CW-MOV-100D, CW Pump Discharge Valve and 1-HV-F-47B, Intake Structure House Exhaust Fan. Minor damage occurred to adjacent cubicles' electrical cabling. The following impacts to plant operation occurred:

- Bearing lube water flow to the CW pumps on both units was lost. Flow was restored after a short period of time with alternate methods.
- Valve position indication and motive power for CW discharge MOV's was lost.

- Power for CW pump/valve interlocks associated with CW intake tunnel overpressure protection was lost.

- A ground was experienced on the 2-I battery bus.

The licensee evaluated the significance of the lost equipment and implemented appropriate compensatory measures. Repairs were conducted within two days and the bus was energized. The licensee took deliberate steps to thoroughly review CW pump interlock logic prior to energizing the bus to avoid a spurious pump trip. The licensee's Corporate Nuclear Safety conducted an investigation of the event to identify root causes and lessons learned.

b. Reactor Trip Followup

The inspectors attended the licensee's post-trip review following the Unit 2 trip on August 6. All safety systems functioned as designed during the event. Prior to terminating safety injection, the pressurizer went solid and one PORV opened several times to relieve pressure. Maximum RCS pressure was 2303 psig. The inspectors reviewed the plant alarm typewriter and other documents and determined that injection flow lasted approximately 17 minutes prior termination. Pressurizer level was initially at approx tel 67 percent, slightly above the programmed band of 64.5 percent, but within specification, and reached 100 percent indicated level in about 12 minutes. The PORV initially opened at about 16 minutes and cycled several times for the next four minutes. Discussion with plant personnel indicated that a spurious safety injection may take anywhere from 14-18 minutes to terminate and that filling up the pressurizer during simulator sessions occurs occasionally. A similar trip on Unit 1 in 1991 showed the maximum pressurizer level to reach about 96 percent.

Since the pressurizer code safety valves provide sufficient overpressure protection, going solid on the pressurizer following events such as this is analyzed in the UFSAR and acceptable, although not necessarily desirable. The inspectors reviewed the background documents for the EOP's and determined that a filled pressurizer is considered a possibility following a small break LOCA. The licensee did not identify any operator performance problems that resulted in the filled pressurizer and reviewed the EOP's to assure themselves that recent revisions had not incorporated unnecessary steps which might hinder proper SI termination.

The inspectors reviewed post-trip data and determined that the minimum steam line pressure following MSTV closure was approximately 772 psig. Since the low steam line pressure bistable trips at 600 psig decreasing, the inspectors questioned how the safety injection logic actuated. The licensee's review of this event and a similar trip in 1991 determined that the low steam line pressure bistable actuated on a decreasing rate which is anticipatory of an impending low steam line pressure condition. While it appears that the design is conservative, the inspectors questioned its basis, since the anticipatory function may be contributing to unnecessary safety injections. The licensee has since initiated an engineering study to evaluate the basis of this function. This is identified as Inspector Followup Item 50-339/92-17-01: Basis For Rate Trip on Steam Line Low Pressure.

The inspectors noted that the licensee's post-trip review process does not generate a complete set of curves tracing plant parameter response. While some curves are produced from the plant event recorder, the process is cumbersome, the curves are not well labelled, and review is difficult. RCS temperature and auxiliary feed flow were examples of parameters which were not plotted for this event. The licensee appears to rely on strip chart recorders for some parameters although the event recorder has a resolution of one msec. The inspectors explained that processing the event recorder data into user-friendly curves would enhance the licensee's ability to verify proper plant response and to identify potential problems and root causes. The licensee is assessing methods to enhance the program.

c. Inoperable Air Ejector Divert to Containment

On August 14, the licensee identified that the Unit 2 air ejector exhaust divert to containment function was inoperable when divert valve 2-SV-TV-201-1 failed to open during the performance of a scheduled surveillance test. The licensee determined that the failure to properly reset the function, following the unit safety injection event of August 6, caused the inoperability. The licensee identified that the procedural step to reset the function was poorly worded and apparently misinterpreted by operators. The step did not reference the reset switch as labelled (COND AIR EJECTOR DIVERT TO CONT SI RESET). The step stated "Reset Air Ejector Divert Valves." The operators mistakenly interpreted this by simply ensuring the air ejector divert valves were in their normally aligned positions. In this case the procedure failed to conform to the requirements of VPAP-0506, EOP Development, Revision, and Maintenance, which specifies the human factors verification criteria that control/display nomenclature in the procedures is consistent with labels in the control room.

The inspectors reviewed the significance of the event. The failure to divert the air ejector exhaust to containment would have resulted in an uncontrollable release if an air ejector high-high radiation condition occurred with no corresponding safety injection. This might have resulted from a steam generator tube leak not large enough to cause a safety injection. The release path would be through air ejector loop seals which normally discharge to floor drains. The lack of an exhaust path to containment would cause air ejector steam supply to blow out the loop seals. (Note: If a safety injection had occurred, the air ejector steam supply would have isolated and no release would result.) The licensee calculated a preliminary offsite dose at the site boundary of 0.1 mrem assuming no operator action for 30 minutes. The licensee reported the event in accordance with 10 CFR 50.72. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy. NCV 50-339/92-17-02: Inadequate Procedure to Reset Air Ejector Divert to Containment.

One non-cited violation was identified.

5. Maintenance Observation (62703)

Station maintenance activities were observed/reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TS requirements.

a. Recirculation Spray Pump Seal Replacement

On July 28, the inspectors observed removal and replacement of the 1-RS-P-2A, Outside Recirculation Spray Pump tandem seal. The licensee had identified leakage of about 1 drop per minute, from the seal head tank through the pump seal, while the pump was idle. The condition was indicated by a periodic control room seal head tank level annunciator. The inspector observed good radiological control practices during the maintenance. Mechanics and engineers displayed a good knowledge level of seal construction and operation. The outboard seal face was found to be somewhat corroded while the inboard seal appeared to be in good condition. Both were replaced. The licensee used helium to leak test between the seals and ran the pump to demonstrate operability.

b. Weld Failure on LHSI Vent

A cracked weld was identified during the August 6 reactor trip downstream of LHSI discharge vent valve, 2-SI-377. The crack was at the joint between the discharge of the valve and the downstream ¼ inch tubing. The licensee was periodically venting the system using normally open valve 2-SI-377 and opening isolation valve, 2-SI-378, on the downstream tubing. The licensee determined that a similar crack occurred at that location on March 28, 1991. The tubing had originally been installed in 1990 under EWR 88-330M to make pipe venting more accessible. The inspectors reviewed the corrective action from the 1991 failure. A root cause evaluation was not performed because the failure was not repetitive. A walkdown of design engineering found the system to be structurally sound and that the tubing was seismically supported. The conclusion was thought to be a faulty weld, although post-weld liquid penetrant examinations were satisfactory.

The licensee has since concluded that the most recent weld crack is a result of stress due to movement of the 8-inch LHSI piping during pump starts. It appears that the 1991 walkdown was ineffective in that it failed to consider effects of pressure spikes in the LHSI system due to the entrapment of gases. This appears to be yet another problem related to LHSI pump starts with gases in the system. URI 50-338/91-22-02 describes chronic relief valve lifting upon pump starts. The inspectors considered the corrective actions to be weak in that the system walkdown did not consider the effects of the known problem of pressure spikes, and a detailed failure analysis of the 1991 weld failure was not performed.

The inspectors reviewed the licensee's corrective action as required by VPAP 1601. Corrective actions are assigned one of four levels of priority; "routine" being the least significant. The 1991 failure was classified "routine" based upon a "component found out-of-tolerance". The inspectors considered this classification inappropriate in that it did not adequately characterize the significance of the deviation. Since a higher priority was not assigned, there existed no formal requirements to perform a cause determination evaluation of the weld failure and therefore one was not done.

The inspectors questioned the adequacy of other vents and components such as instrument lines, which may also be subject to overstressing. The licensee stated that they would evaluate the systems on both units for the concern. The licensee also stated that a "keep-fill" modification is currently being evaluated to alleviate the system pressure spikes. Pending completion of corrective actions and licensee evaluation of root cause initiation threshold, this is identified as URI 50-339/92-17-03: Valve 2-SI-377 Weld Failure. This URI is specific to Unit 2, however, it is related to URI 50-338/91-22-02 on Unit 1 in that both involve pressure spiking in the SI system.

c. MSTV Rupture Disc Inspection

The licensee's investigation of the MSTV closure, which caused the Unit 2 reactor trip on August 6, determined the most likely cause was an air leak at the actuator rupture disc flange. This was based upon an as-found torque on the flange bolts of 55 ft-lbs when the maintenance procedure specified 60-80 ft-lbs. Licensee discussions with the vendor indicated the torque should actually be 48 ft-lbs and later received a vendor notice which provided the specifications. It appears that the cause of the MSTV closure is inconclusive. The inspectors questioned why the licensee did not have the correct torque values for the rupture disc. The maintenance procedure's torque values were based upon standard values for the bolt size and the vendor bulletin stating the correct values was not located in the licensee's vendor manual. The licensee has been involved in a vendor manual upgrade program and this particular manual, BS&B Rupture Discs, had not yet been upgraded.

d. Spurious Letdown Isolations

Following Unit 2 startup on August 8, at least three spurious letdown isolations occurred during the power escalation that appeared to be associated with CVCS blender operations. Each time 2-CH-HCV-2200C, 60 GPM Orifice Isolation Valve, was in service, and, on one occasion, pressurizer level increased to 10 percent above the program band. This appears to be a recurring problem in that several isolations occurred while 2-CH-HCV-2200C was in service immediately after Unit 2 startup from its refueling in April. At the time, the licensee placed 2-CH-HCV-2200B in service and instrumented the circuitry with strip chart recorders in order to capture and record the intermittent failure. However, this effort was apparently discontinued without resolution with no further work order or status item. Therefore, when operators reestablished letdown following the August 6 trip, they were not alerted to the problems with 2-CH-HCV-2200C. This appears to be a weakness in tracking the status of an abnormal condition.

e. 2-MS-TV-211A Repair

The inspectors followed work order 5900150151, Repair Seat Leakage of 2-MS-TV-211A, Main Steam Supply Trip Valve to Turbine Driven Auxiliary Feedwater Pump. The seat ring and valve plug were found to be steam cut. A minor air leak on the actuator was also identified during the maintenance and repaired by replacing the O-rings. The licensee identified that one valve in the tagout for the maintenance was mispositioned. Manual isolation valve 2-MS-261, was found closed when it should have been tagged open in order to establish a vent path within the isolation boundary. The condition was corrected prior to initiating the maintenance and DR N-92-1668 was properly written to document the error.

No violations or deviations were identified.

6. Surveillance Observation (61726)

The inspectors observed/reviewed TS required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met and that any deficiencies identified were properly reviewed and resolved.

a. Station Battery 2-IV Quarterly PT

On July 24, the inspectors observed the performance of 2-PT-66B, DC Distribution System-J Bus, for station battery 2-IV. The test is performed to meet quarterly surveillance requirements of TS 4.8.3.2.b. The PT received a heightened level of management attention because the last battery capacity test indicated the battery capacity to be 82 percent of the manufacturer's rating. TS requires a battery capacity of at least 80 percent. The battery is being replaced with a new battery during the Unit 2 refueling outage scheduled for September 1993. Based on the capacity test, the licensee suspected several cells to be degrading. As a precautionary measure, the licensee established a contingency plan to jumper-out up to two cells or replace up to four cells if the PT fails. This would place the unit into a two hour TS action statement.

The inspectors attended the contingency plan meeting on July 20, and observed the briefing and quarterly PT on July 24. The PT was completed with no problems and all cells were well within their TS limits. The inspectors considered the meetings and briefings prior to the PT to be thorough and the contingency measures to be well planned. The licensee indicated the same measures will be taken for the next quarterly PT.

b. Halon Bottle Test

On August 12, the inspectors observed the licensee perform 1-FPMP-11.0, Halon 1301 Emergency Switchgear Periodic Test. The test requires that each halon bottle be weighed and compared to an acceptance criteria of 95 percent of the full charge weight, excluding the empty weight of the bottle. As a result of the test, the licensee identified one bottle which needed replacement. The inspectors verified that the load cell was within calibration periods and discussed the results of the test with licensee personnel.

No violations or deviations were identified.

7. ESF System Walkdown (71710)

The inspectors performed walkdowns of the post accident thermal hydrogen recombiner system using Procedure 1(2)-OP-63.1 and drawing 11715-FM-106A. The quality of the operating procedure was good in that steps were detailed enough to align and effectively operate the system. Controls and indications for the operating panel were clearly labeled and within calibration periods. No outstanding work orders were found on the system.

The inspectors determined that annunciator response procedures had not been established for the hydrogen recombiners. System isolation valves are operated from the control room, however, the recombiner itself is operated at a local control panel. The control panel has 8 annunciators. While the alarm setpoints for various temperature conditions are actually established by 1(2)-OP-63.1, it was not obvious what would cause other annunciators to actuate. Appendix A of RG 1.33 specifies the need for written procedures for each annunciator on safety related equipment.

The inspectors informed the licensee of the findings and the licensee immediately initiated action to develop annunciator response procedures. The inspectors subsequently reviewed the new procedures. The inspectors concluded that this was an isolated event and that annunciator response procedures exist for other safety related local control panels. This NRC identified violation is not being cited because criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied. NCV 50-338,339/92-17-04: Failure to Have Annunciator Response Procedures for Hydrogen Recombiner.

One non-cited violation was identified.

8. Design Changes and Modifications (37700)

Steam Generator Replacement Project

The new steam generators for Unit 1 were shipped by rail from Pensacola, Florida on July 31, 1992 and arrived at the site on August 9. The licensee performed a receipt inspection of each steam generator in accordance with WP&IR, WR-05.05.00-09(10)(11), Inspection Storage and Maintenance of Lower Assembly A(B)(C). The procedure included requirements to examine for damage to the nozzles, channel head and shell cone ends and the vessel itself and for any indications of rough handling. The procedure also required establishment of housekeeping zones, verification of an adequate nitrogen pressure and review of accelerometer readings.

The inspectors reviewed the licensee's evaluation of the haul route from the rails to the storage facility. Buried conduit 2.5 to 3 feet deep was identified and evaluated to be sufficiently flexible as to not be affected by the passage of the transporter. All three assemblies were lifted from the rail cars and transported to the new steam generator storage facility.

9. LER Followup (92700)

The following LERs were reviewed and closed. The inspector verified that reporting requirements had been met, that causes had been identified, that corrective actions appeared appropriate, and that generic applicability had been considered. Additionally, the inspectors confirmed that no unreviewed safety questions were involved and that violations of regulations or TS conditions had been identified.

a. (Closed) LER 50-338/91-17: Spurious Closure of "A" Main Steam Trip Valve Causing Reactor Trip and Safety Injection

The cause of the event was determined to be water intrusion of a junction box, containing a relay for train B SOV to 1 MS-TV-101A. The water caused corrosion and a subsequent short across the contacts of the relay. The water intrusion was caused by rain water leakage into the QS house that eventually leaked into the junction box via a conduit. The leakage was caused by a defective rain gutter located on the outside of the QS house. To address the problem, the licensee repaired the gutter and sealed possible leakage paths into the QS house and the conduit entering the control relay cabinets. The licensee also initiated efforts to identify and correct leaks that may exist or develop in other areas containing safety related equipment.

The inspectors walked down the area inside the Unit 1 QS basement and noted standing water on the top of various junction boxes. The water was caused by condensation forming on the RWST recirculation piping. The condensation was being directed by a temporary tubing to the QS basement drains, however, the tubing was misaligned due to temporary scaffolding which redirected the tubing and allowed the water to drain onto the junction boxes. The licensee was notified and took appropriate actions. The inspectors revisited the area several days later and noted the scaffolding removed and no further drainage problems.

b. (Closed) LER 50-338/91-23: Inadvertent Flow from LHSI System to RCS During Shutdown With RCS at Low Pressure

The event occurred when LHSI discharge valves were incorrectly left open during RCS depressurization following Type C testing activities. Gravity flow occurred when the RCS depressurized below the static head of the RWST. Corrective actions included operating procedure revisions to verify LHSI discharge valves shut prior to decreasing RCS pressure below 100 psig and additional documentation of valve manipulations following Type C testing.

10. Action on Previous Inspection Items (92701, 92702)

a. (Closed) IFI 50-338/91-07-02: EDG Testing With More Representative Power Factor

The licensee determined that testing the EDGs with a representative power factor of 0.85 during the 18-month, 24-hour endurance run would be a challenging test and meet the intent of IN 91-13, Inadequate Testing of EDGs. Procedures 1(2)-PT-83.4H(J) were revised to accomplish this.

b. (Closed) Violation 50-338/91-14-02: Failure to Conduct MOV Failure Evaluation for 1-SW-MOV-101C

The violation resulted from a repeat failure of the MOV. The cause of the violation was a failure to properly document the initial valve failure via a DR or operations MOV review sheet which would have led to a root cause evaluation. The licensee responded to the violation in correspondence dated September 12, 1991. Corrective action included significant management emphasis and training on the use of DRs for unexpected conditions and additional administrative requirements for submitting them. The licensee also performed extensive refurbishment including repacking of the eight SW supply and return valves for the RSHXs. Each butterfly valve was removed from the system, disassembled, and completely rebuilt.

c. (Closed) Violation 50-339/91-26-02: Failure to Maintain Adequate Controls Over Safeguards Area Ventilation Tests.

This violation involved the inappropriate use of a TP and an EWR to perform test activities on the safeguards area ventilation system. The EWR did not direct work to be performed but was to be used to provide guidance to balance the system in accordance with approved station procedures and drawings. Consequently, an activity screening check list for the EWR was not performed to determine if a safety evaluation was required. The TP was a supplement to a generic acceptance test that was not formally reviewed and approved by appropriate personnel. Upon discovery of this problem, the licensee verified TS compliance by using an approved PT. An EWR addenda was issued with an approved work procedure and an activity screening checklist.

A new procedure change, P5, to ADM 3.7, Engineering Work Requests, Section 5.2 states that physical modifications on a system level are to be controlled by the design change process. Section 7.2.1 in a new revision to STD-GN-0001, Instructions for DCP Preparation, requires that an activity screening checklist or a safety evaluation (if applicable) be included in ??% draft DCPs. Also, a 10 CFR 50.59 activity screening is a new requirement for TPs that are not part of an approved modification package. These two corrective measures should prevent problems of this nature from occurring in the future.

11. Exit (30703)

The inspection scope and findings were summarized on August ??, 1992, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
50-339/92-17-01	(IFI) Basis for Rate Trip on Steam Line Low Pressure (para. 4.b)
50-339/92-17-02	(NCV) Inadequate Procedure to Reset Air Ejector Divert to Containment (para. 4.c)
50-339/92-17-03	(URI) Valve 2-SI-377b Weld Failure (para. 5.b)
50-338,339/92-17-04	(NCV) Failure to Have Annunciator Response Procedure for Hydrogen Recombiner (para. 7)

12. Acronyms and Initialisms

CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
CVCS	Chemical Volume Control System
CW	Circulating Water
DC	Direct Current
DCP	Design Change Package
DR	Deviation Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Features
EOP	Emergency Operating Procedure
EWR	Engineering Work Request
GPM	Gallons Per Minute
IFI	Inspection Followup Item
IN	Information Notice
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
MOV	Motor-Operated Valve
MREM	Millirem
MSEC	Millisecond
MSTV	Main Steam Trip Valve
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
PORV	Power Operated Relief Valve
PSIG	Pounds Per Square Inch Gage
PT	Periodic Test
QS	Quench Spray
RCS	Reactor Coolant System
RG	Regulatory Guide
RSHX	Recirculation Spray Heat Exchanger
RWST	Refueling Water Storage Tank
SI	Safety Injection
SOV	Solenoid-Operated Valve
SW	Service Water
TP	Test Procedure
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	Volts
WP&IR	Work Plan and Inspection Record