U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/95-13 License: DPR-18

Facility: R. E. Ginna Nuclear Power Plant
Rochester Gas and Electric Corporation (RG&E)

Inspection: June 18, 1995 through July 29, 1995

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INSPECTION SCOPE

Plant operations, maintenance, engineering, plant support, and safety assessment/quality verification.

INSPECTION EXECUTIVE SUMMARY

Operations

At the beginning of the inspection period, the plant was operating at full power (approximately 97 percent). On June 26, 1995, temporary loss of one of the main generator's electrical transmission circuits due to a lightning strike resulted in a controlled power reduction to approximately 70 percent. The plant was returned to full power operation the following day. On June 30, 1995, one of the two offsite electrical power supplies deenergized due to a lightning strike. A momentary loss of two of the four class 1E electrical buses occurred until the associated emergency diesel generator started and assumed electrical loads. All engineered safety features equipment functioned as required and the event had no effect on reactor power.

On two occasions (July 4 and July 26, 1995), a problem with the steam pressure regulator for the main air ejectors resulted in an increase in turbine backpressure and a decrease in main generator output. On both occurrences, normal air ejector steam pressure was promptly restored by bypassing the regulator. No operator action to reduce load was required.

On July 19, 1995, power was reduced to 48 percent for repair of a mechanical problem with the B-main feedwater pump. Repairs were completed and the plant was returned to full power operation on the same day.

Maintenance

The inspector observed that the diaphragm housing for a balance-of-plant air operated valve was cocked and had partially separated from the valve body. The failure may have indicated a generic problem and could have represented a potential reactor safety concern. Licensee investigation revealed that five out of the eight bolts that attach the diaphragm housing to the valve body were sheared. At the close of the inspection period, the licensee's root cause determination for the failure was continuing. Preliminary results of this investigation and industry operating experience indicate that such a failure mode is not a generic problem.

The major teardown and rebuild of two safety-related pumps during the 1995 refueling outage was reviewed and found to have been effectively conducted. Vendor assistance was appropriately utilized, and emergent problems were adequately resolved and reviewed for generic applicability. Maintenance procedures were of good quality and experience gained during the work was utilized for maintenance procedure improvement.

The maintenance backlog was reviewed and the facility maintenance performance was determined to be effective in ensuring significant corrective maintenance was completed during outages.

Engineering

To eliminate unnecessary turbine runbacks that occurred when one offsite power supply (circuit 751) was lost, a modification to the reactor protection system was performed during the 1995 refueling outage to change the delta-T runback logic from one-out-of-four to two-out-of-four. Following the outage, unexpected control rod motion occurred when offsite power circuit 751 was lost on June 30, 1995. The licensee subsequently determined that the rod motion was a consequence of the delta-T runback logic modification. The inspector determined that the rod motion had not been identified as a consequence of the modification during design, implementation, or acceptance testing. Additionally, the licensee had not identified the unanticipated rod motion event as a problem to be tracked by their corrective action system. As a result, some aspects of corrective action were not pursued. The licensee plans to enter the unanticipated rod motion event into the corrective action system. The inspector will review the licensee's corrective actions and the Licensee Event Report later.

Plant Support

The inspector observed a simulator-driven emergency preparedness drill. The licensee conducted a test to determine the effect of bypassing the condensate polishers on steam plant water chemistry. This was considered to be a viable possibility due to the reduced circulating water leakage into the condensate that resulted from the recently completed main condenser retubing. The scheduled 1996 steam generator replacement was also a factor in conducting the test at this time. The test demonstrated that bypassing the condensate polishers had little or no derogatory effect on steam plant water chemistry.

Safety Assessment/Quality Verification

During this inspection period, the licensee instituted a single entry point corrective action program. Interface procedure IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (ACTION) Report," replaced most previously existing corrective action programs. The licensee utilized industry experience in developing this program, and the procedure underwent extensive critical review and revision prior to implementation.

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DETAILS

1.0 OPERATIONS (71707)

1.1 Operations Overview

At the beginning of the inspection period, the plant was operating at full power (approximately 97 percent). On June 26, 1995, temporary loss of power from one of the main generator's electrical transmission circuits due to a lightning strike resulted in a controlled power reduction to approximately 70 percent. Repairs to the offsite distribution system were completed and the plant was returned to full power operation the following day. On June 30, 1995, one of the two offsite electrical power supplies deenergized due to a lightning strike. This resulted in a momentary loss of power to two of the four class 1E electrical buses until the associated emergency diesel generator started and assumed electrical loads. All engineered safety features equipment functioned as required and the event had no effect on reactor power. On two occasions (July 4 and July 26, 1995), a problem with the steam pressure regulator for the main air ejectors resulted in an increase in turbine backpressure, and consequently, a decrease in main generator output. On both occurrences, normal air ejector steam pressure was promptly restored by bypassing the regulator, and no operator action to reduce load was required before the condition was resolved. On July 19, 1995, power was reduced to 48 percent for repair of a mechanical problem with the B-main feedwater pump; repairs were completed and the plant was returned to full power operation later the same day. There were no other significant operational events or challenges during the inspection period.

1.2 Operational Experiences

1.2.1 Load Reduction Due To Transmission Line Disturbance

At 6:28 p.m. on June 26, 1995, a lightning strike occurred offsite on one of the plant's electrical transmission circuits (circuit 911). The resultant transient caused the associated onsite circuit breaker, 9X13A72, to trip on overcurrent. Control room operators responded in accordance with operations procedure O-6.9, "Operating Limits For Ginna Station Transmission," to reduce station load to within the steady-state capacity of the remaining transmission circuits. Over a period of 10 minutes, main generator output was reduced to approximately 350 megawatts (corresponding to approximately 70 percent reactor power) in accordance with O-5.1, "Load Reductions." As a result of this rapid downpower, axial flux difference deviated from its target band, as defined in technical specification (TS) 3.10.2.8, for a period of 14 minutes; TS 3.10.2.10 allows for continued operation under this condition, provided that the cumulative period outside of the target band does not exceed one hour in any 24 hour period.

Repairs to circuit 911 were completed by the following day. At 3:33 a.m., a 10 percent per hour load increase was commenced, and full power was achieved at 7:05 a.m.

Through review of logs and discussions with plant personnel, the inspector determined that operators had responded appropriately to the loss of power from circuit 911. The inspector verified that the TS requirements for axial

flux difference had been satisfied. The inspector had no additional concerns on this matter.

1.2.2 Loss of One Offsite Power Source Due To Lightning Strike

At 3:28 p.m. on June 30, 1995, a lightning strike occurred offsite on one of the plant's two offsite electrical power circuits (circuit 751). As a result of the transient, circuit 751 was deenergized by protective relays at offsite station 204. This resulted in a loss of power to the two class 1E 480-volt electrical busses that are normally supplied by circuit 751 (busses 14 and 18). In response to the power loss, the A-emergency diesel generator (EDG) automatically started and reenergized the two busses. Operators responded in accordance with abnormal procedure AP-ELEC.1, "Loss of 12A and/or 12B Busses," to stabilize affected systems. All engineered safeguards equipment functioned as required and plant power was not affected by the transient. An unexpected automatic withdrawal of the control bank control rods occurred shortly after the busses were reenergized; this was an unanticipated consequence of a modification that had been performed to the reactor protection system during the 1995 refueling outage. Operators took manual control of the rod control system and restored rods to their pre-event configuration. The rod withdrawal had no significant effect on reactor plant operating parameters.

At 3:57 p.m., the electrical distribution system was realigned such that the unaffected offsite electrical power circuit (circuit 767) was supplying all four class 1E 480-volt electrical busses. The A-EDG was shut down and returned to standby. Repairs to circuit 751 were completed at 6:04 p.m.; however, the circuit was not placed in service until two days later due to continued storm activity.

Through review of logs and discussions with plant personnel, the inspector determined that operators had responded appropriately to the loss of power from circuit 751. A four-hour non-emergency report was made to the NRC as required by 10 CFR 50.72. The unexpected automatic withdrawal of control bank rods that occurred subsequent to the restoration of power is further discussed in section 3.1 of this report.

1.2.3 Load Reduction Due To Main Feedwater Pump Mechanical Malfunction

On July 19, 1995, an auxiliary operator, conducting his routine rounds, noticed that the sight glass oil indication for the B-main feedwater (MFW) pump lube oil sump appeared milky. He immediately notified the control room. Upon further investigation, shift supervision and maintenance personnel concluded that the oil cooler was leaking, thereby allowing service water into the pump's lube oil system. Shift supervision immediately decided to reduce power to below 50 percent so that the B-MFW pump could be secured to allow repair of the lube oil cooler. Plant power was reduced to about 48 percent shortly before noon and the B-MFW pump was secured. Maintenance personnel replaced the faulty lube oil cooler and, after verification of the lube oil system performance, the B-MFW pump was restarted and returned to service. Plant power was returned to about 97 percent shortly before midnight.

The inspector noted that the auxiliary operator had shown good judgment in immediately notifying the control room about the discrepancy with the pump lube oil. Operators demonstrated good safety perspective and excellent performance by immediately reducing plant power and securing the pump. The problem was diagnosed and resolved in a timely fashion.

2.0 MAINTENANCE (62703, 61726)

2.1 Maintenance Activities

2.1.1 Routine Observations

The inspector observed portions of maintenance activities to verify that correct parts and tools were utilized, applicable industry code and technical specification (TS) requirements were satisfied, adequate measures were in place to ensure personnel safety and prevent damage to plant structures, systems, and components, and to ensure that equipment operability was verified upon completion. The following maintenance activities were observed:

- Work Order 19501563, "Inspect Torque Switch Setting In MOV-4000A" (Auxiliary Feedwater Crossover Valve)

  The inspector observed maintenance personnel open the actuator cover and inspect the torque switch setting. The electrician also inspected the condition of the wires, limit switch and the actuator lubricant. The inspector then performed an independent inspection of the limit switch compartment. The wires appeared to be in good condition and were snugly installed. No excessive grease or indication of grease deterioration was observed inside the switch compartment. The torque switch settings were at approximately 2 "open" and 2 "close," as expected. The electrician conducted the work activities in accordance with the approved work order. The actuator cover was properly restored and the valve stroked and verified operable at the completion of the maintenance inspection activities. The inspector noted no discrepancy.

- Work Order 19501874, "Obtain Grease Sample From Limitorque Operator MOV-4007" (A-Motor Driven Auxiliary Feedwater Pump Discharge Valve)

  The inspector observed a maintenance mechanic obtain grease samples from limitorque operator 4007. The samples were obtained in order to verify that there were no metal shavings present which would be indicative of a malfunctioning actuator. This actuator had been over torqued during the 1995 outage when the torque switch setting drifted to about 5 due to vibration of the actuator. The mechanic performed the work activities in accordance with the approved work order. The samples were obtained from a lower and an upper grease plug location on the main gear housing. The inspector inspected the samples obtained and verified that there was no indication of any dirt, water or metal shavings. The mechanic restored the plugs to their as-found locations. No discrepancies were observed.

2.1.2 Condensate System Air Operated Valve Failure

On July 12, 1995, the inspector noted that the diaphragm housing for air operated valve (AOV)-5561 (Condensate heater 1A high level drain to condenser) was cocked and had partially separated from the valve body. The inspector informed the shift supervisor of the problem. AOV-5561 is a balance-of-plant valve and does not directly affect reactor safety; however, AOVs are used in safety-related applications elsewhere in the plant. Complete separation of an AOV diaphragm housing from valve body would not only render the valve inoperable, it could also invalidate the valve's design "failed" position (that is, the position that the valve would come to upon a loss of operating air). The inspector was concerned that the AOV-5561 failure could be indicative of a generic problem and therefore could represent a potential reactor safety concern.

Licensee investigation revealed that five out of the eight bolts that attach the diaphragm housing to the valve body were sheared. In all cases, the fractures originated in the first thread below the bolt head. In several cases, the fracture surfaces indicated that fatigue had been the cause of failure. Several of the bolts also showed indications of pre-existing flaws, as could have occurred from overtorquing. The licensee determined that the failed joint had not been disassembled through 25 years of service. The licensee verified that the bolts were made of the correct material. At the close of the inspection period, the licensee's root cause determination for the failure of AOV-5561 was continuing.

The inspector considered that the licensee responded aggressively in attempting to determine the cause of the AOV-5561 diaphragm housing failure. Preliminary results of this investigation and industry operating experience indicate that such a failure mode is not a generic problem. The inspector will continue to follow the licensee's investigation of this problem.

2.2 Surveillance and Testing Activities

2.2.1 Routine Observations

Inspectors observed portions of surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operation (LCOs), and correct system restoration following testing. The following surveillances were observed:

- Periodic Test (PT)-16M-T, "Auxiliary Feedwater Turbine Pump - Monthly," revision 10, effective date June 27, 1995, observed June 28, 1995

- PT-3Q, "Containment Spray Pump Quarterly Test," revision 18, effective date March 21, 1995, observed July 10, 1995

- PT-2.7.1, "Service Water Pumps," revision 17, effective date July 17, 1995, observed July 19, 1995

During the performance of PT-2.7.1, problems developed with the B-circulating water pump that caused operators to terminate the test. In order to adjust service water (SW) pump "A" discharge flow for testing purposes, the procedure required that service water flow to the screen wash/circulating water pump seals be isolated. After this was accomplished, test personnel heard abnormal noises from the shaft/seal area of circulating water pump "B". Test personnel immediately restored the seal water flow to the circulating water pump and terminated the service water pump test. The system engineer was notified of this discrepancy and was following up on the issue.

- PT-16Q-B, "Auxiliary Feedwater Pump B - Quarterly," revision 17, effective date April 14, 1995, observed July 20, 1995

  The inspector observed portions of the surveillance activities both from the pump area and the control room. Operators and test personnel conducted activities safely and in accordance with approved procedure. The inspector noted good communication/coordination of activities and proper verification of equipment manipulation.

The inspector determined through observing the above surveillance tests that operations and test personnel adhered to procedures. Equipment operating parameters and test results met their required acceptance criteria, and redundant equipment was available for emergency operation.

2.3 Review of Outage Maintenance

The inspector conducted a review of two safety system pump overhauls to determine the effectiveness of the facility in planning and conducting this type of maintenance. The reviewed activities were:

- WO 19405081, "C-Safety Injection Pump - Major Overhaul"
- WO 19405082, "A-Auxiliary Feedwater Pump - Major Overhaul"

Prior to the outage, the C-safety injection (SI) pump had exhibited high vibration during quarterly surveillance testing. Some corrective maintenance had been done, including pump venting and minor alignment changes, to maintain pump operability, but RG&E decided to completely overhaul the pump during the 1995 outage. The overhaul was completed by vendor representatives under the observation of specially trained RG&E mechanics, and included complete pump teardown, replacement of the drive shaft and pump components, and rebuild. During the overhaul, balance disc and thrust disc clearances were found out-of-tolerance and all bearings were found very worn and degraded. In a post-maintenance review, the root cause of the degradation was determined to be failure of the stuffing box bushing which allowed the shaft to move, causing the degraded clearances and bearing wear.

During the C-SI pump overhaul, mechanics found that the pump mechanical seal cooling and supply line had been totally plugged by boric acid and that this plugging had contributed to degradation of the mechanical seal. Coincident with the pump overhaul, seal cooling and supply lines had been replaced in all

three pumps with stainless steel tubing. The inspector reviewed the disposition of the clogged seal line and determined that, although RG&E had taken no specific action to ensure that clogging would not recur, or occur in the other pumps, enhanced testing of pump vibration and replacement of the cooling lines provided assurance that clogging was not a current problem with any of the SI pumps. Maintenance personnel noted that during final work package review and closeout the seal line clogging would be reviewed to determine if any further action would be necessary to ensure continued pump performance.

During the 1994 outage, failure of the B-SI pump interstage seals had occurred and had been attributed to dead-head pump operation during testing. The interstage seals of the C-pump were removed and saved by RG&E, for evaluation of elasticity, so that a determination as to the capability and service life of the seals could be made. This determination was in progress during the inspection.

The overhaul of the A-auxiliary feedwater pump was a preventive maintenance overhaul and was not based on any performance deficiencies. The effort included complete pump teardown, replacement of the drive shaft and pump internals, and rebuild. No defective components or serious degradation were identified in the overhaul.

The inspector found the procedure control of the maintenance activities to be good. Actions were taken by the facility to improve procedure content during the work to further enhance the instructions. Overhaul work orders for both pumps were prepared with detailed vendor-provided instructions. To improve the content of the instructions, the RG&E mechanics made extensive field notes during the overhaul. After the work was completed, the field experience was used to further improve the procedure content and to facilitate future pump maintenance.

In conclusion, the inspector determined that the major teardown and rebuild of two safety-related pumps were effectively conducted. Vendor assistance was appropriately utilized, and emergent problems were adequately resolved and reviewed for generic applicability. Maintenance procedures were of good quality and experience gained during the work was utilized for procedure improvement.

2.4 Maintenance Backlog Review

The Ginna maintenance backlog was reviewed and the facility maintenance performance was determined to be effective in ensuring significant corrective maintenance was completed during the outage. The reviewed work backlog consisted of 1233 open items, most of which were planned preventative maintenance activities, and low priority, non-safety related corrective items. Of the 1233 items, 926 items were determined to be in closeout review.

One significant corrective maintenance item on the backlog was reviewed in detail. The B-component cooling water pump had been found to be in the alert range high on differential pressure during quarterly inservice testing. Engineering review of the high measurements determined that the observation

was caused by a combination of imprecise pressure instrumentation and a non-optimal test recirculation lineup. The engineering review resulted in an improved valve lineup and installation of precision test gauges, which when implemented, showed pump differential pressure to be the normally expected value. Although the work order was still open, the technical issue had been resolved and demonstrated an effective maintenance-engineering interface.

3.0 ENGINEERING (71707, 37551)

3.1 Delta-T Turbine Runback Logic Change

There are four 120-volt AC instrument busses (A, B, C, and D) at the Ginna plant. These busses provide electrical power for engineered safeguards and reactor plant instrumentation and control systems, including the reactor protection system (RPS). Each instrument bus supplies power to one channel of the RPS. Of the four instrument busses, two (A and C) have backup power supplies that will automatically assume the bus loads if the normal power supply to the bus is deenergized. The remaining two instrument busses (B and D) each have an alternate power supply available, but the transfer must be performed manually. Therefore, loss of the normal power supply to either of these busses will result in the bus being deenergized for some period of time. The normal power supply to instrument bus B is the 480-volt class 1E bus 14 (receiving power from circuit 751 or, alternately, circuit 767). The normal power supply to instrument bus D is the 480-volt bus 15 (during power operations, receiving power from the main generator through the unit auxiliary transformer). As a result, loss of the offsite power circuit that supplies bus 14 (normally, circuit 751) will result in a loss of power to instrument bus B and its associated RPS channel. In such an event, bus 14 will be reenergized in approximately 10 seconds by automatic operation of the A-EDG.

One of the functions that is automatically initiated by the RPS is a turbine runback. This function rapidly reduces power by decreasing turbine load in the event that reactor power is approaching the overtemperature delta-T [temperature difference], or the overpower delta-T reactor trip setpoint. By the original design of the RPS, a signal from any one of the four RPS channels (one-out-of-four logic) would initiate a turbine runback. The problem with this simple logic, however, was that unnecessary runbacks could be caused by failure of a single instrument or loss of power to one channel of the RPS. Unnecessary turbine runbacks have occurred on several occasions in the past due to loss of circuit 751. As a result, a modification of the RPS was developed to change the delta-T turbine runbacks to two-out-of-four logic. Technical Staff Request (TSR) 94-139, "Delta-T Runback Logic Change," accomplished the modification during the 1995 refueling outage.

As discussed in section 1.2.2 of this report, a loss of circuit 751 occurred on June 30, 1995. At the time of the event, the offsite electrical distribution system was in its normal configuration, with bus 14 being supplied by circuit 751. Consequently, instrument bus B lost power for approximately 10 seconds. The delta-T runback logic modification functioned as designed and no turbine runback occurred. However, approximately eight seconds after power was restored to instrument bus B, the control bank of control rods began to automatically withdraw. Control room operators

treated this as a rod control system malfunction and took manual control to stop the rod motion. Instrument and control (I&C) personnel were contacted to troubleshoot the problem. Their investigation determined that no malfunction existed, but that the outward rod motion was an unanticipated consequence of the delta-T runback logic modification.

The outward rod motion resulted from deenergizing and reenergizing the average temperature (Tavg) instrument channel that is powered from instrument bus B, and the Tavg channel's interaction with the automatic rod control system. The automatic rod control system generates rod motion based on comparison of actual Tavg to the value that Tavg should be, based on actual plant power (i.e., "reference Tavg", or Tref). The rod control system uses the average of four Tavg channels as the value of actual Tavg and calculates Tref based on turbine inlet steam pressure. To prevent unnecessary rod motion due to a failed Tavg channel, the rod control system will block rod motion if the difference between any Tavg channel and average Tavg exceeds a set value. Upon loss of power, a Tavg instrument channel output does not immediately drop to zero, but rather ramps down; similarly, when power is restored, the instrument output ramps back to the actual value.

When power to instrument bus B was lost, the output of the associated Tavg channel began to decrease, causing average Tavg to decrease below Tref. However, no rod motion occurred because a second rod motion inhibit signal (the rod drop rod stop) was generated when the instrument bus B power range nuclear instrument deenergized. As the event progressed, the deenergized Tavg channel deviated from the other channels sufficiently to invoke its own rod stop. When instrument bus B was reenergized, the rod drop rod stop cleared. As the reenergized Tavg channel output ramped above the limit for channel agreement (about eight seconds later), the rod control system initiated outward rod motion based on the low value of Tavg.

Through review of TSR 94-139 and discussions with plant personnel, the inspector confirmed that outward rod motion following a loss and subsequent reenergization of instrument bus B had not been identified as a consequence of this modification during design, implementation, or acceptance testing. Additionally, the licensee did not identify the unanticipated rod motion event as a problem to be tracked by the corrective action system. As a result, some aspects of licensee's corrective action process were not pursued. For example: The possible need to revise the safety evaluation for TSR 94-139 had not been examined; it was not clear whether a thorough review of procedures for applicability and possible revision had been performed; and all operations department personnel had not been made aware that automatic rod motion occurred and should be an expected response to reenergizing instrument bus B. As a result of this event, the licensee took action to increase the reliability of electrical power to instrument bus B, and was in the process of revising one procedure.

The inspector discussed these concerns with RG&E management who plans to enter the unanticipated rod motion event into the corrective action system. The inspector will review the licensee's corrective actions and the Licensee Event Report later.

4.0 PLANT SUPPORT (71750)

4.1 Emergency Preparedness

4.1.1 Training Drill

On June 21, 1995, the licensee conducted a simulator-driven emergency preparedness drill. The drill was conducted primarily for training and involved only RG&E personnel. As such, the inspector's involvement was limited to verifying that the drill did not adversely impact actual plant operations.

4.2 Chemistry

4.2.1 Condensate Polisher Bypass and Overboard Blowdown Test

During this inspection period, the licensee conducted a test to determine the effect of bypassing the condensate polishers on steam plant water chemistry. This was considered to be a viable possibility due to the reduced circulating water leakage into the condensate that resulted from the recently completed main condenser retubing. Steam generator replacement, scheduled for 1996, was also a factor in conducting the test at this time. The test was conducted by bypassing the condensate polishers to varying degrees in combination with steam generator blowdowns directed either to the lake or back to the main condensers. The test demonstrated that bypassing the condensate polishers had little or no derogatory effect on steam plant water chemistry. The inspector noted that the operation department's approach to this test was deliberate and conservative. Prior to conduct of the test, the possible effects of condensate polisher bypass operations on secondary plant transients were examined by the Plant Operations Review Committee.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707)

5.1 Procedure For Single Entry Point Corrective Action Program Instituted

Prior to this inspection period, the corrective action program at the Ginna station was a composite of more than 30 individual corrective action processes. During this inspection period, the licensee instituted a "single entry point" corrective action program. Interface procedure IP-CAP-1, "Abnormal Condition Tracking Initiation or Notification (ACTION) Report," replaced most previously existing major corrective action programs. The licensee utilized industry experience in developing this program, and the procedure underwent extensive critical review and revision prior to implementation. The inspector reviewed IP-CAP-1 and concluded that the procedure contained attributes for establishing a more effective corrective action program.

5.2 Periodic Reports

Periodic reports submitted by the licensee pursuant to Technical Specification 6.9.1 were reviewed. The inspector verified that the reports contained information required by the NRC, that test results and/or supporting information were consistent with design predictions and performance specifications, and that the reported information was accurate. The following report was reviewed:

- Monthly Operating Report for June 1995

No unacceptable conditions were identified.

5.3 Licensee Event Reports

A Licensee Event Report (LER) submitted to the NRC was reviewed to determine whether details were clearly reported, causes were properly identified, and corrective actions were appropriate. The inspector also assessed whether potential safety consequences were properly evaluated, generic implications were indicated, events warranted additional follow-up, and applicable requirements of 10 CFR 50.73 were met.

The following LER was reviewed (Note: date indicated is event date):

- 95-005, "Instrument Air Leak in Containment Causes Feedwater Isolation," June 7, 1995

The inspector concluded the LER met regulatory requirements and appropriately evaluated the safety significance of the event. LER 95-005 is closed.

6.0 ADMINISTRATIVE

6.1 Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of inspections. The exit meeting for inspection report 50-244/95-14 (Physical security and fitness for duty programs, conducted July 10-13, 1995) was held by Mr. Ed King on July 13, 1995. The exit meeting for the current resident inspection report 50-244/95-13 was held on August 2, 1995.