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

Report Nos.: 50-269/93-30, 50-270/93-30 and 50-287/93-30

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-0001

Docket Nos.: 50-269, 50-270, 50-287, 72-4

License Nos.: DPR-38, DPR-47, DPR-55, SNM-2503

Facility Name: Oconee Nuclear Station

Inspection Conducted: October 24 - November 27, 1993

Inspectors: [signature] 12/21/93
for P. E. Harmon, Senior Resident Inspector — Date Signed

W. K. Poertner, Resident Inspector
L. A. Keller, Resident Inspector

Approved by: [signature] 12/21/93
M. S. Lesser, Section Chief, — Date Signed
Reactor Projects Section 3A

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, maintenance activities and surveillance testing, engineering, and plant support.

Results: In the Operations area, multiple failures in the Unit 1 main steam stop valves' circuitry resulted in a significant transient on the "B" steam generator, which culminated in a manual reactor trip. Operator response was adequate and actions taken were appropriate. These included an engineering evaluation of the transient and its effect on the operability of the steam generator. (paragraph 2.d).

In the Maintenance area one unresolved item was identified concerning the licensee's classification of the main steam stop valve test solenoid valves as non safety-related and the lack of a preventive maintenance program on these test solenoids per the manufacturer's recommendations (paragraph 3.a).

In the Engineering area, an unresolved item was identified regarding the the potential inability of an auxiliary steam system valve to shut against the maximum postulated differential pressure. This could result in an uncontrolled blowdown of both

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steam generators. The licensee indicated that the blowdown scenario is bounded by an analysis. (paragraph 4.e).

In the Engineering area, an unresolved item was identified regarding a change to the operating procedure to isolate the Continuous Vacuum Priming System from the Condenser Circulating Water System. The evaluation to determine the minimum lake level needed to assure Emergency Condenser Circulating System operability was not rigorous, in that calculations were non-conservative and relied on limited test data (one data point), instrument error was not included, potential pump degradation was not considered and no provisions were established to monitor the system for offgassing, nor were provisions established to verify operability when less than the minimum required pumps were running. Although the inspectors pointed out these concerns, additional action was not initiated until an event occurred on November 15, when air was discovered in the piping. The inspectors consider that the licensee's performance in this area was weak due to lack of effective oversight and lack of a questioning attitude regarding a less-than-rigorous evaluation to assure Emergency Condenser Cooling Water System operability. (Paragraph 4)

In the operations area, a continuing weakness in the licensee's post-trip review process was identified when portions of the plant response following a unit 2 trip remained unexplained. (paragraph 2.c).

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *H. Barron, Station Manager
   S. Benesole, Safety Review Manager
   *D. Coyle, Systems Engineering Manager
   *J. Davis, Safety Assurance Manager
   T. Coutu, Operations Support Manager
   *B. Dolan, Manager, Mechanical/Nuclear Engineering
   W. Foster, Superintendent, Mechanical Maintenance
   *J. Hampton, Vice President, Oconee Site
   D. Hubbard, Component Engineering Manager
   C. Little, Superintendent, Instrument and Electrical (I&E)
   M. Patrick, Regulatory Compliance Manager
   *B. Peele, Engineering Manager
   *S. Perry, Regulatory Compliance
   *G. Rothenberger, Operations Superintendent
   R. Sweigart, Work Control Superintendent

   Other licensee employees contacted included technicians, operators, mechanics, security force members, and staff engineers.

   NRC Resident Inspectors

   *P. Harmon
   *W. Poertner
   *L. Keller
   *G. Humphrey

   *Attended exit interview.

2. Plant Operations (71707)

   a. General

      The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification log and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & electrical (I&E), and engineering personnel.

      Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and night shifts, during weekdays and on weekends. Inspectors attended some shift changes to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's Administrative

Procedures. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

On October 30 the 1D1 heater drain pump motor failed resulting in operation of Unit 1 at or below 88% power. On November 3 failures in the Unit 1 Main Steam Stop Valves (MSSV) circuitry resulted in the inadvertent closure of MSSVs 1, 3 and 4. The resulting secondary transient necessitated a manual reactor trip. This event is described in detail in Section 2.d. During the resulting startup on November 4, the 1D1 heater drain pump was returned to service and Unit 1 resumed 100% power. On November 8, the 1B feedwater pump was removed from service due to abnormal noise. Investigation revealed a damaged gear-driven oil pump assembly. This resulted in operation of Unit 1 at or below 65% until the oil pump was repaired. The 1B feedwater pump was returned to service on November 12.

Unit 2 tripped from 100% power on October 24 due to a spurious actuation of the Power to Flow Imbalance Reactor Trip Circuitry. This event is described in detail in section 2.c.

Unit 3 operated at or near 100% power throughout the inspection period.

c. Unit 2 Reactor Trip

On October 24, 1993, Unit 2 was operating at 100% power with normal plant conditions and no significant problems. At 5:30 a.m. Reactor Protection (RPS) channel C tripped on a Flux/Flow/Imbalance trip signal. The RPS requires a coincident 2/4 channels to trip the reactor. Operators were able to reset the tripped RPS channel within 5 minutes. Spurious, single channel trips of the Flux/Flow/Imbalance had occurred previously on Units 1 and 3, so operators were familiar with single channel trip events. Operators reduced the Megawatt demand in the Integrated Control System's (ICS) Unit Load Demand (ULD) by approximately 2 Megawatts. This was done to increase the unit's margin to the Flux/Flow/Imbalance trip setpoint. RCS flow was steady at 100%, and Flux Imbalance was minimal, so reactor power was the only variable that could be manipulated by the operators to provide margin to the trip setpoint.

At 6:34 a.m. on October 24, Unit 2 tripped on flux/flow/imbalance reactor trip signals on all 4 RPS channels. The trip response was normal with the exception of higher than normal steam line pressures and feed pump control problems. Steam line pressure immediately after the trip increased from 890 psig (normal full power pressure) to 1138 psig and 1130 psig in the A and B steam headers, respectively. Typical post-trip steam pressures are less than 1115 psig. The licensee conducted post-trip reviews and determined that the cause of the trip was spurious low RCS flow indications occurring simultaneously with slightly elevated reactor power. The indicated nuclear power was 100.5% at the time of the trip, while thermal (licensed) power was at 100.0%.

The transient monitor traces for this event clearly indicated nuclear power increasing over a period of approximately 2 hours from approximately 99.7% to 100.5%. The increase appeared to indicate a reactivity addition that was not reflected in rod motion or RCS temperature decrease. The inspector questioned the power increase and the abnormally high steam line pressures. The licensee initially concluded that the reactor power increase was caused by operators increasing unit load demand slightly (not apparent on the transient traces of generator megawatts), or a decrease in plant thermal efficiency. The high steam line pressures were attributed by the licensee to the fact that a turbine bypass valve was not operable at the time of the trip. The inspector did not agree that either the power increase or the high steam pressures were explained by the licensee's conclusions in the trip report. The reactor power increase was clearly not caused by an increase in demanded generator megawatts according to the transient traces. The abnormally high steam pressures were not explainable by the inoperable turbine bypass valve. The code steam line safety valves are designed to prevent exceeding 110% of design pressure (1050 psig), which corresponds to 1155 psig. The transient steam pressure came within 17 psig of the limit, even with the added relief capacity of three operable turbine bypass valves.

The trip review process was completed and approved. The licensee staff determined that the output voltages for RCS flow indication used in the trip setpoint were calibrated conservatively low due to procedural methodology, eliminating approximately 50% of the available margin to trip setpoint. Additionally, reactor power was at approximately 100.5% at the time of the trip, further reducing the margin to trip. Consequently, when relatively common spiking of the flow instruments occurred, all four RPS channels received a trip signal.

At 9:00 p.m. on 24 October, licensee management gave permission to restart Unit 2 provided power would be restricted to less than 98% until the RCS flow setpoint input to the trip function could be recalibrated and thermal efficiency would be monitored during power operation to determine if the pre-trip power increase could be explained. The inspector agreed that the plant was safe for restart based on the licensee's corrective actions to provide a reasonable margin to trip by restricting power. Unit 2 was returned to critical at 2:26 a.m., October 25, 1993.

The licensee held a Post-Trip review meeting at 10:00 a.m. on October 25 to review the post-trip report. At the meeting, the inspector questioned the licensee's staff about the excessively high steam pressures present after the trip, and the cause of the increasing reactor power immediately prior to the trip. The cause of the high pressure was not determined. This item will be followed by Inspector Followup Item IFI 50-270/93-30-01: Elevated Main Steam Line Pressures Following a Unit 2 Trip.

The cause of the increasing reactor power was determined by the licensee to be operators increasing load demand. The inspector did not agree that this conclusion was supported by the transient traces, which indicated steady electrical output. The inspector was informed that other traces, not immediately available indicated electrical output was being increased by the operators. The inspector informed the licensee that the operators had decreased power just prior to the trip to provide margin to the flux/flow/imbalance trip, and it was not reasonable that they would have been increasing power at the time of the trip.

On November 9, 1993, the inspector met with licensee staff members and requested further review of the circumstances of the pre-trip power increase. The licensee agreed to perform a reactivity balance to determine the magnitude and source of the power increase. The initial results of the reactivity balance determined that approximately 0.0108 delta k/k of positive reactivity could not be accounted for. Further investigation by the licensee revealed that operators had performed two separate dilutions prior to the trip. The dilutions at 3:20 a.m. and 5:19 a.m., were performed to restore the controlling rod group position from 95% to 94% withdrawn. The result was an increase in power over the two hour time period prior to the trip. Although the operators were properly diluting to force rods into the core, the unintended result was that power increased to a point where nominal spiking on the RCS flow instruments caused a trip.

The inspector discussed the reactor trip review process described above with licensee management. The inspector concluded that the anomalous indications should have been pursued by the licensee, and a relatively straightforward explanation could have been provided, even before the plant was restarted, simply by reviewing the operator logs detailing the dilution events. The inspector concluded that this event and previous post-trip reviews indicate that adequate time is not being afforded to investigate and resolve unexplained plant responses. The licensee agreed that the power increase should have been pursued more aggressively, and will ensure that unexplained phenomena will be addressed properly in future reviews.

d. Unit 1 Reactor Trip

On November 3, 1993, Unit 1 was operating under steady state conditions at 87% power. The 1D1 heater drain pump had previously been removed from service. There were no other significant equipment problems. At 00:55:59 a.m., Main Steam Stop Valve (MSSV) 2 inadvertently went greater than 5% closed. Once MSSV 2 went greater than 5% closed, a limit switch was actuated which energized the test solenoids of MSSV's 1, 3 and 4 driving them closed. At 00:56:16 a.m. MSSV 2 reopened and repositioned the limit switch which should have opened the other MSSV's, however MSSVs 3 and 4 did not reopen. As a result of the ensuing transient, the reactor was manually tripped at 01:00:25 a.m.

The closure of MSSV's 3 and 4 resulted in the "A" steam line being isolated and an increase in steam demand for the "B" steam line. The "A" loop steam pressure caused the main steam safety relief valves to lift to atmosphere. The maximum pressure on the "A" steam line was 1118.6 psig. Due to increased steam demand on the "B" steam line and Integrated Control System (ICS) interactions with feedwater flow, the "B" steam generator (SG) pressure decreased rapidly. At 00:59:20 a.m., the licensee estimated that steam generator "B" pressure had decreased to the equivalent saturation pressure for the temperature of the feedwater entering the steam generator. At this point there was rapid flashing of feedwater to steam in the "B" steam generator. As the feedwater entering the "B" steam generator flashed to steam and the inventory boiled off, "B" steam generator level and pressure steadily decreased. At 01:00:25 a.m. the operators recognized a low level condition in steam generator "B" and initiated a manual reactor/turbine trip. Steam generator "B" level was < 15 inches, SG "B" pressure was 113 psig, and reactor power was 13% at the time of the trip.

At 01:00:35 a.m. AMSAC channels 1 and 2 actuated on low main feedwater pump (MFDWP) discharge pressure (<770 psig), causing emergency feedwater to actuate. At this point, MFDW was feeding the "B" SG at the maximum rate and SG pressure was increasing, but feedwater was flashing to steam, failing to stop the level reduction. After emergency feedwater (EFW) actuated and the relatively cold EFW injected into the "B" SG, level immediately began to recover. "B" SG level had reached a minimum of 1.3 inches (negligible downcomer level existed) prior to injection of EFW. Prior to EFW restoring "B" SG level and pressure, the "A" steam generator level also decreased (minimum of 10.9 inches) due to the FDWPs discharge pressure being lower than the "A" SG pressure. Prior to "B" SG level and pressure recovering, the "A" and "B" EFW header flows peaked at 1185 and 1150 gpm, respectively. These header flows exceeded the maximum flow of

1098 gpm as stated in the EFW Design Basis Document. The limit was exceeded for 4 seconds on the "A" header and 1.5 seconds on the "B" header. The basis for this limit was to protect the SG tubes from flow induced vibration.

Due to the significance of this transient, the licensee requested that Babcock and Wilcox Nuclear Services (BWNS) evaluate the transient data to assess the potential for damage to the Unit 1 steam generators, prior to restart. The transient data was evaluated for differential pressure, differential temperature, and flow concerns in regards to structural integrity of the SG components. The transient data was compared to previously analyzed transients and the SG Functional Specification. BWNS concluded that the Unit 1 SGs were not affected in a way that would prevent restart.

Following the event, the licensee discovered a broken electrical connector on the terminal strip for the Servo valve on MSSV 2. The licensee postulated that this break in the current loop for the MSSV 2 Servo valve circuit caused a loss of signal and a subsequent reduction in hydraulic pressure, resulting in MSSV 2 inadvertently closing. The failure of MSSV 3 and 4 to reopen was due to the sticking of the test solenoids associated with those two valves. The broken electrical connection was repaired and the sticking test solenoids were cleaned and exercised prior to restart. Additionally, all the MSSVs were successfully tested prior to restart. The inspectors began a review of the adequacy of the maintenance program for the MSSVs as a result of these failures (see paragraph 3.a).

The inspectors concluded that given the complexity of this event the operator performance was adequate and actions taken were appropriate. The inspectors closely followed the post trip review process and the discussions regarding readiness for restart. The post trip review appeared to be adequate. The concerns associated with this event appeared to be adequately addressed prior to restart.

Within the areas reviewed, no violations or deviations were identified.

3. Maintenance and Surveillance Testing (62703), (61726)

a. Main Steam Stop Valve Preventive Maintenance

On November 3, 1993, failures associated with the Unit 1 Main Steam Stop Valves (MSSVs) resulted in a significant transient on the "B" steam generator. Although not the initiating event, the failure of the test solenoid valves for MSSV 3 and 4 to reopen when called upon, resulted in the complications described in paragraph 2.d above. The test solenoid valves (Vickers model F3DG4S4-012A-50) function to open MSSVs 1, 3 and 4; and also function as the backup to the master trip solenoids to close these MSSVs. The test solenoid valves perform their function by positioning an internal spool piece which ports Electrohydraulic (EHC) system operating oil to or from the MSSV hydraulic cylinder. To open MSSV 1, 3 or 4 the test solenoid is deenergized, which allows a spring to position the spool piece to send EHC oil to the hydraulic cylinder. The normal (non emergency) method to close a MSSV sends an electrical signal that energizes the test solenoid coil which overcomes spring pressure to push the spool piece down, allowing EHC oil to bleed off from the MSSV hydraulic cylinder. During the November 3 event, the spool piece internal to the test solenoid valves for MSSV 3 and 4 stuck in the close position.

Following the event, all four MSSV test solenoids were removed and inspected. A residue was found in the internals of MSSV 3 and 4 test solenoids.

The vendor manual for these test solenoids states that "Any sliding spool valve, if held shifted under pressure for long periods of time, may stick and not spring return due to fluid residue formation and, therefore, should be cycled periodically to prevent this from happening." Following the event, the licensee contacted the vendor to determine the recommended periodicity for cycling these solenoids. The vendor recommended cycling these valves every two days. The test solenoid valves were cycled every month during MSSV testing. However, the fast acting solenoids were only tested/cycled during refueling outages. Additionally, there was no preventive maintenance for any of the solenoid valves associated with the MSSVs.

The licensee had not identified the master trip solenoids (Channel A) or the test Solenoids (Channel B) as safety-related equipment. Consequently, there were no requirements for periodic or preventive maintenance. The bases section of the technical specification for the MSSVs states:

"The main steam stop valves limit the Reactor Coolant System cooldown rate and resultant reactivity insertion following a main steam line break accident. Their ability to promptly close upon redundant signals will be verified during each refueling outage. Channel A solenoid valves are designed to close all four turbine stop valves in 240 milliseconds. The backup channel B solenoid valves are designed to close the turbine stop valves in approximately 12 seconds."

The inspectors concluded from the description above that the Channel A and B solenoid valves should be safety-related. The licensee felt that the MSSVs would still be able to perform their intended safety function (close on a valid signal within 15 seconds) with the failure of the Channel B solenoid valves. At the end of the inspection period the licensee stated they would provide the inspectors with documentation supporting this position. This matter is identified as Unresolved Item 269,270,287/93-30-02: MSSV Solenoid Valve Requirements.

b. Turbine Driven Emergency Feedwater Test

In the area of surveillance testing, the inspector observed the quarterly test of the Unit 1 turbine driven emergency feedwater (TDEFW) pump (PT/1/A/0600/12) on October 27, 1993. When the steam admission valve (1MS-93) opened to start the pump the relief valve immediately upstream of 1MS-93 lifted. The relief valve (1MS-92) continued to lift until the pump was secured. After the pump was stopped by closing 1MS-93 the relief valve seated. The test was aborted and main steam isolated to the TDEFW pump while the licensee investigated the cause of the relief valve actuation. The licensee determined that the valve positioner associated with pressure regulating valve 1MS-87 was malfunctioning. Valve 1MS-87 functions to reduce main steam pressure to 300 psig for the TDEFW pump; the relief valve had a lift setpoint of 350 psig.

The applicable LCO for the TDEFW pump was entered prior to the test. The pump remained in the 72 hour LCO until the investigation verified the problem to be the 1MS-87 valve positioner. At Oconee the TDEFW pump is still considered operable with main steam isolated, provided auxiliary steam is available. Therefore the LCO was exited once the problem was identified as the valve positioner. The valve positioner for 1MS-87 was subsequently replaced with a different model with better control characteristics and less drift. The pump was successfully retested using main steam on November 2, 1993. The applicable valve controllers for Units 2 and 3 are scheduled to be replaced in December 1993. A Problem Investigation Report PIP 1-093-0886 was initiated on November 1, 1993 to document and evaluate the incident.

c. Inadequate Core Cooling Monitor (ICCM) Maintenance.

During the inspection period, the inspectors reviewed licensee activities associated with Work Request WR 34391C, ICCM Train A Power Failure. The inspectors reviewed the associated work request and witnessed a portion of the trouble shooting activities conducted to identify the cause of the power failure. The inspectors also verified that the appropriate LCO action statements were entered as a result of the loss of this ICCM train. The licensee determined that the loss of power was caused by the failure of a 5 volt power supply. The power supply was replaced and the channel was returned to service. The inspectors did not identify any discrepancies in the portion of the work activities observed.

Within the areas reviewed, no violations or deviations were identified.

4. Engineering (71707)

a. Isolation of the Continuous Vacuum Priming System

On October 21, the licensee isolated the portion of the continuous vacuum priming system connected to the condenser circulating water (CCW) system intake piping. The purpose of this portion of the continuous vacuum priming system is to remove air from the high points of the CCW system to ensure that the system remains water solid during normal operation and under accident conditions. The CCW system is designed to establish siphon flow through the main condenser if all operating CCW pumps are secured or power to the pump motors is lost. This mode of operation is identified as the emergency condenser circulating water (ECCW) system. The licensee isolated the continuous vacuum priming system due to seismic concerns associated with the continuous vacuum priming system piping (the system is not seismically qualified) and potential single failure concerns. The inspectors previously questioned the adequacy of the design of the ECCW system in NRC Inspection Report 269,270,287/93-13. The ECCW System is required to be operable by Technical Specifications. The licensee position is that the ECCW system is only required to be operable for 1½ hours until a CCW pump can be restarted and that isolation of the continuous vacuum priming system is acceptable if siphon flow can be maintained for this time period. Previously, the licensee stated that the ECCW system was required for 4 hours. The technical specification bases for the ECCW system states that decay heat removal via this flowpath can be maintained for up to 11 hours. The inspectors are concerned that the ECCW system continues to show signs of degradation from the original licensing basis.

b. Review of Licensee's Evaluation

The inspectors reviewed the licensee calculation that justified isolating the continuous vacuum priming system. The licensee calculation is based on an assumed 1 degree temperature rise due to energy added by the CCW pump impeller and pump discharge pressures corrected for lake elevation. The licensee justification is predicated on a minimum number of operating CCW pumps for certain lake levels to maintain pressure in the CCW piping above the value calculated to prevent air from coming out of solution during normal operation of the CCW system. The licensee has administratively established lake levels required for these CCW pump combinations. These lake levels and pump combinations are not addressed in the Technical Specifications and have not been reviewed by the NRC for inclusion into the operating license.

The inspectors questioned the adequacy of the licensee calculation with respect to the test data used to generate the conclusions reached. The lake level calculation for three CCW pumps operating was based on one data point obtained on Unit 1. This data point was obtained with test instrumentation (pressure gages) while CCW pumps 1B, 1C, and 1D were operating at a lake level of 798.3 feet. No other three pump combinations were used to validate system performance. The licensee obtained pressure values of 5.97 psig on 1C and 1D pump header and 4.42 psig on the 1A and 1B pump header (pump 1A was not operating). The licensee reduced the pressure obtained on the 1C and 1D header by 1 tenth of a psig (5.87 psig) to establish the acceptable minimum lake level for three pump operation for all three units. When questioned the licensee had no intentions of performing periodic testing to verify that pump performance did not degrade over time or to obtain additional test data on different pump combinations.

The inspectors questioned the licensee as to why the conservative pressure of 4.42 psig was not used in the calculation to establish the minimum lake level. Using this pressure would have resulted in a minimum lake level of 792.3 feet for three pump operation versus 788.7 feet using 5.972 psig. The licensee stated that the higher pressure value was used because they assumed only one header is required to establish the siphon flow path. The inspectors expressed concern about the effect of swapping pump combinations on the operability of the ECCW system. If air was allowed to accumulate in one header and then the running pump combinations were switched and air was allowed to accumulate in the other header, it does not appear certain the ECCW system would be capable of establishing siphon flow. The licensee stated that the increased flow from starting the second CCW pump in the header that previously only had one CCW pump operating would most likely sweep the accumulated air out of the high point and reestablish a full CCW header. The inspectors questioned the validity of this assumption. The licensee calculation was not based on high flow conditions sweeping air out of the high point, it was based on pressure remaining above the value that would allow air to come out of solution. The licensee had no documentation to support the conclusion that air would not remain in the CCW piping if pump combinations were changed. Lake levels have remained above 792.3 feet throughout the reporting period and the licensee is performing an operability calculation to address increased flow conditions.

The licensee did obtain test data for four CCW pumps operating on all three units. The data indicated that the Unit 2 CCW pumps develop less discharge pressure than the Unit 1 CCW pumps. The minimum discharge pressure recorded on Unit 2 was 8.5 psig versus 8.55 psig minimum discharge pressure on Unit 1. The discharge pressures developed on Unit 3 were above 8.5 psig for pumps 3A, 3B, and 3C, however, CCW pump 3D only indicated 8.138 psig discharge pressure. The licensee used a value of 8.5 psig to establish the minimum acceptable lake level with 4 CCW pumps operating. This value is below the administratively controlled minimum allowable lake level of 785 feet established for low pressure service water pump operability requirements. Using 8.138

also results in a value less than 785 feet. Therefore with 4 CCW pumps operating the licensee's administrative controls are conservative.

The inspectors expressed concern that with the continuous vacuum priming system isolated, the operators in the control room had no indications available to monitor the CCW system and determine that air was not collecting in the intake piping. With the continuous vacuum priming system in service, the operators could monitor vacuum in the vacuum priming tank to ensure that air was being removed from the piping. The CCW system does not have pressure gages installed locally to monitor pressure at the CCW pump discharge nor is pressure indication available in the control room.

The inspectors discussed this concern with licensee personnel. The licensee's initial position was that the calculation was adequate to ensure that the ECCW system would perform as required. In subsequent discussions, the licensee stated that they were evaluating possible methods to monitor the intake piping. This included installation of a sight glass in the vacuum priming system still connected to the CCW piping. The inspectors questioned the adequacy of deleting the continuous vacuum priming system without ensuring that a method was available to monitor the system to ensure that it would perform its intended function during a design basis event. The inspectors questioned why the system could not be vented on a periodic basis to ensure that air was not coming out of solution during normal operation and also questioned why temporary pressure gages couldn't be installed to verify that pressure was above the values assumed in the calculation to prevent air from coming out of solution. The inspectors also questioned why the level switches in the intake piping couldn't be monitored to ensure that level in the piping was above the level required to actuate the switches. These level switches provide an interlock to the CCW high point vent valves but do not provide indication. The status of the level switches can be determined by inspecting to see if the relay is energized or deenergized. The licensee acknowledged the inspectors concerns but did not incorporate a monitoring program, preferring to rely on the calculations.

c. Air Discovered in ECCW System

On November 15, CCW intake high point vent valve 1CCW-28, associated with CCW pumps 1C and 1D, opened when pump 1C was started to allow pump 1A to be secured for screen cleaning. This valve should not have opened when the 1C CCW pump was started.

The high point vent valve receives an automatic open signal if the following three conditions are met:

1) all four CCW pumps are secured
2) Water level is below the level switch contacts
3) CCW pump 1C or 1D is subsequently restarted

The licensee determined that the level switch relay was deenergized indicating that the water level was below the level switch contacts or that the level switch had failed. The initial licensee response was that the level switch had probably failed. The licensee theorized that the interlock associated with the securing of all four CCW pumps had not been unlatched following the performance of the Unit 1 ECCW performance test and that the failed level switch resulted in the valve opening. The licensee subsequently manually reopened the high point vent valve on November 17 and air was released from the high point and the level switch energized, indicating that the water level in the piping had just gone above the level switch. The licensee checked the level switch relays associated with Units 2 and 3. The level switch relays for Unit 2 were energized but one of the relays on Unit 3 was deenergized. The licensee vented the associated header and the Unit 3 level switch relay energized. Subsequent to this event the licensee stated that consideration was being given to establishing a monitoring program on a once per shift frequency to determine the status of the CCW level switches to determine if the water level was above the level switches. This program had not been established as of November 27, the end of the inspection period.

The inspectors expressed concern that a program for monitoring level in the CCW piping had not been established. The inspectors expressed concern about the adequacy of the licensee's actions with respect to isolating the continuous vacuum priming system. The engineering justification was not fully supported, contained questionable and unverified assumptions, and did not address periodic monitoring of the status of the system. These actions indicated a lack of management oversight and a lack of a questioning attitude regarding an evaluation which was neither rigorous nor conservative.

Subsequent to valve 1CCW-28 opening and the inspector's questions, the licensee obtained additional data with respect to operating three CCW pumps per unit. This data was collected on November 17, and consisted of obtaining discharge pressure with three pumps operating on Units 1, 2, and 3. The pump combination on Unit 1 consisted of running the 1A, 1C, and 1D CCW pumps. The pump combination on Unit 3 consisted of 2A, 2C and 2D CCW pumps running. The pump combination on Unit 3 consisted of 3A, 3B, and 3C CCW pumps running. Using the original calculation methodology would have resulted in a calculated minimum lake level of 787.45 feet. The original calculation methodology used the Unit 1 discharge pressure on the side with two CCW pumps running and subtracted .1 psig to bound the other two units. Using the raw data obtained on November 17 for Units 2 and 3 the minimum lake level would be calculated as 787.8 feet for Unit 2 and 788.24 feet for Unit 3. These values do not include the .1 psig factor or instrument error. Both of these lake levels are above the value obtained using the original calculation methodology but are less than the minimum lake level value of 788.7 feet originally calculated at a lake elevation of 798.3 feet.

d. Restoration considerations Following Maintenance on ECCW

On November 23, the licensee removed a Unit 2 CCW pump from service to clean the screen associated with the pump. With the pump secured the number of operating CCW pumps fell below the minimum number of operating pumps for the associated lake level. The 2B CCW had been removed from service previously for maintenance activities and this left only 2 CCW pumps operating on Unit 2. The operators declared the Unit 2 ECCW system inoperable and entered a 7 day LCO. After the screen was cleaned, the CCW pump was restarted and the Unit 2 ECCW system was declared operable. The inspectors questioned the operators the following day whether any attempt had been made to verify that the Unit 2 CCW piping was water solid after the third CCW pump had been restarted. The operators were not aware of any checks to verify that the piping was full and stated that starting the third CCW pump had restored the Unit 2 ECCW system to an operable status. The operators were unaware that the level switches could monitor level in the piping and did not know that the associated relays should be energized if the water level was above the level switch. The inspectors requested that the level switch relays be monitored to verify that the water level was above the level of the switches. The inspectors, unit supervisor and shift manager verified that the level switch relays on Unit 2 were energized. Subsequent to this discussion the inspectors determined that Unit 2 operations staff personnel had monitored the status of the level switch relays after the CCW pump had been restarted. The inspectors are still concerned that the operating procedures do not require that the CCW system be vented or verified full by observation of the level switch relays on a periodic basis especially if CCW pumps are swapped or the number of running pumps falls below the minimum required per the licensee calculation.

The inspectors remained concerned that the continuous vacuum priming system was isolated without conclusive testing to ensure that the system would function in a design basis event. Without adequate instrumentation or programmatic measures to monitor the system for operability, the inspectors consider the licensee's isolation of the continuous vacuum priming system as an example of a willingness to accept minimal compensatory measures and a weak engineering evaluation instead of pursuing plans to upgrade the system. The inspectors will continue to monitor the licensee's actions with respect to the isolation of the continuous vacuum priming system. This item is identified as Unresolved Item 269,270,287/93-30-03: ECCW System Requirements.

e. Failure of Non Code Class Piping Could Result in Blowdown of Both Steam Generators

Two six inch pipe branches from main steam headers "A" and "B" join into an eight inch line which supplies the startup steam header (applicable to all three units). Each six inch line has a motor operated isolation valve (MS-24 & 33). The piping downstream of these isolation valves is not safety-related or seismically qualified (Oconee class "G"). Only one unit at a time supplies the startup steam header, which supplies all three units with auxiliary steam. Unit 2 was supplying the startup header during this inspection period; therefore, its isolation valves were open (2MS-24 & 2MS-33). These valves require operator action to close under both normal and emergency conditions.

Valves MS-24 & 33 were included in the licensee's Generic Letter 89-10 program because they are used to mitigate design basis licensing events, e.g. steam line break, and steam generator tube rupture. As part of the 89-10 program, the licensee determined by calculation that these valves would not close under the maximum differential pressure that would be developed initially following the failure of the class G piping downstream of the valves (delta-P could initially be around 1050 psig, whereas the MOVs had been calculated to be able to close under 400 psig delta-P). This determination resulted in the licensee questioning the ability of these valves to perform their intended safety function. This concern was documented under PIP 0-092-0561.

As part of the PIP resolution process, the licensee performed an engineering operability evaluation that essentially stated the valves were operable, provided efforts to close the valves continued even if the initial attempt failed due to inadequate closing delta-P capability. The rationale for this conclusion was based on the assertion that "the exact pressure at which the valves close is not critical, so long as they do close." The licensee felt that the pressure at which the valves would close was not critical because the break evaluated in FSAR Section 15.13 was much larger than the postulated break in question, and was therefore bounding in terms of DNB and centerline fuel temperature safety limits. Additionally, the licensee felt that by the time operators would take action to close the valves (ten minutes into the event, per the licensee) the steam pressure in both steam generators would have blown down to the point where delta-P across the valve would not prohibit valve closure.

FSAR Section 10.3.2 states "The arrangement of the valving and parallel piping ... prevents blowdown of both steam generators from a single leak in the system." FSAR Section 10.3.4 states

"These valves along with the main steam stop valves prevent uncontrolled blowdown of the unaffected steam generator in the unlikely event of a main steam line break." The inspectors concluded from these statements that the licensee's position contradicted the FSAR. The inspectors agreed that by the time the operators would attempt to close these valves, pressure in the steam generators probably would have decreased to the point where the valves would close. However, allowing both SGs to blow down to some unspecified value did not appear to meet the design basis as stated in the FSAR. At the end of the inspection period the licensee agreed to provide the inspector an analysis of SG pressure versus time up to the time the valves were closed (assumed to be 10 minutes after the initiating event according to the licensee). Pending the results of this analysis, this matter is identified as Unresolved Item 269,270,287/93-30-04: SG Depressurization Times.

5. Inspection of Open Items (92701) (92702)

The following open items were reviewed using licensee reports, inspection record review, and discussions with licensee personnel, as appropriate:

a. (Closed) Violation 287/91-35-01: Failure to Follow Procedures. The licensee responded to this violation by letter dated February 27, 1992. The violation involved a containment isolation valve (3IA-91) being open and a bleed transfer pump suction cross connect valve (3CS-60) being partially open, contrary to procedural requirements. No clear root cause was established for either of these events. The immediate corrective actions for both events returned the valves to the procedurally required status. The long term corrective actions included procedural enhancements and Operations Shift personnel training. The training package stressed the proper techniques in assuring plant component configuration control and the importance of proper documentation of the realignment of plant components.

b. (Closed) Violation 269,270,287/92-08-01: Failure to Follow Procedures. The licensee responded to this violation by letter dated April 23, 1992. This violation had two examples. The first example involved the failure to have the High Pressure Injection (HPI) trains deactivated or isolated per the Low Temperature Overpressure Protection (LTOP) procedural requirements. The second example involved I&E personnel performing a surveillance test on Unit 3 instead of Unit 2 as required by the work request which resulted in a reactor trip on Unit 3.

   For the first example, root causes of inadequate management oversight and failure to follow procedure were identified. Corrective actions included formal counseling for the individuals involved, Operations Management emphasizing proper use of procedures and stronger supervisor involvement with all shift personnel, and an enhancement to procedure OP/1,2,3/A/1104/09, Low Temperature Overpressure Protection. No other LTOP issues or errors have been noted since this incident.

For the second example, the technicians involved failed to identify the correct unit prior to beginning work. The Unit 3 equipment was in very close proximity to some Unit 2 equipment which the technicians had been working on earlier in the shift. The actions of the two I&E technicians involved have been addressed in accordance with the licensee's corrective discipline policy. Additionally, the Station Manager met with I&E staff and technicians to emphasize the importance of utilizing the correct techniques in performing component identification and independent verification.

6. Review of Licensee Event Reports (92700)

The below listed Licensee Event Reports (LER) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, compliance with Technical Specification and regulatory requirements, corrective actions taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. The following LERs are closed:

a. (Closed) LER 287/91-09, Technical Specification Required Containment Integrity Valve Found Mispositioned During Forced Outage Due to Unknown Cause, Possible Inappropriate Action.

This issue was identified as Violation 50-287/91-35-01, and is discussed and closed out in paragraph 5.a above.

b. (Closed) LER 287/92-02, Technicians Performing Preventive Maintenance Test On Shutdown Unit Inappropriately Tested The Wrong Unit Resulting In Unit 3 Reactor Trip.

This issue was identified as the second example of violation 50-269,270,287/92-08-01, and is discussed and closed out in paragraph 5.b above.

c. (Closed) LER 270/92-03, Management Deficiency And Inappropriate Action Result In The Loss Of Technical Specification Required Low Temperature Overpressure Protection.

This issue was identified as the first example of violation 50-269,270,287/92-08-01, and is discussed and closed out in paragraph 5.b above.

d. (Closed) LER 269/91-09, One of Two Diverse Actuation Systems for Loss of Main Feedwater Mitigation Systems Was Found Inoperable Due to a Design Deficiency.

The licensee found that the feedwater pressure remained higher than the actuation setpoint for initiation of Emergency Feedwater after tripping the main feed pumps. By design, the tripping of the main feed pumps would drop feed header pressure below the low pressure setpoint and actuate Emergency Feedwater. The pressure supplied by the heater drain pumps deadheading into the feedwater system kept feed pressure above the actuation setpoint. Corrective actions included removing the tenth stage from the heater drain pumps to lower the deadheaded pressure below the setpoint. This modification was performed on all three units.

e. (Closed) LER 269/91-11, Reactor Trip Results From Electrical Generator Lockout After Equipment Failure In A Generator Protective Relay Circuit.

Loose connections in the Unit 1 Main Generator's protective circuitry caused the spurious actuation of the lockout circuitry, tripping the generator and the reactor. As immediate corrective actions, all connections were inspected and retightened. Subsequently, a logic modification on all three units was implemented. This change precludes actuation of the lockout feature on an open circuit.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on November 30, 1993, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection nor did they provide dissenting comments.

Item Number	Description/Reference Paragraph
IFI 50-270/93-30-01	Elevated Main Steam Line Pressures Following a Unit 2 Trip (paragraph 2.c).
URI 50-269,270,287/93-30-02	MSSV Solenoid Valve Requirements (paragraph 3.a).
URI 50-269,270,287/93-30-03	ECCW System Requirements (paragraph 4.d).
URI 50-269,270,287/93-30-04	SG Depressurization Times (paragraph 4.e).