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

Report No.: 50-302/96-01

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: January 28 through March 9, 1995

Inspector: ______________________ 4/4/96
R. Butcher, Senior Resident Inspector Date Signed

Accompanying Inspectors:

T. Cooper, Resident Inspector
J. Kreh, Radiation Specialist (paragraph 5.4)
W. Miller, Reactor Inspector (paragraphs 5.3.1, 5.3.2, 5.3.3)
L. Raghavan, Project Manager (paragraph 4.6)
M. Thomas, Reactor Inspector (paragraph 6.0)

Approved by: K Landis 4/8/96
K. Landis, Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This inspection was conducted by the resident and Regional inspectors in the areas of plant operations, surveillance observations, maintenance observations, plant support, licensee's corrective action program, on site follow-up review of written reports of non-routine events, engineering activities follow-up, review of the local public document room, organizational changes, and review of the updated Final Safety Analysis Report. Numerous facility tours were conducted and facility operations observed. Backshift inspections were conducted on February 2, 6, 8, 13, 16, 18, 19, 29 and March 2, 6, 8.

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 licensee has taken appropriate actions for the Corrective Action Program items reviewed. Some of the actions had not been implemented long enough to assess their effectiveness. (paragraph 6.0)

A weakness was identified for the licensee not adequately controlling the annunciator logs. (paragraph 2.3)

A weakness was identified for the preplanning and control of shipping of damaged new fuel assemblies back to the manufacturer. (paragraph 2.4)

The operators identification of the design basis issues associated with the high pressure injection system is considered a strength. (paragraph 2.5)

Maintenance:

A weakness was identified regarding the securing or storage of maintenance equipment on or adjacent to safety related piping or equipment. (paragraph 3.1)

Engineering:

A violation (50-302/96-01-01) was identified for inadequate corrective actions to ensure the required high pressure injection flow instrumentation as required in the design basis.

An unresolved issue (50-302/96-01-02) was identified for licensee identified discrepancies in the high pressure injection system that do not meet the design basis analysis. (paragraph 2.5)

The improvements noted in the Plant Review Committee's thoroughness of review, as evidenced by the response to the high pressure injection design basis issue, recommending the shutdown of the plant, which was concurred in by plant management, is considered a strength. (paragraph 2.5)

A violation (50-302/96-01-06) was identified for the failure to meet requirements to correctly translate the design basis for the nuclear services closed cycle cooling system (SW) into specifications, drawings, procedures, and instructions. (paragraph 4.1)

A non-cited violation (50-302/96-01-03) was identified for failure to maintain 10 CFR 50, Appendix R, separation criteria for the emergency feedwater system. (paragraph 4.3)

A non-cited violation (50-302/96-01-04) was identified for failure to maintain accurate drawings which reflect the configuration of the emergency feedwater system. (paragraph 4.3)

An example of a violation (50-302/96-01-05) was identified for failure to update the final safety analysis report for a modification to the makeup system. (paragraph 4.4)

A second example of a violation (50-302/96-01-05) was identified for the failure to update the final safety analysis report to reflect changes to the licensing basis per license amendment 134 regarding the spent fuel pool cooling system. (paragraph 4.5)

Plant Support:

The licensee's strategy for the Thermo-Lag Resolution Implementation Program was thorough and addressed the required attributes; however, a final evaluation of this program was deferred pending NRC's review. (paragraph 5.3.1)

The licensee's evaluation of an Information Notice (IN) 94-58 on reactor coolant pump oil collection systems was of sufficient depth to address the concerns identified by the IN. (paragraph 5.3.2)

The modifications to the lube oil system for the new motor to replace reactor coolant pump 1A and its associated oil collection system satisfactorily addressed the problems associated with catching potential oil leaks from reactor coolant pump motor 1A. (paragraph 5.3.3)

The licensee's preparations and monitoring for a possible steam generator tube leak were considered a strength. (paragraph 5.1)

With one significant exception, the licensee's emergency response capability was being maintained at a fully proficient level of operational readiness. The exception involved the emergency ventilation system for the primary Technical Support Center (TSC). On February 13, 1996, that system was characterized by licensee management as "inoperable for radiological events," in that the system was not operating within its design basis requirements. On March 6, licensee management expressed its intention to bring the emergency ventilation system for the primary TSC into a state of full operability prior to restart of the plant following the current refueling outage. (paragraph 5.4.2)

REPORT DETAILS

Acronyms used in this report are defined in paragraph 12.0.

1.0 Persons Contacted

Licensee Employees

& P. Beard, Senior Vice President, Nuclear Operations
@&*G. Boldt, Vice President Nuclear Production
*J. Campbell, Manager, Nuclear Security
&*J. Campbell, Assistant Director, Maintenance and Radiation Protection
@ *R. Davis, Assistant Director, Nuclear Operations and Chemistry
# M. Donavan, Supervisor, Mechanical Group
@&*R. Enfinger, Manager, Nuclear Safety Assessment
@ M. Fuller, Radiological Emergency Planning Specialist
@& B. Gutherman, Manager, Nuclear Licensing
@ *G. Halnon, Manager, Nuclear Licensing
@& B. Hickle, Director, Nuclear Plant Operations
#@&*L. Kelley, Director, Nuclear Operations Site Support
@ J. Maseda, Manager, Nuclear Engineering Design
# &*P. Mckee, Director, Quality Programs
# *R. McLaughlin, Nuclear Regulatory Specialist
& B. Moore, Production Manager
@ T. Petrowsky, Supervisor, Nuclear Engineering Design
@ S. Powell, Senior Nuclear Licensing Engineer
@ S. Robinson, Manager, Nuclear Quality Assessments
# W. Rossfeld, Manager, Site Nuclear Services
@ J. Stephenson, Manager, Radiological Emergency Planning
@ A. Stern, Senior Nuclear Mechanical Engineer
&*F. Sullivan, Nuclear Plant Technical Support
@& P. Tanguay, Director, Nuclear Engineering and Projects
# S. Ulm, Supervisor, Nuclear Engineering Design
@ A. Washburn, Supervisor, Nuclear Plant Technical Support
& R. Widell, Director, Nuclear Operations Training

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

*Attended exit interview on March 11, 1996
#Attended exit interview on February 1, 1996
&Attended exit interview on February 16, 1996
@Attended exit interview on March 1 and March 6, 1996

2.0 Plant Operations (71707, 92901, 92700)

2.1 Plant Status

At the beginning of this reporting period, Unit 3 was operating at 100% power and had been on line since January 28, 1996. The following evolutions occurred during this assessment period:

- On February 16, 1996 at 8:00 p.m. the unit was taken off line due to the failure to meet the design basis for the HPI system. Mode 2 was entered on February 17, 1996 at 4:00 a.m. and Mode 5 was entered on February 18, 1996 at 11:00 a.m. See paragraph 2.5 for details of the design basis issue.

- The plant was scheduled to begin a refueling outage on February 29, 1996. Due to the required shutdown noted above, the licensee started their refueling outage early.

2.2 Plant Tours

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.

2.3 Control of Main Control Room Annunciators

On February 2, 1996 the resident inspector walked down the control room annunciator boards with the on shift CNO. The purpose of the walk down was to determine the status of the annunciators and to review the open link log. During this review, several discrepancies were noted as follows:

- Three event points (0374, 0701, and 0706) had noted in the open link log that the annunciator window was labeled. However, no label was found on the annunciator windows.

- Event points 0701 and 0706 were noted as annunciator window P-2-8. The correct annunciator window was P-3-8.

Based on the noted discrepancies, the licensee performed a complete review of annunciator links and the results were documented in PR 96-0019, Open Annunciator Link. The control of the annunciator l[illegible] is considered a weakness. See paragraph 2.3 of IR 50-302/95-21 for previously identified annunciator problems.

2.4 Refueling Outage Preparations

In preparation for the refueling outage, the inspectors reviewed the licensee's procedures for new fuel receipt, inspection, and storage. The inspectors observed fuel receipt and inspection prior to the beginning of the outage. Two fuel assemblies were rejected during receipt inspection, due to damage. The licensee determined that the most likely cause of damage was due to an excessive length on the end of the lifting pin attached to some of the fuel lifting strongbacks. The supposition is that either during the insertion of the assemblies into the strongback or during the removal of the assemblies from the strongback, the assemblies are catching the pin and are being damaged. No other problems were observed.

On February 15, 1996, the licensee was preparing to ship the damaged fuel assemblies back to the vendor. The inspectors questioned the SNM manager as to preparations taken to assure the fuel was shipped in accordance with 10 CFR 70 and 10 CFR 71 regulatory requirements. The SNM manager was unaware of either the requirements or whether they had been complied with. The SNM manager referred the inspectors to the person in charge of shipping radioactive packages.

The inspectors verified that the licensee had a procedure in place for the shipping of the fuel, but the procedure addressed the technical aspects of packaging and shipping the fuel. No provisions were present in the procedure for assuring compliance with the regulatory requirements. When asked by the inspectors how compliance would be accomplished, the licensee postponed the plans to ship the fuel assemblies. The licensing department contacted NRR and asked for a clarification on the applicable requirements. After assuring that all requirements were met, the licensee shipped the fuel assemblies on February 21, 1996. The inspectors reviewed the shipping documentation and found that all requirements were satisfied. The preplanning of the fuel assembly shipping was weak, in that until the inspectors questioned the compliance with regulatory requirements, the licensee was not taking actions to assure compliance.

The core offload began on March 5, 1996. The inspectors verified that all prerequisites were completed prior to the beginning of fuel movement. Discrepancies identified with the FSAR discussion of spent fuel pool cooling were addressed prior to 1/3 of the core being offloaded. See paragraph 4.5 for spent fuel pool cooling inspection details. The inspectors observed the PRC meeting which performed the review of the evaluation for the full core offload and identified no problems.

2.5 Reactor Shutdown Due to Failure to Meet the Design Basis Of the HPI System

PR 96-035, EOP Project Review Uncovers Discrepancy in FSAR Single Failure Analysis, was issued on February 15, 1996. This PR identified that the FSAR description of the analysis for a SBLOCA event failed to consider several affected pieces of equipment and therefore did not meet the design basis. These identified discrepancies were as follows:

- FSAR Table 6-19 displays the single failure analysis for the HPI system during a HPI line SBLOCA. A loss of dc Battery results in the loss of a diesel generator. The FSAR discussion did not recognize that the ES signal to the respective side HPI valves is lost due to the complete loss of the respective VBDPs. This would require operator action to open the HPI valves as well as selecting the backup power supply. Also a loss of a VBDP discussion did not recognize that a loss of a vital bus, depending on which vital bus was lost, could result in the loss of the ES signal to the HPI valves associated with that train.

- The FSAR table did not recognize that HPI flow indication may be lost during the guillotine rupture of an HPI line as described in Chapter 14. This accident requires that operator action be taken to balance HPI flows. This is required since HPI flow to the core cannot be assured prior to balancing, and no credit was taken for any HPI flow during the first 20 minutes. If the operator could not determine which HPI line was broken, the operator could not isolate the broken HPI line and balance the flow through the other three HPI lines as required by the design basis.

- Table 6-14 displays the single failure analysis for the HPI system during a RCS cold leg SBLOCA. The table did not recognize the failure of a vital bus. Specifically, VBDP-3 or VBDP-4, depending on which train is being evaluated. Failure of either distribution panel would prevent the respective train HPI valves from receiving their ES signal. This would require operator action to open the valves.

Also on loss of a dc battery does not recognize that when the EGDG is lost due to loss of the battery, the vital busses on the respective side are lost which results in the loss of:

1. Two lines of flow indication.

2. The ES signal to the respective side HPI injection valves.

To satisfy the design basis required one pump and four lines, operator action required would be to select the backup power supply to the HPI valves, and to open the respective HPI valves

- Another concern was related to the test of the HPI system automatic actuation matrix. The matrix energizes a relay that is powered from VBDP-3 (A side) or VBDP-4 (B side). During the performance of SR 3.3.7.1 under TS 3.3.7, Engineered Safeguards Actuation System (ESAS) Automatic Actuation Logic, the relays are not tested and the ES equipment is not verified operable.

PR 96-035 and OCR MU-96-MUV-23, 24, 25, and 26 were generated to document the above concerns and the NSS provided an immediate disposition of operable. This decision was based on the belief that this same issue had been addressed previously by an REA and further investigative followup was required.

A PRC meeting was held on February 16, 1996 to discuss the issues raised by PR 96-035. The PRC determined that on a SBLOCA of an HPI line with a LOOP and the loss of a dc battery (either battery), the operators would not have adequate HPI flow indication to balance the HPI flow in the HPI lines and was therefore outside the design basis of the plant. In the SBLOCA analyses, credit was taken to balance HPI flow between the four nozzles such that approximately 70% of the total flow reached the reactor vessel. After operator action to balance HPI line flows, flow from one pump would be distributed evenly through four injection points. To ensure conservatism in allowing for injection line loss differences, core cooling analysis assumes 30% (as opposed to one-fourth total flow) of the HPI flows out the break. On the loss of either dc battery, the four HPI lines will have only two narrow range and two wide range flow indicators. Due to the inaccuracies associated with the wide range flow indicators, the operators could not assure balanced flow through the HPI injection lines. On February 16, 1996 at 4:30 p.m. the NSS entered TS LCO 3.0.3 because, during the postulated accident scenario, only two narrow range HPI flow indicators and two wide range HPI flow indicators would be available making both trains of the HPI system inoperable. TS 3.5.2, ECCS-Operating, requires in Modes 1, 2, and 3 that two ECCS trains shall be operable. Since the loss of both HPI trains is not allowed, this put the plant into TS LCO 3.0.3.

LER 96-007 stated that on October 26, 1989, the unit shut down from 94% power due to the determination that the accuracy of the HPI flow instrumentation was inadequate. At that time, the only flow instrumentation on the HPI injection lines was the wide range instrumentation. The licensee, during the review for the Technical Specification upgrade program had determined that the wide range instrumentation was not accurate enough at low flows to perform flow balancing following a SBLOCA on a HPI line concurrent with a LOOP, with only one HPI pump operating. The licensee issued LER 50-302/89-037, on this issue. Initial follow-up of this item occurred in Inspection Report 89-28, and Inspector Follow-up Item 50-302/89-28-01, Adequacy of HPI System Flow Indication, was issued. Inspection Report 50-302/89-31 was issued on January 12, 1990 and Inspector Follow-up Item 50-302/89-28-01, was closed. Violation 50-302/89-31-01, Failure to Identify Problem with High Pressure Injection System Flow Indication Instrumentation was issued. There was an Enforcement Conference on this topic on February 1, 1990, which was documented in a meeting summary issued on March 2, 1990. Following this meeting, the apparent violation was issued as a non-cited violation based on the premise that the operator would have been able to take corrective actions to mitigate the postulated accidents despite reliance on only wide range transmitters.

In February, 1996, the licensee determined that with the worst case instrument inaccuracies, the operators would not be able to reliably take control and adequately balance the flows, during a SBLOCA in a HPI line, concurrent with a LOOP, and the loss of either vital dc battery. This accident scenario does not appear to have been adequately evaluated during the development of the corrective actions for the original identification of the issue. 10 CFR 50, Appendix B, Criterion XVI requires that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

However, in October 1989, the licensee failed to implement adequate corrective actions to correct an identified nonconformance of a design basis accident requirement as described in Chapter 14 of the FSAR. Specifically, FSAR Chapter 14 accident analysis for a HPI line SBLOCA concurrent with a LOOP and the loss of one (either) vital battery train requires that HPI line flow instrumentation be designed to allow the operator to balance the flow in the four HPI lines. In October 1989 the licensee identified that the existing HPI line flow instrumentation was not adequate to allow operators to balance the flow through the four HPI lines and subsequently revised the low instrumentation to provide adequate HPI line flow indication. In February 1996 the licensee again identified that the HPI line flow instrumentation was not adequate to allow operators to balance the flow through the four HPI lines. These inadequate corrective actions are a Violation 50-302/96-01-01, inadequate corrective actions to ensure the required high pressure injection flow instrumentation as required in the design basis.

The remaining issues, not addressed by the violation, in the problem report discussion above, are as follows:

- Testing the HPI automatic actuation system matrix.

- Loss of ES signal to the respective side HPI valves.

The licensee is still reviewing the above items for resolution. Pending completion of this review, these items are considered to be unresolved, and will be tracked by URI 50-302/96-01-02: Discrepancies in the high pressure injection system that do not meet design basis analysis.

The original identification of the design basis issue by an operator in the EOP upgrade effort is commendable and is considered a strength. The PRC responded conservatively in the evaluation of this issue, recommending a shutdown as a result of uncertainties identified in the evaluation. Plant management concurred with the PRC's recommendation that required shutting down the plant. The PRC has been demonstrating a more thorough approach to dealing with issues, demanding more complete analysis and documenting the results in more thorough meeting minutes.

These improvements, as demonstrated by the handling of this issue, are considered a strength.

3.0 Maintenance (61726, 62703)

3.1 Maintenance Observations

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.

The inspector witnessed the maintenance being performed under WR NU 0331464, which replaced the A and C battery chargers and balanced the loads between the two chargers. This maintenance implemented MAR 93-05-07-01, Battery Charger Replacement - Train "A". The inspectors verified that the WRs had received the required reviews and approvals, that required clearances were in place, properly hung, and accepted by the technicians, and that supervision and QC inspectors were present throughout the task. No problems were observed with the work practices.

On January 29, 1996 during a tour of the auxiliary building the inspector observed the following:

- A large gas cylinder was secured to the DC cooling water pipe that supplies cooling water to the RWP-3A heat exchanger.

- What appeared to be a welding rig (that had two wheels to make the unit portable) was stored between RWP-2A and RWP-3A. This rig was not restrained in any manner.

The inspector notified the shift manager who had the devices removed. The securing or storage of maintenance equipment on or adjacent to safety related piping or equipment is a poor practice and is considered a weakness.

3.2 Surveillance Observations

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of the TSs. The inspectors also confirmed that 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. The inspectors also verified that 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.

The inspectors witnessed the performance of licensee surveillance, SP-907A, Monthly Functional Test of 4160V ES Bus "A" Undervoltage and Degraded Grid Relaying. The inspectors observed the technicians in the plant during the performance of the test. One of the technicians was in the process of being qualified on the performance of the test and the inspectors observed that the technician, and a chief technician, were present to assure that the task was completed correctly and therefore qualified the technician. The inspector witnessed the performance of the surveillance and noted that no problems were identified or encountered.

4.0 Engineering (37551, 92903, 92700)

4.1 SW System Outside Design Basis

On January 30, 1996 at 6:30 p.m. the licensee notified the NRC via the ENS phone per 10 CFR 50.72(b)(1)(ii)(B), outside the plant design basis, that the potential existed to operate the SW system outside the design basis limits. Also the potential existed for the EGDGs to exceed their kW rating. The postulated event of a LOCA concurrent with a LOOP and the failure of one dc power train (either one depending upon the current valve lineup) would result in all the RB cooling fan SW isolation valves failing open with one SW pump in operation. The design basis only assumes two RB coolers in operation and SW flow balancing was accomplished with one RB cooler isolated. This event could result in less than design flow to other SW components and a higher kW load on the affected EGDG.

At 6:00 p.m. the licensee declared the SW system inoperable and entered TS 3.0.3. AHF-1B was removed from service with the manual SW isolation valves tagged closed and TS 3.0.3 was exited at 6:45 p.m. The licensee has attributed the cause to an error by Architect-Engineering personnel during a plant modification to the SW system. Proper consideration of all failure modes was not included in the analysis for the modification.

The interim corrective action taken by the licensee was to manually isolate SW flow to one cooler during operation. LER 50-302/96-005 was issued on February 28, 1996. The LER provides no permanent corrective actions, but states that the permanent corrective actions will be proposed by May 1, 1996. The licensee stated that a supplemental LER will be provided when permanent corrective actions are determined.

10 CFR 50, Appendix B, Criterion III, requires that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. This is applicable to all activities affecting the safety related functions of those structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public.

However, on January 30, 1996, the licensee determined that a LOCA concurrent with a LOOP and the loss of one dc power train could result in the opening of SW isolation valves to all three RB coolers. For the design basis of the SW system, the emergency heat transfer rate is based on removing the design heat load from each component to be cooled during emergency operations with 2 RB fan coolers in service (worst case heat rejection to SW). This is a failure to meet the requirements of 10 CFR, Appendix B, Criterion III and is identified as Violation 50-302/96-01-06, Failure to meet requirements to correctly translate the design basis for the nuclear services closed cycle cooling system (SW) into specifications, drawings, procedures, and instructions.

4.2 Changes to the Environs Around CR-3

In IR 50-302/95-20, paragraph 1.1.2.3 discussed the proposed installation of a gas pipeline to service the fossil units at the Crystal River facility. Subsequently, the licensee held an internal meeting to discuss the overall impact of the proposed natural gas pipeline on CR-3 operations. Parsons Power (formally Gilbert Commonwealth) was performing an analysis to determine the flammability concentrations at the CR3 control room resulting from a catastrophic failure at various points in the system. The preliminary results indicated the resultant concentrations would be excessive. As a result, Parsons was evaluating what modifications would be required to bring results to within allowable limits. Other impacts, such as the loss of the switchyard, would also require more investigation. Based on the noted concerns and the time and expense required to resolve those concerns, the licensee has decided to fully address and resolve the concerns prior to full scale development of the project. At this time, construction of the proposed gas pipeline is on hold by the licensee.

4.3 Emergency Feedwater Concerns

On January 11, 1996 at 6:28 p.m. with the plant in hot shutdown, the licensee reported that circuits for controlling emergency feedwater flow to both OTSGs pass through a common fire area and were not protected with any fire barrier protection in that common area. This report was made per 10 CFR 50.72(b)(2)(i). During on-going Appendix R related work, it was discovered that conduits (which contain circuits for valves controlling emergency feedwater flow to both steam generators) pass through a common fire area and were not protected with any fire barrier protection in that common area. The fire barrier protection material is currently considered inoperable and the licensee plans to continue compensatory actions (roving fire watch) until the fire barrier material issue is resolved.

The licensee has determined that drawings 215-032 and 213-014, which show the conduit running to the separate 480V ES switchgear rooms do not reflect the as built condition of the plant. Instead both trains run through the A 480V ES switchgear room and the conduits for the B valves, EFV-55 and EFV-56, run through the wall into the B 480V ES switchgear room.

The licensee has taken prompt corrective actions, revising the drawings, verifying that a fire watch does include the area of concern, performing a field verification of additional Appendix R drawings, and including these conduits in the Thermo-lag corrective action plan. The corrective actions were included in LER 50-302/96-001, issued on February 8, 1996. This licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as NCV 50-302/96-01-03, Failure to maintain 10 CFR 50, Appendix R separation for the emergency feedwater system.

Drawing 211-026, Revision 5, shows the two conduits, EFS56 and EFS57, running into the controller for EFV-55. EFS56 provides an instrumentation line and EFS57 is a control power line. The drawing shows EFS57 as having been spared and disconnected from the circuit. The licensee has found that the control power line has not been spared, but is planned to be done during the upcoming refueling outage. The drawing was mistakenly revised prior to the completion of the outstanding MAR and reflects changes not yet made. The licensee has revised the drawings to reflect the actual conditions, has counseled the involved personnel, and has verified that procedural controls do exist detailing the correct methods for updating drawings for a modification. This licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This issue is identified as NCV 50-302/96-01-04, Failure to maintain accurate drawings which reflect the configuration of the emergency feedwater system.

4.4 Make-up System Review

While performing a review of the make-up system description in the FSAR, it was noted that in 1986, a modification was made to the MU system to comply with 10 CFR 50, Appendix R requirements. This modification locked MUV-64 open and installed an interlock to open the BWST suction valves, MUV-58 and MUV-73, on a low MUT level. The opening of the valves was to ensure that the suction source to the HPI pumps is swapped to the BWST prior to hydrogen from the MUT being entrained and causing pump damage. These changes are described in a letter submitted to the NRC on August 6, 1985.

10 CFR 50.71(e) requires that licensees update the FSAR periodically, on a frequency of annually or 6 months after each refueling outage provided the interval between successive updates does not exceed 24 months. The revision must reflect all changes up to a maximum of 6 months prior to the date of filing. The revision submittal shall contain all the changes necessary to reflect information and analyses submitted to the NRC or prepared by the licensee per NRC requirements.

However, in 1986 the licensee made a modification to the plant, to satisfy 10 CFR 50, Appendix R requirements, for which a submittal was made to the NRC, but no revision was made to the FSAR to address the installed interlocks on the valves. This is the first example of VIO 50-302/96-01-05, Failure to update the final safety analysis report for a modification to the makeup system.

4.5 Spent Fuel Cooling System - Full core offload review

The PM performed a review of spent fuel pool practices and current licensing basis as it pertains to spent fuel storage pool safety and refueling outage core offload practices. The purpose of the review was to ensure that licensee operating practice is consistent with the CLB. In performing this effort the PM reviewed the following documents:

- FSAR Sections 5.1, 9.3, 9.6
- TS 3.7.13
- NRC letter dated April 16, 1991, Crystal River 3 - Issuance of Amendment Re: Spent Fuel Expansion (TAC No. 75305)
- NRC letter dated December 15, 1995, Crystal River Nuclear generating Plant Unit 3 - Issuance of Amendment Re: Fuel Enrichment Increase (TAC No. 91536)
- Enhanced Design basis Document, Spent Fuel cooling System
- Operating Procedure, OP-406, Spent Fuel Cooling System Revision 52 dated 2/23/96.
- SP-318, Spent Fuel Pool Boron Concentration Verification
- Surveillance Procedure, SP-381, Locked/Sealed Valve Check List, Revision 60 dated 2/9/96.
- Surveillance Procedure, SP-300, Operating Daily Surveillance Log, Revision 134 dated 1/19/96.
- Surveillance Procedure, SP-301, Shutdown Daily Surveillance Log, Revision 92, dated 8/11/95.

- Surveillance Procedure, SP-406, Refueling Operations Daily Data Requirements, Revision 11 dated 10/2/87.
- Annunciator Response, AR-402, PSA G Annunciator Response, Revision 19, dated 5/10/94.
- Surveillance Procedure SP-406 logs dated October 2, 1987, May 11, 1992 and October 21, 1993 for verification of decay heat time before core offload.

System Design

There are two SFPs. They are constructed of reinforced concrete with a stainless steel liner. The two SFPs, A & B can be separated by a removable stainless steel gate. The gate has a rubber seal around it to ensure a watertight seal. A portion of the B pool is utilized as the spent fuel cask loading pit which has the same type of gate arrangement.

The SFPs are 43 feet 8 inches deep with a combined water volume of 570,000 cf. Normal water level is at an elevation of about 158 feet which provides about 26 feet of water above the top of the stored fuel assemblies. Leakage of the liner is detected by pipes located between the liner and the concrete. These pipes drain into a trough, located in the Make Up pump rooms, and then to the auxiliary building sump. These pipes are to be checked every shift for leakage.

Spent fuel assemblies are stored in the upright position in the fuel storage racks. Both pools have high density storage racks and are capable of storing 1357 fuel assemblies. Both SFPs contain poison material and boroflex and the racks are designed to maintain the fuel assemblies subcritical. The new racks will permit full core offloading through the year 2008.

Two safety-related pumps and two safety-related (tube side) heat exchangers are provided for both the SFPs. Upon loss of the SFP pumps, one train of the decay heat removal system which is permanently piped and valved, can be used to circulate the spent fuel coolant through the decay heat exchangers to maintain the SFP temperatures below 140°F. Both the SFP pumps are powered from a Class 1E on-site power supply.

The spent fuel coolers are vertical U tube heat exchangers. The spent fuel coolant passes through the tubes and gives up its heat to the Nuclear Services Closed Cycle Cooling System which flows through the shell side of the heat exchangers. The cooled water is then returned to the spent fuel pools. The SFP heat exchangers are cooled by Nuclear Services and Decay Heat Sea Water (RW system) which transfer the heat to the ultimate heat sink (UHS).

Audible alarms in the control room are provided for SFP level, and temperature.

Summary of CLB Requirements Regarding Spent Fuel Pool Decay Heat Removal/Refueling Offload Practices

(1) Technical Specification limits are provided as follows: SFP level (23 feet above top of irradiated fuel i.e., >156 ft. plant datum TS 3.7.13), SFP boron concentration (>1925 ppm TS 3.7.14), initial enrichment and burnup of spent fuel assembly (TS 3.7.15) and fuel storage (TS 4.3). No other license conditions exist for these areas.

(2) Maximum heat load in the pool under refueling outage conditions is limited to design analysis input value of 33.5 MBTU/hr (FSAR Table 9-7)

(3) Fuel pool temperature is limited to 128°F for all normal 1/3 core offload and 140°F for full core offload (FSAR 9.3.2.1.2). The staff's safety evaluation dated 4/16/91 for TS amendment 134 allows 157°F for full core offload. The temperature limits are based upon two SFP pumps and two coolers operating. The staff's acceptance of the 157°F is based on the licensee assurance that the demineralizer resin could withstand temperatures in excess of 250°F (SE dated 4-16-91).

(4) For full core offload, the decay heat system which is permanently piped and valved to SFP can be made available to dissipate the heat associated with a full core discharge if the SFP pumps and heat exchangers are not available. For full core offload, the decay heat system is capable of maintaining SFP temperature less than 140°F.

(6) A delay time before fuel transfer of 72 hours is assumed for all fuel transferred to the fuel pool (FSAR 9.6.2.4).

(7) No other implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.

The licensee's outage plan for Refuel 10, indicates that it plans to perform a full core offload. The plant FSAR provides for full core offload. Licensee has procedures to ensure that core offload practices are consistent with CLB. For the current outage, the unit commenced shutdown on February 16, 1996 and core offload began on March 6, 1996, which exceeds the specified 72 hours delay time for unloading the core. In addition, the PM reviewed a sample of previous fuel outages and verified that the licensee has complied with this time requirement.

While reviewing the licensing basis for the spent fuel pool and the spent fuel cooling system, the NRR Project Manager identified several discrepancies in the FSAR regarding the number of spent fuel assemblies allowed to be stored in the spent fuel pool and the number of refueling discharges that can be handled. License amendment 134, issued on April 16, 1991, revised the number of fuel assemblies allowed to be stored in the spent fuel pool from 1180 to 1357. Also the number of refuelings that can be handled was revised from 16 to 19 1/3. The following discrepancies were noted:

1. Maximum heat load in spent fuel pool during a refueling outage is limited to 33.4 x 10^6 BTU/hr (FSAR Table 9-6). The basis for this heat transfer capability is not consistently described. FSAR Table 9-6 states that this heat load is based on 16 successive refueling discharges plus one full core discharge. The licensee's October 31, 1989, licensing submittal describes a design heat load of 33.5 x 10^6 BTU/hr as being based on infinite irradiation of one full core after a two year operating cycle with 72 hours delay plus all previously removed fuel assemblies.

2. Normal heat removal capacity of the spent fuel pool cooling system is 16.7 x 10^6 BTU/hr (FSAR Table 9-6). The basis for this heat removal capability is also not consistently described. FSAR Table 9-6 states that this heat load is based on 16 successive refueling discharges. Section 9.1.3 of the FSAR states that the spent fuel cooling system is designed to maintain the spent fuel pool water temperature below 128°F with a heat load based on removing the decay heat generated from 1180 fuel assemblies that have been discharged during 19 refuelings assuming a time interval of 150 hours between reactor shutdown and core discharge.

3. For conditions other than a full core offload, the normal spent fuel cooling system is in operation maintaining spent fuel pool temperature at or below 128°F. For the full core offload, the temperature limit is 140°F, and the decay heat removal system must be available to supplement the normal cooling system, although the decay heat removal system is not required to be operating.

4. The spent fuel pool temperatures in the FSAR do not agree with the safety analysis submitted with license amendment 134.

5. FSAR 9.3.2.2, Reliability Considerations, states that leakage from the SFP through the leak chase trench is monitored daily. The licensee identified that its Surveillance Procedure SP-301, Shutdown Daily Surveillance Log, Revision 92, does not include an item to verify this leakage monitoring.

Based on these findings, the licensee issued PCs to initiate a change to the FSAR. Also, a PC identified that the spent fuel system EDBD does not agree with license amendment 134.

10 CFR 50.71(e) requires that licensees update the FSAR periodically, on a frequency of annually or 6 months after each refueling outage provided the interval between successive updates does not exceed 24 months. The revision must reflect all changes up to a maximum of 6 months prior to the date of filing. The revision submittal shall contain all the changes necessary to reflect information and analyses submitted to the NRC or prepared by the licensee per NRC requirements.

However, the design basis of the spent fuel pool system as revised by license amendment 134 issued on April 16, 1991 was not incorporated into the UFSAR as follows: FSAR 9.3 incorrectly states that 1180 fuel assemblies are allowed versus the 1357 of license amendment 134; FSAR Table 9-6 incorrectly states 16 refuelings can be handled versus 19 1/3 of license amendment 134. The FSAR incorrectly references a maximum spent fuel temperature of 140°F using spent fuel pool cooling versus the 157°F of amendment 134. And FSAR 9.3.2.2 incorrectly states that leakage from the SFP through the leak chase trench is monitored daily. This is the second example of VIO 50-302/96-01-05, Failure to update the final safety analysis report to reflect changes to the licensing basis per license amendment 134 regarding the spent fuel pool cooling system.

In support of its spent fuel pool rerack license amendment (Amendment No. 134), the licensee calculated maximum spent fuel pool temperature of 157°F for the case of full core offload with both spent fuel trains in operation. The licensee has stated that the demineralizer resin used in the cleanup system could withstand temperatures in excess of 250°F. On this basis, the staff in its safety evaluation found the maximum spent fuel pool temperature of 157°F for the case of full core offload to be acceptable. The PM requested documentation to verify the temperature limit for the demineralizer resin. The licensee could not verify this and wrote a problem report. The licensee performed an evaluation per 10 CFR 50.59 and determined that although the cation resin would release captured radioactive contaminants above 140 °F, the demineralizer could be isolated on spent fuel pool temperatures. Spent fuel pool temperature alarms are received in the control room at 120°F and at 140°F .

5.0 Plant Support (71750, 92904, 64704, 81700, 82701)

5.1 Health Physics and Chemistry Program

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. These observations 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

- 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.

At 7:50 a.m. on January 31, 1996, the control room received alarms on RMA-12, Hotwell Offgas Radiation Monitor, which indicated a slowly increasing trend. This is indicative of an increasing primary to secondary leak. Chemistry began an increased sampling rate of the secondary side at that time.

The licensee held a meeting to discuss actions and contingency plans in case a steam generator tube rupture occurred. At that time, chemistry sampling did not indicate any increased primary to secondary leakage, but the licensee maintained a heightened awareness and an increased sampling frequency. The licensee continued to sample at the increased sampling rate until February 9, 1996. On that date, the licensee resumed sampling at the normal frequency. At no time during that period did any samples indicate an increased leak rate.

The implementation of the health physics and chemistry programs observed during this inspection period were proper and conservative. The licensee's preparations for a possible OTSG tube leak were considered a strength.

5.2 Security Control

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 including protected and vital areas access controls; searching of personnel, packages, and vehicles; badge issuance and retrieval; escorting of visitors; patrols; and compensatory posts. In addition, the inspector observed the operational status of protected area lighting, protected and vital areas barrier integrity, and the security organization interface with operations and maintenance. No performance discrepancies were identified by the inspectors.

5.3 Fire Protection

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.

5.3.1 Implementation of Fire Protection Thermo-Lag Resolution Plan

The inspector reviewed the licensee's program and implementation status for resolution of the Thermo-Lag fire barrier issues at CR-3. This program is required to meet the requirements of 10 CFR 50 Appendix R and included:

- evaluation and reanalysis of the fire protection features and separation of the safe shutdown components for the areas in which Thermo-Lag was originally installed,

- rerouting of circuits where possible to eliminate the requirement for raceway fire barriers,

- development of repair procedures,

- installation of alternative fire barriers (Mecatiss) to replace the existing Thermo-Lag fire barriers,

- submission of an exemption request for plant areas for which further modifications would not improve the overall level of safety, and

- evaluation of the ampacity derating due to the installation of the alternative fire barrier materials.

Analysis Changes

Based on the fire protection and safe shutdown reanalysis, a number of changes have been proposed for the Appendix R post-fire shutdown analysis. These changes will require revisions to plant drawings and design basis documents and included using: manual control in lieu of automatic initiation and control of the emergency feedwater system; offsite power supply for post-fire safe shutdown; auxiliary feedwater pump for initial heat removal; additional instrumentation not included in the previous analysis; post-fire operator manual actions to align breakers and valves; and post-fire repairs to restore equipment needed for cool down and cold shutdown. The reanalysis identified a reduction of approximately 75 percent in the number of fire barriers required for electrical raceways.

At the time of this inspection, the reanalysis was approximately 45 percent complete. Significant revisions are required to Operations Procedure AP-880, Fire Protection, to address the actions required for safe plant shutdown in the event of fire. The changes to this procedure were scheduled to be completed by June 28, 1996. The reanalysis also required additional associated circuit calculations for multiple high impedance faults. This reanalysis was approximately 55 percent complete. The analysis changes and revised calculations were scheduled to be completed by September 30, 1996.

Circuit Reroutes

Rerouting of cables was proposed for a number of circuits associated with off-site and emergency power supplies to safety related components, and HVAC components. Modification packages were being prepared for these changes. The conceptional design requirements were scheduled to be completed by December 1996. The work will be planned to perform circuit rerouting for one train per refueling outage beginning with the 1998 refueling outage. The cable rerouting was scheduled to be completed by the end of the 2000 refueling outage.

Repair Procedures

The development of the procedures for repairs to equipment to be used for cool down and cold shutdown had not yet been started. These procedures are to be completed by the end of the 2000 refueling outage.

Alternative Fire Barriers

The licensee has identified a fire barrier design to replace the existing Thermo-Lag fire barrier materials. The new design uses a material, Mecatiss, which was developed in France. This material has been installed in a number of industrial and nuclear facilities in other countries to provide a fire barrier or leak seal between components or fire areas. The licensee proposes to install this Mecatiss material as an overlay material on the existing Thermo-Lag installations. The licensee indicated that this material had recently passed a number of fire tests which matched the design configurations proposed for installation at CR-3. The final results of these tests were scheduled to be submitted to the licensee by the testing laboratory prior to February 15, 1996. The results of these tests are to be submitted to the NRC for review and approval.

The preparation of the design packages for the installation of the Mecatiss fire barriers were in progress during this inspection. Installation of the new raceway fire barriers was scheduled for the late February - April 1996 refueling outage.

Exemptions

The reanalysis identified several plant areas which did not meet the Appendix R separation requirements. However, the reanalysis determined that a significant fire hazard exposure to both safe shutdown trains did not exist in these areas due to low fire hazards, installation of traditional fire protection features, and the existing separation provided between redundant trains of the safe shutdown equipment, components or cables in these areas. The licensee's analysis concluded that further modifications in these areas would not improve the overall level of safety beyond current conditions. Therefore, justifications for exemptions were being developed for these areas. The request for exemptions in these areas was scheduled to be submitted to the NRC by May 31, 1996.

Ampacity Derating of Cables

Calculations on the ampacity derating of cables installed in the raceways to be enclosed by the new Mecatiss fire barrier installations were in progress. These calculations were to be based on vendor information and on the data obtained from the fire tests recently completed on the fire barrier system. These calculations are scheduled to be completed and sent to the NRC for approval by June 28, 1996.

The licensee's Thermo-Lag Resolution Implementation Program appeared to be thorough and address all of the required attributes; however, an evaluation of this program was deferred pending NRC's review.

5.3.2 Information Notice 94-58, Reactor Coolant Pump Lube Oil Fire

This IN was issued to alert licensees to problems that may exist with oil collection systems installed for RCP motors. The IN discussed problems with the lube oil collection systems which had been identified at two nuclear plants.

The inspector reviewed the licensee's evaluation of this IN. The licensee's evaluation found that the IN was not applicable because at CR-3 the:

- oil collection system does not use PVC or other synthetic piping components,
- reactor coolant system uses mirror insulation which will not become oil soaked,
- ventilation air flow for the reactor coolant pumps moves from the lower pumper elevation to the top of pump motor without creating a cross flow ventilation pattern to blow leaking oil out of the oil collection system,
- oil collection system has side panels to prevent oil from being blown outside the collection system,
- oil collection tanks are large enough to accommodate the oil in all of the reactor coolant pumps, and
- portions of the lube oil system outside of the lube oil enclosure had been evaluated and found not to warrant being included inside the lube oil enclosure. This position has been reviewed and found acceptable by the NRC.

The inspector reviewed the description of the oil collection system in FSAR Section 9.8.7.6 and noted that the installed system conformed to the system described in the FSAR. Also, the inspector concluded that the licensee had performed a sufficient evaluation to address the items identified by the IN.

5.3.3 Closeout Issues

(Open) LER 50-302/95-008, Oil Leakage from Reactor Coolant Pump Motors Not Collected by Lube Oil Collection System Leads to Operations Outside Design Basis.

On May 19, 1995, while operating at full power, the licensee determined that lube oil was leaking from RCP motors and not being caught by the oil collection system. This conclusion was based on the difference between the quantity of oil added to the RCP motors and the amount of oil collected in the system drain tanks. Furthermore, oil was found in the reactor building drain sump.

The licensee's evaluation and development of corrective actions to prevent recurrence of this event were in progress and a supplement to the LER is scheduled to be completed and sent to the NRC by April 30, 1996.

During this inspection, the inspector reviewed the status of the corrective actions which had been taken on this item. Action was taken by the licensee during the January 1996 maintenance outage to locate and correct this leakage. The inspector reviewed the preliminary inspection reports dated January 17, 1996, prepared by the electrical maintenance and the system engineer. These reports indicated that the lube oil leakage was primarily from RCP Motor 1A. There was no oil leakage found coming from the motor thermocouples. Previously, as documented by the LER, these thermocouples had been the suspected source of oil leakage from the lubrication system. The oil leakage on RCP Motor 1A was primarily from a loose flanged connection on the return oil lube line from the oil cooler. The loose bolts to this flange connection were tightened and the leak stopped. There was evidence of additional minor oil leakage from RCP Motor 1A and the other three RCP motors. Due to contamination and inaccessibility, these leaks could not be located, but based on the small amount of oil residue the licensee considered that these leaks did not warrant additional action until the next refueling outage, scheduled for late February - April 1996. The licensee's inspection reports also noted that there were several small leaks in the oil collection system enclosures provided for each RCP motor. These leaks were primarily from deteriorated gasket and seal materials installed at the connection points where various panels for the oil catchment enclosure were connected together. The reports indicated that all of these leaking connections were patched and repaired.

The inspector reviewed the licensee's trending data on the lube oil levels in RCP Motor 1A from January 19 through 26. This data indicated that the leakage in the lube oil system had been corrected since the lube oil level had remained constant.

The licensee advised that a new motor was to be installed on RCP Pump 1A during the upcoming outage. This new motor has a lube oil system which has many of the potential high pressure oil leak connections located inside of the motor housing. The high pressure oil lift pump and connections for the upper motor bearing were located outside the motor housing and will be provided with a fiberglass enclosure designed to catch and contain any potential oil leaks from the high pressure portion of the system. Collection pans are provided beneath the low pressure portions of the lube system to catch any leakage from this portion of the system. All leakage into the collection system will be arranged to drain to the RCP oil collection system drain tanks. The motors for the remaining three pumps, the motor lube oil system, and RCP oil collection system are to be modified to match the arrangement on the new motor. One motor will be modified during each refueling outage beginning in 1998. The modifications to all motors are to be completed by 2002.

The inspector examined the new motor and oil collection system for RCP 1A and noted that the modified oil collection system should continue to meet the commitment and description of the system in FSAR Section 9.8.7.6.

Additional inspections of this item will be made upon completion of the installation of the new motor for RCP Pump 1A, completion of the licensee's evaluation and issuance of the supplement to the LER scheduled for April 30, 1996. This item remains open.

5.4 Emergency Preparedness

5.4.1 Emergency Plan and Implementing Procedures

This area was inspected to determine whether significant changes were made in the licensee's emergency preparedness program since February 1995 (when the last such inspection of this area was performed), to assess the impact of any such changes on the overall state of emergency preparedness at the facility, and to determine whether the licensee's actions in response to actual emergencies were in accordance with the RERP and its implementing procedures. Requirements applicable to this area are found in 10 CFR 50.47(b)(16), 10 CFR 50.54(q), Appendix E to 10 CFR Part 50, and the RERP.

The version of the RERP in effect at the time of the current inspection was Revision 15, which became effective on December 30, 1994. This revision was previously reviewed and formally approved by the NRC. The licensee planned to issue Revision 16 during the first quarter of 1996.

The inspector selectively reviewed licensee records regarding the transmittal of EPIP revisions to the NRC between January 1, 1995 and the date of the current inspection. The records disclosed that each of the revisions made to the EPIPs during that period was transmitted to the NRC within 30 days of the implementation date, as required.

Changes made since February 1995 in the licensee's emergency preparedness program/capability were discussed with the Manager, Radiological Emergency Planning. The major changes were:

- An emergency satellite communications system known as ESATCOM was installed to provide backup communications in the event of the loss of all land-based telephonic lines. The system was accessible from the Control Room, TSC, and EOF using dedicated handsets. Developed by the State of Florida, ESATCOM linked the State's 67 counties, its 3 nuclear power facilities, and the National Hurricane Center in a network designed primarily for hurricane information and response.

- An electronic logkeeping capability was installed at the TSC. The log could be displayed on a monitor in the TSC, and was accessible from the EOF. Cosmetic changes to the TSC included new furniture and status boards.

- The EOF was modified to relocate the room designated for NRC personnel in order to enhance communications and accessibility.

- The Emergency News Center (adjacent to the EOF) received a major functional enhancement with the installation of a large-screen, rear-projection video monitor with multimedia capability.

The inspector determined through discussions and direct observations that the changes listed above did not diminish the licensee's emergency response capabilities, and, in fact, represented enhancements to those capabilities. Review of the EPIPs confirmed that the changes described above were appropriately incorporated into procedures. Requisite changes in the RERP will be assimilated into the forthcoming Revision 16.

The inspector verified that current letters of agreement existed between the licensee and the offsite support organizations listed in Appendix B to the RERP. Also verified through documental examination was the licensee's performance of the required annual review of EALs with State and local governmental authorities for 1995.

Since the February 1995 inspection, two emergency declarations were made by the licensee, both at the NOUE classification. These occurred on June 4 and October 3, 1995. The inspector's scrutiny of licensee documentation of these events concluded that each was correctly classified based on the EALs, and that notifications to offsite authorities were made in accordance with applicable requirements for the latter event. However, confusion and untimeliness prevailed in the June 4 event (Hurricane Allison) when a National Weather Service briefing via conference call consumed 45 minutes and left Control Room staff perplexed as to whether the plant was under a Hurricane Warning or Watch. When the Hurricane Warning status was finally confirmed at about 12:45 p.m., the NSS declared a NOUE and generated notifications as required within 15 minutes to State and local authorities and 60 minutes to the NRC. The only significant problem with respect to RERP implementation during this event was that the NOUE was declared by the NSS to have occurred at 11:00 a.m. (the time at which the tropical storm was upgraded to a hurricane). Neither the licensee's RERP nor NRC guidance make provisions for such a "retrospective" declaration. The licensee generated a Problem Report (PR 95-0103) in an effort to formulate appropriate corrective actions through training emphasis in this realm.

5.4.2 Emergency Facilities, Equipment, Instrumentation, and Supplies

This area was inspected to determine whether the licensee's ERFs and associated equipment, instrumentation, and supplies were maintained in a state of operational readiness, and to assess the impact of any changes in this area upon the emergency preparedness program. Requirements applicable to this area are found in 10 CFR 50.47(b)(8) and (9), 10 CFR 50.54(q), Sections IV.E and VI of Appendix E to 10 CFR Part 50, and the RERP.

The inspector toured the Control Room, TSC/OSC, and EOF. Selective examination of equipment and supplies indicated that, with one exception, a high level of operational readiness was being maintained for these ERFs. Control Room and TSC emergency kits (including survey instruments) were checked and found to be well organized and maintained.

The referenced exception involved the EVS for the TSC. On February 13, 1996, that system was verbally characterized by the Director, Nuclear Plant Operations as "inoperable for radiological events" in that the system was not operating within its design basis requirements. This condition had existed since at least July 1994, and was the subject of a previous NOD in NRC Inspection Report No. 50-302/95-16. The NOD was based upon the licensee's failure to maintain the proper air flow balance of the TSC EVS, thus degrading the expected performance of the charcoal filtration system under accident conditions. The inspector reviewed the licensee's November 9, 1995 response to the NOD and a revised response dated February 7, 1996. The latter correspondence contained the following conclusions:

> ... our overall evaluation has still determined the system cannot be balanced within current design limits without analytical or physical changes.
>
> The TSC Ventilation System is currently considered to be operable but in a degraded state. This could result in O_2, CO_2 and thyroid dose exceeding the allowable limits during an emergency event. To compensate for this, each of these items is monitored in the plant emergency procedure and compensatory action can be taken if adverse conditions are observed.

The due dates for the various corrective steps specified in the February 7 response appeared to be unnecessarily protracted, with October 1, 1996 given as the deadline for a determination of any required system design changes, and December 1, 1996 as the due date for a revision to the corrective action plan if design changes were determined to be required. The inspector discussed this matter with licensee managers, who had apparently already made the same judgment before the current inspection began.

The inspector examined the TSC EVS with the System Engineer, observing operation in both the normal and the emergency mode, and reviewed proposed changes. Aside from its current operational deficiencies, the EVS was well maintained and was functionally tested on a monthly basis. On the final day of the inspection, the inspector observed licensee personnel performing flow measurements to assess the efficacy of a possible modification which would block an exhaust plenum that was inadvertently serving as a major source of unintended air intake in the EVS mode. Other possible physical changes in the EVS were also being evaluated.

A reference earlier to "compensatory action" (in the quotation from the licensee's February 7 NOD response) concerned procedural criteria for relocating the TSC to an alternate facility in the Control Complex if habitability requirements were not met because of radiological or other hazards. The alternate TSC, comprising several offices and a break area adjacent to the Control Room, was inspected in detail and was found to be adequate as a backup facility, in terms of available space and equipment, in the event the primary TSC had to be abandoned during an emergency. The only significant equipment deficiencies in comparison with the primary TSC were the absence of both a dedicated HPN telephone and a Corporate Ringdown line.

During the inspector's second exit interview (on March 6), the Vice President, Nuclear Production expressed his intention to bring the EVS for the primary TSC into a state of full operability (to include conformance with all of its design basis requirements) prior to Unit 3 restart following the current refueling outage (which commenced on February 16). This plan was subsequently confirmed in an NRC letter dated March 21, 1996 acknowledging the licensee's revised NOD response.

Based upon ERF walk-downs, observation of licensee activities, review of changes to the EPIPs, inspection of completed surveillance procedures, and statements by licensee representatives, the inspector concluded that no degradation of capabilities with respect to the ERFs and their associated equipment had occurred since the NRC inspection of this program area in February 1995, except as discussed above in regard to the TSC EVS.

5.4.3 Organization and Management Control

This area was inspected to determine the effects of any changes in the licensee's emergency organization and/or management control systems on the emergency preparedness program, and to verify that any such changes were properly factored into the RERP and EPIPs. Requirements applicable to this area are found in 10 CFR 50.47(b)(1) and (16), Section IV.A of Appendix E to 10 CFR Part 50, and the RERP.

The organization and management of the emergency preparedness program were reviewed and discussed with licensee representatives. No organizational or personnel changes had occurred in this area since last reviewed in February 1995. The emergency planning staff comprised four full-time technical positions -- a manager and three specialists. The Manager, Radiological Emergency Planning functioned under the supervision of the Director, Nuclear Operations Site Support, who reported to the Vice President, Nuclear Production. This organizational structure appeared to give relatively high "visibility" to emergency planning and preparedness at the Crystal River site. No changes had occurred in the organization and staffing of State and local support agencies since the last inspection.

5.4.4 Training

This area was inspected to determine whether the licensee's key emergency response personnel were properly trained and understood their emergency responsibilities. Requirements applicable to this area are contained in 10 CFR 50.47(b)(2) and (15), Section IV.E of Appendix E to 10 CFR Part 50, and the RERP.

The training program for the Crystal River ERO was described in Section 19.0 of the RERP. In an effort to gauge the effectiveness of this training program, the inspector conducted an interview with an NSS (the position designated as interim EC). The purpose of this interview process was to ascertain the NSS's understanding of emergency classification, offsite notifications and PARs, site evacuation, emergency worker dose limits, and nondelegable responsibilities of the EC. The interview, which lasted 45 minutes, began with technical questions relating to the duties, responsibilities, and functions of the EC during an emergency situation, and then presented four simulated accident scenarios that required event classification and PAR formulation, as appropriate. The inspector delineated the guidelines for the interview at the outset, including the "open book" nature of the evaluation. The Manager, Radiological Emergency Planning was present during the interview to allow for confirmation and firsthand understanding of observations. The NSS was judged to have demonstrated a fully inclusive understanding of his duties and responsibilities as EC in the event of an emergency. All emergency classifications and PARs were timely and correct. No problems were identified during this interview.

The inspector reviewed and discussed the licensee's drill program with the Manager, Radiological Emergency Planning. Unlike most counterpart facilities in Region II, the licensee did not conduct integrated emergency response drills on a periodic basis, such as quarterly. Two TSC drills were typically conducted each year, although documentation suggested that these were closer to being classifiable as training sessions than drills. This approach necessitated the conduct of a "dress rehearsal" each year to assure that the ERO was prepared to convincingly demonstrate its capabilities during the actual annual exercise. The licensee's self-assessment of ERO performance during the November 1, 1995 "off-year" exercise assigned an overall rating of only "satisfactory".

On the limited basis of documental review and the NSS interview, the inspector concluded that the licensee's methodology for formally training emergency response personnel appeared to be very effective, although the drill component of the training program was an area for potential improvement.

5.4.5 Independent Audits and Internal Reviews

This area was inspected to determine whether the licensee had performed an independent audit of the emergency preparedness program, and whether the emergency planning staff had conducted a review of the RERP and the EPIPs. Requirements applicable to this area are found in 10 CFR 50.54(t) and the RERP.

The most recent independent audit of the emergency preparedness program was conducted during March 1995, and was documented in Audit Report No. 95-03-SSUP. This audit appeared to have been thorough and detailed, and involved the use of outside expertise (an emergency preparedness specialist from another utility). The audit identified six minor suggestions for improvement and three Good Practices; no PRs were generated. A concern from the NRC's February 1995 inspection was that the independent audit in March 1994 lacked appropriate depth and an aggressive approach to identifying problems. The inspector determined that the licensee had satisfactorily addressed this concern through the changes implemented in the latest audit, which in turn enhanced the licensee's ability to identify and correct emergency preparedness program deficiencies.

The inspector reviewed records of the annual internal reviews of the RERP and EPIPs for 1995. These were performed and documented in accordance with applicable procedures, and adequately assessed program accomplishments and needed corrective actions. The reviews produced RERP Revision 16 (due for issuance soon) and revisions to most of the EPIPs during 1995.

5.4.6 Control Room Emergency Ventilation System (84750)

The inspector interviewed a System Engineer having responsibility for the CREVS in connection with a potential generic NRC concern regarding the operability of humidistats sometimes used to control heaters in such a system. The CREVS at Crystal River utilized heaters but not humidistats, with the heaters being actuated by a combination of temperature transmitters (with pneumatic outputs) and temperature switches. The inspector verified that these heater actuation devices were included in calibration and preventive maintenance programs. The concern regarding the operability of humidistats in the CREVS was determined to be not applicable at this facility.

5.4.7 Licensee Action on Previously Identified Open Items

(Open) NOD 50-302/95-16-05: Deviation from the design commitment for the TSC emergency ventilation system.

For the reasons discussed in detail in Paragraph 5.4.2 above, this item remains open.

6.0 Corrective Action Program (40500)

The inspector reviewed the licensee's implementation actions outlined in their Corrective Action Program (CAP). That plan was discussed in meetings with the NRC on March 1, 1995, August 25, 1995, October 13, 1995, and February 5, 1996. In addition, the licensee's actions were documented in the Corrective Action Plan Meeting Summary dated September 7, 1995. The inspector reviewed the status of selected items that were listed in the licensee's CAP. Documentation and other objective evidence was reviewed to verify that the licensee had completed the specific actions to address the issues. The following action items were reviewed:

<u>Action Item 1:</u> The Mission Statement was revised to place primary emphasis on nuclear safety.

The inspector reviewed the licensee's Nuclear Operations Long Range Plan for Excellence, dated January 1995, and verified that the Mission Statement was revised from 1994 to place nuclear safety before electrical generation. The Long Range Plan established a direction for nuclear operations efforts over the next five years. The inspector also reviewed the Nuclear Operations Long Range Plan for Excellence, dated January 1996, and noted that the key nuclear operations challenge in the Long Range Plan was human performance and safety focus.

<u>Action Item 2:</u> The Long Range Plan identifies safety culture as the top priority and has established actions to go with it. This was also stressed in the 1995 Plan.

The inspector noted that human performance and safety culture improvement was the top nuclear operations challenge in the 1995 Long Range Plan for Excellence. The inspector also reviewed the Nuclear Operations 1995 Annual Plan, dated January 1995. The Annual Plan consisted of the nuclear operations goals and supporting action plans for each department which, in turn, support meeting the key nuclear operations challenges in the Long Range Plan for Excellence. The inspector noted that the 1995 Annual Plan also placed high priority on human performance and safety culture improvement.

Action Item 4: A change was made to the Plan of the Day to remove the number of continuous days on line.

The inspector reviewed various copies of the Plan of the Day for 1995 and 1996 and noted that the number of continuous days on line statement was removed. This statement was removed on January 25, 1995.

Action Item 8: A letter documenting FPC senior management commitment to (and role in achieving) conservative decision making was sent from FPC (Allen Keesler) to INPO (Zack Pate).

The inspector reviewed the subject letter which was dated February 1, 1995. The letter was in response to a request from the president of INPO. The letter positively ensured that the need for conservative decision making was thoroughly ingrained in Crystal River's nuclear organization. The letter also included a brief outline of actions by FPC which ensure conservative decision making.

Action Item 11: A formal business process improvement (BPI) evaluation will be performed on the procedure change process in 1995.

The inspector reviewed documentation and held discussions with licensee personnel who indicated that the formal BPI was scheduled to begin in June 1996, which is after the CR3 refueling outage.

Action Item 13: Procedure ownership is being transferred to end users on a trial basis (beginning in the I&C shop). The purpose of this effort is to enhance ownership and accountability among procedure users and to assure the level of procedure detail (or simplification) is commensurate with user needs. Such efforts, however, must maintain a proper balance of quality of technical input. Therefore, system engineering will remain a close partner in review and approval.

The inspector reviewed inter-office correspondence which documented the transfer of procedures to the various maintenance groups (electrical, I&C, mechanical) and to operations and NPTS. The inspectors also reviewed documentation from the maintenance shops which indicated that the transfer of procedure ownership was going well and maintenance was continuing to work with engineering to ensure the technical requirements of the procedures were met. The inspector also discussed this item with NPTS and operations personnel who provided comments similar to the maintenance feedback. Licensee management indicated that the trial period was successful and the transfer of procedure ownership was permanent.

Action Item 14: A computer program (NUPOST) for recording and tracking procedure change recommendations was implemented.

Operations led the development and implementation of this project.

The inspectors verified that NUPOST was implemented. The inspector also selected several procedures at random and observed a demonstration on how NUPOST works. During the demonstration, the inspector noted that operations personnel were using NUPOST. However, review of procedures owned by NPTS and maintenance did not provide evidence which indicated that these departments were using NUPOST as frequently as operations.

Action Item 15: A training initiative to intentionally fault (or fail) a procedure simulator exercises to verify that operators will use the procedure change process is being implemented.

The inspector reviewed and verified that the lesson plans were prepared for the training activity. The inspector also held discussions with operations and training personnel regarding the manager of nuclear plant operations policy concerning the use of 50.59 and 50.54 to determine appropriate corrective actions for the scenarios.

Action Item 16: When appropriate, new procedures and key changes to existing procedures are tested on the simulator.

The inspector reviewed documentation dated June 5, 1995, which indicated that simulator validation had been performed for procedures EOP-7, EOP-8, SP-110, SP-113, SP-130, and the new AP on Rapid Shutdown.

Action Item 18: To simplify procedures and place more accountability on the performer and performing departments, some hold points have been replaced with witness points (second party verification), and some new witness points have been added.

This item was in progress and was about 50 percent complete. The inspector reviewed selected procedures which had been revised to replace hold points with witness points. The procedures were being revised during their regular revision cycles.

Action Item 22: Formal action plans (using a specific format) were implemented for significant issues.

The inspectors verified that action plans were developed and being implemented for significant issues such as the TSC ventilation system; setpoints; make-up tank and BWST/RB sump level issues; surveillance requirement extension to 24 months; control room habitability envelope; and thermo-lag. The inspector reviewed copies of the action plans. The inspector noted that some of the issues also had issue managers assigned to ensure that adequate attention and focus were being provided to resolve the associated issue.

<u>Action Item 23:</u> A computerized FULTEXT search capability was implemented to help manage change in procedures.

The inspector reviewed the list of documents that were available on FULTEXT and observed a demonstration of how procedures can be retrieved and viewed on FULTEXT. The inspector verified that the latest revision of the procedures was referenced in FULTEXT.

<u>Action Item 24:</u> The System Engineering Manual was updated to include instructions for use of CMIS and FULTEXT and other available tools to verify documents requiring change.

The inspector reviewed revision 9 of the Nuclear Plant Technical Support Manual, dated December 1995, and verified that the manual included instructions for using CMIS and FULTEXT and other available tools to verify documents requiring change.

<u>Action Item 26:</u> Maintenance of system histories in the Tech Support Area will assist with continuity through organizational change. Some examples are the quarterly report, action plans, system libraries, and system outage critiques.

The inspector reviewed quarterly reports for the third and fourth quarters of 1995, selected action plans and system libraries. The information was thorough and detailed and provided the licensee with information on system performance.

<u>Action Item 27:</u> A check list for discussion items to be included in screening and selection of new supervisor candidates was implemented. This provides for senior managers to emphasize change management, safety culture, and conservative decision making with new supervisory candidates prior to organizational change.

The inspector reviewed the check list included in the procedure for the screening and selection of supervisory candidates. The procedure addressed the need for conservative decision making concerning plant safety.

<u>Action Item 28:</u> The 1995 goals include reviewing the AI's and NOD's and other administrative procedures to make sure they are current. A portion of that review was completed in 1994.

The inspector reviewed documentation which indicated that all AI's and NOD's were reviewed by December 31, 1995. Most of the procedures were revised. However, not all the revisions had been completed. The remaining revisions were scheduled to be completed by February 29, 1996.

<u>Action Item 29:</u> Computer software controls are being audited with the purpose of improving change management.

The computer software was reviewed by the licensee in Audit 95-01-SQA, 1995 Audit Report of Software Quality Assurance. Procedure NOD-37, Software Quality Assurance, was revised to comply with the recommendations of the SQA audit.

<u>Action Item 30:</u> Nuclear Operations is taking over the in-processing and fitness for duty programs from Human Resources and has established a project team with a designated transition manager.

The inspector reviewed the documentation which discussed the transfer of the in-processing and fitness for duty programs from Human Resources to Nuclear Operations. As of April 3, 1995, Nuclear Operations had been performing all tasks needed for unescorted access to CR3.

The inspector concluded that the CAP actions for the items reviewed were appropriate. Some of the actions had not been implemented long enough to assess their effectiveness. The implementation and effectiveness of the CAP actions will be reviewed further during subsequent inspections.

7.0 Review of the Local Public Document Room

On March 6, 1996 the resident inspector visited the LPDR in the Coastal Region Library located in Crystal River, FL. The inspector noted that hard copies of various documents such as the FSAR and the TSs were available. Other documents, such as inspection reports, generic letters, information notices, administrative letters, general correspondence, etc, were available on microfiche. To assess the availability and completeness of the documents located in the LPDR, the inspector examined the following documents on microfiche:

- The NRC SALP report (IR 50-302/95-99) dated October 20, 1995 for the Crystal River nuclear plant.

- FPC's response dated December 13, 1995 to the NRC SALP report.

- A Meeting Summary dated June 2, 1995 for a NRC/FPC meeting regarding the licensee's operator requalification program.

- Generic Letter 92-01, Revision 1, Supplement 1, issued May 19, 1995 regarding reactor vessel structural integrity.

- An FPC response dated June 29, 1995 to a request in Federal Register Vol. 60, No. 103 (FR95-13104) for comments from the regulated industry concerning NRC inspection report content, format, and style.

Based on the inspectors examination of the availability of various correspondence and other documents, the inspector concluded that the correspondence in the LPDR was complete and accessible.

8.0 Review of the Updated Final Safety Analysis Report (71707, 37551)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures, and/or parameters observed by the inspectors.

- While reviewing their EOPs, the licensee identified that the HPI system line SBLOCA single failure analysis as described in the UFSAR was inaccurate. This discrepancy resulted in the plant being outside the design basis and a plant shutdown was initiated on February 16, 1996. The details of this issue are discussed in paragraph 2.5.

- While reviewing the makeup system description in the UFSAR, the inspectors noted that a modification which added an interlock to open the BWST isolation valves on low MUT level and to lock open the MUT isolation valve, for 10 CFR 50, Appendix R requirements, was not included in the UFSAR description. The details of this issue are discussed in paragraph 4.4.

- While reviewing the spent fuel pool practices and current licensing basis, the NRR Project Manager identified several conflicts between the current licensing basis, license amendment 134 safety analysis fuel pool temperatures, and the UFSAR descriptions. The details of this issue are discussed in paragraph 4.5.

- The inspectors reviewed the applicable portions of the UFSAR (primarily Section 12.4, "Emergency Plan") that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

9.0 Organizational Changes

The licensee announced that on February 2, 1996 the following organizational changes would become effective:

- Mr. R. Enfinger (formerly Operations Manager at North Anna) will become the Manager, Nuclear Safety Assessment Team.

- Mr. G. Halnon will become Manager, Nuclear Licensing Regional Affairs.

- Mr. B. Gutherman will remain Manager, Nuclear Licensing and will retain lead responsibility for NRC Headquarters licensing issues.

- Ms. S. Johnson will be assigned to the Operations Group and prepare for SRO Certification.

10.0 OTHER NRC PERSONNEL ON SITE

On January 31, and February 2, 1996 Mr. W. Miller, reactor inspector, was on site to inspect the licensee's Thermo-Lag resolution program and reactor coolant pump motor oil leakage problem. Mr. P. Fredrickson, Chief, Special Inspection Branch, was on site on February 2, 1996 to coordinate with Mr. W. Miller. The results of this inspection are included in this report.

On February 13 and 14, 1996 Mr. J. Taylor, Executive Director for Operations (EDO), Mr. L. Reyes, Deputy Regional Administrator for Region II, and Mr. G. Tracy, EDO's Office Regional Coordinator, were on site to meet with the resident inspectors, tour the Crystal River Nuclear Facility, and meet with plant supervision. No report will be issued for this visit.

On February 16, 1996, Mr. K. Landis, Chief, Reactor Projects Branch 3, was onsite to attend the Corrective Action Program inspection exit meeting, tour the plant, and review the Resident Inspection Program activities.

On February 12 through 16, 1996 Mr. M. Thomas, Senior Reactor Inspector, was on site to inspect the licensee's Corrective Action Program. The results of this inspection are included in this report.

On February 28, 29, and March 1, 1996 Mr. L. Raghaven, NRR Project Manager, was on site to review the licensee's FSAR in regards to their spent fuel pool design basis. The results of this review are documented in this report.

On February 26 through March 1, and March 5 and 6, 1996 Mr. J. Kreh, Radiation Specialist, Region II, was on site to inspect the licensee's emergency preparedness program. The results of this inspection are included in this report.

11.0 EXIT

The inspection scope and findings were summarized on March 11, 1996, as described in paragraph 1. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
VIO	50-302/96-01-01	Open	Inadequate corrective actions to ensure the required high pressure injection flow instrumentation as required in the design basis. (paragraph 2.5)

URI	50-302/96-01-02	Open	Discrepancies in the High Pressure Injection Design Basis Analysis. (paragraph 2.5)
NCV	50-302/96-01-03	Closed	Failure to Maintain 10 CFR 50, Appendix R Separation Criteria for the Emergency Feedwater System. (paragraph 4.3)
NCV	50-302/96-01-04	Closed	Failure to maintain accurate drawings which reflect the configuration of the emergency feedwater system. (paragraph 4.3)
VIO	50-302/96-01-05	Open	Two Examples: (1) Failure to Update the FSAR for a Modification to the Makeup System (2) Failure to Update the Final Safety Analysis Report to Reflect Changes to the Licensing Basis per License Amendment 134 Regarding the Spent Fuel Pool Cooling System. (paragraphs 4.4 and 4.5)
VIO	50-302/96-01-06	Open	Failure to meet requirements to correctly translate the design basis for the nuclear services closed cycle cooling system (SW) into specifications, drawings, procedures, and instructions. (paragraph 4.1)
LER	50-302/95-008	Open	Oil Leakage from Reactor Coolant Pump Motors Not Collected by Lube Oil Collection System Leads to Operations Outside Design Basis. (paragraph 5.3.3)
NOD	50-302/95-16-05	Open	Deviation from the Design Commitment for the TSC Emergency Ventilation System. (paragraph 5.4.7)

12.C ACRONYMS

ac - Alternating Current
AHF - Air Handling Fan
AI - Administrative Instruction
AP - Abnormal Operating Procedure
AR - Annunciator Response Procedure
ASME - American Society of Mechanical Engineers
BPI - Business Process Improvement
BWST - Borated Water Storage Tank

CAP - Corrective Action Program
CF - Cubic Feet
CFR - Code of Federal Regulations
CLB - Current Licensing Basis
CMIS - Configuration Management Information System
CNO - Chief Nuclear Operator
CP - Compliance Procedure
CREVS - Control Room Emergency Ventilation System
dc - Direct Current
DC - Decay Heat Closed Cycle Cooling
EAL - Emergency Action Level
EC - Emergency Coordinator
ECCS - Emergency Core Cooling System(s)
EDBD - Enhanced Design Basis Document
EDO - Executive Director for Operations
EFV - Emergency Feedwater Valve
EFW - Emergency Feedwater
EGDG - Emergency Diesel Generators
ENS - Emergency Notification System
EOF - Emergency Operations Facility
EOP - Emergency Operating Procedure
EPIP - Emergency Plan Implementing Procedure
ERF - Emergency Response Facility
ERO - Emergency Response Organization
ES - Engineered Safeguards
ESAS - Engineered Safeguards Actuation System
ESATCOM - Emergency Satellite Communications System
EVS - Emergency Ventilation System
F - Fahrenheit
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
GL - Generic Letter
HPI - High Pressure Injection
HPN - Health Physics Network
HVAC - Heating, Ventilation, and Air Conditioning
I&C - Instrumentation and Controls
IN - Information Notice
INPO - Institute of Nuclear Power Operation
IR - Inspection Report
kW - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
LPDR - Local Public Document Room
MAR - Modification Approval Record
MBTU - Million British Thermal Units
MU - Make Up
MUP - Make-up Pump
MUT - Make-up Tank
MUV - Make-up Valve
MWt - Mega Watts Thermal

NCV - Non-cited Violation
NEP - Nuclear Engineering Procedure
NOD - Notice of Deviation
NOUE - Notification of Unusual Event
NOV - Notice of Violation
NPTS - Nuclear Plant Technical Support
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSS - Nuclear Shift Supervisor
OCR - Operability Concerns Review
OP - Operating Procedure
OSC - Operational Support Center
OTSG - Once Through Steam Generator
PAR - Protective Action Recommendation
PC - Precursor Card
PM - Project Manager
ppm - Parts Per Million
PR - Problem Report
PRC - Plant Review Committee
QA - Quality Assurance
QC - Quality Control
RB - Reactor Building
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RERP - Radiological Emergency Response Plan
RMA - Radiation Monitor - Air
RW - Nuclear Services and Decay Heat Seawater
RWP - Nuclear Services and Decay Heat Seawater Pump
SALP - Systematic Assessment of Licensee Performance
SBLOCA - Small Break Loss-of-Coolant-Accident
SF - Spent Fuel Pool Cooling
SFP - Spent Fuel Pool
SG - Steam Generator
SNM - Special Nuclear Material
SP - Surveillance Procedure
SSOD - Shift Supervisor on Duty
STI - Short Term Instruction
SW - Nuclear Services Closed Cycle Cooling System
SWP - SW System Pump
TS - Technical Specification
TSB - Technical Specification Basis
TSC - Technical Support Center
UFSAR - Updated Final Safety Analysis Report
UHS - Ultimate Heat Sink
URI - Unresolved Item
VBDP - Vital Bus Distribution Panel
VIO - Violation
WR - Work Request