U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/94-07 **License: DPR-18**

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

Inspection: March 9 through May 2, 1994

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Date

INSPECTION SCOPE

Plant operations, maintenance, engineering, and plant support.

INSPECTION EXECUTIVE SUMMARY

Operations

At the beginning of the inspection period, the plant was in refueling shutdown mode, with preparations for full core offload in progress. Fuel handling operations were completed without incident, and were examined in depth as part of a separate inspection (50-244/94-06). Mid-loop operations, required to remove steam generator nozzle dams following core reload, were conducted in a highly professional manner; although two of four of the core exit thermocouples were subsequently discovered to have been inoperable due to a procedural deficiency, safety of the operation was not compromised. Following the reactor coolant system in-service inspection leakage test at normal operating pressure, evidence of slight leakage was observed at a conoseal on the reactor vessel head. Repair of this leak required the RCS to be cooled down and depressurized to atmospheric pressure. Hot shutdown conditions were established on April 16, 1994, and criticality was achieved at 12:44 PM, April 17, 1994. Startup physics testing was completed and, following steam plant startup, the main generator was closed on the grid at 8:08 PM, April 18, 1994. Full power, approximately 97 percent, was reached at 11:05 AM on April 22, 1994.

On April 26, 1994, a controlled steam plant shutdown was conducted to support repair of several minor steam leaks. During power escalation the following day, a reactor trip occurred from 41 percent reactor power due to failure of the "A" MFRV positioner. Both MFRV positioners were replaced, and the plant returned to power operation on April 28, 1994. At the close of the inspection period, the plant was again operating at full power.

Maintenance

Significant outage maintenance included: Extensive valve refurbishment in the service water, component cooling water, and residual heat removal systems; "A" reactor coolant pump motor replacement and seal inspection; steam generator U-tube inspections and repairs; inspection of the high pressure turbine; and, installation of Regulatory Guide 1.97 instrumentation.

Emergent maintenance to replace the "B" safety injection pump rotating assembly due to low pump differential pressure delayed outage completion by several days; a root cause analysis has been initiated.

Engineering

A rod control system modification, designed to prevent a Salem-type fault from producing incorrect rod motion was installed and successfully tested. Strong management involvement was observed in all aspects of this project.

(EXECUTIVE SUMMARY CONTINUED)

Based on inspection and review of outage maintenance activities, three unresolved items were closed: Service water system inspection and refurbishment was assessed to have been thorough and effective (50-244/93-05-01); recording capability was installed for two environmentally qualified channels of reactor coolant system cold leg temperature (50-244/93-09-01); and, redundant channels for residual heat removal system flow indication were installed (50-244/93-09-02).

Plant Support

Improvements were noted in reducing collective radiation exposure and personnel contaminations from those of past outages. These improvements have resulted from aggressive radiological controls, and management that has effectively integrated engineering support to resolving ALARA issues and has assured that routine health physics practices were consistently implemented.

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DETAILS

1.0 OPERATIONS (71707)

1.1 Operational Experiences

At the beginning of the inspection period, the plant was shutdown for the annual refueling outage; the reactor was in refueling shutdown mode, with reactor disassembly in progress in preparation for full core offload. Reactor defueling was completed on March 12, 1994. With core cooling provided by the spent fuel pool, the reactor coolant system (RCS), residual heat removal (RHR) system, and the component cooling water (CCW) system were drained for maintenance. Following completion of "A" reactor coolant pump seal inspection and extensive valve maintenance on the CCW and RHR systems, the RCS was refilled and reactor refueling conducted. Because steam generator U-tube inspections and repairs had not been completed at the point of core reload, RCS reduced inventory operations were subsequently required to remove steam generator nozzle dams. Following the RCS in-service inspection (ISI) leakage test at normal operating pressure, evidence of slight leakage was observed at an instrument penetration (conoseal) on the reactor vessel head. Repair of this leak required the RCS to be cooled down and depressurized to atmospheric pressure. This maintenance was completed and tested satisfactorily on April 13, 1994. Continuation of startup testing was delayed for several days due to emergent maintenance to replace the rotating assembly in the "B" safety injection pump. Hot shutdown conditions were established on April 16, 1994, and criticality was achieved at 12:44 PM, April 17, 1994. Startup physics testing was completed and, following steam plant startup, the main generator was closed on the grid at 8:08 PM, April 18, 1994. Full power, approximately 97 percent, was reached at 11:05 AM on April 22, 1994.

On April 26, 1994, a controlled steam plant shutdown was conducted to support repair of several minor steam leaks. In parallel, a control circuitry problem with the main turbine electrohydraulic control system was corrected, and troubleshooting was conducted to attempt to correct oscillations of the "A" steam generator main feedwater regulating valve (MFRV). During power escalation the following day, a reactor trip occurred from 41 percent reactor power due to failure of the "A" MFRV positioner. Both MFRV positioners were replaced, and the plant returned to power operation on April 28, 1994. At the close of the inspection period, the plant was again operating at full power.

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 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.

Effective command and control of plant activities was demonstrated by the outage manager throughout the period. The Plan-A-Log room served as a central coordinating point, staffed by managers and supervisors, with a Work Control Center set-up outside of the control room for establishing mechanical/electrical isolation work area boundaries for the various jobs. The center was managed by a work control supervisor (a licensed senior reactor operator), with a supporting staff of licensed reactor operators and auxiliary operators to set and maintain plant configuration. Final authorization for requested actions was by the shift supervisor prior to implementation, to provide an added check to assure that the safety of an on-going task would not be compromised by a requested configuration change. The shifting of switching/tagging responsibilities away from the control room to the center decreased the volume of control room traffic and accompanying distractions to the on-shift control room staff.

Throughout the outage, daily safety assessments were performed by the outage coordinators to evaluate the availability of reactivity control systems, core cooling systems, electrical supplies, containment integrity, and reactor coolant inventory make-up paths during system configuration changes. The inspectors found that this graded approach provided an effective management and communication tool to assure that plant safety was not compromised, particularly during mid-loop operations.

Frequent Plant Operations Review Committee (PORC) meetings were held to assess the safety and regulatory significance of off-normal plant incidents, the turnover status of plant modifications, and plant readiness for startup. Strong management oversight was consistently demonstrated in the control of plant activities.

1.3 Reactor Coolant System Draining and Reduced Inventory Operations

Steam generator nozzle dams allow the steam generator primary side to be maintained empty and available for maintenance independent of reactor vessel water level. Installation of these nozzle dams requires that reactor vessel water level be lowered to approximately the mid-loop level. The potential for loss of core cooling capability is significant during such mid-loop operations due to reduced net positive suction head available to the residual heat removal (RHR) pumps; unavailability of redundant components due to outage maintenance is also a possible cause for loss of core cooling while in the mid-loop condition.

During the 1994 refueling outage, a complete core offload to the spent fuel pool was conducted prior to commencement of steam generator U-tube inspections. As a result, vessel water level was not a safety-significant parameter when establishing conditions for the steam generator inspections. However, core reload was conducted prior to completion of steam generator maintenance. In this condition, control of reactor coolant system (RCS) inventory became an important factor during removal of the steam generator nozzle dams.

On March 29, 1994, the inspector observed entry into mid-loop operations, performed in accordance with operating procedure O-2.3.1, "Draining and Operation at Reduced Inventory of the Reactor Coolant System." The inspector observed that operations department personnel

conducted this significant change of plant conditions in an extremely professional manner. Operators were knowledgeable of expected indications as well as of symptoms of potential problems.

Although operations to establish mid-loop conditions were completed without incident, a procedural deficiency was subsequently discovered which had resulted in reduced reliability of RCS temperature indications during operation. Following completion of reduced inventory operations, operators commenced heatup of the RCS in preparation for tensioning the reactor vessel head. As temperature began to increase, operators noted that two of the four core exit thermocouples (CETs) in service at the time were not indicating a change in temperature. The intention of O-2.3.1 is to have at least two CETs, powered from different trains, connected and operable; although two CETs had been operable while establishing reduced inventory conditions, they were powered from the same train.

Troubleshooting revealed the cause to be that the processor for the affected CETs had not been set in the required mode of operation. This instrument only processes one input signal at a time; the remaining CET channels retain their most recently updated values. When operated in the "scan" mode, all available inputs are periodically updated; however, during mid-loop operations, the processor was neither operating in "scan" mode, nor was it selected to monitor one of the operable CETs. As a result, these CET channels were presenting fixed values of temperature rather than real-time information. This problem had not been noted while verifying that the prerequisites of O-2.3.1 were met, because the procedure did not provide sufficient information on CET instrument operation for the operators to have detected the condition. Operators had verified that the CETs were operating by checking them against other RCS temperature indications; because the stored temperature indications in the affected CET channels were approximately the same as the real-time RCS temperature, operators concluded that the CETs were operating satisfactorily. As corrective action, O-2.3.1 will be changed to verify that the two trains of CET instrumentation are operating in the proper mode, and that the CET indications track through actual changes in RCS temperature, prior to commencing RCS inventory reduction.

In summary, reduced inventory operations were conducted in a highly professional manner. Although two of four CETs were not being monitored as specified by the procedure, safety was not compromised, in that power to the monitored CET train was maintained throughout the operation, and multiple, diverse indications of RCS temperature were continuously available. The inspector had no additional concerns in this area.

1.4 Reactor Trip Due to Main Feedwater Regulating Valve Malfunction

On April 27, 1994, the plant was being returned to full power operation following a one-day forced outage to repair several minor steam leaks. At 2:10 PM, with reactor power at approximately 40 percent and a 10 percent per hour load increase in progress, alarm G-22, "ADFCS (Advanced Digital Feedwater Control System) System Trouble," was received in the control room. The cause of this alarm was that the "A" steam generator main feedwater

regulating valve (MFRV) was slowly closing, and had reached the alarm setpoint of 10 percent deviation from the ADFC demand position. Control of the "A" MFRV was shifted from automatic to manual, however, the valve did not respond to manual positioning signals. The "A" MFRV bypass valve was shifted to manual control and fully opened, and main turbine loading was manually reduced to zero, in an attempt to regain control of "A" steam generator level. These actions were not successful in turning the water level decrease prior to reaching the 17 percent reactor protection system (RPS) automatic reactor trip setpoint. The reactor tripped at 2:10 PM, due to lo-lo steam generator water level on two out of three "A" steam generator narrow range water level instrument channels. Plant response to the reactor trip was normal. All safety systems and equipment responded as required. Operators promptly stabilized plant conditions in hot shutdown.

Troubleshooting revealed that the cause of the "A" MFRV failure had been a mechanical malfunction in the valve positioner. Specifically, a leak had developed in the diaphram that translates the control air signal into valve operating air. When this occurred, control of valve position via the positioner was lost; since both automatic and manual control operate through the positioner, the control room operators had no control over valve position after the diaphram leak developed. As valve operating air gradually bled off of the valve operator, the valve slowly drifted shut, producing the low steam generator water level condition.

As corrective action, both MFRV positioners were replaced with older-style positioners that use a metal bellows rather than rubber diaphram. Following completion of acceptance testing, a reactor startup was conducted on April 28, 1994. Criticality was achieved at 12:18 PM and, following a brief hold at 30 percent power to adjust steam plant chemistry, full power was achieved at 11:06 PM on April 29, 1994. The replacement MFRV positioners have operated satisfactorily. The inspector had no additional concerns on this event.

1.5 Control Room Observations During Significant Plant Condition Changes

The inspectors observed portions of the reactor startup, low power physics testing, rod drop testing, and power ascension upon completion of the refueling outage, as well as the reactor startup and power ascension following the reactor trip of April 27, 1994. These operations were conducted in a highly professional manner. Procedural adherence, formality of communications, and supervisory involvement were noteworthy strengths. No deficiencies were noted.

2.0 MAINTENANCE (62703, 61726)

2.1 Preventive/Corrective 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 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:

- Installation of thermal wells and resistance temperature detectors (RTDs) on the CCW side of the CCW heat exchangers

- Flushing valve modifications, to allow post-performance test flushing of low flow areas in service water system piping

- Reactor vessel head lift and cavity flood in preparation for core offload

  -- Refueling activities were the subject of a separate inspection; results are documented in inspection report 50-244/94-06.

- Replacement of valve 4671 (diesel generator A heat exchangers SW outlet block valve)

  -- This valve was a Crane model 143-1/2; as discussed in inspection report 50-244/93-12, stem-disc separation may occur with this model valve due to failure of the stem-disc lock weld. This valve was a particular concern to the inspector because of the rattling noise it made while in service, suggesting that such a lock weld failure may have occurred. Following its removal, the inspector observed that the stem-disc lock weld was actually still intact.

2.1.2 Overhaul "B" Safety Injection Pump

On April 3, 1994, while the "B" safety injection (SI) pump was being used to refill the accumulators, a leak occurred in the outboard mechanical seal. Following replacement of the seal, the performance test (PT-2.1Q) was conducted, on April 9, 1994, to verify pump operability. The pump differential pressure was found to be 1288.7 psid; 67.3 psid below the acceptance criteria of Technical Specification (TS) 4.5.2.1b of 1356 psid, at a recirculation flow of 150 gallons per minute (GPM). This drop off in pressure was a step decrease from the 1367.6 psid that the pump obtained during its last performance test. Increased vibration was also observed during the test, and an oil leak was identified on the outboard thrust bearing cover upon test conclusion. Previous trending data indicated a small decline in discharge press over time, but pump parameters met the acceptance criteria. Subsequent repairs and testing indicated that there was internal pump degradation and a need for a complete internal inspection and overhaul. Following installation of a spare rotating element, the pump was returned to service, having successfully passed the performance test on April 16, 1994, with a discharge pressure of 1431 psid with a 150 gpm recirculation flow.

An initial inspection of the original rotating element by the licensee revealed an extrusion of the elastic interstage seal rings. This condition would cause interstage leakage within the pump, resulting in a decrease in pump efficiency. Since review of past performance tests indicated that the pump had met its operability criteria prior to the April 9th test, the licensee initiated a Root Cause Analysis (RCA No. 94-003) to identify the factors that lead to the rapid degradation.

Upon returning the "B" SI pump to service, enhanced vibration baseline measurements were made of various pump components using a full spectrum vibration analyzer to enable trending this data in subsequent tests. The licensee is directing additional attention to assessing the performance of the "A" and "C" SI pumps. Preventive maintenance data indicate that the operating parameters have remained relatively constant with no degradation evident. However, enhanced vibration monitoring of pump components will be conducted to identify declining performance trends that may not be detectable using normal vibration monitoring equipment.

The inspector observed various phases of the pump overhaul, post-maintenance test, and performance testing. The pump overhaul was performed under Work Package No. 19401576, using procedural guidance contained in maintenance (M) procedure M-11.12.1, "Safety Injection Pump, Mechanical Inspection," revision 15. Since M-11.12.1 is generic to all three SI pumps, and relies heavily on skill-of-the-technician, a draft copy of an upgraded corrective mechanical maintenance (CMM) procedure, CMM-11-01-PSIOIA, was used as supplemental guidance. The work was performed with the appropriate level of management involvement, and properly coordinated through the maintenance, outage planning, and quality control organizations.

Following installation of the rotating element and a series of adjustments, a post-maintenance test and a performance test were performed with the pump meeting the acceptance criteria. The inspector discussed the status of the root cause investigation for the pump failure with the mechanical maintenance analyst. The licensee representative is presently researching the operation and testing of the SI pumps to identify if the current surveillance testing method and use for accumulator fill could lead to accelerated degradation. Additionally, the analyst is reviewing past trended performance data for the "B" SI pump to identify clues that could forecast the onset of a similar condition with the other SI pumps.

The results of these efforts will be incorporated into the licensee's reliability centered maintenance program.

2.2 Surveillance Observations

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:

- Refueling Shutdown Surveillance Procedure (RSSP)-2.1, "Safety Injection Functional Test," revision 46, effective date April 2, 1994, observed April 6, 1994
  - -- The procedure had been extensively revised since the previous outage; as a final check on the adequacy of the procedure, it had been conducted several times in the plant simulator. The inspector considered that this was a good initiative.

- The pretest brief was thorough and productive; operational and procedural concerns were freely expressed and adequately resolved.

- The inspector observed no deficiencies during the conduct of the test.

- RSSP-7.0, "Control Rod Drop Test," revision 22, effective date , observed April 16, 1994

- PT-34.1, "Initial Criticality, and ARO [all rods out] Boron Concentration," revision 20, effective date April 9, 1994, observed on April 17, 1994

- PT-34.3, "RCC [rod control cluster] Bank Worth Measurement," revision 15, effective date May 14, 1993, observed on April 17, 1994

- PT-16Q-T, "Auxiliary Feedwater Turbine Pump - Quarterly," revision 9, effective date February 4, 1994, observed April 18, 1994

The inspector determined through observing this testing that operations and test personnel adhered to procedures, test results and equipment operating parameters met acceptance criteria, and redundant equipment was available for emergency operation.

3.0 ENGINEERING (71707)

3.1 Rod Control System Modification

In June 1993, a Westinghouse pressurized water reactor (PWR) at the Salem Nuclear Generating Station experienced a fault in the rod control system that produced outward control rod motion in response to an in-motion demand signal. This was particularly significant, in that the nature of the fault was such that it would not activate the portion of the rod control system circuitry that had been designed to prevent such incorrect rod motion. With this condition, the sequence of signals being sent to the control rod drive mechanisms (CRDMs) for in or out rod motion was basically correct. However, the signature was sufficiently altered such that, depending on the existing mechanical and electrical tolerances within the individual CRDM, rod motion in either direction could occur. Although accident analysis was still bounded by proper control rod alignment as indicated by rod position instrumentation, the potential for asymmetric rod withdrawal was nonetheless a significant generic concern.

Westinghouse evaluated the malfunction and developed a rod control system modification to address the problem of incorrect outward rod motion. The modification consisted of timing changes applied to the CRDM motion signals at the rod control system logic cabinet; with this modification installed, demand for either in or out rod motion, in the presence of a fault of the type that had occurred at Salem, should produce either no rod motion or inward rod motion.

As a member utility of the Westinghouse Owner's Group (WOG), RG&E volunteered to install and test this modification during their refueling outage, with the results to serve as verification of the generic acceptability of the modification.

The inspector observed installation of the modified circuit cards in the rod control system logic cabinet. Acceptance testing was performed in accordance with Emergency Maintenance Procedure (EM)-782, "Verification Testing of Control Rod Drive Mechanism Timing," revision 1, effective date April 13, 1994. This test consisted of three subtests:

1. Verification that logic cabinet slave cycler timing changes had been properly implemented - With the revised current order timing installed, the outputs from each slave cycler decoder card were recorded and analyzed to verify that the proper revised timing sequences were being produced.

2. Verification that the new current order timing prevents outward rod movement when failures similar to those present during the event at Salem are present - With the revised current order timing installed and faults in current order direction circuits introduced, attempts were made to withdraw and insert each bank of rods from an initial height of 36 steps withdrawn.

3. The recording of a set of current traces for each control rod with the new current order timing installed - A sample of both a withdrawal and an insertion sequence was recorded for each rod. The data was analyzed to ensure that the modification has no adverse effect on normal rod motion and to determine the range of CRDM responses to the revised current orders.

The inspectors observed this testing and verified that, by microprocessor rod position indication (MRPI), only inward rod motion occurred when attempts were made to move each bank of rods with faults introduced in the current order direction circuits. The completed test procedure, including current traces, was evaluated by the NRC Region I staff. The staff concluded that the stated test objectives had been satisfactorily achieved.

In conclusion, a rod control system modification designed to prevent a particular system fault from producing incorrect rod motion was installed and successfully tested. The inspector observed strong management involvement in all aspects of this project. The inspector had no additional concerns.

3.2 Licensee Action on Previous Inspection Findings

3.2.1 (Closed) Unresolved Item (50-244/93-05-01) Service Water System Inspection and Refurbishment Follow-up

During the 1993 outage, the licensee began an inspection/refurbishment of the service water system (SWS). Last year's efforts were directed to accessing valves and piping in the B-SWS loop, with components in the A-SWS loop scheduled for the current outage. During the 1994 outage, the A-SWS loop was isolated and drained to permit piping inspections and valve replacement/refurbishment.

The inspector reviewed the following activities related to SWS inspection and refurbishment:

Visual Inspections of Service Water Supply Header "A"

In response to the 1991 Service Water System Operational Performance Inspection (SWSOPI) at Ginna Station, the licensee committed to performing underground pipe inspections of the SWS.

The inspector reviewed the licensee's plan for inspection of underground SWS "A" header supply piping, and observed video tape recordings of the inspection results. The inspection was performed utilizing a remotely operated, tractor mounted, inspection camera. The inspection covered approximately 620 feet, or 98 percent, of 20-inch and 16-inch diameter prestressed concrete lined steel pipe. This piping has been in service for 24 years without a visual inspection. Based on review of the supporting documentation and the video, the inspector made the following observations:

- The carbon steel section of "A" header had a tightly adhering layer of orange peel-like corrosion on the internal pipe wall. However, the weld reinforcement on the internal side of the butt welded joints was still visible. The external surface of this carbon steel piping is readily accessible for leak detection and other inspection methods. The corrosion was typical of what the inspector observed in other areas of the service water system.

- There was no evidence of longitudinal or circumferential cracking of the concrete liner, loose areas of concrete lining or severe liner joint separation; construction markings were still visible on liner interior, and there was no evidence of biofouling or colonization of zebra mussels.

Based on the above, the inspector concluded that there was no evidence of significant flow blockage, extensive degradation of the concrete liner, or significant joint separation. The piping appeared to be in very good condition and able to perform its intended safety function.

Visual Inspection of Service Water Pump Bay, Circulating Water Pump Bay and the Intake Tunnel (Screen House Inspection)

Lake water is supplied to the screen house structure from the lake intake structure through approximately 3000 feet of submerged, concrete, 10 foot diameter pipe. Inside the screen house, the lake water flows from the intake tunnel through traveling screens and enters the circulating water pump bay. The lake water then flows to the safety related service water pump bay.

The primary goal of the licensee's inspection activities was to determine the amount of silt and zebra mussel accumulation in the screen house water bays. This was determined by a diver utilizing a ruler to measure the depth of silt and zebra mussel build-up.

The inspector observed the diver operated, underwater video camera inspection of the screen house intake structure for the circulating and service water systems. Based on interviews with licensee personnel and observation of the video monitor, the inspector noted the following:

- The service water bay had an overall accumulation of approximately four inches of silt and zebra mussel shells scattered on the bay floor.

- Service water pumps and supporting hangers were in good condition.

- There was no indication of zebra mussel colonization or adherence to any walls of the intake bay.

- The circulation water bay, upstream of the traveling screens, had an average of six to 16 inches of silt, with a general area depth of three to four inches of silt and zebra mussel shells. Subsequent to the video inspection, service water and circulating water bays were vacuumed; approximately 4.7 tons of material were removed.

- The intake tunnel and last 20 feet of the concrete intake piping had very little biofouling and no silt accumulation.

The overall condition of the intake structure was good, with no indication of gross flow blockage or degradation of safety related components.

Service Water Valve Replacement, Refurbishment and Modifications

During the 1994 outage, the licensee replaced 16 SWS valves and refurbished another 18 SWS valves. The majority of these valves were safety related and most of the replacements were like-for-like replacement valves. The valve sizes varied from three- to 20-inches.

Three of the valves replaced were Crane Model No. 101XU gate valves. The upgraded Crane model 47-1/2, that has a 410 stainless steel disc, was the replacement valve model.

Valve refurbishment generally consisted of machining of valve seats and disc; replacement of valve stems and disc; replacement of body-to-bonnet fasteners; and replacement of packing and packing hardware. The scope of the refurbishment was dependent on the as-found conditions during valve disassembly with appropriate corporate/site engineering and quality control oversight.

Valve Work Package Control and Documentation

The inspector reviewed several work packages used at Ginna Station for documented evidence of safety reviews, engineering evaluations, quality assurance involvement and work control, including the following:

- **Work Order 19221497, "Replace MOV-4670"**

The inspector reviewed the work package for replacement of a 10" Crane 47-1/2X motor operated gate valve (MOV-4670, Turbine Building Isolation Valve) with a Crane 47-1/2XU gate valve. The work order contained initial reviews by various groups including operations, health physics, quality control, and scheduling. The contractor, ITI-MOVATS, utilized a "traveler" to sequence the various steps in the valve replacement process. The inspector noted that the traveler and lower tier documents were current and included appropriate reviews for work scope changes and revisions. The inspector also reviewed non-destructive examination documentation, welding and installation records, and material control documentation.

The inspector reviewed the commercial grade dedication for the valve and the MOV mounting hardware. The commercial grade item engineering evaluation included critical characteristics, acceptance criteria, and acceptance methods. The licensee's procurement engineering group provided overall control of the process, utilizing independent analysis by other station groups and off-site vendors. The inspector compared the quality assurance records with the commercial grade item engineering evaluation and found no discrepancies.

Summary

Overall, control by the licensee was good, with effective support by a knowledgeable engineering staff. The licensee exhibited good coordination and oversight of contracted vendor work. The activities and work packages reflected good involvement by the engineering, quality assurance and operations groups. Based on this review, the inspector had no additional concerns regarding the inspection and refurbishment of the SWS. The inspector concluded that the licensee is taking prudent actions to assure the continued reliability of the service water system.

3.2.2 (Closed) Unresolved Item (50-244/93-09-01) Licensee to Install Recording Capability For Two Environmentally Qualified Channels of Cold Leg Temperature

Prior to the 1994 refueling outage, the existing reactor coolant system (RCS) cold leg temperature monitoring instrumentation consisted of: Two Class 1E instrument channels, T409B-1 and T410B-1, for Main Control Board (MCB) indication; and, two non-Class 1E instrument channels, T450 and T451, for MCB chart recording, annunciator alarms, and Plant Process Computer System (PPCS) inputs.

RG&E committed to the NRC to provide recording capabilities for the environmentally qualified Class 1E RCS cold leg temperature channels T409B-1 and T410B-1 to conform to the guidance contained in Regulatory Guide 1.97. An Engineering Work Request (EWR 10106) was developed and a station modification performed during the 1994 refueling outage providing for MCB recording and trending capabilities for the environmentally qualified RCS cold leg temperature channels.

The inputs from non-Class 1E instrument channels T450 and T451 to the MCB chart recorder RK-3 have been disabled, and isolated inputs have been installed from qualified channels T409B-1 and T410B-1 to recorder RK-3 and PPCS. T450 and T451 are available to provide input to the PPCS and MCB annunciators.

This modification provides redundancy for normal operations with four cold leg temperature channels on the PPCS, and eliminates nonqualified cold leg temperature indication from the MCB. Procedures, drawings and applicable sections of the Updated Final Safety Analysis Report (UFSAR) are being revised to address this station modification. Operators have been provided training regarding this new plant feature. The inspector had no further questions on this matter.

3.2.3 (Closed) Unresolved Item (50-244/93-09-02) Licensee to Install Redundant Residual Heat Removal (RHR) Flow Indication

Prior to the 1994 refueling outage, the existing RHR flow indication channel was a single Class 1E channel with no redundancy provisions. RG&E committed to the NRC to install a redundant instrument channel for post-accident RHR flow monitoring to conform to the guidance contained in Regulatory Guide 1.97. EWR 4970 was developed and a station modification performed during the recent outage installing a new environmentally qualified Class 1E redundant flow indication channel to provide a second RHR flow channel for MCB indication.

A Rosemount model 1154DP Alphaline flow transmitter (FT-689), piping, tubing, and valves V-718C and V-718D were installed to the existing spare taps of RHR flow orifice FE-626. The new flow channel has inputs to the PPCS. MCB flow indicator FI-626 has been removed and replaced with a dual scale indicator, FI-626/FI-689, to monitor both flow channels.

This modification provides independent, qualified RHR flow indication. Procedures, drawings, and applicable sections of the UFSAR are being revised to address this recent station modification. Operators have been provided training on the new plant feature. The inspector had no further questions on this matter.

4.0 PLANT SUPPORT (71707)

4.1 Radiological Controls

4.1.1 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.

Additionally, the inspector made the following observation:

- During radiographic examination of piping in the turbine building basement, the inspector noted a weakness in the established radiation area boundaries. Specifically, an infrequently used access between the turbine building middle level and the basement had not been posted. Using this access, it would have been possible for an individual, starting from outside of the radiation area in the middle level, to enter the radiation area in the basement without having passed through a barrier. The inspector discussed this inadequacy with a health physics technician, and the deficiency was promptly corrected. However, the inspector had observed this same deficiency during radiography conducted several months earlier, as discussed in inspection report 50-244/93-24. The inspector concluded that greater attention-to-detail is still warranted in establishing radiation area boundaries prior to conducting radiography.

4.1.2 Outage ALARA Review

During the 1994 outage, improvements were noted in reducing collective radiation exposure and personnel contaminations from those of past outages. For the current outage, the total dosage was 124 person-rem, compared to 155 person-rem, and 228 person-rem for the 1993 and 1992 outages, respectively. Personnel contaminations numbered 70 cases, versus 86 cases and 200 cases for the 1993 and 1992 outages, respectively. The inspectors determined that these improvements have resulted from aggressive radiological controls, and management that has effectively integrated engineering support to resolving ALARA issues and has assured that routine health physics practices were consistently implemented. Throughout the outage, the inspectors observed good adherence to Radiation Work Permits, detailed pre-job ALARA briefings, effective use of a video surrogate tour system, good housekeeping practices, and prompt identification of changing radiological conditions with timely implementation of mitigating controls.

4.2 Security

4.2.1 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.

4.3 Fire Protection

4.3.1 Routine Observations

The inspectors periodically verified the adequacy of combustible 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.

4.4 Emergency Preparedness

4.4.1 Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (50-244/93-11-01) Revise Emergency Plan to Clarify the Local Radiation Emergency Classification.

During a review of the Nuclear Emergency Response Plan (NERP), an inconsistency was identified in the licensee's emergency classification scheme. The classification, "Local Radiation Emergency," was used to identify on-site events associated with monitoring of radioactive material requiring no off-site response. That definition is not in accordance with the standard emergency classification scheme of 10 CFR 50, Appendix E, IV.B.

In response to this finding, the licensee separated the classification, "Local Radiation Emergency," from those emergency classifications requiring state, county and NRC notification and revised the NERP accordingly. The inspector reviewed the applicable portion of the revised (revision 13) NERP and determined that appropriate corrective action has been taken. The inspector had no further questions on this matter.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

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 report was reviewed:

-- Monthly Operating Report for March 1994

No unacceptable conditions were identified.

5.2 Licensee Event Reports

Licensee Event Reports (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 additional onsite follow-up, and applicable requirements of 10 CFR 50.72 were met.

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

- 94-003, Uninstalled Swagelok Tubing Plug, Due to Personnel Error, Causes a Loss of Containment Integrity (February 8, 1994)
- 94-004, Missed Surveillances, Due to Lack of Clearly Defined Interpretations of Technical Specifications Requirements, Resulted in Violations of Technical Specifications (February 14, 1994)
- 94-005, Loss of Offsite Power Circuit 751, Due to Loss of Power to #2 34.5 KV Bus at Station 204, Causes Automatic Actuation of RPS System (Turbine Runback) (February 17, 1994)
- 94-006, Steam Generator Tube Degradation Due to IGA/SCC, Causes Quality Assurance Manual Reportable Limits to be Reached (March 23, 1994)
- 94-S-01, Safeguards Event (February 21, 1994)

The inspector concluded that the LERs were accurate, met regulatory requirements, and appropriately identified the root causes.

6.0 ADMINISTRATIVE (71707, 30702, 94600)

6.1 Backshift and Deep Backshift Inspection

During this inspection period, backshift inspections were conducted on April 6 and April 15, 1994. Deep backshift inspections were conducted on March 12, 19, 26, April 2, 9, 10, 16, and 17, 1994.

6.2 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 inspections. The exit meeting for inspection report 50-244/94-03 (motor operated valve test program, conducted March 21-25, 1994) was held by Mr. Thomas Kenny on March 25, 1994. The exit meeting for inspection report 50-244/94-04 (in-service inspection program, conducted March 21-25, 1994) was held by Mr. Prakash Patniak on March 25, 1994. The exit meeting for inspection report 50-244/94-06 (refueling operations, conducted March 1-11 and March 24-28, 1994) was held by Mr. Lawrence Rossbach on March 28, 1994. The exit meeting for inspection report 50-244/94-08 (outage radiological controls review, conducted March 28 - April 1, 1994) was held by Mr. James Noggle on April 1, 1994. The exit meeting for inspection report 50-244/94-10 (startup operations, conducted April 11-15 and April 19-22, 1994) was held by Mr. Paul Bissett on April 22, 1994. The exit meeting for the current resident inspection report 50-244/94-07 was held on May 3, 1994.