U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/92-02 License: DPR-18

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

Inspection: January, 19 through March 9, 1992

Inspectors: T. A. Moslak, Senior Resident Inspector, Ginna
E. C. Knutson, Resident Inspector, Ginna
D. C. Lew, Project Engineer, Branch 3

Approved by: W. J. Lazarus, Chief, Reactor Projects Section 3B 3/24/92 Date

INSPECTION SCOPE

Plant operations, radiological controls, maintenance/surveillance, security, engineering/technical support, and safety assessment/quality verification.

INSPECTION OVERVIEW

Plant Operations: Operators effectively responded to two reactor trips, stabilizing the plant at hot shutdown conditions. The licensee aggressively pursued the causes of the trips which were related to a possible main generator voltage regulator malfunction and to a main feedwater pump trip, respectively.

Radiological Controls: Formal measures are being developed to account for low level radioactive material released through unmonitored steam flow paths.

Maintenance/Surveillance: Power was reduced to permit plugging of leaking main condenser tubes. Effective management involvement minimized the period of reduced power operation.

Engineering/Technical Support: Deficiencies in engineering support identified during a Service Water System Operational Performance Inspection have resulted in apparent violations of regulatory requirements in the areas of design control and Final Safety Analysis Report updating.

TABLE OF CONTENTS

DETAILS

1.0 PLANT OPERATIONS

1.1 Operational Experiences

The plant operated at approximately 97% power for most of the inspection period. On February 3, 1992, in response to a load dispatcher's request, power was reduced to permit repair to an off-site sub-station. Since a substantial power reduction was required, power was further reduced to 47% to support plugging main condenser tubes. Upon completing repairs, a power escalation began. Coincident with increasing electrical load, the main turbine tripped when the main generator lost excitation voltage. In response, operators attempted to manually stabilize the plant at no-load conditions but a reactor trip occurred when the "A" steam generator reached the low-low level setpoint (17%). Following extensive evaluation to determine the cause for the turbine trip, the plant resumed full power operations on February 10th.

On February 20, 1992, power was reduced to 48% in response to main condenser tube leakage. Five condenser tubes were plugged and power was returned to 97% on February 22, 1992.

On February 29, 1992, an automatic shutdown of the "A" main feedwater pump occurred due to low seal water differential pressure, resulting in low-low (17%) "A" steam generator water level and a subsequent reactor trip. Following review of the trip and completion of repairs, the plant was restarted and full power reached on March 3, 1992.

1.2 Control of Operations

Overall, the inspectors found the R. E. Ginna Nuclear Power plant to be operated safely. Control room staffing was as required. Operators exercised control over access to the control room. Shift supervisors consistently maintained authority over activities and provided detailed turnover briefings to relief crews. The inspectors reviewed control room log books for activities and trends, observed recorder traces for abnormalities, assessed compliance with Technical Specifications, and audited selected safety-related tagouts. During normal work hours and on backshifts, accessible areas of the plant were toured. No inadequacies were identified.

1.3 Loss of Main Generator Excitation Voltage/Reactor Trip

Event Overview

During offsite power distribution system switchgear testing on February 3, 1992, RG&E identified a problem with a main line transformer breaker at one of its off-site substations. Work area isolation for corrective maintenance on this breaker required deenergizing one of Ginna's primary transmission circuits, which consequently limited station power output to

60%. Operators commenced a controlled power reduction at 10:45 AM to support the off-site maintenance. Since a significant power reduction was already required, station management reduced power to less than 50% to support plugging main condenser tube leaks.

Due to small magnitude voltage oscillations experienced while adjusting voltage early in the load reduction, operators placed the main generator voltage regulator in manual control. This eliminated the voltage oscillation problem, and power was stabilized at 47% at approximately 2:00 PM on February 3, 1992. 47% reactor power was selected based on maximizing power production during the main condenser maintenance, while maintaining a 3% margin below the reactor protection system setpoint for an automatic reactor trip due to a main turbine trip (P-9 permissive).

During this period of reduced power operation, the licensee conducted main turbine trip and stop/intercept valve testing. To prevent short-term variations in steam flow, as a result of testing, from producing reactor power oscillations due to automatic rod motion, the rod control system was placed in manual control for the duration of this testing.

At about 10:15 PM, the Control Operator (CO) made a routine small adjustment to main generator voltage. Preparations were in progress to commence the last in the series of main turbine tests when, at 10:20 PM, the "Generator Lockout Relay" annunciator energized. This indicated that the main generator output breakers had opened in response to a loss of generator excitation voltage and that the main turbine had tripped. As anticipated, no reactor trip occurred because power was less than the 50% turbine trip/reactor trip setpoint. The steam dump system actuated to reduce average reactor coolant system (RCS) temperature to its no-load value of 547°F. The steam generator water level control system fully opened the feedwater regulating valves to raise steam generator water levels and ensure an adequate heat sink for the reactor. Despite operator actions to manually coordinate power reduction, RCS pressure control, and steam generator water level control, a reactor trip from 23% power occurred at 10:25 PM when the "A" steam generator low-low water level trip setpoint (17%) was reached.

Following the reactor trip, operators proceeded to stabilize plant conditions in hot shutdown. As RCS cooldown continued, an automatic feedwater header isolation occurred due to low steam generator water level coincident with low RCS average temperature. This in turn, caused an automatic startup of the auxiliary feedwater (AFW) system, including both motor driven pumps and the steam turbine driven pump. Although the system operated as designed, operators noted rapid oscillations of 30 to 40 gpm in turbine driven AFW pump flow. Since both motor driven AFW pumps were operating normally, the turbine driven pump was shut down from the main control board (MCB) after approximately three minutes of operation.

At 10:29 PM, in response to lowering pressurizer level due to the continuing RCS cooldown, the Head Control Operator shut the main steam isolation valves (MSIVs) as pressurizer level reached 6%. This action initially arrested the cooldown at approximately 534°F and

pressurizer level began to increase due to charging pump operation and RCS heatup. However, approximately 13 minutes later, operators noted that the RCS was again cooling down at approximately 0.5°F/minute. At that point, control room personnel noted that the "A" MSIV was not fully seated as indicated on the MCB. The Auxiliary Operator was dispatched to check the position of the "A" MSIV and reported that it was shut by local valve position indication. At 10:52 PM, approximately 23 minutes after the control switch had been placed in the "close" position, the "A" MSIV indicated shut by MCB indication. At 11:15 PM, both steam generator atmospheric relief valves (ARVs) automatically opened due to high steam generator pressure as a result of the RCS heatup. Primary plant conditions were subsequently stabilized at no-load temperature using one motor driven AFW pump and the ARVs for decay heat removal.

Corrective Actions

-- <u>Analysis of Simulator Results</u>

In an attempt to verify that operational guidance provided to operators for future operations at just below 50% reactor power was adequate, the training department used the plant simulator to repeat the trip scenario with varying degrees of operator interaction. Although the results did not definitively identify an optimum mode of operation for avoiding a reactor trip, they did support that automatic control modes for the rod control and feedwater regulating valve control systems provided the greatest margin to reaching a trip setpoint. Results of these simulator runs were disseminated to operations personnel for information but no procedure changes were appropriate. The inspector considered this effort to be a positive initiative by the licensee, both in terms of attempting to identify vulnerabilities in the response to the actual trip, as well as in providing future operational guidance.

-- <u>"A" MSIV Slow Closure</u>

With plant conditions stabilized in hot shutdown, the "A" MSIV was cycled several times to verify its operability. On the first three attempts, the valve rapidly (within a matter of seconds) went to a nearly full shut position (as indicated by local position indication) and then stopped. On subsequent cycles, the valve went fully shut in less than five seconds.

A similar slow closure of the "A" MSIV following a reactor trip occurred on September 26, 1990. In response to that event, the licensee performed an analysis of the adequacy of MSIV operation. The MSIVs are Atwood and Morrill 30-inch swing check valves which employ an air actuated piston for opening and a spring for closure. Closure is also assisted by gravity (the disc drops from a horizontal position to close) and, if present, steam flow from the associated steam generator. In that analysis, RG&E concluded that frictional force developed by the packing on the disc pivot may be sufficient to overcome the force of the closure spring and prevent full closure under low- or no-flow conditions; however, they further concluded that these valves would fully shut under design basis accident conditions, and therefore functioned satisfactorily. Details of the analysis are presented in Inspection Report

50-244/90-19. Failure of the "A" MSIV to fully close during the September 26, 1990 event was attributed to the combination of packing friction and low differential pressure across the disc; its ultimate closure was attributed to increased differential pressure which resulted when steam to the turbine driven auxiliary feedwater pump (which taps off upstream of the MSIV) was secured. Slow closure of the "A" MSIV during the February 3rd trip was similarly attributed to the combination of packing friction and low differential pressure.

In response to the past slow closure experienced on September 26, 1990, the licensee committed to performing several actions to evaluate and improve MSIV performance. During the 1991 refueling outage, many of these items were completed with some scheduled to be performed during future outages. During the 1992 refueling outage, the "A" MSIV will undergo a major inspection and both valves will be repacked with a different type of packing material in an attempt to reduce packing friction. In accordance with Technical Specification 4.7, MSIVs are tested during each refueling outage under no flow and at no load conditions, to verify that they close upon signal within five seconds. Through review of test records, the inspectors confirmed that the valve met this criteria. Since at power conditions affected valve performance, the inspectors will continue to follow licensee efforts to improve MSIV performance as an unresolved item that requires further review and evaluation (50-244/92-02-01).

-- <u>Turbine Driven Auxiliary Feedwater Pump</u>

On February 4, 1992, the turbine driven auxiliary feedwater pump was started in accordance with the monthly performance test procedure (PT-16M-T) in an attempt to identify the source of the flow oscillations that occurred following the reactor trip. Upon startup, significant steam leakage was observed in the area of the throttle block. Subsequent investigation revealed the source to be the seating surface between the throttle block and the turbine casing. The pump had been considered operable until this point because, in spite of the flow oscillations, it was still capable of delivering flow in excess of the technical specification requirement. Repair of the throttle block steam leak, however, made the pump inoperable and placed the licensee in a 72 hour technical specification action statement. The throttle block was removed and the gasket replaced. This eliminated the steam leak, however, rapid flow oscillations were still present when the pump was again started. Pump operation was recorded on video tape; subsequent evaluation of this record revealed the cause of the oscillations to be a loose linkage in the throttle mechanism. Specifically, a stop nut on a threaded rod had worked loose, thereby allowing for travel within the linkage. The linkage was tightened and operational testing was completed satisfactorily. The pump was declared operable on the afternoon of February 4, 1992.

As interim corrective action for the loose stop nut, the licensee instituted a four-hour verification of its position. Permanent corrective action to lock the position of the stop nut is being developed.

-- <u>Main Generator Voltage Regulator</u>

RG&E undertook a thorough examination of the main generator voltage regulating system. This troubleshooting involved both static and operational testing, and was extensively supported by corporate engineering, as well as the vendor and an independent test laboratory.

All other trip-related plant deficiencies had been satisfactorily addressed by the afternoon of February 5. While voltage regulator troubleshooting continued, a reactor startup was conducted on the evening of February 5. Power escalation was halted at approximately 2% rated thermal power, pending resolution of the main generator voltage regulator problem.

By the afternoon of February 6, 1992, shutdown troubleshooting was completed. However, despite a comprehensive effort, no single cause had been identified for the loss of generator excitation. A plan was developed to return to power operation without the voltage regulator problem identified. This plan included: system monitoring at key points in the circuitry using chart recorders to provide both real-time and historic information; continuous electrical engineering support for the operations department; hold points during power ascension for evaluation of system performance; and specific instructions to operations personnel regarding actions to be taken for malfunction or failure of the voltage regulator.

Startup and Power Ascension

A reactor startup was commenced on the evening of February 5, 1992. The inspectors observed portions of the reactor startup, conducted in accordance with Operations Procedure O-1.2, "Plant Startup from Hot Shutdown to Full Load," revision no. 110, effective December 12, 1991. Operations were generally well controlled, and clear, concise communications between supervisors and operators were observed. On one occasion, a procedural step sequence deficiency was encountered which stopped operations until a procedure change was processed.

Criticality was achieved at 10:55 PM on February 5, 1992. Power was increased to approximately 2% and then stabilized for improvement in steam generator water chemistry. The main generator was closed on the grid at 10:04 PM on February 6, 1992. No abnormalities were noted during main generator operations with manual control of the voltage regulator. When voltage regulation was shifted to automatic, small magnitude voltage oscillations were immediately evident. Voltage regulation was promptly returned to manual control. On the recommendation of the Westinghouse representative, an adjustment was made to the automatic voltage regulator damping circuit. This eliminated the voltage oscillation problem, and power escalation to 30% commenced at 12:03 AM on February 7, 1992. Upon achieving steam generator water chemistry specifications, power escalation resumed and full power was achieved at 7:50 PM, February 10, 1992. There were no further problems with main generator voltage regulation during the remainder of the inspection period. The augmented monitoring of voltage regulator components remains in place.

1.4 Reactor Trip Resulting From Loss of "A" Main Feedwater Pump

During operations at approximately full power on February 29, an automatic shutdown of the "A" Main Feedwater (MFW) pump occurred due to low seal water differential pressure (d/p). Operators responded by manually reducing turbine load and starting all auxiliary feedwater pumps. Rod control and feedwater control systems were in automatic at the onset of the transient and remained so throughout. In spite of prompt, correct operator actions, the reactor tripped at 1:46 PM, approximately two minutes after loss of the MFW pump, due to low level (17%) in the "B" steam generator.

Following the reactor trip, operators stabilized the plant in hot shutdown. The MSIVs were subsequently closed to control RCS cooldown; both valves were fully closed within seconds of the close order. The extensive RCS cooldown caused by the reactor trip from high power, combined with the rapid introduction of feedwater, resulted in a decrease in pressurizer level below the indicating range. The pressurizer did not fully drain, as indicated by reactor vessel water level indicating system (RVLIS) remaining at 100% and no step decrease occurring in RCS pressure (both of which would indicate steam bubble formation in the reactor vessel). Pressurizer level indication was regained after approximately five minutes as a result of RCS heatup and charging pump operation. The minimum RCS pressure during the transient was approximately 20 psig above the automatic engineered safeguards features actuation setpoint of 1750 psig.

The inspector was in the main control room at the time of the reactor trip. The response of the control room operators was observed to be highly professional. In light of the slow closure of the "A" MSIV on February 3, 1992, the inspector also verified, by local position indication, prompt closure on this occurrence. The inspector noted no procedural or performance deficiencies during response to the transient and transition to operations in hot shutdown.

The cause of the main feedwater pump trip was found to be a buildup of corrosion products in the seal water d/p switch high pressure sensing line, combined with leakage from an associated compression fitting; this flow restriction and leak path caused the high pressure side of the d/p switch to depressurize, producing the alarm and trip. Corrective action included blowing down the high and low pressure sensing lines, replacing leaking compression fitting and associated tubing, and replacing the d/p switch. In addition, the "B" MFP seal water d/p switch sensing lines were blown down and proper switch calibration was verified. A contributor to the reactor trip was the fact that the delay time between receipt of the low seal water d/p alarm and the MFP trip was only five seconds. This problem had been previously addressed before the trip occurred, and a modification to extend the time interval to one minute had been approved for accomplishment during the upcoming refueling outage. As a result of this trip, the modification was completed prior to resuming full power operations.

Startup commenced at 3:32 AM on March 1, 1992 and criticality was achieved at 5:18 AM. No significant difficulties were encountered during the startup and power ascension. Operations at approximately full power were resumed on March 3, 1992.

2.0 RADIOLOGICAL CONTROLS

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, and postings and labeling were in compliance with procedures and regulations. Through observations of ongoing activities and discussions with plant personnel, the inspectors concluded that radiological controls were conscientiously implemented. No inadequacies were identified.

2.2 Radioactive Material Release Accountability for Unmonitored Discharge Paths

Following the reactor trip of February 3, increasing iodine concentrations in RCS coolant samples indicated that some small fuel rod cladding leakage had developed. Although small in magnitude, the inspector was concerned that accurate radioactivity release estimates were being made, since known steam generator (SG) tube leakage existed (approximately 60 cubic centimeters/minute total) and normal decay heat removal was by discharging steam through the SG atmospheric relief valves, which is an unmonitored release path. The licensee responded by developing a release estimate. The inspector determined that radioactivity release estimates for routine unmonitored steam releases are not routinely performed. This will remain an open item pending evaluation of the licensee's actions to address this concern (50-244/92-02-02).

3.0 MAINTENANCE/SURVEILLANCE

3.1 Corrective Maintenance

3.1.1 Main Condenser Circulating Water Tube Leaks

At 12:10 AM on February 20, 1992, a main condenser circulating water tube leak developed in the 1B2 water box. The first indication that a leak had developed was an annunciator alarm for the all-volatile treatment (AVT) system, which indicated high condensate conductivity. Chemical analysis confirmed that elevated sodium concentrations existed in the "B" condenser hotwell and both steam generators. From the relative concentrations of ionic impurities and sample point locations, further analyses indicated the source of contamination to be lake water leaking into the 1B2 water box. Steady-state impurity concentrations indicated that the leakage rate was approximately 30 gallons per minute. Although the condensate polishing demineralizers removed most of the ionic impurities, they were not designed to accommodate a leak of this magnitude.

A 10%/hr power reduction was commenced at 1:38 AM to support placing the "B" condenser out of service for repairs to the 1B2 water box. The rate of power reduction was subsequently reduced because the boric acid addition rate was limited by in-progress maintenance on the chemical and volume control system (CVCS). Normal letdown was taken out of service the previous day to support a valve replacement. A smaller capacity, excess letdown system, was in operation. Power was stabilized at 45% at approximately 8:30 AM.

The licensee held a management meeting at 8:30 AM to establish an integrated plan for maintenance on the condenser waterbox, the CVCS valve replacement, and any related corrective maintenance. As a result of this meeting, the scope of maintenance activities were clearly defined, priorities were established, and management responsibility for specific actions associated with each maintenance action were positively identified. The inspector considered this to be a positive management initiative which had resulted from PORC discussions of lessons learned from the February 3, 1992 forced outage.

Due to the large size of the circulating water leak, the licensee gave extensive consideration to the possibility that increased backpressure due to air leakage into the condenser once the waterbox was drained might require the main turbine to be tripped. As a result, isolation and draining of the 1B2 waterbox was well planned and closely monitored. Backpressure remained sufficiently low to allow continued turbine operation throughout the waterbox maintenance, and close management involvement allowed immediate resolution of operational concerns which could otherwise have resulted in a turbine trip.

Corrective Actions

A variety of techniques were used to identify leaking circulating water tubes in the 1B2 waterbox. Infrared thermography was used on initial waterbox entry and was successful in identifying two leaking tubes. Use of thermography for identification of tube leaks was a new technique; although initially successful, difficulty was encountered with condensation on the camera lens due to high humidity in the waterbox. One tube leak was identified by covering the tube sheets with plastic wrap; condenser vacuum translated through the leak caused the plastic wrap over the leaking tube to rupture. Two additional leaks were identified and plugged, one using the helium tracer gas technique, and the other during eddy current inspection of tubes adjacent the leaking tubes.

There was no obvious pattern to the leaking tubes, such as would be expected if the cause had been mechanical impingement. RG&E concluded that one of the leaking tubes was probably the major contributor and had failed suddenly; the other four were minor contributors and had existed prior to the problem. The cause of the failures could not be conclusively determined, although tube vibration was considered likely.

Other corrective maintenance observed by the inspector during the period of reduced power operation included replacement of the CVCS nonregenerative heat exchanger inlet drain valve (2232) (Work Order No. 9122368). Through attendance at the pre-job briefing, review of

work package documentation, and observation of craft activities, the inspector concluded that this maintenance was properly controlled with good coordination between the working groups involved.

3.1.2 Nuclear Instrument Power Mismatch Bypass Switch Replacement

On January 28, 1992, the inspector observed corrective maintenance performed on the nuclear instrument system (NIS) power mismatch bypass switch for nuclear instruments N-41 and N-43. The switch was replaced because it was causing erratic signals from the nuclear instruments to the automatic rod control system. This deficiency was identified during troubleshooting of an intermittent problem with the rod control system, as discussed in inspection report 50-244/91-29.

Overall, the maintenance activity was performed effectively. The technician's communications and conduct were formal and professional. Appropriate test equipment and tools were staged and readily available. The inspector verified that test equipment was calibrated, administrative approvals were obtained prior to starting work, quality control hold points were established and implemented, the replacement switch was properly certified and controlled, and technical specification requirements were not violated by this evolution. Control room operators were informed and cognizant of the maintenance activity.

The briefing which was conducted prior to the start of the maintenance activity was constructive. Good interactions were noted among the personnel involved. As a result of this briefing, several enhancements to the procedures were identified, including clarification of Quality Control (QC) verification requirements in TSR No. 92-019, "NIS Power Mismatch Bypass Switch Replacement," more detailed work step descriptions, and addition of a work step to ensure residual voltages were eliminated to prevent incorrect readings. These procedural changes and clarifications were appropriately reviewed and implemented through a Procedure Change Notice, PCN 92T-0045.

During the maintenance activity, the inspector noted an inconsistency between the maintenance procedure, M-57.5, "Replacement of NIS Power Mismatch Bypass Switch," and the corporate engineering procedure, EE-35, which provides specifications for soldering activities including material specifications for consumable items. Although the QC procedure used during the maintenance activity referenced Procedure EE-35, no material specifications for the solder and flux were included in the maintenance procedure. No procurement tracking or control of soldering materials was noted. Through interviews with licensee personnel, it was identified that the flux had a one year shelf life, yet flux had not been ordered through material procurement for several years.

In discussions with Material Procurement personnel, the lack of solder specifications in the plant's procurement process had been identified approximately three weeks prior to the maintenance activity. The material specification was being developed at the time of the maintenance activity and has since been completed. The licensee determined that the solder

used during the maintenance activity conformed to the specification and was acceptable. Based on the fact that flux does not become a permanent component of soldered joints and that soldered joints are inspected prior to acceptance, the licensee concluded that material specifications for flux were not necessary. The licensee stated, however, that the flux would be controlled through their consumable program to ensure that the shelf life is not exceeded.

The pre-job briefing and discussions were thorough and effective. During this briefing, participants identified enhancements to the maintenance procedures and followed the appropriate procedural guidelines to implement the changes. Inconsistency, however, was noted in material specifications and acceptance criteria during the soldering portions of the evolution (refer to section 6.5). These inconsistencies were appropriately addressed by the licensee.

3.2 Surveillance 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 surveillance was observed:

-- Periodic Test (PT) 9.1.17, Undervoltage Protection - 480 Volt Safeguard Bus 17, revision 2, effective date December 10, 1991, observed on February 12, 1992.

No unacceptable conditions were identified.

4.0 SECURITY

4.1 Routine Observations

During this inspection period, the resident 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. Site modifications are in progress to upgrade site security systems. No unacceptable conditions were identified.

5.0 ENGINEERING/TECHNICAL SUPPORT

5.1 Service Water System Operational Performance Inspection (50-244/91-201)

During the period from December 2nd through December 20th, 1991, a Service Water System Operational Performance Inspection was conducted by the Special Inspection Branch of the Office of Nuclear Reactor Regulation. The results of this effort were documented in

Inspection Report 50-244/91-201. Based on a review of the report by the NRC staff, several items were identified as violations of NRC requirements. Details of these findings are provided in Appendix A. In summary, the violations are:

1. Design reports, calculations, and analyses were not properly controlled, verified, and accepted as required by 10 CFR 50, Appendix B, Criterion III, "Design Control" (50-244/91-201-01).

2. The Final Safety Analysis Report was not accurately updated to reflect the actual service water system configuration as required by 10 CFR 50.34(b) and 10 CFR 50.71(e) (50-244/91-201-11).

3. Pre-operational test results were not reviewed to compare current system operation and configuration to the original design basis as required by 10 CFR 50, Appendix B, Criterion III, "Design Control," and Criterion XI, "Test Control" (50-244/91-201-14).

Additionally, the following items are considered unresolved pending further staff review to ascertain whether each is an acceptable item, a deviation, or a violation:

-- Reanalysis of the service water system hydraulic model and application of its results to the system (50-244/91-201-02).

-- Evaluation of the safety classification of the "A" spent fuel pool heat exchanger (50-244/91-201-04).

-- Assessment of the single failure of a service water pump discharge check valve (50-244/91-201-07).

-- Establishment of the appropriate service water system low pressure setpoint (50-244/91-201-12).

-- Evaluation of the controls to assure that redundant equipment will not be taken out of service while companion equipment is undergoing surveillance testing (50-244/91-201-15).

The staff acknowledges actions of RG&E to include other weaknesses and areas for improvement identified in Inspection Report 50-244/91-201 into the RG&E Commitment and Action Tracking System to assure formal resolution of these matters.

Regarding the inclusion of the appropriate number of operable service water pumps in the Ginna Technical Specifications, it is the NRC staff's understanding that an analysis will be submitted for NRC staff review. Pending staff review of this analysis, an interim administrative control has been established by RG&E requiring that three (3) service water pumps be operable and, if less than three pumps are operable, a 72 hour limiting condition

for operation would be entered until a third service water pump is restored to operable status, or the reactor will be placed in hot shutdown within the next six hours and in cold shutdown in the following 30 hours.

RG&E's progress in addressing these issues will be evaluated in future NRC inspections.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

6.1 Licensee Action on Previous Inspection Findings

6.1.1 (Closed) Unresolved Item (50-244/90-31-03) Implementation of Long Term Corrective Actions

This item remained open pending the implementation of long term corrective actions taken in response to the temporary disabling of Engineered Safeguard Features instrumentation in December 1990. In response to the violation, RG&E itemized 29 long term actions that would be taken to prevent recurrence. Through review of relevant documentation and discussions with licensee representatives, the inspector determined that these items are being appropriately addressed. As a final action, the licensee's Nuclear Safety Audit and Review Board will meet on March 10-11, 1992, and perform a review of the effectiveness of these corrective actions. The inspectors had no further concerns on this matter.

6.1.2 (Closed) Unresolved Item (50-244/89-80-06) Evaluation of Site Contingency Procedures Related to Fire Fighting

This item remained open pending the establishment of an action plan to delete fire fighting plans and strategies from site contingency procedures and reformat this information. Through discussions with the site fire protection engineer and review of relevant documentation, the inspector determined that an action plan has been developed. Fire brigade site contingency procedures are now going to be incorporated into a fire response plan. In order to ensure consistencies in the fire response plan and address configuration management considerations, a fire response plan task management manual is being drafted. This manual will provide the technical basis of the fire response plan, the plan task description, a writing and drafting guide, and a milestone schedule. Full development is scheduled for completion by December 31, 1992. The inspectors had no further questions on this item.

6.2 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 1992

-- Semiannual Radioactive Effluent Release Report (July - December, 1991)

No unacceptable conditions were identified.

6.3 Licensee Event Reports (LERs)

LERs submitted to the NRC were 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 onsite follow-up, and applicable requirements of 10 CFR 50.72 were met.

The following LERs were reviewed (Note: date indicated is event date):

92-001 Component Failure in Containment Radiation Monitor Causes Containment Ventilation Isolation (January 5, 1992)

92-002 Feedwater Transient, due to Loss of Main Generator Excitation Induced Turbine/Generator Trip, Causes Low-Low Steam Generator Level Reactor Trip (February 3, 1992)

The inspector concluded that the LERs were accurate and met regulatory requirements. No unacceptable conditions were identified.

6.4 Plant Operations Review Committee Meetings

On January 29, 1992, the inspector observed a scheduled Plant Operational Review Committee (PORC) meeting. Areas reviewed included plant operations events, modifications, procedure changes, corrective action reports, and limiting conditions for operations.

The PORC adequately met the intent and purpose of the meeting. The technical specification requirements for an adequate quorum and items for review were satisfied.

Thorough reviews were noted during the meeting. For example, discussions on a main feedwater pump room ventilation problem were thorough. Although the PORC recognized that this was a non safety-related equipment, they nonetheless determined that it was necessary to track the issue in the corrective action report to ensure that a related issue of nuisance alarms for control room operators as well as the problem itself were resolved. The PORC demonstrated its commitment to address problems from a safety focus rather than strictly a compliance focus.

The inspector also observed a scheduled PORC meeting on February 13, 1992, and PORC post-trip reviews on February 5 and 29, 1992.

6.5 Material Procurement Program Review

As a result of some inconsistencies noted during a maintenance activity in the material specifications for soldering material (Section 3.1.2), the inspector reviewed the plant's material procurement area to determine if these inconsistencies reflected a programmatic weakness.

The licensee is in the process of revising and improving their program. This effort has included development of commercial dedication specifications for safety-related components, controls for consumable items, and consistency between Plant Material Procurement, Corporate Engineering, and Construction requirements. The licensee has completed a significant portion of the component specifications for commercial items. Two commercial grade dedication plans, Crane Valve Co. gate valves (Evaluation No. 91-057) and globe valves (Evaluation No. 91-087), were reviewed and determined to be thorough. These dedication plans included detailed critical parameters for the components as well as the bases for these parameters. The licensee has prioritized the importance of each component, and is continuing to develop specifications, as well as identifying additional components which may require specifications; an example is the solder material described in Section 3.1.2 of this report. At the end of the inspection period, the specifications for solder had been completed.

The licensee has prioritized and made good progress in the control of consumable items and the items maintained by other plant work groups. For example, the solid state drawers, modules, and power supplies which are kept by the Instrument and Controls (I&C) group have been controlled by Maintenance Procedure M-71.2, "Module Rework/Test Procedure." The procedure requires that these modules cannot be placed into operation unless Quality Control has accepted the material. Most consumable items have been returned to the stock room for control. The oversight of the soldering flux was partially attributed to review of material in the I&C shop. All shops, however, had been reviewed. The Material Procurement group intends to review all items in the I&C shop which should address any other potential deficiencies.

The licensee has recognized that the procurement specification and processes between the plant and Corporate Engineering and Construction have inconsistencies. Efforts are continuing to identify the inconsistencies and develop resolution for inconsistencies.

Overall, the licensee has made significant progress and improvements in the material procurement area. The order of problems to be addressed appears to be properly prioritized and weaknesses in the program have been identified and are appropriately being addressed. Deficiencies identified with the solder material did not indicate a programmatic problem.

6.6 Quality Assurance/Quality Control (QA/QC) Subcommittee Meeting

On January 29, 1992, the inspector attended the quarterly meeting of the RG&E corporate QA/QC subcommittee. The inspector observed that the meeting was well attended by plant and corporate management. Discussions were open and candid on the nature and status of audit findings, with good participation by all members. The inspector had no questions on these matters.

7.0 ADMINISTRATIVE

7.1 Backshift and Deep Backshift Inspection

During this inspection period, backshift inspection was conducted on February 5, 1992. Deep backshift inspections were conducted on the following dates: January 25, February 17, 23, 29, and March 1, 1992.

7.2 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 this inspection. The exit meeting for inspection report 50-244/92-02 was held on March 13, 1992 with the following individuals attending:

Name	Title
Thomas Moslak	Sr Resident Inspector-NRC
Edward Knutson	Resident Inspector-NRC
Robert Mecredy	Vice President, Ginna Nuclear Production-RG&E
Joe Widay	Plant Manager-RG&E
Thomas Marlow	Superintendent, Ginna Production-RG&E
Richard Marchionda	Superintendent, Support Services-RG&E
Andy Harhay	Mgr. HP & Chemistry-RG&E
Steve Adams	Mgr. Technical Services-RG&E
Paul Gorski	Mgr. Mech. Maintenance-RG&E
Clair Edgar	Mgr. Electrical Maintenance/I&C-RG&E
Paul Wilkens	Mgr. Nuclear Engineering Services-RG&E
Mike Lilley	Mgr. Nuclear Assurance-RG&E
Jeff Wayland	Reactor Engineer-RG&E
Ron Jaquin	NS&L Engineer-RG&E
Matt Clark	NS&L Engineer-RG&E
Terry White	Operations-RG&E
Jack St. Martin	Corrective Action Coordinator-RG&E
Tom Harding	Modification Support Coordinator-RG&E
Tom Plantz	Planning and Scheduling-RG&E
Fred Mis	Health Physicist-RG&E
Don Filion	Radiochemist-RG&E