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

Report Nos.: 50-338/90-28 and 50-339/90-28

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: October 21, 1990 through November 17, 1990.

Inspectors: C. Ruff for 12/6/90
M.S. Lesser, Senior Resident Inspector Date Signed

C. Ruff for 12/6/90
L.P. King, Resident Inspector Date Signed

Approved by: C. H. [signature] 12/7/90
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, operational event followup, licensee event report followup, Three Mile Island items, and action on previous inspection findings. Inspections of licensee backshift activities were conducted on the following days: October 28, November 2 and 7, 1990.

Results:

The Unit 2 refueling outage was completed effectively and ahead of schedule. This is particularly noteworthy since it commenced unexpectedly two and one-half weeks early. Several aspects of the licensee's outage management were noted to be strengths including activity control, outage workshops, use of performance indicators, and the use of the system outage window concept. (Paragraph 3)

The licensee's startup assessment continues to be a strength. Each department conducted a detailed review of outage accomplishments and open items. All open items were reviewed and presented for management approval for reactor startup. (Paragraph 3)

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- One violation was identified following a reactor trip on Unit 2 involving the failure to have abnormal procedures for a turbine trip. Weaknesses were also identified regarding the licensee's program for determining the impact of design changes on station procedures. (Paragraph 7.a)

- One violation was identified involving the failure to conduct an adequate design review on a design change to the Emergency Diesel Generator start circuitry on undervoltage. This resulted in the failure to identify an incorrect design and the loss of an emergency bus during testing. (Paragraph 7.b)

- Two non-cited violations were identified involving inadequate and unbalanced safety injection flow rates (Paragraph 5.b) and a missed surveillance on the power operated relief valves (Paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

M. Bowling, Assistant Station Manager
L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager
M. Gettler, Superintendent, Site Services
*E. Grecheck, Manager, Nuclear Engineering
*D. Heacock, Superintendent, Engineering
G. Kane, Station Manager
P. Kemp, Supervisor, Licensing
W. Matthews, Superintendent, Maintenance
D. Roberts, Supervisor, Nuclear Safety Engineering
*R. Saunders, Assistant Vice President - Nuclear Operations
R. Shears, Superintendent, Outage Management
J. Smith, Manager, Quality Assurance
A. Stafford, Superintendent, Health Physics
*J. Stall, Superintendent, Operations

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

NRC Resident Inspectors

L. King, Resident Inspector
*M. Lesser, Senior Resident Inspector

*Attended exit interview

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

2. Plant Status

Unit 1 started the reporting period in power coastdown at 82 percent power. On November 1 the unit lost charging for approximately one minute when an operator mistakenly racked out the circuit breaker to the B charging pump instead of the A charging pump. Operators responded by starting the A charging pump and no transients were observed on the unit. The licensee reported the event in accordance with 10 CFR 50.72. The unit ended the reporting period at 65 percent power, day 297 of continuous operation.

Unit 2 started the reporting period in a refueling outage, Mode 5. The scheduled 75 day outage was completed in 72 days. On October 28, the 2J emergency bus inadvertently deenergized during testing. The cause was traced to an inadequate modification (paragraph 7.b.). The unit entered Mode 4 on October 30 and Mode 3 on October 31. The reactor was started up on November 2. While placing the turbine on line, operators lost control of steam generator levels and an automatic reactor trip occurred (paragraph 7.a.). The reactor was restarted later that evening. The unit ended the reporting period at 100 percent power, day 15 of continuous operation.

3. 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, compliance with TS, and 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.

The inspectors observed licensee management's startup assessment at the end of the refueling outage. The assessment included a detailed review of each department's refueling accomplishments and open items. The outage was completed three days ahead of schedule with no major problems. This is particularly noteworthy since it commenced unexpectedly two and one-half weeks early due to increasing primary-to-secondary leakage. Major accomplishments in addition to refueling during the outage were: auxiliary feedwater full flow recirculation piping modification, RCS level instrumentation, CRDR bench board modifications, feedwater heater replacement, containment integrated leak rate test, SG eddy current and plug replacement, and the ten-year in-service inspection and hydrostatic tests.

Additional maintenance included: Over 200 MOV PM's (mechanical and electrical), 64 check valves worked, 990 valve repacks and approximately 80 circuit breaker inspections/refurbishments. Very few items were deferred and each was reviewed to determine that no safety related impact existed. While some weaknesses were noted in the master tagout system, the outage was effectively managed. Contributing to this was the use of the system windows concept, outage workshops, training, control of activity addition and deletion, and performance indicators. Management's control of the outage and the startup assessment was noted to be a strength.

The inspectors toured containment prior to startup and walked down selected portions of systems including the safety injection system and containment isolation valves. The inspectors observed portions of the reactor startup and low power physics testing, including the estimated critical position, reactivity computer checkout, all rods out boron endpoint determination, isothermal temperature coefficient measurement and rod reactivity worth measurements.

During rod withdrawal, control bank B rod (F-4) did not move as indicated by IRPI. The licensee initially believed it was a problem with the IRPI, however, recalibration did not correct the problem. A stationary gripper blown fuse was identified and the inspectors observed its replacement.

No violations or deviations were identified.

4. 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.

The following maintenance activities were reviewed:

EWR 90-361	Add Isolation Between VCT Level and Auxiliary Indication
Work Request 467839	Refurbish Vital Bus Inverter
Work Request 733991	Repair Inoperable Casing Cooling Level Monitor

No violations or deviations were identified.

5. 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. The following surveillances were reviewed:

2-PT-75.6	Service Water System Flow Balance
2-PT-8304	Loss of Offsite Power Test J Bus
2-PT-138.1	High Head Safety Injection Flow Balance Test

b. High Head Safety Injection Flow Balance Test

The licensee performed 2-PT-138.1, High Head Safety Injection Flow Balance Test, on October 20, 1990. The test was performed in response to a 10 CFR 21 notification by Westinghouse regarding ECCS flow inconsistencies. The notification involved the potential for ECCS flow to be lower than that assumed in the LOCA analysis due to seal injection and safety injection flow resistance differences and unbalanced safety injection lines. The licensee's Technical Report Number 770 concluded that the existence of the flow inconsistencies do not represent an unreviewed safety question; however, it recommended flow balance surveillance testing with more accurate instrumentation such that results could be included in plant analysis documentation for long-term resolution of ECCS flow related issues.

PT-2-138.1 used temporary ultrasonic flow instruments and the TS acceptance criteria of "the sums of the injection flow rates, excluding the highest flow rate is greater than or equal to 384 gpm." When the licensee performed the test on Unit 2, it failed. The sum of the two lowest lines was 347 gpm. The license made notification to the NRC pursuant to 10 CFR 50.72.

The following table contains the "as found" and "as left" data:

Valve	2-OP-7.2A Position	As Found Flow	As Left Flow	As Left Position
2-SI-89 (A Cold Leg)	1 7/8 Turns Open	250 GPM	192 GPM	3 1/2 in. *
2-SI-97 (B Cold Leg)	2 3/8 Turns Open	150 GPM	194 GPM	3 9/16 in.*
2-SI-103 (C Cold Leg)	1 3/4 Turns Open	197 GPM	192 GPM	3 9/16 in.*

*Stem Height

Following the Unit 2 test failure, the licensee adjusted the SI throttle valves, using stem height as the means to record valve position instead of the less accurate method of turns open. The throttle valve positions had been determined from the preoperational test 1-PO-36.3, conducted in 1980. Since the three branch line flow instruments were known to be inaccurate, each was calibrated individually during the preop by comparing readings to a combined flow element (FT-2943), which is more accurate. The branch flow instruments were then used to balance the system.

It appears that a combination of preoperational test inaccuracies and imprecise methods to count the number of turns on the throttle valves, contributed to the test failure. Licensee corrective action will minimize operation of the valves and require flow balances if they are operated. The licensee will submit an LER on the event.

Preliminary results showed that sufficient safety analysis margin is available such that the lower ECCS flows would not have exceeded PCT limits.

The inspectors reviewed the preoperational test and applicable procedures for the corresponding Unit 1 valves. The valve positions appeared to be controlled in a better manner. Spacers are used to verify stem height, with T-handle operators.

Further testing was performed on Unit 1 in 1983, in addition to preoperational testing due to concerns with the instrumentation accuracy. The testing appeared to be more thorough and the throttle valve position more closely agreed to one another. The licensee is planning to conduct flow balancing during the upcoming Unit 1 refueling outage. This licensee identified violation is not being cited because criteria specified in Section V.G.1 of the NRC Enforcement Policy were satisfied. NCV 339/90-28-01: Inadequate and Unbalanced Safety Injection Flow Rates.

No violations or deviations were identified.

6. 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.

(CLOSED) LER 339/89-01: Inadvertent Discharge of the Chemical Addition Tank. The licensee reported the event where an operator inadvertently opened the wrong valve and discharged sodium hydroxide from the chemical addition tank to the RWST. The licensee emphasized self checking techniques and conducted an evaluation to install barriers to prevent inadvertent operation. EWR 90-127 has been implemented to install covers over the valve switches.

(CLOSED) LER 339/89-03: Containment Isolation Valves Type C Leakage Exceeded TS Limit. The licensee reported a total of ten containment isolation valves with "as found" unacceptable leak rates. The licensee determined that containment integrity was maintained by a redundant valve or a closed system. All valves were repaired.

(Closed) LER 338,339/89-11: Operation of Control Room Chillers Outside Limits of TS 3.7.7.1. The licensee identified that it had operated the control room ventilation system outside the design basis. While TS 3.7.7.1 requires two chillers per unit, three chillers are available. The C chiller receives power from the H emergency bus only and hence cannot be considered a redundant chiller if the B chiller, powered by the J bus, is inoperable. Prior to December 1, 1988, the licensee had considered the C chiller as an alternate to either the A or B chiller. The licensee has since placed operational restrictions on the system to require redundancy or enter the TS action. The licensee is continuing to investigate the option of a modification to allow the C chiller to swing from either H or J bus.

(CLOSED) LER 338, 339/89-12: Inadvertent start of 1J EDG and 2-SW-P-1A During SSPS Testing. The spurious EDG start was caused by a personnel error while using test equipment. The spurious Service Water Pump start was caused by a procedural error in the SSPS test. The licensee revised the procedure and added precautions where appropriate.

(Closed) LER 339/90-06: Pressurizer Power Operated Relief Valves Not Properly Tested Due to Personnel Error. The event involved the failure to conduct the TS-required channel functional check on the pressurizer PORV prior to entering a condition which required their operability. This occurred on October 15, 1990, while in Mode 5 when the RCS, which was previously vented, and pressurized to conduct reactor coolant pump runs. The cause for the missed surveillance was failure to enter the item in the TS action log when the scheduled surveillance was not performed due to the RCS system being opened to atmosphere.

Licensee corrective actions included verifying the PORVs would have performed their safety function and changing procedures to specifically require an Action Statement Log entry if testing will not be done. This licensee identified violation is not being cited because criteria specified in Section V.G.1 of the NRC Enforcement Policy were satisfied. NCV 339/90-28-02: Missed Surveillance on PORV.

One noncited violation was identified.

7. Followup of Operational Events (93702)

a. Unit 2 Reactor Trip

On November 2, 1990, Unit 2 was operating at about 15 percent power and had just placed the main turbine on line and synchronized it with the electric grid. The resultant increase in steam flow caused steam generator levels to swell. Operators were unable to control levels and at 5:34 p.m. a high-high B steam generator level actuation at 75 percent level occurred. This caused a turbine trip, a MFP trip and a feedwater isolation. AFW pumps started as expected. Operators attempted to restart the B MFP; however, they failed to reset the feedwater bypass valve isolation signal. Although the feedwater bypass valves were demanded open by operators, the valves remained closed due to the lockout signal. Actual valve position is not available in the control room.

The logic is such that starting the B MFP caused the turbine-driven AFW pump to trip. This stopped flow to the A steam generator which reached the low-low steam generator level setpoint at 5:41 p.m. and caused an automatic reactor trip. All safety equipment functioned as expected. The licensee conducted a post trip review and restarted the reactor at 10:41 p.m.

The inspectors were concerned that the operators failed to reset the feedwater bypass valve isolation signal in order to establish main feedwater to the steam generators. The inspectors reviewed the procedures available to the operators and determined that Abnormal Procedures for turbine trip and loss of feedwater do not exist. Annunciator Response Procedures for steam generator high high level turbine trip and main feed pump automatic trip are available but do not encompass the level of detail required by Abnormal Procedures. In this case, available procedures were inadequate to direct operators to reset the feedwater bypass valve isolation signal in order to restore feedwater to the A steam generator.

The licensee had recently implemented DCP 88-04, Eliminate Reactor Trip on Turbine Trip at Less Than 30% Power. Prior to the modification, a reactor trip would result from a turbine trip when above 10 percent power. The modification was installed to reduce unnecessary reactor trips as the North Anna units are designed to withstand a 50 percent load rejection and maintain the reactor critical. Although required by Regulatory Guide 1.33, a turbine trip abnormal procedure may not have been very useful prior to the modification because a turbine trip would generally result in a reactor trip and the appropriate emergency procedures would be used. The licensee was unable to produce any documentation stating this position as the reason for not having a turbine trip abnormal procedure. The modification process failed to identify the need for a turbine trip and loss of feedwater procedures which are clearly needed following modification implementation. The licensee additionally identified at least six annunciator response procedures which were not updated by DCP 88-04 including Feedwater Isolation, Loss of Main Feed pumps, and Turbine Trip on SG High High Level. Each of these directed actions assumed a reactor trip would occur following a turbine trip at power above 10 percent.

The inspectors raised concerns with the adequacy of procedure reviews conducted for impact from modifications. While the review process relies upon the knowledge level of the procedure writers group, a systematic approach does not exist. It is considered that the communication process between engineering and procedure writers is a weakness. In Inspection Report 50-338,339/90-25, a non-cited violation documented a similar weakness. In that violation, administrative procedures to prevent a potential EDG overload from a containment air compressor were not implemented following replacement of the instrument air compressor.

Appendix A of Regulatory Guide 1.33, Quality Assurance Program Requirements, specifies that procedures are required for combating emergencies and other significant events in addition to annunciator response procedures. Turbine and generator trip and loss of feedwater are listed as examples of significant events requiring procedures. The UFSAR additionally states in Section 13.5 that these examples are covered by written procedures. TS 6.8.1 requires the procedures referenced in Regulatory Guide 1.33 to be established. This is identified as a violation of TS 6.8.1, 339/90-28-03: Failure to Have Turbine Trip Abnormal Procedure. The additional procedure examples discussed above are indicative of a programmatic weakness in identifying the impact of DCPs on station procedures.

b. Inadvertent Loss of Power to Emergency Bus

On October 28 with Unit 2 in Mode 5, the licensee was testing the 2J 4160 emergency bus undervoltage and degraded voltage relays. Actuation logic to load shed and start the EDG is 2 out of 3. The test circuitry is such that two relays are tested simultaneously, however, final actuation is prevented during the test by a series of blocking relays. At 10:46 a.m., offsite power was spuriously lost on the 2J bus. The 2J EDG, which had been placed in the manual start mode for the test, was immediately started by operators and placed on the bus. Decay heat removal was not interrupted and no other problems occurred. The licensee properly reported the ESF actuation to the NRC. Troubleshooting did not initially determine the cause and a second test was attempted with similar results; loss of offsite power to the 2J bus at 6:45 p.m. and manual start of the EDG.

The licensee determined that the blocking relays (69B, C, D, and G) failed to block final actuation as a result of an inadequate design change which had been implemented during the refueling outage. DCP 89-33, Diesel Generator Undervoltage Start Relay, was implemented to assure the ability of the diesel start relay (27W) to drop out on loss of voltage. Previous problems had been detected due to a high starting contact resistance which could prevent the 27W relay from dropping out as designed. DCP 89-33 modified the circuit to ensure dropout. The DCP also added an additional diesel generator start at 73 percent of rated voltage in order to be consistent with Unit 1.

The DCP failed to address a 27W contact in the undervoltage testing circuitry necessary to maintain the blocking relays to prevent deenergizing the emergency bus during testing. The design change was performed by the licensee's A/E. The inspectors reviewed portions of the Nuclear Design Control Program as referenced in the licensee's Operational Quality Assurance Program Topical Report (VEP 1-5A), which implements the design control requirements of 10 CFR 50, Appendix B. The Instruction Manual for A/E and A/E Interface Control portions of the Nuclear Design Control Manual clearly require the use of the licensee's Nuclear Standards for all applicable work. Chapter 3.3 of the Nuclear Design Control Manual, Design Verification, clearly requires design reviews to provide assurance that the design documents are correct and meet the intent of the design. In this case, the design change flaw was the result of a failure to properly assess the effects of logic changes in the electrical circuit. The design review process also failed to identify the error.

During the 70 percent complete design review an additional circuit modification was recommended in order to match the Unit 1 circuit design. This recommendation was incorporated into the design but was not documented as required. Thus, when the recommendation was incorrectly designed, the design review process failed to correct it. The error was determined to only effect the test circuitry and not the safety function of the system, however, it resulted in the loss of an emergency bus, without automatic start capability of the EDG. The licensee implemented field change 10 and 11 to correct the circuit.

This is identified as a violation of the licensee's design change program, 339/90-28-04: Failure to Conduct Adequate Design Review of Undervoltage Diesel Start Relay Modification.

One additional concern identified involved the scope of post-modification testing as stated in the DCP. The post-modification tests did not explicitly state that 2-PT-36.9.1J was required to challenge the testing circuitry although discussions with engineering personnel indicated that this was the intent. The PT was performed as a prerequisite to enter Mode 4. The licensee stated that controls would be enhanced to ensure that all intended post-modification tests are stated in the DCP.

Two violations were identified.

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

a. (Closed) Inspector Followup Item 50-338,339/89-28-01: Review of Licensee's Actions Concerning Calibration of Installed TS Related Instrumentation. The licensee determined that installed instrumentation is typically calibrated on a two year periodicity based on manpower restraints. The licensee also determined that a 25 percent grace period is appropriate and is based on grace periods typically assigned in TS surveillances. Maintenance Department Standing Order 90-22B was revised to address information required for calibration stickers. The indicated overdue date now includes grace period.

b. (Closed) Inspector Followup Item 50-338,339/89-26-05: Followup on Deficiencies Found During Unit 1 AFW Walkdown. The licensee revised the drawing to show 1-FW-194 as open per drawing update request 89-554. The licensee determined the reason for throttling 1-FW-187 is to limit flow through the recirculation line to 20 gpm in order to assure adequate flow of 340 gpm is supplied to the steam generator. 1-FW-531, 532, and 533 were added to 1-OP-31.2A, Valve Checkoff-Auxiliary Feedwater.

c. (Closed) Inspector Followup Item 50-338,339/89-30-04: Agreement of Torque Values Between Technical Manual and Maintenance Procedure for Grinnell Diaphragm Valves. The maintenance procedure MMP-C-GV-3, Inspection and Repair of Grinnell Diaphragm Valves, was revised February 9, 1990, with the latest torquing procedure and torque requirements from Grinnell.

d. (Closed) Violation 50-338,339/89-14-03: Failure of Corporate Fuel Audit and Inspection Group to Provide an Accurate Fuel Handling Data Sheet. The violation involved an attempt to store a new fuel assembly in a spent fuel pool location occupied by another assembly. The licensee responded to the violation in correspondence dated July 28, 1989. Corrective actions included procedure changes to ensure the fuel handling report be verified against the station refueling office magnetic board, a requirement to ensure adequate fuel pool lighting, enhanced transmission of fuel handling information from the station to corporate and a computer system used to generate fuel handling reports and data sheets.

e. (Closed) Units 1 and 2, TMI item I.C.1.2.B., Short-Term Accident and Procedures Reviews - Inadequate Core Cooling Revise Procedure. In June 1990 an EOP team inspection was performed at North Anna. This inspection verified that the EOPs were technically accurate and that their specified actions could be accomplished. A review of EOPs was performed including procedures F-0, Critical Safety Function Status Tree, and FR-C.1, Response to Inadequate Core Cooling. The EOP inspection is documented in NRC Report 50-338,339/90-11.

e. (Closed) Units 1 and 2, TMI item II.F.2., Instrumentation for Detection of Inadequate Core Cooling. NRC inspection reports that closed some of the concerns under this item are 50-338/80-16, 50-339/80-17, 50-338/81-05, 50-338,339/84-06 and 50-338,339/85-12. This report closes the remaining portions that were open including II.F.2.4, Instrumentation for Detection of Inadequate Core Cooling, Installation of Additional Instrumentation.

The ICCM system consists of 3 functional subsystems and 2 trains of instrumentation. The subsystems are RVLIS, CETM System, and SMM system. NRC letter of November 6, 1984 that transmitted the safety evaluation for TMI II.F.2. item states North Anna's proposed ICCM is acceptable upon completion of upgrading of the existing ICCM, implementation of revised EOPs, TS change for CETM and calibration of the RVLIS.

The licensee stated that upgrading of the ICCM system was accomplished in accordance with DCP 85-07 and 08, for units 1 and 2 respectively, and their submittal for RG 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident.

A RG 1.97 inspection was performed in April 1989 and is documented in NRC Report 50-338,339/89-11. The revised/upgraded EOPs have been implemented and confirmed by an NRC EOP inspection performed in June 1990 and is documented in NRC Report 50-338,339/90-11.

The TS requirements for operability and surveillance are listed in section 3.3.3.6 and tables 3.3-10 and 4.3-7. RVLIS is specifically listed in the TS and the TS core thermocouple listing applies to the CETM system. The latter was added by amendments 104 and 91, for Units 1 and 2 respectively, to be in conformance with NUREG-0737 and Generic Letter 83-37.

A review was made of recent completed procedures (2-PT-44.2.18 and ICP-RC-2-RVLIS-01, RVLIS Instrumentation Calibration - Sensors) for RVLIS calibration that shows the system is calibrated satisfactorily and meets the procedures' acceptance criteria.

9. Exit (30703)

The inspection scope and findings were summarized on November 16, 1990, 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
NCV 339/90-28-01	Inadequate and Unbalanced Safety Injection Flow Rates (Paragraph 5.b)
NCV 339/90-28-02	Missed Surveillance on PORV (Paragraph 6)
VIO 339/90-28-03	Failure to Have Turbine Trip Abnormal Procedure (Paragraph 7.a)
VIO 339/90-28-04	Failure to Conduct Adequate Design Review of Review of Undervoltage Diesel Start Relay Modification (Paragraph 7.b)

10. Acronyms and Initialisms

A/E - ARCHITECT/ENGINEER
AFW - AUXILIARY FEEDWATER
CETM - CORE EXIT TEMPERATURE MONITORING
CFR - CODE OF FEDERAL REGULATIONS
CRDR - CONTROL ROOM DESIGN REVIEW
DCP - DESIGN CHANGE PACKAGE
ECCS - EMERGENCY CORE COOLING SYSTEM
ECT - EDDY CURRENT TESTING
EDG - EMERGENCY DIESEL GENERATOR
EOP - EMERGENCY OPERATING PROCEDURE
ESF - ENGINEERED SAFETY FEATURES
EWR - ENGINEERING WORK REQUEST
FW - FEEDWATER
GPM - GALLONS PER MINUTE
ICCM - INADEQUATE CORE COOLING MONITORING
IRPI - INDIVIDUAL ROD POSITION INDICATION
LER - LICENSEE EVENT REPORT
LCO - LIMITING CONDITIONS FOR OPERATION
LOCA - LOSS OF COOLANT ACCIDENT
MFP - MAIN FEED PUMP
MOV - MOTOR OPERATED VALVE
NCV - NONCITED VIOLATION
NRC - NUCLEAR REGULATORY COMMISSION
PCT PEAK CENTERLINE TEMPERATURE
PORV - POWER OPERATED RELIEF VALVE
PM - PREVENTIVE MAINTENANCE
PPM - PARTS PER MILLION
PT - PERIODIC TEST
RCS - REACTOR COOLANT SYSTEM
RVLIS - REACTOR VESSEL LEVEL INSTRUMENTATION SYSTEM
RG - REGULATORY GUIDELINE
RWST - REFUELING WATER STORAGE TANK
SG - STEAM GENERATOR
SI - SAFETY INJECTION
SSM - SUBCOOLED MARGIN MONITOR
SSPS - SOLID STATE PROTECTION SYSTEM
TMI THREE MILE ISLAND
TS - TECHNICAL SPECIFICATION
UFSAR- UPDATED FINAL SAFETY ANALYSIS
VCT - VOLUME CONTROL TANK