# U. S. NUCLEAR REGULATORY COMMISSION

## REGION I

Docket No: 50-244
License No: DPR-18

Report No: 50-244/96-06

Licensee: Rochester Gas and Electric Corporation (RG&E)

Facility: R. E. Ginna Nuclear Power Plant

Location: 1503 Lake Road
Ontario, New York 14519

Dates: June 16 - July 20, 1996

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## EXECUTIVE SUMMARY

### R. E. Ginna Nuclear Power Plant

### Inspection Report No. 50-244/96-06

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a five week period of resident inspection. In addition, it includes the results of announced inspections by other inspectors based in the NRC Region I office with support provided by NRR.

**Operations:**

A high temperature condition in the discharge piping of the pressurizer safety relief valves (SRVs) and power operated relief valves (PORVs) midway into the period required a plant shutdown to fix a leaking SRV that was not isolable from the reactor coolant system. Operators maintained good control of plant conditions during the power reduction.

During the plant cooldown with the plant solid at 385 psig and on low temperature overpressure protection (LTOP), the power operated relief valves (PORVs) lifted momentarily in response to a short pressure spike. Operators had not maintained sufficient pressure margin below the LTOP setpoint; however, they responded promptly to regain reactor coolant system (RCS) pressure control, and this event did not significantly interrupt plant cooldown.

After corrective maintenance was completed, operations commenced a plant heatup. During realignment of the condensate system from the recirculation cleanup mode, operators did not anticipate a low main feed pump (MFP) seal differential pressure condition that caused the A-MFP breaker to open and a resulting ESF actuation (auto start of the non-operating auxiliary feedwater (AFW) pump). The subsequent return to normal power was appropriately controlled and without significant operational events.

The service water (SW) system alignment, material condition, and housekeeping were satisfactory. SW components were properly aligned and were labelled consistent with the P&IDs. However, eight SW valves were not locked as required by a technical specification surveillance requirement. Failure to lock these valves and to verify they are locked every 31 days is a violation of technical specification SR 3.7.8.3. **(VIO 50-244/96-06-01)**

Good actions and responses from operators were observed during a simulator training exercise. A clear command structure and communication were notable, and contributed positively to maintaining plant control during simulated transients. Also, the functionality of applicable emergency procedures was well demonstrated by the training staff.

**Maintenance:**

Maintenance performed well in the removal of the A-SW motor, pump assembly, and piping. Mechanical and pipe fitter procedures were well coordinated, and defined individual craft activities well. All maintenance and training activities on the pump and motor were

well controlled by electrical and mechanical foremen. The electrical maintenance craft displayed a high degree of technical knowledge and skill during the pump motor breaker overhaul. Excellent coordination was observed between an electrical foreman, operations, craft, and divers during SW pump and motor maintenance.

Surveillance test activities were well controlled and performed in accordance with detailed test procedures. Surveillance testing adequately revealed the unreliable performance of the AFW pump discharge throttle valves, and corrective measures were promptly taken to restore proper performance.

Maintenance activities to replace a leaking pressurizer SRV were adequate. However, lack of an adequate prejob briefing and a sense of urgency during the forced outage may have contributed to a procedure adherence problem when the SRV was improperly lift tested.

Maintenance to correct a jammed letdown isolation valve was adequate to restore the valve to service. The enhanced foreign material exclusion (FME) controls implemented during the recent refueling outage were generally effective; however, these controls were not fully effective in keeping a small screw out of the RCS that became lodged in a letdown isolation valve.

The licensee appropriately incorporated procedural changes based on information contained in IN 95-022 on circuit breakers maintenance. RG&E's program for incorporating procedure changes in response to Information Notices was adequate.

A well developed Maintenance Rule program was implemented to meet the rule, which became effective on July 10, 1996.

<u>Engineering</u>:

The licensee's design controls were inadequate for a May 1994 modification of the auxiliary building service water system isolation valve 4616. A significant change was made to the closing time of this risk significant, motor-operated valve without performing a safety evaluation which was a violation of 10 CFR 50.59 **(VIO 50-244/96-06-02)**. Furthermore, once the licensee identified the excessive stroke time of MOV-4616 in 1995, their corrective actions were poor regarding the evaluation of any generic concerns with the coordination of design information.

An interdisciplinary review by engineering of the replacement steam generator wet layup system modification was effective in that it resulted in proper consideration of the impact of the design change on containment accident analyses.

Post-modification tests of AFW valves MOV-4007 and 4008 were adequate, but they evidenced little margin available under degraded voltage conditions. Also, their reliability to automatically throttle flow appears related to an inadequate design. An unresolved item was opened to review an intended modification to increase output capability and throttle

reliability as part of the NRC closeout inspection of the MOV program **(URI 50-244/96-06-03).**

The initial service water heat exchanger thermal performance test program, which the licensee committed to perform in response to Generic Letter 89-13, had not been completed. For the 18 sets of service water heat exchanger thermal performance tests performed, only the first (baseline) test of the diesel generator coolers had been fully evaluated with an engineering report written. An unresolved item **(URI 50-244/96-06-04)** was opened to review engineering's ongoing actions and those planned to complete the reviews of these thermal performance tests and this initial test program. Engineering's erosion and corrosion program was effective in detecting degradation in the service water piping serving the safety injection pump thrust bearing coolers. The licensee took prompt corrective action to replace the degraded piping to assure that design flows would be met.

Sound test procedures were effective in monitoring the performance of the replacement steam generators during plant startup. The preliminary test results were in good agreement with the projected values of reactor coolant system flow, and shrink and swell for the replacement steam generators.

Two self-assessments were conducted that provided added assurance regarding the quality of engineering work. Engineering performed a thorough integrated assessment of the Ginna Station improved technical specifications, the replacement steam generators, reactor coolant system reduced Tavg operation, and the new 18-month fuel. This assessment was in response to a Nuclear Safety Audit Review Board open item. A quality assurance audit of the configuration control program provided constructive findings for improving the relatively new plant change record process. However, engineering had not performed well in resolving the issues identified in a December 1994 service water system self-assessment. Fifteen open items still existed in the licensee's commitments and action tracking system.

Electrical and control system design modifications were of good quality and well-supported with sound design basis technical information. The licensee made sound decisions to enhance the overall reliability of the offsite power supply system by adding a new voltage regulator in circuit 767 and a new 75 MVAR capacitor bank on the 115 kV system line.

The licensee's corrective actions taken to resolve electrical component issues were very effective; these included actions to resolve problems associated with fuses and the effects of a loss of offsite power on the control rod withdrawal system.

**Plant Support:**

During the last several years, a strong and aggressive station-wide program was demonstrated for controlling, limiting, and decreasing the generation of radioactive waste that resulted in very low burial volumes (617 $ft^3$ for 1995). The licensee demonstrated excellent solid radwaste performance in limiting the collection and inventory of solid radioactive waste onsite.

Executive Summary (cont'd)

In the radwaste/transportation program area, two sections of the UFSAR were out of date. Both sections were of low safety significance, but indicated at least two years had elapsed since the UFSAR description had changed. These two UFSAR discrepancies are classified as unresolved items pending NRC enforcement review **(URI 50-244/96-06-05).**

Safety Assessment/Quality Verification

ACTION Reports were generally effective in providing prompt problem identification and systematic resolution. However, several problems were not rigorously evaluated. The threshold was appropriate for capturing most events, and event reporting was generally consistent with this threshold.

The root cause analysis system was very well implemented and was conducted by experienced, well-trained personnel. They were technically thorough, used appropriate methodologies, incorporated operating experience and received management review. Root cause training was good; however, some training could be enhanced. The Human Performance Enhancement System (HPES) reviews appropriately addressed human performance problems.

The Operating Experience Section (OES) and the Nuclear Safety and Licensing Department were promptly screening and disseminating industry and regulatory information, and assigning for evaluation/response within the Nuclear Operations Group. The OES was expanding its role by performing corrective action effectiveness reviews. The ACTION Report system was a very effective problem reporting/corrective action follow-up mechanism whereby problems were promptly reported, evaluated, resolved and tracked.

RG&E management had a strong commitment to internal and third party self-assessment. Self-assessments critically focused on management and supervisory issues, communications, effectiveness of corrective actions, and identifying potential equipment performance/material condition problem areas. Findings were comprehensively tracked and analysis of trended data clearly focused management attention on priority issues. Management oversight and involvement in self-assessments was very strong; resulting in prompt dispositioning of findings and accountability of action item follow-up.

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**ATTACHMENT**

## Report Details

## I. Operations

### O1 Conduct of Operations[1]

### O1.1 General Comments (Inspection Procedure (IP) 71707)[2]

The inspectors observed plant operations to verify that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. This review included tours of the accessible areas of the facility, verification of engineered safeguards features (ESF) system operability, verification of proper control room and shift staffing, verification that the plant was operated in conformance with technical specifications and appropriate action statements for out-of-service equipment were implemented, and verification that logs and records were accurate and properly identified equipment status or deficiencies.

### O1.2 Summary of Plant Status

At the beginning of the inspection period, the plant was operating at full power. The plant continued to operate normally until June 20, 1996, when a brief power reduction to 72% was requested by the grid dispatcher because of a faulted condition in an offsite power circuit. The condition did not affect the availability of offsite power to Ginna, and the plant returned to steady full power operations the following day after a 13 hour interruption.

With the plant at full power on the afternoon of July 2, 1996, a high temperature condition occurred in the discharge piping of the pressurizer safety relief valves (SRVs) and power operated relief valves (PORVs). The temperature peaked at about 230 degrees Fahrenheit (°F), and approximately 3.9 gallons per minute (gpm) of reactor coolant was discharging into the pressurizer relief tank (PRT). The leak was greater than the maximum allowable of 2 gpm, and was not isolable from the reactor coolant system. Consequently, the licensee commenced a normal shutdown at 1:00 a.m. on July 3, 1996. At approximately 8:30 a.m., reactor power was held at 32% while a containment entry was made to attempt to stop the leakage. However, the leakage continued, and at 6:50 p.m., the operators continued with the power reduction. At 10:35 p.m., the plant was taken off-line. The plant entered Mode 2 at 10:38 p.m. and Mode 3 at 10:55 p.m., and the reactor was manually tripped at 10:54 p.m. The plant entered Mode 4 (<350°F) at 7:24 a.m. on July 4, 1996.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

[2]The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

A primary plant cooldown and partial draindown was necessary to facilitate replacement of one SRV. Operations entered Mode 5 with the loops filled and <200°F at 4:14 p.m. on July 4th. At 8:05 p.m. that evening, with the plant still solid at 385 psig and on low temperature overpressure protection, the power operated relief valves (PORVs) lifted momentarily in response to a short pressure spike. At 9:02 p.m. that evening, the plant entered Mode 5 with "the RCS loops not filled" as defined by the Technical Specifications (TS)."

Operations maintained the plant in Mode 5 for approximately 48 hours while several maintenance activities were accomplished, including replacement of the leaking SRV, replacement of a letdown isolation valve, repair of the B-feedwater regulating valve (B-FRV), repairs of several electro-hydraulic (EH) system fluid leaks, repair of a main feed pump (MFP) oil leak, adjustments to the main turbine #2 control valve, and minor repairs to various other equipment.

After the above repairs were completed, the plant entered Mode 4 at 10:30 p.m. on July 6, 1996, and operations commenced a plant heatup. The plant entered Mode 3 at 9:17 a.m., July 7, 1996. Throughout the continuing heatup, the SRV discharge piping temperatures remained normal and stable. However, during realignment of the condensate system from the recirculation cleanup mode, a low MFP seal differential pressure condition caused the A-MFP power supply breaker to open, and resulted in an automatic start of the non-operating auxiliary feedwater (AFW) pump (engineered safeguards feature (ESF) actuation). At 8:46 p.m. the same day, the plant entered Mode 2 and the reactor was taken critical at 9:27 p.m. At 12:33 a.m. on July 7, 1996, the plant entered Mode 1, and the generator was subsequently synchronized to the grid at 2:02 a.m.

The plant escalated power normally throughout the day of July 7th, without significant equipment problems or operational events. One of the main turbine-generator bearings, and one of the reactor coolant pump bearings exhibited slightly high vibrations for a period of time; however, these conditions did not interfere with the increase in power, and both eventually subsided. The plant achieved 100% power at approximately 8:55 a.m. on July 9, 1996, and remained at steady full power operations throughout the remainder of the inspection period.

**O2 Operational Status of Facilities and Equipment**

O2.1 <u>Plant Shutdown Required to Repair Leaking Pressurizer Safety Relief Valve</u>

a. <u>Inspection Scope</u> (71707)

On July 3, 1996, the operators commenced a plant shutdown due to a pressurizer safety relief valve (SRV) that was leaking in excess of 2 gpm. The inspectors observed the operators' actions and the plant's response during the power reduction. The inspectors also made evaluations of the operators' responses to equipment malfunctions, and of the operational impact of these malfunctions on the plant.

b. Observations and Findings

At 5:57 p.m. on July 2, 1996, control room operators received high temperature alarms on the main control board (MCB) indicating that the common discharge piping from the pressurizer SRVs and PORVs exceeded 145°F. Also, a pressurizer relief tank (PRT) high pressure alarm annunciated on the MCB. Operators immediately entered abnormal procedure AP-RCS-1, "Reactor Coolant Leak." The temperature in the outlet piping continued to rise and eventually peaked at about 230°F. The initial leakage was estimated to be 3.9 gpm and was all being directed to the PRT. It was not immediately apparent which valve(s) was leaking, but operators suspected it was one of the PORVs because of the history of these valves leaking during full power operations. Consequently, operators cycled closed each PORV block valve in an attempt to stop the leakage. However, this effort had no apparent effect, and leakage to the PRT continued at about 3 gpm. The control room instrument for SRV position indicated that both valves were fully closed. The licensee determined that a containment entry would be necessary to positively identify which valve was leaking.

The initial containment entry made by plant personnel revealed that SRV-434 was leaking, and that the SRV-434 loop seal drain valves (V-513 and V-563) may have also been leaking. The condition suggested that the loop seal to the SRVs was lost, and that a steam volume could have been created on the high pressure side of the SRVs. The SRVs are not leak tight without solid water on the upstream side of the valve disk. Since this leak was not isolable from the reactor coolant system, operations commenced a power reduction at 10% per hour with the intent of going to cold shutdown to repair the SRV. Operators maintained good control of the plant throughout the power decent.

During the power reduction, the licensee evaluated various ways to recover the loop seal with the plant still at power. Power was held at 32% to evaluate the leakage further, and to determine if the working environment around the pressurizer could permit personnel to attempt recovery of the loop seal. The licensee devised an initial recovery process that would apply additional torque to the loop seal drain valves, and then remove lagging around the seal piping. The removed lagging might have provided a relatively cool area around the seal that could drive local steam condensation and fill up the loop. The licensee applied additional torque to the seal drain valves; however, RG&E's licensing department did not approve the removal of lagging with the reactor still at power. Additional torque applied to the seal drain valves did not stop the SRV leakage, which continued above 2.5 gpm. Consequently, operators reinitiated the power reduction toward cold shutdown.

Operators again interrupted the load reduction at 20% power when the B-feedwater regulating valve (B-FRV) stopped responding automatically to the decrease in power. The valve would not automatically close below 20%, so operators declared the valve inoperable and entered TS LCO 3.7.3. The valve was placed in manual control, but local operation of the actuator handwheel was required to drive the valve fully shut. The FRV bypass valves automatically regulated FW flow once power was below 15%. At 5% power, the B-FRV was isolated and both SGs were

fed through the FRV bypass valves. The cause of this problem was not immediately apparent, and this became an additional maintenance work item during the outage (refer to Section M1.1). The plant entered Mode 2 without additional problems. The plant went offline at about 5% power, and the reactor was manually tripped at 10:54 p.m. on July 3, 1996.

During the plant cooldown, operators closed letdown isolation valve AOV-427 from the MCB, but the valve did not go fully shut. Operators attempted to open and close the valve again, but the valve was stuck in position and could not be remotely operated. Auxiliary operators investigated the problem locally and attempted to manually operate the valve, but it appeared to be frozen in position. The cause of this problem was not immediately apparent, and this also became a maintenance work item during the outage (refer to Section M2.3).

During the cooldown, with the plant solid, both PORVs (MOV-430 & MOV-431C) lifted for a very brief time and reseated after a slight reduction in reactor coolant system (RCS) pressure. A high pressure condition also existed in the reactor coolant pump (RCP) leak off line. This occurred approximately 7 minutes after the second RCP was secured, when the RCS pressure transmitters on the A RCP suction pipe sensed a pressure above the low temperature overpressure (LTOP) setpoint. The PORV nominal lift setpoint for LTOP was 410 psig. The maximum RCS pressure recorded by the plant computer at the time was 385 psig; however, the computer input comes from a different pressure transmitter (wide range) than the PORVs, and the recorded points were only updated every two seconds. Operators immediately responded to this event by increasing letdown flow to reduce pressure to maintain a larger pressure margin below the LTOP setpoint. During the subsequent outage, Instrument and Control (I&C) technicians investigated the possibility that a false high RCS pressure signal caused the PORVs to open. A calibration verification of three pressure transmitters was performed, but no deficiencies were noted. The licensee initiated an ACTION Report to review this event. It was noted that closing the RCP seal outlet valves had significantly reduced mass flow out of the RCS, and contributed to the pressure increase. A future revision to operating procedure O-2.2, "Plant Shutdown from Hot Shutdown to Cold Conditions," will caution operators on proper pressure control during solid plant operations. Lifting the PORVs will be reported to the NRC in RG&E's monthly operating report as required by TS 5.6.4.

c. Conclusions

Plant operators responded promptly and appropriately to the high temperature condition in the pressurizer SRV discharge piping. Good efforts were made to quickly diagnose the RCS leakage and to identify the leaking SRV. Operators maintained good control of the plant during the power reduction, and effectively stabilized plant power for an extended period while additional SRV leakage diagnosis was performed. Operator response to the failed B-FRV was appropriate and enabled the plant to achieve shutdown without a secondary system transient. Operators did not closely monitor RCS pressure after securing a main coolant pump when the PORVs lifted on high RCS pressure. However, this had no significant effect on

plant safety, and did not interrupt the plant cooldown. Operators promptly responded to maintain proper RCS pressure control.

O2.2 Reactor Startup and Return to Full Power Operations

a. Inspection Scope (71707)

The inspector observed the plant operators and the plant response to the power increase during the startup. The inspector also made evaluations of operators' response to equipment malfunctions and their operational impact on the plant.

b. Observations and Findings

On July 6, 1996, operators commenced a plant start up from the forced maintenance outage after replacement of pressurizer safety relief valve SRV-434, and other corrective maintenance. During the heatup, and prior to achieving 200°F, valve MOV-869A (refueling water storage tank outlet to the SI, CS, and RHR pumps) failed to go full open on demand. The operator held the valve switch on the MCB to full open, but the valve did not respond. When the switch was returned to the full closed position, the valve again did not respond. Plant heatup was held below 200°F and I&C technicians determined that the MOV breaker controller was faulty. Plant heatup continued after the controller was replaced and the MOV was tested satisfactorily.

The plant entered Mode 4 at 10:30 p.m. on July 6, 1996. Shortly thereafter, operators temporarily switched to a 100%/0% offsite power lineup on Circuits 767 and 751 respectively, in order to minimize a potential disruption on Circuit 751 while a main coolant pump was started. When the offsite power lineup was returned to 50%/50%, an RCS low flow alarm occurred on the MCB for no apparent reason. I&C investigated this problem and replaced a relay in the RCS flow logic for flow transmitter FT-413. This did not interrupt the plant heatup because FT-413 was not required to be operable until the plant was in Mode 1 and greater than 8.5% power. FT-413 was tested satisfactorily prior to entering Mode 3.

Mode 3 was achieved at 9:17 a.m. on July 7, 1996, and plant heatup continued. On that afternoon, an auxiliary operator (AO) noted a squealing noise when the A-charging pump was started. The control room operator promptly secured the pump suction and discharge lines to investigate the problem. The AO later noted that the pump relief valve (RV-285) had lifted. Operators realigned charging flow with the B- and C-charging pumps running at approximately 50% speed, and initiated an ACTION Report (95-0701) for site engineering to investigate this problem. The A-charging pump was held out of service for the remainder of the startup.

As plant heatup continued that evening, operators realigned the condensate system out of its purification recirculation mode. As this transition progressed, a low differential pressure (d/p) condition occurred across the main seal of the A-main feedwater pump (A-MFP), which caused the A-MFP breaker to trip open from the

test position. The open breaker initiated an automatic start of the idle B-AFW pump (ESF actuation). After the B-AFW pump started, operators noted that its discharge throttle valve (MOV-4008) did not throttle properly, but instead went fully closed. Operators promptly secured the B-AFW pump and assessed the system conditions. Prior to the ESF actuation signal, both SGs were being fed from the A-AFW pump through both AFW flow trains that were cross-connected. After MOV-4008 failed to throttle properly, operators split the AFW trains and immediately started the B-AFW pump. This action resulted in MOV-4008 throttling to its proper position (200 - 230 gpm). Operators maintained both AFW flow trains separated, and proceeded with plant heatup. An ACTION Report (96-0702) was initiated for engineering to investigate the anomalous behavior of MOV-4008. An emergency notification system (ENS) call was made at 10:18 p.m. to the NRC operations center to report the ESF actuation.

The plant entered Mode 2 at 8:46 p.m. on July 7, 1996, and the reactor was taken critical at 9:27 p.m. Mode 1 was achieved at 12:33 a.m. the following morning and the generator was synchronized to the grid at 2:08 a.m. Power was held at approximately 28% for chemistry stabilization and a calorimetric analysis until 2:05 p.m. on July 8, 1996, when power ascension continued. Full power was achieved at 8:55 a.m. on July 9, 1996 without further equipment or operational problems.

c. Conclusions

Operators responded well and effectively maintained stable plant conditions after several equipment malfunctions were experienced during the plant startup. Operators promptly diagnosed the impact of malfunctions and abnormal conditions on plant operations, and took appropriate actions to assure safe plant operation. The operators did not anticipate the ESF actuation during realignment of the condensate system. This may have been because the AFW auto start function was defeated prior to entering Mode 1 under the old technical specifications, and a low MFP seal d/p would not have previously caused an AFW pump start. This incident points to a need for further operator training in this area.

**O3 Operations Procedures and Documentation**

O3.1 Engineered Safety Features - Service Water System Walkdown

a. Inspection Scope (71707)

On June 17, 1996, the inspector conducted an independent, detailed walkdown of the accessible, safety-related portions of the service water (SW) system and performed an independent review of system alignment procedures.

b. Observations and Findings

The walkdown consisted of a visual examination of SW system components and focused on: (1) verification that the system lineup and descriptions were consistent

with plant piping and instrumentation diagrams (P&ID); (2) the material condition, required position, and locking of system valves; (3) the installation of proper component labeling; (4) the functionality and calibration of system instrumentation, and (5) the general housekeeping in areas that contain SW system components.

The inspector reviewed procedure S-30.8, "Service Water System Valve Position Verification," for consistency with the improved technical specification (ITS) requirements, and evaluated the adequacy of the procedure for verifying the necessary SW flowpaths to safety-related components. The inspector followed through the procedure steps and visually noted the current positions of all SW system valves. During this review, the inspector noted that eight SW manual valves were not locked as required by ITS surveillance requirement (SR) 3.7.8.3. SR 3.7.8.3 requires the licensee to verify once every 31 days that all SW loop header cross tie valves are locked in the proper position. These valves include V-4610, V-4611, V-4612, and V-4779 (required by SR 3.7.8.3 to be locked closed); and V-4623, V-4639, V-4640, and V-4756 (required by SR 3.7.8.3 to be locked open). All eight valves were in their correct positions as required by the SR and procedure S-30.8. S-30.8 required a monthly verification that these valves were in the correct position, but it did not require a verification that the valves were also locked.

Upon bringing this matter to the attention of the operations manager, locks were immediately installed on all eight valves. Locking these valves was a new requirement placed in the ITS to assure that the proper flow paths exist for SW operation. The ITS was implemented at the Ginna Station on February 24, 1996; however, the requirement to lock the SW loop header cross tie valves was not incorporated into procedure S-30.8 at that time. The inspector also noted that none of the eight subject valves were included in procedure A-52.2, "Control of Locked Valve and Breaker Operation." A-52.2 is performed prior to plant startup after a refueling outage to ensure proper system alignment. In addition, the P&IDs for the SW system did not identify these valves as locked in position.

The licensee initiated an ACTION Report (AR 96-0666) to investigate this matter further, and to determine if any other new SRs contained in the ITS had not been properly incorporated into ITS surveillance procedures. However, the failure to lock the SW loop cross tie valves and to verify they are locked every 31 days is a violation of technical specification SR 3.7.8.3. **(VIO 50-244/96-06-01)**

The oil used in the safety injection (SI) pump thrust bearings is cooled by service water. Prior to plant startup, the proper SW flowpath through the SI pump thrust bearing oil coolers is verified through the combination of startup alignment procedures T-36.1, "Station Service Water Header Valve Alignment for Two Loop Operation," and S-16A, "Safety Injection System Alignment." After plant startup, periodic verification that eight valves affecting SW flow to the SI pump thrust bearing oil coolers are locked open is performed through surveillance procedure S-30.1, "Safety Injection System Valve and Breaker Position Verification." However, the inspector noted two locked-open inlet isolation valves and two unlocked outlet isolation valves included in procedure T-36.1, were not included in

procedure S-30.1. These valves were V-4738 and V-4739 (SW inlet isolations), and V-4739A and V-4739B (SW outlet isolations). The inspector discussed this situation with the operations manager, who indicated that valves V-4738 and V-4739 are verified locked by procedure A-52.2 (the locked valve procedure) prior to startup from a refueling outage. However, he agreed to evaluate the need to add the unlocked valves V-4739A and V-4739B to surveillance procedure S-30.1, or to evaluate locking them and adding them to procedure A-52.2.

Overall, the inspector found the material condition, labeling, and housekeeping around the SW system to be satisfactory. Other than the loop header cross tie valves not being locked, the SW system components were properly aligned and were labelled consistent with the P&IDs. Selected SW system instruments were found to be functional and calibrated. The inspector determined that surveillance procedure S-30.8, when combined with startup alignments and instrument logs during auxiliary operator daily tours, satisfactorily verified service water flow to the emergency diesel generators, the component cooling water heat exchangers, and the spent fuel pool heat exchangers.

c. Conclusions

The SW system alignment, material condition, and housekeeping were satisfactory. SW components were properly aligned and were labelled consistent with the P&IDs. The failure to lock the SW loop cross tie valves and to verify they are locked every 31 days is a violation of technical specification SR 3.7.8.3.

**O5 Operator Training and Qualification**

O5.1 Observation of Simulator Training

a. Inspection Scope (71707)

On July 2, 1996, the inspector observed the training of an operations shift on the control room simulator.

b. Observations and Findings

The training scenario consisted of a sequenced failure of a component cooling water pump and a steam dump valve, followed by a small break loss-of-coolant accident. After each step in the scenario, the simulator was frozen, and the applicable technical specifications, operating procedures, and/or industry experiences were discussed.

The steam dump failure was based upon an industry event during which the resulting decreasing average temperature indications prompted an inappropriate withdrawal of control rods. The Ginna operators correctly diagnosed the situation, basing their actions on high power level indications, and isolated the malfunctioning valve.

c. Conclusions

Overall, good actions and responses from the operations shift were observed. A clear command structure and communication were notable, and these elements resulted in the operations shift responding deliberately and positively through procedures to maintain plant control during the simulated transients. Also, the inspector considered that the functionality of each applicable emergency procedure (e.g., diagnosing, aligning systems, etc.) was well demonstrated by the training staff. No concerns were identified.

## O7 Quality Assurance in Operations

During the period of June 17-21, 1996, NRC inspectors assessed the effectiveness of licensee controls for identifying and correcting conditions that degrade plant operations and safety. This review included programs for corrective action, root cause analysis, self-assessment, and operating experience feedback.

### O7.1 Problem Identification and Resolution

a. Inspection Scope (40500)

The inspector reviewed the licensee's process for identifying, tracking, resolving, and preventing recurrence of problems.

b. Observations and Findings

On July 17, 1995, Nuclear Operations Group Interface Procedure IP-CAP-1, "Abnormal Condition Tracking Initiation Or Notification (ACTION) Report," was implemented as the primary means of entering problems into the corrective action system and was designed to replace multiple corrective action processes with a single point entry program. The licensee drew on industry experience in developing this process, and the resulting procedure underwent extensive, critical in-house review. The licensee has expeditiously implemented process improvements as needs were identified. At the time of this inspection, the procedure had been revised five times, and a sixth revision was being developed.

- Process Overview

IP-CAP-1 provided a method for identification, documentation, notification, segregation, evaluation, disposition, correction, trending, and reporting of conditions, events, activities, and concerns. ACTION Reports can be initiated by any individual. The originator fills out the "Identification" portion and delivers the report to their immediate supervisor. The supervisor reviews the reported problem and, if it has already been identified and is being resolved, so notes and returns to originator. Otherwise, the report is forwarded to the operations office, or the shift supervisor on backshift.

The Operations Department performs an operability/reportability review of the reported condition. If required, Systems Engineering performs an operability assessment. The Shift Technical Advisor then performs a review to determine if NRC written notification is required. Newly generated ACTION Reports are reviewed daily by the Plant Operations Review Committee (PORC) Chairman, who assigns the organization responsible for disposition, priority (three levels available), disposition due date, and PORC review requirements.

When disposition has been assigned, the responsible manager determines, within seven days, if the reported condition is a nonconformance; if a 10 CFR 21 evaluation is required; and if a root cause evaluation should be performed. The individual assigned to disposition is responsible for developing corrective and preventive actions, identifying training and generic implications, documenting the root cause or apparent cause, and determining if a Licensee Event Report is required.

Closure of an ACTION Report occurs when all actions have been completed or are being tracked by another process, such as the corrective action tracking system (CATS). Prior to closure, concurrences must be obtained from groups responsible for disposition and, if initially indicated by the PORC Chairman, PORC must concur in the corrective action. After closure, the Operating Experience Section enters report information into a data base for trending.

- Reporting Threshold

When IP-CAP-1 was implemented, management's expectation was to initially maintain the thresholds associated with the various corrective action programs that the ACTION procedure replaced. This facilitated the transition, but the actual reporting threshold was initially higher than management desired. In response to this, a revision to IP-CAP-1 was developed that provided a consistent and lower threshold through an expanded list of example events and conditions that warranted an ACTION report. Revision 6 to IP-CAP-1 (under development at the time of this inspection) proposed a new fourth priority level for items that are submitted for tracking only; thereby further lowering the reporting threshold.

The inspector noted that the threshold for initiating ACTION reports has lowered since the program was implemented, and that use of the ACTION program by all licensee organizations has increased. The inspector considered the threshold to be appropriate for capturing most events, and considered that event reporting was generally consistent with this threshold. The inspector considered the development of an additional priority to track low level, off-normal conditions to be a good initiative.

- Review of Completed ACTION Reports

To assess the effectiveness of the ACTION Report process, the inspector reviewed nine completed ACTION Report packages for the period November 1995 - May 1996.

The inspector identified no problems in four of these reports, and considered that the corrective actions were appropriate. Specific weaknesses were identified in the remaining five in that the apparent cause was not clearly substantiated, the corrective action scope was limited, or the identified concern was not fully addressed. No regulatory or safety issues were identified in this review; however, the inspector considered the dispositioning of these ACTION reports did not receive the level of attention that prompted their initiation.

- Work Request Processing versus ACTION Report Processing

Equipment problems are entered into the maintenance work control system by use of Work Request/Trouble Reports (WR/TRs). WR/TRs are reviewed by the shift supervisor for equipment operability. Because this level of review is not as extensive as that received by an ACTION report, the inspector considered that equipment operability issues had the potential of not being identified as promptly under a WR/TR. Additionally, other problem analysis techniques (such as root cause analysis and Human Performance Enhancement System (HPES) review) may be bypassed by an item entered in the maintenance work control system.

IP-CAP-1 states that ACTION reports do not apply to items covered by the maintenance work control system, except as specifically noted. However, through discussions with management, the inspector was informed that ACTION Reports were expected to be written for equipment problems involving: 1) safety related equipment; 2) safety significant equipment; 3) equipment covered by the maintenance rule; and 4) reliability centered maintenance equipment. From a review of WR/TRs on equipment in the control room, the inspector noted several instances where ACTION reports were not generated in accordance with management expectations.

1) WR/TR 017657 dated June 17, 1996 - NI-42C (Power range nuclear instrument) Axial offset indication is approximately one percent low versus the other channels.

2) WR/TR 019942 dated June 14, 1996 - PCV-434 (Pressurizer safety valve) Valve position indication is drifting high.

3) WR/TR 019913 dated June 8, 1996 - CV-9703B (Standby auxiliary feedwater pump discharge check valve) CV-9703B will not close.

4) WR/TR 020066 dated May 28, 1996 - Overpressure Accumulator B. Needs to be charged approximately every 5 hours.

Front-end review of problems entered into the maintenance work control system were not as extensive as with the ACTION reporting system, therefore operability/reportability was not immediately reviewed by as many individuals. Additionally, use of system enhancements (root cause analysis and HPES) was not as programmatic as with ACTION Reports. The inspector noted that this condition had not resulted in a significant number of problems, and that the operations and

maintenance managers typically review WR/TRs on a daily basis. Current guidance on parallel use of ACTION Reports and WR/TRs was apparently not consistent with management expectations.

c. Conclusions:

The inspector concluded that ACTION Reports were generally effective in providing prompt problem identification and systematic resolution. However, the inspector noted several cases where problems were not rigorously evaluated. The inspector considered the threshold to be appropriate for capturing most events, and considered that event reporting was generally consistent with this threshold.

O7.2 Root Cause Analysis Program/Human Performance Enhancement System (HPES)

a. Inspection Scope

The scope of this inspection was to assess the Root Cause Analysis/HPES Program with respect to procedural guidance, personnel training in root cause analysis/HPES techniques, management response to identified root causes, trending of causes, and incorporation of operating experience/human performance issues in the root cause process.

b. Observations and Findings

Through Nuclear Directive ND-CAP, "Corrective Action Program," and Interface Procedure, IP-CAP-2, "Root Cause Analysis," the Plant Manager had overall responsibility for implementing the Root Cause Analysis process.

The Operating Experience Section (OES) staff supported this effort by providing training to the site staff and assessing, analyzing, and reporting to management on data gathered during root cause analysis (RCA) investigations.

Approximately 160 individuals have participated in a Ginna-developed root cause analysis training course. The course provided good training to individuals in root cause analysis tools and techniques for both equipment and human performance problems. OES identified a need for advanced training for certain individuals and planned to conduct this training in the near future. From the inspectors review of the training materials and interviews, some training weaknesses were identified. The training course was primarily focused on root cause analysis techniques and relies heavily on staff judgement. Guidance was lacking for determining whether a "root cause" or an "apparent cause" investigation should be initiated. Trained personnel have indicated difficulty in selecting the proper cause code(s). When an "apparent cause" was conducted, guidance was not provided to the root cause assessors if human performance deficiencies should be formally considered; however, human performance deficiencies were formally addressed for the comprehensive "root cause" investigations. The inspector considered these items for which guidance is lacking to be minor shortcomings.

The inspector reviewed a sample of recently closed ACTION Report "cause" evaluations. The majority of the root causes were "apparent causes" and therefore generally involved a single root cause assessor. A comprehensive root cause assessment was conducted for approximately 10-12 ACTION Reports each year. For those, a team of assessors was generally assigned. From interviews of three root-cause assessors, the inspector determined that the individuals had considerable experience and expertise in the root cause analysis process.

An experienced individual in OES reviewed all root cause reports and identified cause trends for low threshold incidents.

Supervisors assigned and effectively reviewed the root cause assessments conducted by their employees. Management and OES involvement in the Root Cause Analysis Program was good. All site managers had participated in the root cause training. Communications between OES and the root cause assessors were also excellent.

The inspector reviewed the closed ACTION Report root cause assessments for 1996 to evaluate whether operating experience (both in-house and industry experience) had been considered. Based on interviews conducted by the inspector, it was apparent that when a comprehensive root cause analysis had been completed the assessors incorporated operating experience (per IP-CAP-2). For those ACTION reports where an "apparent cause" had been completed, the documentation in the body of the ACTION report usually did not have evidence that operating experience had been formally considered. The inspector noted that for those ACTION reports with an "apparent cause," there was reliance on individual initiative and recall to identify station recurring problems and past operating experiences. Although the inspector noted Ginna Station has had an experience and stable work force in the past, the inspector considered the lack of a systematic, documented approach for identifying recurring problems and operating experience a weakness.

The inspector reviewed several root cause investigations of events involving human performance and evaluated how human performance issues were incorporated into the Root Cause Analysis Program. The inspector reviewed the team report from the event (ACTION/HPES 96-0141) concerning the identification that both pressurizer PORVs had been inoperable concurrently and resulted in the plant being in a condition that would have prevented the fulfillment of a safety function. The formal root cause investigation was a thorough evaluation; addressing inter-departmental communications, job planning, and supervisory oversight. The team used several root cause methodologies and is continuing to examine the event to identify the full scope of corrective actions. The inspector also reviewed HPES 95-118 ("Number 3 Bearing Upper Half Was Installed Incorrectly") and AR 96-0196 ("Contaminated Material Transported Offsite"). The root cause and HPES assessments associated with the three events were thorough, comprehensive and used appropriate methodologies. The multi-disciplined teams that performed the three root cause analyses included personnel trained and experienced in performing HPES techniques.

RG&E management's strong commitment to root cause analysis was evident in the RG&E Business Plan (1996-2000), where strategies to improve the Correction Action Program specifically identified action items that were translated into job plans for the Director, Operating Experience to assess the quality, consistency, and effectiveness of RCAs, and to implement identified improvements.

c. Conclusions on Root Cause Analysis Program

The inspector concluded that the root cause analysis system was very well implemented. The root cause analysis assessments were conducted by experienced, well-trained personnel, and were technically thorough, used appropriate methodologies, incorporated operating experience and received management review. The depth of the analysis was commensurate with the safety significance of the problem identified. Root cause training was good with respect to using root cause tools and techniques; however, training could be enhanced by addressing certain minor administrative shortcomings. The HPES reviews conducted in conjunction with other reviews appropriately addressed human performance problems.

O7.3 Operating Experience Feedback

a. Inspection Scope

The scope of this inspection was to assess performance of the Operating Experience Section (OES) by evaluating its organizational responsibilities, effectiveness in disseminating information, and review and assessment activities.

b. Observations and Findings

The six member Operating Experience Section is the licensee's primary group for evaluating and disseminating nuclear industry information and site operating experiences to the Nuclear Operations Group for action. The Director, Operating Experience, was located onsite and reported to the corporate Department Manager, Nuclear Assessment.

Management's expectations for the OES were clearly stated in Nuclear Directive ND-CAP, Revision 4, "Corrective Action Program," which established the requirements for development and execution of a Corrective Action Program (CAP) at Ginna. Administrative procedures A-1404, "Operating Experience Program," and A-201.8 "Operating Experience Section Organization and Responsibilities," adequately outlined the operating experience program, the organizational structure and the responsibilities of the OES staff and the interface with the Nuclear Safety and Licensing Department. Frequent self-assessments of OES performance and the overall effectiveness of the Corrective Action Program have provided management insights into enhancing program capabilities.

OES staff demonstrated to the inspector that industry information such as NRC Bulletins, Generic Letters and Information Notices, INPO operational experience

information reports, Westinghouse reports, and daily reports from other facilities were received and screened for applicability to Ginna in a timely fashion. NRC Bulletins, Generic Letters and Information Notices were screened and distributed by the Nuclear Safety & Licensing Department with action items assigned to a responsible individual and tracked to completion by the Commitment and Action Tracking System (CATS). Newsletters and daily electronic mailings of summaries of events and reports from other facilities are provided by OES to an appropriate Ginna distribution list. The NRC daily Plant Status Reports were provided in a brief format by OES to appropriate personnel. As necessary, personnel received complete descriptions of events or reports. In addition to using normal site-wide communication channels, OES provides daily input of recent industry experiences at the Morning Priorities Action Required (MOPAR) meeting.

In-house operating experience events were occasionally reported externally to the Nuclear Network by the OES. The PORC chairman could request that a report be sent for Nuclear Network Notification at the same time that he assigned an ACTION Report to a specific department for disposition; however, distribution to the Nuclear Network had been done infrequently.

Comprehensive in-house operating experience effectiveness reviews by the OES were being initiated in response to a request from the Nuclear Safety Audit and Review Board (NSARB). The inspector examined a June 18, 1996 draft of an in-process effectiveness review of diesel generator operating history and concluded the effort appeared to be thorough and an excellent initiative; however, the actual benefit of performing this review had yet to be realized.

The OES compared and analyzed the data from ACTION Reports with data from industry events. For 1995, the OES graphed INPO's identified recurring major cause codes for industry events. This allowed OES to then compare Ginna's cause code data from the ACTION Reports to the industry cause code data for feedback to management. The inspector found that this was a good trending initiative.

In response to various self-assessment findings and past corrective action program weaknesses identified in NRC Inspection Report 50-244/94-09, OES was initially tasked with developing a single point problem reporting system that consolidated diverse reporting mechanisms. OES promulgated procedure, IP-CAP-1 (Abnormal Condition Tracking Initiation or Notification (ACTION) Report) on July 17, 1995, that replaced approximately 21 site procedures. Site-wide utilization of the ACTION Report has been expeditiously achieved; however, some administrative inconsistencies exist in related procedures that reference deleted procedures. Additionally, as noted in section 07.2, a more structured approach to recalling and documenting past station operating experiences would enhance the corrective action program effectiveness. ACTION Report data was tracked through the Configuration Management Information System (CMIS). The inspector determined that OES had developed an effective corrective action mechanism that comprehensively captured plant problems and adverse trends and elevated this information at the appropriate management level.

c. Conclusions

The inspector concluded the Operating Experience Section and the Nuclear Safety and Licensing Department were promptly screening and disseminating industry and regulatory information, and assigning it for evaluation/response within the Nuclear Operations Group. The OES was expanding its role by performing corrective action effectiveness reviews. The ACTION Report system developed by OES was a very effective problem reporting/corrective action follow-up mechanism whereby problems were promptly reported, evaluated, resolved and tracked.

O7.4 Self-Assessment Activities

a. Inspection Scope

The scope of this inspection was to evaluate the effectiveness of the self-assessment activities including the scope and frequency of periodic audits, preemptive assessments performed prior to implementing major programmatic changes, and reactive assessments conducted in response to site events.

b. Observations and Findings

- Periodic Self-Assessments

Management philosophy and expectations for conducting independent assessments were clearly articulated in Nuclear Directive, ND-ASU, "Assessments and Surveillances." In addition to referencing relevant regulatory commitments and assigning responsibility for implementing those requirements, the directive provided requirements addressing preparation, performance, reporting, and follow-up for assessment activities. Interface Procedure, IP-ASU-1, "Self-Assessment," established the methodology for carrying out assessments, including internal/external audits, Quality Assurance surveillances, operational assessments, and self-assessments. Through review of completed audits and close examination of an in-process audit of the Radiological Protection/Chemistry programs, the inspector determined that the procedural methods were in-grained in Quality Assurance activities.

Periodic audits required by the Quality Assurance Program for Station Operation were performed within the proper frequency, addressed performance as well as compliance issues, and were reviewed by senior management in a timely manner through participation in the QA/QC Subcommittee of the Nuclear Safety Audit and Review Board (convenes three times per year). The inspector reviewed audits addressing Mechanical Maintenance, the Nuclear Emergency Response Plan, and the Corrective Action Program. These detailed assessments were based on auditor checklists developed from a computerized database (Nuclear Assessment Activity Tracking System). The checklists were properly focused on assessing safety issues, departmental performance, and monitoring recent programmatic changes, i.e., implementation of a single point problem (ACTION) reporting system. Particularly noteworthy was the expeditious issuance of ACTION Reports for audit

findings upon identification, prior to the audit exit meeting and report issuance, to assure a prompt disposition. By procedure, all audit findings were prioritized as a "Category B" to assure that response was taken within 30 days of issuance.

Included on the QA/QC subcommittee's agenda is a review of the Nuclear Assessment Department Quarterly Analysis Report. This report consolidates results from various internal and external assessment mechanisms to provide a comprehensive picture of overall performance. The report for the first quarter of 1996 identified that recent declines in procedural compliance and equipment problems represented a reversal of past gains made in these areas and warranted additional management focus. Recommendations were made to place special emphasis on the quality of pre-job briefings and assuring the work force was avoiding a sense of time pressure while performing tasks. The inspector concluded that the report candidly discussed performance issues but could not determine whether the resulting management actions were effective in curbing the negative trend.

Licensee management was committed to improving self-assessment effectiveness as a committed strategy contained in the RG&E Business Plan (1996-2000). Within the Business Plan, action plans have been established for conducting four in-depth self-assessments in the areas of mechanical maintenance, instrument and control (I&C)/ electrical maintenance, overall periodic maintenance effectiveness, and the maintenance work management process. These actions plans have been translated into individual job plans of the department managers and are due for completion during the summer of 1996.

The licensee actively participated in the Cooperative Management Audit Program (CMAP), in which an independent audit by external (third party) organizations is performed to assess the effectiveness of the Nuclear Assessment Department. Through review of the 94-11-RG&E audit, completed in November 1994, the licensee took prompt actions addressing areas for improvement identified in the report, including development/implementation of a streamlined (single point entry) problem reporting system (IP-CAP-1), that consolidated 21 separate reports and established a meaningful problem tracking/trending process. A second CMAP audit was scheduled for August 1996.

- <u>Tracking and Trending Findings</u>

Through the use of major and minor cause codes, audit findings (and other ACTION Report data) were collectively tracked and trended to identify recurring problems and focus management attention on the leading causes through the use of the Pareto analytical technique. This trend analysis technique identified the major/minor causes, e.g., Document use practices, Equipment Failure-improper operation, Equipment Failure-improper maintenance, etc., that contributed to approximately 50% of the negative findings for a reporting period for which management could take action. For the period mid-July 1995 through May 1996, areas of management concern were identified as: Human Performance-Work Practices (Administrative procedures not followed correctly), and Equipment Failure-

Plant/System operation (aging or degraded subcomponents, particularly in the 125 volt DC system). From the trends, management determined which indicators require further departmental assessment and assigned the action item in the course of the QA/QC subcommittee proceeding. At the QA/QC subcommittee meeting, management attention was also directed to the "Top Ten ACTION Reports" which may include audit findings. Although not formalized as a procedure, the methodology for identifying the "Top Ten" reports had been rigorously developed as guidance for the Nuclear Assessment Department staff selecting the reports to assure management is aware of significant findings or overdue responses.

- Preemptive Self-Assessments

To determine if the various activities supporting implementation of Improved Technical Specifications and the Maintenance Rule were being properly completed prior to the effective dates, self-assessments were completed. These assessments addressed the status of required procedure changes, new procedure development, training adequacy, and resolution of discrepancies between the old and the new requirements. In reviewing the Improved Technical Specification Audit Report (AINT-1996-003-CJK), the inspector determined that the audit identified discrepancies in the Tendon Surveillance Program, oversights in relocating PORV flow test requirements from the old Technical Specifications to the new Technical Requirements Manual, and inconsistencies between decontamination efficiencies used in the Ventilation Filter Testing Program and those recommended in Regulatory Guide 1.52. Accordingly, ACTION Reports were issued and the identified issues were dispositioned. Through review of the Maintenance Audit Report (AINT-1995-0017-CJK), four findings were identified where enhancements could be made to more effectively implement the Maintenance Rule.

During the 1996 refueling outage, an audit dedicated to steam generator replacement project (SGRP) activities was performed, in addition to a separate audit of other outage related activities. The SGRP consisted of 118 surveillance observations by a seven member team to assess the conduct of work by the prime contractor and the effectiveness of the interface with RG&E controlled activities. A separate audit of outage activities by a 13 member team consisted of 50 surveillance observations in the areas of operations, maintenance, engineering, and plant support. Concerns generated during these audits were captured in ACTION Reports and processed by site management for timely resolution.

The inspector determined that these audits were comprehensive and candid, reflecting a proactive management philosophy to provide an early warning of potential problem areas.

- Reactive Self-Assessments

Departmental self-assessments have been performed to evaluate the post-implementation phase of the ACTION reporting system, and the effectiveness of the root cause process (both by OES and the Maintenance Department) in response to external audit findings regarding maintenance-related human performance issues.

Assessments were in-depth and high quality evaluations. They were rigorously constructed using the guidance in IP-ASU-1 and critically assessed those areas where increased management/supervisory involvement was appropriate. Particularly noteworthy was the Maintenance Human Performance Self-Assessment completed in March 1996. As a result of this assessment, recommendations were presented to improve communications by having the maintenance planner present at pre-job briefings. Recommendations were also made to use senior technicians as trainers, use office personnel to write down worker observations to capture information in procedures for work in-process, and to improve management communications to lessen the staff's perception of schedular pressure.

- Supervisory Self-Assessments

  -- SHARP Program

  The SHARP (Safety, Housekeeping and plant equipment condition, Administrative, Reliability, and Productivity) Program was established by "Maintenance Department Guidelines for Maintenance Supervision Work Practice and Equipment Condition Monitoring." The purpose of this program was to provide guidelines for maintenance supervision to monitor work in progress, to encourage good work practices and identify and correct poor work practices, to monitor equipment conditions and housekeeping, and to ensure adequate worker training. Observations are documented in a SHARP Report and reviewed through the Maintenance Superintendent. SHARP Reports were entered in a database for trending, and forwarded to Maintenance Training for retention. Maintenance Supervision and the Training Department initiate training based on significance and applicability of observations; on the order of one out of 10 reports are followed up by training. As of this inspection, approximately 100 SHARP Reports had been completed in 1996.

  The inspector concluded that the SHARP Program was effective in encouraging supervisory oversight of maintenance activities. The number of SHARP Reports that have been generated in 1996 indicates that the program is being aggressively implemented. Utilization of information gained through these observations by the training department expands the effectiveness of the program.

c. Conclusions on Self-Assessments

RG&E management had a strong commitment to internal and third party self-assessment. Self-assessments were critically focused on management and supervisory issues, communications, effectiveness of corrective actions, and identifying potential equipment performance/ material condition problem areas. Findings are comprehensively tracked and analysis of trended data clearly focuses management attention on priority issues. Management oversight and involvement in self-assessments was very strong; resulting in prompt dispositioning of findings and accountability of action item follow-up. The effectiveness of current

management actions initiated to address recent negative trends identified during self-assessment could not be established at this time.

## O8 Miscellaneous Operations Issues

O8.1 (Closed) LER 96-005: Deficient Procedures for Testing Safety-Related Logic Circuits, Identified Using Criteria of NRC Generic Letter 96-01, Resulted in Condition Prohibited by Technical Specifications.

In response to Generic Letter 96-01, the licensee determined that several surveillance test procedures did not fully comply with surveillance requirements of the Ginna Improved Technical Specifications (ITS) section 5.4.1 that procedures be established, implemented, and maintained for these activities. LER 96-005 was written after the licensee determined that sixteen procedure deficiencies and twenty-one weaknesses constituted a substantial breakdown in the surveillance testing program, and warranted a formal report to the NRC. No safety-related logic components had been completely omitted from test procedures as a result of the deficiencies and weaknesses.

RG&E identified multiple related causes for the surveillance test deficiencies, including an assumption that the use of standard industry methods for logic circuit testing was acceptable, and an assumption that testing of parallel circuits and multiple contacts was not necessary. The subsequent procedure revisions and component tests performed during the last refueling outage demonstrated that there were no failures of safety-related logic circuits, and that the identified procedure deficiencies had not resulted in the unavailability of any safety system. All required testing was complete prior to the associated components having to be operable (post outage) in accordance with the ITS. Personnel training was provided to review lessons learned from this report.

The inspector concluded that this LER adequately reported extensive actions the licensee took to identify and correct deficiencies and weaknesses in the surveillance test program, and to address the associated root causes. This LER is closed.

O8.2 (Open) LER 96-006: Containment Penetration Not in Required Status, Due to Personnel Errors, Results in Potential for Uncontrolled Release of Radioactive Material.

LER 96-006 reported a lack of refueling integrity in the containment structure during the first 3-1/2 hours of reactor refueling in the last refueling outage. Details of the incident and associated Notice of Violation are contained in NRC inspection report 50-244/96-05. The licensee identified procedure deficiencies and personnel errors as the causes of this event. The short term corrective actions taken were to immediately suspend refueling operations and to seal the open penetration. Longer term actions were necessary to make procedure revisions and to implement training on lessons learned from the event. A supplement to the LER will also be issued after the licensee performs additional investigations into the circumstances

surrounding this event. Pending NRC review of all long term corrective actions and investigations by the licensee, and supplemental LER, this LER remains open.

O8.3 (Closed) LER 96-007: Control Rods Misaligned, Due to Rod Sequencing Problems.

LER 96-007 reported rod control misalignment and sequencing problems that occurred during a plant startup on June 12, 1996. While the reactor was in Mode 2, but still subcritical, a misalignment between the multiplexing rod position indication (MRPI) and the rod step counters on the main control board, caused operators to drive rods in so that troubleshooting could be performed. As rods were driven in, additional misalignment and rod bank sequencing anomalies resulted and prompted operators to perform a manual reactor trip. Details of this event are described in NRC inspection report 50-244/96-05.

The licensee's troubleshooting identified the root cause of the rod control problems as a multiplexing error in a rod control system cabinet where the proper rod bank overlap circuit was not properly selected by the power cabinet. This was the result of a faulty firing circuit card that receives the multiplexing signal from the logic cabinet. After repairs were made, the reactor startup resumed without further rod control problems.

The inspector concluded that LER 96-007 properly identified the root causes and corrective actions associated with this event. The LER satisfied the criteria of 10 CFR 50.73 (a) (2) (iv) to report actuations of the reactor protection system and is therefore closed.

## II. Maintenance

**M1 Conduct of Maintenance**

M1.1 Maintenance Observations

a. Inspection Scope (IP 62703)

The inspectors observed portions of plant maintenance activities to verify that the correct parts and tools were utilized, the 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 of post maintenance testing.

b. Observations and Findings

The inspectors observed all or portions of the following maintenance activities:

Repair of B-Feedwater Regulating Valve Internals

During the maintenance forced outage, the licensee disassembled the B-FRV because of sluggish performance since startup from the refueling outage, and because of a failure of the valve to automatically regulate flow below 20% power. Upon valve disassembly, the licensee noticed that the "VariSeal" ring was not installed on the valve plug as required by the assembly drawings. Upon investigation of the missing part, the licensee determined that no seal was provided by the valve vendor during the last refueling outage when both FRVs were modified as part of the steam generator replacement project.

Prior to the refueling outage, RG&E delivered a spare set of FRV trim components (valve plug and cage) to the valve vendor for a modification that would accommodate better control of feedwater flow for the new steam generators. These components were returned to the site after modification, were receipt inspected by RG&E, and were placed into the A-FRV after the plant was shut down for the refueling outage. The plug and cage removed from the A-FRV and the B-FRV were also returned to the vendor for modification. After both modified sets were returned to the site, they were also receipt inspected by RG&E. One set was then installed in the B-FRV and the other set put into spares.

The licensee's valve repair outage contractor reassembled the B-FRV without noticing the missing Variseal, although the seal was clearly identified on valve drawings. Also, RG&E's receipt inspection documents did not separately identify each trim component as an inspection item, and consequently, no discrepancy was noted for the missing seals before the B-FRV was reassembled.

The licensee inspected the internals of the B-FRV and noted that no significant damage had resulted from the missing VariSeal. Some abrasion was evident between the valve plug and cage assembly, but nothing was readily apparent that could explain the failure of the valve to close below 20%. The licensee initiated two ACTION Reports (96-0697 & 96-0698) to investigate the missing seal rings and to evaluate the B-FRV as-found conditions. RG&E contacted the valve vendor who discovered that the missing seals had not been returned with the other valve components after modification, and were still in their warehouse. The seals were then delivered to the site and installed on the valve plug prior to reassembly. Reassembly of the B-FRV was performed by RG&E mechanical maintenance personnel under the observation of QC inspectors. No problems were encountered during the reassembly process. The investigations into the causes for this event were ongoing at the close of the inspection period.

Removal of "A" Service Water (SW) Pump Motor, Pump Assembly and Piping

The inspectors observed various maintenance activities on the "A" service water pump which included:

- Removal of the 480 volt electrical breaker from the A-SW motor switchgear, removal of the 480 volt motor connections, and removal of the pump motor.

- Removal of the pump head, reducer pipe, and flexible coupling on the discharge portion of the pump head.

- Removal of the seismic supports for the pump shaft, column pipes and motor shafts, couplings, and pump assembly with its screen.

The inspectors noted the maintenance was performed by supervised mechanical and electrical maintenance trainees and that a quality control (QC) inspector was present during the work activities.

The inspector noted the licensee replaced the 300 hp A-SW motor with a larger 350 hp motor, and also replaced the pump assembly. The inspectors reviewed the licensee's design analysis for the replacement of the existing 300 hp SW motors with 350 hp motors. The analysis ensures that the new motors do not degrade the capability of the service water system or the electrical distribution system (including the diesel generators) from performing their intended functions during both normal and emergency conditions. The analysis was found to be in accordance with industry codes and standards that were referenced in the design documentation. These included IEEE-399-1990, "Recommended Practice for Power System Analysis," EPRI Guide TR-102814, "A Methodology for Determining An EDG's Capability to Start Its Emergency Loads," and NEC-70, "National Electric Code."

The licensee has procured an additional two motors to replace the B- and C-SW pump motors and will rebuild the pumps during their next scheduled maintenance. The licensee has included in its maintenance procedures thermographic inspection of the motors to identify any hot spots, and to trend these hot spots on a monthly bases.

Breaker Maintenance on "A" Service Water (SW) System

The inspector observed the overhaul and shop test of the metal clad circuit breaker for the A-SW pump motor. Major components of the breaker were checked and found to be satisfactory. There were no discrepancies found in the breaker.

The breaker overhaul and test consisted of the following activities:

- The breaker actuator linkage was dissembled cleaned and inspected for contaminated lubricants; none were found. All excess lubricant was removed and a graphite lubricant was applied.

- An instantaneous test of the breaker's solid state protective device (AMTECTOR) was conducted and found to be satisfactory.

- A Multi-Amp test was conducted to functionally test the breaker. The test was satisfactory.

- The breaker arc-shoots were taken off to inspect the breaker contacts for pitting or excessive wear. The contacts were satisfactory.

- The breaker's solid state trip set-points were changed to reflect the new "A" SW pump motor set-point requirements. Procedure M-32-125 was used so that the site drawings could be updated showing the revised set-points for the breaker.

c. Conclusions

The inspector concluded that modification of the B-FRV internal trim components and their reassembly during the past refueling outage was not well controlled. The missing VariSeals were not noted during the receipt inspection of the modified components, or during valve reassembly. The missing seals apparently caused sluggish valve performance after the outage, and may have caused the valve to fail to regulate below 20% during the last power reduction.

The inspector also concluded that each activity in the removal of the A SW pump motor, pump assembly, and piping system was performed in conformance with the licensee's electrical maintenance and safety procedures. The mechanical and pipe fitter crafts had separate procedures that were well coordinated, defining individual craft work boundaries and activities. All maintenance and training activities on the SW pump and motor were well controlled by the electrical and mechanical foremen. The electrical maintenance craft displayed a high degree of technical knowledge and skill during the A-SW pump motor overhaul, and the overhaul activities were well controlled. Personnel properly adhered to maintenance and safety procedures, and to manufacturers recommendations.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed portions of surveillance tests 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 post-test system restoration.

b. Observations and Findings

The inspectors observed all or portions of the following surveillance tests:

- B-FRV (AOV-4720) isolation time test, performed satisfactorily on July 6, 1996. The test required the valve to stroke in ≤10 seconds (SR 3.7.3.2) and the valve closed in 5.79 seconds.

- FT-626 calibration and reset of the low RHR flow alarm setpoint from 400 to 2900 gpm after coming off RHR cooling (as required by procedure O-1.1), satisfactorily performed on July 6, 1996.

- B-AFW pump flow test and auto throttleback of MOV-4008 (PT-16Q-B), performed on July 17, 1996. The valve was required to throttle at 200 - 230 gpm, but its final position was low out of tolerance at ≈80 gpm. I&C personnel adjusted the voltage potentiometer for the valve motor trip bistable setpoint to obtain the correct throttle position.

- A-AFW pump flow test and auto throttleback of MOV-4007 (PT-16Q-A), performed on July 17, 1996. The valve was required to throttle at 200 - 230 gpm, but its final position was low out of tolerance at ≈45 gpm. I&C personnel attempted to adjust the voltage potentiometer for the valve motor trip bistable setpoint to obtain the correct throttle position. However, technicians could not adjust the final throttle flow to >175 gpm because the potentiometer would not achieve more than 9.7 volts and about .2 additional volts were needed. Additional troubleshooting on the valve and adjustment of the potentiometer achieved the additional voltage required to obtain the required throttle flow.

c. Conclusions

The inspector concluded that surveillance test activities were well controlled and performed in accordance with detailed test procedures. The B-FRV and FT-626 met their required test acceptance criteria; however, the AFW pump discharge throttle valves continue to exhibit unreliable automatic throttling. The licensee's surveillance testing adequately revealed this unreliable performance and corrective measures were taken to restore proper performance: However, the unreliable behavior of MOV-4007 and 4008 appear related to inadequate design of the valves and their control mechanism. This is addressed in section E1.1 of this report.

**M2 Maintenance and Material Condition of Facilities and Equipment**

M2.1 Replacement of Leaking Pressurizer Safety Relief Valve 434

a. Inspection Scope (62703)

The inspector reviewed the maintenance actions taken to replace the leaking pressurizer safety relief valve SRV-434.

b. Observations and Findings

After the licensee was unable to stop the leaking SRV-434 while at power, plans were made to obtain a replacement valve for changeout with the plant shut down. The licensee determined that SRV-435, removed in the 1996 refueling outage could be used as a replacement since it was still within its valid lift setpoint time period, as allowed by the ASME code. The acceptability of SRV-435 for this application was documented in a letter from the lead inservice test engineer and the mechanical maintenance manager, dated July 3, 1996.

Consequently, SRV-435 was removed from storage and delivered to the maintenance department for an inspection and leak check prior to installation. After the SRV was leak tested, the licensee determined that a mechanical maintenance technician improperly lifted the SRV at its setpoint pressure. This was contrary to procedure requirements for this specific activity. Subsequently, the SRV was subjected to nitrogen bubble test and no leakage was noted.

The inspector discussed this situation with the mechanical maintenance manager who indicated that an ACTION Report (96-0696) was initiated to investigate the procedure adherence problem. Although the SRV test procedure was temporarily changed to delete the lift check, the maintenance technician did not adhere to the temporary change, and apparently performed the test from habit as trained. It also appeared that the technician did not receive an adequate prejob briefing and that a sense of urgency probably caused him to overlook the written procedure steps. This problem was still under review at the close of the inspection period.

The licensee subsequently reinstalled the replacement SRV onto the SRV-434 location without difficulty. The valve maintained its leak tightness during the subsequent plant startup and power operation.

c. Conclusions

The inspector concluded that the licensee's maintenance activities to replace the leaking SRV were adequate. However, lack of an adequate prejob briefing and a sense of urgency during the forced outage may have contributed to the procedure adherence problem when the SRV was improperly lift tested after its leak check. The inspector also considered that this occurrence was related to other work control and procedural compliance issues noted during a recent forced outage at the Ginna Station as discussed in inspection report 50-244/96-01.

M2.3 Replacement of Non-regenerative Heat Exchanger Isolation Valve AOV-427 Due to Foreign Object

a. Inspection Scope (62703)

During the plant shutdown to replace a leaking pressurizer safety relief valve, AOV-427 became jammed and could not be operated. Disassembly of the valve

was necessary during the forced maintenance outage. The inspector reviewed the licensee's activities to investigate this problem.

b. Observations and Findings

When plant operators attempted to remotely close RCS letdown isolation valve AOV-427, the valve became jammed and would not operate from the control room. Local manual operation was also not possible and the licensee disassembled the valve to investigate this problem. Upon valve disassembly, it was noted that a small screw had become wedged between the valve plug and cage assembly on the inlet side, and prevented any movement of the valve.

The licensee replaced the valve plug and cage with replacement spares and reassembled the valve and actuator without difficulty. An ACTION Report (96-0699) was initiated to investigate this problem; however, it was not immediately apparent where the screw had originated. The licensee had implemented enhanced foreign material exclusion (FME) controls inside the containment building during the past refueling outage, but these were apparently not sufficient to prevent the entry of this screw into the RCS. This incident was still under investigation at the end of the inspection period and the licensee was attempting to identify the source of the screw.

After AOV-427 was reassembled, a post maintenance test (PT-2.6) was successfully performed on the valve prior to returning the plant to operation.

c. Conclusions

The licensee's maintenance to correct the jammed letdown isolation valve was adequate to restore the valve to service. The enhanced FME controls implemented during the recent refueling outage were generally effective for the high level of outage activity inside the containment building during the steam generator replacement project. However, these FME controls were not fully effective in keeping a small screw out of the RCS that became lodged in AOV-427.

M2.6 RG&E's Response to NRC Information Notice 95-22 on Circuit Breaker Maintenance

a. Inspection Scope (62703)

The inspector reviewed the facility's response to NRC Information Notice (IN) 95-22, "Hardened or Contaminated Lubricants Cause Metal Class Circuit Breaker Failures," particularly with regard to the B-component cooling water (CCW) pump failure in January, 1996, and the overhaul of the A-service water pump motor breaker.

b. Observations and Findings

Appropriate changes to remove excess lubricant buildup from all breaker mechanisms were incorporated into maintenance procedures to address the

deficiencies associated with hardened or contaminated lubricants, as identified in the IN. In addition, the cause of the malfunctions for the circuit breaker failures described in IN 95-22 (solidified lubricant/grease in linkage mechanisms) were specifically addressed during the troubleshooting efforts of the B-CCW pump circuit breaker failure and during the A-SW pump motor breaker maintenance. The licensee found no lubrication discrepancies related to IN 95-22 in these breakers.

c. Conclusion

The inspector concluded that the licensee appropriately incorporated procedural changes based on information contained in IN 95-22. RG&E's program for incorporating procedural changes in response to Information Notices was considered to be adequate.

M2.7 Voltage Changes for Circulating Water Intake Heaters "C" and "D"

a. Inspection Scope (62703)

The inspector observed transformer tap changes for the "C" and "D" circulating water intake heaters.

b. Observations and Findings

The inspector observed voltage tap changes on the step-down transformers for the C- and D-circulating water (CW) intake heaters from 480 volts to 240 volts. The licensee changed the voltage from 480 volts to 240 volts because the CW intake heaters are starting to degrade at the higher voltage, and to limit the risk of current leakage to divers while conducting maintenance on the heaters. The divers conducted a routine inspection and took amperage readings on the heaters at the lower voltage settings. The electrical foreman was adjusting the breaker's solid state protection device (AMTECTOR) to compensate for lower voltage and found that the hi-level trip set-point could not be lowered to the required setting. The inspector inquired as to the frequency of failure of these solid state devices and was informed that this was only the second failure. A new AMTECTOR was tested and installed per procedure M-32.1.25, "DB-25 Circuit Breaker Maintenance." This procedure is used whenever breaker set-points are changed so that the site drawings can be updated showing the revised set-points for the breaker. A QC inspector was present during these activities and no discrepancies were found.

c. Conclusion

The inspector observed excellent coordination between the electrical foreman, operations, craft, and divers. Maintenance activities were well controlled, personnel properly adhered to maintenance and safety procedures, and to manufacturers recommendations.

## M3 Maintenance Procedures and Documentation

### M3.1 Procedures Implementing The 10CFR50.65 Maintenance Rule

a. Inspection Scope (37551)

The inspector reviewed program documentation the licensee had developed to establish their Maintenance Rule Program. In addition, the inspector reviewed various program activities over the past year.

b. Observations and Findings

In January 1994, RG&E assigned a Maintenance Rule (MR) director to lead the development and implementation of the MR Program at the Ginna Station. In May 1994, an MR expert panel was assembled that conducted an initial scoping and risk significance study to identify specific plant systems, structures, and components (SSCs) that would be monitored under the 10CFR50.65 Maintenance Rule. The initial scoping efforts considered various categories of plant equipment and used the following selection criteria for including SSCs within the scope of the Rule:

1) All safety-related SSCs, and some nonsafety-related SSCs
2) Nonsafety-related SSCs that are relied on to mitigage accidents or transients
3) Nonsafety-related SSCs that are relied on by the emergency operating procedures
4) Nonsafety-related SSCs whose failure could cause a safety-related SSC to fail to fulfill its safety function
5) Nonsafety-related SSC that could cause a reactor scram or actuate a safety-related system

The expert panel evaluated 75 SSCs for potential scoping under the above criteria and identified 59 SSCs that were within the scope of the Rule. Most of these were complete safety-related systems and structures that met at least one of the selection criteria.

On June 30, 1995, RG&E issued Nuclear Directive ND-REL, "Reliability Program," to formally establish MR administrative requirements throughout all departments in the Nuclear Operations Group, and to establish program guidelines for monitoring the effectiveness of maintenance of SSCs within scope. On July 31, 1995, RG&E initiated performance monitoring of all plant equipment effected by the MR. Fifteen System Engineering Guidelines (SEGs) were developed to define equipment performance criteria and standards, system engineer responsibilities, criteria for identifying maintenance preventable functional failures and risk significance, guidance for the MR expert panel, etc. In addition, Site Planning Group guidance was issued to assist in assessing the impact on critical safety functions when removing equipment from service.

On November 17, 1995, RG&E issued the first quarterly "Systems Engineering Performance Report," that presented plant and system performance information. The report identified nine systems/subsystems/trains that exceeded their

performance criteria through the third quarter of 1995. The performance results captured data from July 1994. The licensee was pursuing the causes for exceeding the performance criteria through the corrective action process when the report was published, and none of the performance results were yet attributed to maintenance preventable functional failures. The report also identified open items in the MR Program that needed to be complete before July 10, 1996, when 10CFR50.65 was in full effect. These included developing a probabilistic safety analysis (PSA) sensitivity evaluation, and developing performance criteria for monitoring the performance of structures within the scope of the MR.

The second quarterly performance report was issued on February 6, 1996. Two systems (SI train B and Blowdown train B) had unacceptable performance and were placed into "Category (a)(1)" where corrective actions and goals to return the systems to acceptable performance were necessary. Four systems exceeded their MR performance criteria and root cause evaluations were initiated. Four other systems exceeded their performance criteria, but for reasons not attributable to maintenance preventable failures. Their performance was acceptable under 10CFR50.65 criteria because there was documented assessments to assure that the causes were known and corrected. Two additional systems had unacceptable performance because additional failures occurred during the assessment period and the root causes were not fully understood, or corrective actions were not fully implemented.

A third quarterly report was issued on April 6, 1996, that contained similar performance results. The report also defined a color code for a System Status Matrix that was created for display in various plant areas. The matrix defined four system performance categories under the MR Program as 1) acceptable performance (green), 2) performance issues (yellow), 3) unacceptable performance (orange), and 4) MR unacceptable performance (red). The matrix was issued in January 1996 and reflected the performance results described in the quarterly report.

The licensee's MR Program had various audits and assessments conducted during its development phase. Industry peer groups and RG&E's QA department performed joint assessments in October 1994, and in January, October, and November 1995. The first "Preventive Maintenance Effectiveness Assessment" (PMEA) is scheduled for September 1996. By July 10, 1996, all MR Program documents were approved and issued, except for one safety evaluation report (SEV) that addressed the periodic PMEA program assessments.

c. Conclusions

The licensee has implemented a well developed Maintenance Rule program and procedures to meet the rule which became effective on July 10, 1996. The program closely monitored equipment performance for over a year, and program effectiveness has been thoroughly evaluated on a regular basis. Maintenance tracking and trending have been effectively used to identify maintenance

preventable functional failures and to take appropriate actions for increased monitoring under the Maintenance Rule.

## III. Engineering

### E1 Conduct of Engineering (IP 37550)

### E1.1 Plant Modifications - Plant Change Records (PCRs)

a. Inspection Scope (37700)

The inspector reviewed several PCRs, focusing on certain aspects (e.g., reviews of the post modification testing and safety evaluations) of the plant change as follows:

- PCR 95-096 - MOV 4616 Stroke Time Reduction - Design analysis, safety evaluation, and plant configuration aspects reviewed.
- PCR 95-059 - Replacement Steam Generator Wet Layup System - Design change requirements reviewed concerning their impact on the containment accident analyses.
- PCR 96-038/039 - Motor Driven Auxiliary Feed Water Pump (MDAFWP) Discharge Globe Valve (MOV 4007/4008) Replacement - Post modification testing reviewed.

These plant modifications were implemented during the 1996 refueling outage. The inspector reviewed the modification packages for these PCRs and discussed pertinent aspects of the changes with the cognizant engineers.

b. Observations and Findings

PCR 95-096 - MOV 4616 Stroke Time Reduction

Motor-operated valve MOV-4616 is a 20-inch normally open, gate valve that supplies service water (SW) to the A-component cooling water (CCW) and spent fuel pool (SFP) heat exchangers. The valve automatically closes upon receipt of a safety injection actuation signal which maximizes SW flow to the emergency diesel generator (EDG) and containment recirculation fan (CRF) coolers. The licensee classified this valve as a high risk MOV as part the Ginna Generic Letter 89-10 program. Currently, the full open position of MOV-4616 is actually only 50% open as specified in PCR 95-096, which accomplished the change by adjusting the open limit switch to limit the opening stroke to approximately 50% open. The licensee's basis for this throttled position of MOV-4616 was provided in various documents issued between 1994 and 1996. These documents were reviewed by the inspector as discussed below.

The original MOV-4616 was a 20-inch Chapman List 155 gate valve which was replaced with a Crane model 47-1/2XU gate valve during the 1994 refueling outage.

However, the replacement valve had different stem characteristics (lead and pitch) compared to the original valve such that the stroke time of MOV-4616 increased from approximately 30 seconds to approximately 120 seconds. The licensee recognized this stroke time change in Technical Staff Request (TSR) 94-528 that documented a technical evaluation of the valve replacement. While the licensee adequately reviewed and revised the mechanical details, including piping and pipe support analyses to accommodate the replacement valve, the stroke time change was not fully evaluated in TSR 94-528 since the licensee considered it not to be critical.

The inspector reviewed the MOV-4616 post modification test results of Procedure PT-2.3 that were evaluated by the cognizant inservice testing (IST) engineer in May 1994. Even though the new stroke time significantly increased almost 4 times, the licensee concluded that the new MOV-4616 stroke time was acceptable as there was no negative impact regarding performance of its safety function (NOTE: Actual closure time was 112 seconds per the PT 2.3 test on April 5, 1994). Specifically, the licensee concluded that whether the valve opened or closed in 30 seconds or 120 seconds was inconsequential as long as the valve went to its final position when called upon. The inspector considered that this MOV-4616 stroke time change was safety significant in that this change could potentially cause inadequate flow to the EDG and CRF coolers during design basis accident conditions. The licensee is required to perform a safety evaluation in accordance with 10 CFR 50.59 for such significant changes. However, no safety evaluation had been performed and this created a potential unanalyzed situation.

Based on discussions in late March 1995 between engineering and licensing personnel, the licensee identified a concern with the delayed closing time (approximate 120 seconds) for MOV-4616. The concern involved the delayed isolation of the SW flow to the CCW and SFP heat exchangers during the injection phase of a postulated design basis pipe rupture (loss of coolant accident or main steam line break) in containment that would result in a temporary reduction in SW flow to the EDG and CRF coolers. The design basis, as listed in Table 9.2-2 of the updated final safety analysis report (UFSAR), assumes that one SW pump is operational, and that all non-safety related loads plus the SW flow to the CCW and SFP heat exchangers have been isolated. The licensee promptly evaluated this concern in Design Analysis DA-ME-95-087, "Evaluation of SWS Accident Flow Response With Delayed Closing Time of Isolation Valve 4616," Revision 0, dated April 15, 1995. The inspector reviewed this document, which consisted of a SW system hydraulic analysis using the computer code KYPIPE (developed by the University of Kentucky) in conjunction with the SW system hydraulic model. The assumptions used by the licensee in this analysis to develop the most conservative case (i.e., where the greatest amount of SW flow was being diverted from the EDG and CRF coolers) appeared to be sound.

The table below provides the results of the most conservative case.

| COMPONENT | FSAR REQUIRED FLOW (gpm) | PREDICTED FLOW (gpm) |
|---|---|---|
| CRFC "A" | 915 | 920 |
| CRFC "D" | 915 | 952 |
| CRFC MTR "A" | 31 | 46 |
| CRFC MTR "D" | 31 | 45 |
| DG CLR "A" | 320 | 316 |

The licensee concluded that the stroke time of approximately 120 seconds for MOV-4616 was acceptable. However, the analysis acknowledged that the remaining margin before the SW flows to the EDG and CRF coolers become unacceptable was small, and any additional SW system resistance due to fouling would further reduce this margin. [NOTE: The licensee considered the low EDG cooler flow to be acceptable based on engineering judgment.] For this reason the licensee recommended that the original MOV-4616 stroke time of 30 seconds should be restored during the 1996 refueling outage. Although DA-ME-95-087 was a more comprehensive evaluation compared to that performed in 1994, the inspector noted that this evaluation also did not meet the requirements of 10 CFR 50.59.

Plant modification PCR 95-096 was prepared in 1996 to modify the actuator gearing of MOV-4616 and thereby restore the approximate 30-second stroke time recommended in Design Analysis DA-ME-95-087. However, further engineering review indicated that these proposed changes would result in an unacceptable actuator thrust at degraded voltage. In modification design change notice 1092 issued on May 17, 1996, the licensee modified PCR 95-096 to adjust the MOV-4616 open limit switch to limit the open stroke to approximately 50% open. This would result in an approximate 60-second closure time. The licensee performed Design Analysis DA-ME-96-046, "MOV-4616 50% Open Throttling Evaluation," Revision 0, May 15, 1996, and Safety Evaluation 1064, "MOV-4616 50% Open Throttling," Revision 0, May 31, 1996 to justify the throttled position of MOV-4616. The inspector reviewed Design Analysis DA-ME-96-046 and agreed with the conclusion that there was a minor impact regarding flow and differential pressure (increase of approximately 0.3 psi) due to the throttled position of MOV-4616. However, in reviewing these documents, the inspector presented several questions to further assess this issue. The NRC questions, licensee responses, and amplifying information are summarized below.

- Were possible long term degradation effects of MOV-4616 considered with the valve disc now located in the SW flow stream?

  The licensee indicated that they had considered the negative effects due to the valve disc being in the flow stream. However, their judgment was that this would not be a problem and quarterly IST testing would assure valve operability. The inspector noted that the licensee had not considered augmenting some quarterly IST tests with diagnostic test equipment to enhance valve performance monitoring.

- When the concern regarding the delayed stroke time of MOV-4616 was identified in 1995, was an action request or a non-conformance report (NCR) issued to assure appropriate corrective actions had been taken to prevent recurrence?

  The licensee stated that an NCR was not issued since Design Analysis DA-ME-95-087 determined the 120 second stroke time to be acceptable. The inspector noted that this approach was poor corrective action since it did not address the generic concern of the lack of coordination of design information. Although the licensee evaluated the specific MOV-4616 problem in 1995, they had not taken other corrective actions to provide the assurance that current plant design and operating procedures were consistent with accident analysis assumptions.

- In 1994 and 1995 what was the technical basis for the maximum acceptable closing time for MOV-4616 and how was this closing time related to the plant accident analysis described in the final safety analysis report (FSAR)?

  The licensee stated that there was no maximum acceptable closing time specified for MOV-4616 but the timing was based upon assumptions included in the accident analysis.

  The inspector noted that there were required SW flows in the FSAR that may not be met in the absence of a maximum stroke time for MOV-4616. For example, Subsection 2. titled "Loss-of-Coolant Accident" of Section 6.2.2.1.2.6 of the FSAR states in part that "The only parameters in the LOCA analysis associated with the service water flow is heat removal (injection phase) via the CRFCs and cooling of the recirculated sump water (recirculation phase)... During the injection phase, a value of 45 MBTU/hr at 286°F was assumed for one service water pump operation. The amount of service water flow required to satisfy the accident analysis is a function of service water temperature and containment recirculation fan cooler air flow. The service water flow of 840 gpm to the cooling coils for each fan cooler was assumed, which is more limiting than the design condition (Table 9.2-2)." When significant increases in stroke time for valves such as MOV-4616 exist, they should be evaluated per 10 CFR 50.59 since such conditions create the potential for being in an unanalyzed situation.

- Does the licensee consider the MOV-4616 closure time to be a part of the plant's design basis?

  While the licensee stated initially that the MOV-4616 closure time was part of the plant's design basis, they concluded by stating it was related to the plant's design basis.

  Notwithstanding the previous information exchange regarding MOV-4616, on July 3, 1996, the inspector requested the following 3 packages of information regarding the CRF coolers to better understand the licensee's review of the significant change made in May 1994 to the closing time of this service water valve.

- Accident analysis information including the calculations of record for the CRF coolers.

- Design basis documentation for the CRF coolers for performing their safety functions.

- Pertinent information included in the UFSAR regarding the capability of the CRF coolers to perform their safety functions.

  The licensee was requested to specifically address how these 3 documents, i.e., the accident analyses, design basis documentation, and UFSAR, were evaluated and changed to reflect the impact of changing the closing time of valve 4616 from approximately 30 seconds to 120 seconds. The inspector expected the 3 information packages to include a description of how service water flow to the CRF coolers was assumed and modeled for the limiting accident analyses as described in the UFSAR.

PCR 95-059 - Replacement Steam Generator (RSG) Wet Layup System

The licensee initiated this plant change record to provide a means for recirculating chemically treated water in the RSGs during extended periods of wet layup. A separate recirculating system for each RSG was being provided which consisted of a 50-60 gpm pump and associated piping, valves, and electrical controls. Each system was permanently located inside containment at elevation 253 ft., but physically disconnected from the RSG during normal operation. When needed, temporary lines would tie the recirculation system to the blowdown and recirculation connections for each RSG. A chemical injection tank with a metering pump would also be temporarily installed when needed.

While PCR 95-059 consisted mostly of material and equipment that were classified as non-safety related, the inspector selected this modification to review the licensee's controls regarding design changes inside containment. The inspector verified that the equipment permanently mounted inside containment was installed to meet seismic category I requirements. During the initial interdisciplinary review of this design change, licensing personnel commented that an inventory of materials

associated with this modification would be needed by plant containment analysis personnel to evaluate any impact on the containment volume and heat sink. The assigned engineer for PCR 95-059 was not aware of this requirement initially. However, he provided the requested inventory of materials to the engineer responsible for containment analyses, who evaluated the impact on past calculations as insignificant.

The inspector observed that the PCR process could be improved by better acquainting design engineers with the need to provide an inventory of materials to the responsible personnel performing containment analyses when designing modifications for inside containment. The current design process seemed to place most of the responsibility for this review on licensing personnel.

PCR 96-038/039 - Motor Driven Auxiliary Feed Water Pump (MDAFWP) Discharge Globe Valve (MOV-4007/4008) Replacement

MOV-4007 and 4008 are normally closed, 3-inch, motor-operated globe valves located at the discharge of the MDAFWPs. They have a safety function to open after the start of the A-MDAFWP and B-MDAFWP, respectively. The inspector reviewed the post modification testing that had been performed regarding these valves since they had been replaced during the recent refueling outage. Both valves were retested satisfactorily with diagnostic test equipment under static and dynamic conditions. However, the inspector noted that a problem was identified concerning the static diagnostic test of MOV-4007 in that the measured unseating torque (150 ft-lb) was found to be greater than the motor capability under degraded voltage conditions (134 ft-lb). The licensee's Procedure M-64.1.2, "MOVATS Testing of Motor-Operated Valves," required the issuance of Action Report (AR) 96-0527 to identify, evaluate, and resolve this problem. [NOTE: A similar problem was also identified during the retest of MOV-4008 as documented in AR 96-0549.] The inspector also noted that the results of the dynamic test of MOV-4007 were different than the static test in that the measured unseating torque (131.19 ft-lb) was found to be less than the motor capability under degraded voltage conditions. This resulted in a 2% margin at degraded voltage.

The inspector reviewed the licensee's basis for resolving AR 96-0527 and noted the following:

- The 134 ft-lb torque value of motor capability at degraded voltage conditions included tolerances for diagnostic equipment error and was based on a stem friction coefficient of 0.20. It also included a torque reduction factor to account for degraded motor performance at higher temperatures.

- The torque reduction factor to account for higher temperatures was considered to be overly conservative as applied to MOV-4007 when considering the provision of the standby auxiliary feed water pumps for a high energy line break in the Intermediate Building. Removing the torque reduction factor for high temperatures from the calculation resulted in a motor capability at degraded voltage conditions of 156 ft-lb (including

diagnostic equipment error), which was greater than the unseating torque of 150 ft-lb (4% margin) during the static test. Under dynamic conditions, the margin at degraded voltage would be approximately 16%.

The inspector discussed this AR resolution with the MOV program engineer responsible for the issue. While the resolution of the AR appeared to be adequate for the short term, the inspector considered that little margin was available under degraded voltage conditions to account for degradation of MOV-4007 between periodic MOV diagnostic tests. The licensee indicated that they intended to modify the actuators on MOV-4007 and 4008 to increase their output capability.

The inspector also noted that several occurrences of MOV-4007 and 4008 not automatically throttling to their proper flow setting after starting their respective motor driven auxiliary feedwater pump (see section O1.2 and M1.2). The licensee indicated that the replacement valves were hydraulically equivalent to the old valves; however, a slightly different plug design may have caused the new valves more difficulty in achieving the proper throttle flow under varying SG pressures and valve d/p conditions. The valves are only about 5% open at the correct throttle position. Both valves were throttle tested at full SG pressure after MOVATS testing (post valve replacement), and both throttled properly at that time. The AFW system engineer and I&C personnel indicated that a complete redesign of the valves and their controls should be done to assure their long term reliability. The inspector noted a technical services request was written to address this issue.

c. Conclusions

Regarding the reduction of the MOV-4616 stroke time in PCR 95-096, the inspector noted that the Code of Federal regulations 10 CFR 50.59(b)(1) requires that the licensee maintain records of changes in the facility and of changes in procedures made pursuant to this section, to the extent that these changes constitute changes in the facility as described in the safety analysis report or to the extent that they constitute changes in procedures as described in the safety analysis report. The failure of the licensee to perform a safety evaluation after modifying MOV-4616 in May 1994, even though this modification involved a significant change to the valve closing time and created the potential for not meeting the assumed or design SW flows listed in the FSAR for the DG and CRF coolers, is a violation of 10 CFR 50.59 **(VIO 50-244/96-06-02)**. Also, once the licensee identified the excessive stroke time of MOV-4616 in 1995, their corrective actions were poor regarding the evaluation of any generic concerns with the coordination of design information. To obtain further clarification of the licensee actions regarding the excessive stroke time of MOV-4616, the inspector requested the licensee to provide accident analysis, design basis documentation and FSAR information.

The inspector concluded that a good interdisciplinary review of the design change for the replacement steam generator wet layup system resulted in proper consideration of the impact of the design change on containment accident analyses.

While the post-modification test results of MOV-4007 and 4008 were adequate, they evidenced little margin available under degraded voltage conditions to account for degradation between periodic MOV diagnostic tests. Also, the valves' reliability to automatically throttle flow appears related to an inadequate design of the valves and their control mechanism. The licensee indicated their intention to modify the valves, actuators, and control circuits to increase their output capability and their throttle reliability. An unresolved item is being opened to review this matter as part of the NRC closeout inspection of the Ginna MOV program **(URI 50-244/96-06-03).**

E1.2 Service Water System Reliability Optimization Program

a. Inspection Scope

The inspector reviewed the "Service Water System Reliability Optimization Program (SWSROP)", Revision 2, for the Ginna Station. The inspector's review focused on SW heat exchanger performance testing conducted by the licensee. Specifically, the inspector reviewed the preliminary test reports of several component cooling water heat exchanger tests.

b. Observations and Findings

The licensee developed the SWSROP as an engineered program to address the requested actions of Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and to ensure that the SW system performs its safety functions. The inspector noted that the SWSROP was discussed several times in Section 9.2.1 of the Updated Final Safety Analysis Report (UFSAR) as a document containing programs for heat exchanger performance testing and SW system flushing and cleaning. However, the inspector observed that the SWSROP had not been revised since September 1993 and hence did not reflect the current SW system configuration in many respects. Many modifications had been made to the SW system since then, such as replacement of the SW header gate and butterfly valves. The inspector further noted that a December 1994 licensee SW self-assessment identified six findings and observations where the SWSROP needed revision. The status of the corrective actions regarding these items was designated as incomplete in the licensee's commitment and action tracking system. Discussion with the Nuclear Engineering Services manager indicated that the responsible engineer had been temporarily assigned to the replacement steam generator project and these items were expected to be completed by the end of 1996.

The heat exchanger (HX) performance testing program in the SWSROP included (1) four containment recirculating fan coolers (CRFC) each with 3 coils, (2) four CRF motor coolers, (3) A- and B-component cooling water (CCW) HXs, (4) B-spent fuel pool (SFP) HX, (5) A- and B-emergency diesel generator jacket water HXs, and A- and B-lube oil cooler HXs, and (6) A- and B-standby auxiliary feedwater (SAFW) pump room coolers. Between 1992 and 1995 the licensee had conducted 3 performance tests on each of these HXs, consistent with the request in GL 89-13 to establish an initial HX test program. However, the licensee was still evaluating this data to determine the required frequency of the performance test for each HX as

part of the HX periodic retest program described in GL 89-13. For the 18 sets of HX tests performed, only the first (baseline) test of the EDG HXs had been fully evaluated with an engineering report issued. The remaining 17 sets of data were in various stages of review, except the last test (1995) of the CRFCs and CRF motors coolers for which reviews had not begun. The inspector was concerned with this incomplete status since the licensee's lack of completed reviews of the past HX performance data could challenge SW system operability if degraded conditions were determined to exist upon completion of the reviews. This concern was lessened somewhat for the CCW and EDG HXs, which were inspected and cleaned during the recent refueling outage, and the CRFCs which were replaced in 1993. The Nuclear Engineering Services manager stated that the licensee intended to complete these reviews in 1996.

To evaluate the impact regarding the licensee's lack of completed evaluations of HX performance test data, the inspector reviewed the preliminary CCW HX test reports which evaluated the data gathered from tests conducted in 1993, 1994, and 1995. The inspector conducted a more detailed review of the 1995 preliminary test report that the cognizant engineer had prepared. The required heat transfer capability of the CCW HX is given as 25,150,000 BTU/hr in the UFSAR. The CCW HX manufacturer's specification sheet listed a fouling factor assumption of 0.0005 and 0.001 for the shell and tube sides, respectively, while the clean and in-service overall heat transfer coefficients were given as 774 and 330 BTU/hr-ft$^2$-°F, respectively. The inspector verified that the test reports used this and other design information from the CCW HX manufacturer's specification sheet appropriately in the calculations. However, the inspector had several observations that will require follow-up inspection.

The licensee calculated the fouling factors from the test data to evaluate the adequacy of the thermal performance of the CCW HX. A summary of the fouling factors from the 1993, 1994, and 1995 reports is presented below.

| HX | FOULING FACTORS | | | |
|---|---|---|---|---|
| | | 1993 TEST | 1994 TEST | 1995 TEST |
| "A" CCW | Calculated/Estimated<br>Possible Range Max<br>Acceptable Limit | .00142<br>-<br>.001916 | .00126<br>-<br>.001916 | .0016<br>.0010 - .0023<br>.001916 |
| "B" CCW | Calculated/Estimated<br>Possible Range Max<br>Acceptable Limit | .00030<br>-<br>.001901 | .00233<br>-<br>.001901 | .0014<br>.0013 - .0016<br>.001901 |

The three fouling factor values in the table were developed as follows:

- Calculated/Estimated: The calculated fouling factor values were obtained from the licensee's "HTX2" computer program based on the test data gathered. Twenty-two data sets were obtained for the 1995 test with a fouling factor calculated for each data set. The resultant fouling factors were further evaluated to arrive at the most likely fouling factor, i.e. the estimated fouling factor.

- Possible Range: Based on the scatter of the data results, the licensee determined a possible range of low/high fouling factors.

- Max Acceptable Limit: In addition to accounting for the resistances of the tube wall metal, tube wall fouling, film coefficients, and margin, the licensee incorporated into the max acceptable fouling factor limit an allowance for the number of tubes known to be plugged - 19 and 24 plugged tubes for the A- and B-CCW HXs respectively.

The inspector discussed these 1993, 1994, and 1995 results with the cognizant engineer who recommended that additional thermal performance tests be conducted each refueling outage to obtain more reliable data before lessening the test frequency. The inconsistency of the B-CCW HX data was of most concern. While the 1995 fouling factor data appeared to be acceptable, it did not explain the 1993 data which evidenced unrealistically low fouling factors, and the 1994 data which estimated the fouling factor to be above the max acceptable limit. The cognizant engineer determined the 1994 results to be inconclusive in light of 1993 and 1995 data. While the A-CCW HX data appeared to be acceptable and fairly consistent as compared to the B-CCW HX, the upper range of the fouling factor was given as .0023 which was above the max acceptable limit. This area will require follow-up inspection.

The inspector determined that inspection, cleaning, and repair activities for both CCW HXs during the past refueling outage evidenced tube blockage problems that were not reflected in the above calculations. Some macrofouling was observed in the inlet heads for both CCW HXs and an allowance for this condition was not included in prior calculations. Specifically, foreign material was blocking about 10 tubes in each HX. Also, tube wall pitting was detected, based on eddy current indications, and required additional tube plugging such that the A- and B-CCW HXs now have 42 and 25 plugged tubes respectively. The licensee had issued Action Reports (ARs) 96-0330 and 96-0331 to determine the apparent causes and to take appropriate corrective actions. In discussing these ARs with the CCW system engineer, the inspector noted that the AR resolution described a tube plugging limit of 102 tubes (9% of 1110 tubes), which would still afford 100% heat transfer capability. The inspector observed that the use of this plugging criteria without appropriate consideration for any macrofouling

during service would not be conservative. This area will require follow-up inspection.

The cognizant engineer had also served as the reviewer of the 1993 and 1994 CCW HX test reports which had been prepared by another engineer no longer employed by RG&E. Several errors were found in these reports by the cognizant engineer and these same errors could have been made in the other HX test reports. For example, the effect of plugged tubes was not incorporated into the acceptance criteria for the fouling factors. Also, the report preparer had incorrectly used the parallel flow option in lieu of the counterflow option in the "HTX1" computer program for calculating fouling factors. This area will also require follow-up inspection.

c. Conclusions

The inspector concluded that follow-up inspection was required in several areas:

- The SWSROP was significantly out-of-date and should be revised to reflect the current SW system configuration.

- The licensee has not fully evaluated the 1993, 1994, and 1995 data regarding HX thermal performance tests. The Nuclear Engineering Services manager indicated that the engineering reports regarding these tests would be completed in 1996 consistent with the licensee's GL 89-13 commitment to complete the initial HX test program.

- Upon review of the initial draft of the 1993 and 1994 CCW HX test report, the licensee identified several errors, such as not incorporating the effect of plugged tubes into the acceptance criteria for the fouling factors. These specific errors need to be corrected. Also, other HX reports need to be reviewed to determine if similar errors exist.

- The licensee's performance calculations of the CCW HXs had not accounted for possible macrofouling in the SW side of the HX. Also, possible macrofouling was not being considered when establishing the maximum number of plugged tubes for the CCW HXs. While these comments refer to the CCW HXs, the licensee should review the applicability of these comments to the other HXs cooled by the SW system.

  Pending licensee actions to resolve these issues and NRC review of the resolution, this item is unresolved **(URI 50-244/96-06-04)**.

E1.3 Replacement of SW Piping to Safety Injection Pump Thrust Bearing Coolers

a. Inspection Scope

The inspector reviewed the licensee's procedures for assuring adequate SW flow to the safety injection (SI) pump thrust bearing coolers. This review included recent

licensee corrective actions taken to replace the piping supplying SW to the three SI pump thrust bearing coolers.

b. Observations and Findings

The Surveillance requirements in the SWSROP include periodic monitoring of required flows through safety-related HXs cooled by SW and inspection of SW piping for degradation. Ginna Station Procedure PT-2.1S, "Safety Injection Pump Service Water Cooler Discharge Flow Check," implemented this flow requirement for the SI pump thrust bearing coolers by performing a semi-annual test to determine if the UFSAR required flow of 3 gpm was being met. The licensee observed that the flow was approximately 7 gpm during the last two tests and had been trending down. Also, during the recent refueling outage, as part of the erosion/corrosion program, the licensee's inservice inspection group radiographed this piping and recommended that the piping be replaced. This inspection point was one of approximately 30 SW piping inspection points performed during the outage. The licensee completed this emergent work task during the outage. In discussing the work performed with maintenance personnel, the inspector learned that visual inspection of the original 3/4-inch piping evidenced significant blockage throughout most of the piping internal diameter, while the 1-inch piping back to the 3-inch header was blocked about 50%. After pipe replacement, post modification testing evidenced a flow of approximately 17 gpm through the coolers.

c. Conclusions

The licensee's erosion/corrosion program was effective in detecting degradation in the SW piping serving the SI pump thrust bearing coolers. The licensee took prompt corrective action to replace the degraded piping and thereby assured that design flows would be met. Appropriate surveillance tests have demonstrated adequate flows through the SI pump thrust bearing coolers.

E1.4 Startup Testing of Replacement Steam Generators

a. Inspection Scope

The inspector reviewed the licensee's procedures developed to monitor the performance of the replacement steam generators (RSGs) during plant startup.

- Procedure SM-10034-7.21, "Steam Generator Replacement Start-up Testing, Reactor Coolant System (RCS) Flow Differential Pressure Verification"

- Procedure SM-10034-7.22, "Steam Generator Replacement Start-up Testing, Advanced Digital Feedwater Control System (ADFCS) Tuning"

The review included inspector observation of portions of this testing at 75% power.

b. Observations and Findings

The RCS flow procedure SM-10034-7.21 was developed to verify and, if necessary, adjust the six RCS elbow tap flow transmitter calibrations so that 100% flow would be indicated at 100% nominal power conditions. The major portion of the review involved the ADFCS tuning procedure SM-10034-7.22, which was developed to verify and identify required adjustments to the ADFCS and thereby assure stable level control of the RSGs.

The inspector observed the review of these RSG startup test procedures by the plant onsite review committee (PORC), such as their comment emphasizing the need for close test coordination with control room personnel during the ADFCS tuning test. The responsible test engineer, who evidenced a good understanding of the technical requirements, briefed the PORC members regarding the conduct of the proposed tests.

The best estimate of RCS flow at 100% power was 91,000 gpm per steam generator with the original steam generators (OSGs) while 93,500 gpm was expected with the RSGs. The licensee performed calculations to determine the new calibration spans for the RCS flow transmitters to produce an indication of 100% flow at 100% power. The RCS flow procedure SM-10034-7.21 was then used to record the flow transmitter outputs at 350°F, 533°F, and at 100% power, and to make adjustments to the instrument calibration, if necessary. The inspector verified that the initial data recorded at 350°F and 533°F was within the minimum and maximum values established for the RCS flow transmitter outputs. No adjustments were required based on this initial data.

It was apparent to the inspector that the licensee had thoroughly evaluated the expected secondary side response of the RSGs compared to the OSGs. Several evaluation points included the following:

- The licensee concluded that the secondary side response of the RSGs would be better than the OSGs since every parameter changed led them to believe more stable SG levels (i.e., less shrink and swell) would exist. For example, the downcomer annulus was wider resulting in less frictional pressure drop effects on level instruments and a higher circulation ratio resulted in less subcooling in the downcomer region.

- Analytical information from the vendor per the equipment specification confirmed that the RSGs should demonstrate more stable SG levels.

  The ADFCS tuning procedure SM-10034-7.22 included two tests to be conducted at approximately 30% and 75% power. A 5% feedwater flow increase was input to observe the resultant RSG response. The response was expected to be about a 4% level change. However, review of the plant process computer traces of RSG level, feed flow and steam flow evidenced no discernable shrink or swell during the tests conducted at 30% and 75% power. While the RSG levels were restored to the normal program setpoint

shortly after termination of the test, the test engineer noted that the response of the feedwater regulating valves was sluggish. The valve actuator slightly lagged the valve demand signal causing sluggish operation. The test engineer indicated recommendations to improve feedwater control valve response would be included in the test report to be presented to the PORC.

The inspector observed the actual conduct of the ADFCS tuning test conducted at 75% power on June 14, 1996, and noted that the test was well coordinated with good command and control exercised by the control room personnel in conjunction with the test engineer. A RSG vendor representative was present for technical support during the testing.

The inspector also noted that the licensee had evaluated the RSG secondary side performance in response to a 15% power reduction caused by a turbine trip experienced during plant startup which was not a specific part of the ADFCS tuning test procedure. Review of the RSG level traces indicated about a 3% actual level shrink versus 5% projected, which evidenced good RSG performance during this downpower transient.

c. Conclusions

The inspector concluded that engineering had developed sound test procedures that were used to effectively monitor the performance of the RSGs during plant startup. Cognizant engineering personnel were knowledgeable concerning these tests and had closely coordinated the testing with plant operations personnel while obtaining appropriate technical support from the RSG vendor. Although the final engineering reports for the RCS flow and ADFCS tuning tests had not yet been issued, the preliminary results were in good agreement with the projected values of RCS flow and shrink and swell for the RSGs.

E1.5 Temporary Modifications

a. Inspection Scope (37550)

The inspector reviewed the licensee's procedure for the control of temporary modifications.

b. Observations and Findings

Ginna Station Procedure A-1406, "Control of Temporary Modifications," defines the licensee's process for the evaluation, control, and installation of temporary modifications. A safety review was required for each temporary modification. The temporary modification coordinator issued a monthly status report to plant personnel concerning the status of open temporary modifications. The status report provided useful information for the proper control of temporary modifications, such as separate categorization of leak repair temporary modifications, and also trended the temporary modification backlog for the last 12 months. The inspector reviewed

this status report for the period ending May 1996 and learned that only 13 temporary modifications were outstanding. Most of these temporary modifications were installed in nonsafety-related systems, and none were older than one operating cycle.

c. Conclusions

The inspector concluded that the licensee's temporary modification process was being controlled well.

**E2 Engineering Support of Facilities and Equipment**

E2.1 Major Electrical Modifications Review

a. Inspection Scope (37550)

The inspectors reviewed selected safety-related/important-to-safety electrical and control system design changes implemented in the station to verify their conformance with the applicable installation and testing requirements. The following plant change records (PCRs) were reviewed:

- PCR 96-047: Installation of a voltage regulator at Station 13A on Offsite Power Source Circuit 767 modification.
- PCR 95-046: Service water pump "D" motor replacement modification.
- PCR 94-004: Reactor coolant pump (RCP) seal leakoff flowmeter and transmitter replacement modification.

b. Observations and Findings

Plant Design Change Package Review of New Voltage Regulator at Station 13A on Offsite Power Source Circuit 767

PCR 96-047 was initiated to add a new voltage regulator at Station 13A on one of the two independent offsite power source lines (Circuit 767). The purpose of this new voltage regulator was to improve the Ginna Station electrical distribution system voltage capability and its reliability to supply the plant safety loads during normal and abnormal conditions.

The inspector noted that the licensee had experienced several failures with the second offsite source (Circuit 751) due to its overhead construction design and its being more susceptible to harsh weather conditions. The licensee occasionally realigns the offsite power Line 767 to supply the electrical loads of all safety-related buses under those conditions.

The inspector noted that the installation and testing for the new regulator and associated switches in Station 13A was done by the licensee's Transmission and

Distribution Department (T&D) staff. The licensee's corporate engineering department staff coordinated this modification work with T&D and other station departments. The corporate engineering department completed this PCR to ensure that all the applicable changes and its impact on the Ginna electrical distribution system and procedures was appropriately documented and evaluated.

The inspector's review of the PCR documentation revealed that the licensee had appropriately included the applicable design inputs and a 10 CFR 50.59 safety review. The licensee also performed a design analysis (DA-EE-96-068-03) for the offsite power source's capability to maintain adequate voltage regulation for all of the required station normal and emergency operating conditions. The review of the licensee's completed analysis indicated that, during the initial voltage transient following a station trip, the system voltages would not go below the loss of voltage relay setpoint on the 480 volt buses. The analysis showed that Circuit 767 and Circuit 751 voltage regulators would respond, raising bus voltages above the degraded voltage relay settings within the acceptable time to prevent relay actuation.

The inspector determined that the installation of the new voltage regulator for Circuit 767 would improve the circuit capability to respond to grid voltage transients, and prevent the degraded voltage relays from timing out, which would cause a loss of offsite power to the plant. The inspector found the post-modification tests performed to be appropriate and review of the results indicated no concerns. The inspectors noted that the applicable UFSAR sections were appropriately identified to be updated per the established procedures.

Design Basis Documentation Review

The inspector also reviewed the licensee's design basis documentation and the applicable UFSAR sections to assure that the station was licensed to align the electrical distribution system with a single offsite line during the normal and abnormal plant operating conditions.

During normal plant operation, offsite power Circuit 767 from Station 13A provides power via Station Auxiliary Transformer (SAT) 12B to two of the four plant safety-related 480 volt buses. The remaining two safety-related buses are powered from the second offsite power source Circuit 751 via SAT 12A from Station 204. During normal plant operation, the plant auxiliary loads are supplied from the main generator via Unit Auxiliary Step-Down Transformer 11. The inspector noted that when the unit is tripped, the main generator remains connected to the transmission system for 60 seconds. During this time, the unit's megawatt output decreases rapidly while the generator is still capable of supplying positive MVARs. As a result, the voltage on the 115 kV system line does not change significantly until the generator has separated from the 115 kV grid and the MVAR support from Ginna is gone. The offsite power system supply to the Ginna station can also be configured in a 50%/50% or 100%/0%, either from Circuits 767 or 751, respectively, per established procedures, depending upon the plant and offsite power circuit conditions.

The inspectors' review of the design basis documentation indicated that the Ginna Station was initially licensed with one offsite power line operable from the grid system, and with provision of a delayed backfeed from the 115 kV system. The original design of the offsite power supply consisted of two independent 34.5 kV lines, with each line capable of serving a single 4160 volt SAT. To switch from one line to another required manual operation by the plant operators. SAT-12A served a dual purpose in that it was used as a start-up source and was also a dedicated offsite source for all Class 1E equipment. A spare auxiliary transformer (12B) was installed following original plant startup, but it was not connected. As it existed, the design was less reliable in that the loss of Transformer 12A resulted in the reliance on two onsite emergency diesel generators (EDGs) until such time as the generator startup transformer (GSU) could be backfed through the 115 kV system. Backfeeding the GSU is considered a delayed access source and results in a long-term reliance on the EDGs and batteries for maintaining safe shutdown loads. Should a loss of offsite power occur, it would require about eight hours to change from the existing configuration to backfeed through the GSU.

During the NRC's systematic evaluation program (SEP), the NRC indicated that the 8-hour requirement to reconfigure the offsite systems was not desirable. However, the SEP review concluded that Ginna Station met the General Design Criterion 17 requirements (GDC-17). Although the offsite power system met the requirements of all existing licensing commitments, the operating margin during the licensee's 1989 design review determined that the operating margin was not adequate. Consequently. the licensee revisited its offsite circuit configuration during a design bases review. As stated above, the original configuration of these lines was off transformer 12A, and transformer 12B was a spare. To switch from one line to another required manual switching by the operators. During this review, the licensee found that there was a safety and risk benefit to separate the offsite circuits to their respect transformers in the switchyard, which would increase the available margin of offsite power in the event of a single failure. The licensee decided to use spare transformer 12B for Circuit 767, which gave the Ginna Station a third offsite power source. This was in addition to the backfeed capability from the GSU.

Based on the above review, the inspectors concluded that the Ginna Station was licensed to operate with one offsite power supply from the grid system with a delayed-back feed capability during normal and abnormal plant operating conditions.

Ginna Station Voltage and VARs Flow Review

The inspectors reviewed the RG&E grid system voltage conditions, and the Ginna Station VARS flow conditions (in and out) effect on the station to ensure that no degrading effect exists on the station during normal and abnormal operational conditions.

To review the above issue, the inspectors conducted a tour of RG&E's Energy Control Center (ECC) facility, located in Rochester, New York. The normal offsite power voltage levels are controlled by RG&E's ECC staff. Based on discussion with

the ECC staff and plant engineering department personnel, the inspectors determined that the alarm setpoints for the 115 kV grid system are set approximately at 123 kV (high alarm) and 118 kV (low alarm). The inspectors noted that the Ginna station offsite lines were given a higher priority to improve their system voltage in the event of a low voltage alarm observed by the ECC.

Should a transient occur on offsite power lines, the worst case would be a trip of Ginna Station, in which case the 115 kV system voltage could drop below the low alarm setting (118 kV). If this occurred, the ECC would stabilize the voltage and make the appropriate corrections by adjusting other systems. The voltage support to the local grid that the Ginna Station provides is a function of its "Net MVAR" output. The "Gross MVAR" output includes the MVAR losses in the GSU. When the station is at full power, there are approximately 50 MVARs of losses in the GSU.

During the transfer of power, there are "real" (Watts) and "imaginary" (VARS) power losses on transmission line circuits. In addition to power losses, voltage drop occurs across transmission lines when power is transferred across them. These losses and voltage drop are directly related to the magnitude of transmission line current impedance. Watt losses result from the resistance of the circuit and VAR loses from the reactive component. The reactive impedance consists of inductive and capacitive components. The inductive component increases as line current increases. The capacitive component is independent of line current. When these components are equal, the transmission line impedance becomes purely resistive and VAR losses are zero. In addition, the line current is lowered, which reduces the line's voltage drop.

Electric load generally requires VARS. VARS are supplied by electric generators or by installed capacitor banks on the system. Capacitor banks are normally placed near electric load centers, which reduces the need to transfer VARS across transmission lines. This results in reduction in line current, which reduces the voltage drop and transmission line inductance. Therefore, when capacitors are "switched in" at a substation, voltage immediately rises, i.e., less voltage drop in the substation feeder lines.

To ensure adequate voltage levels at the end of the transmission line when a large-power (Watts and VARS) transfer occurs, VAR support is required along transmission paths. At low power transfers, transmission line voltage tends to increase and additional VAR loading is required along a transmission path. VAR support is supplied by generators or capacitors. VAR loads are loads supplied by generators. To ensure the adequate voltage conditions, it is common to operate generators in such a way in local regions to adjust generator VARS during large load swings and power flow to maintain acceptable voltage on the grid system.

The inspector noted that the Station 122 is one of the two substations where the cross-state 345 kV system meets. (345 kV transmission line and the 115 kV transmission lines that feed RG&E system loads). Based on discussion with the licensee, the inspector determined that, since June 1996, the RG&E had installed a

75 MVAR capacitor bank at this substation on the 115 kV line to stabilize grid voltage. This capacitor bank is used by the ECC to provide voltage support for the RG&E system, which lessens the dependency on Ginna station. This capacitor bank is "switched in" to provide VAR support for the region when the grid voltage is low during the peak loading hours. Before the installation of this capacitor bank, when the grid voltage was low (during peak loading periods), the ECC would call the Ginna Station to generate more VARS, which would result in increased voltage from the Ginna station to stabilize grid voltage. If the grid voltage were high due to less power consumption at night, the ECC would have Ginna take more VARS in to stabilize the voltage. Based on discussion with the licensee, the inspector determined that the Ginna Station was providing VARs support (approximately up to +/-110 MVARS and approximately +/-2 kV) to stabilize the grid voltage prior to the installation of this capacitor bank. Since the Ginna Station was the only power station in this quadrant of NY State that could have an immediate effect on stabilization of the local grid, the station was supplying excessive MVARS.

The inspector determined that with the installation of a new 75 MVAR capacitor in the RG&E system; and new guidance in place to first utilize the 75 MVAR capacitor bank to stabilize grid system voltages, the ongoing frequent significant increase and decrease in the MVARS flow from station would be substantially reduced or minimized. The inspector estimated that net MVAR output from Ginna station to be approximately 40 MVARs, and thus would eliminate the requirement for Ginna to operate at 110 Net MVARs output in peak hours in the future. As a result, this will require less excitation of Ginna's main generator and make it more efficient and reliable to support plant safe operation.

The inspector concluded that by taking the above appropriate corrective actions, the licensee has enhanced the overall Ginna station offsite power line system reliability and system voltage conditions for safe operation of the plant.

D-Service Water (SW) Pump Motor Replacement Modification

As documented in NRC Inspection 50-244/95-15, after the D-SW pump motor failed several times, the licensee decided to upgrade the existing 300 HP motor with a 350 HP motor. The failures were attributed due to the motor being run at its service factor rating (approximately 310 HP) for a prolonged period of time, which resulted in a degraded condition. The existing motor was located in the screen house area and had Class H-type insulation rated for 311°F. The upgraded motor would have Class F insulation-type rated for 350°F. The licensee procured this motor as commercial-grade and then dedicated it for safety-related use.

PCR 95-0046 was initiated by the licensee to replace the existing 300 HP motor with a new 350 HP motor. The PCR included a detailed design input/output form, a 10CFR50.59 safety evaluation, and a design analysis (DB-EE-95-129-06) to justify the difference between the existing and new motor and the potential effects on the plant systems. The current inspection focused primarily on the electrical portion of the design changes, since other aspects were already reviewed in previous inspections.

The inspector's review of the design documents indicated that the following key electrical parameters were different between the two motors:

| KEY PARAMETERS | EXISTING MOTOR | NEW MOTOR |
|---|---|---|
| Horsepower | 300 HP | 350 HP |
| Full Load Ampere | 346 | 380 |
| Locked Rotor | 2,197 | 2,481 |
| Efficiency | 92.9% | 94.5% |
| Nameplate Voltage | 440 | 460 |
| Insulation Class | H | F |

The inspector noted that in the above analysis (DB-EE-95-129-06) that the licensee evaluated the potential effects of new motor parameters such as the inrush, full load, and fault currents; motor acceleration time; steady state and dynamic responses during accident-load sequencing; and degraded voltage performance during normal and accident conditions. Review of the short circuit analysis indicated that under the worst-case loading conditions, the new motor net short circuit current would be increased approximately 298 amperes. This was found to be within the existing bus and breaker-interrupting ratings. The prefault voltage at the faulted bus (1.05 PU) considered in this analysis was conservative. The inspector also verified that the existing breaker trip settings and the new motor's coordination with other breakers was not effected.

The load on the diesel generator of the new motor was found to be slightly less than 2% of the existing considered load. This change in load was attributed to increased efficiency in the new motor design. The dynamic response analysis performed using the "ETAP" program on the B-EDG during accident load sequencing, considering worst possible timer tolerance during starting of Steps 2 and 3 loads, indicated that the new motor was capable of accelerating successfully. The inspector noted that the EDG frequency and voltage would be within 95% (57 hertz) and 75% (360 volts) of the acceptable requirements of Regulatory Guide 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants." The loss of voltage relay setpoint and voltage dips duration was found to be less than the UV time delay setpoints, as plotted in the licensee's simulated analysis.

The inspector found the design modification documentation, including the design input/output form, 10CFR50.59 safety review, specialty groups review, and the post-modification test results to be in conformance with the licensee's established procedures. The inspector performed a walkdown of the new pump installation and found it consistent with the design change drawings, and observed that the new D-SW pump was operating relatively cooler than the other SW pumps.

Based on the above review, the inspector concluded that the design change package was thorough and well supported with technically sound analysis in conformance with the licensee's applicable procedures.

Reactor Coolant Pump (RCP) Seal Leakoff Flowmeter and Transmitter Replacement Modification

PCR 94-004 was initiated to replace the existing RCP seal flowmeter and associated transmitters due to a lack of availability of spare parts. In addition, the RCP seal leakoff piping was modified to accommodate the new flowmeter.

During normal plant operating conditions, the RCP seal leakoff flowmeter and transmitters provide flow indication in the main control room. These components also provide data to the plant computer system.

The inspector's review of the design change package revealed no concerns. The inspector determined that the replacement components selected for the system satisfied the design basis requirements, such as the maximum RCP system design pressure, temperature, and the flow conditions in this case, and were found to be consistent with the UFSAR, Section 5.4.1 requirements. The inspector found the plant modification package was thorough with sound technical basis and in conformance with the applicable procurement, installation and testing requirements.

c. Conclusions

Overall, the design modifications were of good quality, well supported with sound design basis technical information and in conformance with established control procedures. The inspector noted that the licensee had made sound decisions to enhance the overall reliability of the offsite power supply and the service water systems by adding a new voltage regulator in Circuit 767 and by replacing the existing degraded D-SW pump motor. In addition, adding the 75 MVAR capacitor on the 115 kV line could also reduce the dependance on the Ginna Station for MVAR's and would enhance the station's system reliability for safe plant operation.

E2.2 Design Review of Instrument Buses and Twinco Panels

a. Inspection Scope (37551)

The inspector reviewed the design analysis of new digital voltage meters for the instrument buses and "Twinco" panels. Also, the inspector conducted interviews with engineering personnel associated with the replacement meters.

b. Observations and Findings

During the last refueling outage, the instrumentation and controls (I&C) department found meter inaccuracies on the instrument buses and the Twinco panels during calibration testing. These buses and panels had inverters that produce harmonics which were induced in the existing analog meters causing the meters to be inaccurate. Also, the existing analog meters were not accurate enough to meet the new ITS surveillance requirements (SR 3.8.9.1), so the licensee initiated procedure 06.11, Attachment 9, "Testing Instrument Buses and Twinco Panels." This

procedure required digital testing of the instrument buses and Twinco panels to meet the ITS requirements.

The inspector verified that Procedure 06.11, Attachment 9, was in accordance with ITS SR 3.8.9.1. The inspector verified that this procedure became effective on February 21, 1996, and was coordinated with the ITS, which was implemented on February 24, 1996. The inspector sampled licensee logs from March 13, 20, & 27, 1996, and verified that the readings were within SR 3.8.9.1 requirements. The inspector confirmed that the licensee has procured new digital AC voltmeters that are to be accurate to 1/2 percent (0.005). Installation is scheduled to begin after QC has inspected the new meters.

The inspector interviewed the design and system engineers for this project to discuss the implementation of Procedure 06.11, and to determine if there were any other meters that would have this type of problem. The system engineer stated that there were no other meters in the plant that had this type of problem. The inspector and design engineer reviewed DWG 03201-0102, and Inner-Office Correspondence, dated April 23, 1996, "Operating Voltage of Twinco Panels," and PCN A-601, Revision 39, effective on February 21, 1996, which dealt with the harmonics issue in the inverters. Procedure 06.11, Attachment 9, was modified and put into effect to supplement the IST requirements until new digital meters could be installed. The Procedure was implemented before the IST became effective on February 24, 1996. The design engineer stated that there were 2 Twinco units not in use and that are in the process of being evaluated for upgrading and use as spares.

c. Conclusion

The inspector concluded that the analysis was in accordance with applicable codes and standards referenced in the design documentation. These included IEEE-336-1971, "Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations," and NEC-70-1993, "National Electric Code." The design and system engineers displayed a high level of technical competence during the interviews and the design reviews.

## E3 Engineering Procedures and Documentation

### E3.1 Modification Procedures

a. Inspection Scope (37550)

The inspector assessed RG&E's process for performing and controlling plant modifications. This review included discussions with RG&E management and engineering personnel, review of selected plant modification procedures, and detailed review of four selected plant modifications.

b. Observations and Findings

RG&E has a plant change process Interface Procedure, IP-DES-2, that provides a comprehensive step-by-step description of the plant change process and identifies applicable plant procedures. The inspector determined that this interface procedure contains excellent guidance to facilitate engineering personnel's understanding of the modification process including installation, testing, and turnover process.

Plant changes are initiated by the licensee after an evaluation is conducted in response to a technical staff request (TSR), an engineering work request (EWR), action report (AR), maintenance work request (WR/TR), material request (MR), or purchase requisition (PR).

The PCR packages reviewed were complete, implemented per appropriate plant procedures, and received the appropriate level of review and approval. Design input documents provided good technical descriptions of the modifications and accurately reflected the system design basis described in the updated final safety analysis report (UFSAR). The 10CFR50.59 evaluations were technically adequate. The appropriate procedures, drawings, design basis documents, and sections of the UFSAR were revised to reflect the modifications.

c. Conclusions

RG&E demonstrated good performance in developing and implementing plant modifications in accordance with plant procedures and applicable regulatory requirements.

E3.2 Review of Electrical Equipment Failure Action Reports (ARs)

a. Inspection Scope (37550)

The inspector reviewed the following selected ACTION Reports (ARs) dealing in various electrical component problems to assess the overall effectiveness of the AR process. The review included root cause determinations and corrective actions identified and implemented to resolve these problems.

- 96-0315, A-EDG - Rated Load Achievement Problem
- 96-0408, 4 kV Protective Relay Setpoint Concern
- 96-0478, #17 Transformer Worn and Loose Insulator Problems
- 96-0547 & 0313, Design Discrepancy Problems
- 96-0095 & 0096, Fuses Failed the Procurement Order Requirements During the Test Verification Process
- 95-0029, Turbine Runback Logic Issues and the Licensee's Corrective Actions Resulting From a Loss of DC Bus "B" and "D" Following a Loss of Offsite Power Line 751 (discussed in NRC inspection report 50-244/95-13).

b. Observations and Findings

The inspector's review of the above ARs indicated that all component problems were appropriately dispositioned. The inspector found that the licensee performed a comprehensive root cause analysis, where applicable, to address these plant issues. The licensee's efforts which identified the fuse failure (AR96-0095) to meet the time current characteristics were noteworthy. The engineering staff identified the fuse deficiency and corrected the manufacturer's fuse production process. The licensee also promptly completed appropriate corrective actions such as completion of a required evaluation of the previously-identified concern with control rod withdrawal during the loss of offsite supply line 751, that resulted in momentarily loss of 125 Vdc bus B (documented on the AR 95-0029). A brief discussion of selected significant ARs is provided below:

AR 96-0095

AR 96-0095 was issued on February 13, 1996, to document discrepancies identified in Bussman-type fuses during a commercial-grade dedication testing process. The licensee determined that the Bussman-type LPN-RK-40SP 40A fuses failed to meet the 135% trip time requirements (within 60 minutes), as specified in RG&E's Specification EE-100 and the fuse manufacturer's published data. The licensee found other time-current trip parameters within the requirements and requested the fuse manufacturer to evaluate the cause of these failures. Further evaluations performed by the manufacturer confirmed that the nonconformance problem did exist with the subject fuses. This condition was due to the manufacturer's component part being skewed to the upper specification limit by the manufacturer, and that explained why it would cause a fuse not to blow within the 60 minute time limit at 135%. As a result of this finding, the manufacturer issued an engineering change notice (ECN) and changed the heater strip design to ensure conformance to all test parameters.

AR 96-0315

AR 96-0315 was issued on April 20, 1996, when the A-EDG was unable to achieve its short-term-rated load of 2300 kW at a 90% power factor during surveillance testing. The EDG could only be loaded to 2250 kW at a 90% power factor. 2300 kW is much higher than the 1999 kW accident load requirements stated in UFSAR. A comprehensive evaluation and further testing of the EDG demonstrated that it did achieve the expected 2300 kW rating. The licensee concluded that excessive voltage was on to the bus, and that the current transformer was in the higher range of the saturation area. These conditions apparently caused the power meter to be inaccurate. Since the EDGs are not usually tested at this higher rating, the existing condition was found acceptable. The licensee initiated an engineering work request (EWR-10425) to evaluate the need to upgrade the existing meters in the control room.

AR 95-0029

As documented in NRC Inspection Report 50-244/95-13, instrument bus B lost power for approximately 10 seconds as a result of a loss of offsite power circuit 751 on June 30, 1995. The delta-T runback logic modification (TSR 94-139) functioned as designed and no turbine runback occurred. However, approximately eight seconds after the power was restored to the bus, a control bank of control rods began to automatically withdraw. The licensee's investigation determined that no malfunction existed, but that the outward rod motion was an unanticipated consequence of the delta-T runback logic modification. At that time, the licensee took action to increase the reliability of electrical power to instrument bus B, and was in the process of revising one procedure.

To address this issue, the licensee initiated AR 95-0229 on July 28, 1995. An evaluation reconfirmed that the rod control system operated as designed. The licensee determined that prior to the installation of this modification, a turbine runback would have occurred during this event. If the primary temperatures would have been elevated, no outward rod motion would have occurred. The outward rod motion that occurred was unexpected by operations. It also appeared that this change in plant response may have not been realized or reviewed during of the modification design process. Thus, no training of operations personnel occurred for this change in plant response. The licensee concluded that this may be a shortcoming in their modification program. An action item was assigned to engineering to evaluate this concern.

Engineering also reviewed the modification process and determined that the existing plant change request (PCR) process in place at that time (described by procedure EP-2-P-102) was open to interpretation. Since then, the licensee has issued a new design change procedure (IP-DES-2), where appropriate guidance was added to eliminate the possibility of different interpretation of responsibilities of assigned engineers. The inspector reviewed this procedure and noted that the licensee had appropriately clarified it to eliminate the potential of different interpretation of assigned responsibilities of the modification engineer.

c. Conclusions

Overall, the inspector concluded that the licensee had a very effective corrective action program, good root cause determinations with sound technical bases. The above issues were resolved appropriately and in a timely manner. The resolutions of problems associated with the fuses (identification of not meeting time current characteristics as claimed by the manufacturer) and corrective actions to address an old issue dealing with the effects of loss of offsite Circuit 751 were appropriate.

E3.3 UFSAR Review

While performing the inspections discussed in the Engineering Section, the inspectors reviewed the applicable portions of the UFSAR and found no concerns with the UFSAR-related issues. The design modifications and other corrective

actions appropriately refer and use the design basis requirements. All above modifications packages had identified and included the appropriate UFSAR changes to be incorporated in the UFSAR as required.

## E7 Quality Assurance in Engineering Activities

### E7.1 Independent and Self Assessments

a. Inspection Scope (37550)

The inspector reviewed licensee efforts regarding the following self and independent assessment activities.

- Nuclear Safety Audit Review Board Open Item 214-01 - Assessment of the overall Integration Adequacy Involving Issues Relative to the Steam Generator Replacement Project and Operational Readiness
- Status of Licensee Efforts Regarding Followup Actions to the Findings of the December 1994 Service Water Self-Assessment
- Quality Assurance Audit of Configuration Control Program

The inspector reviewed documentation associated with each assessment and discussed the assessment results with cognizant licensee personnel.

b. Observations and Findings

Nuclear Safety Audit Review Board Open (NSARB) Item 214-01 - Assessment of the Overall Integration Adequacy Involving Issues Relative to the Steam Generator Replacement Project and Operational Readiness

During a January 1996 meeting, the NSARB requested that an integrated assessment be conducted prior to startup concerning the incorporation of the Ginna Station improved technical specifications (ITS) and three major design changes - namely, the replacement steam generators, RCS reduced Tavg operation, and new 18-month fuel. The Nuclear Engineering Services (NES) manager had the overall responsibility for executing this task, which was identified as NSARB open item 214-01. The assessment culminated with a presentation of the technical issues given at an NSARB meeting on May 21, 1996. Based on discussions with several presenters, including the NES manager and a review of the meeting minutes, the inspector determined that the assessment team conducted a thorough effort during a high activity period. No major flaws were found in the design changes or their integrated relationship. While the assessment was conducted with predominantly licensee personnel, an element of objectivity was afforded by utilizing the services of a contractor with experience in startup activities involving instrumentation and control changes. The NSARB effort was viewed as proactive in requesting this integrated assessment.

Status of Licensee Efforts Regarding Followup Actions to the Findings of the December 1994 Service Water Self-Assessment

In December 1994 the licensee conducted a self-assessment of the status of actions being taken to resolve the open items identified during an NRC service water system operational performance inspection which was performed in December 1991. The self-assessment also compared the effectiveness of procedures in place at Ginna, such as the SWSROP, to address industry problems concerning service water systems. The self-assessment had identified many open items that were included in the licensee's commitments and action tracking system.

The licensee has performed poorly in addressing the many open items identified during the December 1994 self-assessment. The inspector discussed this comment with the NES manager who indicated that the lack of completion of the open items was due to resource allocation conflicts with the replacement steam generator project. Fifteen items still remained open as listed in the licensee's commitments and action tracking system. The major technical issues are related to HX performance testing as discussed in Section E1.2 of this report.

Quality Assurance Audit of Configuration Control Program

This audit was conducted in November 1995 by the licensee's quality assurance (QA) group to evaluate RG&E's engineering capabilities in controlling activities at Ginna involving planning, implementation, and turnover of completed modifications. Based upon discussions with licensee personnel associated with the audit and a review of the audit report, the inspector determined that the audit was constructive toward improving the relatively new plant change record (PCR) process. For example, an audit observation noted some weaknesses in the change impact evaluation form associated with the PCR process. Corrective actions to address these weaknesses should improve the implementation of design changes with proper consideration given to their impact on existing engineered programs, such as inservice testing. Five reports were issued to capture the findings from the audit and to ensure that appropriate corrective actions were taken.

c. Conclusions

The inspector concluded that the licensee's performance was mixed regarding several self and independent assessments of engineering activities. The integrated assessment requested by the NSARB prior to startup and the QA audit of the configuration control program were proactive efforts that provided added assurance to ongoing engineering work. The licensee has not performed well in addressing the issues identified in a December 1994 SW system self-assessment since 15 open items still exist.

E8 Miscellaneous Engineering Issues (37550)

E8.1 (Closed) URI 50-244/91-201-07: Single Failure of Service Water Pump Discharge Check Valve

This unresolved item was identified in an NRC service water system operational performance inspection wherein the ability of the service water system design to withstand a single (fail-open) failure of a SW pump discharge check valve was questioned. The item had been updated in NRC Inspection Report 50-244/94-24 which left the issue open pending completion of the licensee's review of a contractor (Bell Engineering) report. The inspector determined that the licensee completed the review of the applicable Bell Engineering Report 9014-NE-001, "Single Active Failure Analysis of the R.E. Ginna Station Service Water System," Revision 1, dated August 1, 1995. This report, which the licensee submitted to the NRC on September 21, 1995, noted that the SW system was capable of sustaining a stuck open pump discharge check valve and maintaining sufficient flow to necessary components. This item is closed.

## IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Station Radiological Surveys

a. Inspection Scope (83750)

The inspector reviewed selected radiological surveys of the station performed during the first half of 1996. The review evaluated the surveys with respect to procedure requirements and assessed the quality of the results.

b. Observations and Findings

The licensee has established radiological area survey frequencies of weekly, monthly, semi-annually, and yearly. For all areas sampled, the inspector found that the survey requirements were met. No discrepancies were noted.

c. Conclusions

In general, the surveys were of good quality, and indicated relatively low dose rates and contamination levels in the plant.

R1.2 Radiation Work Permits (RWP) (83750)

The inspector reviewed the RWPs active during this inspection and observed a very good level of specific radiological control was prescribed for radiologically-significant tasks. Of particular note, the licensee has established an emergency RWP to allow prompt, but controlled response in the event of an emergency; and an RWP for emergency workers obtaining post-accident samples. The licensee generally utilized

electronic dosimeter setpoints effectively; however, the inspector noted one RWP (96-1005) that specified a very low integrated dose setpoint with a very high dose rate setpoint, which was not mutually consistent. The licensee stated that this RWP would be reevaluated and revised as necessary.

R1.3 Radwaste Generation (86750)

Due to several licensee initiatives to reduce radwaste, the amount of radioactive waste for offsite burial has trended down significantly over the past several years as indicated below:

| | | | | | |
|---|---|---|---|---|---|
| 1989 | 9118.9 | $ft^3$ | 1993 | 1697 | $ft^3$ |
| 1990 | 7279 | $ft^3$ | 1994 | 1103 | $ft^3$ |
| 1991 | 2180.2 | $ft^3$ | 1995 | 617.3 | $ft^3$ |
| 1992 | 2162.5 | $ft^3$ | | | |

This record of radwaste reduction was very commendable and was the result of a strong and aggressive station-wide program of controlling and limiting the generation of radioactive waste.

R1.4 Radwaste Streams, Sampling and Analysis

a. Inspection Scope (86750)

The inspector reviewed the licensee's sampling and characterization of each solid radioactive waste stream through the review of records and through interviews with applicable licensee staff.

b. Observations and Findings

Radioactive liquids entering the waste disposal system of the plant are collected in sumps and tanks, are periodically sampled and analyzed and, depending on established release criteria, are either recycled in a plant system, are discharged from the plant, or enter the liquid radwaste processing system. Most of the radioactive liquids discharged from the reactor coolant system are processed and retained inside the plant by the chemical and volume control system. This minimizes liquid input to the waste disposal system which processes relatively small quantities of generally low activity level wastes. Processing the liquid wastes results in the deposition of radioactive contaminates on cartridge filters, on the surfaces of ion exchange bead resins, in the form of sludges, and contaminated oils. There are six types of solid waste generated by the licensee. These include: liquid radwaste system bead resin, primary system bead resin, sludge, oily waste, filters, and trash known as dry active waste (DAW). Bead resins, sludge, and filters are transferred into polyethylene liners and dewatered prior to storage on site. Oily waste and DAW are sent to an offsite vendor for processing.

Primary bead resin is collected in the spent resin storage tank. Prior to sampling this waste stream, the contents of the spent resin storage tank are mixed utilizing

an air sparger system. The liquid radwaste system, which consists of a charcoal filter and five 15 $ft^3$ demineralizer vessels, deposits its spent resin in a 200 $ft^3$ polyethylene storage liner. This waste stream does not have a method for mixing its contents prior to sampling. During final transfer to a shipping liner, the licensee valves off a composite sample at the beginning, middle and near the end of the resin transfer. The inspector noted that each shipment would contain approximately 10-12 layers of stratified resins in the liner and that valving off a composite during three arbitrary times during transfer would not necessarily provide a representative sample for this waste stream. The licensee indicated that fairly uniform dose rates are obtained from a completely filled liner and therefore differences between resin layers was not expected to be very significant. Based on the uniform radiation levels, the inspector's review indicated that the characterization of the waste appeared to meet applicable criteria established by the NRC. The licensee indicated they will review potential improvements or enhancements for the characterization of the waste. All other waste streams were appropriately sampled and were accurate representations of each waste stream.

Due to the low production of solid radioactive waste at Ginna, shipments of each waste stream do not occur every year except for dry active wastes. The inspector verified that the biennial requirement for class A wastes were met for this waste stream. All other waste streams are sampled and characterized for each liner shipment being made. The licensee owns a large cylindrical shield for storing a shipping liner of solid radioactive waste until the offsite laboratory analysis results are obtained. After the wastes are subsequently characterized, the radioactive waste contents are determined for each shipping liner. The inspector verified that for each waste shipment for the previous two years, a waste sample characterization had been performed in accordance with the applicable Branch Technical Position.

The licensee utilizes the RADMAN computer program to process the sample analytical results and derive applicable scaling factors for the difficult to measure radionuclides in the waste material. The RADMAN program was reviewed as a topical report by the NRC and has been found acceptable to derive applicable scaling factors and to correctly determine waste classifications. The inspector verified that the new A1 and A2 limits (as specified in 49 CFR 173.435) for determining Type A and B package requirements were updated in the current RADMAN software utilized by the licensee.

c. Conclusions

The licensee appropriately segregated solid radioactive waste streams by sampling and characterizing each for radionuclide content. The sampling of the liquid radwaste system spent resin and charcoal wastes could be enhanced to ensure accurate waste characterization is always obtained. The licensee provided timely waste stream analyses within the time constraints specified in the NRC "Low Level Waste Licensing Branch Technical Position on Radioactive Waste Classification," dated May 1983. No other discrepancies with radwaste stream sampling or waste characterization were noted.

R2 **Status of Radiation Protection and & Chemistry (RP&C) facilities and Equipment (83750)**

During this inspection, the inspector conducted numerous tours of the plant during operating conditions and noted that all required radiological postings were established and high radiation areas were controlled in accordance with regulatory requirements. The areas were clear of unnecessary equipment and free of safety hazards.

R2.1 Onsite Radioactive Material/Waste Storage

a. Inspection Scope (86750)

The inspector observed the principal solid radioactive material storage locations at Ginna station and reviewed the radiological posting and control aspects of the storage conditions.

b. Observations and Findings

Due to the current availability of offsite low level radioactive waste disposal, the licensee's onsite interim radwaste storage facility was not in use. The inspector verified that it was empty.

The upper radwaste storage facility was used for the collection and temporary storage of solid radioactive wastes prior to shipment offsite and is used as a staging area for loading of radioactive waste shipments. At the time of this inspection, this building was well maintained with less than complete shipments of various waste types and all radwastes were packaged appropriately in containers that were externally free of removable contamination, clearly posted, and accurately inventoried by the radwaste staff. Outside of this building, located on the north wall, were several B-25 metal storage boxes. Three of these boxes were not correctly marked, as out-dated radioactive material stickers continued to indicate dose rate and contamination levels associated with the boxes and the same boxes had other markings that indicated they were empty. The licensee verified that each of the boxes were empty and defaced the invalid radioactive material stickers.

The drumming station, located on the operating floor of the auxiliary building, was a third location where some high radiation area wastes (used detectors) were stored. The inspector noted that this area was posted as a high radiation area and met applicable regulatory requirements. However, the storage area was not controlled by a locked barricade to prevent inadvertent removal of the lead blankets covering the sources. To enhance control of the transportable high radiation area sources, the licensee performed an inventory, closed the existing gate at the drumming station, and locked the area. The area would not have been required to have been locked had the lead blankets been removed.

The inspector toured the plant warehouse and meteorological tower storage areas. Both areas contained minor amounts of radioactive material that were properly

stored. Some of the radioactive material stickers in the meteorological tower storage area had faded due to sunlight exposure and were relabeled by the radwaste group.

The contaminated storage building (CSB) was connected to the Auxiliary Building inside the RCA. This building received contaminated equipment after outages and provided decontamination, monitoring, and some storage capacity for routinely used outage equipment and tools. This building was being well maintained at the time of this inspection. All equipment was stored in clean metal storage containers and generally secured from inadvertent opening. An inventory of equipment was maintained to allow effective reuse of the equipment. No discrepancies were noted with respect to this radioactive material storage location.

The inspector reviewed the radioactive material storage building (RMSB). This building was separated from other plant buildings and was not normally occupied. The building was kept locked and a current inventory of radioactive material was maintained. The radioactive material in this building was effectively stored in metal storage containers that were sealed and labeled. While this building was full, it appeared to be well maintained and controlled. Outside of the RMSB, adjoining the east wall extending along the length of the building, was a shed that had been enclosed by the installation of sliding doors that protected the storage area from the weather. This shed was full of wooden storage boxes containing contaminated scaffold material. There were no safety discrepancies with the storage and control of the RMSB.

c. Conclusions

The licensee demonstrated excellent performance in maintaining limited collection of solid radioactive waste onsite. Only the drumming station was not inventoried or controlled; however, this storage location did comply with all regulatory requirements. All radioactive material storage areas were well inventoried and controlled. Only a few minor package marking discrepancies were observed.

**R3 RP&C Procedures and Documentation**

R3.1 Dosimetry Processing

a. Inspection Scope (83750)

The inspector reviewed the TLD processing NVLAP accreditation status and associated documentation.

b. Observations and Findings

NVLAP accreditation was granted by the National Institute of Standards and Technology through September 30, 1996. The licensee utilized Panasonic TLD model number UD809 for measuring record occupational exposures for normal plant use and TLD model number UD812 for measuring neutron exposures during

containment entries at power. NVLAP testing results, dated February 16, 1995, indicated Panasonic TLD model number UD809 demonstrated excellent performance testing results with a positive bias of 12-14% in the low energy and mixed energy photon categories and more accurate response in the other radiation categories. Panasonic TLD model number UD812 testing results, dated February 16, 1995, indicated failure for category VII for photon/beta radiation mixture. The precision measurement was out of tolerance and required retesting. The licensee readjusted the applicable dose calculation algorithm and retested the UD812 dosimeter in categories IV, V, and VII with excellent performance testing results, dated July 25, 1995.

In addition, the licensee has evaluated the Radose 51R electronic dosimeter against the NVLAP testing criteria in categories IV and IX (high energy photon and angular dependence) with excellent results reported in NVLAP correspondence, dated February 29, 1995. A slight negative bias of 1% was indicated in the photon testing response and a negative bias of 6% due to angular response testing. The Radose 51R electronic dosimeter does not respond to beta radiation and was not tested in this category. Low energy photon response was not tested. The Principal Health Physicist indicated that the type of low energy photon source used in performance testing (continuous beam versus pulse), may affect test results for electronic dosimeters. Testing of low energy photon response is expected to be conducted after clarification of testing laboratory source requirements for electronic dosimeters is obtained from NVLAP.

Review of the latest NVLAP Onsite Assessment Report conducted from March 4-5, 1994, indicated two discrepancies that required correction.

1) There was no procedure established describing actions to be taken if a quality control dosimeter failed its test criteria in a processing file. In response, the licensee revised Procedure RP-TLD-710A, "TLD Reader", to include instructions for comparing QC TLD results and followup actions required.

2) There was no procedure for identifying, documenting, investigating, or resolving TLD anomalous dosimetry results. Subsequently, the licensee revised procedure RP-RDMS-TLD-READS, to include two data comparisons. One that compares TLD and electronic dosimetry results for discrepancies $\geq$10%. The second, compares the four TLD element readings from each TLD and tests for any reading that is greater than a factor of four. The procedure requires documentation and investigation of each TLD discrepancy from the two TLD data comparisons and resolution approval by the Principal Health Physicist.

c. Conclusions

The inspector observed that the NVLAP deficiencies had been properly dispositioned. The TLD processing program was of good quality. Continuing NVLAP testing of electronic dosimeters was considered a good initiative.

R3.2 ALARA Outage Performance

a. Inspection Scope (83750)

The inspector reviewed the licensee's draft ALARA Outage Report and conducted interviews with applicable licensee personnel.

b. Observations and Findings

Based on licensee's data, the inspector compiled the following table of personnel exposure performance during the Spring 1996 refueling and steam generator replacement outage. Based on detailed exposure estimates the licensee had established a steam generator project 1996 outage goal of 106 person-rem and an overall outage goal of 140 person-rem.

Steam Generator Project

| Major Task | Actual Dose (REM) | Estimated Dose | % of Est. |
|---|---|---|---|
| Machine and weld RCS pipe | 25.571 | 31.46 | 81.3 |
| Scaffold use | 10.409 | 9.449 | 110.2 |
| Remove Steam Generators | 9.568 | 16.823 | 56.9 |
| RP coverage | 8.61 | 6.48 | 132.9 |
| Decon & Housekeeping | 7.479 | 9.232 | 81.0 |
| Inspections | 7.198 | 12.497 | 57.6 |
| New Steam Generator support | 4.702 | 4.925 | 95.5 |
| Insulation | 4.677 | 7.671 | 61.0 |
| Pipe end decon | 4.366 | 4.963 | 88.0 |
| Install secondary piping | 3.054 | 5.681 | 53.8 |
| Shielding | 1.759 | 5.86 | 30.0 |
| Temporary services | 1.501 | 2.596 | 57.8 |
| Radiography testing | 1.136 | 2.141 | 53.1 |
| Dome opening/restoration | 0.302 | 0.217 | 139.2 |
| Aux. spent fuel pool cooling | 0.027 | 0.116 | 23.3 |
| Totals (13.1 rem from 1995 outage is not included) | 90.359 | 120.111 | 75.2 |

Other Outage Activities

| | | | |
|---|---|---|---|
| Refueling | 15.209 | 15.713 | 96.8 |
| Mechanical maintenance | 11.489 | 13.212 | 87.0 |
| Inspect/Sample | 5.139 | 7.15 | 71.9 |
| Valve repair | 3.336 | 4.406 | 77.5 |
| Insulation | 3.116 | 1.071 | 209.9 |
| I & C | 2.783 | 3.068 | 90.7 |
| Decon | 2.446 | 4.823 | 50.7 |
| Steam Generator support | 2.183 | 2.365 | 92.3 |
| RP | 2.065 | 2.64 | 78.2 |
| Scaffold use | 1.601 | 1.779 | 90.0 |
| Electrical | 1.304 | 0.852 | 153.0 |
| Others | 9.713 | 12.732 | 76.3 |
| **Totals** | 60.384 | 69.811 | 86.5 |
| | | | |
| **Outage Grand Total** | 150.743 | 189.922 | 79.4 |

The steam generator project performed within the overall exposure goal; however, due to a large amount of emergent work, the overall outage goal was not achieved.

The ALARA group investigated the major tasks that exceeded exposure estimates and provided the following causes.

- Scaffold use - scaffold storage areas in the containment basement and near the reactor head were not optimum background radiation locations.

- RP coverage - additional duties were not anticipated that included: CCTV maintenance, cleanup of machining debris and HEPA hose maintenance.

- Dome work - the cause of additional exposure was undetermined at the time of this inspection.

- Insulation - additional workscope was due to asbestos abatement, some unrecognized scope, and some insulation removal that was not necessary.

- Electrical - additional valves were added for MOVATs testing.

- Significant emergent work was added to the end of the outage.

The ALARA post-job reviews also indicated several opportunities where exposures could have been reduced.

- During RCS pipe welding operations, welders occupied the steam generator platforms, although the welding was performed using a completely remote welding process.

- The need for removing welding arc-strikes from the reactor coolant piping resulted in removal of temporary shielding several days before the end of containment close-out.

- The new steam generators were found to have a residue in the tubes after having been installed in the plant, which resulted in additional unplanned exposure.

- The 431B spray valve repair was scheduled as emergent work early in the outage; however, valve repair rework was necessary after being damaged during the outage and the 431C PORV air operator was also damaged during the outage requiring replacement.

c. Conclusions

Over the past 15 years, there have been approximately 20 nuclear power plant steam generator replacement projects. Personnel exposures have declined from a high of 717 person-rem per steam generator in 1982 to between 47.5 to 80 person-rem per steam generator during the last several years. Ginna established excellent performance at 52 person-rem per steam generator, which is second only to North Anna Unit 2's performance of 47.5 person-rem per steam generator established in 1995.

The personnel exposure performance was excellent in most areas due to excellent work planning, very effective ALARA activities that minimized radiological hazards, and through excellent radiation protection staff coverage of the outage. Some areas for improvement were identified by the licensee as lessons learned for future steam generator replacements by the industry.

R3.3 Radioactive Material Transportation Procedures and Records

a. Inspection Scope (86750, TI 2515-133)

The inspector reviewed all of the radioactive material packaging, release and transportation procedures (23) with respect to the new requirements of 49 CFR 171-177 and 10 CFR 71. Selected shipping records were also reviewed.

b. Observations and Findings

The inspector noted only minor errors in the newly revised procedures. All of the new transportation requirements and concepts were found correctly applied in the licensee's shipping program. No significant discrepancies were noted.

The inspector reviewed the following shipping documentation.

| Shipment No. | Activity (Ci) | Volume ($ft^3$) | Waste Type |
|---|---|---|---|
| 94-24 | 0.96 | 170 | Filters/Bead Resin |
| 94-28 | 12.7 | 120 | Filters/Bead Resin |
| 94-30 | 73.7 | 120 | Filters/Bead Resin |
| 96-30 | 5.7E-3 | 20 | Equipment |
| 96-35 | 3E-3 | 1536 | Laundry |
| 96-39 | 7.2E-2 | 2500 | DAW, LSA II |
| 96-42 | 2.5E-4 | 1024 | Scaffolding, LQ |
| 96-45 | 1.33 | 7.5 | DAW, Type A |
| 96-48 | 4.9E-2 | 656 | DAW, SCO |
| 96-51 | 2E-3 | 9.5 | Equipment, SCO II |
| 96-52 | 1.1E-4 | 1.1 | Samples, LQ |

All shipping records were determined to be complete, contained quality control inspection reports, and were found to meet the applicable requirements of 10 CFR Parts 20, 61 and the revised requirements of 10 CFR 71, and 49 CFR Parts 171-178. No safety concerns or violations were identified.

**R5 Staff Training and Qualification in RP&C**

R5.1 Training and Qualification of Shift RP Technicians

a. Inspection Scope (83750)

The inspector reviewed training and qualification records of shift RP technicians and training lesson plans for radiation workers with respect to regulatory requirements. Also, the inspector witnessed the performance of a job performance measure for a new contamination monitoring instrument.

b. Observations and Findings

The inspector observed a job performance measure (JPM) conducted on a SAM-9 (small article monitor) instrument that was in the process of being brought into service as a new contamination monitoring instrument at Ginna. The instructor provided good direction and elicited appropriate feedback to determine qualification to use the instrument. The inspector questioned several aspects of the instruments use that have not yet been addressed in the instrument use procedure. These issues included: what is the appropriate alarm setpoint that compensates for the unmeasured beta-radiation component of the contamination? What are the limitations of the instrument due to article self-shielding for detecting internal contamination of an article? Also the calibration and source-check geometry had not been established in a repeatable configuration. These issues were provided to the Principal Health Physicist for evaluation.

In reviewing training and qualification records for shift RP/chemistry technicians, the inspector noted that most were issued training waivers that were established in 1994 to provide documentation of previous RP technician qualifications. The training waivers were based on interviews with the technicians conducted in 1994. In 1995, the training department administered the Mid-Atlantic Nuclear Training Group (MANTG) RP technician examination (that is utilized for testing the temporary contractor RP technician work force) to the permanent shift RP technicians. The results indicated that some weaknesses in RP knowledge existed both in general, and on an individual basis.

The training department has been addressing these weaknesses in continuing formal training and in one-on-one individual instruction with certain RP technicians. To date, the licensee has not retested the shift RP technicians to determine if the level of RP knowledge has improved. The inspector noted that the training department had recommended the establishment of RP technician recertification on a periodic basis to standardize and maintain a high level of performance. The Radiation Protection Manager stated that recertification of station RP technicians would be conducted.

The inspector reviewed the general employee training for radiation workers and found it to be of excellent quality and up-to-date with current plant practices and licensee management expectations. The inspector noted that the general employee training program had established a curriculum committee in September 1995, that meets semi-annually to reevaluate the content of the program by the station staff.

c. Conclusions

The general RP knowledge of shift RP technicians had been tested by the licensee and determined that some enhancements in training were needed. The licensee has provided some additional training, and has been developing a recertification program for RP technicians that will be administered at a later date. The training program has been aggressive in identifying training deficiencies and is taking the appropriate steps to ensure a high level of RP technician performance is attained. The general employee training program was found to be of excellent quality. No training discrepancies were identified.

R5.2 Radwaste/Transportation Training

a. Inspection Scope (86750, TI 2515/133)

The inspector reviewed the licensee's training program for the radwaste shipping staff and quality control inspectors. The inspector reviewed training lesson plans and reviewed applicable training attendance and examination records. The inspector also interviewed applicable training personnel.

b. Observations and Findings

The inspector verified that the three authorized shippers, the radwaste supervisor, and the two radwaste quality control inspectors had received training in the recently revised radioactive material shipping regulations in February 1996 prior to implementation of the new requirements in April 1996. In addition, all radiation protection technicians and supervisors were given a "Receipt and Shipment of Radioactive Material" update training class in January 1996. The inspector reviewed all lesson plan materials and verified training attendance and test records. No discrepancies were noted.

c. Conclusions

The licensee had effectively anticipated the April 1996 implementation date of the revision to 49 CFR 171-178 and 10 CFR 71 and provided a very effective training program that included the appropriate radwaste, quality control, and radiation protection staff individuals.

**R6 RP&C Organization and Administration**

R6.1 Radiation Protection Organization Changes

The inspector reviewed the radiation protection organization changes and noted that the Health Physicist-Operations had left the licensee's organization at the conclusion of the Spring refueling outage and the Radiation Protection Manager indicated that this position will not be refilled. The Health Physicist-ALARA has currently assumed the additional Health Physicist-Operations duties. Due to the completion of the steam generator replacement project, the Health Physicist that was assigned to this project has returned to the RP organization. The inspector determined that there was no net reduction in RP staffing due to the indicated changes.

**R7 Quality Assurance in RP&C Activities**

R7.1 Management Oversight of RP&C Activities

a. Inspection Scope (83750)

The inspector reviewed documentation of management oversight of the radiation controls program.

b. Observations and Findings

During July 1995, an audit of the RP, chemistry, and radwaste programs was conducted. Only minor discrepancies were identified in the RP program area.

Just prior to commencement of the Spring 1996 outage, an independent assessment of the steam generator replacement project RP program was conducted. This assessment was conducted by the quality assurance group with assistance

provided by an outside technical specialist. This effort provided an excellent review of planning and preparations, and verification of resources to successfully conduct the project from a radiological safety standpoint. The assessment verified that a thorough review of previous steam generator replacement projects had been made and that specific action items had been assigned to incorporate previous industry experience into the Ginna project.

During the outage, the RP organization implemented a self-assessment program, requiring RP supervision to make regular station tours and complete safety checklists. Weekly trending and reporting of the results were made during a seven-week period of the outage. Over 200 safety checklists were completed and over 30 RP tour reports were documented. This inspection program provided for early identification of RP issues (e.g., hard hat use in containment, housekeeping standards, and exposure minimization practices). The Radiation Protection Manager indicated that some form of self-assessment program would continue in the future.

c. Conclusions

The inspector's review determined that the licensee had conducted very effective independent audits of program performance and had instituted a self-assessment program during the Spring refueling outage that resulted in the prompt identification of radiological issues and provided RP technicians with standards of performance. The management oversight and review of the radiation controls program was determined to be excellent and a program strength.

R7.2 RP&C Audits and Surveillances (86750)

The licensee conducted an audit of Ginna Station radwaste and 10 CFR 20 programs on July 18-22, 1994 (Audit No. 94-25-GFS). This audit included an outside technical reviewer. No findings or observations were noted. Among the comments, radwaste procedure weaknesses were described. Since this audit, all of the radwaste/transportation procedures have been rewritten. This appeared to be a good audit and provided a sufficient review of this program area.

The licensee conducts quality control inspections of each radioactive material or radwaste shipment that leaves Ginna Station. The inspector reviewed the qualifications of the quality control inspectors and noted that the two individuals had continued to maintain training qualification in the radioactive material and radwaste shipping regulations. During the inspection of shipping records, the inspector verified documentation that each shipment had been independently verified by a quality control inspector prior to leaving the station. The inspector determined that very good management oversight was provided to ensure a high level of program quality was maintained.

## R8 Miscellaneous RP&C Issues

### R8.1 Updated Final Safety Analysis Report (UFSAR)

a. Inspection Scope (83750)

The inspector reviewed the applicable portions of the UFSAR that related to the radiological protection areas inspected. The inspector reviewed current Ginna Station practices based on Sections 11.2 through 11.4 of the Ginna UFSAR.

b. Observations and Findings

The following inconsistencies were noted between the wording of the UFSAR and current plant practices observed by the inspector.

Section 11.2.2.19 describes the method for laundering contaminated protective clothing onsite utilizing a dry cleaning unit. The licensee removed the dry cleaning unit over two years ago in order to cease production of mixed waste and contracted the services of an offsite laundry service at that time.

Section 11.4.1.1.1 describes the types of solid waste generated at Ginna station. Cemented evaporator bottoms is listed, which has not been produced since 1990. Also oily waste is listed as a waste type that is processed onsite, however for approximately two years, oily waste has been shipped for offsite processing and incineration.

The above discrepancies were acknowledged by the licensee. The licensee indicated that a staff Health Physicist has been assigned to update all of the radiation protection and radwaste sections of the UFSAR.

c. Conclusions

The inspector determined that in the radwaste/transportation program area, only two sections of the UFSAR were out of date. Both sections were of low safety significance, but indicated at least two years had elapsed since the UFSAR description had changed. Due to current NRC enforcement policy, these two UFSAR discrepancies will be classified as unresolved items pending NRC enforcement review **(URI 50-244/96-06-05).**

### R8.2 Spent Fuel Pool Leakage

a. Inspection Scope (83750)

During several previous inspection reports, the NRC reported two potential pathways of releasing radioactivity into the soil under the plant (i.e., the spent fuel pool and the steam generator blowdown tank). During this inspection, a further review of this issue was pursued through interviews with plant personnel and examinations of radioactivity measurement data.

b. Observations and Findings

The licensee has been working to seal and isolate the transfer canal slot as a source of leakage. The licensee plans to install a new spent fuel pool gate bladder to seal the spent fuel pool from the transfer slot. The licensee will also epoxy seal the bottom of the transfer slot where anchor bolts penetrate the liner. After this work is accomplished, the licensee will attempt to quantify the pool losses due to evaporation by simultaneously measuring the level in the pool and in an evaporation tray placed on the pool's surface. Currently there is approximately 9 gallons/week leaking into the RHR pump room and total spent fuel pool losses of approximately 125 gallons/day.

In the Fall of 1995, low level tritium activity was detected in the containment perimeter drain collection system located in the intermediate building sub-basement. The highest tritium concentrations were measured on the north side of the building's perimeter drain system. Low level iodine-131 activity was also measured, which indicated that the steam generator blowdown tank, which is located in the vicinity, was likely leaking. Consequently, the licensee replaced the blowdown tank outlet piping and rerouted the system with hard piping to a main condenser water box during the Spring 1996 refueling outage, in order to isolate this source of leakage.

During this effort, the licensee discovered that the steam generator blowdown tank piping was eroded and had washed-out the soil in the vicinity. As a result, a large void was created in a portion of the ground that normally supported the turbine building basement floor. After repairing the discharge tunnel end of the steam generator blowdown tank outlet piping, the licensee proceeded to determine the extent of void under the turbine building. Several core borings in the concrete floor were made to allow video camera examinations. Currently, the licensee has determined that a void (approximately 72 ft long, 20 ft wide, and 2 ft deep) has been created that runs east from the steam generator blowdown tank to a foundation footing of the turbine building; and north (approximately 125 ft long, 20 ft wide, and about 1 ft deep).

The licensee has completed preliminary evaluations and determined that all plant equipment above the areas affected by the void is well supported with concrete pedestals that communicate with bedrock. The licensee currently plans to fill the void space with grout to support the turbine building floor. The inspector questioned the licensee about the radioactivity levels in the soil around the steam generator blowdown tank. The licensee committed to sample the soil prior to grouting to determine if there was a spill requiring documentation for decommissioning as required by 10 CFR 50.75(g).

The licensee has continued monitoring of the containment perimeter drain collection system and the onsite environmental wells. A review of this data indicates that tritium levels in the containment perimeter drain collection system and in the north environmental well continue to indicate stable detectable tritium levels, but well below the Environmental Protection Agency (EPA) drinking water limits.

c. Conclusions

The licensee is continuing to pursue isolation of the sources of tritium contamination and is providing effective monitoring and trending information of the groundwater in-leakage in and around the plant.

**P3 EP Procedures and Documentation**

P3.1 Review of Emergency Plan Implementing Procedure Revisions

a. Inspection Scope (82701)

An in-office review of revisions to the emergency plan implementing procedures (EPIPs) submitted by the licensee was completed.

b. Observations and Findings

Review of the licensee's EPIP revisions revealed no deficiencies. A list of the specific revisions reviewed is included in Attachment 1 to this inspection report.

c. Conclusions

The inspector concluded that the revisions did not reduce the effectiveness of the emergency plan and were acceptable.

**S8 Miscellaneous Security and Safeguards Issues**

S8.1 (Closed) LER 96-S03: Security Officer Found Inattentive to Duty.

On May 28, 1996, a security officer was found inattentive to duty while posted at the control access point for the containment vessel equipment hatch. This incident was described in NRC inspection report 50-244/95-05. The inattentive officer was an individual performance issue with the individual and the licensee's security organization took immediate corrective actions to rectify the situation. No programmatic problems were apparent.

This LER met all requirements of 10 CFR 73.71, Appendix G, both in documented content and in timeliness of reporting. This LER is closed

## V. Management Meetings

**X1 Exit Meeting Summary**

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of the inspection. The exit meeting for resident inspection report 50-244/96-06 was held on July 25, 1996.

## L1 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. Discrepancies between the UFSAR wording and observed plant practices, procedures and/or parameters in the Radiological Controls area are described in Section R8.1.

ATTACHMENT 1

## REVIEW OF THE EPIPs

| Procedure No. | Procedure Title | Revision(s) |
|---|---|---|
| EPIP 1-5 | Notifications | 26 |
| EPIP 1-14 | Station Call List | 8 |
| EPIP 2-16 | Core Damage Estimation | 6 |
| EPIP 3-6 | Corporate Notifications | 22 |
| EPIP 5-2 | Onsite Emergency Response Facilities and Equipment Periodic Inventory Checks and Testing | 13 |
| EPIP 5-7 | Emergency Organization | 13 |