

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/95-07

License: DPR-18

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

Inspection: February 7, 1995 through March 11, 1995

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Approved by:

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4/13/95
Date

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 98 percent). On February 10, 1995, a planned power reduction to 46 percent was performed to plug a leaking main condenser circulating water tube. The plant was returned to full power on February 11, 1995, and remained at full power for the balance of the inspection period.

Maintenance

On February 12, 1995, one of two subsystems of the microprocessor rod position indication (MRPI) system failed. The other subsystem (subsystem 2), which provides indication through the primary plant computer system (PPCS) remained operable, thus satisfying technical specification (TS) requirements for control rod position indication. The two subsystem 1 power supply modules were replaced as the first step in troubleshooting; however, when technicians attempted to reinitiate subsystem 1, PPCS MRPI (subsystem 2) failed. With no operable MRPI, the plant was in a condition not allowed by TS. Normal operation of PPCS MRPI was restored by deenergizing subsystem 1. All MRPI had been inoperable for approximately 2.5 minutes. During subsequent troubleshooting, PPCS MRPI was lost for a short period on two additional occasions. The cause of the loss of all MRPI was determined to be a ground on the MRPI chassis that had been created during the power supply module replacement (one of the chassis mounting screws had penetrated the insulation on a wire inside the module). The cause of the original (channel 1) MRPI failure was determined to be a failed resistor in one of the power supply modules.

The inspector concluded that the corrective maintenance effort had been effective. Troubleshooting was complicated by introduction of the chassis fault; nonetheless, the sequence of troubleshooting actions was logical and well thought-out. The inspector did not consider that the chassis ground was due to personnel error, in that it is a reasonable expectation that mounting hardware can be reused in a like-for-like replacement. The inspector observed effective PORC involvement, however, the inspector considered that PORC involvement could have been more timely.

Two problems with the instrument air (IA) system air dryers occurred during the inspection period. The A-IA dryer developed a problem with the timing of valve operations during automatic air blowdown of the unit, such that both the dryer isolation valve and blowdown valve were simultaneously open for short periods of time. This caused IA system pressure to decrease to the point at which the backup IA compressor would automatically start. Before pressure was reduced to the point of affecting equipment operation, the blowdown would automatically secure. The problem was determined to be that the cams that sequence the valve operations had become out of adjustment.

In the second instance, mechanical failure of the B-IA dryer isolation valve with the valve in the open position similarly resulted in a reduction of IA pressure. In this instance, however, operator action was required to isolate

INSPECTION EXECUTIVE SUMMARY

the dryer. Although the pressure reduction was greater than had occurred in the case of the A-IA dryer, the problem still had no operational affect. The defective valve was subsequently replaced.

The inspector considered these IA problems to be significant, due the operational consequences of a loss of IA, and because loss of IA is the major contributor to core damage as determined by the licensee's individual plant evaluation (IPE). The licensee is in the process of reevaluating the significance of loss of IA, using more realistic assumptions for the probabilistic risk assessment (PRA). Planned IA system improvements will not be affected by the results of this reevaluation.

Engineering

During review of post-installation lift test results for pressurizer safety valves V-434 and V-435, the licensee determined that the as-found lift pressures for both valves slightly exceeded the maximum allowable setpoint. These valves had been installed during the 1993-1994 operating cycle, and were removed for testing during the 1994 outage. In response to this determination, the engineering department had Westinghouse evaluate the effect of the setpoint deviation on the most limiting design basis accidents. Reanalysis of these transients demonstrated that the valves would still have satisfied the criteria for all UFSAR design basis events.

Plant Support

Routine observations in the areas of radiological controls, security, and fire protection indicated that these programs were effectively implemented. On February 27, 1995, the annual full duration audible test of public notification system sirens was conducted. 93 of the system's 96 sirens operated satisfactorily during the test. The remaining three sirens were repaired and tested satisfactorily later the same day.



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DETAILS

1.0 OPERATIONS (71707)

1.1 Operational Experiences

At the beginning of the inspection period, the plant was operating at full power (approximately 98 percent). On February 10, 1995, a planned power reduction to 46 percent was performed to plug a leaking main condenser circulating water tube. The plant was returned to full power on February 11, 1995, and remained at full power for the balance of the inspection period. There were no other significant operational events or challenges during the inspection period.

1.2 Control of Operations

Control room staffing was as required. Operators exercised control over access to the control room. Shift supervisors maintained authority over activities and provided detailed turnover briefings to relief crews. Operators adhered to approved procedures and were knowledgeable of off-normal plant conditions. The inspectors reviewed control room log books for activities and trends, observed recorder traces for abnormalities, assessed compliance with technical specifications, and verified equipment availability was consistent with the requirements for existing plant conditions. During normal work hours and on backshifts, accessible areas of the plant were toured. No operational inadequacies or concerns were identified.

1.3 Main Condenser Tube Plugging

On February 10, 1995, a main condenser circulating water tube developed significant leakage. Prior to this, chemistry department personnel had been monitoring main condenser tube leakage and had noted a gradual increase in leakage into the 1B2 waterbox. Plant management was aware of this problem, but, as of the morning of February 10, the leakage rate was within the capacity of the condensate polishers to clean up. At that time, it was decided to continue monitoring rather than to reduce power to affect repairs. However, as the day progressed, the leakage rate increased rapidly, as indicated by a threefold increase in feedwater cation conductivity. The decision was made to reduce power to less than 50 percent to remove the 1B2 waterbox from service for repair.

At 4:40 p.m. on February 10, 1995, operators commenced power reduction at 10 percent per hour. Power was stabilized at 46 percent at 9:43 p.m. Entry into the 1B2 waterbox revealed that the leak was from a single circulating water tube. The leaking tube was detectable by sound (air being drawn into the main condenser through the fault), indicating the presence of a large fault. This was further supported by the chemistry department's measured leakage rate of approximately two gallons per minute, as would result from failure of a single circulating water tube. The leaking tube was plugged and the waterbox was returned to service. Power escalation commenced at 3:39 a.m., and full power was reached at 11:48 a.m., February 11, 1995.

The inspector concluded that licensee management had responded promptly to reduce power and correct the 1B2 waterbox leak. Power reduction and escalation were completed without incident. The inspector had no additional concerns on this matter.



1.4 Increased Frequency of A-Containment Sump Pumpdown

As discussed in inspection report 50-244/95-03, the A-containment sump automatic pumpdown interval has trended downward during this operating cycle, from a historic value on the order of 50 hours, to approximately 12 hours as of the beginning of this inspection period. Periodic containment entries have identified and repaired several water leaks from secondary plant systems; however leakage was still occurring from the A-steam generator (SG) secondary side manway and from an unidentified location on the B-SG (originally suspected to be the secondary side blowdown piping).

During this inspection period, the licensee identified the probable source of B-SG leakage to be a secondary side hand hole gasket leak. The combined leakage rate from the A-SG manway and B-SG hand hole slowly increased over the course of the inspection period; the A-containment sump pumpdown interval had decreased to approximately eight hours as of the close of the inspection period. The engineering department analyzed the historic data and determined that the leakage rate has been increasing linearly. On this basis, the containment sump pumpdown interval is projected to reach approximately five hours (approximately 0.3 gallons per minute leak rate) by the time that the plant would be shut down on March 27 to begin the 1995 refueling outage. Operators continue to closely monitor the containment sump pumpdown interval.

2.0 MAINTENANCE (62703, 61726)

2.1 Preventive Maintenance

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 (WO) 19500462, "Control Room MRPI [Microprocessor Rod Position Indication] CRT [Cathode Ray Tube] Indication Has Failed," performed in accordance with maintenance procedure M-51.14, "Microprocessor Rod Position Indication System (MRPI) Maintenance," revision 8, effective date October 6, 1994, observed February 14, 1995
 - Observed removal of the 12V/5V DC power supply module, as discussed in section 2.2.1 of this report
- WO 19402921, "Refurbish MOV-4000B (Auxiliary feedwater crossover valve)," performed in accordance with corrective maintenance procedure CMP-37-08-4000B, "Rockwell Edward, 3-inch, 1500-lb Globe Stop Valve, Maintenance for 4000B," revision 0, effective date February 9, 1995, observed February 28 and March 1, 1995
 - Observed preparation of body/bonnet joint for dye penetrant examination. The inspector noted that area housekeeping was weak, with grinding debris noted on the domes of both MDAFW pump



recirculation flow control valves (the equivalent valve associated with the A-MDAFW pump had been refurbished just prior to this maintenance). This was of concern due to recent AOV failures involving orifice plugging by small debris. The inspector discussed this observation with licensee management, and the area was promptly and thoroughly cleaned.

- Observed final seat/disk blue check, QC closeout inspection, and assembly of valve bonnet to the body. The inspector noted that the closeout inspection was thorough.

2.1.2 Safety System Maintenance Outages

During this inspection period, the following safety systems were taken out of service for corrective/preventive maintenance, as identified by the associated work orders (WOs):

- B-Emergency Diesel Generator (EDG)
Taken out of service (OOS) 8:41 a.m. February 13, 1995
Returned to service (RTS) 9:39 p.m. February 13, 1995
Allowed outage time (AOT) 7 days per TS 3.7.2.2.b
 - WO 19500332, "Test EG1B1 breaker and inspect"
- D-Standby Auxiliary Feedwater (SAFW) Pump
OOS 4:53 a.m. February 14, 1995
RTS 2:26 p.m. February 14, 1995
AOT 14 days per TS 3.4.2.3
 - WO 19404297, "Replace latch SAFW pump breaker 16/17C"
 - WO 19404331, "SAFW pump D - Minor PM inspection"
 - WO 19500232, "Perform electrical tests on D-SAFW pump motor"
- B-Residual Heat Removal (RHR) Pump
OOS 5:55 a.m. February 16, 1995
RTS 2:13 p.m. February 16, 1995
AOT 72 hours per TS 3.3.1.5.a
 - WO 19403730, "Replace latch RHR pump breaker 16/15A"
 - WO 19404320, "RHR pump B - Minor PM inspection"
 - WO 19500232, "Perform electrical tests on B-RHR pump motor"
- B-Containment Spray (CS) Pump
OOS 6:34 a.m. February 21, 1995
RTS 2:13 p.m. February 21, 1995
AOT 72 hours per TS 3.3.2.2.b
 - WO 19404306, "Replace latch CS pump breaker 16/13B, replace right hand rail latch in cubicle"
 - WO 19404335, "CS pump B - Minor PM inspection"
 - WO 19500226, "Perform electrical tests on B-CS pump motor"



The inspector verified that the duration of these system outages was less than the allowed outage time as permitted by technical specifications, that the redundant train was operable, and that acceptance testing adequately verified system operability.

2.2 Corrective Maintenance

2.2.1 Microprocessor Rod Position Indication System Power Supply Failure

At 4:10 p.m. on Sunday, February 12, 1995, a problem developed with the microprocessor rod position indication (MRPI) system. The screen on the main control board (MCB) that provides MRPI indication went blank and MCB annunciator C-29, "MRPI System Failure," alarmed. Operators responded by performing alarm response procedure AR-C-29 and applicable portions of abnormal procedure AP-RCC.2, "RCC/RPI Malfunction." Operators noted that only the MCB MRPI indication had failed and that MRPI on the primary plant computer system (PPCS) appeared to be operating normally. Individual rod position indication is processed by the MRPI system through two subsystems; one subsystem provides MCB indication, and the other provides PPCS indication. The PPCS MRPI subsystem was verified to be operable by moving all control rods through a MRPI transition in accordance with PT-1, "Rod Control System." With PPCS MRPI operable, the applicable Technical Specification (TS) requirements for control rod position indication (section 3.10.5) were satisfied. Instrument and control (I&C) personnel were notified of the problem.

Troubleshooting revealed that the DC power supply breaker to the MCB MRPI (subsystem 1) was open. When technicians attempted to reclose the breaker, it immediately tripped open. The subsystem 1 power supplies (consisting of a 15VDC module and a 12VDC/5VDC module) were then replaced in accordance with maintenance procedure M-51.14, "Microprocessor Rod Position Indication System (MRPI) Maintenance." Subsystem 1 was successfully reenergized, however, as technicians attempted to reinitiate subsystem 1, PPCS MRPI (subsystem 2) failed. With no operable MRPI, the plant was in a condition not allowed by TS; as such, TS 3.0.1 allows one hour to correct the condition before requiring that the reactor be shut down. Operators immediately informed the I&C technicians of the loss of PPCS MRPI. The technicians deenergized subsystem 1 and PPCS MRPI returned to normal operation. All MRPI had been inoperable for approximately 2.5 minutes.

Troubleshooting continued on Monday, February 13. The plan for troubleshooting was to remove selected circuit cards, reenergize subsystem 1, and then monitor for the fault to recur as the circuit cards were individually replaced. This approach was not successful in identifying the source of the fault, and twice resulted in brief losses of PPCS (and therefore, all) MRPI when power was reapplied to subsystem 1.

On Tuesday, February 14, the Plant Operations Review Committee met to discuss the MRPI problem. By that time, shop examination had identified a failed resistor in the original 15VDC power supply module; no problems were identified with the original 12VDC/5VDC module. Following a review of completed troubleshooting activities and discussion of possible fault sources, it was concluded that the original 12VDC/5VDC power supply module should be reinstalled as the next step in troubleshooting. When the replacement 12VDC/5VDC module was removed, it was discovered that one of the chassis



mounting screws had penetrated the insulation on a wire inside the module. This had produced a ground to the MRPI chassis, and accounted for the unexpected translation, to subsystem 2, of what had initially been a subsystem 1 malfunction. The original 12VDC/5VDC power supply module was reinstalled and subsystem 1 was restored to operation without further difficulty.

Through observation of maintenance and testing, discussions with personnel, review of documentation, and attendance of the February 14 PORC meeting, the inspector concluded that corrective maintenance on the MRPI system was effectively performed. Troubleshooting was complicated by introduction of the chassis fault during installation of the replacement power supply; nonetheless, the sequence of troubleshooting actions was logical and well thought out. The inspector did not consider the damage that occurred to the 12VDC/5VDC power supply module during installation to be due to personnel error, in that it is a reasonable expectation that mounting hardware can be reused in a like-for-like replacement. Additionally, had the vendor manual been consulted prior to installation, it would only have verified that the in-use mounting screws were of the correct length. The inspector observed extensive management involvement during the PORC meeting. During this meeting, troubleshooting options were thoroughly discussed and operational considerations during the maintenance were examined. A TS interpretation of MRPI operability determinations was conservatively modified by PORC. The inspector considered that PORC involvement could have been more timely, given that a loss of all MRPI indication had occurred on three occasions prior to the meeting. The inspector had no additional concerns on this matter.

2.2.2 Instrument Air Dryer Malfunctions

Two problems with the instrument air (IA) system air dryers occurred during the inspection period. The A-IA dryer developed a problem with the timing of valve operations during air blowdown of the unit. Air blowdown is performed, periodically and automatically, to remove excess moisture from the unit. Normally, a valve closes to isolate the dryer from the rest of the IA system, and then the blowdown valve opens to rapidly depressurize the unit and remove moisture by entrainment. The controller closes the blowdown valve when it senses that the unit has been depressurized (indicating that the blowdown has been completed). In this case, however, the blowdown valve was opening before the isolation valve had closed. This caused IA system pressure to decrease to the point at which the backup IA compressor would automatically start. Before pressure was reduced to the point of affecting equipment operation, the blowdown would automatically secure. The problem was determined to be misadjustment of cams that sequence the valve operations.

In the second instance, mechanical failure of the B-IA dryer isolation valve with the valve in the open position similarly resulted in a reduction of IA pressure. In this instance, however, operator action was required to isolate the dryer. Although the pressure reduction was greater than had occurred in the case of the A-IA dryer, the problem still had no operational affect. The defective valve was subsequently replaced.

The inspector considered these IA problems to be significant; beyond the operational consequences, i.e., a reactor trip on low steam generator water level due to closure of the feedwater regulating valves, loss of IA is the major contributor to core damage as determined by the licensee's individual



plant evaluation (IPE). The inspector noted, however, that the licensee is in the process of reevaluating this conclusion. In a recent correspondence to the NRC, the licensee stated that the assumptions that went into the probabilistic risk assessment (PRA) (which forms the basis of the IPE) were overly conservative. The licensee went on to state that the results of this reevaluation would not affect planned IA system improvements.

2.3 Surveillance Observations

2.3.1 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-B, "Auxiliary Feedwater Pump B - Monthly," revision 5, effective date May 19, 1994, observed February 8, 1995
- PT-1, "Rod Control System," revision 36, effective date , observed February 14, 1995
 - Performed as acceptance testing for MRPI power supply replacement
- PT-2.1M, "Safety Injection System Monthly Test," revision 14, effective date February 9, 1995, observed February 28, 1995
 - Observed C-SI pump testing - Testing of the C-SI pump is being conducted at twice the normal frequency due to vibration measurements in the alert range. On this occasion, the procedure had been modified per procedure change notice (PCN) 95-T-0057 to operate the pump for 70 minutes for additional vibration monitoring.
 - The inspector reviewed the completed procedure and noted that the independent verification for one valve that had been operated during the test (V-879,) had been marked "N/A". Licensee review determined that this was an administrative error, and that the independent verification had actually been performed.

The inspector determined through observing this testing that operations and test personnel adhered to procedures, corrective action was promptly initiated if test results and equipment operating parameters did not meet acceptance criteria, and redundant equipment was available for emergency operation.

2.3.2 Steam Generator Low Level Relay Contact Problem Discovered During Surveillance Testing

On March 9, 1995, while Instrument and Control (I&C) technicians were performing CPI-TRIP-TEST 5.10, "Reactor Trip System Testing of Reactor Protection System Channel 1", annunciator D-6, "LO-LO Steam Generator Level Loop B" alarm, was received. This alarm is not normally received during this testing. Other normally expected alarms and indications received were



annunciator G-30, "S/G B LO-LO Level Channel Alert 17%", and bistable status light S/G B LO-LO Level. The D-6 alarm would indicate that at least two of three S/G B level logic indications were satisfied. Such an actual condition would result in a turbine/reactor trip. This alarm was considered erroneous because no changes occurred in S/G levels nor in plant operating status that would produce this alarm.

I&C technicians performing the trip testing immediately stopped the test at this point, in accordance with their instructions and training. Additional I&C personnel were summoned to evaluate this condition. A discussion was held between operations and I&C personnel in preparation for returning the bistable proving switch to its original position. Subsequently, the switch was returned to its normal condition and the D-6 alarm cleared.

A meeting between the system engineer, I&C planners and I&C shop personnel was promptly convened to prepare a plan to identify the cause of the alarm. A number of troubleshooting options were developed and presented. The cause was narrowed down to one of four relays in the alarm indication circuitry in the reactor protection racks. A course of action was developed in which the trip testing procedure would be repeated to duplicate the alarm conditions that previously occurred, then voltage readings would be taken in the protection racks of the relay room to identify the train and relay causing the D-6 alarm to occur.

Troubleshooting was satisfactorily carried out and a faulty relay was identified in the A-protection train. The open (faulty) relay was identified by measuring a reading of 125 volts across the open contacts. The desired relay position was closed, which would have indicated 0.0 volts across the contacts. Subsequent testing of the remaining channels exercised this relay, resulting in its operating satisfactorily in a repeated test. No definite root cause could be established since the relay could not be safely removed from the circuitry during power operations. Normal wear and aging of the contacts is considered the most probable cause. Further investigation will be undertaken after relay replacement during the outage which was starting in a few days.

Through close observation of operations and I&C personnel response to this incident, the inspector concluded that prudent decisions were made to promptly stop testing, evaluate the effect on plant operations, develop a troubleshooting plan, and coordinate these activities to assure safe plant operations. Particularly noteworthy is that the integrated response to developing a course of action initiated at the first line supervision level with minimum site management direction. PORC reviewed the plan and concurred with the identified actions. Technicians executed the troubleshooting instruction slowly and deliberately with due caution to assure the proper relay was identified.

3.0 ENGINEERING (71707, 37551)

3.1 Licensee Event Report

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 inspectors 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):

- 95-001, Pressurizer Safety Valves Lift Settings Found Above Technical Specification Tolerance During Post-Service Testing at Off-site Facility, Due to Setpoint Shifts. (February 3, 1995)

During the 1994 annual outage, the pressurizer safety valves, V-434 and V-435 (Crosby valves Model HB-BP-86E), were removed for testing at Wyle Laboratories. Upon reviewing the test results from the tests conducted on January 11, 1995, the licensee concluded that the "as-found" set pressures for the lift settings had shifted from the initial (pre-installed) "as left" set pressure of 2485 psig (+/- 1%). The "as-found" setpoints were 2525 psig for V-434 (2485 psig+1.6%) and 2543 psig for V-435 (2485 psig+2.3%), which exceeded the 2485 +/- 1% acceptance criteria. In response to this determination, the engineering department had Westinghouse evaluate the safety significance and through this analysis determined that the setpoint deviation did not impact the safety valves' capability to perform their intended function for the most limiting design basis accidents, a locked rotor transient and a loss of load transient. These transients were re-analyzed by Westinghouse and this reanalysis shows that the valves would have lifted at the "as-found" setpoints, satisfying the criteria for all UFSAR design basis events.

The inspector concluded the LER met regulatory requirements and appropriately evaluated the safety significance. RG&E engineering appropriately demonstrated that safety function was not compromised by the higher setpoints.

4.0 PLANT SUPPORT (71750)

4.1 Emergency Preparedness

4.1.1 Annual Emergency Siren Test

On February 27, 1995, the annual test of public notification system sirens was conducted. This test was a full duration audible test of the entire system, with siren activation controlled by Wayne and Monroe county officials and siren operation verified by the licensee. 93 of the system's 96 sirens operated satisfactorily during the test. The remaining three sirens were repaired and tested satisfactorily later the same day.

4.2 Radiological Controls

4.2.1 Routine Observations

The inspectors periodically confirmed that radiation work permits were effectively implemented, dosimetry was correctly worn in controlled areas and dosimeter readings were accurately recorded, access to high radiation areas was adequately controlled, survey information was kept current, and postings

and labeling were in compliance with regulatory requirements. Through observations of ongoing activities and discussions with plant personnel, the inspectors concluded that the licensee's radiological controls were effective.

4.3 Security

4.3.1 Routine Observations

During this inspection period, the inspectors verified that x-ray machines and metal and explosive detectors were operable, protected area and vital area barriers were well maintained, personnel were properly badged for unescorted or escorted access, and compensatory measures were implemented when necessary. No unacceptable conditions were identified.

4.4 Fire Protection

4.4.1 Routine Observations

The inspectors periodically verified the adequacy of combustibile material controls and storage in safety-related areas of the plant, monitored transient fire loads, verified the operability of fire detection and suppression systems, assessed the condition of fire barriers, and verified the adequacy of required compensatory measures. No discrepancies were noted.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707)

5.1 Periodic Reports

Periodic reports submitted by the licensee pursuant to Technical Specification 6.9.1 were reviewed. Inspectors 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 reported information was accurate. The following reports were reviewed:

- Monthly Operating Reports for January and February 1995
- Semiannual Radioactive Effluent Release Report (July - December 1994)

No unacceptable conditions were identified.

6.0 ADMINISTRATIVE

6.1 Senior NRC Management Site Visit

During this inspection period, two senior NRC managers visited Ginna Station. On February 15-16, 1995, Mr. Ledyard Marsh, Director, Project Directorate II-2 of the Office of Nuclear Reactor Regulation, toured the site and met with senior licensee management. On March 6, Mr. A. Randolph Blough, Acting Deputy Director of the Region I Division of Reactor Safety, toured the site and met with senior licensee management.

6.2 Backshift and Deep Backshift Inspection .

During this inspection period, deep backshift inspections were conducted on February 11, 25, 26, March 5, and 11, 1995.

6.3 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 the current resident inspection report 50-244/95-07 was held on March 16, 1995.