U.S. NUCLEAR REGULATORY COMMISSION

REGION 2

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

Report No: 50-302/96-04

Licensee: Florida Power Corporation

Facility: Crystal River 3 Nuclear Station

Location: 15760 West Power Line Street
Crystal River, FL 34428-6708

Dates: April 21, 1996 - May 18, 1996

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## EXECUTIVE SUMMARY

Crystal River 3 Nuclear Station
NRC Inspection Report 50-302/96-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 4-week period of resident inspection; in addition, it includes the results of announced inspections by six Reactor Inspectors and one Reactor Engineer from Region II.

Operations

Additional examples were identified of Violation 50-302/95-22-01, Nine Examples of Operation of the Makeup Tank Outside of Acceptable Operating Region. (paragraph O1.1)

Another example of a previously identified weakness was identified which involved operators exceeding the lower level limit specified for the makeup tank. (paragraph O1.1)

Additional examples of unauthorized tests were identified which were similar to the examples cited as Violation 50-302/95-22-02, Unauthorized Tests/Experiments During Which the Plant Was Operated in a Nonconservative Manner Outside the Acceptable Operating Region Without a Safety Evaluation. These tests were identified as Unresolved Item 50-302/96-04-08, Evaluation of Evolutions as Unreviewed Safety Questions. Over a period of several years preceding apparent Violation 50-302/95-22-02, the test, collectively, indicated a continued and pervasive failure to meet the requirements of 10 CFR 50.59 and operation of the plant outside the scope of established written procedures. (paragraph O1.1)

An Unresolved Item (50-302/96-04-01) was identified concerning the discrepancies in the Enhanced Design Basis Document and the Final Safety Analysis Report regarding prevention of boron precipitation post Loss of Coolant Accident. (paragraph O3.1)

A violation (50-302/96-04-02) was identified for failure to take adequate corrective actions to revise procedure VP-580. (paragraph O3.2)

The inspectors concluded that the current procedures had adequate provisions against entering alarm conditions. (paragraph O3.3)

An Inspector Follow-up Item (50-302/96-04-03) was identified to monitor the effect of setpoint calculations on Emergency Operating Procedure revisions. (paragraph O3.4)

The inspectors concluded that the licensee had informally implemented the management oversight stated in the predecisional enforcement conference of March 27, 1996. Formal incorporation of the position responsibilities into the licensee's program remained to be completed. (paragraph O6.1)

Maintenance

Another example of Unresolved Item 50-302/96-03-10 regarding the failure to initiate a problem report to document and disposition the failure of a surveillance test was identified. (paragraph M1.1)

A weakness was identified in that the Modification Approval Record for the redundant High Pressure Injection narrow range flow indicators was not signed off as complete, however the modification was released as complete to the operations department. (paragraph M3.1)

A Non-Cited Violation (50-302/96-04-04) was identified for failure to correctly implement Technical Specification required control room emergency ventilation system testing requirements into procedures. (paragraph M3.3)

A Non-Cited Violation (50-302/96-04-05) was identified for failure to collect reactor coolant pump motor oil leakage. (paragraph M8.1)

Engineering

The licensee determined that a 10 CFR Part 21 report regarding Dixon instruments used at CR-3 was not an operability concern. (paragraph E2.1)

An Unresolved Item (50-302/96-04-09) was identified for failure to incorporate design information into operations procedures. (paragraph E2.3)

An Unresolved Item (50-302/96-04-06) was identified for untimely corrective actions to address Emergency Feedwater Initiation and Control system concerns and problems. (paragraph E2.4)

The engineering review of failure modes performed during the development of modification approval record 88-05-25-05 for operation of cooling water to the reactor building cooling units was weak. (paragraph E8.1)

Plant Support

The management directive to operate the plant with the reactor coolant system at an increased hydrogen concentration of 25-50 cc/kg was not properly evaluated for consequences on plant operation and was not incorporated into plant procedures prior to implementation. (paragraph R1.1)

An Unresolved Item (50-302/96-04-07) was identified for failure to perform a 10 CFR 50.59 safety evaluation for revising procedures involving dissolved Hydrogen concentration changes as described in the Final Safety Analysis Report. (paragraph R1.1)

Report Details

Summary of Plant Status

At the beginning of this report period the plant was in Mode 5 for refueling outage 10. The following evolutions occurred:

- On May 4, 1996 at 1:23 a.m. the plant entered Mode 4.

- On May 5, 1996 at 12:24 a.m. the plant entered Mode 3.

- On May 11, 1996 at 1:26 p.m., the plant entered Mode 2.

- On May 11, 1996 at 2:11 p.m., the reactor was taken critical.

- On May 12, 1996 at 2:39 p.m., following completion of the majority of low power physics testing, the plant entered Mode 3, to allow adjustments of the main turbine governor and throttle valves.

- On May 15, 1996 at 11:41 a.m., following completion of the adjustments on the turbine governor and throttle valves, the plant entered Mode 2. The plant achieved criticality at 11:59 a.m.

- On May 16, 1996 at 12:42 a.m., following completion of the remainder of the low power physics tests, the plant entered Mode 1. The main generator output breakers were closed at 8:31 p.m., on May 17, 1996 and power was increased to 25% of rated thermal power.

- Reactor power was increased to 45% on May 18, 1996 to allow low power physics testing and turbine vibration data gathering. Following completion of the tests, reactor power was decreased to remove the turbine from line for balancing and overspeed trip testing. The reactor was at 25 percent power at the end of the inspection period.

## I. Operations

## O1 Conduct of Operations

### O1.1 Review of Operational Evolutions

a. Inspection Scope (92901)

This inspection examined several operational evolutions to determine if they constituted violations of 10 CFR 50.59, similar to examples cited in apparent violation 50-302/95-22-02. Apparent violation 95-22-02 cited makeup tank (MUT) pressure and level evolutions performed September 4 and 5, 1994. On these dates, the requirements of 10 CFR 50.59 were apparently violated in that the evolutions were found to be tests that were not described in the safety analysis report and no written safety evaluations had been prepared which stated the basis for not considering these tests to involve unreviewed safety questions. The September 4 and 5, 1994 evolutions (tests) involved operation outside the design bases of the facility. They were considered tests because they were conducted primarily to collect data rather than as responses to plant conditions.

The evolutions examined in the current inspection involved additional MUT pressure and level evolutions conducted July 21 and 22, 1994, and the following other evolutions:

- shutting off spent fuel pool cooling pumps to gauge heatup rate (performed on several occasions in the 1980s and 1990s)

- shutting off the reactor cavity cooling system (industrial cooling water) supply pumps to gauge reactor cavity heatup rate (performed in 1994)

- shutting off reactor building penetration cooling fans to gauge heatup rate (performed in 1994)

- assessing instrument air system pressure decay by shutting off the compressors during plant operation (performed in the early 1980s)

- resetting a diesel generator 4160V undervoltage relay without first removing dc power from the lockout relay as specified in procedures (performed during the 1994 refueling outage)

- shutting off the circulating water box air removal vacuum pump to determine plant response (performed late 1970s)

The evolutions above were mentioned in the licensee's September 6, 1995 investigation report, which was furnished to the NRC in a letter dated April 22, 1996. The inspectors noted that a former shift supervisor had admitted to conducting five of the evolutions. He currently held an Senior Reactor Operator license but no longer stood watch.

The inspectors examined the MUT evolutions through reviews of chart recorder and computer records. They examined the other evolutions primarily through direct interviews with operations, engineering, and maintenance personnel; and through reviews of testimony provided by operations personnel. Operations logs were reviewed when specific evolution dates could be identified. Related system drawings, operating procedures, and Final Safety Analysis Report (FSAR) sections were reviewed to aid in understanding the required functions and operating limits for the systems involved.

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

<u>Makeup Tank (MUT) Evolutions Performed July 21 and 22, 1994</u>

The inspectors found that evolutions similar to the evolutions cited in apparent violation 95-22-02 occurred on July 21 and 22, 1994, in that data was taken during tank level and hydrogen pressure changes. However, from a review of computer data and chart records, the inspectors found that the MUT evolutions conducted on July 21 and 22, 1994 were not tests in that they were performed as necessary responses to plant conditions. The computer and chart records indicated that they had been initiated when MUT hydrogen overpressure dropped to a point where hydrogen addition was deemed desirable (about 20 psig at a MUT level of about 76 inches). Hydrogen addition was terminated in each evolution when the pressure reached approximately the computer pressure alarm limit. The inspectors found that the evolutions did not constitute additional examples of apparent Violation 50-302/95-22-02.

The computer and chart data indicated that the pressure alarm limit, based on Curve 8 of OP-103B, was exceeded near the termination of the hydrogen additions during the July 21 and 22 evolutions. In exceeding the Curve 8 limit these evolutions violated OP-402 instructions indicating that Curve 8 provided the maximum allowed overpressure. The inspectors determined that this violation was like example 1 of apparent violation 50-302/95-22-01, except that Curve 8 was exceeded for much shorter periods and by lower pressures in the July evolutions. The inspectors concluded that the July 21 and 22 evolutions were additional, but less severe, examples of apparent violation 50-302/95-22-01.

Inspection Report 50-302/95-22 identified that the low MUT fluid level limit of 55 inches was exceeded during the evolution cited as example 1 of apparent violation 50-302/95-22-01. It identified this as a weakness. This low level was similarly exceeded in the July 22 evolution. This was considered another example of the weakness specified in IR 50-302/95-22.

Other Evolutions

Operations supervisors responsible for the evolutions or who were present during the evolutions, confirmed their performance in interviews with the inspectors and in recorded testimony. Additionally, engineers interviewed by the inspectors indicated they knew of and had been provided data from all but the instrument air and circulating water air removal evolutions. The dates and circumstances of the evolutions were consistent with those briefly stated above in paragraph O1.1.a.

The inspectors obtained the following documented evidence of three of the evolutions:

- Nuclear Shift Supervisor's Log entry for June 20, 1994: This entry stated that the industrial cooling water pumps had been secured and that all available reactor cavity temperature indication had been observed for about 3 hours. It further noted that the temperatures had increased about 6°F at some locations and had decreased at others. The only temperature value mentioned in the log was 101°F at the 125 foot elevation. (Log entries dated October 22 and November 15, 1993 indicated that similar evolutions might also have been performed on those dates.)

Copy of an electronic mail message dated January 1, 199G: This message referenced the November 1993 and June 1994 log entries mentioned above and stated that the industrial cooling water pumps had been secured by Operations for 18 days for the November 1993 evolution and 11 days for the June 1994 evolution.

- Nuclear Shift Supervisor's Log entry for January 10, 1994: This entry stated that the penetration cooling fans (AHF-9A and 9B) had been shut down to monitor resultant changes in penetration temperatures. This was done in anticipation of possible troubleshooting of severe fan flow oscillations. The entry recorded that the temperatures of the penetrations monitored increased about 8°F in 1½ hours and then returned to within 1° of their original temperatures. A penetration cooling fan was returned to service after 4 hours. (Informal data from the test was provided to the inspectors. The data was consistent with log entries. The highest temperature obtained at any location was 145°F about 1½ hours into the evolution.)

- Request for Engineering Assistance (REA) 940588, dated May 15, 1994: This REA requested evaluation of resetting the 4160V Engineered Safeguards (ES) undervoltage relay by a different method than currently stated in procedures AP-770 and EOP-12. The REA proposed to eliminate first opening knife switch AY to remove power from the synch-check relay as specified in AP-770 and EOP-12. The REA stated that the method had been tried under controlled conditions and caused relay chatter. Engineering's response to the REA rejected the proposed change because there was no analysis available to establish the failure modes of all the relays that would be affected. (Note: Interviews conducted by the NRC inspectors revealed that the method had been performed with the involved system out of service for ES testing during the 1994 refueling outage.)

In their interviews and reviews of log entries, the inspectors questioned whether any alarms were received or any limits specified by procedures, Technical Specifications, or the FSAR were exceeded. They found no evidence that a limit was closely approached or an alarm activated, except in the case of the instrument air evolution. The instrument air evolution (performed in the early 1980s) was stated to have occurred as follows:

- The running compressors were secured to determine how fast pressure would decay, as would occur in a station blackout.

- The pressure decayed to the alarm (about 90 psig), at which point one compressor was restarted.

- The alarm stayed on until the one compressor tripped on high temperature (about 10 minutes), at which time additional compressors were started and provided adequate air pressure.

The operations supervisor responsible for the above instrument air evolution stated that it had been performed to (1) gauge the pressure decay that would occur should power to the compressors be lost, and (2) assess whether one compressor could provide adequate pressure following such a power loss. He stated that the results had been reported to management and resulted in upgrades to the system.

From their interviews with engineers, and their reviews of the FSAR and system drawings, the inspectors had the following observations with regard to the safety and regulatory significance of the six evolutions:

- Except in the case of resetting the 4160V undervoltage relay, the evolutions were conducted during normal operation. The undervoltage relay was reset while the system was out of service during a refueling outage. The relay was reportedly tripped as a planned part of the preventive maintenance activity.

- No design or Technical Specification limit was exceeded.

- The evolutions did not result in any conflict with limits stated in the FSAR.

- The evolutions did not result in any conflict with functional descriptions stated in the FSAR except in the cases of the reactor cavity cooling and penetration cooling. The FSAR (page.9-59) indicated that reactor cavity cooling would be served by the industrial cooling water system during normal operation. Also, it indicated (page 9-58) that one penetration cooling fan (AHF-9A or AHF-9B) would be in service during normal operation. In the related evolutions the industrial cooling water and both penetration cooling fans were removed from service during normal operation.

- Instrument air was not a safety related system. However, its function was important to safety, in that instrument air pressure decay could result in a plant trip (e. g., through a loss of feedwater control). Based on the inspectors' interview, the decay that occurred during the subject evolution did not cause a plant trip. A compressor did trip as already stated above.

- The fuel pool cooling system and its function were safety related. The fuel pool cooling evolution did not result in temperatures approaching a design or regulatory limit. Heatup was reportedly slow (½ to 1½°F per hour) and reached a maximum of about 90°F.

- The reactor cavity cooling industrial cooling water was not classified as safety related by the licensee . However, it effects safety in that it provides cooling in support of safety related equipment and structures during normal operation. The responsible engineer informed the inspectors that the lowest temperature limit of concern in a loss of cavity cooling would be the containment concrete limit of 200°F. The inspectors found this limit in the FSAR. No other related limit was described in the FSAR. The engineer stated that qualification limits for nuclear instrumentation located in the cavity were greater than the concrete limit. As noted previously above, the shift supervisors' log reported a temperature rise of about 6°F and a measured value of 101°F at one location.

- The penetration cooling fans were found to be safety related. Their principal importance was in assuring the containment concrete temperature limit was not exceeded at hot penetrations, such as feedwater and main steam piping penetrations. The highest temperature obtained at any location in a performance of the evolution was 145°F about 1½ hours into the evolution. .

- The 4160V undervoltage relay was safety related. The performance of the resetting activity during and outage, with the system out of service, had no safety significance. The only safety concern would be possible damage to the relays or associated circuits. Based on discussions with a cognizant licensee relay maintenance technician and with an NRC specialist, the inspectors concluded that the single evolution performed did not result in any damage.

- The circulating water air removal evolution, performed in about the late 1970s, was not an activity affecting safety. The evolution involved equipment that was neither safety related nor was required to support safety related equipment during the evolution. The inspectors did not consider that the requirements of 10 CFR 50.59 were applicable to this evolution.

- As resetting the 4160V undervoltage relay was performed while the plant was in an outage and the system was out of service, the requirements of 10 CFR 50.59 were not considered applicable.

- The spent fuel pool cooling, reactor cavity cooling, reactor building penetration cooling, and instrument air evolutions involved activities that affected safety and involved equipment that was either safety related or supported safety related equipment or structures. The requirements of 10 CFR 50.59 were applicable to those evolutions.

- None of the evolutions were considered in the safety analysis report and none were described in the approved operating procedures.

The inspectors found that the instrument air, fuel pool cooling, reactor cavity cooling, and containment penetration cooling evolutions described above were conducted in violation of 10 CFR 50.59 in that:

- The evolutions were tests, as they had been conducted to collect data and not in response to plant conditions.

- The safety analysis report did not specify any of these tests.

- They were performed without the written safety evaluation required for tests by 10 CFR 50.59.

The above violation examples were considered similar to the examples cited in apparent violation 50-302/95-22-02.

c. Conclusions

The inspectors concluded that at least four tests, in addition to those cited in apparent violation 50-302/95-22-02, were performed without the documented safety evaluations required by 10 CFR 50.59. These tests occurred during the period from the late 1970's through July 1994. None of these tests were prescribed by written procedures. Pending completion of an NRC evaluation to determine if the tests involve unreviewed safety questions, they were identified as unresolved item 50-302/96-04-08, Evaluation of Evolutions as Unreviewed Safety Questions. Over a period of several years preceding apparent violation 50-302/95-22-02, the tests, collectively, indicated a continued and pervasive failure to meet the requirements of 10 CFR 50.59 and operation of the plant outside the scope of established written procedures.

## O3 Operations Procedures and Documentation

### O3.1 Preventing Boron Precipitation Post-LOCA (71707)

The NSS's log dated May 4, 1996 contained an entry that read as follows:

- During the performance of SP-340B, DHV-41 was discovered to have a stroke time exceeding the limits of ASME Section XI and FSAR Table 5-9. DHV-41, although a motor operated valve, has no automatic closure features and as such, is considered a manual containment isolation valve. TS basis B 3.6.3 states normally closed isolation valves are considered operable when manual valves are closed. DHV-41 is now closed and therefore remains TS operable as a containment isolation valve and subsequent Mode escalation is allowed. The actions of TS 3.6.3 must however be entered whenever DHV-41 is opened due to its inoperability from an ASME Section XI standpoint. Per the EDBD, the DH dropline may serve as a method of preventing boron precipitation post-LOCA and its remote closure function is required if the valve is opened.

Valve DHV-41 is the outside containment isolation valve for the DH drop line from the RCS hot leg to the B OTSG. The licensee subsequently re-evaluated the test data for DHV-41 and determined that it had met the required stroke time and was therefore operable. However, the following procedural guidance is in effect for the use of DHV-41 post LOCA.

- EOP-08, LOCA Cooldown, steps 3.41 or 3.42, state that if LPI flow is less than 1,400 gpm and ECCS suction transfer has been performed, then go to OP-404, Decay Heat Removal System, Section 4.12.

- OP-404, Section 4.12, DH Operation During a LOCA, establishes conditions to place DHR system in service during a LOCA.

- OP-404, Section 4.13, Long Term Post Accident Cooling, has a Note that states to avoid boron precipitation, the ECCS shall be placed in the following condition as soon as possible after the accident. One train of HPI and LPI flow is established, then the opposite train is aligned so that flow from the RCS through the drop line and into the RB sump is accomplished.

The reactor core is required to remain intact and in a coolable geometry following any design basis accident. In order to ensure that the coolant flow channels remain open, it is necessary to have a method of diluting the boric acid which is dissolved in the coolant. As long as the flow channels remain unblocked, the coolant can cool the fuel. To mitigate a postulated CLPD LOCA, a method to ensure the dilution of the boric acid is necessary. The reactor vessel contains and directs the coolant to the reactor core. The vessel and its internals are designed to normally separate incoming cold coolant and outgoing hot coolant. However, following a postulated CLPD LOCA, if the pressure of the outlet region above the core becomes higher than the pressure of the inlet region, due to boiling in the core, the reactor vessel vent valves open to relieve the pressure. This prevents a pressure buildup which could force the water covering the core downward and out of the reactor vessel to the break location, thus uncovering the core.

By letter dated March 9, 1993 from Mr. Ashok Thadani, Director, Division of Systems Safety and Analysis, NRR to Mr. P. Walsh, B&W Owners Group, the NRC stated in part that during a meeting on December 3, 1992, the B&W Owners Group had supplied the NRC with the results of their analysis which demonstrated that gaps between the reactor outlet nozzles and the reactor internals provide an adequate <u>backup</u> to the primary recirculation flow path and the B&W Owners Group considered this issue to be resolved. Mr. Thadani's letter stated the NRC had reviewed the results of B&W's analysis and agreed with their position on this manner.

Plant Design Basis Document Temporary Change number 369 dated January, 1995 revised the EDBD to reflect the reactor vessel internal gaps, a passive boron dilution method, as replacing the decay heat drop line and the hot leg injection methods of dilution to prevent boron precipitation. The CR-3 FSAR, paragraph 4.3.10.1, Boron Dilution, discusses the same CLPD LOCA as the EDBD and also concludes that the passive method of boron dilution through the reactor internals gaps is adequate to mitigate the postulated CLPD LOCA. The FSAR further states that the method of dilution through the decay heat drop line still exists but is not necessary. The EDBD and the FSAR both appear to not be consistent with the NRC position regarding the primary required flow path for preventing boron precipitation post LOCA.

Also, the inspector noted that procedures previously required that the primary recirculation flowpath be put into operation within 24 hours following the initiation of the LOCA. Procedures now state to initiate the primary recirculation flowpath as soon as possible, which could mean it may not be put in operation. It is not clear to the inspector that this condition is acceptable.

The inspectors are continuing to gather information to disposition this concern. This item will remain unresolved, pending the completion of the inspector's evaluation. The item will be tracked as URI 50-302/96-04-01, Discrepancies in the EDBD and the FSAR regarding prevention of boron precipitation post LOCA.

O3.2 STA Verification Procedure

a. Inspection Scope (42001)

The inspector reviewed Procedure VP-580, Plant Safety Verification Procedure, Revision 21 as part of the EOP follow-up inspection. The guidance in this procedure was compared against the current revision of the Emergency Operating Procedures (EOPs).

b. Observations and Findings

The inspector noted that VP-580, Plant Safety Verification Procedure, had not been updated since September, 1993. The current revision of the EOPs effected during the week of the inspection contained significant changes upon which the operators were trained. However, the procedure to be used by the STA, procedure VP-580, contained outdated and incorrect information that conflicted with the EOP instructions. The licensee had conducted a biennial review of this procedure on June 30, 1995. This review documented discrepancies that existed in the procedure at that time, but had yet to be corrected:

Current revision was written to a superseded Writer's Guide
Flow charts were not written to current EOP Revision

The most recent revision to the EOPs significantly altered the EOP RULES contained in EOP-13. Procedure VP-580 contained the old RULES 1 through 4 which contained wrong information. The licensee had the procedure revised, reviewed by the Plant Review Committee, and issued on the day of the exit meeting, May 03, 1996. 10 CFR 50 Appendix B Criterion XVI requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. The inspector determined that a condition adverse to quality had existed since June 30, 1995, in that procedure VP-580 had not been corrected until May 3, 1996. Failure to correct the previously identified discrepancies of VP-580 in a timely manner is a violation of 10 CFR 50 Appendix B Criterion XVI, Corrective Action, 50-302/96-04-02, Failure to take adequate corrective actions and revise procedure VP-580 in a timely manner.

c. Conclusions

The inspector identified one violation for failure to take prompt corrective action and revise procedure VP-580 in a timely manner. The licensee had intended to delete this procedure with the next revision to administrative procedure AI-505, Conduct of Operations During Operational Events and Emergency Events. However, it is not acceptable that the procedure in the control room becomes more inadequate while awaiting the revision to replacement guidance.

O3.3 Practice Used in Raising and Lowering Tank Level

a. Inspection Scope (92901)

The licensee's practices in raising and lowering tank pressures and levels were inspected to determine if alarm levels were routinely exceeded, as had occurred in the makeup tank (MUT) evolutions cited in apparent violation 50-302/95-22-01. The inspectors reviewed licensee procedures to determine the actions specified in raising and lowering tank pressures and levels. Additionally, seven operators were interviewed to determine the practice used in raising and lowering tank pressures and levels. Through these reviews and interviews the inspectors sampled the practices specified and used by the licensee to determine if they provided adequate assurance that alarms were properly addressed, such that operational limits would not be exceeded. The procedure review conducted by the inspectors predominantly examined the revisions currently effective but also included the procedure in effect and applicable to the MUT evolution cited in apparent violation 95-22-01. Additionally, one surveillance procedure in effect at the time of the MUT evolution (September 1994) was also reviewed. The procedures reviewed were as follows:

Currently effective:

Operations Procedures, OI-09, Rev. 01
Makeup and Purification System, OP-402, Rev. 84
Core Flood System, OP-401, Rev. 42
ESB Annunciator Response (for core flood tank), AR-302, Rev. 17
Recirculation of Boric Acid Storage Tank, OP-403A, Rev. 10
Emergency Feedwater System, OP-450, Rev. 15
Nuclear Services Cooling System, OP-408, Rev. 80
Operations of Reactor Drain Tank, OP-407J, Rev. 16

Effective September 1994:

Makeup and Purification System, OP-402, Rev. 75
RC System Water Inventory Balance, SP-317, Rev. 44

b. Observations and Findings

OI-9 required operators to determine the cause and required action for each alarm condition. It indicated that no action in response to an alarm was required if the alarm condition was caused by the evolution being performed and was both expected and permitted by the procedure. Where not expected or permitted by procedure, the evolution was to be stopped and the action required by the alarm response procedure was to be taken immediately.

The inspectors did not identify any instances where the current procedures indicated that entering alarm conditions were permitted. However, the procedures did contain provisions for filling and venting the tanks and in such cases alarms would be expected.

The inspectors observed that the 1994 MUT procedure implied that it was acceptable to enter the low level alarm when lowering level (step 4.4.3). The inspectors found that the current MUT procedure had been revised in this area and no longer gave any indication that it was acceptable to enter the low level alarm when lowering level. The 1994 procedure SP-317 did not mention any level alarms.

In the interviews, the inspectors were informed that operators would not as a practice intentionally go to an alarm level (except when filling and venting a tank for start up). Two operators mentioned a procedural problem that had caused alarms in performing nuclear service closed cycle cooling water surge tank evolutions but operators indicated this had recently been corrected. Two operators also indicated that it had been difficult avoiding the alarm level in reactor coolant drain tank evolutions. The condition described to the inspectors appeared to have limited significance. The inspectors informed the MNPO, who agreed to investigate the condition and take any appropriate corrective action.

c. <u>Conclusions</u>

The inspectors concluded that the current procedures had adequate provisions against entering alarm conditions.

O3.4 <u>EOP Setpoint Revisions (42001)</u>

The licensee has performed engineering and EOP setpoint calculations which have resulted in significant changes to the EOPs. The ability of the EOPS to safely mitigate the consequences of reactor accidents is contingent upon the accuracy and assumptions that were used to derive the EOP setpoints. Numerous EOP setpoints and other associated calculations have been affected. In particular, EOP-13 Rule 3, EFW Control, was significantly altered as a result of the analysis of potential instrument errors. The methods being employed for these calculations and the instruments being used need to be examined to determine if they are acceptable. The licensee has temporarily suspended EOP revisions due to setpoint calculations until a review indicates that the methods and conservative approaches being used are correct. This item will be tracked as Inspector Follow-up Item 50-302/96-04-03, Effect of setpoint calculations on EOP revisions.

## O6 Operations Organization and Administration

### O6.1 Review of Management Oversight

a. Inspection Scope (92901)

In a predecisional enforcement conference conducted at the NRC Region II office in Atlanta, Georgia, on March 27, 1996, the licensee informed the NRC of additional management oversight intended to assure satisfactory conduct of control room operations activities. This oversight was to include:

- An additional management position to focus on shift operations, with sole responsibility for management, providing management assistance and oversight, and assessment of shifts on duty.

- Engineering management attendance at operations turnover meetings on a daily basis.

The inspectors examined the licensee's implementation of the above oversight.

b. Observations and Findings

As explained to the inspectors, the licensee had assigned the previous responsibilities of Manager of Nuclear Power Operations to two positions with one of the positions to be largely divorced from the administrative burden and more involved in day to day operations activities. The titles of these positions were "Assistant Director for Plant Operations and Chemistry" and "Manager of Nuclear Power Operations" (MNPO). The new MNPO position was described as reporting to the Assistant Director for Plant Operations and Chemistry and it was the MNPO's responsibility to provide operations oversight. The inspectors requested the documented description of the new position responsibilities and were informed that they were still in preparation. Although the position changes had been announced in December 1995, corporate processing of the position descriptions had taken several months and was expected to be completed soon. Revisions to plant procedures were being delayed pending completion of the position descriptions. The inspectors were informed that the failure to revise plant procedures to incorporate the new position responsibilities had been identified by the licensee's Quality Assurance organization. The inspectors verified that this was documented in Problem Report 96-0083, originated March 3, 1996.

The inspectors conducted interviews with operations managers, shift supervisors, and other operations personnel and visited the control room on several occasions to verify that the above oversight had been implemented. The shift supervisors and other operations personnel confirmed attendance of engineering management at turnover meetings and confirmed the increased presence and involvement of management in oversight of control room operations. They indicated improved management involvement and communication. On several occasions the inspectors observed the presence of the MNPO at the control room during their visits.

c. Conclusions

The inspectors concluded that the licensee had informally implemented the management oversight stated in the predecisional enforcement conference of March 27, 1996. Formal incorporation of the position responsibilities into the licensee's program remained to be completed.

**07 Quality Assurance in Operations**

07.1 Review of FSAR Commitments (40500)

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the FSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. The inspectors noted that the FSAR description for prevention of post LOCA boron precipitation did not agree with the NRC's position as described in correspondence. This issue is discussed in further detail in paragraph O3.1.

**08 Miscellaneous Operations Issues**

08.1 LER 50-302/95-005, Engineering evaluation determines insufficient LPI pump net positive suction head may result in operation outside design basis.

Event Number 28573 was reported regarding inadequate post-LOCA inventory to support EOP cooldown with one LPI pump. During the analysis for the MUT/EOP reviews, it was determined that there was inadequate post-LOCA reactor building inventory to support the current EOPs for cooldown in the configuration where one LPI Pump supplied two HPI Pumps in the piggy-back mode. The inspector reviewed the corrective actions contained in Problem Report 95-0059 and reviewed applicable steps of EOP-07, Inadequate Core Cooling, and EOP-08, LOCA Cooldown.

The inspector reviewed EOP-07 REV 03 (IC01) step 3.10 and EOP-08 REV 04 (IC02) step 3.15. These procedures direct that a HPI Pump be secured if the same train LPI Pump is not running. The guidance ensures that a single LPI pump supplies only a single HPI pump in the piggy-back mode. The HPI suction cross connect valve is normally closed and is administratively controlled. The licensee's corrective actions were adequate to correct the procedural problems that were outside the plant design basis.

This LER was previously closed in IR 50-302/95-16 and any additional corrective actions will be followed-up under the response to apparent violation 50-302/95-22-04, Four examples of inadequate design control concerning Curve 8, various setpoints, and tank volumes.

O8.2 <u>(Closed) LER 50-302/95-026-01, Unqualified flow instrument used in determining HPI pump runout conditions caused by failure to recognize applicability of Reg. Guide 1.97.</u>

Unqualified flow instrument used in determining HPI Pump runout conditions. This item was reported as Event Number 29582. During a review of the EOP setpoints, engineering personnel determined that operators used an unqualified RCP seal injection flow instrument to aid in preventing HPI pump runout conditions. The HPI flow to the RCP seals is in addition to the HPI flow measured by the RG 1.97 instruments and was not considered in the hydraulic analysis for the HPI pumps. The inspector reviewed documentation related to this issue including problem reports, inter-office correspondence and changes to the EOPs. In addition, the inspector attended the Plant Review Committee meeting which approved changes to affected procedures.

The inspector found that the licensee's resolution to this problem was to isolate seal injection at step 3.5 in EOP-03 (Loss of Subcooling Margin) in addition to isolating normal make-up flow to ensure all HPI flow is directed through the injection valves. This removes the unqualified instrument from consideration. The remaining HPI flow indicators are RG 1.97 instrumentation. In addition, licensee engineering reviews determined that HPI pump runout could only occur when in the piggy-back mode of operation (single LPI pump supplying single HPI pump). HPI pump runout is not an issue until 0 psig RCS pressure and piggy-back mode of operation in operation. The EOPs provide guidance to the operators to throttle HPI to prevent runout in this scenario. The inspector determined that the resolution of this item was acceptable since no significant consequences should result from isolation of seal injection.

O8.3 <u>(Open) VIO 50-302/93-16-07, Inadequate EOP and AP procedures.</u>

This item (originally identified as EEI 50-302/93-16-04) concerned multiple examples of a violation of 10 CFR 50, Appendix B, Criterion V. The inspector reviewed the procedures cited in the violation with the exception of AP-581, Loss of NNI-X, and AP-582, Loss of NNI-Y, (Non-Nuclear Instrumentation power supplies). The following procedures were reviewed:

| | |
|---|---|
| EOP-03 | Inadequate Subcooling Margin |
| EOP-14 | Emergency Operating Procedure 14 Enclosure 6 |
| AP-470 | Loss of Instrument Air |
| AI-402A | Writer's Guide for Emergency Operating Procedures |
| AI-402C | EOP Verification and Validation Plan |

The inspector noted that all procedural discrepancies noted in the Notice of Violation had been corrected for these procedures. This item will remain open pending review of procedures AP-581 and AP-582.

08.4 (Closed) VIO 50-302/93-16-08, Inadequate PSTG, violation of an NRC Order (This item was originally identified as EEI 50-302/93-16-01). The licensee had developed and implemented a complete revision of the EOPs and did so in violation of an NRC order which required the maintenance of Plant Specific Technical Guidelines (PSTG). The PSTG consisted of the B&W Technical Basis Documents (TBD) and a deviation document. The licensee did not have a deviation document which explained the differences between the B&W Technical Basis Document Guidelines (VOL 1) and the licensee's revised procedures on a step by step basis.

The inspector reviewed the administrative procedures governing development of the EOPs and the licensee's documents which explained deviations from the TBD Volume 1. The inspector noted that the licensee's definition of the PSTG included the Deviation Document, which only identified safety significant deviations from the TBD and the EOPs. The licensee had developed two other documents (EOP-TBD Cross-step Document and the TBD-EOP Cross-step Document) which detailed all of the deviations from the generic guidelines. Together these references meet the requirements of the PSTG. These documents contain sufficient detail to successfully audit the EOP development process. The inspector concluded that the licensee had developed a satisfactory PSTG and met the requirements of the NRC Order.

08.5 (Closed) VIO 50-302/93-16-09, Failure to control quality documents

This item (originally identified as EEI 50-302/93-16-03) dealt with a violation of Appendix B Criterion VI, Document Control. The inspectors found two examples where the licensee failed to meet the requirements of the regulation. In the first example, the licensee had failed to maintain the Deviation Document for the previous revision of the EOPs as a controlled document. In addition, during the inspection, an inspector discovered a superseded Appendix 12C in a controlled copy of the FSAR.

The inspector reviewed the current Deviation and Cross Reference Documents used for the development of the EOPs and the FSAR volumes in the library. The inspector found that the documents used in the EOP development process were controlled satisfactorily in accordance with the licensee's procedures. In addition, no superseded pages were found in the FSAR.

08.6 (Closed) VIO 50-302/93-16-10, Inadequate 50.59 reviews of EOPs

(This item was originally identified as EEI 50-302/93-16-06) The licensee had developed and implemented a new revision to the EOPs. The safety evaluations for each of these new EOPs were found to be inadequate because they contained inaccurate and/or insufficient information. The inspector reviewed several safety evaluations for the EOPs and found no inaccurate or misleading information. The evaluations contained sufficient information to withstand an independent review.

08.7 (Closed) VIO 50-302/93-16-11, Failure to follow V & V procedure

This item (originally identified as EEI 93-16-05) dealt with the licensee's failure to follow procedure AI-402C, EOP Verification and Validation Plan, when developing and implementing a complete revision to the EOPs. Independent reviewer signatures were missing from the required documentation and all of the documents reviewed indicated that differences between the EOPs and the TBD were documented and explained, when, in fact, they had not been documented.

The inspector reviewed verification and validation documents for the EOPs. The inspector noted that the documentation for the verification and validation of the procedures had been performed in accordance with procedure AI-402C instructions. Procedural steps had been compared against the requirements of the Writer's Guide and the PSTG with comments and resolutions annotated as required. Proper signatures and management review was also noted. The inspector concluded that the administrative controls on the EOP revision, review and approval process had been satisfactorily conducted.

## II. Maintenance

## M1 Conduct of Maintenance

### M1.1 Reactor Coolant System (RCS) Makeup Tank Instrumentation

a. Inspection Scope

The inspectors reviewed the reliability of the instrumentation provided for the RCS MUT for monitoring the water level and pressure maintained in the MUT.

b. Observations and Findings

The MUT for the makeup and purification system is a 600 cubic foot tank provided with two level instruments, MU-14-LT1 and MU-14-LT2, and one pressure instrument, MU-17-PT.

The inspectors reviewed the most recent calibration records for level instrument MU-14-LT2 and pressure instrument MU-17-PT which were performed on March 23 and March 26, 1996. The data for the calibration of MU-14-LT1 was in the licensee's review process and was not available for review.

MU-14-LT2 was found to be slightly out of calibration on March 23 for two of the eight electrical input points but the as found level instrumentation on the main control board was within the required tolerance. However, MU-17-PT was found out of calibration on eight of the nine calibration check points with a maximum error of 2.5 percent. The instruments were recalibrated and returned to service.

The inspectors reviewed the calibration records for the two previous calibrations for MU-17-PT which were performed on November 27, 1992, and October 31, 1994. These calibrations also found instrument MU-17-PT to be out of calibration by a maximum error of 2.5 percent in 1994 and 4 percent in 1992.

Surveillance Procedure SP-169G, Makeup Tank Instrumentation Calibration, Section 4.2.1.5, required that a precursor card be initiated (and upgraded to a problem report, if required) if any as found calibration data was not within the specified tolerance. However, neither a precursor card nor a problem report was issued for instrumentation MU-17-PT which was found out of tolerance during the March 1996 calibration surveillance. This problem was similar to URI 50-302/96-03-10, regarding failure of the licensee to initiate a problem report to document and disposition the failure of a surveillance test, and is considered another example of this URI.

c. Conclusions on Conduct of Maintenance

The corrective action for the calibration of the makeup tank pressure instrumentation found out of tolerance was not being performed in accordance with station procedures. Following completion of the March 1996 calibration, neither a required precursor card nor a problem report was issued for the pressure instrument found out of tolerance. The failure to perform the required corrective actions for instrumentation found out of tolerance was a negative finding and was identified as another example of URI 50-302/96-03-10 which was previously identified.

## M2 Maintenance and Material Condition of Facilities and Equipment

### M2.1 RWH-66A Concerns (61726)

On April 30, 1996, a PC was issued identifying concerns with RWH-66A, a hanger on the RW line exiting the B side DC heat exchanger. Concrete spalls above and to the right of the embedded plate were identified. The spall above the plate was approximately one inch deep along the 4-1/2 inches at the right side of the plate. A small gap was visible behind the plate in the deepest area. The top edge of the plate was pulled out from the intact concrete surface by about 3/16 of an inch for about four inches from the left side. As a result of the degraded condition of the support, the licensee SSOD declared the B DH RW train to be inoperable, on May 1, 1996.

The licensee concluded that the plate had been overloaded in tension, inconsistent with any possible water hammer event, as the direction of flow in the pipe would have resulted in compressive forces during a water hammer. All surrounding supports on the line were examined and no signs of damage existed on any of them. The licensee speculated that the probable cause was a load being applied to the support, possible being used to anchor a rigging for a lift in the area.

The inspectors reviewed the documentation of the event and performed a walkdown of the area in the auxiliary building. At the time of the walkdown, the licensee was in the process of performing modifications to the base plate, to grind off the damaged portions of the existing base plate, and place a larger base plate over the remains of the existing base plate. This base plate would be anchored with eight concrete anchor bolts and would be welded to the coupling of the existing base plate. This would, by analysis conducted by the licensee, increase the strength of the existing support. Following completion of the modification, on May 3, 1996, the licensee returned the system to operable status.

## M3 Maintenance Procedures and Documentation

### M3.1 Conduct of Surveillance

a. Inspection Scope (62703)

On May 5, 1996 the residents observed the conduct of Performance testing procedure PT-444, High Pressure Injection Flow Verification Test. The intent of this procedure was to demonstrate the operability of the HPI system by performing a flow balance test following modifications that may have altered system flow characteristics or whenever the system engineer deems the test is necessary.

b. Observations and Findings

This test was conducted with the plant in Mode three with three reactor coolant pumps operating and the plant at greater than 655 psig. The pretest briefing was conducted by the SSOD and the DNPO briefing was conducted by the Shift Manager. The briefings were detailed and complete and all participants had an opportunity to input to the discussion. This test was conducted on the A MUP only. The A MUP was chosen since it had been overhauled during the refueling outage.

In addition to performing the test to assess the performance of MUP-1A, the licensee gathered data during the test to complete the MAR functional test procedure for the redundant HPI narrow range flow indication, installed during the outage.

The licensee gathered the necessary data and released the modification as complete to the operations department. The MAR functional test procedure was not signed off as complete, pending the receipt of analysis by Framatome on the MUP-1A operation. According to the licensee, this did not impact the operability of the flow indicators and they were declared operable. During the review of the test, the inspectors determined that the completion of the indicator calibration, per SP-169E, Makeup System Instrumentation Calibration, was a prerequisite for the MAR functional test. Even though the data gathering and calibration were complete prior to the beginning of PT-444, the final review of the SP-169E procedure was not completed until

May 21, 1996. This delay in the final review of this procedure is a weakness.

c. Conclusion

A weakness was identified in that the documentation of the MAR functional test and the prerequisite instrument calibrations were signed off as complete to operations prior to the MAR being signed off as complete.

M3.2 Conduct of Surveillance

a. Inspection Scope (62703)

On May 26, 1996, the inspectors observed the performance of SP-417, Refueling Interval Integrated Plant Response to an engineered Safeguard Actuation. This procedure is designed to verify on an simulated loss of offsite power signal, in conjunction with a simulated ES actuation signal, that the emergency buses deenergize, the emergency buses load shed, and that the EGDG auto-starts from standby conditions and auto loads its emergency loads.

b. Observations and Findings

The inspectors attended the pre-job briefing and noted that a single individual, as described in the procedure, had been appointed to coordinate the performance of the test. The procedure had recently been revised, to allow performance in mode 5 versus mode 3 as has been performed in the past. Some additional temporary changes had been made, to take into account actual conditions in the plant, such as maintenance on the DH system preventing DHV-5 from automatically opening.

The inspector witnessed the performance of the procedure for the A train of ECCS.

c. Conclusions

The test was performed adequately, with a minimum of problems. The results of the test were satisfactory.

M3.3 Control Room Emergency Ventilation Filter Testing (92902)

TS 5.6.2.12, Ventilation Filter Testing Program (VFTP), requires that a program shall be established for the CREVS per the requirements specified in RG 1.52, Revision 2, 1978 and in accordance with ASME N510-1975 and ASME N509-1976. This program shall demonstrate that for each train of CREVS, an inplace test of the HEPA filters shows a penetration and system bypass less than 0.05% and for each train of CREVS that an inplace test of the charcoal adsorber shows a penetration and system bypass less than 0.05%. These numbers agree with the requirements discussed in FSAR 9.7.4.1, Control Complex Emergency Air and Adsorption

Filters. The TS revision for the improved TS became effective in March, 1994.

Prior to the issuance of the improved TS, the testing of the CREVS filter system was performed under TS 4.7.7.1.c, Surveillance Requirements - Control Room Emergency Ventilation System. This TS required that the total bypass flow of the system is less than or equal to 1% for the HEPA and charcoal filters.

During April 30, 1996, following the completion of SP-186, AHFL-4 A/B (Control Room) In-Place Filter Testing, the licensee discovered that the acceptance criteria for the test had never been changed from the values in the old TS. The testing for the system was performed using equipment which, while capable of measuring accurately enough for the old TS requirements, was not sensitive enough for the existing TS acceptance criteria. The results of the test, performed in March, 1996 were recorded as less than 0.10%. The previous test, in 1994 was also performed using the wrong criteria. The results of that test were the charcoal adsorbers tested less than 0.03% bypass and penetration and the HEPA filters tested less than 0.10% bypass and penetration. According to the licensee, the high numbers on the HEPA filters reflect the sensitivity of the instrumentation used during that test.

The licensee brought equipment in which was sensitive enough to perform the test with the lower acceptance criteria. On May 1, 1996, the licensee performed the testing for a second time, during 10R, and the results for the B charcoal adsorber were within 0.02% and for both of the HEPA trains and the A charcoal adsorber were less than 0.01%. With the more sensitive test equipment, it was easily shown that TS requirements were met. Since the system was unchanged prior to test, the licensee assumed that if the prior test, in 1994 and March 1996, had been performed using the more sensitive test equipment, it would have passed, also. However, the test performed in 1994 did not use the applicable test criteria.

TS 5.6.2.12 was not properly translated into a program for testing of the CREVS. SP-186, which implements the VFTP, incorrectly used obsolete acceptance criteria, less conservative than that in the TS. This licensee identified and corrected violation is identified as a non-cited violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. This is Violation is identified as NCV 50-302/96-04-04, Failure to correctly implement Technical Specification Control Room Emergency Ventilation System testing requirements into procedures.

M3.4 Conduct of Surveillances During Reactor Startup

a. Inspection Scope (62703)

During the startup of the unit, the inspectors witnessed several surveillance procedures, including low power physics testing and preparation for power ascension.

b. Observations and Findings

The inspectors witnessed the performance of SP-113, Power Range Nuclear Instrumentation Calibration, to verify the high flux trips prior to the zero power physics testing. The procedure was completed satisfactorily, with good coordination between operations and I&C.

Portions of PT-110, Controlling Procedure for Zero Power Physics Testing were witnessed, during the criticality pull. The communications between the operations personnel, the engineering personnel, and contract personnel performing the testing was adequate. The inspectors observed the 1/M plots being performed to evaluate approach to criticality, as part of PT-110.

Following criticality, the inspectors witnessed the performance of PT-116, Sensible Heat Determination. All results were satisfactory.

The inspectors witnessed portions of the data gathering for SP-103, Moderator Temperature Coefficient Determination at Startup Following Refueling.

c. Conclusions

The test results were reviewed by the inspector and the test was completed satisfactorily, with no problems encountered.

**M8 Miscellaneous Maintenance Issues**

M8.1 (Closed) LER 50-302/95-008-01, Oil Leakage from Reactor Coolant Pump Motors Not Collected by the Lube Oil Collection System Leads to Operation Outside Design Basis

See NRC Inspection Reports 50-302/95-11 and 50-302/96-01 for documentation of previous inspections of this LER.

a. Inspection Scope (92700)

On May 19, 1995, a 10 CFR 50.72 Report identified that not all of the oil leakage from the Reactor Coolant Pumps (RCPs) was being collected by the Lube Oil Collection (LOC) system. The initial LER was submitted on June 16, 1995, with a supplemental submittal dated April 26, 1996. The following summarizes the licensee's corrective actions and NRC inspection activities to verify completion of corrective actions:

b. Observations and Findings

- Licensee Corrective Actions

As of April 1995, based on trending results for lube oil additions to the RCPs and collections from the Lube Oil Tanks (LOTs), the licensee concluded that almost all of the approximately 115 gallons of oil added since June 1994, had not been recovered by the LOC system. This was treated as a potential design basis issue and an operability evaluation performed. Based on the most probable leak paths, the operability evaluation concluded that the LOC system was degraded, but operable. This evaluation was based on the premise that leakage from the LOC would end up in the Reactor Building (RB) Sump. This premise was verified with a RB entry on June 8, 1995. Based on measurement of the oil slick on the surface of the RB Sump, it was estimated that 45 to 95 gallons of oil had collected in the sump.

Considering the oil leakage would migrate to the RB sump, the licensee evaluated the effect on a Large Break Loss of Coolant Accident (LBLOCA), assuming the entire RCP lube oil (760 gallons) spilled from the system. This was an existing evaluation documented in Babcock & Wilcox (B&W) document 77-1172291, Evaluation of RCP Lube Oil in RB Sump, that concluded only an insignificant effect on the postulated event.

The evaluation also considered the fire hazard issue and concluded, based on a previous study as part of an unrelated issue, that oil leakage would be contained within the secondary shield wall and migrate to the RB Sump, and in the unlikely event of a fire, safe shutdown capability of the plant would not be compromised.

On January 11, 1996, during a forced outage, the licensee entered the RB and identified and repaired several LOC system leaks.

During the current outage (RFO 10), the licensee performed a comprehensive inspection of the LOC system and found the source of leakage to be two primary leak paths. First, the thermocouples installed in the RCP motors were not designed for oil submergence. This allowed oil to leak from the lube oil system into the thermocouple conduits and out of the LOC system. Second, pinhole leaks in the lower seam of the LOC sheet metal encapsulation boxes were identified. In addition, the licensee identified that the lube oil system itself had excessive leakage at pipe flanges.

The motor for RCP-1A was replaced with a new style motor. RCP-1A motor was leaking worse than any of the other pumps. The new motor is expected to greatly reduce the probability of LOC leakage since the bottom seam of the collection enclosure is welded in lieu of the bolted seam for the existing pumps. In addition to an improved LOC system, the pump also has an improved and simplified lube oil system. Plans are to eventually replace the other RCPs with the new design.

Gaskets in lube oil system flanges were replaced with improved gaskets and Belleville washers were installed on the flange bolting to ensure that the flange connections remain tight. This should greatly decrease the amount of leakage from the lube oil system.

All thermocouples were replaced with thermocouples designed with oil and vapor seals.

All sheet metal encapsulation enclosure seams were inspected, cleaned and resealed as required.

- NRC Inspection Activities

The inspectors reviewed the following records and documents to verify completion of the above corrective actions:

Problem Report (PR) 95-96

Completed Work Requests (WRs) NU 0328364, NU 0328365, NU 0328366, NU 0328367, and NU 0328368, which documented replacement of thermocouples for all pump motors, including replaced pump motor 1A (now considered a spare)

Completed WRs NU 0319423, NU 0319814, NU 0319813, NU 0319262, which documented the annual preventive maintenance (PM) for the pump motors - These PMs included inspection and repair of the LOC system, including replacement and sealing of the LOC sheet metal panels.

Completed WR NU 0330600, which documented walkdown, inspection for leaks, and repair of the lube oil system for all pump motors - This included change-out of the gaskets on the flanged joints.

Completed WR NU 0333489, which documented installation of Belleville washers on the flange bolting for the lube oil system

Plant Equipment Equivalency Replacement Evaluation (PEERE) Sheets 1342, 1318, 1235, 1228, 1237, and 1236, which documented justification for replacement thermocouples, gasket materials, and Belleville washers - The inspectors also reviewed parts inventory data relative to the previous use of thermocouples that were not designed with an oil seal. It was not clear why, but in 1986 the parts inventory had been revised to allow the use of a Leeds and Northrup model thermocouple that did not have an oil and vapor seal. It appears that the Engineer who approved the change in 1986 considered it to be a non-technical change in accordance with Section 3.6 of Revision 4 of the Nuclear Procurement and Storage Manual. There was no evidence that the Manual was not followed as written in 1986. Today, the parts replacement procedures have been improved with the PEERE. which requires a more detailed review for replacement parts.

c. Conclusions

The inspectors concluded that all corrective actions identified in the LER have been completed and were appropriate. However, failure of the LOC to collect leakage from all RCP potential leakage sites is in violation of 10 CFR 50, Appendix R, Section III O. and Section 6.7 of licensee Fire Protection Plan, which require that the LOC system be capable of collecting lube oil from all potential leakage sites. This licensee identified and corrected violation is identified as a non-cited violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. The violation is identified as NCV 50-302/96-04-05, Failure to collect RCP motor oil leakage.

This LER is closed.

## III. Engineering

### E2 Engineering Support of Facilities and Equipment

#### E2.1 Dixon Digital Indicators

a. Inspection Scope (92903)

On April 19, 1996 the licensee received notification of a 10 CFR Part 21 report that affected certain Dixon instruments that were being installed in safety related applications at Crystal River unit 3 during the present refueling outage.

b. Observations and Findings

An anomaly had been identified in Ametek/Dixon Pro-series bargraph models SA101A, SA202P, SN101P, and SN202P units. The anomaly was identified that the specific bargraph can potentially indicate an erroneous under range condition at a very specific input point. When this condition occurs, the instrument will indicate a zero reading on the bargraph portion, indicate dashes on the digital display portion, and the relay (if used) will track this indication. This is typically a momentary condition, and the unit immediately returns to normal operation after the anomalous condition stops. This is a very uncommon condition, and if the condition occurs, the response by the operator is unknown to Ametek/Dixson since the bargraphs are used in varying applications. It is believed that an incorrect response would be the worst case condition, however, its low probability of occurrence and very short term duration would tend to limit this likelihood.

The licensee initiated PR 96-0137, Dixon Digital Indicator Part 21 Notification,to document that the models noted above were presently being installed by MAR 96-02-09-01 (HPI flows) and MAR 96-03-12-01 (EGDG Kw meters) but had not yet been turned over to operations.

By interoffice correspondence dated April 25, 1996 (NED96-0269) the engineering department provided the following analysis:

The meter hardware and software architecture will sample and convert an input signal into a digital signal which is used to display operator information in the form of a bargraph display and digital meter readout. The analog signal is resolved into 71,000 levels. The software anomaly, which causes a momentary loss (approximately one sample period of 175 msec.) of indication, occurs at on specific level of 65,536.

For the HPI wide range flow meters, the momentary loss of signal for the high range flow meters (0 to 500 gpm) occurs in the flow range of 480.372 to 480.375 gpm. Note that any other flow signal outside this boundary will not cause a loss of signal. Additionally, if the flow signal were to occur within this narrow flow span (0.003 gpm), indication would be lost for 175 msec. Do to the nature of the flow signals, the input signal would not remain within this small band. Therefore, the software anomaly will not impact the use of the meters.

For the HPI narrow range flow meters (0 to 200 gpm) the loss of indication occurs at 192.149 to 192.150 gpm (span of 0.001 gpm). Using the same reasoning, this small range would not impact the indication to the operator.

For the EGDG kW meters, the loss of indication occurs in the range of 3692.113 to 3692.169 kW (span of .056kW). Since the diesel is rated at 3500 kW (maximum limit for the EGDG 30 minute rating) and could only reach the 3692 kW value while starting equipment (such as block loading) the software anomaly would not affect the use of the equipment.

Based on the above information, NED felt the 10 CFR Part 21 issue would have no effect on the operability of the new meters.

c. Conclusions

The licensee's response to this issue was considered appropriate. No further action is required on this issue.

E2.2 Engineering Review of Operating Curves

a. Inspection Scope (37550, 37551)

The inspectors reviewed engineering's involvement in the development of Curve 8 in Procedure OP-103B and in reviewing and evaluating various revisions to Curve 8 to ensure the accuracy and adequacy of the information for the curve.

b. Observations and Findings

The inspectors reviewed the history of the development of Curve 8, Maximum Makeup Tank Operating Pressure vs Level. This curve was included in Operating Procedure OP-103B, Plant Operating Curves. The inspectors reviewed Engineering transmittals of information to operations relative to Curve 8. The inspectors also reviewed the 10 CFR 50.59 screenings and safety evaluations and the PRC reviews and approvals for selected Curve 8 revisions.

Curve 8 was provided by the NSSS supplier (B&W) and was initially labeled as Curve 2.7 in OP-103. Procedure OP-103 was initially titled

Plant Curve Book. Curve 2.7 was later changed to Curve 9 when OP-103 was re-written and retitled OP-103B, Heatup/Cooldown Curves, Revision 0 (approved 12/2/85). Curve 9 was relabeled as Curve 8 in Revision 1 to OP-103B. In Revision 7 to OP-103B (approved 2/26/91), Curve 8 was redrawn and a note was added to the curve to administratively limit the MUT pressure to 12 PSIG. Engineering recommended that the note be added to Curve 8 in order to address the concern of hydrogen binding of the MUPs. The concern with hydrogen binding had been documented previously in Problem Report 90-009.

In Revision 11 to OP-103B (approved 4/17/93), Engineering provided information for a revision to Curve 8. This revision removed the note "Administrative Limit is 12 PSIG" and specified the acceptable region on the curve as being below and to the right of the operating pressure and level curve. Engineering transmitted the information necessary for revising Curve 8 to Operations via IOC NEA93-0267, dated February 26, 1993. The IOC included a table and curve depicting allowable indicated MUT overpressure for indicated water level. The table and curve were part of additional MUT pressure and level calculations that were performed by Gilbert/Commonwealth Incorporated, who was the architect engineer for Crystal River 3. The IOC further stated that the values included worst case instrument errors for both level and pressure and represented a safe pressure for a given level that assured a two foot water column in the MUT outlet piping to protect the MUPs from gas entrainment at the start of switch-over to recirculation with maximum ECCS flow during a large break LOCA.

The inspectors discussed IOC NEA93-0267 with Engineering and Operations personnel. Engineering personnel indicated that the information transmitted by the IOC was considered to be design basis information. However, as discussed in NRC IR 50-302/95-22, it was not until November 16, 1994 (which was after the unauthorized evolutions on September 4 and 5, 1994), that Engineering determined that Curve 8 was nonconservative and outside the design basis. Operations personnel indicated that the operators did not know that Curve 8 was a design basis curve. The inspectors noted that Operations personnel used the information transmitted by IOC NEA93-0267 when they prepared the Revision 11 to OP-103B. Revision 11 to OP-103B was also reviewed and approved by the PRC (Meeting No. 93-16) on April 22, 1993.

Curve 8 was not changed in Revision 12 to OP-103B (approved 2/18/94). Revision 12 was in effect during the unauthorized evolutions on September 4 and 5, 1994. Subsequent to these unauthorized evolutions, the licensee determined that Curve 8 was nonconservat[illegible] and did not provide adequate margin to prevent hydrogen entrainmen[illegible] the MUPs during a LOCA. In Revision 13 to OP-103B (approved 1/30/[illegible]), Curve 8 was replaced with Curve 8A and Curve 8B. However, subsequent to its issuance, the licensee determined that Revision 13 was also nonconservative. The design deficiencies relative to Curve 8 are discussed in greater detail in NRC IR 50-302/95-22. These design deficiencies are currently being reviewed by the NRC for enforcement actions.

Revision 16 to OP-103B (approved 2/2/96) included curves 8A, 8B, and 8C for the MUT pressure vs level. Curve 8 was being reviewed by the NRC for technical adequacy. This review had not been completed by the NRC at the conclusion of this inspection.

c. Conclusions

Although Engineering had been involved in reviewing and evaluating information relative to Curve 8, the past reviews by Engineering (up to and including Revision 13 to OP-103B) were not always effective in ensuring the accuracy and adequacy of Curve 8.

E2.3 Makeup Tank Instrumentation

a. Inspection Scope (37550)

The inspectors reviewed the adequacy of the instrumentation provided for the monitoring of water level and pressure maintained in the MUT. The inspectors also reviewed the adequacy of the procedural guidance provided to operators on loss of MUT level indication during accident conditions.

b. Observations and Findings

The MUT is a 600 cubic foot tank. The tank has two level instruments, MU-14-LT1 and MU-14-LT2, and one pressure instrument, MU-17-PT.

Hydrogen was used to provide a cover gas for the MUT for the purpose of scavenging oxygen within the RCS solution. Pressure instrument MU-17-PT was used to monitor the hydrogen overpressure in the MUT and provided a low pressure alarm at 3 psig in the tank. The high pressure alarm was a variable alarm based on the maximum design pressure curve and offset a minimum of 3 psig of pressure below the design basis curve (Curve 8 in OP-103B) at a MUT level of 55-inches of water.

Prior to 1995, the level instrumentation was set to alarm at tank levels of 55 inches for low level and 86 inches for high level. Plant modification MAR-95-01-07-02 changed the high level alarm setpoint to actuate at 100 inches. Following completion of this modification, Operations Procedure OP-402, Makeup and Purification System, (Revision 80 effective October 5, 1995) was revised to incorporate this change and required that the MUT pressure and level be maintained within the limits established by Curve 8A or Curve 8B in Procedure OP-103B. The inspectors reviewed the safety evaluation for MAR-95-01-07-02 and noted that the change to the tank high level alarm had received an appropriate 10 CFR 50.59 safety evaluation.

The inspectors reviewed the Enhanced Design Basis Document for the Makeup and Purification System, Revision 5 dated February 29, 1996, with Temporary Change TC-487. This document stated that the minimum allowable water level for the MUT was 18 inches and the maximum water level was 100 inches. The maximum MUT pressure permitted was a function of indicated water level. An excessive overpressure of hydrogen gas was a concern since gas could become entrained in the suction to the MUPs during high pressure injection if the hydrogen gas pressure in the empty MUT and piping exceeded the fluid pressure from the BWST at their piping interconnecting tie-in point. The licensee's calculations indicated that during the worst case LOCA event, the level of water in the MUT would be lost but that at least two feet of water column would be available in the piping system to the MUPs which should prevent hydrogen gas from becoming entrained in the MUPs. However, the operators would not have indication of the water level available to the suction of the MUPs throughout the duration of this event.

Initially, air operated valve MUV-64, which is located between the MUT and the MUPs, was designed to close automatically on an ES actuation. To avoid inadvertent closure and pump damage, this automatic feature was eliminated in 1984. The valve was locked in the open position in 1985 to address Appendix R criteria and the operator for this valve was disabled in 1989 by removing the electrical power and motive air.

During this current refueling outage, MAR 95-01-07-01 was implemented to address, in part, the concerns of operations personnel regarding the loss of level indication in the MUT during LOCA conditions and the potential for hydrogen gas being entrained in the suction to the MUPs. This MAR replaced the air operator for valve MUV-64 with a new manual gear driven chain operator. The valve was provided with both local and control room valve position indication. The inspectors noted that the design input record of the MAR package discussed adding the manual gear driven chain operator for better access in the manual mode since it might be necessary to quickly stroke the valve closed in certain accident scenarios with the new higher MUT hydrogen gas pressures (e.g., certain Appendix R fires, keeping the MUT level indication on scale post LOCA, rapid boration requirements, etc.). During review of this MAR, the inspectors noted that the modification/procedure review, which was performed by various plant departments, indicated that no operations procedure revisions were required. The inspectors further noted that the proposed use of valve MUV-64 during accident conditions had not been incorporated into plant procedures and training had not been provided to the operators on the use of this valve. The valve was identified in the valve lineup section of operating procedure OP-402, Makeup and Purification System, Revision 84. The procedure only showed the valve position as being sealed open and there was no discussion on operation of the valve during potential accident conditions.

The inspectors discussed this issue with licensee personnel who stated that, other than the valve's position being shown in the valve lineup section of OP-402, the use of MUV-64 was initially not intended to be covered by the operations procedures. The inspectors informed the licensee during the pre-exit meeting on May 10, 1996, that this design control issue would be identified as URI 50-302/96-04-09, Failure to Incorporate Design Information Into Operations Procedures. This issue remains unresolved pending NRC review to determine if it is an additional example of an apparent violation discussed at the predecisional enforcement conference on March 27, 1996. During the pre-exit meeting, licensee management stated that they did not agree with the NRC position on this issue because they had reviewed operations and other plant department procedures (in accordance with their design control process) and determined that no procedures needed to be revised. The licensee stated that they would continue to evaluate this issue to determine if and how the use of this valve should be addressed in operations procedures.

The inspectors also reviewed an issue discussed in NRC IR 50-302/95-22 concerning human factors aspects of the MUT information displayed in the main control room were weak in supporting operation near Curve 8. The inspectors reviewed Curve 8 (8A, 8B, 8C) included in Revision 16 of OP-103B (dated February 6, 1996), reviewed control room instrumentation, and held discussions with operators regarding this issue. The inspectors determined that Curve 8 provided more detailed information to the operators and more margin had been added between the alarm setpoints and the design limit for Curve 8. The inspectors also noted during discussions with various operators that there was an increased sensitivity and awareness by operators regarding operation within the appropriate limits of Curve 8. The inspectors concluded that the licensee's actions have adequately addressed the issue relative to human factors aspects of the MUT information displayed in the main control room.

c. Conclusions

Appropriate instrumentation was provided for monitoring hydrogen gas pressure and water level in the MUT during normal plant operations. However, during a large break LOCA, the instrumentation would not provide level indication once the tank level reached the lower level of the tank. The lack of level indication does not provide the operators a means to monitor tank level in order to permit appropriate manual actions, if needed, to prevent hydrogen gas in the MUT from being entrained into the MUPs. An URI was identified because the use of MUV-64, which is a manual sealed open isolation valve between the MUT and the MUPs, had not been included in an operations procedure and training had not been provided to operators for the use of the valve during accident conditions. This negative finding is associated with design control and inadequate operations procedures.

E2.4 Problem Identification and Resolution

a. Inspection Scope (37550, 40500)

The inspectors reviewed Engineering's involvement in identifying and resolving plant problems. The inspectors examined some of the licensee's problem reports and other operational issues to determine if the technical disposition and root cause determinations were adequate and to see if the corrective actions had been completed.

b. Observations and Findings

Problem reports PR 94-0151, Torque of Valve Packing Gland Nuts; and PR 94-0169, Bolting Connection for Raw Water Flange, were completed and closed in an adequate manner. The inspectors had the following observations during review of other problem reports.

PR 94-0149, Make Up Valve MUV-60 Stuck Open

This was an extensive PR and all the corrective actions were not yet complete. This PR concerned a noticeable decrease in the MUT when MUV-60 was first opened, which indicated that MUV-60, a check valve, was stuck open. This PR was used to address a number of problems with the MUT, which included potential runout of the MUPs as well as other issues. This report had 13 corrective action steps with three of them not yet completed. Some of the corrective actions were being worked on during this outage.

In addition to PR 94-0149, the inspectors also discussed other related MUT issues and operational concerns (and Engineering's involvement in resolving those issues) with Operations personnel. Some of these issues included higher MUT pressure needed to maintain higher hydrogen concentration (cc/kg) in the RCS, loss of MUT level indication during a LOCA, and hydrogen supply regulator problems. Operations personnel indicated that, prior to the unauthorized evolutions on September 4 and 5, 1994, Engineering had not been timely or effective in addressing some of these issues. However, since the unauthorized evolutions, there had been increased management attention and focus on some of these issues which resulted in them being resolved. Alarm setpoint changes and procedural changes were necessary to address the higher MUT pressure and increased RCS hydrogen concentration. Engineering actions to address the loss of MUT level indication during a LOCA is discussed in greater detail in paragraph E2.3 of this inspection report. Although Engineering took actions to address the hydrogen supply regulator concern, Operations had revised their procedures to allow use of an alternate path to add hydrogen to the RCS. Except for the issues relative to the MUT and emergency feedwater initiation and control (EFIC) system, Operations personnel did not identify any other operational concerns (during this discussion with the inspectors) where Engineering had not been timely or effective in resolving.

PR 95-0177 Apparent Deficiency in ASME Section XI Testing of Valves CFV-1 and CFV-3

This issue was discussed in IR 95-18 in which NCV 50-302/95-18-04 was issued for failure to test CFV-1 and CFV-3 in accordance with ASME Section XI as required by TS. The NRC (RIs, Region II personnel, and NRR staff) discussed with the licensee the JCO associated with the operability determination and found it to be acceptable. During those discussions, the licensee committed to full flow testing during the next refueling outage (current RFO 10). During the current inspection, the inspectors verified through discussions with Engineering personnel and documentation review that the licensee had performed the full flow test and had used acoustic monitoring to ascertain that the check valves had functioned properly.

EFIC Level Control and Flow Control Upgrade

The EFIC system was discussed in NRC IR 50-302/95-22 as another example of an issue where operators were dissatisfied with the timeliness of the corrective actions. There were several operator concerns and design inadequacies associated with the EFIC system. One of the concerns identified by operators in 1993 was that the design of the control modules for EFIC created a potential for overfeeding the steam generators and causing the EFW pumps to exceed their pump runout limits if the EFW control valves were left in automatic control. There was also a potential problem that could occur during a natural circulation event (on a loss of all RCPs) where the control valves could go closed. The operators felt that with the present design, they were compelled to take manual control of the control valves and place a dedicated operator at the emergency feedwater control station. The operators felt that this was a significant additional operator burden which needed to be corrected.

The inspectors reviewed the FSAR description for the EFIC system (Section 7.2.4) and concluded that the operator concerns and design inadequacies associated with the EFIC system indicated that the system does not properly operate in accordance with the automatic mode of operation described in the FSAR.

In response to the operators' concerns and other problems with EFIC, the licensee formed an EFIC Simplification Task Force in February 1993 to address the concerns and problems with EFIC. The EFIC Task Force consisted of a total of 15 members from various departments and disciplines (e.g., operations and engineering). The Task Force recommended modifications to existing equipment to correct the EFIC problems. These recommendations were provided to the Nuclear General Review Committee (NGRC) in interoffice correspondence IOC NPTS94-0075 dated February 25, 1994. The NGRC is composed of senior licensee management personnel and senior management consultants. The EFIC Task Force modification recommendations provided the basis and justification in the request for project approval (RPA), EFIC Level and Flow Control Upgrades. The RPA was approved by the Vice President, Nuclear Production on June 15, 1994. Approval of the RPA authorized and allocated funds for development of the necessary modifications. The RPA stated that installation of the modifications was scheduled for RFO 10 in the spring of 1996.

The inspectors reviewed the RPA and discussed the EFIC concerns with engineering and operations personnel. During these discussions and review of additional documentation, the inspectors noted that the modifications initially scheduled for implementation during RFO 10 to address the EFIC/EFW control system concerns, had been deferred until RFO 11 in 1998. The inspectors noted that the Manager, Nuclear Plant

Operations (MNPO) expressed concern over the possible deferral of the EFIC modifications past RFO 10. In a memorandum to the Plant Review Committee (PRC) (IOC OP95-0069, dated July 21, 1995, which transmitted the operability evaluation for EFIC control of EFW flow vs operator action and the use of Rule 3 of EOP-13, EFW Control), the MNPO stated that operators had worked around the problem since 1986 and it was time to make the modifications based on the recommendations of the EFIC Task Force. The inspectors further noted that the PRC also expressed concern over the EFIC modification deferrals and recommended that all EFIC Task Force items be resolved prior to exiting RFO 10 (IOC NPRC 95-0048 dated August 7, 1995).

The inspectors discussed the deferred EFIC modifications with licensee senior management (Director, Nuclear Engineering and Projects; and Director, Nuclear Plant Operations (DNPO)). During these discussions, licensee management stated that the EFIC modifications were deferred because of time restraints and engineering manpower restraints due to other overriding priorities. The DNPO further stated that one of the indicators used in the determination to defer the EFIC modifications was that the operators had received simulator training on Rule 3 of EOP-13 and no deficiencies related to operator performance had been identified. Rule 3 provided guidance for taking manual control of the EFW flow control valves.

The inspectors reviewed Rule 3 of EOP-13, EFW Control, Revision 2, and the operability evaluation included with IOC OP95-0069. The inspectors concluded that the licensee provided adequate bases to support their conclusions that the EFIC/EFW system was operable. However, the inspectors also concluded that the licensee has not taken timely corrective actions to resolve the EFIC system concerns and problems. The inspectors informed the licensee that failure to take timely corrective actions for the EFIC system concerns and problems would be identified as URI 50-302/96-04-06, Untimely Corrective Actions for the EFIC System Concerns and Problems. This issue remains unresolved pending NRC review to determine if it is an additional example of an apparent violation discussed at the predecisional enforcement conference on March 27, 1996.

c. <u>Conclusions on Problem Identification and Resolution</u>

The inspectors concluded that Engineering support of facilities and equipment was not always timely and the quality varied as indicated by the actions to address some of the issues related to the MUT and to resolve the EFIC system concerns and problems.

Engineering support has been less than effective in that timely corrective actions have not been taken to address the longstanding operator concerns and design inadequacies associated with the EFIC system. An unresolved item was identified for this issue.

Poor communications in the past between operations and engineering personnel contributed to the engineering support being less than effective. The inspectors noted that the licensee has taken actions to improve the communications between Operations and Engineering.

## E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 96-005, Inadequate Failure Modes Review Creates Possibility of Cooling Water Flow Outside Design Basis

The inspectors reviewed the notification that had been made on January 30, 1996 (EN 29909) and the LER, issued on February 28, 1996 and a subsequent revision issued on May 1, 1996, for a potential operation outside of the design basis. The investigation conducted by the licensee, concluded that the root cause of the operation outside of the design basis was caused by an inadequate review of failure modes during the development of MAR 88-05-25-05. This modification, which was installed in 1994, changed circuitry to provide cooling to 2 out of the 3 RB cooling units. Prior to the installation of this modification, all 3 fans received cooling flow during ES conditions. This inadequate review is considered a weakness. The result of the inadequate review has already been addressed as a violation, VIO 50-302/96-01-06.

The licensee took immediate corrective actions, by manually isolating one of the RB cooling units inside containment. This prevents the SW cooling valves to the unit from failing open during the scenario of concern. Instructions to isolate any of the three cooling units have been incorporated into the procedure, OP-417, Containment Operating Procedure. A review is being conducted, to determine if any additional corrective actions are required. The licensee has a schedule to complete this review by August 30, 1996. At present, no operability concerns or design basis concerns exist. Corrective actions to this event will be followed up under the violation. This LER is closed.

E8.2 LER 96-001, Personnel Error by Contractor Results in Operation Outside 10 CFR 50, Appendix R Design Basis

The inspectors walked down the conduits described in the LER and verified that the conditions described in the LER and in the 10 CFR 50.72 notification (EN 29826) remained unchanged. The inspectors also verified, through discussions and visual observations, that the compensatory measures described in the LER were being performed. No problems were detected. The fire watch in the areas continues. At present, no operability or design basis issues remain open.

Permanent resolution to the design problem will be completed as part of the TSI - Thermo-lag resolution. This LER was previously closed in IR 50-302/96-01.

E8.3 (Closed) LER 95-023, Inconsistent Design Assumptions Cause Building Spray Pump Flowrate Concerns Resulting in Operation Outside the Design Basis

The inspectors reviewed the LER and its associated root cause evaluation and corrective actions. This issue was identified as a 10 CFR 50.72 notification (EN 29517) on October 27, 1995. A Non-cited violation, NCV 50-302/95-18-03, has been issued to address the issue.

The inspectors verified that the corrective actions addressed in the LER have been completed. The inspectors performed a review to assure that the assumptions in the affected calculations have been revised and are consistent. An analysis was performed to evaluate the establishment of a 1000 gpm BS flow rate to assure adequate iodine removal in the RB. This analysis justified the low actual flow rate limit of 1112 gpm. The inspectors reviewed this change and verified that the EDBD was revised to incorporate the low BS flow rate limit.

At this time, no operability or design basis issues remain open for this LER. This LER is closed.

E8.4 Event Report 30323, Insufficient Electrical Separation of Toxic Gas Monitor Channels

a. Inspection Scope (92700)

On April 19, 1996, the licensee determined that the electrical separation requirements were not met for the Toxic Gas Analyzers and submitted a 10 CFR 50.72 Report. The following summarizes the corrective actions taken by the licensee and the NRC inspection activities:

b. Observations and Findings

- Licensee Corrective Actions

During performance of Modification Approval Record (MAR) 91-08-26-07, part of the corrective actions being taken in response to cable separation problems identified by NRC Violation 302/91-01-02, the licensee found inadequate separation for Toxic Gas Analyzer power cables AHF-1048 and AHF-1051. The cables, which supplied power from 120VAC Distribution Panels ACDP-51 and ACDP-52 to the Analyzers, were routed from the panels into a "red" (train A) cable tray and exited from the "red" tray to a "XB" (non-safety) tray. In addition, the power supply (Panels ACDP-51 and ACDP-52) and the power cables from the panels to the first terminal box were found to be non-safety-related, whereas the power cables from the terminal boxes to the Analyzers were safety-related. No isolation devices were installed between the safety-related and non-safety-related cables. Since the Analyzers are safety-related, the power supplies and the cables should have been safety-related. Similar conditions of lack of isolation devices and non-safety-related-cables were found for the control cables for the Analyzers. The separation and isolation conditions were determined to be outside the design basis documented in Section 8.2.2.12 of the Final Safety Analysis Report (FSAR) and the Crystal River 3 Electrical Design Criteria. At the time of the original design, the designers determined that the Analyzers did not require power from a safety-related source since a loss of power would cause the Control Room Emergency Ventilation System (CREVS) to fail in the safe direction (recirculation mode).

PR 96-0135 was issued to define and document corrective actions for this problem. The condition was determined to be outside the design basis.

FCN 09 was issued under MAR 91-08-26-04 to: (1) change the power source for the Analyzers from non-safety-related panels to 120VAC Vital bus Panels VBDP-5 and VBDP-6, (2) correct the separation problems with power cables AHF-1048 and AHF-1051 by installing new cables in accordance with separation criteria, and (3) upgrade all Toxic Gas Analyzer power and control cables to safety-related.

- NRC Inspection Activities

The inspectors verified the corrective actions completed before startup from RFO 10 by review of the following documents:

MAR 91-08-26-04, FCN 09

PR 96-0135 documenting corrective actions

Completed WR NU 0334961, documenting pulling new cables to meet separation requirements, upgrading non-safety-related cables to safety-related, and post modification testing

In addition, the inspectors reviewed with licensee Engineering personnel the status of the electrical separation corrective action program for violation 302/91-01-02. All corrective actions should be completed by July 1996 as documented in NRC Inspection Report 50-302/94-12.

The inspectors also walked down portions of the modifications made by MAR 91-08-26-04, FCN 09, for the power and control cables.

c. <u>Conclusions</u>

Appropriate corrective actions for the specific separation and isolation problems relative to the Toxic Gas Analyzers have been corrected. The inspectors concluded that corrective actions were adequate for startup from 10R.

Additional inspections relative to extent of condition corrective actions will be inspected after issuance of the LER.

E8.5 (Closed) LER 95-021-00, Inadequate Pipe Supports Allow Stress on Motor Cooler Nozzle Resulting in Operation Outside the Design Basis

See NRC Inspection Report 50-302/95-18 for documentation of a previous inspection of this item.

a. Inspection Scope (92700)

On October 4, 1995, the licensee determined stresses exceeded code allowables for the Reactor Building Spray Pump (BSP) Motor Cooler outlet nozzles. The nozzles are a series (12) 5/8" diameter tubes between the cooler tube sheet and the 2" diameter Decay Heat Closed Cycle Cooling (DC) system return header. Paragraph b. below summarizes the corrective actions taken by the licensee and the NRC inspection activities.

b. Observations and Findings

- Licensee Corrective Actions

This problem resulted when Engineering attempted to evaluate the BSP-1B Motor Cooler nozzles using a classic rigorous analysis. This analysis was performed in response to a Request for Engineering Assistance (REA) issued to evaluate incorrectly installed pipe support baseplate concrete anchor bolts on two of the Cooler return pipe supports. The anchor bolts were installed at an angle resulting in the support base plates not being snug against the wall. Since analysis or design data relative to the hangers in question could not be located, the licensee attempted to determine the support load requirements for the nozzles by developing a new analysis model. The preliminary analysis, using a number of assumptions since the original motor cooler design documentation could not be retrieved, raised questions pertaining to adequacy of the supports and the nozzles.

A PR was issued and an Operability Assessment performed. Further analysis and evaluations determined that the piping and supports are within code allowables. The original large bore rigorous analysis for the return piping and supports justified the piping to be acceptable without the two supports in question. It was not clear why the two supports had been added. Since the original analysis determined the piping to be acceptable without the two questionable supports, the supports and piping were accepted and the two supports abandoned in place.

For the nozzles, the new analysis model indicated that the nozzle stresses would exceed allowables in a seismic event. Since the analysis made a number of assumptions, showed the stresses to be acceptable except for seismic considerations, and the nozzle configuration did not lend itself to standard rigorous analyses, the license concluded that the nozzles could be dispositioned in accordance with the Seismic Qualification Users Group (SQUG) requirements of the Unreviewed Safety Issue (USI) 46 program for older plants. The coolers had originally been dispositioned under the SQUG requirements during seismic qualification under NUREG 1211. As part of disposition of the PR and LER, the same contractor who originally walked down the piping and coolers in question for the USI 46 program, re-walked the BSP-1B motor cooler piping with licensee Engineers and again concluded the nozzles could be dispositioned as acceptable under SQUG requirements.

Revision 1 to Calculation S-92-0162 was issued to show disposition of the nozzles under the SQUG requirements.

Other pump motors with similar coolers were inspected and found to be acceptable under the same criteria as used for the BSP motor coolers.

- NRC Inspection Activities

The following documents were reviewed to verify the licensee's corrective actions for the LER:

Calculation S-92-0162, Revision 1
Calculation M-75-0002, Revision 2
PR 95-0192
REA 941290
BSP-1A Motor Cooler nozzles and return piping

In addition, the inspectors observed the condition of the Motor Cooler Nozzles and return piping for the BP-1B and MUP-1A Motors.

c. <u>Conclusions</u>

The inspectors concluded that corrective actions identified in the LER had been completed and adequately resolved the identified problem.

The LER is closed.

E8.6 <u>(Open) LER 96-006-00, Consideration of Instrument Error Results in Unacceptable Margin for HPI Flow in SBLOCA Analysis (92700)</u>

See NRC Inspection Reports 50-302/95-20, 50-302/95-21, 50-302/96-03, and URI 50-302/95-20-01 for documentation of previous inspections of this issue.

On January 30, 1996, Engineering determined that unacceptable analytical results are obtained when worst case instrument error and EOP setpoints for preventing High Pressure Injection (HPI) pump runout are used in the Small Break Loss of Coolant Accident (SBLOCA). The cause of the event was inadequate incorporation of design assumptions and appropriate flow instrument error in an EOP.

As part of the corrective actions for this problem, MAR 96-02-09-01, HPI Flow Indicators, was issued to upgrade the High Pressure Injection (HPI) flow indication system by replacing the existing low/high dual flow indicators with new instruments and installing two new low range indicators on each ESF train.

During the current inspection, the inspectors verified that the licensee had initiated revisions to the Technical Specification (TS) bases and the FSAR to incorporate the updated HPI flow instrumentation. In addition, the inspectors verified that the question of HPI Pump runout concerns with two pumps running had been addressed. The following documents were reviewed:

Attachment A to Nuclear Licensing Procedure NL-07, dated 4/29/96, documenting change to TS Bases B 3.3.17, Section 6

Interoffice Correspondence NED96-0177, dated April 3, 1996, documenting changes to be made to the FSAR

Interoffice Correspondence NED96-0236, dated April 12, 1996, addressing the concerns regarding the possibility of reaching runout conditions with two Makeup Pumps operating in parallel

Based on review of the above documents, the inspectors concluded that the licensee has initiated actions to revise the TS bases and the FSAR to reflect the upgraded HPI flow indicators. In addition, the concerns relative to Makeup Pump runout have been addressed.

E8.9 (Open) URI 96-03-08, Battery Chargers Degraded Voltage; and MAR 93-05-07-01, Battery Charger Replacement

a. Inspection Scope (37550, 92700)

This URI was opened to track the licensee's resolution of an issue with battery charger testing. The design basis for the new A train battery chargers installed in March 1996 was, in part, to maintain dc output voltage within plus or minus one-half percent, from no load to full load (200 amperes dc output), for design basis input ac voltages including as low as 427V (degraded grid voltage). However, the inspectors had noted that vendor test data supplied with the new battery chargers indicated that they had been tested to only as low as 432V. The inspectors followed up on this issue.

b. Observations and Findings

The licensee had purchased six new battery chargers from C&D Charter Power Systems in 1995. Two had been installed in the A train in March 1996 and the other four were still in the licensee's warehouse. In response to this issue, the licensee contacted C&D, who stated that they had never tested battery chargers to below 432V ac input. The licensee then sent one of the new battery chargers from the warehouse, and also sent one of the old battery chargers (that had been removed from the A train in March 1996), to the vendor for additional testing in April 1996.

The inspector reviewed the vendor's April 1996 test results on the two battery chargers. The new battery charger had passed the test, demonstrating satisfactory output voltage regulation with input voltage at 432V, 427V, 423V, and 414V. The old battery charger had failed the test, demonstrating satisfactory output voltage regulation with input voltage at 432V and unsatisfactory output voltage regulation with input voltage at 427V and 423V. Based on the test information, the licensee's operability assessment on the old battery chargers, that were still installed as the B train and spare chargers, was that they were operable but degraded with the plant in Mode 5. This determination was based on the fact that the ES loads were substantially less in Mode 5 than in Modes 1 through 4 such that the battery charger would be able to maintain rated output voltage with input ac voltage as low as 427 volts. The operability assessment also concluded that the justification for continued operation was only applicable for the plant in mode 5, and that prior to ascension into mode 4 the B train battery chargers must be replaced to provide a fully operable B train dc electric power subsystem.

The inspector found the licensee's operability assessment for the battery chargers to be conservative. Also, the inspector concluded that the licensee's prompt testing of a new battery charger adequately addressed the design basis and operability status of the installed new A train battery chargers. Additionally, the inspector concluded that there was no past operability concern with the new A train battery chargers, since a sample one had passed the test and since they had been installed and in service with the plant in Mode 5 prior to the satisfactory testing.

The inspector reviewed purchase order specifications, receipt inspection records, and receipt inspection procedures for the new battery chargers and the old battery chargers. Based on this review, the inspector concluded that purchase order specifications adequately supported the design basis. However, six new safety-related battery chargers were improperly accepted on receipt inspection in 1995. The vendor had supplied a certificate of conformance with the licensee's purchase order; however, test data from the vendor that had been supplied with the battery chargers indicated that the battery chargers had not been tested to assure they would operate at the lowest ac input voltage specified in the purchase order or required by the design basis. The licensee's Receiving Inspection Report, dated November 1, 1995, accepted the six battery chargers.

The inspector also concluded that six safety-related battery chargers were improperly accepted on receipt inspections in 1972. The vendor (C&D Batteries) had supplied a certificate of compliance with the licensee's purchase order; however, test data from the vendor that had been supplied with the battery chargers indicated that the battery chargers had not been tested to assure they would operate at the lowest ac input voltage specified in the purchase order or required by the design basis. The test data also indicated that one of the battery chargers failed to meet dc output voltage regulation requirements at ac input voltages to which it was tested. The licensee's receipt inspection report, dated July 17, 1972, accepted the six battery chargers from C&D Batteries and stated: "A letter of compliance and certified test reports, as required by above specs are present and acceptable." The battery chargers were installed during original construction as the A train (A and C), B train (B and D), and installed spare (E and F) chargers, with the charger that had failed initial tests installed in the B train.

In summary, test results from 1972 and 1996 indicated that one of the two B train battery chargers and one of the two A train battery chargers failed to regulate dc output voltage as required by the original purchase specifications, the original design basis, and the current design basis. The other battery chargers (one A train, one B train, and two spares) had not been adequately tested to assure they could perform their design safety function. The licensee's April 1996 operability evaluation of these battery chargers was that they were operable but degraded in Mode 5 and were inoperable in Modes 1 through 4. However, these battery chargers had been relied upon for operability from plant licensing in December 1976 through April 1996.

The inspector reviewed receipt inspection procedures. Procedure FPC-016, Receiving Inspection of Equipment and Material, Rev. 0, dated April 24, 1972, step 4.2.2.2 required that Q. C. Inspection personnel verify that any documentation required is present and that test results conform to the specifications. Nuclear Procurement & Storage Manual, Section 8.4, Receiving Inspection, Rev. 12, dated June 7, 1995, step 8.4.3.2 required that the Nuclear Materials QC Inspector verify that the documentation, such as Certificate of Conformance, furnished by the vendor meets the requirements of the FPC purchase order. Step 8.4.3.2 also required that test documents shall describe the type of operation and provide evidence of completion and/or verification. The inspector concluded that the licensee's receipt inspections of battery chargers in 1992 and 1995 failed to comply with these procedures.

On May 13, 1996, the licensee issued LER 96-012, Operation Outside Design Basis Caused by Battery Chargers Having Had Inadequate Test Results Accepted in Error. The inspector reviewed the LER and noted that it did not completely address past ability of the battery chargers to perform their safety function prior to 1991. By telephone call of May 16, 1996, between A. Gibson of the NRC and B. Hickle of FPC, FPC stated that they planned to submit a revised LER that would better address the licensee's assessment of past operability of the battery chargers. This URI will remain open pending receipt of the licensee's revised LER and additional NRC review of past operability of the battery chargers.

The inspector verified that the licensee was pursuing the need for a 10 CFR Part 21 report on the deficient battery charger testing with the vendor, C&D Charter Power Systems.

c. Conclusions

The inspectors concluded that the licensee had performed inadequate receipt inspections of safety-related battery chargers in 1972 and 1995. URI 50-302/96-03-08, Battery chargers degraded voltage, remains open pending further review of past operability.

## IV. Plant Support

### R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Reactor Coolant System Water Chemistry

a. Inspection Scope (92903, 71750)

The inspectors reviewed the procedures for the control of hydrogen concentration for the RCS chemistry to determine if these procedures met the provisions of the FSAR and that changes to these procedures were provided with appropriate safety evaluations.

b. Observations and Findings

Limits on dissolved hydrogen in the RCS were established to control the production of free oxygen as a result of the radiolytical decomposition of water and to provide a reduced environment in the RCS to minimize the production of corrosion products.

The CR3 FSAR, Section 4.1.2.7, Table 4-10 and Table 9-3 indicated that the dissolved hydrogen concentration level in the RCS was maintained between the limits of 15 to 40 cc/kg. The licensee informed the inspectors that these limits were established by B&W and that the plant had operated within these limits from 1977 until 1993.

The November 1990 revision to EPRI PWR Primary Water Chemistry Guidelines, and the December 1992 revision to the B&W Water Chemistry Manual for 177FA Plants (CR3 is a 177FA Plant) recommended that the level of dissolved hydrogen in the RCS be maintained between 25-50 cc/kg while the reactor was at power.

After issuance of the revisions to these B&W and EPRI documents the CR3 management initiated actions to maintain the dissolved hydrogen concentration in the RCS closer to the new recommended limits of 25-50 cc/kg. These actions were in the form of verbal directives by CR3 management. This required the plant operators to periodically lower the makeup tank level, add hydrogen to the tank and then increase the water level in the tank to increase the makeup tank pressure in order to dissolve the hydrogen into the RCS solution. During these evolutions, operations attempted to maintain the level of water and pressure in the makeup tank at a point below the safe levels established by Curve 8 in OP-103B, as referenced by procedure OP-402, Makeup and Purification System. Operations personnel experienced difficulty in maintaining the newly established dissolved hydrogen concentration limits of 25-50 cc/kg. As documented by NRC IRs 50-302/95-13 and 95-22, these limits had been exceeded a number of times.

Procedure CP-142, Primary Water Chemistry Guidelines, Table 3 established the chemistry parameters to be measured for the RCS and the action to be taken if the parameters were not met. The value of dissolved hydrogen levels to be maintained during normal plant operations was set at 15 to 40 cc/kg. If the hydrogen level was less than 10 cc/kg, the RCS was to be restored to greater than 10 cc/kg within 24 hours or the unit was to be shutdown within 24 hours. If the hydrogen level was less than 15 or greater than 40 cc/kg, the level was to be restored to the normal level within 7 days or a technical evaluation was to be performed and a corrective action program implemented.

Licensee personnel informed the inspectors that the dissolved hydrogen limits in effect at CR3 had essentially been the same from 1977 until Revision 4 of Procedure CP-142 became effective on December 11, 1995. Prior to December 1995, Procedure CP-142 permitted the hydrogen level in the RCS to be maintained at any level between 15 and 40 cc/kg. Revision 4 to Procedure CP-142 changed the RCS dissolved hydrogen value to any level between 25 and 50 cc/kg. This was a change from the values listed in the FSAR.

The inspectors noted that, although the new values on dissolved hydrogen concentration were not incorporated into plant procedures until December 1995, the plant had been operating under the new limits for over a year. The inspectors did not see where the licensee had performed an evaluation to determine if and how the new dissolved hydrogen concentration limits would impact plant operation.

The measuring methods, procedures, frequency and acceptance criteria for the CR3 chemistry program were covered by Procedure CH-400, Nuclear Chemistry Master Scheduling Program. Procedure CH-400, Enclosure 2 indicated that the hydrogen requirements for the RCS were to be measured by a hydrogen monitoring instrument each Monday through Friday. This procedure was revised by Revision 3, effective December 18, 1995, to change the lower acceptance limits from 15 to 25 cc/kg and the upper limits from 40 to 50 cc/kg. As noted, these limits were different from those listed in the FSAR.

The inspectors reviewed the procedure revision packages for Revision 4 to Procedure CP-142 and Revision 3 to Procedure CH-400 and noted that 10 CFR 50.59 safety evaluations had not been performed for these revision. The licensee's 10 CFR 50.59 screening review failed to identify that these revisions changed the RCS dissolved hydrogen limits which were identified in the FSAR.

The failure to fully evaluate the operational consequences of the increased dissolved hydrogen concentration prior to implementation and failure to perform a safety evaluation for changes to facilities or procedures as described in the FSAR to determine if the proposed changes involved an unreviewed safety question is identified as URI 50-302/96-04-07, Failure to Perform 10 CFR 50.59 Safety Evaluation for Procedures Involving Dissolved Hydrogen Concentration Changes as Described in the FSAR. This item remains unresolved pending NRC review to determine if it is an additional example of an apparent violation discussed at the predecisional enforcement conference on March 27, 1996.

On March 12, 1996, the licensee identified that the changes to Procedures CP-142 and CH-400 resulted in changes which required revisions to the FSAR. Action was initiated to update the FSAR. However, the failure to perform a 10 CFR 50.59 safety evaluation for the changes to the procedures was not identified by the licensee as a discrepancy. After this item was identified by the inspectors, the licensee initiated a precursor card to review this item, determine the cause, and initiate appropriate corrective action.

The licensee had recently identified numerous other examples where implementing procedures did not agree with the FSAR information and commitments. Problem Report 96-119, FSAR Review Findings, had been issued to review this issue and determine the appropriate corrective actions. The resolution of this issue will be reviewed during the review of the corrective action taken on the above URI.

c. Conclusions on RP&C Controls

The inspectors concluded that management directed operators to increase the dissolved hydrogen concentration in the RCS to 25-50 cc/kg without fully evaluating the operational consequences of this directive. Implementation of the directive reduced operating margins and contributed to operation outside the limits of Curve 8 in Procedure OP-103B and the design basis of the plant. Furthermore, when the chemistry procedures for obtaining and evaluating the RCS dissolved hydrogen concentrations were revised in December 1995, the revised acceptance criteria did not conform to data in the FSAR and 10 CFR 50.59 safety evaluations were not performed. The failure to perform appropriate 10 CFR 50.59 safety evaluations to address plant changes which were not consistent with the FSAR was identified as an unresolved item.

**P8 Miscellaneous EP Issues**

P8.1 (Closed) Notice of Deviation 50-302/95-16-05, Deviation From the Design Commitments for the TSC Emergency Ventilation System. (92904)

The licensee provided a response to the NOD on November 9, 1996, revised that response by letter dated February 7, 1996, and submitted another revised response on March 29, 1996. The licensee had identified that the normal and emergency TSC ventilation systems required redesign to permit the TSC ventilation system to properly function in the emergency mode. The revised design eliminated bypass leakage paths, improved the testability of the system, utilized manual dampers to improve repeatable performance, and provided positive closure of the non-emergency outside air intakes during emergency operation. By letter dated April 30, 1996 the licensee revised their earlier responses and provided details of the TSC ventilation system modifications. The modifications have been completed and the system has been balanced according to design calculations. The TSC emergency ventilation system performance was reviewed and found acceptable as documented in IR 50-302/96-03, paragraph P2, therefore this NOD is closed.

## V. Management Meetings

### X1 Exit Meeting Summary

The inspection scope and findings were summarized on May 21, 1996 with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. The licensee took exception to URI 50-302/96-04-05, but stated they would continue to evaluate this issue.

### PARTIAL LIST OF PERSONS CONTACTED

**Licensees**

K. Baker, Manager, Nuclear Configuration Management
P. Beard, Senior Vice President Nuclear Operations
G. Boldt, Vice President Nuclear Production
J. Campbell, Manager, Nuclear Security
J. Campbell, Assistant Plant Director, Maintenance and Radiation Protection
W. Conklin, Jr., Director, Nuclear Operations Materials and Controls
R. Davis, Assistant Plant Director, Operations and Chemistry
D. DeMontfort, Superintendent, Nuclear Operations
R. Enfinger, Manager, Safety Assessment Team
R. Fuller, Manager, Nuclear Chemistry
B. Gutherman, Manager, Nuclear Licensing
G. Halnon, Manager, Nuclear Licensing
E. Hickle, Director, Nuclear Plant Operations
L. Kelley, Director, Nuclear Operations Site Support
K. Koon, Manager, Nuclear Outages
K. Lancaster, Manager, Nuclear Projects
J. Maseda, Manager, Nuclear Engineering Design
P. McKee, Director, Quality Programs
R. McLaughlin, Nuclear Regulatory Specialist
B. Moore, Manager, Nuclear Integrated Scheduling
W. Rossfeld, Manager, Site Nuclear Services
J. Stephenson, Manager, Radiological Emergency Planning
F. Sullivan, Manager, Nuclear Plant Technical Services
P. Tanguay, Director, Nuclear Engineering and Projects
R. Widell, Director, Nuclear Operations Training
D. Wilder, Manager, Radiation Protection

**NRC**

B. Crowley, Reactor Inspector, Region II (April 29 through May 3, 1996)
E. Girard, Reactor Inspector, Region II (April 29 through May 10, 1996)
F. Hebdon, Director, Project Directorate II-3, NRR (May 3, 1996)
G. Hopper, Reactor Inspector, Region II (April 29 through May 3, 1996)
J. Jacobson, Special Inspection Branch, NRR (May 9, 1996)
W. Miller, Reactor Inspector, Region II (April 22 through April 26, 1996)
L. Raghavan, Project Manager, NRR (May 3, 14, and 15, 1996)
R. Schin, Reactor Inspector, Region II (April 29 through May 3, 1996)
A. Thadani, Associate Director for Technical Review, NRR (May 3, 1996)
M. Thomas, Reactor Inspector, Region II (April 22 through April 26, and May 6 through May 10,1996)
J. York, Reactor Inspector, Region II (April 22 through 26, 1996)

## INSPECTION PROCEDURES USED

| | |
|---|---|
| IP 37550: | Engineering |
| IP 37551: | Onsite Engineering |
| IP 40500: | Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems |
| IP 42001: | Emergency Operating Procedures |
| IP 61726: | Surveillance Observations |
| IP 62703: | Maintenance Observations |
| IP 71707: | Plant Operations |
| IP 71750: | Plant Support Activities |
| IP 92700: | Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities |
| IP 92901: | Followup - Operations |
| IP 92902: | Followup - Engineering |
| IP 92903: | Followup - Maintenance |

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| Type | Item Number | Status | Description and Reference |
|---|---|---|---|
| URI | 96-04-01 | Open | Discrepancies in the EDBD and the FSAR regarding the prevention of boron precipitation post LOCA. (paragraph O3.1) |
| VIO | 96-04-02 | Open | Failure to take adequate corrective actions and revise procedure VP-580 in a timely manner. (paragraph O3.2) |
| IFI | 96-04-03 | Open | Effect of setpoint calculations on EOP revisions. (paragraph O3.4) |
| URI | 96-04-07 | Open | Failure to Perform 10 CFR 50.59 Safety Evaluation For Procedures Involving Dissolved Hydrogen Concentration Changes as Described in the FSAR (Paragraph R1.1) |
| URI | 96-04-08 | Open | Evaluation of evolutions described as unreviewed safety questions. (paragraph O1.1) |
| URI | 96-04-09 | Open | Failure to Incorporate Design Information into Operations Procedure for MUV-64 (Paragraph E2.3) |

| | | | | |
|---|---|---|---|---|
| URI | 96-04-06 | Open | Untimely Corrective Actions for the EFIC System Concerns and Problems (Paragraph E2.4) |

Closed

| Type | Item Number | Status | Description and Reference |
|---|---|---|---|
| NOD | 50-302/95-16-05 | Closed | Deviation from the design commitments for the Technical Support Center emergency ventilation system. (paragraph P8.1) |
| LER | 95-008-01 | Closed | Oil Leakage from Reactor Coolant Pump Motors Not Collected by the Lube Oil Collection System Leads to Operation Outside Design Basis (paragraph M8.1) |
| LER | 95-021 | Closed | Inadequate Pipe Supports Allow Stress on Motor Cooler Nozzle Resulting in Operation Outside the Design Basis (paragraph E8.5) |
| LER | 95-023 | Closed | Inconsistent design assumption cause building spray pump flowrate concerns resulting in operation outside the design basis. (paragraph E8.3) |
| LER | 95-026-01 | Closed | Unqualified flow instrument used in determining HPI pump runout conditions caused by failure to recognize applicability of Reg. Guide 1.97. (paragraph O8.2) |
| LER | 96-005 | Closed | Inadequate failure modes review creates possibility of cooling water flow outside design basis. (paragraph E8.1) |
| NCV | 96-04-04 | Closed | Failure to correctly implement Technical Specification Control Room Emergency Ventilation System testing requirements. (paragraph M3.3) |
| NCV | 96-04-05 | Closed | Failure to Collect RCP Motor Oil Leakage (paragraph M8.1) |
| VIO | 93-16-08 | Closed | Inadequate PSTG, violation of an NRC Order (paragraph O8.4) |

| | | | |
|---|---|---|---|
| VIO | 93-16-10 | Closed | Inadequate 50.59 reviews of EOPs (paragraph O8.6) |
| VIO | 93-16-11 | Closed | Failure to follow V&V procedure (paragraph O8.7) |

**Discussed**

| Type | Item Number | Status | Description and Reference |
|---|---|---|---|
| VIO | 93-16-07 | Open | Inadequate EOP and AP procedures. (paragraph O8.3) |
| URI | 96-03-08 | Open | Battery Charger Degraded Voltage (paragraph E8.9) |
| LER | 95-005 | Closed | Engineering evaluation determines insufficient LPI pump net positive suction head may result in operation outside design basis. (paragraph O8.1) |
| LER | 96-001 | Closed | Personnel error by contractor results in operation outside 10 CFR 50 Appendix R design basis. (paragraph E8.2) |
| LER | 96-006 | Open | Consideration of Instrument Error Results in Unacceptable Margin for HPI Flow in SBLOCA Analysis (paragraph E8.6) |
| URI | 96-03-10 | Open | Failure to Initiate Problem Report to Document and Disposition the Failure of a Surveillance Test. Additional examples of this URI were identified where the licensee failed to initiate a precursor card for out of tolerance instrument calibrations (Paragraph M1.1) |
| VIO | 95-22-01 | Open | Additional examples of (paragraph O1.1) |
| VIO | 95-22-02 | Open | Additional examples of (paragraph O1.1) |

LIST OF ACRONYMS USED

ac - Alternating Current
ADI - Absolute Drift Indications
AHD - Air Handling Vent and Cooling Damper
AHV - Air Handling Vent and Cooling Valve
AI - Administrative Instruction
ALARA - As Low as Reasonably Achievable
ANSI - American National Standards Institute
ANSS - Assistant Nuclear Shift Supervisor
AP - Abnormal Procedure
APC - Alternate Plugging Criteria
ASME - American Society of Mechanical Engineers
ASV - Auxiliary Steam Valve
ATWS - Anticipated Transient Without a Scram
B&PV - Boiler and Pressure Vessel
B&W - Babcock & Wilcox
BAST - Boric Acid Storage Tank
BS - Building Spray
BSP - Building Spray Pump
BVT - Below Voltage Threshold
BWST - Borated Water Storage Tank
CAL - Confirmatory Action Letter
cc - Cubic Centimeters
CCTV - Closed Circuit Television
CFR - Code of Federal Regulations
CFT - Core Flood Tank
CFV - Core Flood Valve
CLPD - Cold Leg Pump Discharge
CP - Compliance Procedure
CREVS - Control Room Emergency Ventilation System
CR3 - Crystal River Unit 3
CST - Condensate Storage Tank
dc - Direct Current
DC - Decay Heat Closed Cycle Cooling
DCHE - DC Heat Exchanger
DEV - Deviation
DFP - Diesel Fuel Pump
DH - Decay Heat
DHHE - Decay Heat Heat Exchanger
DHP - Decay Heat Pump
DHR - Decay Heat Removal
DHV - Decay Heat Valve
DNPO - Director, Nuclear Plant Operations
dp - Differential Pressure
EA - Enforcement Action
ECCS - Emergency Core Cooling System(s)
EDBD - Enhanced Design Basis Document
EEI - Escalation Enforcement Item
EFIC - Emergency Feedwater Initiation and Control
EFP - Emergency Feedwater Pump
EFT - Emergency Feedwater Tank

EFW - Emergency Feedwater
EFV - Emergency Feedwater Valve
EGDG - Emergency Diesel Generators
EM - Emergency Plan Implementing Procedure
EOP - Emergency Operating Procedure
EP - Emergency Preparedness
EPRI - Electric Power and Research Institute
ES - Engineered Safeguards
ESF - Engineered Safeguards Feature
ESAS - Engineered Safety Actuation System
ET - Eddy Current Test
EVS - Emergency Ventilation System
F - Fahrenheit
FCN - Field Change Notice
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
FWP - Feedwater Pump
FWV - Feedwater Valve
GL - Generic Letter
gpm - Gallons Per Minute
HELB - High Energy Line Break
HP - Health Physics
HPI - High Pressure Injection
in. Hg - Inches of Mercury
I&C - Instrumentation and Control
ICC - Inadequate Core Cooling
ICS - Integrated Control System
IEEE - Institute of Electrical and Electronics Engineers
IFI - Inspection Followup Item
INPO - Institute of Nuclear Power Operations
IR - Inspection Report
ISA - Instrument Society of America
ISI - Inservice Inspection
ISO - Isometric Drawing
IST - Inservice Test
ITS - Improved Technical Specification
JCO - Justification for Continued Operation
JPM - Job Performance Measure
kg - Kilogram
Kv - Kilovolt
Kw - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
LTE - Lower Tube End
LTS - Lower Tube Sheet
MAR - Modification Approval Record
MCB - Main Control Board
MCC - Motor Control Center
MFW - Main Feedwater
MNPO - Manager of Nuclear Power Operations

MOV - Motor Operated Valve
MOVATS - Motor Operated Valve Analysis and Test System
MP - Maintenance Procedure
MRP - Management Review Panel
MSV - Main Steam Valve
MT - Magnetic Particle Testing
MU - Make Up
MUP - Make-up Pump
MUT - Make-up Tank
MUV - Make-up Valve
MW - Megawatt
NCV - Non-cited Violation
NDE - Nondestructive Examination
NEP - Nuclear Engineering Procedure
NOD - Nuclear Operations Department
NOV - Notice of Violation
NPSH - Net Positive Suction Head
NQI - Non-Quantifiable Indication
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSM - Nuclear Shift Manager
NSSS - Nuclear Steam System Supplier
NUREG - NRC technical report designation
OCR - Operability Concerns Resolution
OP - Operating Procedure
OSB - Operations Study Book
OTSG - Once Through Steam Generator
PM - Preventive Maintenance
PORV - Power Operated Relief Valve
ppb - Parts Per Billion
PR - Problem Report
PRC - Plant Review Committee
PSI - Preservice Inspection
psig - pounds per square inch gauge
PT - Liquid Penetrant
PTLR - Pressure and Temperature Limits Report
PWR - Pressurized Water Reactor
QC - Quality Control
QA - Quality Assurance
QAP - Quality Assurance Procedure
RB - Reactor Building
RC - Reactor Coolant
RCA - Radiation Control Area
RCP - Reactor Coolant Pump
RCPPM - Reactor Coolant Pump Power Monitor
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RFO - Refueling Outage
RG - Regulatory Guide
RO - Reactor Operator
RPC - Rotating Pancake Coil
RP&C - Radiological Protection and Chemistry

RT - Radiographic Inspection
RW - Nuclear Services and Decay Heat Seawater
RWP - Nuclear Services and Decay Heat Seawater Pump
RWV - Nuclear Services and Decay Heat Seawater Valve
SALP - Systematic Assessment of Licensee Performance
SAT - Systems Approach to Training
SDT - Station Drain Tank
SER - Safety Evaluation Report
SFPD - Safety Function Determination Program
SG - Steam Generator
SOER - Significant Operating Event Report
SP - Surveillance Procedure
SR - Surveillance Requirement
SSOD - Shift Supervisor on Duty
STI - Short Term Instruction
SW - Nuclear Services Closed Cycle Cooling System
SWHE - SW Heat Exchanger
SWP - SW System Pump
SWV - SW System Valve
TBD - Technical Basis Document
$T_c$ - Cold Leg Temperature
TI - Temporary Instruction
TMAR - Temporary Modification Approval Record
TMI - Three Mile Island
TS - Technical Specification
TSC - Technical Support Center
TSCR - Technical Specification Change Request
TW - Through Wall
UAf - A measure of heat exchanger effectiveness
UHS - Ultimate Heat Sink
URI - Unresolved Item
USAS - United States of America Standards
USI - Unreviewed Safety Issue
UT - Ultrasonic Test
VIO - Violation
VOTES - Valve Operation Test and Evaluation System
Vpp - Volts point-to-point
vs - Versus
WR - Work Request