U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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EXECUTIVE SUMMARY

Crystal River 3 Nuclear Station
NRC Inspection Report 50-302/97-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 5-week period of resident inspection; in addition, it includes the results of announced inspections by 4 reactor inspectors from Region II and 1 project manager from NRR.

Operations

Examples of management expectations not translated into procedural requirements and resultant operator performance were observed. Operations department ownership and control of the plant remains an issue but it is being adequately addressed by licensee management (Sections O1.1, O1.2 and O1.3).

Several deficiencies caused the inspectors to conclude that significant problems still exist in the licensee's clearance tagging process. An additional example of a pending violation was identified. An inadequate electrical clearance that could have resulted in a significant personnel injury was discovered by electricians prior to starting their work. Emphasis was placed on ensuring each tag was hung on the properly labelled component, but not on ensuring that clearances were accurate. Other examples where the clearance procedure did not adequately delineate management expectations for tagging and operation of equipment were identified. (Section O1.2).

The licensee's tracking of containment penetrations was a challenge to the ability to ensure containment closure when required and was considered a weakness. However, the successful performance of an unannounced drill was proactive and a good test of their ability to meet the containment closure requirements (Section O1.3).

A review of the Operator Workaround List identified that the licensee was appropriately prioritizing and scheduling items to be corrected (Section O3.1).

Operations ownership and cognizance of plant spaces, equipment, and processes remains a challenge to the licensee. However, licensee management was aggressively pursuing the causes of the problems in an effort to improve performance (Section O4.1).

Licensee self-assessment activities continued to be effective. The Nuclear Quality Assurance group identified several significant problems and licensee management remains committed to staffing them with diverse and talented individuals (Section O7.1).

There has been improvement in the corrective action process as compared to the process used before the Integrated Performance Assessment Process inspection. However, as indicated by the findings, there were still weaknesses in some areas which warrant increased management attention (Section O7.2).

A Violation (VIO 50-302/97-07-01) was identified for failure to follow Compliance Procedure CP-111. Several examples were noted where the program was not being implemented with regard to timeliness of Precursor Card responses, training of individuals performing the functions of the Root Cause Team Leaders and Apparent Cause Evaluators, and grading of Precursor Cards (Section O7.2).

The initiation of PC 97-1515 and PC 97-1520 were positive reflections on the licensee's extent of condition programs (System Readiness Review and FSAR Review Project Team) which resulted in the identification of the SDBIs documented in these PCs (Sections O7.2 and E8.1).

The Nuclear Assurance Group in the Quality Programs Department has been active in identifying continued weaknesses and areas for improvement in the licensee's corrective action program and various other activities (Section O7.3).

The inspectors concluded, based on the review of the licensee's assessment and their own review of the licensee EOPs, that adequate guidance did exist in the licensee's EOPs to address the concerns of IN 97-06 Section O8.1).

The inspectors concluded that the licensee's corrective actions were good for Enforcement Action 95-126, Violations I.A and I.B. These violations involved operators not following procedures for makeup tank pressure and level and operators conducting unauthorized tests. The corrective actions, including actions to prevent recurrence of the violations, had been implemented, and were effective improvements (Sections O8.2, O8.3).

<u>Maintenance</u>

A violation (VIO 50-302/97-07-02) was identified for inadequate Engineering oversight, Maintenance knowledge of the requirements, and Operations involvement with a hydrostatic test of emergency feedwater piping. The licensee did not have a comprehensive site policy or expectation for the content or performance of pre-job briefings (Section M1.1).

The licensee was pro-active in utilizing the maintenance outage time to complete the second 10-year Inservice Inspection requirements and completely updating the isometric drawing used for Inservice Inspection (Section M1.2).

The licensee's steam generator inspection program appeared good. The decision to baseline and inspect fully the Once Through Steam Generators, using the latest qualified eddy current techniques, was a sound technical decision (Section M1.3).

Weaknesses were displayed in the planning, preparation, and coordination for the A train Emergency Feedwater cavitating venturi test. Improvements were noted in these facets of the B train testing. All acceptance testing for these parts of the functional test were met (Section M1.4).

The licensee's project to repair or replace the protective coatings inside the Reactor Building appeared to lack overall management and engineering involvement. The project appeared to have a narrow focus on the repair and replacement of the coatings. Identified problems associated with the project were as follows:

- A program weakness was identified concerning the fact that three-year old procedures were implemented without an engineering and quality review to determine if requirements had changed during the interim (Section M2.1).
- An Unresolved Item (URI 50-302/97-07-03) was identified concerning Reactor Building liner plate degradation that was painted over without inspection or analysis (Section M2.1).
- An Unresolved Item (URI 50-302/97-07-04) was identified concerning the potential that Reactor Building ventilation ductwork may contain an unanalyzed, combustible burden in the form of oil (Section M2.1).

Engineering

Some examples of excellent engineering support were observed but other examples of poor support were included as parts of violations in other areas (Section E1.1)

There was a weakness in the Corrective Action Program in that the engineering Suspected Design Basis Issue (SDBI) evaluations were of poor quality. Three of three engineering SDBI evaluations reviewed had insufficient technical justifications to support the conclusions that there was not a reportable DBI. The engineering evaluations included incomplete determinations of the licensing and design bases and incorrect interpretations of NRC regulations. The licensee's definition of a design basis issue was narrow and not consistent with NRC regulations. Additionally, engineering personnel performing SDBI evaluations were not trained in existing interpretations of the NRC regulations on reporting as published by the NRC in NUREG-1022 (Section O7.2).

The licensee was implementing appropriate Low Temperature Overpressure Protection restrictions and was developing a permanent solution via a Technical Specification change (Section E1.2).

The inspectors concluded that the licensee was in the process of implementing an effective program to meet the intent of Generic Letter 96-01. The onsite contract engineer has been effective in reviewing, validating, and identifying deficiencies. However, the Generic Letter 96-01 program had not been completed at this time (Section E1.3).

The inspectors concluded that the licensee was in the process of implementing an effective DC Power Failure Modes and Effects Analysis program. The contractor implementing the program and the contractor reviewing the program had identified and resolved concerns in the Class 1E DC Power system in a satisfactory manner. However, the Failure Modes and Effects Analysis program had not been completed at this time, and there were open Precursor Cards (Section E1.4).

The inspectors concluded that the licensee's engineering design basis (reportability) evaluation of Precursor Card 97-2026, Design Basis Concern Relative to Control Room Habitability Dampers, was of very poor quality. It included incorrect statements related to engineering calculations, shallow and improper analyses, incorrect interpretations of NRC requirements, and incorrect conclusions (Section E8.1).

The inspectors concluded that the licensee's corrective actions for two violations were good. Corrective actions for Enforcement Action 95-126, Violations I.D.2 and II.A, had been implemented, included actions to prevent recurrence of the violation, and were effective improvements. These violations involved swapover of the Emergency Core Cooling System pumps and insufficient net positive suction head for the low pressure injection pump (Sections E8.2 and E8.3).

The inspectors concluded that the licensee's corrective actions for EA 95-126, VIO I.C.1, had been implemented, included actions to prevent recurrence of the violation, and were effective improvements. The inspectors also concluded that the licensee's analyses and conclusions in resolving the questions addressed by URI 96-01-02 were good (Sections E8.4 and E8.5).

Plant Support

A degradation in radiation workers adherence to good radiation work practices and adherence to the applicable procedures resulted in a Non-Cited Violation (NCV 50-302/97-07-05). The licensee identified this trend and took strong corrective actions to address the issue; including developing and documenting management's expectations for radiation workers and assuring that all personnel were trained on the expectations and aware of the consequences for failure to meet these expectations (Section R1.1).

The inspectors reviewed the self-assessment report on health physics and radiation control areas access control program, and concluded that while some of the strengths identified seemed inappropriately classified, the observations and identified weaknesses were timely and self critical (Section R7.1).

A violation (VIO 50-302/97-07-06) was identified for inadequate corrective action regarding the use of an uninterruptible power supply unit in the security central alarm station. Several loss of power events revealed a security staff lack of familiarity with the operation and function of the uninterruptible power supply. Prior opportunities to address the inevitable degradation of the power supply batteries and the lack of a need for the uninterruptible power supply were not recognized by engineering or security personnel (Section S2.1).

The inspectors assessed the licensee's performance concerning the five areas of continuing NRC concern in the following paragraphs: the assessments are limited to the specific issues addressed in the respective paragraphs.

NRC AREA OF CONCERN	ASSESSMENT PARAGRAPH																
	O3.1	O4.1	O7.1	O7.2	O7.3	O8.2	O8.3	E1.3	E1.4	E8.1	E8.2	E8.3	E8.4	E8.5	E8.6	E8.7	E8.8
Management Oversight	G	A	G	A	G	G	G	G	G	I	G	G	G	G	G	G	G
Engineering Effectiveness	A			A		G		G	G	I	G	G	G	G			
Knowledge of Design Basis				A		G	A	G	G	I	G	G	G	G			
Compliance With Regulations	A	A	G	A	G	G	G	G	A	I	G	G	G	G	G	G	G
Operator Performance	A	A				G	G				G	G	G	G			

S = Superior G = Good A = Adequate/Acceptable I = Inadequate
Blank = Not Evaluated/Insufficient Information

Paragraph O3.1: Operator Workaround List

Paragraph O4.1: Operator Performance Observations and Safety Culture Examples

Paragraph O7.1: Licensee Self-Assessment Activities

Paragraph O7.2: Corrective Action Program

Paragraph O7.3: Quality Assurance Audits and Surveillances

Paragraph O8.2: Followup on EA 95-126, Violation I.A, Nine Instances Where Operators Violated Procedures for Makeup Tank Pressure/Level Control

Paragraph O8.3: Followup on EA 95-126, Violation I.B, Conduct of Unauthorized Tests of Makeup Tank Without 10 CFR 50.59 Evaluation

Paragraph E1.3: NRC Generic Letter 96-01, Testing of Safety-Related Logic Circuits.

Paragraph E1.4: DC System Failure Modes & Effects Analysis (FMEA).

Paragraph E8.1: Followup on URI 95-02-02, Control Room Habitability Envelope Leakage

Paragraph E8.2: Followup on EA 95-126, VIO I.D.2: Swapover of ECCS Pumps' Suction from BWST (at five feet) to Reactor Building Sump Was Inadequate.

Paragraph E8.3: Followup on EA 95-126, VIO II.A: EOPs Allowed Single LPI Pump to Supply Two HPI Pumps, With Insufficient NPSH For LPI Pump.

Paragraph E8.4: Followup on EA 95-126, VIO I.C.1: Failure to Take Adequate Corrective Actions for Operator Concerns Regarding OP-103B, Curve 8, for Makeup Tank Pressure/Level Limits.

Paragraph E8.5: Followup on URI 96-01-02: Discrepancies in the High Pressure Injection System that do not Meet Design Basis Analysis.

Paragraph E8.6: Followup on EA 96-365, EA 96-465, EA 96-527, VIO A.5 (01052), USQ Involving a Decrease in the Reliability and an Increase in the Probability of Failure of EFP-2.

Paragraph E8.7: Followup on EA 96-365, EA 96-465, EA 96-527, VIO B (Example 1) (02013), Failure to Update Applicable Design Documents to Incorporate Design Information.

Paragraph E8.8: Followup on EA 96-365, EA 96-465, EA 96-527, VIO B (Example 2) (02013), Failure to Include Applicable Design Information in the Design Input Requirements for a Modification.

Report Details

Summary of Plant Status

The unit remained in Mode 5 throughout the inspection period, continuing in the outage that began on September 2, 1996. On May 28 the pressurizer steam bubble was collapsed and replaced with a nitrogen overpressure volume to support pending draindown of the reactor coolant system and steam generator inspections. The secondary side of both steam generators were completely drained this period to support main steam isolation valve refurbishment. Work on several major physical modifications related to the licensee's restart efforts continued this report period. These included Emergency Feedwater (EFW) cavitating venturis, EFW motor-operated cross-tie valve EFV-12, and overpressurization chambers for containment penetration isolations to address concerns in NRC Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707 the inspectors conducted routine reviews of ongoing plant operations which included shift turnovers, response to problems, log review, and review of clearance tagging processes. Significant observations are discussed in the following paragraphs.

The inspectors observed several Operations shift turnovers and concluded they were thorough. Turnover paperwork appeared complete and controlled. However, the briefings by the Shift Supervisors (SSOD) were occasionally disjointed because the SSOD was briefing from the daily logs, which indicated a lack of preparation to the inspector. Shift turnover was conducted after each watchstation had individually turned over, which meant that one operator had to monitor the control boards and can not pay attention to the turnover. The licensee was considering changes to turnovers which included doing a shift briefing prior to individual turnovers.

The inspectors reviewed the Operability Concern Resolution (OCR) book and determined the category of "Conditionally Operable/Potentially Inoperable" was a non-conservative method of determining operability. Licensee management agreed and has taken initial steps to revise the process to ensure a clear operability determination and status would be made in future cases.

An inspector observed the operators respond to a Non Nuclear Instrumentation (NNI) Channel Y failure on May 13, 1997. The operators quickly entered Abnormal Procedure (AP) 582, Loss of NNI-Y, Revision 4, and deliberately performed the required actions. Operators verified what instrument indications were reliable and the effect of the lost indications. The pressurizer Power Operated Relief Valve (PORV) was rendered inoperable by the failure, but appropriate steps were taken by the operators to compensate. The shift supervisor conducted a control room brief at an appropriate point in the event to ensure each operator was cognizant of all the problems and has plans to correct them. The operators also took steps to protect the remaining indications by stopping work or blocking access to related areas. The inspector concluded the operators did a very good job responding to the unexpected event, which was later determined to be caused by a faulty power supply circuit.

The inspector followed up on a previously identified weakness regarding the unavailability of system prints and schematics to operators. The licensee had taken significant action to allow operations personnel access to the computer drawing database. This enabled the operators to research or print the latest revision of any drawing as well as access a larger inventory of drawing types. However, the licensee has not delineated the use of these prints in any written guidance so control of the prints and their acceptable uses have still not been resolved. The licensee is considering additional changes.

The inspectors observed that operator log content was very diverse and depended largely on the individual logtaker. The inspector determined from interviews with the operators that consistent expectations were either not known or not enforced. One example the inspector noticed was that the completion of Technical Specification surveillances did not appear to be required to be logged, although some individuals did while some did not. As discussed in Sections O1.2 and O1.3, the inspectors continue to observe further examples where management expectations are not translated into procedural requirements and resultant operator performance.

The inspectors determined from their above observations and from the specific issues discussed in the following paragraphs, that Operations department ownership and control of the plant remained an issue, but it was being adequately addressed by licensee management. The inspectors concluded, that management's challenge was to instill a critical questioning attitude and desire to change in the Operations staff.

O1.2 <u>Clearance Tagging Problems</u>

a. <u>Inspection Scope (71707)</u>

The inspectors reviewed the licensee's response to further examples of clearance tagging problems. The licensee has had an ongoing effort to correct deficiencies in their clearance tagging system in response to previously documented problems and violations. Although significant management attention has been focused on the process, problems have continued to occur.

b. Observations and Findings

On May 12 maintenance personnel were preparing to work on an air compressor motor when the original clearance order (97-05-064), written by Operations to support the work, was determined to be inadequate because it had omitted tagging the motor heaters. This had been noted by a Chief Electrician during his pre-acceptance clearance walkdown. He coordinated with the clearance Chief Nuclear Operator (CNO) to research and process an addendum to the clearance and add one red tag to the motor heater breaker, #5 on AC distribution panel (ACDP) 4. However, the CNO then inadvertently wrote the addendum for breaker #15 which was approved by the Auxiliary Nuclear Shift Supervisor (ANSS), and the tag was hung. The ANSS based his approval on the need to tag the heaters and was not required to verify the adequacy of the clearance. The new tag was verified hanging in the correct position per the clearance order (breaker #15 as written by the CNO) by the operator hanging the tag, a second operator verifying the first's work, a senior reactor operator (SRO), and a second Chief Electrician who would be overseeing the work. The SRO verification and the maintenance chief involvement were both short term corrective action requirements implemented for previous problems with hanging of clearances on incorrect components. The clearance was accepted, and work was ready to commence when an electrician performed a routine check to ensure the motor was deenergized and discovered voltage was still present on the 480 volt motor heaters. The maintenance crew stopped all work, consulted with the CNO, the first Electrical Chief, and the shift supervisor who then determined the wrong breaker had been tagged. Although four different individuals checked the tag hanging in the correct location per the clearance order, no individual checked or was required to check the CNO's work in writing the addendum for adequacy. Additionally, the breaker labelling in the ACDP did not give any information other than the breaker number, so the operators and electricians could not check that the tag was hanging on a breaker for the motor heaters without using a procedure or print as a reference. Consequently, the incorrect tag was not detected until the last possible barrier, which was the good work practices of the electricians. The licensee initiated an immediate investigation, and root cause evaluation under Precursor Card 97-2045. Licensee management appropriately recognized the significance of this event and prioritized the investigation so that the results could be reviewed within the week by the Corrective Action Review Board (CARB). The licensee also immediately initiated a Night Order to require all new clearance orders to obtain a second review for adequacy and all operators hanging electrical tags to verify against the operating procedure breaker list that the breaker number on the clearance was the correct breaker for the load to be tagged. Compliance Procedure (CP)-115, Nuclear Plant Tags and Tagging Orders, Revision 74, step 4.6.1, had allowed the CNO to decide if a clearance was complex enough to warrant a second review for adequacy. This option was rarely exercised due to Operations manpower limitations.

The licensee's root cause and corrective action plan was presented to CARB on May 16 and again on May 23 to address problems the licensee noted on the first review. The inspector observed several other problems after the CARB had approved the final report on the latter date. Several deficiencies the inspector considered pertinent to the event were not addressed in the final report or questioned by the CARB including:

- the unwritten practice by Operations of NOT routinely tagging heaters for electrical clearances unless motor removal was specified;

- a corrective action system precursor card (PC) was not generated after the original clearance was found to be inadequate by the first Electrical Chief and the CNO because the clearance hadn't been accepted yet;

- inconsistencies between maintenance management's expectations and requirements for pre-acceptance clearance walkdowns;

- the involvement of two separate Electrical Chiefs in the pre-acceptance walkdowns;

- an item cited as a contributing cause in the report that did not have any associated corrective actions to address it.

These items were appropriately dispositioned later by Operations management and the CARB after the inspector questioned them. However, the items indicated a less than complete solution to the recognized problem and pointed out further inadequacies with CP-115. Violation 50-302/97-05-01, which described four other examples of failure to follow CP-115, was issued to the licensee on June 2, 1997. The inspectors considered this problem to be similar to those problems and considered that the scope of the licensee's pending corrective actions, which include a complete rewrite of CP-115, would be adequate to correct this example. Consequently, the inspectors consider this problem as an additional example of that violation. The licensee has agreed to address the above problem in their violation response.

On May 15 the inspectors observed another problem in that two clearances in the "To Be Pulled" box in the Tagging Office were signed for release on May 10 and 11 respectively. Per procedure (CP-115) when the tagouts are released, the authorizing individual identifies the tag removal sequence and component repositioning based on the current plant conditions. The plant conditions that the authorized releaser assumed were no longer assured because the tag removal and repositioning for these tags would be at least 4 to 5 days after the signed release. Operations management indicated their expectation was that the tags be removed expeditiously, but there was no stated time requirement in CP-115. This time delay, in conjunction with changing plant conditions, could create the potential for personnel injuries or equipment damage.

On May 21, during performance of EFW flow testing, the inspector observed that several red-tagged closed test boundary valves were leaking and had to be tightened to reduce the leaks. The inspector questioned the operators as to how they manipulated the red tagged valves and determined that the operators considered it acceptable to manipulate a tagged valve as long as it was in the tagged direction or if the clearance was not accepted by the work organization. The inspector observed various minor differences in the operator's interpretations which the inspector attributed to the lack of guidance in CP-115 for this situation. The inspector also observed that Operations management's expectations were that red-tagged components were not to be manipulated. These expectations were neither formally implemented nor carried out by the operators. PC 97-3478 was initiated to provide corrective action but one week later, on a subsequent EFW flow test, the inspector again observed that a shift supervisor stated that it was acceptable to tighten red-tagged valves as long as the clearance was not accepted by the work organization. Again, this was not the result of any written guidance. Operations management has since clearly defined their expectations that red-tagged components can not be manipulated and incorporated it into the pending Revision 75 of CP-115.

The licensee has also identified more problems implementing CP-115. PC 97-3471 documented eight active clearances that had not been recertified to ensure they were still hanging correctly within the required 30 days. PC 97-3469 documented a tag that was mislabelled for an "A" train component but was correctly hung on the "B" train component. It was found after it had been supposedly verified by two licensed operators. Both of these PCs were graded as Level Cs and will receive apparent cause evaluations.

c. Conclusions

The inspector concluded that the licensee's prioritization to complete the motor heater tagging investigation quickly was a good initiative to correct significant problems in a timely manner. However, several deficiencies with that effort and other observations caused the inspectors to conclude that significant problems still exist in the licensee's tagging process. The existing revision of CP-115, Revision 74, does not adequately delineate management expectations for tagging and operation of equipment. Plant labelling remains weak. Improper emphasis was placed on ensuring each tag was hung on the properly labelled component and not on ensuring that clearances were accurate. Allowing CNOs to decide if a second review was required was inadequate and an example of inconsistent implementation and lack of verification of management expectations. The interpretation that a clearance was not valid until "accepted" was not conservative. The inspectors concluded that consistently implementing Operations management expectations in the field remained a challenge to the licensee. The inspectors reviewed the changes in Revision 75 to CP-115 and will inspect implementation of the revision. This effort will be documented in a future report.

O1.3 Containment Penetration Tracking

a. Inspection Scope (71707)

The inspector reviewed the licensee's process for tracking and controlling containment penetration breaches in preparation for a pending reactor coolant system (RCS) draindown evolution.

b. Observations and Findings

The inspector observed that adequate guidance existed to delineate when containment closure was required and that the SSOD was the responsible individual to ensure penetrations were closed when containment integrity was required. However, the inspector observed that an active index of specifically which penetrations were open did not exist, nor was it required. Therefore the SSOD was unable to state how many open penetrations existed in the containment at any given time. The inspector reviewed the procedural requirements contained in CP-115, Nuclear Plant Tags and Tagging Orders, Revision 74, and observed that the licensee utilized the clearance tagging system to identify and track each open penetration. Each clearance holder that had a potential open penetration was required to complete a Form 6 that delineated closure plans. Although the penetration might not have been open at the time, all active clearances that had the potential to open a penetration were required to have this form in the containment penetration logbook. The inspector reviewed this book in the control room on May 26 and did not identify any penetrations that were open and did not have a form in the book. However, the inspector identified numerous administrative problems. An uncontrolled and inconsistently used index list was present in the front of the book. The licensee intended for this to be used to track penetrations open solely for leak rate testing but this expectation was not documented, the log was not an accurate reflection of open penetrations, and SSODs had various opinions on the use of it. The log had numerous Form 6s for the same penetration because the licensee's system logs openings by containment penetration number only, so a single pipe penetration may have numerous openings, each with a Form 6. The form did not have a place to annotate where the opening actually was but the inspector noted it was frequently handwritten below the penetration number. The inspector also observed redundant Form 6s for the same penetration opening, some with altered guidance and different approval signatures. One single penetration had four separate Form 6s. None of the extra forms presented a significant challenge to closing the penetration when required, but the inspector was concerned that the licensee's system was uncontrolled and created the potential for more than one penetration closure plan. Another penetration Form 6 had a note that stated Operations would close specific feedwater valves if they were installed in the system. The SSOD was unfamiliar with the details of this penetration which was later determined to be newly installed valves on the EFW cavitating venturis. The inspector was concerned if the guidance was adequate to support closure of the penetration. The licensee revised the Form 6 to clearly describe the closure plan.

The inspector physically inspected the open penetrations and observed that Form 6's were staged locally that differed from those in the control room log. Some of these differences included the responsible group for closure. The licensee addressed this concern by eliminating the local copies of the Form 6, making the control room copy a single controlled copy to eliminate the potential for numerous conflicting copies. The inspector did observe that the penetrations did have generally good closure plans and equipment was appropriately staged to close the penetration.

The licensee also removed the uncontrolled index in the penetration log book but placed it in the back of the log book to ensure it was used for only leak rate test tracking. This and the other planned corrective actions were not permanent solutions in that they were not incorporated into any written guidance or changes to CP-115. The licensee was evaluating their program to ensure their expectations would be consistently implemented.

Licensee management initiated an unannounced drill on May 28 that simulated a loss of decay heat removal and required Operations to initiate containment closure. The inspector reviewed the results of the drill and observed that the requirement of closing containment within two and one half hours was easily met. Discrepancies were identified by the licensee's Quality Assurance auditor regarding labelling of staged equipment and penetrations, expired rigging, and cognizance of closure responsibility by groups other than Operations. Appropriate actions were taken to address each deficiency.

c. Conclusions

The inspectors concluded that the licensee's tracking of containment penetrations was a challenge to the SSOD's ability to prioritize resources and ensure containment closure when required. The inspectors considered this a weakness. However, the licensee's response to run an unannounced drill was proactive and a good test of the ability to meet the containment closure requirements.

O3 Operations Procedures and Documentation

O3.1 Operator Workaround List (71707)

The inspector reviewed the licensee's workaround list which is one of the licensee's restart items. The licensee's definition of a workaround is a "tolerated, but economically correctable, practice or condition that negatively impacts transient response, or is caused by a procedure, process, or equipment not performing as designed or needed and additional work is required to achieve the necessary result." The licensee's list contained 25 items, 16 of which were firmly scheduled to be fixed before the licensee's scheduled restart date. Their goal was to reduce the number of open items to less than 7 prior to startup which the inspector considered achievable. Several of the remaining items were being evaluated and would likely be fixed prior to startup. The inspector reviewed the items scheduled to remain after startup and did not identify any problems with the licensee's planned corrections or schedule. The inspector noted that each item was assigned to a single accountable individual and had a scheduled date for completion. The inspector also noted that the number of items on the licensee's list increased significantly from 11 in January of 1997, to the current 25 in May. This was a result of a licensee effort to solicit any other potential workaround items from the operators to ensure they were tracked and corrected. This effort yielded numerous items, most of which were not workarounds. The inspector concluded this was a good effort by the licensee to ensure problems affecting the operators were identified. The inspector did not identify any problems with the items on the list during this preliminary inspection.

The inspector assessed the licensee's performance, with respect to this restart-related issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - Adequate
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Adequate
- Operator Performance - Adequate

O4 Operator Knowledge and Performance

O4.1 Operator Performance Observations and Safety Culture Examples

a. Inspection Scope (71707)

The inspectors continued to review and document examples of Operations performance that were indicative of the operators questioning attitudes and safety culture. Licensee management has focused on improving performance in these areas.

b. Observations and Findings

An inspector observed a Justification for Continued Operation (JCO) Book in the Control Room which had approximately 8 JCO's identified. All of the JCO's were dated in 1989 and shift operators were not familiar with the reference and could not state whether any of the JCO's were active or resolved. The book had a disclaimer that it was not official and might not be current; however, it was in the reference book shelf in the middle of the Control Room for anyone to review. The licensee removed the book. The inspector was concerned that there was inaccurate and uncontrolled information available to operators.

It was stated by Operations during a morning turnover that draining of the only full Once Through Steam Generator (OTSG) was not a Operations responsibility. It was to be conducted by the test director. During the turnover operators asked questions that resulted in changing some of the planned tagging boundaries. The inspector considered this an example of poor Operations ownership and planning.

Following an event at another similar plant, the licensee researched the method of level indication on their make-up tank (MUT) reference leg to assess their vulnerability to a similar problem. On May 5 and 9 the inspector observed members of plant operating management state the MUT used a dry reference leg. However, on May 7 and 14, the inspector observed members of Engineering state that the MUT used a filled, wet reference leg. The latter version was correct. The inspector concluded this was an example of poor research into a problem and poor communications between Engineering and Operations.

Abnormally high decay heat closed cycle cooling pump 1B amps were questioned on a startup by operators on May 12. This resulted in discovery of problems with a positioner on valve DCV-178. The inspector concluded this was an example of a good questioning attitude.

The inspectors observed several examples of poor plant housekeeping that indicated ownership of operating spaces by buildings operators still has room to improve. The examples included items such as duct tape on valve flanges, chairs and carts left in safety related areas, and unchocked equipment boxes.

c. Conclusions

These observations caused the inspectors to conclude that Operations ownership and cognizance of plant spaces, equipment, and processes remains a challenge to the licensee. However, licensee management was aggressively pursuing the causes of the problems in an effort to improve performance.

The inspector assessed the licensee's performance, with respect to this restart-related issue, in the five NRC continuing areas of concern:

- Management Oversight - Adequate
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Adequate
- Operator Performance - Adequate

O6 Operations Organization and Administration

O6.1 The following organizational changes were announced by Florida Power Corporation (FPC):

- Effective May 5, 1997, Mark Marano became the Director, Nuclear Site & Business Support, which combines the Director, Nuclear Operations Materials and Controls, and Director, Nuclear Operations Site Support, into one position.

- As of May 20, 1997, Walter Pike was appointed Manager, Nuclear Regulatory Assurance. Ed Schrull, who was filling this position temporarily, remains in the Regulatory Assurance group as Supervisor for restart commitments.

- Effective May 5, 1997, Dave Kunsemiller was appointed Acting Manager, Nuclear Licensing, replacing Brian Gutherman, who will be in SRO Certification training for the next six months.

- Effective May 5, 1997, John Lind was appointed Acting Director, Nuclear Operations Training, replacing Rolf Widell, who will also be in certification training for the next six months.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities

a. Inspection Scope (71707, 40500)

The inspectors reviewed various licensee self-assessment activities and corrective action process which included:

- routine reviews of Nuclear Quality Assessments (NQA) activities and surveillance report findings;

- observation of the NQA monthly Audit 97-04 exit interview and review of the report;

- reviews of precursor cards entered in to the corrective action system;

- observation of management CARB meetings;

- observations of a licensee Restart Panel meeting;

- observations of the licensee's Plant Review Committee meetings;

- observations of the licensee's Nuclear General Review Committee offsite review group meeting on May 14.

Notable observations are discussed below.

b. Observations and Findings

The inspector's review of NQA inspections identified that they continue to be responsive to licensee problems and requests by licensee management to review suspected weak areas. NQA inspections have identified some significant findings including electrical switchyard battery and equipment degradation, Technical Specification surveillance scheduling into the 25% grace period, poor control by engineering management of a corrective action backlog, and potential emergency diesel generator surveillance preconditioning. The inspector observed NQA auditors present for almost all significant licensee evolutions and concluded the NQA organization was appropriately planning their discretionary inspections to review a broad spectrum of areas. The inspector reviewed pending NQA staff assignments and rotations with other site departments and concluded licensee management remains committed to staffing NQA with diverse and talented individuals.

The inspector attended the Nuclear General Review Committee (NGRC) meetings on May 14, 1997, and observed that the NGRC reviews were a benefit to the licensee. The Committee appeared knowledgeable, active, and the members demonstrated a desire for high standards. The Final Safety Analysis Report (FSAR) requirements appeared to have been adequately met during the meeting. The NGRC sub-committees were thorough and appeared to provide adequate reviews of their areas. The overall board was relatively well focused, maintained their work scope and perspective, yet allowed for good cross-discussion of significant licensee issues.

c. Conclusions

The inspectors concluded the licensee self-assessment activities were effective.

The inspector assessed the licensee's performance, with respect to this restart-related issue, in the five NRC continuing areas of concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

O7.2 Corrective Action Program

a. Inspection Scope (40500)

The scope of this inspection was to examine the problem identification portion of the licensee's corrective action program. This included reviewing licensee actions implemented to address weaknesses identified by the NRC during the Integrated Performance Assessment Process (IPAP) inspection and documented in Inspection Report 50-302/96-201. Compliance Procedure CP-111, Processing Of Precursor Cards For Corrective Action Program, Revision 56, was reviewed to determine the requirements for the initiation, grading, evaluation, and tracking of PCs. In addition, selected PCs initiated during the time period from December 1996 to May 5, 1997, were reviewed to verify that the PCs were being processed in accordance with the requirements of Procedure CP-111. A sample of PCs was reviewed to determine if the PCs were properly graded in accordance with Procedure CP-111. Selected Grade "B" PCs were reviewed by the inspectors to assess the adequacy of Engineering evaluations performed to determine if there were design basis issues associated with the PCs. The purpose of these Engineering evaluations was to assist the Operations Shift Manager in making a determination as to whether or not the licensee was required, by 10 CFR 50.72 or 10 CFR

50.73, to report the issues to the NRC. The inspectors reviewed quality assurance (QA) assessments and audits performed by the Nuclear Quality Assurance group in the Quality Programs Department. The inspectors also interviewed selected plant personnel to ascertain their views on the PC process.

b. Observations and Findings

Corrective Action Program Improvements and Procedure Revisions

The NRC performed an IPAP inspection in July 1996 and identified weaknesses in the licensee's corrective action program. The licensee issued Revision 55 to CP-111, which addressed some of the weaknesses identified during the IPAP inspection. The current program, corresponding to Revision 55 of CP-111, went into effect November 20, 1996. Revision 56 to Procedure CP-111 went into effect on February 25, 1997. The main differences between the current program and the old program (prior to Revision 55 of CP-111), were summarized as follows. When a problem was identified under the old program, it would be written on a PC. If the PC was determined to involve a significant problem, the PC would be upgraded to a problem report (PR). If the PC was determined to involve a minor problem, it would remain a PC. The licensee determined (and the NRC concluded during the IPAP inspection) that this system would often introduce unacceptable time delays in addressing significant problems. Under the current program, the licensee eliminated the PR system and established a singled graded PC system. All problems identified on a PC are now being processed, from initiation to closure, as a PC.

Also, the old program did not lend itself to timely and consistent review and evaluation of the various problems. The current program utilized a precursor card screening committee (PCSC) which met daily to grade the PCs into one of four grades (A-D), with each grade invoking different time goals and levels of attention. Although not defined in Procedure CP-111, most of the major departments had representation on the PCSC. The inspectors discussed the makeup of the PCSC with licensee personnel who stated that the PCSC would not conduct business unless all chairs were filled.

Suspected design basis issues were now being tracked by management against a 10-day allowed review time.

Another improvement was the establishment of a CARB, which was comprised of senior site managers (Directors) who meet to review root cause determinations and corrective action plans for Grades "A" and "B" PCs. In addition, training and qualifications requirements were established for persons performing root cause evaluations for Grades "A" and "B" PCs, and apparent cause summary reports for Grade "C" PCs.

At the time of this inspection, the licensee had prepared and approved, but not yet implemented, Revision 57 to CP-111 to further improve the corrective action program. Licensee personnel indicated that this latest revision had not gone into effect because they were in the process of providing training to plant personnel on Revision 57. The inspectors reviewed Revision 57 and noted that improvements in the process included, but were not limited to, the following.

- Established the goal and expectation that, to the extent practical, that PCs should be presented to the Nuclear Shift Manager (NSM) within the same shift that the problem is identified. There was no time goal specified in Revision 56 for presenting a PC to the NSM. In fact, Revision 56 implied that, for problems determined to be not urgent by the initiator, the PCs could be mailed to the NSM. The inspectors observed that, in general, PCs were being reviewed by the PCSC on the work day following the initiation date given on the card.

- Reduced the time allowed for development of corrective action plans. Request for extensions to the allowed time must be approved by a board of managers.

- Added Grade C Precursor Cards to the ones having corrective action implementation tracked by the Nuclear Safety Assessment Team (NSAT).

- Added more definite requirements for determining extent of condition and corrective actions to prevent recurrence for Grade C Precursor Cards.

Another improvement to the process that was in the implementation stages was the transition to a more sophisticated software for the data base. This improvement would provide for better tracking and trending capabilities and would allow generation of reports not currently available, such as a summary of all PCs written against a system.

During further review of Revisions 56 and 57 to Procedure CP-111, the inspectors noted the following observations which were brought to the attention of licensee management.

- The word "should" was used often throughout the procedure, and in some of those instances, it appeared that "shall" would have been the more appropriate word to use. The inspectors discussed this observation with licensee management who indicated that the management expectation which had been communicated to plant personnel was that "should" would be treated the same as "shall" during procedure usage.

- The procedure did not provide clear guidance with regard to the NSM signing and dating the PC to provide a record of the NSM's review. This observation also applied to the SSOD signing and dating PCs to indicate the SSOD's review for operability when required. The inspectors noted some examples where there was more than one working day after the initiation date before the PCs were reviewed by the PCSC. The inspectors were unable to determine when these PCs (that took more than one work day to reach the PCSC) were reviewed by the NSM because the NSM initialed on the PCs to indicate the NSM review but did not provide the date of the review.

Precursor Card Review

The inspectors reviewed a small sample (15) of Grade "C" PCs initiated during the December 1996 through April 1997 time period. The inspectors selected the sample to include the work of as many organizational groups (assigned as responsible PC manager or owner) as possible. Ten organizational units were represented. The original intent was to review only closed status PCs. However, the final sample included thirteen PCs that had been closed and two PCs that were still open.

The files for the sample of 15 Grade "C" PCs were obtained and reviewed for the attributes of problem statement clarity, immediate corrective actions (C/A), reporting requirements, grading, cause determination, definition of C/As including restart issue screening, and timeliness.

Observations related to the sample of Grade "C" PCs are summarized below.

PC No.	Organization	C/A Times (Days)	Observations
97-0038	Design Engr.	14	* Comments discussed below.
97-0039	Modifications	57	**
97-0046	Maintenance	22	**
97-0697	Maintenance	23	* Not all problems had corresponding CAs. Some CAs lacked specificity and date.
97-0698	Systems Engr.	11	*
97-0700	Design Engr.	72	* Time for completion of apparent cause extended to June 27, 1997.
97-0705	Planning	10	*
97-0723	Outage Mgt.	17	*CAs lack specificity and date
97-0767	Maintenance	10	None
97-0784	Licensing	0	None
97-0786	Procurement	23	None
97-0800	Operations	-	None. Time for completion of apparent cause extended to June 27, 1997.

97-0867	Design Engr.	30	CAs not explicitly stated.
97-0892	Security	8	Apparent cause given was actually restatement of problem rather than cause.
97-2360	Operations	11	** CAs were not complete.

* Indicates the Apparent Cause Evaluator (ACE) had not received the training (required by procedure CP-111) for the task he performed.

** Indicates neither the ACE nor the approving Responsible PC Manager (or designee) had received the training required by Procedure CP-111.

With regard to the time allowed for preparing the apparent cause summary and the corrective actions for a Grade "C" PC (refer to column labeled "C/A Time" in above summary), CP-111 specified 15 calendar days plus 5 days review time. The procedure (Steps 4.6 and 4.11) provided for extensions to the time, as long as a record of the extension request was included in the file for the PC. These procedural requirements were contained in Steps 4.6, 4.11, and Table 2, Event Reporting Timetable. The extensions for five of the PCs (97-0039, 0046, 0697, 0786 and 0867) were in violation of those procedural requirements in that the 20-days (total time) specified in CP-111 was exceeded and there was no record of any extension requests in the file. Based on the statistics of the sample size, the inspectors concluded that this problem was extensive. The inspectors noted that a contributor to the PC timeliness problem was the inconsistent information that was being provided to the responsible PC manager regarding the allowable time to respond to a Grade "C" PC. Some Grade "C" PCs were transmitted with a note which allowed 20 working days for the response, while others were transmitted with a note which allowed 20 calendar days for the response. The correct time was 20 calendar days as specified in Procedure CP-111. The licensee stated that they were aware of timeliness problems. The timeliness problem was identified during QA Audit 97-04 where a PC was initiated by QA to address this problem (97-2754), with the recommendation that the PC be graded an "A." The inspectors noted that the PC was given a Grade "B" by the PCSC. The inspectors informed the licensee that these timeliness problems were examples of failure to follow Procedure CP-111 that represented a violation of 10 CFR 50, Appendix B, Criterion V, Instructions Procedures and Drawings. Two additional sets of examples will be discussed in the following paragraphs within this section. Therefore, this issue will be identified as the first example of VIO 50-302/97-07-01, Failure to Follow Procedure CP-111 for the Processing of Precursor Cards.

Precursor Card 97-0038, which involved two spring can hangers on small bore piping, had three notes in the form of questions written on the card. One of the questions was: "Was there an operability concern?" Answers to these questions were not documented in the apparent cause summary or corrective actions for this PC. The inspectors learned that such notes may be written on a PC at the PCSC meeting or at a later stage. As far as the inspectors could determine, operability of the questionable hangers had not been addressed in any other documented form. This circumstance raised the question regarding the status of notes written on PCs, as this matter was not covered by the procedure. A representative of the NSAT indicated that this question would be reviewed further.

Step 4.10.1.1 and Enclosure 8 of CP-111 required that documentation to ensure traceability of closure, along with due dates, shall be included with the apparent cause summary for a Grade C precursor card. As noted in the review summary above, four of the PC files were weak in complying with these procedural requirements. In three of these four cases, the person preparing the apparent cause summary was not "qualified" in accordance with CP-111. There appeared to be a correlation between the weak apparent cause summaries and the lack of apparent cause training of the individuals performing the evaluations. The inspectors concluded that the examples represented a weakness in the PC process in that continued lack of specificity in the corrective action statement could lead to an identified deficiency not being adequately corrected in a timely manner. These examples were discussed with licensee management who indicated that the specific PCs in question would be reviewed and additional actions taken as necessary.

Personnel Training and Qualifications

Step 3.2.5.1 of Procedure CP-111 stated that the ACE must be qualified, which included receiving apparent cause training and performing ACE functions at least yearly thereafter. During the review of the Grade "C" PCs listed above, the inspectors noted that individuals performing the ACE function for nine of the fifteen PCs were not qualified in that they had not received the apparent cause training. Also, for three of these nine PCs, neither the ACE nor the approving Responsible PC Manager had received the apparent cause training. Also, the inspectors identified one case where the Root Cause Team (RCT) Leader for a Grade "B" PC (97-0052) was not fully qualified to perform the function of a RCT Leader in that the individual had not received all the specified training. Step 3.2.11 of Procedure CP-111 stated that the NSAT was responsible for maintaining the list of qualified RCT Leaders. Step 4.3.2.1.4 of Procedure CP-111 further stated that the PCSC will designate a qualified RCT Leader for Grade "B" RCTs. The inspectors reviewed the list of qualified RCT Leaders and noted this individual was listed as not being fully qualified. The inspectors discussed this issue with licensee management who stated that the decision was made to use individuals who had not been fully trained to perform the ACE and RCT Leader functions, in part, to address the PC backlogs. Licensee management further stated that they considered the intent of CP-111 was being met as long as the approving Responsible PC Manager had received the ACE training. The inspectors noted that this was not always the case. Licensee management also stated that a fully qualified RCT Leader from the NSAT participated in the root cause evaluation for the Grade "B" PC in question. However, the inspectors noted that the Grade "B" PC did not indicate that there were other participants besides the RCT Leader. The inspectors informed the licensee that using non-qualified individuals to perform the functions of the RCT Leaders and the ACEs for

Grades "B" and "C" PCs was another example of failure to follow Procedure CP-111. This item will be identified as the second example of VIO 50-302/97-07-01, Failure to Follow Procedure CP-111 for the Processing of Precursor Cards.

Precursor Card Grading

The inspectors identified that one of the PCSC functions was to review the PCs daily and grade each PC in accordance with Enclosure 3, PC Grading Guidance, of Procedure CP-111. The grades available for the PCs were A, B, C, and D, with "D" having the least significance. The guidance stated that "when the applicability of a higher grading is uncertain, be conservative and presume it is applicable. Defaulting to a higher grade with subsequent downgrading, demonstrates a higher level of safety sensitivity, than defaulting to a lower grade..." The guidance for Grades "A" and "B" PCs stated there was significant consequences for safety and equipment damage. Grade "C" guidance stated that there was moderate consequence for some reduction in safety and minor equipment damage. Grade "D" guidance stated there was low or no consequence for minor or no equipment damage and no reduction in safety.

The inspectors reviewed a printout of the 2978 PCs that were initiated from January 1, 1997, to May 5, 1997, in order to select a sample of PCs for detailed examination. Of the 2978 PCs, 656 were graded as "C" and 2245 were graded as "D". The remaining PCs were graded as "B". The inspectors reviewed 578 PC summaries from the printout to determine if the grading was within the PC grading guidance of Procedure CP-111. The inspectors selected 79 PCs for a detailed examination against the grading guidance. Of the 79 PCs examined, 72 were graded "D." The inspectors did not have any questions regarding the seven PCs reviewed that were graded either "B" or "C." However, for a number of the Grade "D" PCs examined, the guidance listed in Enclosure 3 of CP-111 indicated that the PCs should have been graded as a "C." These PCs met some portion of the guidance for grade "C" PCs. These grade "C" guidance areas were: 1) some reduction in safety, 2) equipment damage, 3) unavailable fire protection equipment, 4) minor spills or spread of radioactive material and 5) calculation errors. Step 4.3.2.1.1 of Procedure CP-111 stated that the PCSC was to grade each PC in accordance with Enclosure 3 of Procedure CP-111. Several examples of these D level PCs and the applicable grading criteria for a C level are as follows:

- PC 97-0296, Calculations - discrepancies between the breaker trip setting on drawings, calculations, and the breakers in the field. There would be some reduction in safety if the breaker trip setting were not set properly. Grade "C" guidance - some reduction in safety.

- PC 97-0376, Potential design basis requirement to test fire pump house ventilation equipment such as solenoids for the dampers. Failures of the solenoids may prevent the damper from opening and prevent the diesel driven pump from operating as designed. This

PC met example 15 of the Grade "C" guidance - Unavailable fire protection equipment.

- PC 97-0624, Appendix R Valve FSV-638 had its yoke broken while closing. This valve was a fire protection valve. This PC met example 15 of the Grade "C" guidance - Unavailable fire protection equipment.

- PC 97-1540, Relief Valves MUV-137 and MUV-139 should be added to Inservice Test (IST) program since they may be needed to protect the MUT from overpressure. Grade "C" guidance - some reduction in safety.

- PC 97-1671, Flush of Valve MUV-191 may have caused spread of contamination and high dose rate, needs nipple welded on. This PC met example 13 of the Grade "C" guidance - Minor spills or spread of radioactive material.

- PC 97-1871, Unanalyzed Emergency Diesel Generator (EGDG)-1A loading scenario during Loss of Coolant Accident/Loss of Offsite Power (LOCA/LOOP) caused by loss of DC power. This may be an equipment reliability issue that affects the EDG and emergency feedwater pump. This PC met the Grade "C" guidance - some reduction in safety.

In discussions with the inspectors, licensee management personnel stated that a management decision was made to grade certain PCs as "D" instead of "B" or "C" because the problems in these PCs were considered to be additional examples of problems that had already been evaluated in special categories, such as FSAR Discrepancies, Technical Specifications Discrepancies, Enhanced Design Basis Document (EDBD) Discrepancies, and Design Basis Issues. Therefore, there was no need to make them Grade "B" or "C" since these PCs were just examples of the other special categories and would be tracked accordingly. The inspectors could not verify that any of the specific Grade "D" PCs reviewed had been downgraded due to the PC being tracked in one of these special areas, in that there was no documented justification included in any of the PCs to indicate whether the PCs had been downgraded or not. The inspectors verified that some of the grade "D" PCs were assigned to other departments and special groups such as Nuclear Operations Engineering, Nuclear Plant Technical Support, System Readiness Review Group, and Design Basis Document Group, for evaluation and corrective action. The inspectors expressed concern that some Grade "D" PCs were not being processed in accordance with the guidance in CP-111. In addition, the inspectors also noted that Grade "D" PCs were not required to be tracked for apparent cause and common cause identification and corrective action. The inspectors informed the licensee that the above six examples of improper grading of PCs was another example of failure to follow procedure CP-111. This item will be identified as the third example of VIO 50-302/97-07-01, Failure to Follow Procedure CP-111 for the Processing of Precursor Cards.

Personnel Interviews

The inspectors interviewed several individuals within operations to ascertain their views on the PC system. The operations personnel indicated that, in general, the PC system was an effective method for identifying problems. There was one comment made during the interviews regarding the lack of feedback being provided to PC originators. Some of the individuals indicated that there should be more feedback provided to the PC originator regarding what actions were being taken to the PC rather than the statement that the PC had been entered in the database for trending. This comment appeared to apply to Grade "D" PCs, which included a generic response to the PC originators thanking them for submitting the PC. The Grade "D" generic response also informed the PC originator that the PC was graded a "D" by the PCSC which indicated that no apparent cause evaluation was necessary and the information was being entered in the PC database for statistical trending. The inspectors discussed this comment with licensee personnel who indicated that this comment would be addressed with the implementation of Revision 57 to Procedure CP-111, which will require a written response for Grade "D" PCs. The inspectors also noted that a similar comment had been identified by QA during interviews of craft personnel. QA wrote a PC (97-1311) on this issue and the PCSC graded the PC as a "C."

Observations and Findings (Suspected Design Basis Issue Evaluations)

The inspectors selected three PCs for review which had been classified by the licensee as being suspected design basis issues (SDBIs). These PCs were classified as Grade "B" PCs in accordance with licensee Procedure CP-111 because the PCs were being considered as SDBIs. The inspectors reviewed the PCs to assess the quality and the adequacy of the SDBI evaluations performed by Nuclear Operations Engineering (NOE). Two of the PCs (97-1515 and 97-1520) are discussed below. The third PC (97-2026) is discussed in paragraph E8.3 of this inspection report. During review of the PCs and the associated NOE evaluations, the inspectors made the following observations.

PC 97-1515 Waste Disposal Components not Seismic Class I per the FSAR/EDBD

This PC involved seismic classification discrepancies for several components in the waste disposal (WD) system. These discrepancies were identified during the System Readiness Review (SRR) performed by the licensee for the WD system. The PC identified a potential design discrepancy and indicated that the WD system components were not seismically qualified as stated in the FSAR. FSAR Section 5.1, Structural Design Classification, paragraph 5.1.1.1.i, stated that the WD system tanks, pumps, and other components were designated as seismic Class I. These components were also designated as seismic Class I in FSAR Table 11-5 and the CR-3 Enhanced Design Basis Document (EDBD). The PC requested that NOE evaluate the discrepancies identified in the PC to determine if CR-3 was meeting its design basis for the WD system.

The NOE evaluation for this PC, dated April 7, 1997, concluded that the seismic design discrepancies did not constitute a design basis issue. The bases for the NOE determination included the following.

- "...the defined conditions will not result in systems, structures or components being rendered incapable to perform their safety function in preventing or mitigating design basis events."

- Regulatory Guide (RG) 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-cooled Nuclear Power Plants, indicated that systems handling radioactive materials in liquids need not be seismically designed.

- RG 1.143 stated that gaseous radwaste systems should be seismically qualified. However, the NOE evaluation stated that the lack of seismic design for the CR-3 waste gas piping associated with the waste gas decay tank (WGDT) and waste gas surge tank (WGST) did not constitute a design basis issue provided the established radioactivity limit for the tanks was not exceeded. A Florida Power Corporation (FPC) letter to the NRC dated June 16, 1982, established the radioactivity limit.

- Simultaneous failure of the piping associated with the WGST and WGDT was not assumed based on earthquake experience data for small bore piping. Further, the actual piping accelerations associated with low frequency systems at 5% damping would be significantly less and not a credible failure mode for simultaneous failures.

- The NOE evaluation stated that the design basis for the WGDT was to ensure radiation doses resulting from a postulated WGDT rupture accident would be within 10 CFR 100 limits, as discussed in FSAR Chapter 14.2.2.8.

The inspectors concluded that none of the above statements demonstrated design basis compliance and found several problems with the above determinations as discussed below.

- The licensee's position as to what constituted a design basis issue was narrow and not fully consistent with the regulations. This position was defined in licensee Procedure CP-111, Processing of Precursor Cards for Corrective Action Program, and was being implemented by NOE during the preparation of SDBI evaluations. The inspectors noted that 10 CFR 50.34(b) requires that the FSAR "...shall include information that describes the facility, presents the design bases..." Accordingly, the information included in FSAR Section 5.1.1.1, FSAR Section 11.2, and FSAR Table 11-5 regarding the WD system would constitute the design basis for the WD system components.

- RG 1.143 was not included or referenced in the FSAR and therefore, the applicability of the RG to the CR-3 licensing and design bases had not been established. Accordingly, the basis for the lack of seismic qualification of the liquid WD systems components was not clear.

- The radioactivity limit for the WD system tanks specified in FPC's June 16, 1982, letter (less than or equal to 39,000 Curies in each tank) did not constitute a licensing/design basis. Accordingly, the lack of seismic qualification for the gaseous WD system as stated in the FSAR could be a design basis issue. In addition, dispositioning the lack of seismic design for the WGST and WGDT as not constituting a design basis issue "...provided compliance with the inventory limit is maintained" was inconclusive and open. No action was taken to determine whether the radioactivity limit (specified in the June 16, 1982, letter) in the WGDT had been exceeded.

- The engineering judgement related to simultaneous failures of piping and actual piping accelerations at damping values higher than the design values, was not relevant to the determination of design basis compliance and was not adequately supported.

- The FSAR Section (14.2.2.8) referenced in the NOE response to the PC did not provide the design basis for the WGDT, but described the analysis performed to show that if a WGDT were to rupture, the 10 CFR 100 limits would not be exceeded. The design basis for the WGDT stated in the NOE response was not consistent with the design basis for the WGDT stated in FSAR Sections 5.1.1.1 and 11.2. These two FSAR Sections indicated that the design basis for the WGDT and the related piping (Seismic Class I) was to maintain their functional integrity during and after a seismic event.

- The NOE response to the PC did not attempt to address the historical basis for the seismic classification of the components, the current FSAR and EDBD specification, or the anomalies with the licensee's configuration management data base and the design drawings (302-series flow diagrams).

<u>PC 97-1520</u> Unknown if Reactor Building Pressure Sensing Lines Meet Requirements of Regulatory Guide 1.11

This PC involved a question of whether the design of the reactor building (RB) pressure sensing lines was in compliance with NRC Regulatory Guide (RG) 1.11, Instrument Lines Penetrating Primary Reactor Containment. This issue was identified by the licensee's FSAR Review Project Team. The PC stated that, in response to an NRC question, FPC was required to provide design details in the FSAR demonstrating compliance with RG 1.11. FSAR Section 5.3.1, did not provide the required design details for the RB pressure sensing lines.

The NOE evaluation dated April 7, 1997, concluded that this was not a design basis issue (DBI). The inspectors had several concerns with this conclusion as follows.

- The NOE evaluation stated that deviations from design values such as those identified in the FSAR or Enhanced Design Basis Document (EDBD) may or may not constitute a DBI. It further stated that a "condition should only be considered a DBI if the deviation prevents the SSC from accomplishing its functional goals." This position as to what constituted a DBI was consistent with Procedure CP-111. However, this definition was incomplete in that it did not include all design related aspects of the reportability requirements of 10 CFR 50.34, 50.72, and 50.73.

- The NOE conclusion further stated that the lack of any correspondence between the NRC and FPC on this topic since 1973 is "...strong indication that the issue was resolved" is not an adequate basis for the determination that the issue is not a DBI. Lack of regulatory correspondence does not constitute a licensing basis.

- The NOE conclusion statement that the "design meets all the criteria outlined in Containment Isolation Topical Design Basis Document" did not have a regulatory basis for determining a DBI in that the Containment Isolation Topical Design Basis Document was not part of the licensing design basis.

- Further, the engineering evaluation did not make a positive determination as to whether the design of the RB pressure sensing line was consistent with NRC RG 1.11.

- The inspectors reviewed the RB pressure sensing line design and discussed the SDBI evaluation with NOE personnel. The inspectors concluded that the design of the RB pressure sensing line was not consistent with RG 1.11. RG 1.11 stated that there should be a containment isolation valve located just outside the containment that was automatically or remotely operated. The licensee's design included no automatically or remotely operated containment isolation valve. It did include a locked open manual valve located just outside the containment and then about 20 feet of piping to the instrument cabinet, which contained several valves.

- The engineering evaluation did not address whether the approximately 20 feet of pressure sensing lines outside of containment were seismically designed. Subsequent review during this inspection found that one drawing indicated the lines were seismically designed, another drawing indicated they were not, and the Configuration Management Information System indicated they were not.

- The inspectors could not readily determine if the licensee was committed to RG 1.11. The licensee's Quality Assurance Program, as stated in the FSAR Chapter 1, did not include a commitment to RG 1.11. However, licensing personnel stated that the Quality Assurance Program did not include a complete listing of RGs to which the licensee was committed.

- Engineering personnel who performed the SDBI evaluations were not trained in existing interpretations of NRC regulations on reporting as published in NUREG-1022.

The inspectors found that there was insufficient information in the NOE evaluations or available at the end of the inspection to conclude whether the issues described in PC 97-1515 and PC 97-1520 were DBIs or were required to be reported to the NRC. The inspectors discussed the NOE evaluations with licensee personnel who acknowledged the inspectors' findings. Licensee personnel indicated that these two PCs would be reopened and re-evaluated as SDBIs. In addition, licensee personnel further indicated that all of the other PCs previously evaluated as SDBIs and determined not to be DBIs would be re-evaluated.

c. Conclusions

Based on findings and observations from review of the PC samples, the inspectors concluded that there has been noted improvement in the corrective action process as compared to the process used before the IPAP inspection. However, as indicated by the above findings, there were still programmatic problems in evaluating design basis issues which may lead to incorrect reportability determinations and weaknesses in other areas which warrant increased management attention. The program was still undergoing changes. Other assessments of the program included the following.

- Improvement was noted in the timeliness with regard to the review of issues for suspected design basis issues, evaluation for operability and reportability.

- Problem statement and clarity, immediate corrective actions, and cause determination were good.

- No problems were identified regarding reportability.

- Several examples were noted where the program was not being implemented with regard to timeliness of PC responses, training of individuals performing the functions of the RCT Leaders and ACEs, and grading of PCs. A violation was identified for failure to follow procedure CP-111 for the examples.

- The lack of training appeared to have contributed to some weak definition of corrective action statements.

- PC screening for restart was initiated some time after the current program was implemented. Later PCs were screened for restart as evidenced by a stamp on the PC and observed by the inspectors during attendance at a PCSC meeting. Licensee personnel indicated that earlier PCs would be re-reviewed for restart.

- There was a weakness in the Corrective Action Program in that the engineering SDBI evaluations were of poor quality. Three of three engineering SDBI evaluations reviewed (for PCs 97-1515 and 97-1520 discussed in this paragraph above and for PC 97-2026 discussed in paragraph E8.3 of this inspection report) had insufficient technical justifications to support the conclusions that there was not a reportable DBI. The engineering evaluations included incomplete determinations of the licensing and design bases and incorrect interpretations of NRC regulations. The licensee's definition of a design basis issue was narrow and not consistent with NRC regulations. Additionally, engineering personnel performing SDBI evaluations were not trained in existing interpretations of the NRC regulations on reporting as published by the NRC in NUREG-1022.

- The initiation of PC 97-1515 and PC 97-1520 were positive reflections on the licensee's 'extent of condition' programs (SRR and FSAR Review Project Team) which resulted in the identification the SDBIs documented in these PCs.

The inspectors assessed the licensee's performance, relative to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Adequate
- Engineering Effectiveness - Inadequate
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Inadequate
- Operator Performance - N/A

O7.3 <u>Quality Assurance Audits and Surveillances</u>

a. <u>Inspection Scope (40500)</u>

The inspectors reviewed selected audits and surveillances performed by the Nuclear Quality Assurance group in the Quality Programs Department (QPD). These audits and surveillances were performed on various corrective action program activities.

b. <u>Observations and Findings</u>

The inspectors noted that the QPD had performed four audits and 63 quality programs surveillances (QPS) since January 1997. The inspectors reviewed the following audit and QPS reports:

- Audit 97-02, Problem Identification, Problem Resolution, and Restart Readiness;

- QPS-97-0015, Evaluation of Category "C" Precursors;

- QPS-97-0018, Assess the NSM Screening of PCs for Reportability and Operability; and

- QPS-97-0024, Restart Item Identification and Tracking

During Audit 97-02, the QPD issued 28 PCs (2 Grade "B", 13 Grade "C", and 13 Grade "D"). Some of the findings from the audits and QPS reports concluded the following

- There had been untimely completion of PC corrective action steps.
- There were numerous deficiencies in the implementation, definition, and development of processes to trend and monitor performance of the current corrective action program.
- The restart program continued to be ineffective in communication of issues and expectations.
- The current PC process did not assure that documentation was maintained for the resolution of Grade "C" PCs.

c. Conclusions

The inspectors concluded that the QPD has been active in identifying continued weaknesses and areas for improvement in the licensee's corrective action program and various other activities.

The inspectors assessed the licensee's performance, relative to this issue, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

O8 Miscellaneous Operations Issues

O8.1 Review of NRC Information Notice 97-06, Weaknesses in Plant Specific Emergency Operating Procedures for Refilling the Secondary Side of Dry Once Through Steam Generators

a. Inspection Scope (92901)

Information Notice (IN) 97-06 was issued March 4, 1997, documenting a concern where an OTSG is isolated and allowed to become dry prior to or during RCS cooldown. The inspectors reviewed the licensee's assessment of the emergency operating procedures (EOP) and their adequacy for addressing these concerns.

b. Observations and Findings

The concern of the IN was if an OTSG were isolated and allowed to become dry, then thermal communication between the tubes and the shell of the dry OTSG would become highly degraded. Given that forced RC flow was occurring, the tubes will remain at thermal equilibrium with the RC. However, the shell would cool via ambient losses. If the tube temperature is held constant, the shell would eventually become cooler than the tubes. This situation would place the OTSG tubes in compression, possibly leading to excessive loads on the tubes. The IN emphasizes the need for emergency operating procedures containing guidance for refilling OTSGs.

On May 19, 1997, the licensee and a contractor completed reviews of the IN and related industry guidance to verify that the existing EOPs adequately addressed the concerns raised in both documents.

The conclusion of the reviews was that the existing EOPs did contain adequate guidance to address the IN concerns. The level restoration was accomplished prior to transitioning from excessive primary to secondary heat transfer guidance to subsequent cooldown guidance. The conclusions reached were that expeditious recovery of dry OTSGs coupled with OTSG tube to shell delta temperature control guidance, enhanced the EOP ability to control tube to shell delta temperatures for the situations discussed in the INs. The licensee concluded that to address this issue, no changes were necessary in the existing EOPs.

The inspectors reviewed the licensee's EOPs to assess their capability and guidance for dealing with the situations addressed in the IN. EOP-5, Excessive Heat Transfer, states that if OTSG level < 12.5 inches then the operators are to refer to Enclosure 3, Dry OTSG Recovery, which provides detailed instructions for refilling a dry OTSG. Several EOPs address controlling tube-to-shell delta temperature within limits established in the EOPs. EOP-6, Steam Generator Tube Rupture, EOP-8, LOCA Cooldown, EOP-9, Natural Circulation Cooldown, and EOP-10, Post-Trip Stabilization, all provide guidance for maintaining delta temperature within limits.

c. Conclusions

The inspectors concluded, based on the review of the licensee's assessment and their own review of the licensee EOPs, that adequate guidance did exist in the licensee's EOPs to address the concerns of IN 97-06. No further actions were required as a result of this issue.

O8.2 (Closed) EA 95-126, VIO I.A, Nine Instances Where Operators Violated Procedures for Makeup Tank Pressure/Level Control

a. Inspection Scope (92903)

This violation involved violations of three different operating procedures, on numerous occasions, and also involved essentially all of the licensed operators at the plant. The inspectors followed up on the licensee's corrective actions by reviewing procedure changes, training records, modification packages, inspecting conditions in the plant, and interviewing operators.

b. Observations and Findings

Procedures and modifications reviewed by the inspectors included:

- AI-500, Conduct of Operations, Operations Department Organization and Administration, Rev. 92, dated March 11, 1997;
- AI-501, Conduct of Nuclear Plant Operations Assessments, Rev. 9, dated April 19, 1996;
- OI-05, Log Keeping, Rev. 2, dated September 16, 1996;
- OI-09, Operations Procedures, Rev. 6, dated November 14, 1996;
- OI-12, Investigation of Abnormal Events, Rev. 1, dated July 1, 1996;
- OI-31, Self Checking and Questioning Attitude, Rev. 0, dated December 15, 1995;
- OI-32, Operations Mentor Program, Rev. 0, dated March 10, 1997;
- OI-42, Operations Work Control Supervisor Position, Rev. 0, dated September 30, 1996;
- OP-103B, Curves 8A and 8B, Max. Makeup Tank (MUT) Operating Pressure vs. Level, Rev. 17, dated October 18, 1996;
- AR-403, Annunciator Response, PSA H Annunciator Response, Rev. 26, dated October 28, 1996; Event Point 1064, MUT Level High/Low; and
- MAR 95-01-07-02, Increase MUT High Level Alarm and Install Computer Pre-Alarm, dated September 6, 1995.

The inspectors verified that the licensee restored adequate operating margins for makeup tank pressure and level control by:

- revising the makeup tank overpressure curve, creating a separate operating alarm curve and limit curve, and labeling the curve better;
- increasing the makeup tank high level alarm; and
- installing a computer pre-alarm.

The inspectors also verified that the licensee took actions to improve the questioning attitude of operators on shift by implementing the Event-Free Operations Program, which included:

- establishment of expectations for human performance,
- use of tools for human performance improvement,

- use of the Stop, Think, Act, Review (STAR) self-checking technique,
- use of peer checking and communication protocol, and
- use of performance assessments and tracking and trending human performance.

In addition, the inspectors verified that the licensee strengthened expectations and procedures governing alarm response by:

- revising administrative procedures, and
- training operators.

Also, the inspectors verified that the licensee took actions to strengthen management oversight of control room activities by:

- adding an additional management position to focus solely on-shift operations,
- establishing a management mentor program for SROs,
- initiating operator investigations of abnormal events,
- implementing a self-assessment program in the operations department,
- initiating and trending operating shift performance indicators, and
- creating a SRO certified work controls position, which was to be fully staffed on the day shift. However, the inspector found that the position was staffed only about 80% of the time on weekday shifts. The ANSS stated that, when the work controls position was not manned, there was a noticeable large increase in traffic into the control room and increase in work for the NSS and ANSS. The individual staffing the work controls position stated that there were only two individuals assigned to the position, that they had been also assigned several other duties, and that between them they could only man the position about 80% of the time. The ANSS stated that the NSS and ANSS were supposed to be spending time in the plant with the plant operators, but could not do so when the work controls position was not staffed.

c. Conclusions

The inspectors concluded that the licensee's corrective actions included actions to prevent recurrence of the violation, had been implemented, and were effective improvements. EA 95-126, VIO I.A is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

O8.3 <u>(Closed) EA 95-126, VIO I.B, Conduct of Unauthorized Tests of Makeup Tank Without 10 CFR 50.59 Evaluation</u>

a. <u>Inspection Scope (92903)</u>

This violation involved operators conducting unauthorized tests of makeup tank level and pressure and also involved additional examples of unauthorized tests conducted by operators. The inspectors followed up on the licensee's corrective actions by reviewing procedure changes, training records, and internal correspondence; inspecting conditions in the plant; and interviewing operators.

b. <u>Observations and Findings</u>

In addition to the procedures reviewed above for EA 95-126, VIO I.A, the inspector reviewed the following procedures:

- AI-400C, New Procedures and Procedure Change Process, Rev. 19, dated March 31, 1997

- CP-213, Preparation of a Safety Assessment and Unreviewed Safety Question Determination (10 CFR 50.59 Safety Evaluation), Rev. 1, dated April 4, 1997

The inspectors verified that the licensee strengthened management expectations and on-shift leadership by:

- revising procedures to provide more guidance to control room personnel as to what constitutes an infrequently performed test or evolution, including a checklist;

- revising procedures to better address shift supervisor authority;

- creating an administrative procedure to provide additional guidance to operations personnel for procedure use; and

- making several personnel rotations within the Operations Department.

The inspectors also verified that the licensee conducted training to address lessons learned from this violation, including procedure changes and the Event Free Operations Program. The training specifically addressed:

- shift supervisor authority,

- avenues for resolving issues,

- importance of maintaining operational limits, and

- correct methods for performing normal evolutions, unusual evolutions, and tests.

In addition, the inspectors verified that the licensee provided for additional management oversight of control room activities by:

- adding management oversight and operations support personnel,

- improving log keeping, standards, and practices,

- establishing a mentor program for Nuclear Shift Supervisors and targeted future Nuclear Shift Supervisors to improve communications with senior management,

- clarifying standards for self-checking and procedure compliance,

- adding new talent into operations and allowing licensed personnel to move into other parts of the organization,

- using self assessments and precursors by operations, and

- developing and using shift performance indicators.

c. Conclusions

The inspectors concluded that the licensee's corrective actions included actions to prevent recurrence of the violation, had been implemented, and were effective improvements. EA 95-126, VIO I.B is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - Adequate
- Compliance with Regulations - Good
- Operator Performance - Good

II. Maintenance

M1 Conduct of Maintenance

M1.1 Emergency Feedwater Cavitating Venturi Hydrostatic Test

a. Inspection Scope (62707)

The inspector reviewed the preparations and observed the performance of hydrostatic testing of the newly installed EFW cavitating venturis performed under Modification Approval Record (MAR) 96-10-02-01.

b. Observations and Findings

The inspector reviewed Maintenance Procedure (MP) 137, System Hydrostatic Pressure Testing, Revision 28, which was a generic test procedure contained within MAR 96-10-02-01 to perform the hydrostatic test. Enclosures 2 and 3 of the MP delineated specific test boundaries, pressures, relief valves, water quality, instrumentation, and hold time. The inspector verified the test parameters were appropriate and incorporated the ANSI B31.1.0 1967 construction code and ASME Section XI code requirements. The test was scheduled to be performed by a contract maintenance crew on May 7. The inspector attended the morning planning and scheduling meeting and Operations morning shift turnover meeting that day and observed that the test was not discussed in any detail at either meeting and was not part of any planned SSOD brief. However, a licensed operator at turnover questioned the test boundaries and water sources. Only a single set of boundary valves separated the test portion of EFW from the nearly full OTSGs. The Operations Manager further questioned the consequences if these boundary valves leaked by, pressurizing the OTSGs. The only individual cognizant of the test at the meeting was the clearance CNO and he was unable to answer these questions so the SSOD suggested that the maintenance crew needed to come discuss the test with the operators. The inspector determined from discussions with the operators that a briefing of this sort for Operations was neither required nor routinely expected unless the evolution had direct impact on Operations. The inspector also determined from the discussions that this briefing would not have happened if the operator had not raised the questions she did, and it was not required to be done per the MAR or MP-137.

The inspector attended the briefing in the Operations break room later that morning. The maintenance crew and foreman were present to brief the NSM, SSOD, and clearance chief. No other individuals from Operations were present, and no individuals from Engineering were present. Although the test was performed under an engineering MAR, it was considered a maintenance activity so the Modifications Engineer overseeing the MAR was not involved. The inspector had to request that music playing in the break room be turned off because it was difficult to hear the brief comments. The maintenance foreman discussed the already established test boundaries and general plans and asked if the Operations individuals had any questions. The inspector observed the meeting was very informal and did not have any prescribed format or content. The SSOD had a copy of Operations Instruction (OI) 14, Evolution Briefings, Revision 5, and asked the maintenance foreman to address items in the Pre-job Briefing Checklist in the OI. The foreman stated that the maintenance crew had already done their own pre-job brief and that he was unfamiliar with the existence or content of the OI-14 checklist, but that he would attempt tho answer the checklist items. Although OI-14 directed an "SSOD Pre-job Briefing" occur for infrequent tests, it was not clear on exactly what this entailed and who was responsible for preparing the brief and conducting it. The remainder of the "briefing" consisted of the SSOD asking the foreman the generic questions from the checklist and the foreman attempting to respond. The inspector observed that many of the questions were not adequately addressed since they required preparation to answer and that the discussion focused on personnel safety and did not address specific hydrostatic test requirements.

At the end of the brief, the maintenance crew stated they were ready to fill and vent the system and commence the test. At this point the inspector questioned how the specific Operations Manager's concerns for pressurizing the OTSGs were going to be addressed. The SSOD and maintenance crew agreed that if they observed excess water being pumped into the system to maintain test pressure, that could indicate leakage past the boundary valves and they would notify operations to monitor the OTSGs. However, what constituted excess leakage was never defined so the inspector concluded the concern was not adequately addressed. The inspector then questioned other test boundaries and how leakage past boundary valves was considered. The maintenance crew stated that they had either double valve protection or extremely thick blank flanges at all the other boundaries. However, the inspector observed that the second valves used for this lineup were not part of the planned clearance tagout and created the potential for hydrostatically testing adjacent and unmonitored systems. This could occur if the first boundary valve leaked by because the portion of pipe between the two valves was water solid. The inspector determined that the maintenance crew was not aware of this concern, and the adjacent piping had not been analyzed to ensure it would withstand hydrostatic pressure and would not be monitored during the test for leakage. The inspector determined the clearance written to support the test by Operations was inadequate because it merely incorporated the test boundaries suggested by engineering on the Enclosure 3 form in MP-137. Neither the enclosure or the clearance considered the effect on adjacent systems. Step 4.2.2 of MP-137 required components and system piping not under test to be vented or monitored during the test. The inspector determined that the engineers who had determined the scope of the test boundaries had not coordinated with the Operations clearance authors to ensure these concerns were implemented. Although several portions of adjacent piping were discovered by the licensee to be vented by other portions of the clearance hung for the original venturi installation, it had not been planned to support the test. Although the clearance CNO considered this adequate, the NSM recognized that the licensee had not adequately prepared for the evolution and stopped the test. He initiated corrective action document PC 97-3110.

Criterion 9, Appendix B, 10 CFR 50, Control of Special Processes, requires that processes such as nondestructive testing are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements. The inspectors concluded the licensee's failure to plan adequately and control adequately the hydrostatic test, which involved several licensee disciplines, was a violation of this requirement. Specifically, under Operations, the lack of a clear briefing requirement or routine briefing expectation was inadequate Operations involvement with a safety-related plant test performed by another group. The addendum to clearance Engineering Change Order (ECO) 97-04-026 issued for the test was inadequate because it did not incorporate requirements for protecting adjacent systems. Under Engineering, the completed MP-137 Enclosure 3, System Test Requirements, did not incorporate requirements for protecting adjacent systems, and the lack of engineering presence or involvement with the planned performance of the test was inadequate oversight. Under Maintenance, the maintenance crew performing the test procedure did not recognize or understand the requirements for protecting adjacent systems. These items are identified as VIO 50-302/97-07-02, Inadequate Planning and Controlling of Hydrostatic Testing.

PC 97-3110 was graded as a Level C, requiring an apparent cause evaluation, and was assigned to the Maintenance department. Maintenance performed an investigation and implemented corrective actions which included revising MP-137 and discussing the problem with all maintenance personnel. The PC was then closed on May 20. The inspector did not identify any problems with the specific actions taken but noted that the investigation and actions focused solely on the maintenance issues so the Operations and Engineering problems were not addressed by PC 97-3110 or any other PC. Additionally, the Maintenance department developed more extensive pre-job checklists contained in their Nuclear Maintenance Manual, a manually controlled solely within maintenance and not distributed throughout the site. The inspector considered this would only further compound the problem observed when the maintenance foreman was unaware of the Operations department's briefing checklist from OI-14.

The licensee's short term corrective actions addressed the above concerns and the test was completed satisfactorily on May 12. However, an attempt on May 11 was aborted when the test pressure was questioned by Operations personnel. The originally prescribed test pressure of 1760 psig, or 110% of a design pressure of 1600 psig, was determined to be inadequate since the system experienced pressures of approximately 2000 psig during EFW pump overspeed testing. The test pressure was changed to 2150 psig on the basis of an analysis in Request for Engineering Assistance (REA) 97-0503. The inspector verified this pressure was within the code requirements and did not identify any other concerns.

c. Conclusions

The inspector concluded the Engineering oversight, Maintenance knowledge of the requirements, and Operations involvement with this test was inadequate considering the hydrostatic test was only separated by one valve from a full OTSG considered operable as a shutdown decay heat removal option. Licensee management didn't recognize the lack of oversight until it was revealed by questioning of the inspector. The inspector also concluded the licensee did not have a comprehensive site policy or expectation for the content or performance of pre-job briefings.

M1.2 Inservice Inspection (ISI)

a. Inspection Scope (73753)

The inspector reviewed program plans and documentation related to the conduct of ISI Inspection activities during the ongoing maintenance outage.

b. Observations and Findings

Crystal River 3 was in the final months of the second, 10-year ISI interval. The interval was scheduled to be completed on March 14, 1997, but the licensee was taking advantage of the provisions in IWA-2430 of ASME, Section XI, which allowed for the extension of an ISI interval for outages which exceed six-months. The third, 10-year ISI interval would start approximately six months after restart from the current maintenance outage.

The licensee's ISI staff was taking advantage of the ongoing maintenance outage to correct and complete the second ten-year ISI inspection program. Prior to the past refueling outage (Spring 1996), the licensee established a contract to assess the ISI program independently. The project included a detailed review of all required inspections, which identified a number of mistakes and omissions in the licensee's ISI program.

The licensee's ISI staff was also using this time to review completely and revise the isometric piping drawings used in the ISI inspection program and to add these drawings to the plant controlled drawings so that they would be updated when modifications are made to the piping systems.

The inspector reviewed the final assessment report from the ISI review contractor, which was issued in June 1996, and reviewed corrective actions which have been taken to date. This included a review of documentation pertaining to inspections which would have been missed during the second, 10-year ISI interval. Plans for completing all required inspections during current maintenance outage were also reviewed.

c. Conclusions

The licensee was pro-acti. in utilizing the maintenance outage time to complete the second 10-year ISI requirements and completely updating the isometric drawing used for ISI.

M1.3 Once Through Steam Generator Inspections

a. Inspection Scope (50002)

Through discussions with the licensee, the inspector reviewed preparations and plans for inspection of the OTSGs during the current maintenance outage.

b. Observations and Findings

The last eddy current (EC) inspection of the OTSGs occurred during the Spring 1996 refueling outage. NRC inspections of the licensee's OTSG activities during that outage were reported in inspection reports 50-302/96-03 and 50-302/96-06.

The inspector reviewed the current status of the OTSG program and observed preparations for the EC inspections which were planned for this maintenance outage. The licensee was planning to conduct a comprehensive "baseline" inspection of the OTSGs, using established, state-of-the-art, EC equipment and techniques.

The inspector also discussed the licensee's plans for a OTSG management document which included a six-year plan for OTSG maintenance and inspection activities.

c. Conclusions

The licensee's steam generator inspection program appeared good. The decision to baseline and inspect the OTSGs fully, using latest qualified eddy current techniques, was a sound technical decision.

M1.4 Emergency Feedwater Cavitating Venturi Modification Functional Testing

a. Inspection Scope (61726, 92902)

The inspectors witnessed the post-modification functional testing for the emergency feedwater cavitating venturi installation. The tests inspected during this period included tests of the two individual trains.

b. Observations and Findings

The inspectors reviewed licensee test procedure (TP) MAR 96-10-02-01, TP#2, A - Train EFW Flow Verification, Revision 0 and Revision 1, prior to the performance of the functional test. The original revision was approved on May 16, 1997, by the Plant Review Committee (PRC) prior to the verification and validation. On May 19, 1997, it was identified that Revision 0 had used preliminary instrument error numbers in the acceptance criteria. When the final numbers were calculated, on May 20, 1997, they differed from the preliminary numbers, necessitating a revision to the procedure. The inspectors had attended the original PRC and noted that the test engineer presenting the original procedure had not informed the PRC that preliminary numbers were being used. The revision of the procedure was approved by the PRC on May 20, 1997.

During the review of the procedure, on May 19, 1997, the inspector noted that while the procedure required that calibration be verified for test equipment, in places, permanently installed instrumentation was being used to obtain test values. The procedure did not require that these instruments be verified to be in calibration. The inspector discussed this with the SRO assigned to perform the test. During the pre-job briefing, the SRO stated that operations had verified that all permanently installed instrumentation used during the test was in calibration.

During the second PRC review, the PRC noted that the safety evaluation performed for the test procedure neglected to identify this evolution as a test or infrequently performed evolution. The PRC directed engineering to modify the evaluation to be accurate.

On May 20, 1997, the inspectors attended the pre-job briefing for the test of the A train cavitating venturies. This briefing was conducted by the SRO scheduled to be the Nuclear Shift Supervisor (NSS) on the day of the test. The SRO assured that all personnel involved and needed to complete the testing were present during the briefing. After a brief description of the test by the test engineer, the SRO discussed additional items needed to be completed prior to beginning the test. The SRO assigned the task to verify the installed instrumentation was in calibration, informed engineering to supply operations with the last pump curve taken on the emergency feedwater pump, for comparison, and the SRO directed electrical maintenance to perform a Megger of the pump motor, since it had been idle since September, 1996. These initiatives taken by the operations SRO were proactive; however, the fact that they had not been considered prior to the pre-job briefing was of concern to the inspectors. Certain aspects of the preparation for the test were not thorough, necessitating procedural revision late in the process and additional preparations being taken by operations, which were outside of originally scheduled actions.

The test was performed on May 21, 1997. The inspectors witnessed the test from the main control room, from the pump area, and from the data collection point. The test results were satisfactory, with all acceptance criteria met. The engineers verified the emergency feedwater pump curve was not significantly affected by the modification.

Weaknesses were noted during and after the performance of the test. The licensee directed the plant operators to tighten down on leaking red-tagged valves which is discussed further in Section O1.2.

Two valves, SUV-39 and FWV-163, which were manipulated during the performance of the test, needed to be restored to a closed position following the test. However, the test procedure did not direct operations to restore the valves to a closed position. Valve FWV-163 was required to be closed for containment integrity considerations.

The SDT-1, secondary drain tank, level was high at the beginning of the test. Leaks on the secondary side significantly increased levels in the tank. Even though the licensee was aware that secondary side leaks were probable, the licensee's planning did not verify sufficient volume was available in SDT-1 for significant leaks.

The test for train B cavitating venturi, MAR 96-10-02-01, TP#1, B - Train EFW Flow Verification, Revision 1, was performed on May 30, 1997. During the pre-job briefing, a non-licensed operator questioned whether anyone had checked levels in SDT-1. When checked, it was again found that the tank was essentially full. Water had to be processed and the tank level reduced prior to the beginning of the B train functional test. The test of the B train EFW cavitating venturi was successful, with the resulting data meeting all acceptance criteria.

c. <u>Conclusions</u>

Weaknesses were displayed in the planning, preparation, and coordination for the A train EFW cavitating venturi test. Improvements were noted in these facets of the B train testing. All acceptance testing for these parts of the functional test were met. The final test of the integrated system performance will be inspected in a future inspection report.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 <u>Reactor Building (RB) Coatings</u>

a. <u>Inspection Scope (62700)</u>

The inspector reviewed procedures and documentation, and observed work activities involved with the removal and replacement of protective coatings inside the RB.

b. <u>Observations and Findings</u>

The inspector reviewed the following documents associated with the repair and replacement of protective coatings inside the RB:

Document No./Rev./Date	Title/Subject
RO-3147, Revision 4, December 2, 1993	Requirement Outline Painting and Protective Coatings
MP-139A, Revision 14, November 24, 1993	Application of Protective Coatings for Reactor Building (Inside)

Document No./Rev./Date	Title/Subject
Plasite® Technical Bulletin 9028, January 1984	Plasite® 9028M1 & 9028M2 Masonry & Concrete Filler-Sealer
QCS-97-0015, April 17, 1997	Quality Control Surveillance Report
QCS-97-0036, May 8, 1997	Quality Control Surveillance Report
Precursor Card 97-2042, May 12, 1997	RB liner was prepped and re-coated without the required Section XI inspections.
Precursor Card 97-3243, May 13, 1997	Personnel Hatch Door was prepped and re-coated without required Section XI inspections

The inspector noted that the two major control documents for the RB coating repairs and replacement were about three years old when the current Reactor Building coating project was started in December 1996. (MP-139A, Revision 14, was prepared November 24, 1993, with an effective date of January 10, 1994, and RO-3147, Revision 4, was dated December 2, 1993). The inspector noted that, since the issue of the current revisions to these two documents, and prior to the start of the current project, the "Maintenance Rule" became effective (July 10, 1996), and the "Containment Rule" had been issued, (September 6, 1996). Both of these rules could have impacted the work being done. During review of documentation and discussions with licensee personnel, the inspector found no evidence that these procedures had been subjected to an engineered or quality review to determine if any requirements had changed in the three years. This lack of review was considered to be a program weakness in the area of maintenance implementation.

During walk-through inspections of the coating work in the RB, the inspector noted evidence of degradation of the containment liner plate on the 95-foot level, at the junction of the toriconical segment of the liner plate and the concrete floor. The coating on the ⅜-inch thick liner plate had degraded in several spots, and there was visual evidence of localized rusting of the liner plate. (The licensee was apparently not fully aware of NRC Information Notice 97-10, Liner Plate Corrosion in Concrete Containments, issued March 13, 1997, which provided information concerning this type of problem.)

The inspector also noted that the area of RB liner plate that was the subject of PC 97-2042, (it had been prepped and re-coated without required ASME Section XI inspections) was the toriconical section of liner plate, abutting the concrete floor, in the vicinity of the in-core instrumentation tubes. An inspection of the plate surface adjacent to the concrete showed irregularities symptomatic of surface degradation, to a height of about four-inches above the floor. The degradation appeared to be general areas of pitting or wastage, but it was hard to tell how severe the wall loss was because the area had already been recoated. The NRC identified degradation of the RB liner plate material was identified as an unresolved item (URI) pending the licensee's evaluation of the severity of the problem. This will be identified as URI 50-302/97-07-03, Reactor Building Liner Plate Degradation.

During the general walk-through inspection of the containment, the inspector noted evidence of oil on walls and equipment; especially on and around Heating, Ventilation and Air Conditioning (HVAC) ductwork. (The oil was apparently the result of significant leakage from one of the Reactor Coolant Pumps during past operation.) Of particular note was evidence that oil had come from a duct-top vent, at the end of a long horizontal run, on the highest elevation of the ductwork.

Based on this observation, the inspector raised a question about how much oil was still in RB HVAC ductwork. When asked, the licensee informed the inspector that, at the time of the inspection, the licensee was only planning to clean the exterior and the vents, and had no plans to inspect or clean the interior of the RB HVAC ductwork. The issue of a potential unknown quantity of combustible materials inside of the ductwork was expressed as a concern to the licensee during the exit meeting on May 23, 1997. The licensee was informed that the inspector would identify the condition of the RB HVAC ductwork as an unresolved item, URI 50-302/97-07-04, Unanalyzed Combustible Burden in Reactor Building HVAC Ductwork.

c. Conclusions

The licensee's project to repair and replace the protective coatings inside the Reactor Building appeared to lack overall management and engineering involvement. The project appeared to have a narrow focus on the repair and replacement of the coatings. Identified problems associated with the project were as follows:

- A program weakness was identified concerning the fact that three-year old procedures were implemented without an engineering of quality review to determine if requirements had changed during the interim.

- An Unresolved Item was identified concerning Reactor Building liner plate degradation that was painted over without inspection or analysis.

- An Unresolved Item was identified concerning the potential that Reactor Building ventilation ductwork may contain an unanalyzed, combustible burden in the form of oil.

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551)

On the evening of June 5, 1997, EGDG 1A was being run per the operating procedure to support test data gathering when a governor oil fitting leak was discovered. The EGDG was shut down; a precursor card was initiated, and Technical Support system engineering contacted to support investigation of the problem. By early the next morning, June 6, the fitting had been repaired; the failed fitting had been sent to a laboratory to be analyzed for failure mode, and the 1B EGDG had been evaluated to ensure a similar problem would not present an operability concern. The system engineers had documented the above actions in a thorough written action plan which also evaluated the necessary post-maintenance testing required, initiated industry searches for similar failures, and documented maintenance history on the failed portion of the system. The failure was determined to be due to fatigue, and an REA was generated to modify the fitting lines from copper to stainless steel. The inspectors considered these actions to be an example of excellent and timely support by Engineering to Operations. The licensee exhibited good sensitivity to maintain shutdown plant power source availability above requirements considering one of the offsite power source lines was out of service for maintenance.

A similar example of good support by Engineering to Operations was observed by the inspector on May 12 and 13. When operators questioned abnormal amperage indication on a Decay Heat Closed Cycle Cooling (DC) pump start and generated PC 97-2044, system engineering coordinated with Operations and quickly developed a troubleshooting plan per MP-531, Troubleshooting Plant Equipment, Revision 9. This effort quickly revealed problems with a DC system valve (DCV-178) positioner and allowed corrective maintenance and operability determinations to be done in a timely manner. Again, the inspectors considered this good engineering support and good sensitivity for maintaining needed shutdown plant equipment.

However, the inspectors also observed examples of poor engineering support and involvement as discussed in Section M1.1 regarding the EFW hydrostatic test and Section S2.1 regarding support to Security for alarm station power supply failures. These examples were cited as parts of violations for each of those problems.

E1.2 Low Temperature Overpressure Protection (LTOP) Compensatory Actions

a. Inspection Scope (37551, 61726)

The inspectors reviewed the implementation of the licensee's LTOP commitments contained in letter 3F0497-05 dated April 7, 1997.

b. Observations and Findings

In a letter dated February 4, 1997, the staff requested the licensee accelerate their planned schedule and submit a proposed LTOP Technical Specification (TS) within 60 days due to the extended plant shutdown and current applicability of LTOP actions. The licensee's current LTOP requirements are only administrative controls. The licensee responded in the April 7 letter and committed to submit a TS change request by September 18, 1997. The licensee also committed to restrict RCS pressure administratively to a maximum of 100 psig and revise the pressurizer PORV setpoint by May 23, 1997. These actions were considered acceptable by the staff. The inspector verified the licensee issued Short Term Instruction 97-011 on April 5, 1997, to limit pressure to 100 psig. The inspector verified RCS pressure was maintained below this limit and that operators were aware of the reason for the requirement and its source. The inspector also noted this commitment prevents a reactor coolant pump start and therefore a plant startup so the TS will need to be resolved prior to these occurring. The inspector also verified the licensee performed Surveillance Procedure 132, Engineered Safeguards Channel Calibration, Revision 35, on May 23 to lower the PORV low setpoint to 454 psig. In letter 3F0697-23 dated June 6, 1997, the licensee confirmed to the staff that they had met their commitments and revised their commitment to submit a TS change from September 18 to July 16, 1997. The licensee will base the change on 15 Effective Full Power Year (EFPY) pressure-temperature curves and will work on a long term solution based on 32 EFPY curves.

c. Conclusions

The licensee was implementing appropriate LTOP restrictions and was developing a permanent solution via a TS change

E1.3 NRC Generic Letter 96-01, Testing of Safety-Related Logic Circuits

a. Inspection Scope (37550)

Generic Letter 96-01, issued January 10, 1996, requested that all operating nuclear power reactors take the following actions to address problems with testing of safety-related logic circuits:

- Compare electrical schematic drawings and logic diagrams for the reactor protection system, EDG load shedding and sequencing, and actuation logic for the engineered safety features systems against plant surveillance test procedures to ensure that all portions of the logic circuitry, including the parallel logic, interlocks, bypasses and inhibit circuits, are adequately covered in the surveillance procedures to fulfill the TS requirements. This review should also include relay contacts, control switches, and other relevant electrical components within theses systems, utilized in the logic circuits performing a safety function.

- Modify the surveillance procedures as necessary for complete testing to comply with technical specifications.

The initial GL 96-01 inspection was conducted March 17-21, 1997, and documented in NRC Inspection Report 50-302/97-01. During this inspection, the inspectors continued to examine the licensee's actions relative to the testing of TS safety-related logic circuits described in GL 96-01.

b. Observations and Findings

The inspector verified that all the initial offsite work had been completed in a satisfactory manner, and all the initial "GL 96-01 Review XXXX System Functional Boundary Documents" had been submitted for review and validation. In addition, all initial review and validation had been completed in a satisfactory manner by the onsite engineer except for the Reactor Protection System review which was in progress. Not all work was completed and there were eight open items identified on PCs. The open PCs need to be resolved and corrective action implemented where required. These open PCs were PC 97-0054, PC 97-0057, PC 97-1516, PC 97-2036, PC 97-2677, PC 97-2797, PC 97-2798, and PC 97-3413.

The following items for the GL 96-01 program had not been completed at the time of this inspection:

- Reactor Protection System review and validation by the licensee.
- Licensee closure of the eight open PCs identified above.
- Submittal of the final GL 96-01 Report by the contractor.
- Final review, approval, and closure by the licensee of all GL 96-01 documents.

c. Conclusions

The inspector concluded that the licensee was in the process of implementing an effective program to meet the intent of GL 96-01. The onsite contract engineer has been effective in reviewing, validating, and identifying deficiencies. The GL 96-01 program had not been completed at this time. The inspectors assessed the licensee's performance, with respect to the licensee's response to GL 96-01, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - N/A

E1.4 DC System Failure Modes & Effects Analysis (FMEA)

a. Inspection Scope (37550)

The licensee's letter, 3F1096-22, dated October 28, 1996, discussed Crystal River Unit 3's forced outage and other safety concerns. Several of the concerns or issues identified by the licensee were failure modes of safety systems. In this letter, the licensee stated the letter's purpose was to inform the NRC of the plans to address these issues prior to restarting the plant. There were eight concerns (issues) identified. Concern 7, Failure Modes and Effects Analysis of Loss of DC Power was one the issues. The licensee stated that DC Power FMEA, including evaluation of system interactions, would be performed.

The licensee initiated an engineering project that addressed the DC Power FMEA. The scope of the project was to perform a FMEA for a specific accident scenario of LOCA/LOOP/Loss of DC safety-related power. The FMEA included a detailed systems interaction evaluation to understand the impact that equipment/component failures would have on redundant safety systems. The scope of the DC Power FMEA included the 22 systems that were powered from the safety-related Class 1E 125/250VDC system. Also included was the 120VAC Vital Bus powered from the Class 1E inverters.

The DC Power FMEA project was managed by a licensee engineering manager. The licensee's architect/engineer (AE) was contracted to perform the detailed FMEA. A different independent engineering firm was contracted to perform a third party review of the methodology and results of the AE's work. In addition, a third major firm was contracted to support both of the other contractors as needed. Guidelines in Institute of Electrical and Electronic Engineers (IEEE) Standard 352-1987 were used for the FMEA. The inspectors reviewed the licensee's FMEA program and documentation to determine if the licensee's plans in Letter 3F1096-22 and the guidelines in IEEE Standard 352-1987 were implemented in a satisfactory manner.

b. Observations and Findings

The inspectors reviewed the procedure, Class 1E DC Power Distribution System Failure Modes and Effects Analysis Methodology Document (FMEA Document), Revision 1, dated December 24, 1996, and verified that it was adequate to provide requirements for the DC Power FMEA program. The FMEA Document addressed the scope, boundaries, design inputs, technical approach, electrical review guidelines, list of systems, documentation required, and acceptance criteria.

The documentation and review required for each of the 22 systems from the contractors included; 1) initial FMEA review by the AE, 2) initial third party review by a different engineering firm, 3) AE response to third party review comments, 4) third party accepts AE's resolution, 5) 1 through 4 sent to the licensee for review and comments, and 6) final report issued. The inspector reviewed and verified that the documentation for 1) through 5) was completed in a satisfactory manner. In addition, the inspector reviewed all the electrical drawings (Elementary Diagrams) for the Reactor Building Spray System, 208-009; Reactor Coolant System, 208-047; and the Feedwater System, 208-032 and verified that all Class 1E DC components were included in the system FMEA. The inspector verified that all third party comments were satisfactorily resolved. However, not all work had been completed and eleven open items on PCs remain to be addressed. The eleven open PCs were PC 97-238, PC 97-294, PC 97-487, PC 97-491, PC 97-492, PC 97-1351, PC 97-1353, PC 97 1870, PC 97-1871, PC 97-2468, and PC 97-2485.

The following open items for the DC Power FMEA had not been completed at the time of this inspection:

- The Class 1E 120VAC Vital Bus FMEA had not been completed.
- Closure of the eleven open PCs identified above.
- Final submittal by the AE.
- Final review, approval, and closure by the licensee of all DC Power FMEA reports.

c. Conclusions

The inspectors concluded that the licensee was in the process of implementing an effective DC Power FMEA program. The contractor implementing the FMEA and the contractor reviewing the FMEA had identified and resolved concerns in the Class 1E DC Power system in a satisfactory manner. The FMEA had not been completed at this time. The inspectors assessed the licensee's performance, with respect to this DC Power FMEA program, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Adequate
- Operator Performance - N/A

E8 Miscellaneous Engineering Issues

E8.1 (Open) URI 95-02-02, Control Room Habitability Envelope Leakage

a. Inspection Scope (92903)

The inspectors reviewed an engineering design basis (reportability) evaluation of an issue described in PC 97-2026, Design Basis Concern Relative to Control Room Habitability Dampers.

b. Observations and Findings

The licensee had written PC 97-2026 on April 11, 1997, in response to an NRC inspector's concern. The PC stated: "Differential pressures assumed by FPC across habitability boundary dampers have recently been questioned by a Region II NRC inspector. These assumptions, if found to be in error, may affect conclusions reached in the following FPC calculations and documents previously provided to the NRC: I86-0003, Rev. 8; I92-0011, Rev. 1; 3F0687-16, dated 6/30/87; and 3F0588-10, dated 5/23/88. The NRC has observed that different pressure values are used to calculate in/out leakage through the supply and exhaust dampers which are only a few feet apart in the same duct. The concern is that 0.7" w.g. of positive pressure (as assumed at AHD-2) may exist at AHD-1 instead of 1.0" w.g. negative pressure as assumed. This could result in a greater value for unfiltered inleakage than is presently assumed and may impact operator dose analyses."

The PC recommended that engineering evaluate the validity of the design assumptions in the calculations in question. A note on the PC stated that the NSM requested that, on completion of the engineering design basis evaluation, the results be reviewed for operability and reportability.

The inspectors reviewed the engineering evaluation response to the PC. The evaluation was dated May 6, 1997; had been approved by an engineering supervisor; and had gone through the Precursor Card Screening Committee. However, the inspectors noted that the evaluation contained several deficiencies.

- The engineering evaluation incorrectly stated that Calculation I92-0011, Rev. 1, calculated control room ventilation system pressure at damper AHD-1 to be 0.11 inches w.g. positive. However, the value in the calculation was actually 0.11 inches w.g. negative.

- The engineering evaluation incorrectly stated that the assumed value in the calculation of 1.0 inches w.g. negative (in place of the 0.11 inches) at damper AHD-1 was conservative and did not lead to any nonconservative errors in the control room dose rate calculation. The inspectors noted that the assumption of a more negative value for the pressure at damper AHD-1 resulted in higher calculated inleakage through AHD-1, higher filtered leakage, lower unfiltered leakage in the control room dose rate calculation, and lower calculated dose to the operators. The assumption of a more negative value for ventilation system pressure at damper AHD-1 was therefore actually nonconservative. In addition, the inspectors noted that the calculation for pressure at AHD-1 was incorrect in that it failed to include a baffle plate that had been installed in the ventilation duct, at the cooling coils, to prevent moisture carryover and wetting of the control room ceiling. The inspectors noted that inclusion of this baffle in the calculation would likely result in a positive value for the pressure at AHD-1 and a substantial increase in calculated operator dose.

- The engineering evaluation incorrectly stated that FPC has met the intent of the commitment to the NRC that the Control Room recirculation air mode system shall be single-failure proof or have compensatory actions proceduralized. The evaluation stated that the system was not single-failure proof, but that compensatory measures were provided in EOP-3, AP-513, and AP-250. Those actions were that operators were required to verify that the dampers were closed. In the event that one was not closed, operators would contact the technical support center (TSC) for assistance per EM-102. The evaluation further stated that the dampers could be accessed and closed by personnel staffing the TSC. The inspector noted that contacting the TSC for assistance does not constitute having compensatory actions proceduralized. Also, it could take the licensee up to one hour to man the TSC during an event. The inspector noted that the licensee had no instructions or equipment (i.e., ladders, tools) staged for repairing dampers or otherwise sealing the leakage paths. The inspector further noted that existing procedures for toxic gas directed operators to don self-contained breathing apparatus (SCBAs) and to stop the control room ventilation return fan, AHF-19, to reduce the inleakage of air in the event that any of the control room isolation dampers did not close. However, the procedures for an engineered safeguards (ES) or high radiation actuation of the control room emergency ventilation system gave no similar guidance to operators. A licensed operator who was interviewed stated that he would not want to don SCBAs because they would interfere with performing the EOPs, but stopping AHF-19 might be a good action to take.

- The engineering evaluation incorrectly stated that the issue was not reportable because the control complex habitability envelope (CCHE) does not represent a "principal safety barrier," and a damper failure which creates a breach in the envelope does not represent a condition which "alone could have prevented the fulfillment of a safety function." The inspector noted that the licensee in the past has recognized that breaches of the CCHE, including damper failures, can result in being outside the design basis of the plant and being in a condition prohibited by the TS. Such conditions have in the past been reported by the licensee.

The inspectors discussed these issues with a group of engineering and licensing personnel, who then stated that they better understood the inspectors' concerns and would redo the analysis.

c. Conclusions

The inspectors concluded that the licensee's engineering design basis (reportability) evaluation of PC 97-2026, Design Basis Concern Relative to Control Room Habitability Dampers, was of very poor quality. It included incorrect statements related to engineering calculations, shallow and improper analyses, incorrect interpretations of NRC requirements, and incorrect conclusions.

The inspectors assessed the licensee's performance, relative to this engineering design basis (reportability) evaluation, in the five areas of continuing NRC concern:

- Management Oversight - Inadequate
- Engineering Effectiveness - Inadequate
- Knowledge of the Design Basis - Inadequate
- Compliance with Regulations - Inadequate
- Operator Performance - N/A

E8.2 (Closed) EA 95-126, VIO I.D.2: Swapover of ECCS Pumps' Suction from BWST (at five feet) to Reactor Building Sump Was Inadequate

a. Inspection Scope (92903)

This violation involved an inadequate engineering evaluation of an EOP step. That EOP step directed operators to swap over manually the emergency core cooling system (ECCS) pumps' suction from the borated water storage tank (BWST) to the reactor building sump at a BWST level of five feet. However, a BWST level of five feet was insufficient to ensure that all of the ECCS pumps would not be damaged by air entrainment from vortexing in the BWST. Also, the licensee had no official design calculation to support the swap over level of five feet. An internal engineering memorandum was inappropriately used to support the swap over level of five feet.

b. Observations and Findings

The inspectors reviewed the licensee's response to this violation, interviewed licensee engineering and operations personnel, and reviewed the following procedures:

- EOP-07, Inadequate Core Cooling, Rev. 3, dated August 30, 1996;
- EOP-08, LOCA Cooldown, Rev. 4, dated August 30, 1996;
- AI-400F, New Procedures and Procedure Change Processes for EOPs, APs, and VPs, Rev. 1, dated August 30, 1996;
- AI-300, Plant Review Committee Charter, Rev. 40, dated March 27, 1997;
- CP-213, Preparation of a Safety Assessment and Unreviewed Safety Question Determination (10 CFR 50.59 Safety Evaluation), Rev. 1, dated April 4, 1997; and
- NL-08, Control of Crystal River Unit 3 FSAR, Rev. 6, dated September 17, 1996

The inspectors verified that the licensee had established a focussed EOP group in 1995, headed by a former design engineering manager who had received a senior reactor operator's license and that group was still intact. The inspectors also verified that the process for writing and revising EOPs had been revised to require system engineering and design engineering reviews. The new EOP revision process also proceduralized requirements for validation of EOP changes assuring correct technical criteria and human factors are included. Also, the procedure change screening process included a review of the FSAR for applicability to 10 CFR 50.59 safety evaluations.

In addition, the inspectors verified that EOP-07 and EOP-08 had been revised to include a higher swapover point from BWST suction to reactor building sump (at 15 feet in the BWST), and that swapover level was appropriately supported by engineering calculations. Also, the licensee had completed a review of the FSAR, in February 1997, to ensure that FSAR information was correctly incorporated into plant procedures. Further, the licensee had undertaken an EOP Enhancement Plan with a scheduled completion of November 21, 1997; prior to the restart from the current outage.

c. Conclusions

The inspectors concluded that the licensee's corrective actions had been implemented, included actions to prevent recurrence of the violation, and were effective improvements. EA 95-126, VIO I.D.2 is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

E8.3 (Closed) EA 95-126, VIO II.A: EOPs Allowed Single LPI Pump to Supply Two HPI Pumps, With Insufficient NPSH For LPI Pump

a. Inspection Scope (92903)

This violation involved an inadequate engineering evaluation of an EOP step. That EOP step directed operators, under certain circumstances during post loss-of-coolant-accident operation, to align one low pressure injection (LPI) pump to take suction from the reactor building sump and discharge to two high pressure (HPI) pumps. However, this alignment would have resulted in inadequate NPSH for the LPI pump.

b. Observations and Findings

The licensee's corrective actions were essentially the same as for EA 95-126, VIO I.D.2. In addition, the inspectors verified that EOP-07 and EOP-08 had been revised to preclude operation of two HPI pumps supplied from a single LPI pump.

c. Conclusions

The inspectors concluded that the licensee's corrective actions had been implemented, included actions to prevent recurrence of the violation, and were effective improvements. EA 95-126, VIO II.A is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

..4 (Closed) EA 95-126, VIO I.C.1: Failure to Take Adequate Corrective Actions for Operator Concerns Regarding OP-103B, Curve 8, for Makeup Tank Pressure/Level Limits

a. Inspection Scope (92903)

This violation involved inadequate corrective action for a Problem Report where operators identified a concern with the accuracy of OP-103B, Curve 8. Curve 8 was the makeup tank overpressure limit curve. The licensee's engineering review of the operators' concern failed to identify promptly the significant errors that were present in Curve 8 and in the calculations that were the basis for the curve. As a result, plant operations using the curve were frequently outside the design basis of the facility. The inspectors followed up on the licensee's corrective actions for this violation.

b. Observations and Findings

The inspectors reviewed the licensee's response to this violation, interviewed licensee engineering and operations personnel, and reviewed the following procedures:

- AI-1700, Conduct of Nuclear Engineering and Projects, Rev. 0, dated December 9, 1996;

- NEP-213, Design Analysis/Calculations, Rev. 9, dated June 26, 1996;

- Nuclear Operations Engineering Standard OES-1: Design Review Board Expectations, Policies, and Practices; Rev. 1, dated March 11, 1997;

- OI-9, Operations Procedures, Rev. 0, dated December 13, 1995; and

- QAP-27, Tracking/Trending System, Rev. 14, dated May 30, 1997.

The inspectors verified that the licensee had improved process controls for interdepartmental and interdisciplinary interfaces. The process used by design engineers to produce calculations had been revised to require joint reviews with operations and system engineering personnel. Also, independent third party review of selected design calculations was being performed. The inspectors reviewed the third party review of two modifications and related calculations. These third party reviews had identified no significant errors in the calculations but did include some interesting comments.

The inspectors also verified that the licensee had strengthened management oversight of design activities, including enhanced processes and personnel changes. The licensee had implemented and continued to use a management single point of contact (issue manager) for important technical issues. Also, the licensee had implemented an interdisciplinary Design Engineering Review Board (DERB) to review design work for technical accuracy and adherence to requirements. The DERB was reviewing approximately 90% of all safety-related modifications being installed during the current outage, including all complex or multi-disciplinary modifications. In addition, the licensee established an Engineering Programs Group to focus on longer duration technical issues.

In addition, the inspectors verified that the licensee had strengthened expectations for engineering and operations personnel. Personnel involved in the violation had been counselled. Also, expectations had been communicated to all engineering personnel in "all hands" meetings and to supervisory personnel under joint signature of the engineering director and plant manager. An engineering representative was attending the operations morning turnover meeting to promote increased attention to operations' issues by engineering management. Both Design Engineering and Systems Engineering had required reading books that contained many pertinent pieces of information, such as guidance on 10 CFR 50.59 evaluations. The engineering Event-Free Operations Program no longer tracked performance trends and human errors; however, the Quality Programs group planned to begin trending Precursor Cards and had addressed that in procedure QAP-27, Tracking/Trending System, Rev. 14, dated May 30, 1997.

The inspectors also verified that operators had participated in seminars with the operations manager, during requalification training at the Training Center, regarding communication strategies and methods to prevent "cockpit isolation." Also, these philosophies had been proceduralized in operations instructions.

c. Conclusions

The inspectors concluded that the licensee's corrective actions had been implemented, included actions to prevent recurrence of the violation, and were effective improvements. EA 95-126, VIO I.C.1 is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

E8.5 (Closed) URI 96-01-02: Discrepancies in the High Pressure Injection System that do not Meet Design Basis Analysis

a. Inspection Scope (92903)

This unresolved item was opened for further review of two issues that had been addressed in Problem Report 96-035, EOP Project Review Uncovers Discrepancy in FSAR Single Failure Analysis. The two issues were:

1) Testing the HPI automatic actuation system matrix. The concern was that relays 3MUV-23x (AY), 3MUV-24X (AZ), 3MUV-25X (Z) and 3MUV-26X (AA) were not being tested bimonthly as part of the HPI automatic actuation system logic, as required by ITS 3.3.7.

2) Loss of ES signal to the respective side HPI valves. The concern was that, on loss of a vital battery, the ES signal to the respective side HPI valves would be lost as well as the power to the valve operators, and this was not considered in the FSAR.

b. Observations and Findings

The inspectors reviewed Problem Report 96-035, the licensee's response to the PR, including a root cause evaluation, related TS, LER 96-007-01, HPI Line Break with Loss of Battery Could Result in Operator Reliance on Instrumentation Inadequate for Accident, Drawing B-208-041, Sheets MU-19 through 22, showing the HPI automatic actuation system matrix, and Surveillance Procedure SP-457, Refueling Interval ECCS Response to a Safety Injection Test Signal.

The licensee concluded that Relays 3MUV-23x (AY), 3MUV-24X (AZ), 3MUV-25X (Z) and 3MUV-26X (AA) were not part of the HPI automatic actuation system logic, but instead were part of the end devices (HPI injection valves). Therefore, bimonthly testing per ITS 3.3.7 was not required. The relays were tested in SP-447 and SP-457A on a refueling interval, as required. The inspectors verified the licensee's analysis and concurred with the licensee's conclusion.

The licensee concluded that, on loss of a vital battery, the ES signal to the respective side HPI valves would be lost as well as the power to the valve operators. However, this design was correct. By procedure, on loss of a vital battery, operators are directed to switch power to the valve control logic, which allows them to control the HPI injection valves manually, to obtain power from the other train. The inspectors verified the licensee's analysis and concurred with the licensee's conclusion.

c. Conclusions

The inspectors concluded that the licensee's analyses and conclusions in resolving the questions addressed by this URI were good. URI 96-01-02 is closed.

The inspectors assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - Good
- Knowledge of the Design Basis - Good
- Compliance with Regulations - Good
- Operator Performance - Good

E8.6 (Open) EA 96-365, EA 96-465, EA 96-527, VIO A.5 (01052), USQ Involving a Decrease in the Reliability and an Increase in the Probability of Failure of EFP-2

a. Inspection Scope (92903)

This violation involved the licensee's implementation of a modification which removed the automatic open signal from valve ASV-204, which was one of the automatic steam supplies to the turbine driven emergency feedwater pump (EFP-2). The modification resulted in an unreviewed safety question (USQ) due to a decrease in the reliability and an increase in the probability of failure of EFP-2. The inspectors followed up on the licensee's corrective actions specified in their response to this VIO dated April 11, 1997.

b. Observations and Findings

The resolution of this item was being tracked under licensee restart item R-4-A. The licensee established the Safety Analysis Group to perform independent reviews. These reviews also included 10 CFR 50.59 safety evaluations. The licensee had issued a revision to Compliance Procedure CP-213, Preparation of a Safety Assessment and Unreviewed Safety Question Determination (10 CFR 50.59 Safety Evaluation). This revision to the procedure became effective April 4, 1997, and was the controlling procedure for the licensee's 50.59 safety evaluation process. The procedure was being used by all organizational units at Crystal River Unit 3 (CR-3). Training on Procedure CP-213 had been provided to members of the Safety Assessment Group and other engineering and plant personnel.

The licensee had prepared modification approval record (MAR) 96-11-01-01 to re-install the automatic open signal to Valve ASV-204. This MAR had not been implemented at the time of this inspection, but was scheduled to be implemented in late June 1997.

The NRC will assess the adequacy of Procedure CP-213, the effectiveness of the corrective actions, and the quality of recently completed 50.59 safety evaluations during an upcoming inspection of the licensee's 50.59 safety evaluation and USQ determination process.

c. <u>Conclusion</u>

The inspector concluded that the licensee had completed some of the corrective actions specified in the VIO response for this item. The adequacy and effectiveness of the corrective actions will be reviewed further during an upcoming NRC inspection of the licensee's 50.59 safety evaluation process.

The inspectors assessed the licensee's performance, relative to the corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.7 <u>(Open) EA 96-365, EA 96-465, EA 96-527, VIO B (Example 1) (02013), Failure to Update Applicable Design Documents to Incorporate Design Information</u>

a. <u>Inspection Scope (37550, 92903)</u>

This violation involved the licensee's failure to update the Final Safety Analysis Report (FSAR), the Enhanced Design Basis Document (EDBD), and the Improved Technical Specifications (ITS) Bases with regard to operation of EFP-2 for certain accident scenarios. The inspector followed up on the licensee's corrective actions by reviewing procedure changes, training records, internal licensee correspondence, and interviewing engineering personnel.

b. <u>Observations and Findings</u>

The inspector noted that some of the corrective actions being implemented to address this VIO were being tracked under licensee restart items OP-6 and OP-7. The inspector reviewed some of the actions addressed under restart item OP-6. These corrective actions included changes to the following Nuclear Engineering Procedures (NEPs):

- NEP-104, Interface Design Control
- NEP-210, Modification Approval Record
- NEP-211, Commercial Grade Design Control
- NEP-212, Processing of Modification Projects by Nuclear Projects
- NEP-213, Design Analysis/Calculations
- NEP-222, Qualification for Equipment in the Scope of 10 CFR 50.49
- NEP-224, Emergency Diesel Generator Load Calculations
- NEP-234, Station Blackout
- NEP-253, Preparation and Control of a Document Change Notice
- NEP-254, Plant Equipment Equivalency Replacement Evaluation
- NEP-261, Design Verification

Changes to the above procedures included, but were not limited to, the incorporation of Procedure CP-213 requirements, additional guidance regarding design inputs, and guidance regarding prompt revision to design basis documents following implementation of a plant modification. The inspector noted that changes to additional engineering procedures and plant administrative procedures had not been completed at the time of this inspection. In addition, training of engineering personnel on the changes to the various NEPs had not been completed. Since some of the modifications had been implemented, the applicable design basis documents had not been updated. Licensee completion of the remaining corrective actions will be reviewed during a subsequent NRC inspection.

c. Conclusions

The inspector concluded that all of the licensee's corrective actions for this violation had not been completed at the time of this inspection. This item remains open and will be reviewed further during subsequent NRC inspections.

The inspector assessed the licensee's performance, relative to corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

E8.8 <u>(Open) EA 96-365, EA 96-465, EA 96-527, VIO B (Example 2) (02013), Failure to Include Applicable Design Information in the Design Input Requirements for a Modification</u>

a. <u>Inspection Scope (92903)</u>

This violation involved a failure to include design basis information in the design input requirements for the MAR which disabled the automatic opening of Valve ASV-204. The inspector followed up on the licensee's corrective actions by reviewing procedure changes, training records, internal licensee correspondence, and interviewing engineering personnel.

b. <u>Observations and Findings</u>

The inspector noted that some of the corrective actions being implemented to address this VIO were being tracked under licensee restart items OP-6 and OP-7. The inspector reviewed some of the actions which included the actions discussed in paragraph E8.Y of this report. In addition to the programmatic changes made, the licensee had also prepared MAR 96-11-01-01 to re-install the automatic open signal to valve ASV-204. This MAR had not been implemented at the time of this inspection, but was scheduled to be implemented in late June 1997. Also, applicable design basis documents had not been updated because all of the modifications had not been implemented. The inspector further noted that all of the training related to the corrective actions for this violation had not been completed. Licensee completion of the remaining corrective actions will be reviewed during a subsequent NRC inspection.

c. <u>Conclusions</u>

The inspector concluded that all of the licensee's corrective actions for this violation had not been completed at the time of this inspection. This item remains open and will be reviewed further during subsequent NRC inspections.

The inspector assessed the licensee's performance, relative to the corrective actions for this violation, in the five areas of continuing NRC concern:

- Management Oversight - Good
- Engineering Effectiveness - N/A
- Knowledge of the Design Basis - N/A
- Compliance with Regulations - Good
- Operator Performance - N/A

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiation Protection Issues

a. Inspection Scope (92904)

The inspectors reviewed a number of issues involving radiation protection issues identified recently by the licensee.

b. Observations and Findings

On April 11, 1997, the Manager of Radiation Protection issued a memorandum to all licensee personnel stating that three events had occurred when personnel entered the radiation control area (RCA) without dosimetry or without being signed onto a Radiation Work Permit (RWP). The memorandum also discussed an event in which evidence was identified of personnel consuming food and beverage inside the RCA. This memorandum stated management expectations for workers when working in the RCA and outlined potential disciplinary actions that would be taken for personnel failing to meet these expectations.

During the next several months, more examples of licensee employees failing to adhere to either the licensee procedures or the management expectations were identified. During the inspection period, five individuals entered the RCA without properly activating their electronic alarming dosimeter (EAD), or else leaving the EAD in the reader at the entry point when logging in. One of these workers entered a posted high radiation area, contrary to procedural requirements for entering those areas. One worker was observed entering the RCA area at the exit point to perform cleaning, without logging onto a RWP. One person was observed exiting and entering the RCA, by crossing the rope barriers, on the berm. Several instances occurred where individuals exited dress out areas and left their EADs at the step off pads.

The licensee performed a review of these events and determined that the culpable personnel were not contract outage personnel, as they had surmised, but were primarily experienced, permanent plant personnel for the most part. A Health Physics Self-Assessment done by the licensee during this report period as discussed in Section R7.1, discusses some of these issues as being symptomatic of bad radiation work habits, complacency, and poor communications of expectations by management.

On May 29, 1997, the manager of Radiation Protection issued a memorandum addressed to all managers and directors. In this memorandum, the statement was made that unescorted access to the RCA is granted based upon being a qualified radiation worker. The licensee stated that whenever an individual fails to adequately perform as a radiation worker, their qualifications for unescorted access is brought into question. As a result, when a radiation worker violates procedural requirements, the licensee will remove the person's thermoluminescent dosimetry (TLD) and suspend access to the RCA. The memorandum provided a list of actions that would result in permanent RCA denial. The majority of these actions involve willful disregard of requirements; however, one of the criterion was repetitive failure by an individual to follow radiological practices. The manager of radiation protection made the statement in the memorandum that no remediation for RCA access would be allowed for individuals meeting the above criterion.

The May 29, 1997, memorandum also discussed types of actions that would result in temporary RCA access denial; these included: failure to log into the access control system properly, failure to have required dosimetry in the RCA, violation of RWPs, failure to control a locked high radiation barrier, violation of radiological postings, and improper radiological work practices. The minimum requirements for an individual to regain RCA access were also outlined. The memorandum also stated that additional disciplinary measures would be imposed by station management, depending upon the severity of the event and the individuals total work record.

The licensee required that all station personnel be trained on this policy. The inspectors verified that this training has been accomplished.

Licensee Procedure, RSP-101, Basic Radiological Safety Informati‑n and Instructions for Radiation Workers, Revision 23, provided basic requirements for radiation workers. Step 3.4.2, Limits and Precautions, required that any entry into a RCA be authorized via an RWP. Step 3.4.13, Entrance to a High Radiation Area, stated that any entry to a high radiation area would be controlled by issuance of a RWP and that any personnel entering a high radiation area would have radiation dose monitoring, such as a radiation monitoring device, which continuously indicated the radiation dose rate in the area, an integrating alarm dosimeter (IAD), which alarmed when a preset integrated dose or dose rate was received, or a qualified Health Physics technician with a radiation dose rate monitoring device. These identified issues were examples of failure to follow Procedure RSP-101. However, the licensee has taken corrective measures to prevent recurrence, including establishing and documenting expectations for radiation workers and training all personnel in these expectations. Consistent with Section VII.B.1 of the NRC Enforcement Policy, this licensee-identified and corrected violation was treated as a Non-Cited Violation, NCV 50-302/97-07-05, Failure to Follow Procedure for Access to a Radiation Control Area.

c. Conclusions

A degradation in radiation workers adherence to good radiation work practices and adherence to the applicable procedures was noted. The licensee identified this trend and took strong corrective actions to address the issue; these actions included developing and documenting management's expectations for radiation workers and assuring that all personnel were trained on the expectations and aware of the consequences for failure to meet these expectations.

R7 Quality Assurance in RP&C Activities

R7.1 Health Physics Self-Assessment (CRSA 97-03)

a. Inspection Scope (71750)

The inspector reviewed the licensee's self-assessment in the area of health physics and RCA access control program.

b. Observations and Findings

The licensee's self-assessment included reviews of industry experience, precursor card, field observations and interviews, and a third party verification of the radiation work permit program. As a result of the self-assessment, thirteen PCs were issued. Four of these were to document identified strengths. The inspectors reviewed the strengths identified in the self-assessment and concluded that characterizing several of these findings as strengths and issuing PCs to document them may have been inappropriate. The fact that personnel were aware that when questions exist on the meaning of an RWP, they were to discuss the subject with health physics technicians, was an appropriate response, but not necessarily a matter to be distinguished as a strength.

The licensee noted weaknesses in general work practices, specifically, frisking problems and dress out problems. These weaknesses were noted throughout the plant employee population. The self-assessment concluded that these acts were symptomatic of bad radiation work habits, complacency, and poor communications of expectations. The assessors noted that health physics technicians were also noted performing some of these practices and that it would be unrealistic to expect the radiation worker perform to a higher standard than the health physics organization.

c. Conclusions

The inspectors reviewed the self-assessment report and concluded that while some of the strengths identified seemed inappropriately classified, the observations and identified weaknesses were timely and self critical.

S1 Conduct of Security and Safeguards Activities

S1.1 Loss of Protected Area Alarm Zones (71750)

On May 30, 1997, work on the perimeter intrusion detection system was being conducted by maintenance technicians. The security operator disabled the affected security zone alarms and a guard was posted per procedure to allow the maintenance to be performed. However, the security operator failed to reenable the zone when the technician and guard informed him that the work was complete. Consequently, the zone did not have alarm capability and was not properly compensated for approximately two hours until it was discovered and reenabled by a subsequent operator. The licensee determined the event was reportable to the NRC per 10 CFR 73.71, made a one hour phone report, and was developing written Licensee Event Report (LER) 97-S02. The inspectors will evaluate the adequacy of licensee's actions during their review of the LER.

S2 Status of Security Facilities and Equipment

S2.1 Temporary Loss of Power to Central Alarm Station Equipment and Subsequent Replacement of an Uninterruptible Power Supply Unit

a. Inspection Scope (71750)

The inspector reviewed the licensee's resolution of problems previously documented in NRC Inspection Report (IR) 50-302/97-05. The inspector reviewed security logs, Security Information Reports, precursor cards, a problem report, and procedure PM-134, Testing of Security Systems Alternate Power Sources, Revision 13. The inspectors attended meetings that discussed actions to replace an uninterruptible power supply (UPS) unit in the central alarm station (CAS). The inspectors also observed activities during the replacement of the UPS unit.

b. Observations and Findings

A problem report (PR 96-0270) and precursor card (PC 96-3573) written by security in July 1996 documented a problem during a routine transfer of primary power to alternate power on the "C" inverter (VBIT-1C). This transfer caused degradation of security camera coverage on eight cameras covering the protected area intrusion detection system. The PR stated that, historically, when the "C" vital bus was transferred from VBIT-1C to VBTR-4C (vital bus transformer) and back, there had been "minor problems" noted by security. These minor problems were related to degradation of the picture quality on the security television monitors.

No apparent cause was determined for the vital bus transfer problem; nevertheless, a corrective action plan was developed. The corrective actions were to monitor the equipment during the next scheduled transfer, analyze the data collected during the next transfer, develop an action plan to resolve any abnormalities identified from the collected data, and inform security personnel to notify Operations as soon as possible after a similar type problem was identified. By September 1996, two of the four corrective actions had been completed. These were: informing security personnel to notify Operations and connecting equipment to the vital bus for monitoring.

On January 22, 1997, a transfer of primary power to alternate power on the "C" inverter (VBIT-1C) was performed. This transfer caused degradation of security camera coverage and required intensive posting of security officers, similar to the July 30, 1996, event. PC 97-0618 was written by security documenting this event and was assigned to the Operations Department with a grade level "D". The power transfer was done to troubleshoot a problem with VBIT-1C. A blown fuse was identified as the root cause for the problem and replaced. When Operations transferred power back to the primary source (VBIT-1C), security camera picture quality was restored (self-corrected). However, for three days, security was required to post extra personnel in the areas affected by the poor picture quality. Although Operations initiated the transfer causing the camera degradation, the cause of the problem was not an Operations issue, and any subsequent investigation and corrective action should have been done by Maintenance or Engineering. However, as of May 30, PC 97-0618 was still open and still assigned to Operations. The inspector considered this to be poor assignment and implementation of corrective action. Operations initiated a transfer of PC 97-0618 to another department.

The next series of events occurred on April 17, 1997, and was related to a UPS unit in the CAS; however, the events began with a power transfer evolution. The power transfer evolution was a troubleshooting effort by electrical maintenance personnel to support the resolution of the security camera picture quality problem. The security camera picture quality problem was resolved, but a new problem was identified when an unexpected power loss to the CAS workstations and intelligent multiplexer (IMUX-2) occurred when power was transferred between the alternate and primary power sources (for additional details refer to NRC IR 50-302/97-05). Power was lost two more times that day as a result of operation of the UPS that was not understood by the CAS operators.

It was not until the inspector questioned several maintenance and security personnel that action was taken by security to attempt to understand and provide guidance to alarm station operators on the purpose and function of the CAS UPS unit and to prevent another similar loss of CAS and IMUX-2 power. On April 30, written instructions were provided, via a Security Information Report, to CAS operators on the frequency of monitoring the UPS indication lights and what to do when certain indicator lights were lit or flashing. Long term corrective actions were also being evaluated by Engineering.

On May 14 at 03:18 a.m., power was again unexpectedly lost to the CAS workstations and IMUX-2. After electricians discovered and replaced a blown fuse in the CAS 2 Distribution Panel, the CAS workstations and IMUX re-powered. At approximately 0800 hours, power was again unexpectedly lost to the CAS workstations and IMUX-2. From this time until the replacement of the CAS UPS on May 16, security was pre-posting personnel because it was determined that the UPS was tripping approximately every three hours and three minutes. Precursor Card 97-3312 was written by security documenting the event and was assigned to Engineering with a grade level "C". The apparent cause for this PC was due on June 4, 1997.

In December 1995, the secondary alarm station (SAS) had its UPS removed by Field Change Notice (FCN) 5, Security UPS#2 Removal, of MAR 88-03-04-

25, Security Upgrade - IMUX and Perimeter Installation. Battery swelling due to old age was identified as the root cause for this UPS failure, but an extent of condition was not considered for the UPS in the CAS. A preventive maintenance (PM) program for the CAS and SAS UPS units was not in place, nor was one considered for the CAS UPS once the SAS UPS battery swelling problem was identified.

The Engineering evaluation for the April 17 events determined that the CAS UPS could not handle the quickness of a power transfer (on the order of milliseconds) and therefore must either be removed or replaced. Engineering determined that replacement of the unit would be the best short term option. Another need for an expeditious solution was because the UPS unit was tripping every three hours and required security to post various locations throughout the plant and test several vital area doors and alarms each time power was temporarily lost to the CAS workstations and IMUX-2.

Plans to remove the UPS were pursued in parallel with plans for replacement. Three state-of-the-art UPS units were ordered with specifications that would assure these units would handle the power transfer. The reason three UPS units were ordered were in case Engineering determined that the SAS UPS units would need to be put back in. The CAS UPS was replaced and satisfactorily tested on May 16, 1997. Engineering is still evaluating whether to remove the CAS UPS or re-install the SAS UPS units.

c. Conclusions

The inspectors concluded that security failed to understand their equipment and elevate to the proper level their concern with the malfunctioning of their equipment. Also, engineering failed to consider the extent of condition when it was identified that the SAS UPS batteries had swollen due to old age. In addition, consideration was not given to establishing a PM program to maintain the UPS units adequately. These examples of inadequate corrective action are considered a violation of NRC requirements. The violation will be tracked as VIO 50-302/97-07-06, Inadequate Corrective Action For Use of an Uninterruptible Power Supply Unit in the Security Central Alarm Station.

S6 Security Organization and Administration

S6.1 Effective June 2, 1997, Fred Marcussen became the new Security Manager, reporting to Mark Marano, Director, Nuclear Site and Business Support. Dave Watson, who has been the Security Manager since October 1996, will remain in the Security organization in a senior staff position.

V. Management Meetings

X1 Exit Meeting Summary

The inspection scope and findings were summarized on May 9, May 23 and June 9, 1997. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

X3 Management Meeting Summary

X3.1 A meeting was held at the Region II office in Atlanta on May 8, 1997. The purpose of the meeting was Engineering - Extent of Condition requested by the NRC. A separate meeting summary was issued on May 15, 1997.

X3.2 A meeting was held at the Region II office in Atlanta on May 9, 1997. The purpose of the meeting was to discuss items related to restart. A separate meeting summary was issued on May 14, 1997.

PARTIAL LIST OF PERSONS CONTACTED

Licensees

R. Anderson, Senior Vice President, Nuclear Operations
J. Baumstark, Director, Quality Programs
J. Campbell, Assistant Plant Director, Maintenance and Radiation Protection
J. Cowan, Vice President, Nuclear Production
R. Davis, Assistant Plant Director, Operations and Chemistry
R. Grazio, Director, Nuclear Regulatory Affairs
G. Halnon, Assistant Plant Director, Nuclear Safety
B. Hickle, Director, Nuclear Plant Operations
J. Holden, Director, Nuclear Engineering and Projects
D. Kunsemiller, Manager, Nuclear Licensing
M. Marano, Director, Nuclear Site and Business Support
W. Pike, Manager, Nuclear Regulatory Assurance

NRC

J. Blake, Sr. Project Manager, Maintenance, Region II (May 19 through 23, 1997)
R. Caldwell, Resident Inspector, Farley (May 12 through 16, 1997)
P. Fillion, Reactor Inspector, Region II (May 5 through 9, 1997)
P. Harmon, Reactor Engineer, Region II (June 2 through 6, 1997)
G. Hopper, Reactor Engineer, Region II (June 2 through 6, 1997)
J. Hunter, Budget & Financial Analyst, Region II (May 15, 1997)
K. Landis, Branch Chief, Region II (May 5 through 6, 1997)
M. Miller, Reactor Inspector, Region II (May 5 through 9, May 19 through 23, June 2 through 6, 1997)
L. Raghavan, Project Manager, NRR (May 14 through 15, May 28, 1997)
R. Schin, Reactor Inspector, Region II (May 5 through 9, May 19 through 23, June 2 through 6, 1997)
P. Steiner, Reactor Engineer, Region II (June 2 through 4, 1997)

M. Thomas, Reactor Inspector, Region II (May 5 through 9, June 2 through 6, 1997)
R. Zimmerman, Associate Director, Projects, NRR (May 28, 1997)

INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems
IP 50002: Steam Generators
IP 61726: Surveillance Observations
IP 62700: Maintenance Implementation
IP 62707: Conduct of Maintenance
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73753: Inservice Inspection
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

Type	Item Number	Status	Description and Reference
VIO	50-302/97-07-01	Open	Failure to Follow Procedure CP-111 for the Processing of Precursor Cards. (paragraph O7.2)
VIO	50-302/97-07-02	Open	Inadequate Planning and Controlling of Hydrostatic Testing. (paragraph M1.1)
URI	50-302/97-07-03	Open	Reactor Building Liner Plate Degradation. (paragraph M2.1)
URI	50-302/97-07-04	Open	Unanalyzed Combustible Burden in Reactor Building HVAC Ductwork. (paragraph M2.1)
VIO	50-302/97-07-06	Open	Inadequate Corrective Action For Use of an Uninterruptible Power Supply Unit in the Security Central Alarm Station. (paragraph S2.1)

Closed

Type	Item Number	Status	Description and Reference
EA	95-126, VIO I.A	Closed	Nine Instances Where Operators Violated Procedures for Makeup Tank Pressure/Level Control. (paragraph O8.2)
EA	95-126, VIO I.B	Closed	Conduct of Unauthorized Tests of Makeup Tank Without 10 CFR 50.59 Evaluation. (paragraph O8.3)
EA	95-126, VIO I.D.2	Closed	Swapover of ECCS Pumps' Suction from BWST (at five feet) to Reactor Building Sump Was Inadequate. (paragraph E8.2)
EA	95-126, VIO II.A	Closed	EOPs Allowed Single LPI Pump to Supply Two HPI Pumps, With Insufficient NPSH For LPI Pump. (paragraph E8.3)
EA	95-126, VIO I.C.1	Closed	Failure to take adequate corrective actions for Operator concerns regarding OP-103B, Curve 8, for Makeup Tank Pressure/Level Limits. (paragraph E8.4)
URI	96-01-02	Closed	Discrepancies in the High Pressure Injection System that do not meet Design Basis Analysis. (paragraph E8.5)
NCV	50-302/97-07-05	Closed	Failure to Follow Procedure for Access to a Radiation Control Area. (paragraph R1.1)

Discussed

Type	Item Number	Status	Description and Reference
VIO	50-302/97-05-01	Open	Failure To Follow Equipment Tagging Control Procedural Requirements. (paragraph O1.2)
URI	50-302/95-02-02	Open	Control Room Habitability Envelope Leakage. (paragraph E8.1)

EA	96-365, 96-465, (01052)	Open	USQ Involving a Decrease in the Reliability and an Increase 96-527, VIO A.5 in the Probability of Failure of EFP-2 (paragraph E8.6)
EA	96-365, 96-465 96-527, VIO B Ex. 1 (02013)	Open	Failure to Update Applicable Design Documents to Incorporate Design Information (paragraph E8.7)
EA	96-365, 96-465 96-527, VIO B Ex. 2 (02013)	Open	Failure to Include Applicable Design Information in the Design Input Requirements for a Modification (paragraph E8.8)

LIST OF ACRONYMS USED

AC - Alternating Current
ACDP - AC Distribution Panel
ACE - Apparent Cause Evaluator
AE - Architect/Engineer
AI - Administrative Instruction
ANSS - Assistant Nuclear Shift Supervisor
AP - Abnormal Procedures
ASME - American Society of Mechanical Engineers
BWST - Borated Water Storage Tank
CARB - Corrective Action Review Board
CAS - Central Alarm Station
CCHE - Control Complex Habitability Envelope
CFR - Code of Federal Regulations
CNO - Chief Nuclear Operator
CP - Compliance Procedure
CREVS - Control Room Emergency Ventilation System
CR3 - Crystal River Unit 3
DBI - Design Basis Issue
DC - Decay Heat Closed Cycle Cooling
EA - Enforcement Action
EAD - Electronic Alarming Dosimeter
EC - Eddy Current
ECCS - Emergency Core Cooling System
ECO - Engineering Change Order
ECCS - Emergency Core Cooling System
EDBD - Enhanced Design Basis Document
EDG - Emergency Diesel Generator
EFP - Turbine Driven Emergency Feedwater Pump
EFW - Emergency Feedwater
EOP - Emergency Operating Procedure
ES - Engineered Safeguards
FCN - Field Change Notice
FMEA - Failure Modes and Effects Analysis
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
GL - Generic Letter

HPI - High Pressure Injection
HVAC - Heating Ventilation and Air Conditioning
IAD - Integrating Alarm Dosimeter
IEEE - Institute of Electrical and Electronic Engineers
IFI - Inspection Followup Item
IN - Information Notice
INPO - Institute for Nuclear Power Operations
IPAP - Integrated Performance Assessment Process
IR - Inspection Report
ISI - Inservice Inspection
IST - Inservice Test
JCO - Justification for Continued Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
LPI - Low Pressure Injection
LTOP - Low Temperature Overpressure Protection
MAR - Modification Approval Record
MP - Maintenance Procedure
MUT - Make-up Tank
NCV - Non-cited Violation
NEP - Nuclear Engineering Procedure
NGRC - Nuclear General Review Committee
NNI - Non Nuclear Instrumentation
NOE - Nuclear Operations Engineering
NOV - Notice of Violation
NQA - Nuclear Quality Assessments
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAT - Nuclear Safety Assessment Team
NSM - Nuclear Shift Manager
NSS - Nuclear Shift Supervisor
OCR - Operability Concerns Resolution
OI - Operating Instruction
OTSG - Once Through Steam Generator
PC - Precursor Card
PCSC - Precursor Card Screening Committee
PM - Preventive Maintenance
PORV - Power Operated Relief Valve
PR - Problem Report
PRC - Plant Review Committee
QA - Quality Assurance
QPD - Quality Programs Department
QPS - Quality Programs Surveillances
RB - Reactor Building
RCA - Radiologically Controlled Area
RCS - Reactor Coolant System
RCT - Root Cause Team
REA - Request for Engineering Assistance
RG - Regulatory Guide
RP&C - Radiological Protection and Chemistry
RWP - Radiation Work Permit

SAS	-	Secondary Alarm Station
SCBA	-	Self-Contained Breathing Apparatus
SDBI	-	Suspected Design Basis Issue
SER	-	Safety Evaluation Report
SP	-	Surveillance Procedure
SRO	-	Senior Reactor Operator
SRR	-	System Readiness Review
SSOD	-	Shift Supervisor on Duty
STAR	-	Stop, Think, Act, Review
TLD	-	Thermoluminescent Dosimetry
TP	-	Test Procedure
TS	-	Technical Specification
TSC	-	Technical Support Center
UPS	-	Uninterruptible Power Supply
URI	-	Unresolved Item
VIO	-	Violation
WD	-	Waste Disposal System
WGDT	-	Waste Gas Decay Tank
WGST	-	Waste Gas Surge Tank