UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report No.: 50-302/95-16

Licensee: Florida Power Corporation
3201 34th Street, South
St. Petersburg, FL 33733

Docket No.: 50-302 License No.: DPR-72

Facility Name: Crystal River 3

Inspection Conducted: August 6 through September 16, 1995

Inspector: R. Schin for 10/11/95
R. Butcher, Senior Resident Inspector Date Signed

Accompanying Inspectors:

T. Cooper, Resident Inspector
T. Johnson, Senior Resident Inspector - Turkey Point Nuclear Plant
K. Landis, Acting Branch Chief, Division of Reactor Projects
L. Raghavan, Project Manager, Nuclear Reactor Regulation
R. Schin, Project Engineer
M. Scott, Resident Inspector - Farley Nuclear Plant
M. Thomas, Reactor Engineer, Division of Reactor Safety

Approved by: K. Landis 10/11/95
K. Landis, Acting Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

These inspections were conducted by the resident and regional inspectors in the areas of plant operations, surveillance observations, maintenance observations, plant support, self assessment, on-site engineering evaluation, on-site follow-up and in-office review of written reports of non-routine events and 10 CFR Part 21 reviews, plant operations follow-up, maintenance activities follow-up, engineering activities follow-up, plant support follow-up, and a follow-up inspection of the licensee's Corrective Action Plan. Numerous facility tours were conducted and facility operations observed. Backshift inspections were conducted on August 9, 10, 11, 21, 22, 23, 29, 30, and September 6, 7, 11, 12, 13, 14, 1995.

Results:

During this inspection period, the inspectors had comments and findings in the following areas:

Plant Operations:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations.

The operability determination for the Emergency Feedwater Initiation and Control natural circulation cooldown setpoint stated the system was operable based on the guidance in the EOPs and that a Short Term Instruction would be issued to instruct the operators on the issue. This was not done until the next day. This is identified as a weakness. (paragraph 1.1.2.5)

A violation (50-302/95-16-03) was identified for an inadequate procedure for operation of the Makeup Pump 1A cooling water. (paragraph 1.8.2.3)

The inspectors considered the licensee's actions for Tropical Storm Jerry to be conservative and proper. (paragraph 1.1.2.3)

The actions taken by the shift supervisor on duty in questioning the adequacy of SP-907A are considered a strength. (paragraph 1.2.2.2)

A non-cited violation (50-302/95-16-04) was identified for the failure to follow the control complex habitability envelope breach procedure. (paragraph 1.10.2.1)

The Operations Department Event Free Operations Program was well established, set the standard for the other departments, and was considered a strength. (paragraph 2.1.2.1.a)

With the notable exception of the operations area, the licensee's tracking and trending process for the Event-Free Operations Program was not clearly defined, was inconsistently applied, and could fail to identify adverse trends. This was identified as a weakness. (paragraph 2.1.2.1.e)

Management oversight of significant issues needs to be strengthened. Several examples were identified where issues had not received adequate management attention (i.e. operability determination process, control complex habitability envelope resolution, root cause evaluations, large Request for Engineering Assistance backlog, etc.). This was identified as a weakness. (paragraph 2.1.2.2)

For operability determinations, the clear expectations reflecting management's highest safety standard was absent. This was shown by the lack of a detailed and thorough process with rigorous guidance for making operability determinations. This was identified as a weakness. (paragraph 2.1.2.3)

Maintenance:

The failure to notify the operations personnel of the inoperable reactor building pressure indicator (BS-91-PI) is a weakness in communications and indicative of weak management oversight on the follow-up of the failure to complete the calibration. (paragraph 1.9.2)

A non-cited violation (50-302/95-16-01) was identified for inadequate procedures for the performance of the emergency diesel generator undervoltage relay surveillance testing. (paragraph 1.2.2.3)

A non-cited violation was identified for failure to follow instructions for the wiring of the engineered safeguards core flood valve, CFV-25. (paragraph 1.3.2.2)

Engineering:

The inspectors noted a sound program for the control of temporary modifications. (paragraph 1.6.2)

A deviation from the design commitments for the technical support center emergency ventilation system was identified. (paragraph 1.11.2.1)

The failure to correctly incorporate the design basis for the Emergency Feedwater Initiation and Control natural circulation cooldown setpoint into procedures was identified as an additional example of violation 50-302/95-02-04. (paragraph 1.1.2.5)

The failure to meet Technical Specification requirements for Emergency Feedwater actuation circuitry on low steam generator level is considered an additional example of violation 50-302/95-02-04. (paragraph 1.1.2.4)

The inspector concluded that the licensee's control room habitability envelope action plan was weak in assuring that the plant was currently operating within its Control Complex Habitability Envelope design basis. (paragraph 1.10.2.1)

Systems engineering efforts to resolve the issues with the technical support center ventilation is considered a strength. (paragraph 1.11.2.1)

Plant Support:

The observation by a security guard of an oil leak on a service air compressor and the prompt notification of operations is considered a strength. (paragraph 1.4.2.2)

Several weaknesses were identified in a housekeeping tour of the auxiliary building. (paragraph 1.4.2.3)

Other Comments:

Licensee notifications to the NRC Operations Center that the Emergency Response Data System (ERDS) was inoperable were never recorded and NRC management was not notified. (paragraph 1.1.2.7)

TABLE OF CONTENTS

REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

W. Bandhauer, Nuclear Shift Manager
*P. Beard, Senior Vice President, Nuclear Operations
*G. Boldt, Vice President Nuclear Production
*J. Campbell, Manager, Nuclear Plant Technical Support
*R. Davis, Manager, Nuclear Plant Maintenance
R. Fuller, Manager, Nuclear Chemistry
*G. Halnon, Manager, Nuclear Plant Operations
*B. Hickle, Director, Nuclear Plant Operations
*L. Kelley, Director, Nuclear Operations Site Support
H. Koon, Manager, Nuclear Outage
*G. Longhouser, Manager, Nuclear Security
W. Marshall, Nuclear Shift Manager
J. Maseda, Manager, Nuclear Engineering Design
*P. McKee, Director, Quality Programs
*R. McLaughlin, Nuclear Regulatory Specialist
L. Moffatt, Nuclear Shift Manager
*B. Moore, Manager, Production
J. Stephenson, Manager, Radiological Emergency Planning
W. Stephenson, Nuclear Shift Manager
F. Sullivan, Nuclear Shift Manager
R. Sweeney, Nuclear Shift Manager
*P. Tanguay, Director, Nuclear Engineering and Projects
R. Widell, Director, Nuclear Operations Training
*D. Wilder, Manager, Radiation Protection
G. Wilson, Nuclear Shift Manager

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

1.2 NRC Resident Inspectors

*R. Butcher, Senior Resident Inspector
*T. Cooper, Resident Inspector

*Attended exit interview

1.3 Other NRC Personnel on Site

A. Gibson, Director, Reactor Safety, Region II
T. Johnson, Senior Resident Inspector, Turkey Point Nuclear Plant
D. Matthews, Project Directorate, NRR
E. Merschoff, Director, Reactor Projects, Region II
R. Prevatte, Senior Resident Inspector, St. Lucie Nuclear Plant
L. Raghavan, Project Manager, NRR
*R. Schin, Projector Engineer, Reactor Projects, Region II
M. Scott, Resident Inspector, Farley Nuclear Plant
*M. Thomas, Reactor Engineer, Reactor Safety, Region II

2.0 Other NRC Inspections Performed During This Period

A meeting was held in the NRC regional office on August 25, 1995, to discuss the licensee's corrective actions in response to NRC concerns expressed during the March 1, 1995, meeting. The details on this meeting will be issued in a meeting summary.

Mr. T. Johnson was on site from August 21 through 25, 1995. Mr. Johnson helped the resident inspectors perform their inspection program and the results of his inspection are included in this report.

Mr. R. Schin was on site from August 14 through 18, 1995 to assist the resident inspectors in the performance of their inspection program. The results of his inspection are included in this report.

Mr. R. Prevatte was on site on August 11, 1995 to maintain current access to the site and to remain familiar with the site. No report will be issued for the visit.

Mr. E. Merschoff was on site on September 1, 1995. Mr. Merschoff attended an operations turnover meeting, Plan of the Day Meeting, and toured the facility with the residents. He also met with plant management to discuss open issues regarding plant performance. No report will be issued for this visit.

Mr. M. Scott was on site from September 5 through 8, 1995. Mr. Scott helped the resident inspectors perform their inspection program and the results of his inspection are included in this report.

Mr. A. Gibson was on site on September 6, 1995. Mr. Gibson attended the Plan of the Day Meeting and toured the facility with licensee management. He also met with plant management to discuss open issues regarding plant performance. No report will be issued for this visit.

Mr. D. Matthews was on site on September 12, 1995. Mr. Matthews met with plant management to discuss open issues regarding plant performance. No report will be issued for this visit.

Mr. K. Landis, Mr. R. Schin, Mr. M. Thomas, Mr. L. Raghavan, Mr. R. Butcher, and Mr. T. Cooper conducted an assessment of the management Corrective Action Plan. The results of this assessment are included in Attachment 2 to this report.

3.0 Plant Status

At the beginning of this reporting period, Unit 3 was operating at 100% power and had been on line since December 4, 1994. The following evolutions occurred during this assessment period:

On August 15, 1995, the unit reduced power to 93% to maintain the generator cold gas temperature within limits, per request by the load dispatcher. Full power operation resumed later that day.

Due to secondary cooling heat exchanger fouling, on August 18, 1995, at 9:30 p.m., reactor power was reduced to approximately 95% to reduce load. Power was reduced to approximately 70% on August 18, 1995, to maintain generator cold gas temperature within limits. At 6:30 a.m. on August 20, power was reduced to 58% to permit cleaning of the secondary heat exchangers. At 4:11 a.m. on August 21, after SCHE-1A was cleaned, power was increased to 100% power on the one heat exchanger.

Due to the entering of TS 3.0.3 for EFIC setpoint problems, the unit began a shutdown at 11:55 a.m., on August 30, 1995. The setpoint calibration was completed at 3:30 p.m. and the TS action statement was exited at 3:33 p.m. Reactor power was at approximately 40% when the statement was exited. Power was returned to approximately 100%.

Due to a failure in the RCPPM on the D RCP, on August 31, 1995, the licensee reduced power to 96.8% reactor power in accordance with TS 3.3.1, Condition E. Power remained at 96.8% at the end of this report period.

4.0 Exit Interview Summary

The inspection scope and findings were summarized on September 14, 1995, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
NCV	95-16-01	Closed	Inadequate procedure for the performance of the emergency diesel generator undervoltage relay surveillance testing (paragraph 1.2.2.3)
NCV	95-16-02	Closed	Failure to follow the instructions for wiring CFV-25 (paragraph 1.3.2.2)
VIO	95-16-03	Open	Inadequate Procedure for Operation of the Makeup Pump 1A Cooling Water (paragraph 1.8.2.3)
NCV	95-16-04	Closed	Failure to follow CCHE breach procedure (paragraph 1.10.2.1)
DEV	95-16-05	Open	Deviation From the Design Commitments for the Technical Support Center Emergency Ventilation System (paragraph 1.11.2.1)

EEI	95-02-04	Open	Two Additional Examples of Instrumentation Setpoint Violations. (paragraphs 1.1.2.4 and 1.1.2.5)
IFI	95-08-03	Open	Emergency Operating Procedure Update Program (paragraph 1.8.2.2)
IFI	92-22-01	Closed	Completion and Implementation of Upgraded Annunciator Response Procedures and Review of Procedure MP-402C (paragraph 1.8.2.4)
URI	95-11-02	Closed	Operating MUP-1A Outside the Design Basis (paragraph 1.8.2.3)
URI	95-02-02	Open	Control Room Habitability Envelope Leakage Plan (paragraph 1.10.2)
LER	92-03	Closed	Personnel Error and Lack of Technical Review in Past Procedure Revision Process Leads to Incorrect Procedures Resulting in Violation of Technical Specifications and Design Basis (paragraph 1.7.2.8)
LER	94-06	Closed	Deficiency in Understanding of Technical Requirements Leads to Nonconservative RPS Setpoint and Potential Violation of Technical Specifications (paragraph 1.7.2.1)
LER	94-07	Closed	Personnel Error Leads to Failure to Perform Surveillance Resulting in Violation of Technical Specification (paragraph 1.7.2.4)
LER	95-01	Closed	Inspection Determines Control Complex Habitability Envelope In-Leakage Area Exceeds Requirements Resulting in Condition Potentially Outside Design Basis (paragraph 1.7.2.2)
LER	95-04	Closed	Control Complex Habitability Envelope Breach Due to Personnel Leaving Two Doors Open (paragraph 1.7.2.5)
LER	95-05	Closed	Engineering Evaluation Determines Insufficient LPI Pump Net Positive Suction Head May Result in Operation

			Outside Design Basis (paragraph 1.7.2.7)
LER	95-06	Closed	General Knowledge Deficiency Causes Level Instrumentation to be Subjected to Low Temperatures Resulting in Challenge to Design Basis (paragraph 1.7.2.6)
LER	95-10	Closed	Inadequate Procedure Causes Low Cooling Water Flow to Makeup Pump Resulting in Operation Outside the Design Basis (paragraph 1.7.2.3)

Attachment 1
Resident's Inspection
(R. Butcher, T. Cooper, T. Johnson, R. Schin, M. Scott)

1.1.0 Plant Operations (71707)

1.1.1 Inspection Scope

Throughout the inspection period, facility tours were conducted to observe operations and maintenance activities in progress. The tours included entries into the protected areas and the radiologically controlled areas of the plant. During these inspections, discussions were held with operators, health physics and instrument and controls technicians, mechanics, security personnel, engineers, supervisors, and plant management. Some operations and maintenance activity observations were conducted during backshifts. Licensee meetings were attended by the inspector to observe planning and management activities. The inspections confirmed FPC's compliance with 10 CFR, Technical Specifications, License Conditions, and Administrative Procedures.

The inspectors performed an inspection designed to verify the status of the Reactor Building Spray System. This was accomplished by performing a complete walkdown of all accessible equipment. The following criteria were used, as appropriate, during this inspection:

- systems line-up procedures matched plant drawings and as-built configuration;
- housekeeping was adequate, and appropriate levels of cleanliness were being maintained;
- valves in the system were correctly installed and did not exhibit signs of gross packing leakage, bent stems, missing handwheels, or improper labeling;
- hangers and supports were made up properly and aligned correctly; and
- valves in the flow paths were in correct position as required by the applicable procedures with power available, and valves were locked/lock wired as required.

1.1.2 Observations and Findings

1.1.2.1 Walkdown of the Reactor Building Spray System

The general condition of the RBS System was observed to be good. Valves were positioned per the system operating procedure; components were correctly labeled; no missing parts or gross packing leaks were observed; and painting, housekeeping, and cleanliness were very good. System line-up procedures generally matched plant drawings and as-built configuration. The FSAR had been updated to reflect the use of TSP in place of sodium hydroxide for post-LOCA containment sump pH control. The sodium hydroxide injection system had been abandoned in place in a controlled manner by a MAR. The following observations were noted:

- Valves BSV-59 and BSV-60, pressure indicator isolation valves, were required to be closed by the operating procedure and were actually closed but were shown as open on the system flow diagram drawing.

- BSV-11 and BSV-12, isolation valves for BST-1 and BST-2 (sodium hydroxide tanks that were not in use and were abandoned in place) had their motor power cables disconnected, but not removed. Instead, the power cables were hanging free near the valves.

- Some of the blue valve position indicating lights in the control room were very difficult to determine if they were lit or not.

In addition, the following minor deficiencies were noted:

- BSV-36 and BSV-37, BST isolation valves, were shown on the system operating procedure to be located in the 95′ elevation of the Auxiliary Building. However, they were actually located in A and B Decay Heat Pits.

- The room in which BST-1 and BST-2 were located was flooded with about four inches of water. The water was in contact with the side of the BWST, which occupied the same room.

The inspector gave these comments to the licensee for followup.

1.1.2.2 Organizational Changes

By memo dated August 18, 1995, Mr. P. Beard, Senior Vice President, Nuclear Production, issued a reorganization plan to be effective August 25, 1995. The changes were as follows:

- H. Koon, Manager, Nuclear Outage, P. Skramstad, Administrator, Master Schedule, and B. Moore, Manager, Production (and the production scheduling group) will report to Bruce Hickle, Director, Nuclear Plant Operations. They previously reported to G. Boldt, Vice President, Nuclear Production.

- J. Campbell, Manager, Nuclear Plant Technical Support, (and the technical support department) will report to P. Tanguay, Director, Nuclear Engineering and Projects. He previously reported to G. Boldt.

- P. Tanguay will report to G. Boldt. He previously reported to P. Beard.

- D. O'Shea, Manager, Nuclear Fuel Management and Safety Analysis, (and the nuclear fuels group) will report to P. Tanguay. He previously reported to L. Kelly, Director, Nuclear Operations Site Support.

- D. Watson, Manager, Nuclear Operations Access Control, will report to R. Widell, Director, Nuclear Operations Training. He previously reported to L. Kelly.

- V. Hernandez, Employee Concerns Representative, (and the employee concerns function) will report to P. McKee, Director, Quality Programs. He previously reported to L. Kelly.

An attachment to the interoffice correspondence provided a description of the revised roles and responsibilities of the Senior Vice President, Vice President, and the DNPO.

On September 13, 1995, the licensee announced that B. Gutherman will assume the duties on Nuclear Licensing Manager effective October 2, 1995, reporting to L. Kelly. He was previously Supervisor of Design Engineering.

1.1.2.3 Tropical Storm Jerry

On August 23, 1995, at 2:00 p.m. Tropical Depression 11 was upgraded to a Tropical Storm and named Jerry. The center was located near West Palm Beach, FL and maximum sustained winds were 40 mph. A Tropical Storm watch was in effect for the west coast of FL from Tarpon Springs to Panama City. This included Citrus County where CR-3 is located. The licensee entered their procedure EM-220, Violent Weather, and since Tropical Storm Jerry was not predicted to increase in severity, but was expected to lose strength, the DNPO directed the Shift Manager to take specific actions of portions of EM-220. The residents reviewed the Violent Weather log being kept in the control room and had no questions.

At 5:15 a.m. on August 24, Citrus County was designated as being in a Tropical Storm Warning area. Tropical Storm Jerry was near Lakeland, FL and had maximum sustained winds of 40 mph. At 11:00 a.m. on August 25, the storm warnings for Tropical Storm Jerry were lifted and the licensee exited the actions of EM-220. The inspectors considered the licensee's actions for Tropical Storm Jerry to be conservative and proper.

1.1.2.4 Plant Shutdown Required Under TS 3.0.3

On August 30, 1995 at 12:16 p.m. the licensee made a notification of plant shutdown required under TS 3.0.3. The notification was made per 10 CFR 50.72(b)(1)(i)(A), Plant Shutdown required by TS, and 10 CFR 50.72(b)(1)(ii)(B), Outside Design Basis. As part of their plant setpoint calculation program, the licensee discovered that the EFW initiation setpoint for low OTSG water level was lower than required by TSs. This made all four channels of EFW inoperable and a shutdown was initiated at 11:55 a.m.

TS 3.3.11, Emergency Feedwater Initiation and Control (EFIC) System Instrumentation, Table 3.3.11-1, Function 1.b, OTSG Level-Low, requires 4 channels per OTSG with an allowable value of greater than or equal to 0 inches. To provide for instrumentation and other potential errors. The existing setting per SP-146A, EFIC Monthly Functional Test (During Modes 1,2,3), was 6 inches. Per the latest licensee calculation, this value should be 9.3 inches. The licensee revised the existing procedure, held a PRC review, and then, to allow for some margin, the EFIC settings were changed to 11 inches. TS 3.0.3 was exited at 3:26 p.m. when 3 of the EFIC channels had been reset to the new setpoints and entered TS 3.3.11, Condition A. TS 3.3.11, Condition A was exited at 3:33 p.m. when all 4 EFIC channels were reset.

The licensee initiated PR 95-0162, Initiated TS Required Shutdown, TS 3.0.3, to document the actions taken and any required corrective actions to be taken. STI 95-0045 was issued to alert the operators that the EFIC initiate setpoints, on low OTSG water level, had been changed from 6 inches to 11 inches.

The issue of non-conservative trip setpoints for safety related instrumentation was previously reported in NRC IRs 50-302/94-22, 94-25, and 95-02. Also EA 95-016, Notice of Violation and Proposed Imposition of Civil Penalty- $25,000, was issued on March 24, 1995. As part of the licensee's corrective action was the detailed evaluation to assure all TS limits were incorporated into implementing documents.

The failure to have four operable channels for EFW actuation on OTSG low level per TS Table 3.3.11-1, function 1.b, is a violation. This violation is considered an additional example of violation 50-302/95-02-04 which was issued under EA 95-016.

1.1.2.5 Non-Conservative EFIC Natural Circulation Cooldown Setpoint

On August 31, 1995 at 3:51 p.m. the licensee made a notification to the NRC pursuant to 10 CFR 50.72(b)(1)(ii)(B) for being outside the design basis for the EFIC setpoint for natural circulation cooldown. During the setpoint verification process (see paragraph 1.1.2.4 above) the licensee identified that the natural circulation setpoint did not accurately account for maximum string inaccuracies. The existing EFIC setpoint of 281 inches in the OTSG should actually be 316 inches per the latest calculation. PR 95-0164 was initiated to document this problem and required corrective actions. Also, an NOD-14, Evaluating Operability and Determining Safety Function Status, was conducted for this event.

The NOD-14 concluded that the EFIC system was operable based on the guidance in the EOPs that operators can assist in the establishment of natural circulation if the present automatic setpoint for water level was not adequate. EOP-09, Natural Circulation Cooldown, step 3.1 states to ensure OTSG levels are at or trending to 60 to 70%. Step 3.2 states that if MFW is being used to feed the OTSGs, then maintain OTSG level 60 to 70% manually. Step 3.4 states that if natural circulation cannot be verified, then go to EOP-04, Inadequate Heat Transfer. The original setpoint of 281 inches corresponds to 61.3 % in the OTSG and the new setpoint of 316 inches corresponds to 73.4% in the OTSG.

The NOD also stated that operations would initiate an OSB entry describing what could occur with the existing setpoint. PR 95-0164 had a statement that an STI would be issued to change the EOP setpoint utilized for maintaining natural circulation. On September 1, at the 7:00 a.m. operations turnover meeting no mention was made of the new operability requirement for EFIC, no OSB entry had been made, and no STI had been issued regarding this problem. An OSB entry (OSB #9509.04) was issued later in the day on September 1, 1995. This failure to promptly perform the actions designated on PR 95-0164 and on the NOD-14 is a weakness and was brought to the attention of the DNPO.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that applicable regulatory requirements and the Design Basis, as defined in 10 CFR 50.2, Definitions, and as specified in the license application, are correctly transmitted into specifications, drawings, procedures, and instructions.

FSAR paragraph 7.2.4.1, Design Basis, states in part, that the EFIC system is designed to provide OTSG level control of emergency feedwater. Paragraph 7.2.4.2, System Design, states that the OTSG high range transmitters (SP-17-LT and SP-24-LT) are used for level control when the system is controlling at the natural circulation setpoints.

However, the design basis for the EFIC natural circulation cooldown setpoint was not correctly incorporated into procedures in that on August 31, 1995 the licensee found that the EFIC natural circulation cooldown setpoints were presently set at 281 inches in the OTSG in lieu of the required 316 inches. This a violation of 10 CFR 50, Appendix B, Criterion III and is identified as an additional example of the violation 50-302/95-02-04 which was issued under EA 95-016.

1.1.2.6 Failure of a RCPPM

On August 31, 1995, at 2:50 p.m. the licensee identified that during a heavy rain, temporary sleeving that was attached to new storm drains being installed on the intermediate building roof ruptured allowing water to spray on electrical equipment. The licensee installed temporary covers on the affected equipment. Subsequently, at 5:00 p.m., while performing SP-300, Operating Daily Surveillance Log, the auxiliary building operator noted that D RCPPM Number 1 was indicating out of specification low. Licensee investigation showed that the input to the channel was from the same electrical equipment reported as becoming wet from the temporary roof drain. The operators entered TS 3.3.1, Reactor Protection System (RPS) Instrumentation, Condition C, One or More RCPPMs For One RCP Inoperable; which required the RCPPM be tripped within 4 hours. Subsequently, the operators entered TS 3.3.1, Condition E, which requires within one hour, (if Condition C is not met) that operators (1) verify 4 RCPs are in operation, and (2) reduce reactor thermal power to < 2475 MW_{th}. The TS basis states that this trip function is not necessary when thermal power is less than 2475 MW_{th} and four RCPs are in operation. RCPPM number 1 for RCP D was placed in bypass and TS 3.3.1, Condition E, was entered at 8:55 pm.

On September 1, 1995, at 1:05 am, OP-507, Operation of the ES, RPS, and ATWS Systems, had been revised and RCPPM number 1 for RCP D was placed back in the tripped condition per TS 3.3.1, Condition C. Power was returned to 100% at 1:45 a.m.

On September 1, 1995, at 11:25 a.m., the C RPS power/pump bistable tripped causing the C RPS channel to trip. The condition immediately cleared and the licensee was unable to determine the input signal causing the C RPS channel to trip. Since only the C RPS channel tripped, and the D RCPPM was already indicating a trip signal to all four RPS channels, the assumption is that the C RPS received a second intermittent RCPPM signal that then went away. Operators reset the C RPS channel at 11:30 a.m.

Per WR 330211, the licensee performed troubleshooting to determine the root cause for the failure of RCPPM channel 1 for RCP D. Investigation indicated that the PT for RCTR-2 supplying the RCP D RCPPM. Channel 1 had no output which could be from a failed PT or a blown fuse on the primary side. This will require removing the D RCP from service for repair. The RCTR-2 power supply to RCP D RCPPM channel 2 showed no abnormalities.

On September 2, 1995, at 4:50 a.m., the licensee entered TS 3.3.1, Condition E and exited TS 3.3.1, Condition C. Four RCPs were verified to be in operation and power was reduced to < 2475 MW_{th} (approximately 97% RTP). This was done to allow maintenance activities associated with the RCPPM input from RCP C to the C RPS channel. Input from the D RCP to RCPPM channel 1 was placed in bypass. Trouble shooting activities confirmed that a problem existed with the pump to power bistable. The licensee is attempting to obtain replacement parts for the RCPPM before attempting to troubleshoot and repair.

On September 4, 1995, at 9:28 p.m., PR 95-0168 was initiated documenting the degraded trip string for the C RPS channel. The C RPS channel was declared inoperable at that time. On September 11, 1995, the licensee successfully completed SP-110, Reactor Protection System Functional Testing, and declared the C RPS channel operable. The RPS channel was removed from bypass at that time.

A review by the inspectors noted that on two previous occasions, the licensee had identified the possibility of leakage through the roof impacting energized electrical components. PC 95-0007 and 95-0119 were both written to address this issue. The licensee dispositioned these PCs with the plans to reroof the buildings. Interim repairs and the temporary drain system was determined to be sufficient to protect the electrical components. The failure of the drain was not anticipated in the development of the corrective actions.

1.1.2.7 Emergency Response Data System

On August 1, 1995, at approximately 10:00 am, the licensee notified the inspectors that the ERDS system had failed the communications check and had been declared inoperable. At that time, the SSOD made a courtesy notification to the NRC Operations Center of the status of ERDS. Per the licensee procedure NOD-31, Non-Safety Related Equipment/Reliability Improvement Policy, this equipment receives special consideration when it is inoperable. The procedure directs that maintenance be initiated as soon as practicable and if the system is not restored within 30 days, a PR will be initiated.

Initially, the licensee concluded that the problem was with the NRC supplied modem, but were unable to confirm this because of problems communicating with the NRC vendor who administers the ERDS program. Parallel with the effort to replace the modem, the licensee was performing a review and rewrite of their software which is used to gather and transmit the ERDS data.

On August 11, 1995, the licensee again notified the NRC Operations Center that ERDS was inoperable. The inspectors spoke with NRC personnel in the regional office and NRR and verified that they were not aware ERDS was inoperable. The inspectors contacted the NRC Operations Center and determined that the notifications by the licensee were not recorded nor communicated to NRC management.

10 CFR 50, Appendix E, Section VI, requires that the licensee have a ERDS system. However, it appears that when the system is inoperable, even if the licensee notifies the NRC, there is no tracking or notification of NRC management of the degraded condition of the system. The inspectors verified that the notifications made to the NRC Operations Center were not recorded and the information had not been passed on to NRC management.

The NRC supplied a replacement modem to the licensee and the licensee was able to confirm that the problem was with the software at the site. The licensee rewrote the software and instructed the licensee operations staff on the use of the new programs. ERDS was restored to operable status on September 2, 1995. Since the system was inoperable for more than 30 days, the inspectors verified that a PR was issued in accordance with NOD-31. The licensee is preparing a special report detailing the changes to the software and the circumstances involved in the change, as required by 10 CFR 50, Appendix E, Section VI.3.b, to the NRC on the issue.

1.1.2.8 Preparation for Nuclear Services Closed Cycle Cooling Flow Balance

During the licensee review of the procedures for the SW flow balance, it was determined that the chilled water valves CHV-68 and CHV-69, which control the flow of SW water through the control complex chillers, fail open on a loss of air to the control solenoids. The air to these solenoids is supplied from a local air compressor. The potential exists, that on a loss of offsite power, with a single diesel generator failing to start, the valve to one chiller will fail open. If that chiller is the idle chiller, SW flow will be diverted to both chillers and away from safety related loads.

The inspectors verified the licensee took appropriate corrective actions, isolating the SW valves to the idle chiller and taking control to prevent them from being opened. Operations is revising procedures to assure that the SW valves to the chillers will be manually controlled.

1.1.2.9 INPO Report Review

During the week of May 23, 1995, INPO conducted an assist visit of design engineering interfaces and communications at Crystal River 3. A final report of that evaluation was issued to FPC management in June 1995. In accordance with NRC Field Policy Manual #9, the resident inspectors reviewed the INPO final report and concluded that no new safety concerns were identified. Based on the above review, no additional NRC follow-up of issues discussed in the INPO report is planned.

1.1.3 Results

Two additional examples of a previously cited violation were identified, concerning setpoint control issues.

1.2.0 Surveillance Observations (61726)

1.2.1 Inspection Scope

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of the TSs; testing was performed in accordance with adequate procedures; test instrumentation was calibrated; limiting conditions for operation were met; test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspectors verified testing frequencies were met and tests were performed by qualified individuals.

1.2.2 Observations and Findings

1.2.2.1 Surveillance Observations

The inspectors witnessed/reviewed portions of the following test activities:

-SP-146A EFIC Monthly Functional Test, During Modes 1,2,3

1.2.2.2 Review of SP-904, Calibration of 4160 Volt ES Bus Degraded Grid Relays

The inspectors, while reviewing SP-904, Calibration of 4160 Volt ES Bus Degraded Grid Relays, noted that the procedure did not require a functional test following the maintenance on the relays, prior to declaring the system operable. This procedure is the 18-month channel calibration performed per SR 3.3.8.2.

Discussions between the inspectors and the SSOD revealed that the licensee's operators had previously identified multiple concerns over the adequacy of the procedure. Until these concerns are answered, the procedure performance has been postponed. Licensing and engineering have been tasked with answering these questions by the end of September, to allow the procedure to be revised and the performance of the surveillance in October, within the allowable grace period of the SR.

This procedure is normally performed in conjunction with OP-703, Plant Distribution System. One concern is the potential of defeating the bus stripping on degraded conditions during the performance of the test.

1.2.2.3 Review of SP-907A, Monthly Functional Test of 4160V ES Bus "A" Undervoltage Relaying

In response to the questions raised on SP-904 as described in paragraph 1.2.2.2, the SSOD reviewed SP-907A, prior to its scheduled performance on September 12, 1995. It was determined at that time that the note associated with TS SR 3.3.8.1, which allows the instrument to be rendered inoperable for up to four hours during the performance of the surveillance without entering the appropriate condition statement, does not apply since the test is conducted with all three of the relays on a bus removed from service simultaneously.

The licensee determined that during the performance of the surveillance test, the diesel generator is rendered inoperable at the beginning of the test, by manually positioning the fuel racks to full closed, to prevent a spurious start. When this step is done, the procedure has the licensee enter TS 3.8.1, AC Sources - Operating, Action B, which allows the EDG to be inoperable for 72 hours. Even though the procedure references the note in the TS, it also references TS 3.3.8.1, Action B, if the test exceeds the note exemption. That action statement requires the restoration of the undervoltage function within one hour. If the function is not restored within one hour, TS 3.3.8.1, Action C requires that the appropriate TS be entered for a diesel generator rendered inoperable by an inoperable undervoltage relay. This is TS 3.8.1, which the licensee enters at the beginning of the procedure. The result is that even using the procedure, the TS requirements are not violated.

In past performances of SP-907A and B, the licensee has avoided violating TS by entering TS 3.8.1. However, the procedure did apply the note to TS 3.3.8.1, incorrectly. This inadequate procedure did not correctly address TS requirements, nor recognize that the testing methodology differed from that assumed in the TS note. The fact that the procedure has the licensee enter the TS for an inoperable EDG, reduces the significance of the violation. Therefore, the criteria of section VII.B of the Enforcement Policy are satisfied and this is a non-cited violation, NCV 50-302/95-16-01: Inadequate procedure for the performance of the emergency diesel generator undervoltage relay surveillance testing. The action taken by the SSOD in questioning the adequacy of the procedure is considered a strength.

1.2.3 Results

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs.

One non-cited violation was identified concerning an inadequate procedure to perform TS surveillance testing on the emergency diesel generator undervoltage relays.

1.3.0 Maintenance Observations (62703)

1.3.1 Inspection Scope

Station maintenance activities of safety-related systems and components were observed and reviewed to ascertain they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with the TSs.

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

1.3.2 Observation and Findings

1.3.2.1 WR NU 0330347, Troubleshoot and Repair AHF-17B

The inspectors witnessed/reviewed portions of the following maintenance activities in progress:

- WR NU 0330347, Troubleshoot and Repair AHF-17B

The inspectors reviewed the work package to verify that the work was properly planned and approvals had been received prior to beginning the work. The work was completed in a timely manner and post-maintenance testing verified that the corrective actions were appropriate.

1.3.2.2 WR NU 0329538, Core Flood Valve Wiring Discrepancy

On August 8, 1995, during the performance of WR 329538, the relay which controls the ES isolation function of CFV-25 was found to be incorrectly wired. The licensee's investigation revealed that the wiring matrix was such that CFV-25, which is a containment isolation valve for the core flood tank, would have gone closed if one out of three channels tripped, in lieu of the two out of three channels, as designed.

CFV-25 is normally closed during power operations which is also its ES position. This wiring error placed the ES matrix in a conservative condition, providing an ES closure signal to this valve on a one out of three signal.

On August 10, 1995, the licensee made a notification of this event per 10 CFR 50.72(b)(2)(ii), ESF actuation, due to the uncertainty of whether an ESF actuation had occurred while this valve was opened for filling the core flood tank.

The licensee evaluation was unable to determine if the valve was miswired during original installation or during a later (approximately 1985) modification to install a test matrix for the ES valves. The inspectors reviewed the results of the licensee evaluations and determined that the notification and approach to corrective actions was conservative and proper. The wiring was corrected at the time that the discrepancy was identified. Further followup by the licensee showed no further discrepancies in similar installations.

The failure to install the wiring of the CFV-25 valve is a violation of 10 CFR 50, Appendix B, Criterion V, in that the work instructions used to install this system were not appropriately followed. This licensee identified violation meets the criteria for an NCV per Section VII.B of the Enforcement Policy and is not being cited. This is identified as NCV 50-302/95-16-02: Failure to follow the instructions for wiring CFV-25.

1.3.3 Results

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders.

One non-cited violation was identified concerning the failure to follow the instructions for the wiring of a core flood valve.

1.4.0 Plant Support (71750)

1.4.1 Inspection Scope

Radiation protection control activities were observed to verify that these activities were in conformance with the facility policies and procedures, and in compliance with regulatory requirements.

In the course of the monthly activities, the inspector included a review of the licensee's physical security program.

The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages, and vehicles; badge issuance and retrieval; escorting of visitors; patrols; and compensatory posts.

Fire protection activities, staffing, and equipment were observed to verify that fire brigade staffing was appropriate and that fire alarms, extinguishing equipment, actuating controls, fire fighting equipment, emergency equipment, and fire barriers were operable.

1.4.2 Observations and Findings

1.4.2.1 Health Physics Observations

The observations in the health physics program included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;
- Area postings and controls;
- Work activity within radiation, high radiation, and contaminated areas;
- RCA exiting practices;
- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment; and
- NRC form 3 and NOVs involving radiological working conditions were posted in accordance with 10 CFR 19.11.

Effluent and environmental monitoring was observed to determine that radiation and meteorological recorders and indicators were operable with no unexplained abnormal traces evident. Other observations verified that control room toxic monitors were operable and that plant chemistry was within TS and procedural limits.

1.4.2.2 Security Observations

On August 12, 1995, a security guard, while performing his rounds reported an abnormal condition to the operations shift concerning the operating station air compressor. The guard noted a local low oil level alarm present which was indicative of an oil leak.

Following the notification, operations was able to locate and isolate the leak before it caused the compressor to trip and while the amount of oil was still small enough to be easily contained in the compressor enclosure, preventing a potential oil spill into the environment.

The inspectors reviewed the incident and consider the actions by the guard to identify a plant problem and take appropriate actions by notifying operations to be conservative and a strength.

1.4.2.3 Housekeeping Observations

The inspectors toured the site on several occasions, observing general housekeeping conditions. Areas where degraded conditions existed were identified to licensee management. Some observations noted during this inspection period include:

Auxiliary Building - 95 foot elevation

A loose handwheel was observed on the floor in the makeup valve alley.

The floor in the seawater room was dirty, with a large deposit of mud and corrosion on the floor underneath the RWP discharge check valves.

There were unsecured ladders and roll-steps leaning against the DC heat exchangers.

Multiple examples of unsecured equipment was stored behind the SW surge tank.

Auxiliary Building - 119 foot elevation

A plastic rope, secured in the cable trays overhead, was lying on the floor.

Two SCBAs were in the middle of an aisle near the BASTs.

The lights were all out in the MUT room. A tag on the door states that this condition has existed since December 23, 1994.

An unsecured ladder was leaning up against the wall outside of the contaminated laundry room.

Auxiliary Building - 143 foot elevation

The floor was dirty, including clods of mud in the general area.

There were many unsecured cleaning supplies stored in the general area; including mops and buckets, trash carts, hydraulic lifts, power sweepers, and hoses.

An unsecured hoist was parked adjacent to the auxiliary building ventilation system.

A second tour, conducted on the following day, revealed that many of these conditions had been corrected. The inspectors consider the poor housekeeping noted to be a weakness.

1.4.3 Inspection Results

Except as noted, the implementation of the plant support program observed during this inspection period were proper and conservative.

Violations or deviations were not identified.

1.5.0 Self Assessment (40500)

1.5.1 Inspection Scope

The licensee routinely performs Quality Program audits of plant activities as required under its QA program or as requested by management. To assess the effectiveness of these licensee audits, the inspectors examined the status, scope, findings and recommendations of the audit reports.

1.5.2 Inspection Observations and Findings

The inspectors reviewed the following audit report.

REPORT NO.	TITLE	NO. OF FINDINGS	NO. OF RECOMMENDATIONS
95-07-MAIN	Nuclear Plant Maintenance	0	12

There were no findings, therefore no NRC follow-up will be taken. Plant management is aware of the recommendations. The inspectors noted that the management of the maintenance department is aware of the recommendations and is taking aggressive actions to review and respond to them.

1.5.3 Inspection Results

Violations or deviations were not identified.

1.6.0 Onsite Engineering Evaluation (37551)

1.6.1 Inspection Scope

The licensee's Temporary Modification Program and its controls were reviewed by the inspectors.

1.6.2 Inspection Observation and Findings

Controls for temporary modifications are established using procedures NEP-210, Modification Approval Records, and NEP 212, Processing of Modification Projects by Nuclear Projects.

As of August 24, 1995, the inspector noted the presence of 22 active TMARs. These TMARs were further categorized as follows: 5 safety related, 10 Furmanite leak repairs, 1 from 1990, 1 from 1992, 2 from 1993, 14 from 1994, and 4 from 1995. The licensee tracks these TMARs, including a weekly status in the POD each Thursday. Further, the engineering projects group and the control room maintain an active listing of TMARs.

The inspector reviewed the overall TMAR listing, and reviewed in detail the following TMARs:

- T94-06-14-01, temporary CFV-11 ES indication,

- T95-07-07-01, BSV-153 flange spacer, and

- T95-08-19-01, MTTR-3A control panel cooler.

The inspector verified that the documentation packages were complete, including safety evaluations and reviews by system and design engineering, QA/QC, PRC, plant management, and control room operators. The inspector walked down these TMARs in the field and verified that the control room status, including drawings, was generally up-to-date. One TMAR, T95-01-13-01, installed a temporary sample valve in the makeup system in January 1995. The control room drawings were updated (red lined). The TMAR was removed in February 1995, however, the control room drawings were not updated. The inspector informed the engineering projects group and the document control issue was corrected. Further, the inspector verified that licensee had plans to remove these TMARs as appropriate. Only one TMAR was not scheduled to be removed by the upcoming refueling outage (10R in March, 1996). This TMAR (T90-07-01-01) was associated with a repair of the high pressure turbine main steam flange leak.

The inspector had the following comments relative to the TMAR program:

- No formal goal for TMAR age nor number exists. Although management indicated that their ultimate goal was zero.

- The PRC only reviews TMARs which are 10 CFR 50.59 screened. Thus, a safety related TMAR would bypass PRC review if the 10 CFR 50.59 review screens it out.

- There were no specific or unique identification tags to denote, or highlight TMAR installation in the field.

- The use of a TMAR document to track leak repairs (e.g., Furmanite) may be conservative.

In conclusion, the inspector noted a sound program for temporary modifications. However, one minor drawing discrepancy was noted and several program enhancements were discussed.

1.6.3 Inspection Results

Violations or deviations were not identified.

1.7.0 Onsite Follow-up and In-Office Review of Written Reports of Non-routine Events and 10 CFR Part 21 Reviews (92700, 90712)

1.7.1 Inspection Scope

The Licensee Event Reports and/or 10 CFR Part 21 Reports discussed below were reviewed. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. Additionally, the inspectors verified the licensee had reviewed each event, corrective actions were implemented, responsibility for corrective actions not fully completed was clearly assigned, safety questions had been evaluated and resolved, and violations of regulations or TS conditions had been identified. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

1.7.2 Inspection Observations and Findings

1.7.2.1 (Closed) LER 94-06: Deficiency in Understanding of Technical Requirements Leads to Nonconservative RPS Setpoint and Potential Violation of TS

The LER is administratively closed. On February 28, 1995, the licensee was apprised of an apparent Violation 50-302/95-02-04, Use of Non-Conservative Trip Setpoints fo. Calibrating Safety-Related Equipment. The NRC issued a Notice of Violation and Proposed Imposition of Civil Penalty (EA 95-016) on Marth 24, 1995. The licensee was completing their corrective actions regarding the setpoints (at the time of this writing) and those actions will be tracked and closed under the above violation number.

1.7.2.2 (Closed) LER 95-01: Inspection Determines Control Complex Habitability Envelope In-Leakage Area Exceeds Requirements Resulting in Condition Potentially Outside Design Basis

This LER is administratively closed. Unresolved item 50-302/95-02-02, Control Room Habitability Envelope Leakage (paragraph 3.f), discussed and covered the issues of the above LER. A number of questions have been routed to NRC Headquarters for resolution

(Task Interface Agreement 95003). The URI will track the issues of the LER and the text of the report to closure.

1.7.2.3 (Closed) LER 95-10: Inadequate Procedure Causes Low Cooling Water Flow to Makeup Pump Resulting in Operation Outside the Design Basis

This event is the same as the event discussed in paragraph 1.8.2.3, concerning operations of the MUP-1A outside of the design basis. The licensee has determined that the root cause was an inadequate procedure used to balance the cooling water flow to the pump motor. Corrective actions for this event will be followed under the violation issued in paragraph 1.8.2.3. This LER is closed.

1.7.2.4 (Closed) LER 94-07: Personnel Error Leads to Failure to Perform Surveillance Resulting in Violation of TS

This LER was written because of a missed surveillance caused by systems engineering, ISI and operations failing to recognize procedural impact as a result of MAR 93-12-07-02. This MAR added additional test taps to containment penetrations, which should have been tested every 31 days, per TS 3.6.3, Containment Isolation Valves. This event occurred in the same time frame as the AMSAC issue with procedures not being revised following modifications (see IR 50-302/94-19). Programmatic corrective actions for the AMSAC event should also be applicable in this instance. Additional corrective actions for this event include identifying additional procedures impacted by this MAR. The inspectors verified that this has been accomplished. Those procedures which are routinely performed (monthly or quarterly) have been verified to have already been revised. The inspectors verified that those procedures impacted which will be utilized in the next refueling outage have been identified, are being revised, and will be issued prior to the beginning of the outage. This LER is closed.

1.7.2.5 (Closed) LER 95-04: CCHE Breach due to Personnel Leaving Two Doors Open

This LER was issued following the identification by an operator of two instances during a shift where the CCHE door was not properly closed. As corrective actions, the licensee repaired the door so that it would close properly. The doors into the control complex have been equipped with local alarms to remind personnel to close the doors when passing through, the 124 foot elevation has been locked, leading from the turbine building into the control complex, and the elevator has been set to operate only with a key, to discourage unnecessary traffic into the control complex. Additional replacements are planned for the control complex doors and a change to TS is planned to be requested to change requirements for the door control. The corrective actions accomplished to date have minimized additional examples of the doors not being closed. The planned corrective actions remaining have the potential to eliminate recurrences. These actions will be followed as part of the followup on URI 50-302/95-02-02. This LER is closed.

1.7.2.6 (Closed) LER 95-06: General Knowledge Deficiency Causes Level Instrumentation to be Subjected to Low Temperatures Resulting in Challenge to Design Basis

On April 17, 1995, with the plant at 100% power, an engineering review determined that during the time period of January 31, 1995, through February 17, 1995, the BWST level instrumentation may have been exposed to ambient temperatures less than the minimum temperature considered in level measurement error calculations.

The BWST level instrumentation contains Regulatory 1.97 instrumentation; and TS Table 3.3.17-1, Post Accident Monitoring Instrumentation, requires two operable channels of BWST level instrumentation. The BWST level instrumentation must be error corrected, since the BWST level is used as an input to several safety related functions, including post accident operator dose calculations, BWST vortex calculations, and LPI pump NPSH. The licensee calculation I91-0012, Revision 0, BWST Level Accuracy, provided the error correction and was developed using a temperature range of 40°F through 110°F.

A check of ambient temperature recorded by the REDAS revealed that during the period in question, the ambient outdoor temperature was, at times, less than 40°F.

Based on the fact that, at times, the recorded ambient outdoor temperature was below the temperature range used in the error calculation, and on conservative engineering judgement, on April 17, 1995, the licensee determined that this event constituted operation outside the design basis. At 4:50 pm, a 1-hour non-emergency report was made per the requirements of 10 CFR 50.72(b)(1)(ii)(B) and was assigned the NRC event number 28699.

Subsequently, an engineering analysis based on calculation I91-0012, Revision 0, determined that the temperature effects observed had no meaningful impact on BWST level accuracy. Although this event resulted in operation outside the assumptions of the design basis calculation, it did not constitute operation outside the design basis. As a result, the licensee made the report a voluntary LER.

The inspectors verified that all the corrective actions discussed in the LER were completed. Signs have been posted on the entrance door to the BWST room to remind personnel to close the door when exiting the room. All the new calculations have been performed on the room ambient temperatures, with no discrepancies identified. This LER is closed.

1.7.2.7 (Closed) LER 95-05: Engineering Evaluation Determines Insufficient LPI Pump Net Positive Suction Head May Result in Operation Outside Design Basis

The LER was issued when an engineering evaluation determined that insufficient net positive suction head existed for the LPI pumps when two pumps were piggy-backed to a single HPI pump. This item is addressed as one of the examples in the apparent violation 50-302/95-13-03. Follow-up of this item will be tracked by the corrective actions for the violation. This LER is closed.

1.7.2.8 (Closed) LER 92-03: Personnel Error and Lack of Technical Review in Past Procedure Revision Process Leads to Incorrect Procedures Resulting in Violation of Technical Specifications and Design Basis

The inspectors have reviewed the corrective actions for this LER. Many issues remain outstanding with this item. Apparent violation 50-302/95-13-03 addresses an example which corresponds to the issue discussed in this LER. The corrective actions will be tracked under that violation. This LER is closed.

1.7.3 Inspection Results

Violations or deviations were not identified.

1.8.0 Plant Operations Follow-up (92901)

1.8.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.8.2 Observations and Findings

1.8.2.1 Licensed Operator Disciplined

On August 24, 1995, at 3:20 p.m. the licensee made a report per 10 CFR 50.72(b)(2)(vi), regarding licensed operators disciplined for conducting an unauthorized test on the make-up system. See IR 50-302/95-13 for more information. PR 95-0156, Licensed Operators Disciplined, was issued to document the problem and any required corrective actions.

1.8.2.2 (Open) IFI 95-08-03: Emergency Operating Procedure Update Program

The inspectors reviewed the corrective actions taken by the licensee for the EOP update program. A detailed table top review was performed by individuals in the operations, design engineering, systems engineering, licensing, configuration management, training, and BWNT from June 12 through June 23, 1995.

Each EOP step was evaluated to determine the design related interfaces with plant structures, systems, and components. This evaluation included a review of all equipment used for accident mitigation to ensure consistency with the EQ program. This review did not validate the EOP step against the design criteria, but performed a qualitative review and assessment to ensure consistency with the plant design basis. The significance of each step as it related to accident mitigation was determined to develop the relative priority for design engineering to perform a detailed step basis validation.

The licensee established three priorities for the steps. Priority 1 steps typically included equipment evolutions that were critical for accident mitigation or were required to preserve the integrity of the structures, systems, and components required for accident mitigation. Priority 2 steps were considered less critical but still very important or the basis is well known. Priority 3 steps will not require validation by Design Engineering. They included actions that protect balance of plant equipment not used for accident mitigation, or steps that are based on existing well established operating practices or obvious, simple evolutions.

Similar prioritization was performed on setpoints used in the EOPs and on the previously identified open items against the EOPs.

A final corrective action schedule has not been issued to implement corrective actions, but a proposed schedule has been developed. This schedule includes parallel engineering evaluations of the identified items and revision, validation, and verification of the EOPs. This item remains open pending further progression towards resolving the outstanding concerns with the EOPs.

1.8.2.3 (Closed) URI 95-11-02: Operating MUP-1A Outside the Design Basis

The inspectors reviewed the evaluation of the MUP-1A operation with cooling water flow from the DC system at an amount less than the design basis. The licensee determined that the DC cooling water temperature at the time it was valved to the MUP was lower than the normal SW cooling water temperature. According to the licensee analysis, heat transfer was sufficient to adequately cool the motor with the DC cooling flow. The licensee's conclusions were that no operability concern existed.

The inspectors reviewed the licensee's evaluation and determined that the cause of the event was an inadequate procedure. The normal cooling water supply to MUP-1A is the SW system. An alternate cooling water supply is the DC system. Since DC flow rates are normally lower than the SW flow rates, licensee procedure PT-136, DC and SW System Flow Measurements and EGDG-1A KW Loading Due to ES Pumps, was written to balance the flow as supplied by the DC system. The procedure did not contain steps requiring the balancing of SW flow to the pump. Before using the procedure to perform the system balance, an interim change was made to balance the flow to the motor cooler from the SW system, but omitted the DC system. The justification for this change was that MUP-1A was normally supplied by the SW system and not the DC system. Since DC is the limiting flow to the pump, of the two systems, the original procedure contained the accurate steps for balancing the flow to the pump both from its normal and alternate supplies.

TS 5.6.1.1 requires that written procedures be established, implemented, and maintained for activities recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Among these are procedures for the operation of the makeup and purification system. The failure to maintain an adequate procedure to perform a flow balance of the cooling water to MUP-1A is a violation of this requirement, VIO 50-302/95-16-03: Inadequate procedures for operation of the makeup pump 1A cooling water. Corrective actions for the URI will be tracked under the violation. This URI is closed.

1.8.2.4 (Closed) IFI 92-22-01: Completion and Implementation of Upgraded Annunciator Response Procedures and Review of Procedure MP-402C

The inspector reviewed the completed ARPs and internal memorandums transmitting the upgraded ARPs to Operations. The safety-related ARPs were upgraded and implemented first. The remaining ARPs were upgraded and implemented shortly afterwards. All upgraded ARPs were implemented at the time of this inspection. This IFI is closed.

1.8.3 Inspection Results

One violation was identified for inadequate procedures to control cooling water flow to makeup pump 1A.

1.9.0 Maintenance Activities Follow-up (92902)

1.9.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.9.2 Inspection Observation and Findings

During a review of scheduled maintenance activities, it was discovered that on May 11, 1994, WR 319244 identified BS-91-PI, a post accident monitoring wide range reactor building pressure indicator as being out of tolerance per SP-162, Post-Accident Monitoring Instrumentation Calibration. At that time, the plant was in a refueling outage. It was discovered that the pressure instrument had not been scheduled to be correctly calibrated prior to the end of the outage. The pressure indicator, located within the main control room, was not identified to the operators as being inoperable. In the event that the indicator was required, during a post accident condition, inaccurate information would have been displayed. The failure to notify the operations personnel of the inoperable indicator is a weakness in communications and indicative of weak management oversight on the follow-up of the failure to complete the calibration.

The licensee originally determined that the event was a violation of TS 3.3.17.A, Post Accident Monitoring (PAM) Instrumentation. This TS states that if the instrument is out of service for more than 30 days, the licensee is to submit a special report per TS 5.7.2.A, Special Reports, within the following 14 days. Prior to submitting the report, the licensee identified that a recorder, BS-91-PR, located elsewhere in the control complex, was operable and is redundant to the pressure indicator. The licensee concluded that both channels of PAM wide range reactor building pressure were operable and no report was required. The inspectors have reviewed the results of the initial review of the event and have no outstanding safety concerns. The licensee has not identified the root cause of the failure to take appropriate corrective actions when the indicator was not calibrated. The inspectors will continue to follow the licensee's corrective actions.

1.9.3 Inspection Results

No violations or deviations were identified.

1.10.0 Engineering Activities Follow-up (92903)

1.10.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.10.2 Inspection Observation and Findings

1.10.2.1 (Open) URI 50-302/95-02-02, Control Room Habitability Envelope Leakage

In inspection report 95-09, paragraph 1.6, the inspector documented an April 1995 followup inspection of unresolved item 95-02-02, Control Room Habitability Envelope Leakage. At that time, the licensee could not locate supporting data and calculations for their design basis CCHE leakage for dampers (unfiltered path) of 30 CFM, or for their conversion factor of 2.96 CFM per square inch of CCHE leakage path. During this inspection, the licensee provided the requested supporting data and calculations, which they had obtained in April and May 1995 from their architect/engineer contractors.

The inspector reviewed the supporting data and calculations and noted no currently applicable problems with the 30 CFM or the 2.96 CFM per square inch calculations. However, the inspector did note an error in a CCHE damper leakage calculation. The leakage calculation for damper AHD-99, which had been done in February 1986, concluded that AHD-99 would leak 16 CFM with a differential pressure of 1/8 in. wg. The analysis also stated that a teleconference with the site maintenance supervisor revealed that damper AHD-99 was always open, even during the recirculation mode. With AHD-99 open, a leakage of path of 10,304 CFM would exist. The analysis further stated that this "leakage will not be continuous. Air will leak into the room until a pressure in the room builds up to 1/8 inch. At this equalized pressure condition, the leak will stop." The analysis then disregarded the 10,304 CFM leakage path through an open AHD-99. The inspector concluded that disregarding the 10,304 CFM of leakage path was erroneous and grossly nonconservative. However, the 10,304 CFM was not applicable to existing plant conditions because AHD-99 was currently designed and tested to close automatically with the other CCHE dampers on receipt of a high containment pressure, high control room intake air radiation, or high sulfur dioxide signal. While this error did not affect current plant operation, it indicated a need for close review of architect/engineer calculations.

The inspector found that the current instructions to operators on the CCHE design basis were in a Nuclear Plant Operations Night Order dated May 19, 1995. The Night Order stated "If any combination of CCHE breaches or any single CCHE breach exceeds 32 square inches in area, the CCHE is considered to be outside the design basis." The inspector found that the engineering basis for the 32 square inches was documented in an internal memorandum from nuclear design engineering to the DNPO dated March 9, 1995. The inspector noted that the memorandum was, in effect, a revision of official calculation I-92-0011, Control Room Habitability Evaluation of Potential Inleakage. That calculation had concluded in 1992 that the planned installation of three new double doors would increase the CCHE calculated inleakage to approximately 368 CFM, which would exceed the design basis of 355 CFM (as reported to the NRC in response to NUREG-0703 Item III.D.3.4 and incorporated by reference in the FSAR) but would remain within the 10 CFR 50, Appendix A, GDC 19 limits. The official calculation left no margin for additional CCHE leakage. The inspector noted that the door modification was partially complete (one of the three new double doors was installed) and that the modification package did not include a change to the FSAR. The inspector concluded that the lack of an FSAR change indicated a lack of thoroughness in the licensee's modification package.

The March 9 memorandum did not follow the process for official calculations - for example, it did not include independent verification by a second engineer and it was not a QA record. The CCHE analysis in the March 9 memorandum removed some of the conservatism from the calculated CCHE inleakage in calculation I-92-0011. Calculation I-92-0011 used a calculated value of 191 CFM for damper leakage (filtered path) through AHD-1. The memorandum included a leakage value of about 36 CFM for each of the new double doors and a value of 70 CFM for damper leakage (filtered path) through AHD-1. The inspector had previously noted that the value of 70 CFM leakage through AHD-1 was apparently in error and should have been higher, about 94 CFM (see IR 50-302/95-09, paragraph 1.6.2). This previously noted nonconservative discrepancy had not been addressed by the licensee. The inspector assessed that the difference between 94 CFM and 70 CFM, of 24 CFM, when divided by the 2.96 conversion factor, would equal a potential nonconservatism of about 8 square inches in the licensee's 32 square inch design basis margin. The inspector concluded that this potential nonconservatism by itself would not cause the CCHE to be outside of its design basis. However, the licensee's failure to address it in a timely manner and the licensee's use of a memorandum to effectively revise an official design calculation were indications of lack of thoroughness in addressing the CCHE issue.

The inspector inquired about licensee inspection of CCHE dampers and doors, and was told that a new PM had been instituted to inspect all CCHE dampers and another new PM had been instituted to inspect all CCHE doors. The inspector reviewed the new PMs. PM-175, Control Complex Habitability Envelope (CCHE) Door Maintenance, Rev. 0, dated May 26, 1995, did include instructions to check for any door seal leakage, by using flashlights and feelers. The procedure also included a space for listing as-found conditions, and required notification of the NSS of the completion and results of the inspection. However, the procedure did not require documenting an estimate of the square inches of leakage path around each door. PM-139, HVAC Equipment Check and Service, Rev. 8, dated February 13, 1995, which had recently been required to be performed on CCHE dampers, did not include instructions to check for damper leakage, did not include a space for listing as-found conditions, did not require documenting an estimate of the square inches of leakage path through each damper, and did not require notification of the NSS of the completion or results of the inspection. The inspector concluded that the PMs for CCHE doors and dampers were not well written to support inspection or tracking of CCHE integrity. The inspector assessed this lack of detail in PMs as another example of lack of licensee thoroughness in addressing the CCHE issue.

The inspector observed the condition of the CCHE doors in the plant. Double door C508 was a "new" door that had been installed in January 1995 and its visible leakage was about one square inch, which was not significantly different from the one-half square inch observed by the inspector in April. Double door C301 was the same "old" door that had been in place in April - its visible leakage was about four square inches, which was more than the one square inch observed in April. Most of the four square inches was due to a degraded and poorly adjusted seal at the bottom of the door. Door C101, which in April had been removed for replacement with a new door, was still missing and was still replaced by a temporary wooden enclosure and wooden door. The visible leakage of the wooden enclosure and door was about one square inch, which was unchanged from April. Single doors C701 and C501 each had visible leakage of about one-half square inch, which was not substantially different from April. Single door C802, the door to the roof, had a visible leakage of about one square inch due to becoming warped. The inspector concluded that the observed total of about eight square inches of door leakage did not by itself exceed the CCHE design basis margin of 32 square inches and that the most significant leakage observed was the four square inches around door C301.

The inspector reviewed the licensee's records of door leakage with Fire Protection personnel, who had been assigned responsibility for tracking the overall CCHE leakage to assure that it was within the 32 square inch design basis margin. They were aware that they had been assigned this responsibility, and had noted on a chalkboard that door C301 had a breach of three square inches. The inspector verified that this breach was recorded in the licensee's computerized Breach Log. Fire Protection personnel stated that the chalkboard was the only record of overall CCHE leakage. They had obtained the information on door C301 by inspecting the door for leakage in response to a phonecall from a Nuclear Shift Supervisor. They had not received the information about door C301 leakage from the routine monthly door inspection PM program. A review of recent licensee CCHE door inspection PM results revealed that no leakage had been recorded for any of the CCHE doors. Fire Protection personnel stated that the failure to record any CCHE door leakage was probably due to a lack of training of the people performing the door inspection PMs. The inspector concluded that the failure of the CCHE door inspection PMs to document any door leakage was another example of licensee lack of thoroughness in addressing the CCHE issue.

Fire protection personnel stated that, after inspecting the C301 door and noting the breach, they had discussed the degraded door seal with a maintenance supervisor. They stated that since a new replacement door had been ordered to replace the existing door and since the observed breach of three square inches was less than the design basis margin of 32 square inches, maintenance decided to not repair the C301 door seal. The inspector reviewed procedure CP-137, Breach Authorization Program, Rev. 12, for licensee requirements for handling CCHE breaches. CP-137 stated:

> Breaches in the CCHE require temporary seals or enclosures be in place to maintain envelope integrity. These seals or enclosures must be established within one hour after an unauthorized breach has been detected... Multiple breaches in the envelope may exist but no penetration may be left unattended without a temporary seal.

CP-137 included no provisions for leaving a CCHE breach unattended without a temporary seal. There was no form or process for formal review and approval of leaving an unattended CCHE breach in place. The inspector concluded that the unattended breach in the C301 door seal was a violation of procedure CP-137. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. This item will be identified a NCV 50-302/95-16-04, Failure to follow CCHE breach procedure.

The inspector reviewed the maintenance history for each CCHE damper and found that they had not been inspected for damper leakage in the past. The inspector also reviewed the PM schedule and found that all CCHE dampers were scheduled for the new PM inspection, and that the first such inspection was scheduled to begin in September 1995. The inspector requested, and the licensee agreed, that the licensee would inform the NRC resident inspectors before they opened each CCHE damper for inspection so the NRC could have the opportunity to be present and to inspect the condition of the dampers.

While reviewing the PM schedule, the inspector noted that one other PM was scheduled for some of the CCHE dampers, to inspect the solenoid actuator. This PM was being done as a licensee commitment to the NRC made in LER 92-017. LER 92-017 attributed the root cause of a failure of auxiliary building ventilation (and consequent entry into TS LCO 3.0.3) to be that there was no PM program to inspect or replace damper solenoids on a routine basis to prevent in-service end-of-life failures. In LER 92-017, the licensee stated that solenoid valves in air handling control panels for air handling equipment, which are considered important to plant operation, will be added to the PM program (for periodic inspection or replacement). The inspector found that all CCHE damper solenoids were in that PM program except AHD-99, 24, 25, 26, and 27. The inspector noted that all CCHE dampers, including AHD-99, 24, 25, 26, and 27, were designed to close automatically on receipt of certain emergency signals. Also, all had been modified a few years ago to upgrade the air actuating lines to seismic grade tubing. AHD-99 was a single damper located such that, if it failed to close when required, could by itself cause a CCHE leakage path to the outside air of about 10,304 CFM. That would substantially exceed the licensee's design basis CCHE leakage margin of 94 CFM. The inspector concluded that AHD-99, 24, 25, 26, and 27 were important to plant operation and that the licensee's failure to include their actuating solenoids in the PM program was a weakness in the scope of the licensee's corrective actions for LER 92-017.

The inspector reviewed Problem Report 95-0090, which described the discovery of air inleakage into the CCHE from the Auxiliary Building by security guards on May 10, 1995. The air inleakage was through two four-inch diameter floor drains in the CREVS charcoal filter areas in the 164 ft. elevation of the control complex, which drain to the Auxiliary Building hot laundry and shower sump. Engineering calculation I-92-0011, Control Room Habitability Evaluation of Potential Inleakage, assumed that no air would leak through these paths because scheduled preventive maintenance should maintain water in the drain traps and because the Auxiliary Building end of the pipe is normally submerged in the laundry and shower sump. The licensee had not identified this May 10 floor drain leakage as causing the CCHE to be outside its design basis. The inspector assessed that the leakage path through the two four-inch diameter drains would total about 24 square inches, which by itself or even added to the inspector's estimate of eight square inches of door leakage would not exceed the 32 square inches of CCHE margin. The inspector concluded that the licensee's failure to maintain these floor drain leakage paths was another example of lack of thoroughness in addressing the CCHE issue.

The inspector was shown an extensive Control Room Habitability Envelope Action Plan, with an assigned manager, for the CCHE leakage issue. As of September 1, 1995, 59 action items were listed and scheduled, and about 75% of them were shown as completed. Two of the completed action items were: developing CCHE door inspection procedures and providing guidance to Fire Protection for use in conducting monthly habitability envelope inspections. As previously described, the inspector found that the monthly CCHE door inspections were not effective in identifying CCHE door leakage. The inspector noted that this weakness in CCHE door inspections indicated a potential lack of quality control and followup on the CCHE Action Plan items. The inspector also noted that inspection or testing of CCHE dampers for leakage was not included in the CCHE Action Plan. Since the CCHE dampers were very large and represented a significant element of the CCHE, the inspector noted that the failure to include them in the CCHE Action Plan represented a weakness in the scope of the plan. The inspector concluded that the licensee had an apparently extensive CCHE action plan, but that its scope was incomplete and that its implementation was weak in assuring that the plant was currently operating within its CCHE design basis.

The inspector concluded that the licensee's Control Room Habitability Envelope Action Plan was weak in assuring that the plant was currently operating within its CCHE design basis. The plan did not address CCHE dampers, PM inspection procedures for CCHE doors and dampers lacked appropriate detail, personnel using the PM inspection procedures failed to identify existing CCHE door leakage, the CCHE Breach Authorization Program procedure was not followed (identified as a Non-Cited Violation), CCHE floor drain water seals were not maintained, the scope of the corrective actions for ventilation damper solenoids per LER 92-017 was weak, a previously identified potential nonconservatism in the CCHE design basis margin calculation had not been addressed, an official engineering calculation of CCHE margin was effectively modified by an internal memo, and a modification that resulted in a change to the CCHE design basis failed to include a change to the FSAR. URI 50-302/95-02-02, Control Room Habitability Envelope Leakage, remains open pending NRC review of: the CCHE design basis and licensing basis, the effects of a breach in the CCHE on CREVS operability, the need for changes to the CREVS TS Bases, and the need for a CREVS TS surveillance for CCHE integrity. This URI also remains open pending the licensee's inspection of CCHE dampers for leakage.

1.10.3 Inspection Results

One non-cited violation was identified for the failure to follow procedures for a CCHE breach.

1.11.0 Plant Support Follow-up (92904)

1.11.1 Inspection Scope

The open items addressed below were inspected to determine that adequate corrective actions have been taken, their root causes have been identified, their generic implications have been addressed, and that the licensee's procedures and practices have been appropriately modified to prevent recurrence.

1.11.2 Inspection Observation and Findings

1.11.2.1 TSC Emergency Ventilation System Deficiencies

On August 18, 1995, at 11:40 p.m., the licensee identified a condition of system high flow rate while the TSC ventilation system was in the recirculation (emergency) mode. This was noted during an annual PM (CS5086) per WR No. NU321590. The PM inspected dampers and measured system air flow rates. The required flow rate was 3000 CFM (500 CFM outside air makeup and 2500 CFM recirculation flow rate): however, the as found flow rate was 4600 CFM. As a result, the licensee made a 10 CFR 50.72 notification per paragraph (b)(1)(ii)(B), a condition outside the design basis at 12:04 a.m. on August 19, 1995.

The TSC ventilation system has been previously identified as being inadequate to perform its design function as follows:

- IR 50-302/91-08, paragraph 8.c, identified concerns raised regarding the capabilities, operability, and startup of the TSC building emergency ventilation system. At that time it was identified that the emergency system was unable to supply comfortable makeup air for the facility, there was no startup guidance for the system, and no identified method for verifying proper system operability. These concerns were documented as one example in IN 92-32, Problems Identified with Emergency Ventilation Systems for Near Site (within 10 miles) Emergency Operations Facilities and Technical Support Centers.

- The NRC had inspected the TSC ventilation system as documented in NRC Inspection Report No. 50-302/94-05. In that report the inspectors described the regulatory requirements and system requirements for the TSC ventilation system. That report described issues with procedures and the existing PM program. Licensee corrective actions in early 1994 included procedural enhancements and PM program development. The flow balance/damper inspection PM was completed in July 1994.

After the recent problem, the licensee initiated efforts to address a number of issues, both self-identified and NRC identified, including initiation of a problem report (PR95-0154).

The NRC identified issues included the following:

- 10 CFR 50.72 report was in error as it reported the TSC ventilation system as operable. The licensee subsequently revised the report on August 22, 1995 at 4:37 p.m.

- An August 21, 1995, memo (REP95-0072) had an incorrect reference per procedure EM-102, Activation, Operation, And Staffing of the TSC/OSC. The licensee subsequently corrected the memo.

- It was not clear to the control room operators whether the TSC ventilation was operable as the shift log for August 19, 1995, incorrectly stated that damper positions had been corrected, system status was not tracked on the degraded equipment/EOOS lists, and operators' knowledge was inconsistent. The licensee also corrected and addressed these issues

- The PM guidance and frequency was inadequate in that M&TE was not listed, a step-by-step approach was not included, acceptance criteria was not specified, and previous performance (July 1994) also required adjustments and may have been incorrectly performed. The licensee is currently addressing these issues.

- The procedures, design information, and drawings do not address damper positions for various modes.

- The ventilation problem was not initially worked or designated as a high priority job.

- The SCBA air compressor is located in the TSC ventilation room which is not protected against radiation contamination. The inspectors could find no procedural reference to use of the air compressor for replenishment of depleted SCBAs.

The licensee identified several maintenance and design issues with the dampers and M&TE. The various series drawings of the dampers did not agree and had to be changed to match the field installation.

A potentiometer was connected and appeared to control damper position independent of the motor limit switches. A review of the electrical drawings was performed by electrical design and systems engineering to determine if the potentiometer could be connected to the damper used to control air flow in normal and emergency modes. Tests were conducted and it was determined that the potentiometer would not provide fine enough control to adjust the damper position appropriately. The licensee issued a MAR to electrically disable the damper in normal and emergency modes of operation and mechanically adjust the damper position to its flow balanced position. It appears that the TSC ventilation system was outside its design basis from July 1994 until September 1995. The "Licensee Enhanced Design Base Document" states, in part, "The TSC air handling system emergency filter Fan ASH-62 design flow requirement is 3000 cfm."

NUREG-0737, Clarification of TMI Action Plan Requirements, Supplement 1, item III.A.1.2, Upgrade Emergency Support Facilities, requires (in part) that each facility shall have a TSC which will be habitable to the same degree as the control room for postulated accident conditions.

NUREG-0654 (FEMA-REP-1), Revision 1, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, Section H.1, Emergency Facilities and Equipment, states that each licensee shall establish a TSC and OSC in accordance with NUREG-0696, Revision 1. NUREG-0696, Functional Criteria for Emergency Response Facilities, Section 2.6, Habitability, states (in part) the following:

> Since the TSC is to provide direct management and technical support to the control room during an accident, it shall have the same radiological habitability as the control room under accident conditions. TSC personnel shall be protected from radiological hazards, including direct radiation and airborne radioactivity from inplant sources under accident conditions, to the same degree as control room personnel.
>
> The TSC ventilation system shall function in a manner comparable to the control room ventilation system. The TSC ventilation system need not be seismic category I qualified, redundant, instrumented in the control room, or automatically activated to fulfill its role. A TSC ventilation system that includes high-efficiency particulate air (HEPA) and charcoal filters is needed, as a minimum.

In a letter to the NRC dated January 11, 1980, the licensee committed to providing protection from radiological hazards, including direct radiation and airborne contaminants as per General Design Criterion 19 and SRP 6.4 for the TSC including the ventilation system.

Acceptance Criteria in SRP 6.4 includes meeting the requirements of GDC 19, as it relates to maintaining the control room in a safe, habitable condition under accident conditions by providing adequate protection against radiation.

The TSC ventilation system, operating outside of its design basis, is a deviation from the licensee commitment and is identified as NOD 50-302/95-16-05: Deviation from the design commitment for the Technical Support Center emergency ventilation system.

The inspectors observed maintenance activities in the field, discussed issues with system and design engineering personnel, and discussed this item and related issues with management personnel. The inspectors noted positive control of work by maintenance supervision and outstanding system engineering involvement.

1.11.2.2 Inoperable Waste Gas Analyzer

On August 11, 1995, the licensee issued Special Report 95-01, concerning the cause and corrective action for the inoperable status of the waste gas analyzer, WDGA-1. The analyzer was declared inoperable on June 30, 1995, due to a calibration problem involving accessing the menu of the microprocessor unit. The ODCM requires equipment restoration to service within 30 days or the submission of a Special Report.

The failure of the analyzer was due to a deficiency in the microprocessor. The microprocessor was replaced and WDGA-1 returned to normal operations on August 3, 1995, with the unit having been out of service for 34 days.

The inspectors monitored the corrective actions taken and reviewed the Special Report issued on the subject. The significance of the event was minimal, since manual grab samples were taken at least once per four hours during degassing operations and at least once per 24 hours during other operations. No further follow-up is required.

1.11.3 Inspection Results

One deviation was identified for the failure to meet commitments concerning the technical support center emergency ventilation system.

Attachment 2
Regional Inspection
(K. Landis, R. Butcher, T. Cooper, L. Raghavan, R. Schin, M. Scott, M. Thomas)

2.1.0 Corrective Action Plan (40500)

2.1.1 Inspection Scope

The inspectors reviewed the licensee's implementation of actions outlined in their Corrective Action Plan. That plan was discussed in meetings with the NRC on March 1, 1995, and August 25, 1995; and was documented in the Corrective Action Plan Meeting Summary dated September 7, 1995. The areas reviewed included: Event-Free Operations Programs, line management accountability and management oversight, operability determinations, self-assessments, engineering interfaces and support enhancements, and enhancements to engineering processes.

2.1.2 Observations and Findings

2.1.2.1 Event-Free Operations Program

The inspectors reviewed the overall Event-Free Operations Program, which had been approved by the Senior Vice President, Nuclear Operations. The stated program objective was to ensure that all personnel are properly equipped with and utilize the "tools" necessary to perform their job function with the result being an ever-decreasing frequency and significance of errors to the point that operations is event free. The program applied to all personnel; including operations, engineering, maintenance, contractors, etc.; who work within Nuclear Operations.

2.1.2.1.a Operations Department

The Operations Department Event-Free Operations Program is defined by Areas of Emphasis. The following five Areas of Emphasis are defined in the Event Free Operations Program:

- Human Performance Tool Bag. The tangible and intangible human performance tools available to improve and maintain Event Free Operations are defined.

- Training and Expectations on Tool Use. Each tool defined above has formal and informal training sources defined.

- Monitoring of Tool Use. Examples of monitoring techniques include field observations, root cause evaluations, formal and informal self assessments, and training critiques.

- Effectiveness Indicators. A severity level classification chart for significant and non-significant incidents has been developed. Specific trends in areas that are of primary importance to the safe, legal, and efficient operation of CR-3 will be documented for evaluation by Operations management.

- Feedback and Follow-up. Positive reinforcement for desired behavior and positive discipline for undesired behavior is discussed with a matrix providing the what, who, and how to bring the behavior of an employee to the desired performance level.

The inspectors reviewed a typical tool bag input process and followed how data was trended. The trending program was well established and was becoming more useful as the data base was expanded. The Event Free Operations Program was previously inspected (see IR 50-302/95-08, paragraph 8) and it was noted that the program elements were incorporated into the monitoring and critiquing of operator performance on the simulator.

The inspectors reviewed operations initiatives to enhance the safety culture of the Event-Free Program. Outside the actions taken for operators involved in the make-up tank test issue (See IR 50-302/95-13) three licensed operators have been removed from licensed operator duties due to performance inadequacies. Also, Operations formed a committee to develop a consistent policy for procedure use. Areas clarified were requirements for when a procedure must be in hand, documentation requirements, and the revision process. A night order was issued by the MNPO that defined every operations procedure requiring operator action into three categories as follows:

- Cat. 1. Procedure in hand and documentation to Quality files.
- Cat. 2. Procedure in hand. No formal documentation required.
- Cat. 3. Procedure not required to be in hand. Operator must follow procedure steps.

All surveillance procedures were defined as Cat. 1. Operations procedures will be revised to reflect the appropriate category during the next revision.

The inspectors concluded that the Operations Department Event-Free Operations Program "set the standard" and was a strength. It was well defined and implemented, and operators had been trained on it (the program was in its seventh operator training cycle).

2.1.2.1.b Engineering Department

The inspectors reviewed the Event-Free Operation Program for Nuclear Engineering and Projects (NEP), Rev. 0, dated June 28, 1995, and the Event-Free Operation Program for Nuclear Plant Technical Support (NPTS), Rev. 0, dated June 19, 1995. NEP included primarily design engineers and NPTS included primarily system engineers, with both groups reporting to the Director, Nuclear Operations Engineering and Projects. The two similar programs provided an integrated approach to human performance and safety culture enhancement. The objective of both programs was to ensure that all personnel are equipped with and utilize the tools necessary to perform their job function, with the result being an ever decreasing frequency and significance of errors to the point that operations is event free.

The inspectors reviewed the NEP and NPTS Event-Free Operations Programs, discussed them with affected personnel, and reviewed associated documentation to assess the status of program implementation. Program attributes and associated implementation actions addressed behaviors or conditions such as safety awareness, technical input, prioritization of work, knowledge/skills, planning, time to do the job right, control of contractors, equipment monitoring, and communications. Documentation reviewed included training records, procedures, and inter-office correspondence, all of which provided evidence of actions taken to address attributes in the Event-Free Operations Programs.

The inspectors selected 10 of the approximately 56 action items from the NPTS program for review. The licensee was able to demonstrate knowledge of and to show the inspectors documented examples of the implementation of each of the 10 items. In addition, the licensee had begun a process of reviewing precursor cards related to NPTS performance, categorizing them by which of the eight NPTS work groups was affected and by behavior or condition (as identified in the NPTS Event-Free Operations Program), and tracking them on a matrix form. After only about one month of data, the NPTS precursor tracking was beginning to indicate a potential trend, that could be worthy of further licensee review, in an area of equipment monitoring. NPTS plans to use this tracking and trending tool to monitor their Event-Free Operation Program performance and to identify inappropriate trends for evaluation and development of corrective actions. The inspectors concluded that the NPTS Event-Free Operation Program was reasonably comprehensive and that its initial implementation was well underway.

During discussions with NEP personnel, the inspectors noted that the program document was not distributed to the Nuclear Engineering Design (NED) personnel within NEP until September 1995, which was over two months after the program was approved. Thus, specific actions by the various discipline supervisors in NED had not been fully developed for implementation of the program. Although a copy of the program was slow in being provided to NED personnel, actions had been implemented prior to approval of the NEP Event-Free Operation Program to address some of the Implementation Action Plan attributes. The inspectors noted that certain implementation actions in the program had already been implemented by NEP. Most of the actions were either implemented prior to approval of the program or were already part of NEP's normal process. For example, implementation of the NED monthly prioritization meetings earlier this year and relocation of NEP personnel to the site in June 1995 addressed the prioritization of work and the communication action items. The inspectors noted that NEP actions to assess the effectiveness of the Event-Free Operations Program were not fully developed or implemented. For example, the tracking, trending, and analysis of data from precursor cards was not well defined.

The inspectors concluded that the Engineering Department Event-Free Operations Programs were developed. NPTS had been trending implementation for a few months, while NEP had not fully implemented trending of Event-Free Operations. The move of design engineers in June delayed the start of the program. Overall, the Engineering Department was implementing Event-Free Operations and was still refining the monitoring and trending process.

2.1.2.1.c Chemistry and Radiation Protection Departments

The inspectors reviewed the Event-Free Operations program adopted by the chemistry and radiation protection departments at the site. The two groups were using the same program, as described in the Chem/Rad Instruction, CRI -005, Chemrad Department Event Free Operations, which became effective on July 10, 1995.

The instruction defined the event free operation concept and described the expectations to be taken to achieve this goal. A questioning attitude, self verification, correct data taking practices, procedure use and adherence, the use of precursor cards, and good communications were stressed in the instruction. Examples of a good questioning attitude were detailed in the procedure. Self verification, using the STAR (Stop, Think, Act, Review) methodology was discussed and the individuals in the departments had received STAR training.

The instruction included provisions for a self assessment process to be used during the Event-Free Operations program. An annual review was to be performed to assess the major functions. No specific guidance was provided on how this was to be accomplished. For a shorter interval, the instruction provided for post-task critiques when the activity was complex enough to require pre-job planning or if it resulted in a human error or event.

The inspectors verified that only a small number of events (two in radiation protection and one in chemistry) had occurred in the group and that too small a sample existed to make an assessment as to the effectiveness of the chemistry and radiation protection event free operations program. These events had been captured by the precursor card/problem report program and were being tracked.

The inspectors concluded that the Chemistry and Radiation Protection Departments' Event-Free Operations Program was developed and implemented. At the time of this inspection, there was too small a population of precursor cards to assess the program effectiveness.

2.1.2.1.d Maintenance Department

The inspectors verified that the maintenance sub-tier portion of the Event-Free Operations Program had been generated (April 4, 1995) and pursued. The maintenance department had a peer review group assess the department (April 15 to 19, 1995). The inspector verified that the results of the this assessment were being adequately tracked and addressed by the department. The licensee cyclic review of the EFOP was scheduled for October 1995.

In July 1995, the maintenance department was audited (rpt # 95-07-MAIN, issued 8-7-95) by the site QA group with an emphasis on the EFOP. There were no compliance issues but there were 12 recommendations made regarding work process improvements, industrial safety, and work practices. The inspectors discussed the audit details with various department personnel determining that the audit had a positive impact. The audit text stated that during the post audit conference, the department demonstrated...a willingness to consider even the most subjective information as potentially useful. This traditionally uncommon attitude toward broad, non-compliance based results clearly indicates strong top down management support for identifying and resolving problems.

2.1.2.1.e. Tracking and Trending

The inspectors found that the licensee's tracking and trending group was receiving precursor cards and problem reports, tracking them, and trending them (at a high level). However, weaknesses in this process were noted:

- o Responsibility for trending was not clearly addressed in CP-111, which was in the process of being modified along with CP-144.

- o Trending was being inconsistently applied and departments were trending to different levels of detail.

- o The inspectors identified examples of trends that could be assessed by the licensee:

  - Corrective actions - there were seven precursor cards in this area in a nine month period.

  - Drawings - there were approximately 20 precursor cards in this area in the last nine months.

Assessment: Overall, the inspectors concluded that Event-Free Operations Program implementation was excellent in the operations department and acceptable in all departments. Remaining licensee challenges were to more consistently apply Event Free Operations in all departments and to monitor and trend in more detail.

2.1.2.2 Line Management Accountability and Management Oversight

Director and manager levels knew priorities and had meetings designed to resolve any concerns about improper prioritization. Tracking tools were in place to maintain accountability and the licensee was working on enhancements to the prioritization model. The model was detailed and appeared to heavily weight safety significance. Examples of meetings: Weekly Boldt and Beard Director level staff meeting, PMRG, NED Monthly Meeting, Monthly Operator Work Around Meeting, Biweekly Manager Level Meeting, Daily Work Planning Meeting, as needed for significant issues Management Review Panel

While the tools exist for exercising detailed line management accountability, many examples remain where management oversight has been weak. Examples include the following:

- the expectations for the Issue Manager were not well defined and were incomplete as displayed by the lack of clear expectations for the CCHE Issue Manager,

- the CCHE issue remains unresolved without adequate operability criteria even though this issue had been on the FOCUS list as one of the top 10 items,

- the licensee has not developed a rigorous process for making operability determinations even though this issue has been on the FOCUS list as one of the top 10 items,

- root cause evaluations have been performed without referring to the licensee's procedure and management staff has let this practice go unchallenged,

- the engineering REA backlog continues to be very large without a structured model for screening out those items which do not warrant engineering resource expenditure and prioritization of the REAs was weak, and

- a structured method involving multiple discipline interface for determining corrective actions was only recently under development using a Management Review Panel (MRP).

Assessment: Noticeable progress has been observed in the exercise of management oversight especially in the Event Free Operations Program. While the tools and process are available to plan, prioritize, execute, and control significant issues, the above examples indicate that management oversight still needs to be strengthened.

2.1.2.3 Operability Determinations

The licensee's operability determination program is defined in Nuclear Operations Department Instruction NOD-14, Evaluating Operability and Determining Safety Function Status. During a meeting on March 1, 1995, regarding corrective actions, the NRC participants had discussed the inadequacy of NOD-14 and noted that it did not reflect the guidance given in GL 91-18. At the time of this inspection the licensee was using NOD-14 and a draft of Compliance Procedure CP-150, Identifying and Processing Operability Concerns. NOD-14, CP-150, and two recent licensee operability determinations in response to PRs were reviewed as part of this inspection.

- PR 95-0068, RCV-10 at Wyle labs failed to open at 2450 psi during pre-refurbishment test.

- PR 95-0164, Non-conservative EFIC natural recirculation setpoint.

The two operability determinations were considered inadequate in that the documentation was not in sufficient detail to support the conclusion. By discussion of the issues with the licensee, the inspectors did not disagree with the conclusions regarding equipment still being operable (but degraded), however the NOD-14 supporting documentation was almost non-existent. Also, it was significant that the operability evaluation for RCV-10 failed to recognize that the function of the PORV (RCV-10) to prevent the lifting of the code safety valves is, although not safety related, important to safety.

The two procedures, NOD-14 and CP-150, were both considered inadequate and lacking the guidance provided in GL 91-18. Specific comments regarding the identified procedural deficiencies were discussed with licensee supervision.

Assessment: The management attention and oversight to the issue of operability determinations has been inadequate and is considered a weakness. It has been six months since the subject of inadequate operability determinations was discussed with licensee management and an improved procedure was still not available. It should be pointed out that the licensee's briefings of the NRC on operability issues have been good and conservative. However, written operability determinations are very brief with few details and generally considered inadequate. The clear expectations reflecting management's highest safety standard was absent as shown by the lack of a detailed and thorough process with rigorous guidance for making operability determinations.

2.1.2.4 Self-Assessments

The inspectors reviewed various licensee self assessment programs, as they pertain to the management corrective action plan. The second quarter manager level assessment report was reviewed by the inspectors and found to be candid and self critical. Findings included areas of ineffective communications, poor teamwork, lack of a common focus, and a number of process, human performance, equipment, and procedure conditions that may adversely impact operations of the plant. The inspectors verified that assignments had been made to address each of the assessment report concerns.

The inspectors observed a PRC meeting. During this meeting, the PRC members demonstrated a strong, questioning attitude. At one point, a 10 CFR 50.59 evaluation was rejected and was revised, at the direction of the PRC, to reflect a possible impact on the safe operations of the plant. The questions asked by the members, were direct, with good technical content and detail. This PRC meeting showed a marked improvement over earlier meetings attended by the inspectors.

The inspectors attended NGRC and several NGRC subcommittee meetings. The NGRC appeared to perform a good job of assessing plant operations and identifying issues that warranting follow up. Examples of these issues include commitment tracking, CCHE issues, service water inspection issues, and Quality Programs developing a program to identify potential issues, among others.

The inspectors attended significant portions of the NGRC operations and maintenance subcommittee meeting and observed a thorough, detailed technical review of several issues; including the service water inspections, the makeup tank issues, and evaluations of cause and corrective actions for problem reports and precursor cards. The subcommittee concluded that in some cases, the licensee needed to be more candid with respect to personnel errors, and stop building programmatic fixes for every error.

The inspectors attended a meeting of the NGRC subcommittee on engineering and technical support. The head of the subcommittee was not a regular licensee employee and had considerable nuclear industry experience, including being currently on similar oversight committees at other nuclear plants. He contributed some industry wide perspectives on issues. Other subcommittee members included the DNPO and an individual acting for the Director, Nuclear Operations Training. A representative from NEP also attended. A total of approximately 92 documents had been distributed to subcommittee members for review prior to the meeting. Those documents included performance indicator reports; assessment and audit reports; corrective action plans; problem reports; LERs; MARs; NODs and other plant procedures; NRC inspection reports, Information Notices, Bulletins, and Generic

Letters; and INPO SERs and other notices and reports. The subcommittee went down a list of the 92 documents and discussed those on which members had questions or comments. The meeting also included presentations by plant personnel on areas of interest to the subcommittee including the service water action plan, the boric acid inspection program, and the MOV program. The presenters were all well prepared, knowledgeable, and made good presentations. The DNPO was not present for the entire meeting, but while in attendance added substantial value by presenting many good questions and comments which indicated a broad safety perspective and detailed knowledge of overall plant operations. The inspector concluded that the meeting was well organized, presentations to the subcommittee were well done, and that some of the subcommittee members contributed notably to the safety oversight function of the NGRC.

The inspectors noted that the licensee has established a Senior Management Self-Assessment meeting on a biannual basis. This is considered an excellent initiative with the potential to greatly enhance the licensee's self assessment process.

The inspectors have witnessed several strong initiatives to perform self assessments of management and plant performance. These new programs and enhancements to existing programs are still relatively new, and while they have identified some substantive issues, corrective actions have not been completely implemented. The inspectors will continue to monitor the programs to determine their effectiveness.

Assessment: The licensee's self assessment programs are a strong initiative to identify areas that need improvement. The one remaining challenge is the implementation of corrective actions for the issues identified by the assessments.

2.1.2.5 Engineering Interfaces and Support Enhancements

The inspectors reviewed various initiatives implemented by the licensee to improve NEP's interface and support to the plant. Initiatives that have been implemented included the following:

- NEP was relocated from the corporate office to the site.

- Combined all engineering resources (NEP and NPTS) into one organization.

- Multidiscipline project teams have been established with representatives from the various plant departments for all major projects and modifications. A project manager from NEP is assigned as the single point of accountability. Representatives present their department's position instead of personal opinion and provide input on the project in an effort to ensure that the needs of the plant are addressed.

- The project team performs a post project critique to capture lessons learned and provide feedback into the process.

- In addition to the project critiques for major modifications and projects, a modification evaluation summary prepared by the project manager for each modification at closure and a monthly modification evaluation summary report is being issued. This process was initiated in April 1995 to provide feedback to the modification process.

- NED implemented monthly design engineering priority meeting with representatives from various plant departments. The meetings were held to discuss emergent plant issues, prioritize REAs, and discuss NED workload versus plant needs.

- A single point of contact was established within the plant operations organization for technical issues.

- Monthly operator work-around meetings were established.

The inspectors noted that the project critiques were implemented in July 1995. There has been one project critique issued to date. The inspectors reviewed the project critique issued by the Radiation Monitor Upgrade/Replacement Project Team. The critique had observations in human performance, procedures, process issues, equipment problems, and provided recommendations to enhance the overall process. The inspectors also reviewed the NED prioritization meeting minutes dated June 6, 1995, and September 8, 1995. The minutes included the NED priority list and the attendees. The inspectors noted that personnel from other plant departments were in attendance at the meeting.

The inspectors concluded that substantial improvements have been made in the area of engineering interface and support of the organization at Crystal River 3. Project teams have been established, with representation from the different departments, for each major modification in an effort to better support the end user. Representatives present the department position instead of personal opinions. Monthly NED Design Priorities Meetings were held with representatives from various departments. An INPO assist visit was performed in May providing good recommendations for improvement. Post-project critique was used to provide feedback into the process.

Assessment: Substantial improvements have been made in the area of engineering interface and support of the organization at the site.

2.1.2.6. Enhancements to Engineering Processes

The inspectors reviewed various initiatives that have been implemented to enhance the engineering processes. These initiatives included the following:

- Revised the design calculation process to include systems engineering and operations concurrence on design inputs, assumptions, and results.

- Implemented a multidiscipline design engineering review board within NEP to review design activities for technical accuracy and adherence to requirements, to improve the quality of the end product.

- Enhanced the screening criteria for modifications and procedures by including two additional questions in the 10 CFR 50.59 screening criteria. The two questions were: 1) Can this potentially reduce the level of safety of the plant?, and 2) Can this possibly lead to an event that would impact plant operation?

- Revised design control procedures to strengthen the process for ensuring that required documents are revised prior to modification package closure and system turnover. The project manager monitors and tracks the revision of other plant documents which require a change.

- The relocation of NEP to the Crystal River site.

- Implemented NED monthly priority meeting which assigns priorities to new REAs.

- Requested reevaluation of REAs by the initiators to determine if there was still a need for the REAs. This was an attempt to reduce the large backlog of REAs assigned to NEP.

The inspectors reviewed various documentation which provided evidence of the engineering enhancements that have been implemented. Documentation reviewed included various design control procedures, approved modification packages, required modification procedure revision tracking reports, Design Engineering Review Board charter and meeting minutes, and NED monthly priority meeting minutes. In addition, the inspectors observed the enhanced 50.59 screening criteria being used by the PRC to assure that a BOP (SC cooling/flow balance) procedure received PRC review for revisions.

The inspectors reviewed the large backlog of REAs to assess whether they potentially affected safety system operability. First, inspectors reviewed a listing of all outstanding REAs (about 700), which included for each REA an identification of the affected equipment and a brief description of the problem. During that review, the inspectors noted that many of the REAs affected non-safety equipment but the majority affected equipment important to safety. The inspectors selected eight of the REAs that involved equipment important to safety, reviewed additional documentation for those eight REAs, discussed the problems with

REA originators and engineers, and found that none of the eight had any apparent impact on current operability. However, two of them had potential future affects on operability - one dealing with potential cold weather affects on the diesel driven fire pumps and one dealing with potential NPSH concerns with shutdown cooling pumps during periods of reduced RCS level that might occur during a refueling outage. The engineer assigned to the NPSH concern had it scheduled for completion prior to the next refueling outage. However, the diesel fire pump concern had no assigned schedule for completion and the inspector noted that fact to the Director, Nuclear Operations Engineering and Projects, as an example of the potential need to review all old REAs for appropriate prioritization and scheduling.

The inspectors concluded that the enhancements to the engineering processes have improved NEP's ability to provide more timely and effective support to the plant. Continued management attention is needed to address the large REA backlog, with special attention devoted to solving the problem in the long term and assuring all safety-related REAs are handled in a timely manner.

Assessment: Additional management attention is needed to address the large REA backlog with special attention devoted to solving the problem in the long term and assuring that all safety related REAs are handled on a priority basis.

The enhanced screening criteria was observed to be used by the PRC to assure that a BOP (SC cooling/flow balance) procedure will receive PRC review for future revisions.

2.1.3 Results

The inspection results indicate that the licensee has made significant progress in implementing the actions outlined in their Corrective Action Plan that was presented to the NRC during a March 1, 1995 meeting.

One strength and one weakness were identified in the Event Free Operations program.

Strength: The Operations Department Event-Free Operations Program was found to be well established and set the standard for other departments. (paragraph 2.1.2.1.a)

Weakness: With the notable exception of the operations area, the licensee's tracking and trending process for the Event Free Operations program was not clearly defined, was inconsistently applied, and could fail to identify adverse trends. (paragraph 2.1.2.1.e)

Two weaknesses were identified in the remaining Corrective Action Plan.

Weakness: Management oversight of significant issues needs to be strengthened. Several examples were identified where issues had not received adequate management attention (i.e. operability determination process, CCHE resolution, root cause evaluations, large REA backlog, etc.). (paragraph 2.1.2.2)

Weakness: For operability determinations, the clear expectations reflecting management's highest safety standard was absent. This was shown by the lack of a detailed and thorough process with rigorous guidance for making operability determinations.

Acronyms and Abbreviations

AHD - Air Handling Damper
AHF - Air Handling Fan
ALARA - As Low as Reasonably Achievable
AMSAC - ATWS Mitigation System Actuation Circuitry
ARP - Annunciator Response Procedure
ATWS - Accidental Transient Without Scram
BOP - Balance of Plant
BS - Building Spray
BSV - Building Spray Valve
BST - Building Spray Tank
BWNT - Babcock & Wilcox Nuclear Technology
BWST - Borated Water Storage Tank
B&W - Babcock & Wilcox
CCHE - Control Complex Habitability Envelope
CCTV - Closed Circuit Television
CFM - Cubic Feet per Minute
CFV - Core Flood Valve
CHV - Chiller Valve
CP - Compliance Procedure
CREVS - Control Room Emergency Ventilation System
DC - Decay Heat Closed Cycle Cooling
DEV - Deviation
ECCS - Emergency Core Cooling System(s)
EDG - Emergency Diesel Generators
EEI - Escalated Enforcement Item
EFIC - Emergency Feedwater Initiation Circuitry
EFOP - Error Free Operations Program
EFP - Emergency Feedwater Pump
EFW - Emergency Feedwater
EM - Emergency Management Procedure
EOP - Emergency Operating Procedure
EQ - Environmental Qualification
ERDS - Emergency Response Data System
ES - Engineered Safeguards
ESF - Engineered Safeguards Feature
F - Fahrenheit
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
gpm - gallons per minute
HP - Health Physics
HPI - High Pressure Injection
I&C - Instrumentation and Control
ICC - Inadequate Core Cooling
ICS - Integrated Control System
IFI - Inspection Followup Item
INPO - Institute of Nuclear Power Operations
IR - Inspection Report
ISI - Inservice Inspection
IST - Inservice Test

kV - kilovolt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LPI - Low Pressure Injection
MAR - Modification Approval Record
MOV - Motor Operated Valve
MNPO - Manager Nuclear Plant Operations
MP - Maintenance Procedure
M&TE - Maintenance and Test Equipment
MUP - Make-up Pump
MW - Megawatt
NCV - Non-cited Violation
NED - Nuclear Engineering Department
NEP - Nuclear Engineering Procedure
NGRC - Nuclear Generation Review Committee
NOD - Notice of Deviation
NOV - Notice of Violation
NPSH - Net Positive Suction Head
NPTS - Nuclear Plant Technical Support
NSS - Nuclear Shift Supervisor
OSB - Operations Study Book
OSC - Operations Support Center
OTSG - Once Through Steam Generator
PAM - Post Accident Monitor
PC - Precursor Card
PM - Preventive Maintenance
PMRG - Plant Management Review Group
POD - Plan of the Day
PORV - Power Operated Relief Valve
PR - Problem Report
PRC - Plant Review Committee
psig - pounds per square inch gauge
QC - Quality Control
QA - Quality Assurance
RBS - Reactor Building Spray
RCA - Radiation Control Area
RCP - Reactor Coolant Pump
RCPPM - Reactor Coolant Pump Power Monitor
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RO - Reactor Operator
RPS - Reactor Protection System
RTP - Rated Thermal Power
RWP - Radiation Work Permit
SCBA - Self Contained Breathing Apparatus
SG - Steam Generator
SP - Surveillance Procedure
SRP - Standard Review Plan
SSOD - Shift Supervisor on Duty
STI - Short Term Instruction
SW - Nuclear Services Closed Cycle Cooling System

TMAR - Temporary Modification Approval Record
TS - Technical Specification
TSC - Technical Support Center
URI - Unresolved Item
VIO - Violation
WDGA - Waste Decay Gas Analyzer
WR - Work Request