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

Report No.: 50-302/95-18

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

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

Facility Name: Crystal River 3

Inspection Conducted: September 17 through November 4, 1995

Inspector: Ross Butcher 11-9-95
R. Butcher, Senior Resident Inspector Date Signed

Accompanying Inspector:

T. Cooper, Resident Inspector

Approved by: K Landis 11-9-95
K. Landis, Chief, Branch 3 Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This inspection was conducted by the resident inspectors in the areas of plant operations, surveillance observations, maintenance observations, plant support, self assessment, evaluation of on-line maintenance, on-site follow-up and in-office review of written reports of non-routine events and 10 CFR Part 21 reviews, and engineering activities follow-up. Numerous facility tours were conducted and facility operations observed. Backshift inspections were conducted on October 2, 3, 4, 10, 11, 12, 14, and 24, 1995.

Results:

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

Plant Operations:

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

A weakness was identified involving the decision to voluntarily remove two safety systems from service concurrently. (paragraph 1.1.2.9)

A strength was identified regarding the questioning attitude and conservative decisions by the Shift Supervisor regarding the surveillance testing of the Engineered Safety Actuation System logic matrices. (paragraph 1.2.2.3)

Maintenance:

A weakness was identified regarding the failure to properly install/replace the restraining clips on the Reactor Building sump grating. (paragraph 1.1.2.6)

Non-Cited Violation 50-302/95-18-04, Failure to test core flood valves CFV-1 and CFV-3 in accordance with ASME Section XI as required by TS. (paragraph 1.2.2.2)

Non-Cited Violation 50-302/95-18-05, Inadequate procedure to perform surveillance on Engineered Safety Actuation System logic matrices. (paragraph 1.2.2.3)

Non-Cited Violation 50-302/95-18-06, Failure to install spool piece RW-44 per design drawings. (paragraph 1.2.2.5)

Engineering:

A weakness was identified regarding the lack of timely followup on a 1992 concern regarding operating with both steam generator cross tie valves being open at the same time. (paragraph 1.1.2.1)

Non-Cited Violation 50-302/95-18-01, Failure to maintain the make-up pump lube oil pumps as safety related components. (paragraph 1.1.2.2)

Non-Cited Violation 50-302/95-18-02, Inadequate procedure to flow balance the Decay Heat Closed Cycle Cooling system. (paragraph 1.1.2.8)

Non-Cited Violation 50-302/95-18-03, Inconsistent design assumptions used for the Reactor Building spray system calculations. (paragraph 1.1.2.10)

Plant Support:

A strength was identified regarding a health physics technician identifying that a section of the Reactor Building sump grating was not properly restrained. (paragraph 1.1.2.6)

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REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

W. Bandhauer, Nuclear Shift Manager
* K. Baker, Manager, Nuclear Configuration Management
G. Boldt, Vice President Nuclear Production
J. Campbell, Manager, Nuclear Plant Technical Support
R. Davis, Manager, Nuclear Plant Maintenance
* B. Gutherman, Manager, Nuclear Licensing
* G. Halnon, Manager, Nuclear Plant Operations
B. Hickle, Director, Nuclear Plant Operations
L. Kelley, Director, Nuclear Operations Site Support
* G. Longhouser, Manager, Security
* W. Marshall, Nuclear Shift Manager
* P. McKee, Director, Quality Programs
* R. McLaughlin, Nuclear Regulatory Specialist
* B. Moore, Manager, Work Controls
* S. Robinson, Manager, Nuclear Quality Assurance
W. Rossfeld, Manager, Site Nuclear Services
W. Stephenson, Nuclear Shift Manager
F. Sullivan, Nuclear Shift Manager
G. Wilson, Nuclear Shift Manager

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

1.2 NRC Resident Inspectors

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

* Attended exit interview

1.3 Other NRC Personnel on Site

#@ S. Ebneter, Regional Administrator, Region II
#@ K. Landis, Branch Chief, Reactor Projects, Region II
#@ E. Merschoff, Division Director, Reactor Projects, Region II
F. Miraglia, Deputy Director, NRR
#@ L. Raghaven, Project Manager, NRR
@ G. Wunder, Project Manager, NRR
@ K. Clark, Public Affairs, Region II

Attended management meeting on October 13, 1995
@ Attended SALP presentation on October 31, 1995

2.0 Other NRC Inspections Performed During This Period

2.1 On October 13, 1995 a meeting was held at the CR-3 site to allow licensee management to present the status of their Corrective

Action Plan to NRC management. The Corrective Action Plan resulted from a March 1, 1995 meeting where the NRC expressed concerns regarding CR-3 operations. The details on this meeting will be issued in a meeting summary.

2.2 On October 31, 1995 a meeting was held at the CR-3 site in order for the NRC to present the results of the Crystal River SALP for the period of February 20, 1994 through September 16, 1995. The details on this meeting will be issued in a meeting summary.

3.0 Plant Status

At the beginning of this reporting period, Unit 3 was operating at approximately 97% which was the maximum allowable power per TS 3.3.1 due to a failure in the RCPPM on the D RCP. The unit had been on line since December 4, 1994. The following major evolutions occurred during this assessment period:

On October 13, 1995 at 11:45 p.m. a power reduction was initiated to take the unit off line for an outage to repair the D RCPPM. The unit reached 10% reactor power at 7:40 a.m. on October 14, 1995.

The unit was placed back on line at approximately 10:48 a.m. and was returned to 100% reactor power at 9:52 p.m. on October 15, 1995.

4.0 Exit Interview Summary

The inspection scope and findings were summarized on November 6, 1995, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
NCV	50-302/95-18-01	Closed	Failure to maintain the make-up pump lube oil pumps as safety related components. (paragraph 1.1.2.2)
NCV	50-302/95-18-02	Closed	Inadequate procedure to flow balance the Decay Heat Closed Cycle Cooling system. (paragraph 1.1.2.8)
NCV	50-302/95-18-03	Closed	Inconsistent design assumptions used for the Reactor Building spray system calculations. (paragraph 1.1.2.10)
NCV	50-302/95-18-04	Closed	Failure to test core flood valves CFV-1 and CFV-3 in accordance with ASME Section XI as required by TS. (paragraph 1.2.2.2)

NCV	50-302/95-18-05	Closed	Inadequate procedure to perform surveillance on Engineered Safety Actuation System logic matrices. (paragraph 1.2.2.3)
NCV	50-302/95-18-06	Closed	Failure to install spool piece RW-44 per design drawings. (paragraph 1.2.2.5)
LER	95-003	Closed	Personnel Error in Calculation May Cause Peak Fuel Clad Temperature to Exceed 2200 Degrees Fahrenheit Exceeding Acceptance Criteria of 10 CFR 50.46. (paragraph 1.6.2.1)
LER	95-011	Closed	Personnel Error Leads to Incorrect Orientation of Door Seals Resulting in Operation Outside the Design Basis. (paragraph 1.6.2.2)
LER	95-012	Closed	Design Error Leads to Inadequate Circuit Isolation Resulting in Operation Outside the Licensing (Design) Basis of the Plant. (paragraph 1.6.2.3)
LER	94-014	Closed	Reactor Building Fan/Cooler Operation Develops Cooling System Flow Imbalance and Heat Loading Having the Potential for Operation Outside the Design Basis. (paragraph 1.6.2.4)
IFI	94-22-04	Closed	Follow-up of Instrument Air System Corrective Action Plan. (paragraph 1.7.2.2)
IFI	95-08-02	Open	Corrective Actions for Make-Up System Audit Findings. (paragraph 1.7.2.3)
IFI	95-09-01	Closed	Review of Setpoint Control Program Implementation. (paragraph 1.7.2.4)

Attachment 1
Resident's Inspection

1.1.0 Plant Operations (71707)

1.1.1 Inspection Scope

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

1.1.2 Observations and Findings

1.1.2.1 Lack of Procedural Controls for OTSG Blowdown Cross Connect Isolation Valves

During a review of REA 92-0439, which had expressed a concern about both the OTSG blow down cross connect valves (MSV-130 and MSV-148) being open above 600 psig during a start up or a cooldown of the reactor, the licensee identified a potential condition for operation outside of the design basis. The licensee verified that no automatic closure exist for these valves. If, while above 600 psig, a faulted steam generator event were to occur, the possibility existed for the OTSGs to be cross connected. Although MFW would be isolated to both OTSGs, EFW would feed the good OTSG. Since the OTSGs could be cross connected, the faulted OTSG would continue to receive EFW, defeating the intent of the isolation.

The Topical Design Basis Document for the Single Failure Criteria identifies a main steam cross connected condition to supply the steam driven emergency feedwater pump. Further, the blowdown of both OTSGs due to a pipe failure downstream of MSV-55 and MSV-56 was analyzed and was determined to be within the design basis, with operator action used to mitigate the accident. Directions to close MSV-55 and MSV-56 are covered in EOP-5, Excessive Heat Transfer. No directions were contained in EOP-5 to isolate MSV-130 or MSV-148 if they were open.

The licensee reported this as a condition outside of the design basis, per 10 CFR 50.72(b)(1)(ii)(B), at 6:46 p.m. on September 27, 1995. The licensee determined that since both valves were presently closed, no immediate operability concerns existed. As an immediate action to prevent the valves from being opened simultaneously, the licensee issued a clearance assigned to the SSOD, which would allow their operation only with his approval.

By letter dated October 25, 1995, the licensee withdrew the above report. The valves in question, MSV-130 and MSV-148, are not part of the main steam line isolation or main feedwater isolation functions of the EFIC system. They are used during startup and shutdown for OTSG blowdown. During the performance of procedure OP-608, OTSG's and Main Steam Systems, there is a short time period (approximately 45 seconds to one minute) during which both of these valves are opened simultaneously, thereby cross-connecting the OTSGs. If an automatic actuation were to occur while these valves were open, they would not receive an automatic closure signal.

Subsequent to the noted NRC report, the licensee determined that two previous analysis conducted by the NSSS vendor (B&W) bounded the condition of MSV-130 and MSV-148 being open simultaneously. Based on this information, the licensee determined that this condition did not place CR-3 outside its design basis.

This issue was identified as a concern in a 1992 REA, but has just recently been investigated adequately to ensure it did not constitute operation outside the plant design basis. This lack of timeliness in following up a safety concern is considered to be a weakness.

1.1.2.2 Loss of MUP's ac Lube Oil Pump Following a Loss of Off Site Power

On September 29, 1995, the licensee notified the NRC per 10 CFR 50.72(b)(1)(ii)(B) of a condition outside of the design basis that had been identified during an engineering review. The licensee's review determined that on a loss of off site power event, the MUP's ac lube oil pumps (MUP-2A, 2B, and 2C) would be load shed from the ES bus along with the MUPs. However, the MUPs would be loaded back on the ES bus after the EGDGs start, and the ac lube oil pumps would not. This requires that the MUPs then rely on the backup dc lube oil pumps (MUP-3A, 3B, and 3C) for operability. The licensee investigated and determined that the makeup pumps and associated lubricating oil pumps were originally supplied under a single safety related purchase order as part of a skid mounted set of components. A review of the maintenance history on the pumps revealed that only the MUP-1B dc oil pump motor has been replaced. It was replaced with a safety related replacement motor. However, in 1985, the licensee had downgraded the dc lube oil pumps for the MUPs from safety related to non-safety related.

The auto start on the dc oil pumps is routinely tested quarterly, during the performance of SP-340C; MUP-1A, MUP-1B, and Valve Surveillance, and SP-340F; MUP-1C and Valve Surveillance. These procedures require that the pumps be started per the instruction in OP-402, Makeup and Purification System, which includes directions to verify the auto start capabilities of the dc oil pumps. Based on this information, the licensee had high confidence that the dc lube oil pumps could be re-qualified for safety related applications and therefore, considered the dc oil pumps to be operable.

The dc oil pumps are powered from safety related power supplies. The B MUP's dc oil pump can be powered from either the A or B safety related dc power supplies. The licensee determined that the transfer switch to select the power supply for the B dc oil pump was procured as nonsafety related. Based on these considerations, the licensee has directed that the MUP-1B have a clearance hung to prevent that pump from being selected as an ES pump. MUPs 1A and 1C were considered operable.

TS 3.5.2, ECCS - Operating, requires that two trains of ECCS be operable in Modes 1, 2, and 3. By design, only two MUPs are selected to perform as HPI pumps at any one time. With MUP-1B out of service, the required two HPI pumps were still available and no TS actions were required.

By MAR 95-10-02-01, MUP-2A/2B/2C Auto Start, the licensee replaced the existing MCB control switch for MUPs-2A, 2B, and 2C with a new control switch that would cause a running MUP-2A, 2B, or 2C to auto-start after a LOOP. This change allowed MUP-2A, 2B, and 2C to assume full responsibility for providing lube oil to MUPs 1A, 1B, and 1C for accident conditions. After the incorporation of MAR 95-10-02-01, all three MUPs were considered operable. MUP-2B was modified on October 25, MUP-2A was modified on October 27, and MUP-2C was modified on October 30, 1995.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that applicable regulatory requirements and the design basis, as defined in paragraph 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. The failure to ensure the MUPs lube oil pumps were maintained as safety related components is a violation of 10 CFR 50, Appendix B. This licensee identified violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy. This violation is identified as NCV 50-302/95-18-01, Failure to maintain the make-up pumps lube oil pumps as safety related components.

1.1.2.3 SW Cooling Water Differential Flow to RB Fans

While preparing a procedure for the SW system flow balance, the licensee determined that a discrepancy existed with the differential flow indicators for the RB ventilation fan assemblies. These indicators consist of a comparison between flow signals from the inlet flow indicator and the outlet flow indicator. If the difference between the inlet and outlet flow indicators exceeds 90 gpm, an alarm indicating a leak in the SW lines into containment, is received in the control room. The licensee made a notification to the NRC per 10 CFR 50.72(b)(1)(ii)(B) on September 29, 1995 at 12:00 p.m.

The licensee discovered, during their investigation that the flow to these indicators is normally greater than 2000 gpm. The indicators have a range of 1940 gpm, but are normally calibrated for a 0 - 930 gpm range. This results in the indicators being unable to alarm even if a leak of approximately 90 gpm is present. Redundant means of detecting a SW leak are available, such as the SW surge tank level indicator and the RB sump level indicator. These indicators are not required to be operable by TS.

The licensee has developed corrective actions to resolve this issue, including plans to recalibrate the instruments to a higher range, analysis of system design when on the alternate cooling water supply to the RB ventilation fan assemblies, and the reevaluation of the design basis requirement for the 90 gpm differential flow leak detection system.

The inspectors have reviewed the licensee's evaluation and planned corrective actions and have identified no safety concerns. The inspectors plan to review the corrective actions, as they are completed.

1.1.2.4 Hurricane Opal

On October 3, 1995, at 11:30 p.m. the licensee declared an unusual event, when a Hurricane Warning was issued for the area due to Hurricane Opal. A notification was made to the NRC per 10 CFR 50.72(a)(1)(i), after the emergency plan was entered. A violent weather committee meeting was held in the afternoon on October 3, 1995 and again in the morning on October 4, 1995. The licensee began preparations for the hurricane on October 3, 1995, per procedure EM-220, Violent Weather. Hurricane Opal traveled through the gulf and went ashore in the Pensacola, FL area. The Hurricane Warning was terminated at 1:00 a.m. on October 5, 1995 and the unusual event was exited at 2:22 a.m.

1.1.2.5 DC Piping, Support, and Nozzle Qualification Concerns

At 4:41 p.m., on October 5, 1995, the licensee notified the NRC, per 10 CFR 50.72(b)(1)(ii)(B), operation outside the design basis, for analyzed stresses on a DC piping and support arrangement that exceed maximum allowable by the code. An REA, 94-1290, had been written to request an investigation of the two pipe supports located on a DC pipe that supplies cooling water to the motor cooler for BSP-1B. Based on the analysis done by the licensee, it appears that the copper tubing at the header could experience a worst case stress level in excess of code allowables, but less than the yield stress of the assumed tubing.

The licensee performed an operability determination per procedure CP-150, Identifying and Processing Operability Concerns, and determined that the operability of the BSP was not impacted based on an inspection of the piping and supports in question. This inspection determined that no visible degradation of the components was noted, no previous failures had occurred, and substantial margin had existed between the assumed yield stress and the calculated stress levels expected to be seen. The inspectors reviewed the operability determination and had no safety concerns with the conclusions. An LER is being prepared on this issue. The inspectors will follow-up this issue under the LER corrective actions.

1.1.2.6 Reactor Building Sump Grating Clips Not Installed

On October 12, 1995 during a routine entry into the RB, a health physics technician noticed that a section of grating (2′ by 3′) over the RB sump was not physically secured. Investigation by the licensee showed that the grating in question was designed to be secured by restraining clips as indicated by MAR 91-08-32-01. An operability determination was conducted in accordance with Compliance Procedure CP-150, Identifying and Processing Operability Concerns. The engineering review per CP-150 indicated that volumetric flow rates would not result in sufficient force to dislodge the grating. The RB sump grating was determined to be operable, but degraded. The licensee designates the clips and grating as non-safety related. PR 95-198, RB Sump Grating Clips Not Installed, was issued to document this problem and required corrective actions. The licensee intends to wait until a Mode 5 outage to replace the missing clips.

The discovery of a RB sump grating that was not physically restrained as designed was an alert observation and is considered a strength. The failure to install the required restraining clips on RB sump grating is considered to be a weakness. The operability determination per CP-150 was considered to be comprehensive and well documented.

1.1.2.7 Plant Outage to Repair RCPPM

On October 13, 1995 at 11:45 p.m. a power reduction was initiated to take the unit off line in order to repair the D number 1 RCPPM. The failure of the number 1 D RCPPM was previously reported in IR 50-302/95-16, paragraph 1.1.2.6. The maintenance work witnessed by the inspectors is discussed in paragraph 1.3.0, Maintenance Observations, in this report. Several other outage items were worked concurrently with the RCPPM repair.

The outage was well planned and controlled. The briefings in the control room were detailed and everyone was reminded to take their time and to work safely.

The unit was placed back on line at approximately 10:48 a.m. and was returned to 100% reactor power at 9:52 p.m. on October 15, 1995.

1.1.2.8 B Train DC System Flows Found Outside the Design Basis

On October 18, 1995 a system outage was initiated on the B train of the DC system. Due to questions raised during the service water self assessment, a flow balance of the DC system was scheduled. During the performance of Performance Test PT-136B, Decay Heat Closed Cycle Cooling (DC) System Flow Balance, two components were found to have indicated flow less than the flow required in the Enhanced Design Basis Document. The nuclear services and decay heat sea water pump, RWP-3B, motor cooler is required to have a minimum DC flow of 24 gpm while the as found DC flow was 20 gpm. The decay heat removal heat exchanger, DHHE-1B, is required to have a minimum DC flow of 3,000 gpm (a later engineering calculation had decreased this required flow to 2,918 gpm) while the as found DC flow was 2,925 gpm (without a 2% instrument error included). Based on these two DC cooled components having less than the procedurally required DC flow, at 10:50 a.m. the DC system and its supported components were declared inoperable by the SSOD. Following a meeting with operations, engineering, and licensing, the licensee determined that the DC system was outside the design basis. A preliminary review of calculations indicates that the DHHE-1B would have performed adequately, even with the reduced DC flow, given the current ultimate heat sink temperature which was approximately 75 degrees F. At 1:57 p.m. on October 18, 1995 the NRC was notified of this condition under 10 CFR 50.72(b)(1)(ii)(B) as a condition outside the design basis of the plant. PT-136B was being conducted due to questions which resulted from the plants service water system operational performance assessment. PR 95-0204, Less than design basis DC flow to DHHE-1B and RWP-3B motor cooler, was issued to document the discrepancy and corrective actions. The DC system flow balance would normally only be performed if some system parameter changed. PT-136B had also been previously revised due to the questions noted above. The plant manager requested engineering conduct an operability determination to justify continued operation until the A DC system flow balance, which is scheduled for December 1995, could be performed.

The flow balance per PT-136B was completed (with adequate flow to DHHE-1B and RWP-3B motor cooler) and the B train DC system was returned to service at 3:30 a.m. on October 20, 1995. Blue tags (which require the SSOD's permission to operate) were hung on the valves that were repositioned while performing PT-136B until a revision to OP-404, Decay Heat Removal System, could be issued.

Also, an STI has been issued concerning the manual control of DCV-178, 3B Decay Heat Removal Heat Exchanger Outlet Manual Handjack. STI 95-0054 states that the current position of DCV-178 is throttled 5 3/4 turns closed from the full open position. This position conflicted with existing procedures and placards and a blue tag was hung on DCV-178 for administrative control until procedural revisions were made.

Technical Specification 5.6.1.1 requires that written procedures be established, implemented, and maintained for activities recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A requires procedures be developed for the operation of component cooling water systems. The failure to have an adequate procedure for accomplishing the flow balancing of the DC system is a violation. This licensee identified violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy. This violation is identified as NCV 50-302/95-18-02, Inadequate procedure to flow balance the DC system.

1.1.2.9 Voluntarily Removing Two Safety Systems From Service Concurrently

On October 18, 1995 at 5:38 a.m. the SSOD entered the actions of TS 3.7.8, Decay Heat Closed Cooling Water (DC) System, Condition A, One DC train inoperable, when removing the B train of DC from service for system flow balancing. Shortly thereafter, the fuel rack for the A EGDG was tripped to restore the EGDG from a surveillance (SP-354A) which made the EGDG inoperable for the time period of 5:39 a.m. to 5:46 a.m. This condition resulted in the B train of DC and the A EGDG both being technically inoperable from 5:39 a.m. to 5:46 a.m. on October 18, 1995.

Also, on October 18, 1995 (subsequent to the determination that the B train of the DC system was inoperable at 10:50 a.m.) the SSOD authorized the connection of instrumentation to accomplish SP-146C, EFIC Flow Control Verification. The actions of TS 3.7.5, Emergency Feedwater (EFW) System, Condition B, One EFW train inoperable for reasons other than Condition A, were entered from 11:55 a.m. until 12:43 p.m. for EFW train A and from 1:11 p.m. until 1:44 p.m. for EFW train B. This condition resulted in the B train of the DC system and a train of the EFW system (one train at a time) both being inoperable at the same time.

Although there is no TS or regulation prohibiting the conditions noted above, the NRC considers it highly undesirable to enter conditions such as noted above voluntarily for maintenance, surveillance, or other discretionary reasons and is considered to be a weakness. The NRC has issued guidance on this issue in the NRC Inspection Manual, Part 9900: Technical Guidance, Maintenance - Voluntary Entry Into Limiting Conditions for Operation Action Statements to Perform Preventive Maintenance.

1.1.2.10 Inconsistent Design Assumptions for RB Spray Flow

On October 27, 1995 at 4:59 p.m. the licensee made a report per 10 CFR 50.72(b)(1)(ii)(B) regarding a suspected design basis issue regarding the design assumptions for the required RB spray flow. During a review of EOP setpoints per the licensee's EOP Enhancement Program, a discrepancy was identified with the BS flow settings during design basis events.

The current licensing basis is as noted:

- EDBD Section 6.4 - minimum required flow (1200 gpm) to mitigate thyroid dose limits post LOCA.

- Calculation M90-0021, Revision 5 - describes NPSH required to support RB spray pump operation from the RB sump.

- FSAR Table 6-12, Post Accident NPSH Requirements - flowrate for RB spray is 1200 gpm in recirculation mode.

Description of Identified Concern:

- Calculation I90-0015, Revision 1 - calculates flow error associated with the flow indicators on the MCB vertical ES section (BS-1-FI1/2). At a BS flowrate of 1200 gpm, the error calculation indicates approximately +31 gpm.

- Calculation I90-0022, Revision 0 - calculates instrument error for the flow controller. At a BS flowrate of 1250 gpm, the instrument error is +105/-107 gpm. At a BS flowrate of 1150 gpm, the instrument error is +107/-109 gpm.

- Calculation M90-0021, Revision 5 - Calculates NPSH required for BSP and DHP operation while aligned to the RB sump. This calculation assumed 1200 gpm BS flow with an additional 31 gpm flow error from calculation I90-0015.

- Calculation M95-0005, Revision 1 - calculates minimum BWST level necessary to prevent vortexing during drawdown. This calculation assumed 1200 gpm BS flow with an additional 31 gpm flow error from I90-0015. These conditions are not bounding for the vortexing scenario.

The NPSH calculation did not consider the error associated with the flow controller suggesting that actual flow could be more than what was assumed.

In regards to continuous low flow operation, the BSPs should not be operated at flow rates lower than 1,100 gpm.

The EDBD assumes a minimum BS flow of 1200 gpm at a RB pressure of 55 psig to bound the control room thyroid dose.

EOP-08, LOCA Cooldown, Step 3.14, required the operators to lower BS flow to 1200 gpm to establish suction from the RB sump. This value does not include errors associated with either the control board flow indication or the controller function. Therefore, NPSH, control room iodine dose, and continuous low spray flow conditions may not be bounded by current calculations.

PR 95-219, Inconsistent Design Assumptions for Required Building Spray Flow, was initiated to document the above problem and proposed corrective actions. An operability evaluation was accomplished and the BS system is considered operable for the following reasons: The results of preliminary engineering calculations indicate that adequate NPSH is available for the BSPs using the higher flow error (+110 gpm), and the reduced RB spray flow (approximately 80 gpm less than used in the current analysis) is expected to have minimum impact on off-site dose and control room operator thyroid dose. The minimum flow for long term operation of the BSP is 1100 gpm. The larger flow error could result in a flow of 1090 gpm which is not expected to have a significant impact on pump longevity.

The inspectors have reviewed the licensee's evaluation and had no safety concerns. The inspectors plan to review the licensee's corrective actions, as they are completed.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that applicable regulatory requirements and the design basis, as defined in paragraph 50.2 and as specified in the license application, are correctly translated into specifications, drawings, procedures, and instructions. The failure to correctly translate the design basis for the RB spray system into design specifications is a violation. This licensee identified violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy. This violation is identified as NCV 50-302/95-18-03, Inconsistent design assumptions used for the RB spray system calculations.

1.1.3 Results

Three NCVs, one strength, and two weaknesses were identified.

1.2.0 Surveillance Observations (61726)

1.2.1 Inspection Scope

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

1.2.2 Observations and Findings

1.2.2.1 Surveillance Testing

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

SP-113 Power Range Nuclear Instrumentation Calibration

SP-340E DHP-1B, BSP-1B, and Valve Surveillance

1.2.2.2 ASME Testing of CFV-1 and CFV-3

On September 19, 1995, the inspectors were notified by the licensee that a routine review of their IST program, prompted by an inquiry by another licensee, had determined that there was an apparent discrepancy in the ASME Section XI testing of CFV-1 and CFV-3, the CFTs discharge check valves.

During the review of Generic Letter 89-04, Guidance on Developing Acceptable Inservice Testing Programs, the licensee determined that position 1 of the GL allowed a full stroke of a check valve to be demonstrated by passing the maximum required accident flow rate through the valve. Position 2 of the GL described a sample disassembly and inspection program.

During the review of the GL, the licensee made the determination that the accident flow rate through the check valves was less than 2800 gpm. The licensee decided to test the valves using flow from the DHPs, with a flow rate of 3000 gpm, to test the check valves. The two valves were added to SP-435, Cold Shutdown Valve Testing, and verified full open by passing 3000 gpm decay heat flow. During subsequent development of the IST Basis Document in 1993, the licensee readdressed the question of maximum accident flow in an REA. The response received from a contractor stated that if the resistance factor (L/D) limit of the CFT lines was not exceeded, then the required flow rate could be expected to occur. The licensee interpreted this to mean that since no flow rate was provided, the previous flow rate was considered valid.

During the recent reevaluation, prompted by the question from another plant, the licensee determined that their previous assumption of a maximum flow rate of 2800 gpm was incorrect and that the correct flow rate was 22,600 gpm. As a result, it was determined that the testing that was conducted on CFV-1 and CFV-3 did not meet the ASME Section XI requirements. The licensee in

1990 performed flow testing, visual inspection of the valves, and acoustical monitoring. No signs of degradation were noted. Flow testing, using the 3000 gpm value, has also been performed since that time on an annual basis. Although 3000 gpm is less than post LOCA core flood tank accident flow, the licensee concluded that the capability of the valves to pass the flow provides indication that the valves have continued to open. Identical valves, CFV-2 and CFV-4, with similar service histories have been disassembled more recently and they also exhibit no signs of degradation. The licensee performed a NOD-14, Evaluating Operability and Determining Safety Function Status, for the issue with the conclusion that the core flood system remained operable. The licensee inservice testing plan includes provisions to assist in dispositioning ASME Code nonconformances, which included a JCO while corrective actions are being taken. The licensee had a telecommunication with the NRC, regional and NRR personnel and discussed the JCO associated with the operability determination. The NRC staff found the JCO to be acceptable, CFV-1 and CFV-3 operability determination to be adequate, and determined that the licensee's determination that the valves remain operable to be adequate. The licensee is planning to perform a full flow test during the upcoming 10R refueling outage.

TS 5.6.2.9, Inservice Testing Program, requires that the licensee have a testing program for Class 1, 2, and 3 components in accordance with ASME Section XI as required by 10 CFR 50.55a. Contrary to the above, the licensee failed to adequately test the check valves as required by ASME Section XI and in accordance with the guidance provided in GL 89-04. This licensee-identified violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy. This violation is identified as NCV 50-302/95-18-04, Failure to test CFV-1 and CFV-3 in accordance with ASME Section XI as required by TS.

1.2.2.3 ES Matrix Surveillance Testing

While preparing to perform SP-358C, Operations ES Monthly Automatic Logic Functional Test #3, on September 22, 1995, the SSOD questioned the applicability of the note associated with TS SR 3.3.7.1. This note allows delayed entry into TS 3.3.7, Engineered Safeguards Actuation System (ESAS) Automatic Actuation Logic, Action A, One or more automatic actuation logic matrices inoperable, for up to eight hours during the performance of the surveillance provided the associated function is maintained. During the performance of the surveillance, however, groups of ES components from a single ES train are blocked from actuating while simulated actuation signals are inserted. During this time period, these components are not available for automatic actuation. This procedure had last been performed on August 30, 1995.

The licensee reviewed the TS SR note and determined that the manner in which this test is conducted precludes the use of the note. To perform the test, the entire logic matrix must be bypassed, to prevent an actuation of the component. Therefore, the function is not maintained operable.

The SSOD, in a conservative decision, entered TS 3.3.7, Condition A, during the performance of the SP-358C. The licensee conducted a review and determined that based on the design of the system and the fact that the ESAS automatic actuation logic matrix being tested is removed from service and does not remain functional during the performance of the test, the note could not be applied during the surveillance testing.

On August 30, 1995, and previous dates, the surveillance requirement for TS SR 3.3.7.1 was being conducted, the action statement was not being entered, and the ESAS function was not maintained, as required by the note. TS 3.3.7, Condition A, requires that with one channel inoperable, place the associated ES component in its ES function within one hour or declare the associated ES component inoperable within one hour and enter the appropriate action statement. As an interim corrective action, the licensee is entering the action statement whenever these procedures are being used, instead of utilizing the note in the surveillance requirement.

TS 5.6.1.1 and Regulatory Guide 1.33, Appendix A, Revision 2, February 1978, requires that procedures be developed, implemented, and maintained for the performance of surveillance testing of safety related equipment. On August 30, 1995, the licensee performed the surveillance test SP-358A, without entering the action statement, as required, when the logic matrix was made inoperable. The cause was an inadequate procedure, which did not properly delineate the steps necessary to perform the surveillance and comply with the TS requirements, which is a violation. This licensee identified violation is being treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy. This violation is identified as NCV 50-302/95-18-05, Inadequate procedure to perform surveillance testing on the Engineered Safety Actuation System logic matrices.

The questioning attitude and conservative decisions exhibited by the SSOD regarding surveillance testing of the ESAS logic matrices is considered a strength.

1.2.2.4 Fuel Leak on EGDG-1B

At 8:27 p.m. on October 24, 1995 while performing SP-354B, Monthly Functional Test of the Emergency Diesel Generator EGDG-1B, a fuel leak was observed in the fuel line in the area of the #12 cylinder fuel injector. The licensee's investigation revealed a crack at the entrance of the fuel header. PR 95-213 was initiated to document this problem and corrective actions. The EGDG-1B had previously been declared inoperable at 9:23 a.m. on October 24 and TS 3.8.1, Condition B, One EGDG inoperable, had been entered to perform surveillance SP-907B, Monthly Functional Test of 4160V ES Bus B Undervoltage and Degraded Grid Relaying.

An investigation of the fuel leak revealed a crack on a manifold section at the entrance of the fuel header. The licensee performed an inspection on EGDG-1A to determine if a similar problem existed. The common cause failure determination was completed at 1:35 a.m. on October 25, 1995 and no indications of cracking were found on the 1A EGDG. The licensee contacted Coltec, the EGDG vendor, and verified that a new manifold section was in stock at the factory. A new manifold section was ordered and arrived on site the evening of October 25. The leaking manifold was removed from EGDG-1B at 7:30 p.m. and compared to the new part and it was found that the new part was a mirror image of the leaking manifold and would not fit. Coltec was contacted and confirmed that the part shipped was the wrong part because of an error in the vendor's technical manual. Coltec did not have the correct part in stock.

The licensee took parallel courses of action; the leaking manifold was returned to Coltec for expedited repairs and a spare part was being obtained from TMI. Replacement parts were received the evening of October 26 and the repaired manifold was installed on the 1B EGDG. After EGDG-1B was returned to full load, the #12 cylinder exhaust temperature was found to be operating at 440 degrees F. Normal exhaust temperature for that cylinder is approximately 700 degrees F. The low temperature was validated by comparing cylinder firing pressures and the #12 cylinder was out of specification low. At 1:39 a.m. on October 27 the EGDG-1B was tagged out to allow for further repairs. The licensee's investigation revealed a frozen fuel pump that supplies the #12 cylinder. The faulty fuel pump was replaced and at 6:05 a.m. on October 27, the EGDG-1B was loaded to 2600 kw for an operability run. Data was taken at 7:05 a.m. (after a one hour run) and the SSOD declared the EGDG-1B operable at 7:37 a.m. During the period the EGDG-1B was out of service, the licensee restricted the discretionary removal of other safety related equipment.

1.2.2.5 Seismic Concern For a RW System Annubar Flow Tap

As a followup of REA 95-0310 that resulted from a service water self assessment concern and subsequent field walkdown, a question of the adequacy of the RW system annubar flow tap design was raised. The RW flow instrument taps consist of a short length of 2 inch diameter pipe connected to the 24 inch diameter RW headers at three locations in the seawater room. The 2 inch line terminates in a ball valve and flange. These taps are used for mounting an annubar assembly for flow measurement in the RW headers. The RW headers and the flow taps (to the outboard ends of the valve) are classified as seismic class 1. The licensee could not verify seismic qualification of the taps with the annubar installed had been performed. Preliminary calculations indicate that the flow taps as designed and shown on CR3-P-6133-RW-1.3 meet all seismic class 1 requirements. However, during a field walkdown while performing the calculations, the licensee identified that the flow tap at RWV-147 was not installed at the orientation shown on the design drawing. The drawing specifies that the flow tap be installed at 30 degrees off verticle, but the installation in the field was measured to be approximately 48 degrees off verticle. The difference amounts to one bolt hole misalignment in the flanged spool piece (RW-44) in which the tap is installed. PR 95-0220, RW Annubar Flow Tap Seismic Qualification Concerns, was issued on October 30, 1995 to document the discrepancy and document corrective actions.

The licensee's preliminary calculations for the tap at RWV-147 indicate that the stresses exceed the allowables by about 18% for the case where the annubar assembly is installed but the annubar probe is not inserted into the flow stream. The installation meets all seismic class 1 requirements when the annubar probe is inserted into the flow stream. Deadweight stresses are within allowables with the probe inserted or retracted. The only non-qualified case for the as-built orientation of the flow tap is loading with the annubar assembly installed on the flow tap and the annubar retracted. The annubar assembly is only installed when performing a flow measurement of the RW headers, so there is no immediate safety concern. Spool piece RW-44 is scheduled to be replaced (by RW-85 per MAR 93-07-05-01) during refuel 10R in the spring of 1996. Engineering is to provide guidance prior to the next scheduled performance of the flow test.

10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The failure to install spool piece RW-44 in accordance with the design drawings is a violation of 10 CFR 50, Appendix B, Criterion V. This licensee identified violation is being treated as a non-cited violation, consistent with Section VII of the enforcement Policy. This violation is identified as NCV 50-302/95-18-06, Failure to install spool piece RW-44 per design drawings.

1.2.3 Results

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TSs. Three non-cited violations and one strength were identified.

1.3.0 Maintenance Observations (62703)

1.3.1 Inspection Scope

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

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

1.3.2 Observation and Findings

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

WR NU 0330483 Troubleshoot and repair the RCP-1D pump power monitor

The inspectors witnessed the task of troubleshooting and repairing the RCP-1D pump power monitor, which was rendered inoperable by a rain water leak. The inspectors reviewed the completed clearance request, 95-10-044, prior to beginning of the work and noted that clearance was designed to completely deenergize the components prior to the beginning of work.

The inspectors witnessed the task and noted the conservative approach that the electricians took by verifying that each individual component was deenergized before performing any maintenance. This task was well planned, with maintenance line management involvement in the planning and implementation of the task. In addition, systems engineering and engineering management were present throughout the performance of the maintenance, providing excellent support and evaluation.

There were indications that water had gotten on all of the fuses in the panel, but the examination revealed only one obvious failure mechanism; one of the current limiting fuses on one of the four potential transformers was tripped. The licensee made the decision to replace all of the fuses and perform current to current ratio testing on all of the potential transformers, to test for additional degradation. While the components were deenergized, the electricians performed routine preventive maintenance, such as cleaning, visual examination, etc. No additional problems were noted, other than the extremely dirty condition of the equipment. The inspectors noted that this equipment is not on the normal outage PM program.

1.3.3 Results

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

Violations or deviations were not identified.

1.4.0 Plant Support (71750)

1.4.1 Inspection Scope

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

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

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

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

1.4.2 Observations and Findings

The observations in the health physics program included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;
- Area postings and controls;

- Work activity within radiation, high radiation, and contaminated areas;

- RCA exiting practices;

- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment; and

- NRC form 3 and NOVs involving radiological working conditions were posted in accordance with 10 CFR 19.11.

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

In addition, the inspector observed the operational status of protected area lighting, protected and vital areas barrier integrity, and the security organization interface with operations and maintenance.

1.4.3 Inspection Results

The implementation of the plant support program observed during this inspection period were proper and conservative.

Violations or deviations were not identified.

1.5.0 Self Assessment (40500)

1.5.1 Inspection Scope

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

1.5.2 Observations and Findings

1.5.2.1 Audit Reports

The inspectors reviewed the following audit report(s).

REPORT NO.	TITLE	NO. OF WEAKNESSES	NO. OF RECOMMENDATIONS
95-08-CAP	Corrective Action Program	3	3
95-08-FFD	Fitness for Duty	1	15

95-09-OPS Nuclear Plant Operations 2 4

No additional NRC follow-up will be taken on the weaknesses referenced above because they were identified by the licensee's audit program and corrective actions have either been completed or are currently underway. PCs were initiated on the findings and plant management is aware of the identified weaknesses.

1.5.2.2 Event Free Operations

The inspectors reviewed Quality Programs Surveillance Report #QPS-95-0092, on the Event Free Operations Program for the site. The surveillance noted one good work practice, the use by operations of the tool bag tags to effectively focus on the use of human performance tools.

The surveillance report identified several areas where improvement could be realized: (1) most of the human performance indicators currently being tracked are not adequate to provide the quality of information necessary to determine the causes of deficiencies in the use of the human performance tools as identified in the event free operation program descriptions, (2) the licensee does not recognize that poor or inadequate use of management tools can also contribute to poor human performance, (3) the manner in which data is currently being provided to the individual departments by the Tracking and Trending Group is not adequate to allow these organizations to satisfactorily evaluate performance, (4) with the exception of Nuclear Plant Operations, most of the data trended focuses on numbers rather than actions, and (5) most of the emphasis on safety deals with personnel safety at the departmental or individual level.

The surveillance report concluded that all program descriptions, with the exception of the program developed by Quality Programs, could be considered minimally adequate. The auditor recommended that the licensee place less emphasis on answering precursors cards and counting the numbers assigned to individual organizations and focus more on why the condition occurred and how to effectively address it to prevent it from occurring again. The auditor also recommended that the licensee place more attention on active, timely, and effective communications between organizations. This includes feedback and sharing of ideas and solutions for human performance problems.

The inspectors reviewed the surveillance report and discussed the results with the auditor. This surveillance did not identify any new safety related concerns. The inspectors plan to continue to monitor the event free operations programs.

1.5.3 Inspection Results

Violations or deviations were not identified.

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

1.6.1 Inspection Scope

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

1.6.2 Observations and Findings

1.6.2.1 LER 95-003, Personnel Error in Calculation May Cause Peak Fuel Clad Temperature to Exceed 2200 Degrees Fahrenheit Exceeding Acceptance Criteria of 10 CFR 50.46.

On January 27, 1995 B&W Nuclear Technologies advised the NRC of a potential safety concern arising from a discovered error in the initial conditions used for large break LOCA analysis for ECCS. In addition, it was determined that an error in data transferred between blowdown calculations and fuel pin heatup calculations may also have been non-conservative during a short period of the heatup calculation. The correction of these errors resulted in a peak cladding temperature above the 2200 degrees Fahrenheit limit specified in 10 CFR 50.46(b). Existing proceduralized operating limits at CR-3 were more conservative than the limits which would be imposed using the newly developed results. The LOCA limits in the COLR are to be revised when the final reduced LOCA limits become effective. NRC Headquarters technical staff were aware of this B&W issue and were monitoring the corrective actions. There were no current operability concerns. This LER is closed.

1.6.2.2 LER 95-11, Personnel Error Leads to Incorrect Orientation of Door Seals Resulting in Operation Outside the Design Basis

The inspectors reviewed the corrective actions associated with this LER and verified that all actions discussed had been completed. The NOD-14 formal operability evaluation was reviewed and found to be acceptable. The inspectors verified, by reviewing the attendance sheet, that the training in print and drawing reading had been completed for the mechanical personnel. The initial and follow-up corrective actions appear to be adequate to prevent recurrence. This issue was addressed as NCV 95-14-04. This LER is closed.

1.6.2.3 LER 95-12, Design Error Leads to Inadequate Circuit Isolation Resulting in Operation Outside the Licensing (Design) Basis of the Plant

The inspectors reviewed this LER and the proposed corrective actions associated with it. The NOD-14 operability evaluation, dated July 7, 1995 was reviewed and found to be acceptable. The inspectors verified that SWP-1B was placed in service as the normal duty SW pump until the issue was resolved. This was analyzed by the licensee to allow both SWP-1B and SWP-1C to remain operable, in case of the assumed fire. The inspectors reviewed the modification, MAR 95-07-03-01, which was installed on July 9, 1995, to resolve this issue, and found it to be acceptable. This issue was addressed as NCV 95-14-01. This LER is closed.

1.6.2.4 LER 94-014, Reactor Building Fan/Cooler Operation Develops Cooling System Flow Imbalance and Heat Loading Having the Potential for Operation Outside the Design Basis.

The inspectors reviewed the LER and the proposed corrective actions. The licensee had identified a deficiency in the design of the RBCUs in that on an ES signal, the trip of the non-ES selected RBCU would occur only if the fan was in normal (high) speed. The inspectors verified that procedures were revised to allow only two RBCUs be operated, or if a third non-ES selected RBCU was operated, it could only be run in fast speed. This would ensure that following an ES signal, the non-ES selected RBCU would be stripped off the bus. The licensee decided not to install a plant modification to trip a third RBCU running in slow speed on an ES signal. This LER is closed.

1.6.3 Inspection Results

Violations or deviations were not identified.

1.7.0 Engineering Activities Follow-up (92903)

1.7.1 Inspection Scope

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

1.7.2 Observations and Findings

1.7.2.1 MUT Alarm Setpoint Modifications

The licensee performed MAR 95-01-07-02 on October 5, 1995, which changed the MUT high level alarm from 86 inches to 100 inches. In addition, the variable annunciator alarm has been changed.

Before, the alarm was set to mimic the design curve for the MUT pressure versus level. After the modification, the annunciator now comes on at a curve three psi below the design curve at 55 inches and six and one-half psi below the curve at 100 inches. In addition, a computer alarm was added below the annunciator alarm to alert the operator of the approach to the annunciator curve. Exceeding the computer alarm does not require any immediate corrective actions.

Parallel to the installation of the MAR, the issuance of revisions to procedures OP-103B, Plant Operating Curves; AR-403, PSA H Annunciator Response; OP-402, Makeup and Purification System; and OP-204, Power Operations were issued to reflect the changes. Additional procedures, for startup and shutdown were identified which need changes prior to their next use. The licensee is in the process of revising them.

The licensee has revised the operating curves for the makeup tank volume/level. The new curves include a clearer representation of the allowable operating region. A sheet of instructions for the use of the curves has been included in OP-103B. This sheet defines the preferred operating region, the acceptable operating region, and the restricted regions of the curve. The alarms installed or modified by the MAR are explained in the instructions in order to minimize confusion. A OSB entry was issued when the MAR was installed, to instruct the operators on the correct use of the new curves and the procedure revisions.

The inspectors reviewed the revised curves in OP-103B and the OSB entry issued. The calculation, M94-0053, Revision 2, was reviewed by the inspectors and has been forwarded to NRR for additional review. No concerns exist at this time with the revised curves. The inspectors will continue to follow up on MUT in future reports.

1.7.2.2 IFI 94-22-04, Follow-up of Instrument Air System Corrective Action Plan

As part of the corrective ...on. for the deficiencies identified with the instrument and se vice air systems, the licensee had a contractor, who specialize in air systems, perform an audit and provide recommendations fo the dispositioning of the air systems. The contractor determined that the design basis for the air systems has been increased gradually since original installation until the needed output exceeded the design capacity of the compressors. The contractor also concluded that several of the replacement compressors obtained after the original design were not reliable, resulting in costly operation and repetitive maintenance needs.

The contractor provided a recommended replacement system, designed for higher output and a more reliable service life. The recommended system also provides for air receivers, to allow a longer response time on a loss of air compressors. The licensee has accepted the redesign of the system as a preliminary design and is in the process of evaluating and finalizing the design. Final installation of the new system could be accomplished on line. Based on the aggressive actions being pursued by the licensee, this item is closed.

1.7.2.3 IFI 95-08-02, Corrective Actions for Make-Up System Audit Findings

The inspectors reviewed the corrective action plans for the four PRs and the 18 precursor cards written for the licensee's audit. The majority of the corrective actions, including those needing immediate actions, were complete. There were two corrective actions from PR 95-0041 that were outstanding. The first was the revision and issuance of the plant drawings and the cross reference listings of the various types of drawings for the piping layouts. The other was the analysis and evaluation of the bulk of the discrepancies identified during the system walkdowns. Both of these actions had initially been scheduled to be complete by July 1, 1996. However, the first corrective action had been rescheduled to be completed by October 1, 1995 and the second item was rescheduled for November 1, 1995. As of October 11, 1995 neither item had been reported to the Tracking and Trending Group as completed. This item will remain open until the corrective actions described above are completed.

1.7.2.4 IFI 95-09-01, Review of Setpoint Control Program Implementation

The inspectors have reviewed the ongoing setpoint control program. Additional inspections have been conducted and are scheduled to be conducted in the future on this issue. An escalated enforcement violation was issued as VIO 50-302/95-02-04, with additional examples identified in IR 95-16. The corrective actions will be followed under the violation and its associated response. This item is closed.

1.7.3 Inspection Results

Violations or deviations were not identified.

Acronyms and Abbreviations

ac - Alternating Current
ALARA - As Low as Reasonably Achievable
ASME - American SSociety of Mechanical Engineers
B&W - Babcock & Wilcox
BS - Building Spray
BSP - Building Spray Pump
BWST - Borated Water Storage Tank
CCTV - Closed Circuit Television
CFT - Core Flood Tank
CFV - Core Flood Valve
CP - Compliance Procedure
dc - Direct Current
DC - Decay Heat Closed Cycle Cooling
DEV - Deviation
DHHE - Decay Heat Heat Exchanger
DHP - Decay Heat Pump
ECCS - Emergency Core Cooling System(s)
EDBD - Enhanced Design Basis Document
EFIC - Emergency Feedwater Initiation and Control
EFP - Emergency Feedwater Pump
EFW - Emergency Feedwater
EGDG - Emergency Diesel Generators
EM - Emergency Plan Implementing Procedure
EOP - Emergency Operating Procedure
ES - Engineered Safeguards
ESAS - Engineered Safety Actuation System
F - Fahrenheit
FPC - Florida Power Corporation
FSAR - Final Safety Analysis Report
GL - Generic Letter
gpm - Gallons Per Minute
HP - Health Physics
HPI - High Pressure Injection
I&C - Instrumentation and Control
ICC - Inadequate Core Cooling
ICS - Integrated Control System
IFI - Inspection Followup Item
ISI - Inservice Inspection
IST - Inservice Test
JCO - Justification for Continuedm Operation
kV - Kilovolt
kw - Kilowatt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOOP - Loss of Offsite Power
MAR - Modification Approval Record
MCB - Main Control Board
MFW - Main Feedwater
MOV - Motor Operated Valve

MP - Maintenance Procedure
MSV - Main Steam Valve
MUP - Make-up Pump
MW - Megawatt
NCV - Non-cited Violation
NOD - Nuclear Operations Department
NOV - Notice of Violation
NPSH - Net Positive Suction Head
NSSS - Nuclear Steam System Supplier
OP - Operating Procedure
OSN - Operations Study Book
OTSG - Once Through Steam Generator
PM - Preventive Maintenance
PORV - Power Operated Relief Valve
PR - Problem Report
psig - pounds per square inch gauge
QC - Quality Control
QA - Quality Assurance
RB - Reactor Building
RCA - Radiation Control Area
RCP - Reactor Coolant Pump
RCPPM - Reactor Coolant Pump Power Monitor
RCS - Reactor Coolant System
REA - Request for Engineering Assistance
RO - Reactor Operator
RW - Nuclear Services and Decay Heat Seawater
RWP - Nuclear Services and Decay Heat Seawater Pump
SALP - Systematic Assessment of Licensee Performance
SG - Steam Generator
SP - Surveillance Procedure
SR - Surveillance Requirement
SSOD - Shift Supervisor on Duty
STI - Short Term Instruction
SW - Nuclear Services Closed Cycle Cooling System
TMI - Three Mile Island
TS - Technical Specification
URI - Unresolved Item
VIO - Violation
WR - Work Request