U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/96-01 License: DPR-18

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

Inspection: January 28, 1996 through March 23, 1996

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Inspection Summary:

Core, regional initiative, and reactive inspections performed by the resident and region-based inspectors during plant activities are documented in the areas of plant operations, maintenance, engineering, and plant support.

Results:

See Executive Summary.

## EXECUTIVE SUMMARY

## R. E. Ginna Nuclear Power Plant

## Inspection Report No. 50-244/96-01

Operations: Following thorough preparation, the licensee implemented Improved Technical Specifications (ITS). No problems were noted in the transition.

The reactor was manually tripped from approximately 50 percent reactor power due to a secondary plant transient that was caused by the loss of a main circulating water pump. Operator response to this event was very good and the plant was promptly stabilized in hot shutdown. Several emergent maintenance activities required the plant to remain shut down for three days. During the forced outage, operator response to a failed-open steam generator atmospheric relief valve was excellent, and the subsequent plant startup was well controlled. However, during the outage, inadequate implementation of a temporary procedure change to a maintenance procedure, and poor communications and coordination between the operations and maintenance organizations, caused both power operated relief valves (PORVs) to be inoperable simultaneously. The failure to properly implement the temporary procedure change process was a violation of Technical Specification Section 5.4.1.

Maintenance: The containment hydrogen recombiners did not have a surveillance test requirement under the old technical specifications and required various tests to meet the surveillance requirements of the ITS. One test revealed a significant flow blockage in the A-train. The cause was determined to be corrosion particles in the orifice of a pressure regulating valve. The valve was cleaned and A-train testing was successfully completed.

The licensee determined that an inservice test for the service water suction check valve to the C-standby auxiliary feedwater (AFW) pump was not performed within the time frame required by an ASME Code relief request. Specifically, the valve was to be disassembled every other year during a refueling outage. Although the valve was disassembled within the last two years, it was not done during a refueling outage. The inspector witnessed the subsequent valve disassembly and testing. The valve was operable as-found, and no significant degradation was noted.

As a result of AFW system operation during the forced outage, the A-motor driven auxiliary feedwater (MDAFW) pump discharge check valve was found to have excessive seat leakage. The valve seat and disc were replaced and the valve was tested satisfactorily; however, during routine surveillance testing a week later, the valve again demonstrated excessive seat leakage. The licensee determined that the cause was an earlier modification to the valve body that had not been accounted for during the previous maintenance. The licensee is performing a root cause analysis of this problem.

During an attempted reactor startup, operators observed that the step counter for control bank C group 1 did not operate. Subsequent troubleshooting involved replacement of the step counter module and several iterations of

single/multiple circuit card replacements in the rod control cabinet. The problem was ultimately traced to a circuit card malfunction; however, troubleshooting had been complicated by a second malfunction that was introduced by the replacement step counter module. The inspectors considered that earlier involvement by front line management may have provided better overall direction and a more prompt resolution.

The A-emergency diesel generator (EDG) fuel oil transfer pump recirculation valve failed due to degradation of the solenoid operator. The operations, maintenance, and engineering departments initiated prompt and extensive actions to evaluate the condition from a safety and regulatory perspective, and to restore the A-EDG to service by installing a temporary modification. A suitable replacement for the failed valve was identified, and expeditiously installed and tested.

A control room operator noted that the two main control board instruments for B-MDAFW pump discharge flow were showing erratic indication shortly after the pump was secured. Review of archived data revealed that this type of indication had been occurring for both MDAFW pumps for a long period. The inspectors considered that the licensee did not initially respond aggressively to the B-MDAFW pump anomalous flow indication, in that a condition that potentially affected the operability of a safety system was not promptly entered into the corrective action system.

Engineering: Overall, RG&E's management of the steam generator replacement project has been excellent. A temporary work facility was erected near the station warehouse to house the new steam generators during preparation for installation. Installation of the upper support ring and the preparation of pipe nozzles for welding is in progress. The Lampson Transilift crane assembly was completed and a load test was performed. Although some welder qualifications have been behind schedule, overall coordination and preparation for the project has been very good and on time.

One channel of reactor coolant system (RCS) average coolant temperature (Tavg) and differential temperature (ΔT) was indicating lower than the other three. The RCS loop A hot leg temperature detector for the affected Tavg/ΔT channel had shown some minor inconsistency during the previous annual calibration check. Subsequent testing indicated that the detector had drifted about 2.5°F lower since the beginning of the current operating cycle.

Nuclear Engineering Services performed an operability assessment of the affected reactor protection system (RPS) channel temperatures. The assessment determined that the effect of the drift on the OTΔT and OPΔT setpoints was in the non-conservative direction, but were still within the UFSAR limits. The assessment recommended that a delta T span adjustment be performed for the RPS channel to reduce the non-conservative drift effect on the calculated values of OTΔT and OPΔT. The inspectors concluded that nuclear engineering services provided timely, conservative support in resolving the TE-401A drift problem.

The licensee's response to a failure of instrument bus inverter A was excellent. The use of sophisticated monitoring equipment made it possible for

I&C technicians to record a short duration event that led to identification of the problem.

Plant Support: The licensee implemented and maintained good, routine, radioactive liquid and gaseous effluent control programs, sufficient to protect the public health and safety and the environment. The Chemistry staff demonstrated good knowledge and ability. Sufficient management oversight and control and technical attention was directed to the monitoring program for potential leakage affecting the steam generator blowdown tank and the spent fuel pool.

The licensee continues to maintain a good emergency preparedness program. The emergency plan and emergency plan implementing procedures were current and effectively implemented. The emergency facilities, equipment, instruments and supplies were found to be maintained in a state of readiness. All required 1995 surveillance were completed. A sampling of emergency response organization personnel training records indicated that training and qualifications were current. Quality Assurance Department audit reports of the EP program satisfied NRC requirements; however, the inspectors questioned the independence of the audit process. A violation was issued for not having procedures to utilize the Assessment Facility as a radiological laboratory. In addition, that facility and its functions have never been exercised during a drill or exercise. The inspectors also identified several minor discrepancies between the licensee's practices and procedures and statements in the emergency plan. Two previously identified follow-up items were closed.

A preimplementation review of the SG replacement project security program found that the licensee's proposed plans and procedure changes were adequate.

Safety Assessment/Quality Verification: The inspectors observed receipt inspection of new fuel assemblies by a licensee quality control (QC) inspector. The QC inspector identified two fuel assemblies with bent tabs on their grid straps during the receipt inspection. The condition was not significant enough to reject the assemblies; a fuel vendor representative came to the Ginna Station to perform a repair of the tabs. After the repair was made, a complete receipt inspection was reperformed with satisfactory results on the two assemblies. The inspectors reviewed the QC records after the receipt inspection was completed on all assemblies. The documentation was accurate and complete. Overall the receipt inspection process for the new fuel was thorough and well controlled.

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ATTACHMENT 1

Attachment 1 - Review of the NERP and EPIPs

## DETAILS

## 1.0 OPERATIONS (Inspection Procedure (IP) 71707)[1]

### 1.1 Operations Overview

At the beginning of the inspection period, the plant was operating at full power (approximately 97 percent). On March 7, 1996, the reactor was manually tripped from approximately 50 percent reactor power due to a secondary plant transient that was caused by an automatic trip of a main circulating water pump motor. All engineered safety features equipment functioned as required and operators promptly stabilized the plant in hot shutdown. A plant startup was performed on March 11, 1996, and the plant operated at full power for the remainder of the inspection period. There were no other significant operational events or significant challenges to plant equipment during the inspection period. Overall, operator performance was very good during the reporting period.

### 1.2 Implementation of Improved Technical Specifications

On February 24, 1996, the licensee implemented Amendment 61 to the operating license for the R. E. Ginna Station. The Amendment comprised a complete revision of Appendix A to the license which contained the Improved Technical Specifications (ITS) that were approved by the NRC on February 13, 1996. The ITS imposed several new program changes on the licensee (see NRC Inspection Report 50-244/95-21) and required a total of 1380 new and revised station procedures prior to implementation. Prior to February 24, the inspector verified that all necessary new and revised procedures were completed, reviewed, and approved. On February 24, the inspector verified that all materials (procedures, etc.) in the control room pertaining to the old technical specifications were removed, and that all materials pertaining to the ITS were in place available for use by operating personnel.

### 1.3 Control of Operations

The inspectors observed plant operation 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 identified equipment status or deficiencies. One operational inadequacy occurred when the on-shift operating crew authorized work that physically made both pressurizer power operated relief valves simultaneously inoperable, as discussed in section 1.5 of this report.

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

## 1.4 Manual Reactor Trip due to Loss of a Main Circulating Water Pump

The main circulating water system supplies cooling water to the main condensers to condense exhaust steam from the two low pressure turbines. The system consists of two headers, each of which is supplied by a circulating water (CW) pump. Each header supplies a main condenser. The headers are cross-connected upstream of the main condensers to allow for reduced power operations with a single operating CW pump. After passing through the main condensers, main circulating water is returned to the lake via a common discharge canal.

At 6:15 p.m. on March 7, 1996, the B-CW pump motor tripped. Control room operators were alerted to the problem by the associated main control board annunciator. Turbine load was rapidly reduced to approximately 50 percent in accordance with abnormal procedure AP-CW.1, "Loss of a Circulating Water Pump." The reduction in heat removal from the B-main condenser from reduced circulating water flow caused an increase in the associated turbine backpressure. The low pressure turbines are not designed to operate at the high backpressure conditions that existed following the B-CW pump trip. A vendor-recommended limitation of five minutes of operation applies under high backpressure conditions.

The rapid power reduction caused steam generator (SG) water levels to decrease (i.e., "shrink"). Although the actual feedwater requirement was reduced, the automatic feedwater control system overcompensated for the shrink in an attempt to restore normal SG water levels, and the water levels in both SGs began to rise. Due to the response time of the automatic feedwater control system relative to the rate of SG water level increase, level continued to rise to the engineered safety features (ESF) feedwater isolation setpoint of 67 percent. After several high level ESF isolations had occurred on both SGs, levels began to stabilize. Although backpressure in the B-main condenser was also recovering, it did not occur quickly enough to avoid exceeding the five minute turbine operating restriction. At 6:22 p.m., the shift supervisor directed that the reactor be manually tripped. Plant response to the trip was normal. All safety systems and equipment responded as required, with the exception of one source range nuclear instrument channel (N-31), which failed to indicate after it was energized. Operators promptly stabilized plant conditions in hot shutdown.

Investigation revealed that the B-CW pump breaker had tripped due to actuation of the power factor relay. The relay trip setpoint was checked and found to be correctly set. Inspection and testing of the breaker and the B-CW pump motor revealed no obvious problems. From review of available data for the B-CW pump, the licensee determined that the motor power factor had been gradually decreasing over a period of months. The licensee attributed this to development of an oxide layer at the wiper contact for the variable transformer that supplies the exciter field. This resulted in reduced voltage, and therefore reduced current supplied to the exciter and a lagging motor power factor. The licensee determined that the likely cause of the power factor trip had been the gradual decrease in the exciter current, combined with normal variation in the 4KV supply bus voltage. In this case, a voltage increase also caused the power factor to decrease. As corrective

action, the exciter variable transformer was cleaned. Additionally, operations instituted a requirement to record B-CW pump power factor and exciter field current whenever 4KV bus voltage changed by 50 volts. This was intended to provide early indication of a downward trend in power factor and allow for adjustment of the exciter field current before the power factor trip set point was approached.

The inspectors noted that the secondary plant transient during this event was significantly different from the loss of the B-CW pump event that occurred in August 1995. In both cases, increased backpressure in the B-main condenser resulted in condensate being transferred from the B-hotwell to the A-hotwell via the common header that supplies the condensate pumps. On the earlier occasion, the hotwell level transient resulted in a loss of net positive suction head (NPSH) to the condensate and main feedwater pumps, and the plant was manually tripped based on concern that these pumps could be damaged by cavitation. On this occasion, NPSH was adequate throughout the transient. The inspectors considered that the most likely cause of the difference was that power had been reduced more rapidly during the recent event than it had during the August 1995 event. As a result, the maximum backpressure was lower than in the August event and a water seal was maintained between the condenser and the condensate pumps suction. No pump cavitation was evident during this event.

Source range nuclear instrument channel N-31 was required to be operable prior to conducting a reactor startup. Troubleshooting indicated that the detector had failed. Also, the initial replacement detector was found to be defective following replacement. As a result, time was available to conduct several other maintenance activities prior to startup. Among these activities were adjustment of the pressurizer power operated relief valve (PORV) stroke times (discussed in section 1.5 of this report) and replacement of valve internals for the A-motor driven auxiliary feedwater pump discharge check valve, CV-4009. Following completion of planned maintenance on the evening of March 9, 1996, failure of the A-steam generator atmospheric relief valve further delayed startup; this item is discussed in section 1.6 of this report. Problems encountered with the control rod step counters during attempted startup (discussed in section 2.1.1 of this report) delayed reactor startup until the morning of March 11, 1996.

A reactor startup was successfully completed on March 11, 1996, with criticality being achieved at 3:54 a.m. The main generator was paralleled to the grid and power was escalated. Full power was achieved at 9:22 a.m. on March 12, 1996.

The inspectors considered that the operator's response to loss of the B-CW pump was very good. Through discussions with licensee personnel and review of archived plant data, the inspectors concluded that the plant responded normally to the reactor trip, with the exception of source range nuclear instrument channel N-31. A four-hour non-emergency report was made to the NRC as required by 10 CFR 50.72 and was subsequently reported in LER 96-003 on April 8, 1996. Operator performance during the reactor startup and power escalation was very good; communications were precise and actions were deliberate. The inspectors had no additional concerns on this matter.

## 1.5 Both Pressurizer Power Operated Relief Valves Made Inoperable During Stroke Time Adjustments

During the March 7-10 forced outage, the licensee performed maintenance on the pressurizer power operated relief valves (PORVs). As discussed in inspection report 50-244/95-17, the PORV block valves have been closed for most of the operating cycle to control minor PORV seat leakage. Earlier attempts to stop this leakage had involved mechanical ("benchset") adjustment of the PORVs, which, in turn, had affected their stroke times. The PORVs also serve as relief valves for the low temperature overpressure protection (LTOP) system (only used while the reactor is shut down and cooled down), a function in which stroke time is a critical parameter. The purpose of the PORV maintenance conducted on March 8, 1996, was to make adjustments to the valves and verify their stroke times, in preparation for placing the LTOP system in service during the upcoming refueling outage.

The work was to be conducted in accordance with maintenance procedure M-37.150, "Copes-Vulcan/Blaw-Knox Air Operated Control Valves Inspection and Refurbishment." A work package (WO 19503588) had already been prepared to accomplish this work during the upcoming outage. Conducting this maintenance with the plant at normal operating temperature (rather than during plant cooldown) required work in a higher temperature environment than would normally be the case. To minimize the amount of time that the workers would have to spend in this adverse environment, M-37.150 was modified to allow work on both PORVs simultaneously. The procedure involved disconnecting the normal air/nitrogen supply from the PORV actuator. While the normal air/nitrogen supply was disconnected, operation of the PORV from the main control board would not possible. Therefore, an inadvertent result of the procedure change was that both PORVs would simultaneously be made inoperable.

Based upon subsequent discussions with the licensee, the inspectors noted the on-shift operations personnel reviewed the PORV maintenance package prior to authorizing work to begin. Operators apparently believed, in error, that the maintenance would only affect the ability to operate the PORVs with air, and that they would still be able to operate the valves using nitrogen. They concluded that PORV operability would not be affected and authorized the work to begin.

At approximately 2:55 p.m. on March 8, 1996, both PORVs were made inoperable when the air/nitrogen supply lines were disconnected from the valve actuators. The maintenance was completed and the air/nitrogen supply lines were reconnected by approximately 4:32 p.m. causing both PORVs to be physically inoperable for a total of 1 hour and 37 minutes. Technical Specification LCO 3.4.11 requires that both PORVs be operable in Modes 1, 2, and 3; and actions required if both PORVs are inoperable are 1) immediately initiate action to restore one PORV to operable status, 2) within one hour, close and remove power from the associated block valves, and 3) within eight hours, be in Mode 3 with Tavg less than 500°F. The unavailability of both PORVs above 500°F represents the loss of the available vent path safety function and invalidates other assumptions in the accident analysis for a steam generator tube rupture.

The change to procedure M-37.150 that allowed work to be done on both PORVs at the same time was accomplished by adding a note to an existing temporary procedure change (PCN 96-T-0055) that had been developed as part of the original work package. However, the 10 CFR 50.59 applicability review was not reperformed. The entire change received a subsequent independent review as required by A-601.3, "Procedure Control - Temporary Changes." According to this procedure, the independent reviewer is responsible for reviewing the 10 CFR 50.59 Safety Review Form for adequacy and completeness. The shift supervisor also reviewed and approved the change; according to A-601.3, review responsibilities included a review of the temporary change for impact on plant operations. However, in this case neither the independent reviewer nor the shift supervisor adequately accomplished the review. Technical Specification Section 5.4.1 requires that written procedures be established, implemented and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33 recommends a written administrative procedure covering procedure adherence and temporary procedure changes. Administrative procedure A-601.3, "Procedure Control - Temporary Changes," was established to meet this recommendation. The failure to properly implement procedure A-601.3 for the temporary procedure change for the PORV maintenance is a violation of TS Section 5.4.1 **(VIO 50-244/96-01-01)**.

Stroke time testing on the PORVs was completed at approximately 5:59 p.m. and was immediately followed by seat leakage testing. The first PORV tested, PCV-430, exhibited significant leakage (on the order of 20 gallons per minute). Since the benchset on the other PORV (PCV-431C) had been similarly adjusted, operators concluded that it would also have excessive seat leakage; therefore, a seat leakage test was not performed on PCV-431C. Technical specification (TS) 3.4.13 states that identified leakage from the reactor coolant system shall be limited to 10 gallons per minute. Based on this requirement, operators declared both PORVs inoperable at 7:40 p.m. Accordingly, power was removed from the block valves (to meet TS 3.4.11) and work was initiated to readjust the PORV benchsets to their original values. Acceptance testing was completed and the PORVs were declared operable at 1:23 a.m., March 9, 1996. Both instances of PORV inoperability were reported to the NRC in LER 96-003 on April 8, 1996.

The inspectors concluded that the licensee's preparations for maintenance on the PORVs on March 8, 1996 were not thorough. The procedure change that authorized simultaneous maintenance on the PORVs did not account for the TS operability requirements, and this was not identified during preparation, approval, or implementation of the change. The PORV operability problem was recognized after the PORVs were leak tested, and the licensee then took prompt action to comply with TS LCO 3.4.11.

The licensee is performing a human performance review of this event. However, the inspectors considered that an apparent lack of communication and coordination between the maintenance and operations organizations also contributed significantly to this event.

## 1.6 Failure of the A-Steam Generator Atmospheric Relief Valve While Shutdown

During the March 7-10 forced outage, maintenance was performed on the A-motor driven auxiliary feedwater (MDAFW) pump discharge check valve (discussed in section 2.1.1 of this report). During the outage, reactor coolant system (RCS) temperature was being controlled by steam release through the steam generator atmospheric relief valves (ARVs). Operators had closed the A-main steam isolation valve (MSIV) and were controlling RCS temperature using only the B-SG and B-MDAFW pump, since the work isolation for the check valve maintenance made adding feedwater to the A-SG difficult.

At 9:20 p.m. on March 9, 1996, when restoring from the A-MDAFW pump maintenance, operators attempted to establish steam flow in the header and slightly opened the A-SG ARV to assist in opening the A-MSIV. However, rather than opening slightly, the ARV failed open to approximately 60 percent. After the valve opened, controls on the main control board had no further affect on valve position. RCS temperature and pressure, and SG water levels, all began to lower. Level in the A-SG was initially low (22 percent) due to no feedwater addition during the AFW pump maintenance, and reached the 17 percent low level ESF setpoint approximately three minutes into the event. This generated a reactor trip signal (all rods were already fully inserted) and caused an automatic start of the non-operating B-MDAFW pump.

Operators responded to the event by shutting the A-MSIV and dispatching an auxiliary operator (AO) to manually isolate the A-ARV. Two AOs responded; one began to shut the manual isolation valve while the other attempted to close the ARV using its manual operator. The isolation valve was fully closed in approximately 3½ minutes and stopped the steam release.

As a result of this transient, RCS temperature dropped approximately 15 degrees Fahrenheit (°F), RCS pressure dropped approximately 120 psi, and water level in the A-SG reached approximately six percent. The low level in the A-SG made the A-RCS loop inoperable for heat removal. Technical Specification LCO 3.4.5 allows 72 hours to restore operability, and the A-RCS loop was restored to operability at 9:40 p.m. when SG water level was returned to ≥16 percent.

The cause of the A-SG ARV failure was determined to be a failed air system volume booster relay that translates the control air signal into operating air for the valve. The relay was replaced, and the ARV was returned to service on March 10, 1996.

The inspector was in the control room throughout this event and assessed that operator response was excellent. Control room operators rapidly determined the cause of the transient and took action to isolated the fault by shutting the A-MSIV and dispatching operators. The AOs responded quickly into an extremely harsh noise environment and rapidly isolated the failed ARV. A four-hour non-emergency report was made to the NRC as required by 10 CFR 50.72 and was subsequently reported in LER 96-004 on April 8, 1996. The inspectors had no additional concerns on this matter.

# 2.0 MAINTENANCE

## 2.1 Maintenance Activities (IP 62703)

### 2.1.1 Routine Observations

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. The following maintenance activities were observed:

- Hydrogen recombiner corrective maintenance

  -- Prior to implementing Improved Technical Specifications (ITS) at the Ginna Station on February 24, 1996, the licensee required that all surveillance tests included in the ITS be current. Since the containment hydrogen recombiners did not have a surveillance test requirement under the old technical specifications, these systems needed a 24 month functional test to meet surveillance requirements SR 3.6.7.1 and SR 3.6.7.2 of the ITS.

  Several functional tests were performed on the A- & B-recombiner system trains before February 24, 1996. One test revealed a significant flow blockage in the A-train that caused flow to be less than the system's minimum requirements. The inspectors observed the troubleshooting and disassembly of portions of the A-train components. After identifying the blocked region as an orifice near pressure regulating valve V-10200, approximately one-half cup of iron oxide particles was removed when the valve was disassembled. After the system was restored, the A train was successfully flow tested. All maintenance and testing on the recombiners was well controlled and the procedures used for these activities were available and followed. Operations personnel made the necessary systems isolations and tagouts with independent verifications for the maintenance and test work.

- C-standby auxiliary feedwater (SAFW) pump service water check valve CV-9627A inspection for missed IST observed on February 23, 1996

  -- On February 15, 1996, the licensee determined that an inservice test for check valve 9627A was not performed in the time frame identified in a relief request (VR-5) for ASME Code, Section IX test requirements (See section 5.3 of this report). The valve is in the service water suction line to the C-SAFW pump, and the required inspection involves disassembly and full stroke exercising the valve every other refueling outage. The inspectors witnessed the valve disassembly and testing activity on February 22, 1996. A small amount of silt was noted around the ledge of the valve seat and at the bottom of the valve body. However, it did not appear that the amount of material present would have prevented full valve closure. The licensee exercised the valve

disk and observed freedom of motion through its complete range. The valve disk was then blue checked and full seat contact was confirmed. The valve was reassembled and properly torqued in accordance with procedure requirements. All portions of this work were performed in the presence of a QC inspector and all inspection verifications were properly made. The valve was subsequently restored to operability. The inspectors concluded that this work was timely and well controlled in accordance with procedure requirements.

- Auxiliary feedwater pump discharge check valve CV-4009 final bonnet torquing, observed on March 9, 1996
  -- AFW system operation during the March 7-10 forced outage revealed that the A-MDAFW pump discharge check valve, CV-4009, had excessive seat leakage. The valve seat and disc were replaced and the valve was tested satisfactorily on March 9, 1996; however, on March 20, 1996, during routine surveillance testing, the valve again demonstrated excessive seat leakage. During rework, the licensee determined that the cause was that an earlier modification to the valve body in the area that accepts the seat ring had not been accounted for during the March 9 maintenance, and the seat ring in the replacement valve internals was not modified. This resulted in an improper reassembly that caused the test failure on March 20. The licensee is performing a root cause analysis (AR 96-0172) of the CV-4009 maintenance problems. (IFI 50-244/96-01-02).

- Control rod step counter troubleshooting, observed on March 10, 1996

  -- During an attempted reactor startup, operators observed that the step counter for control bank C group 1 did not operate. Replacement of the counter module failed to correct the problem. Subsequent troubleshooting involved several iterations of single and multiple circuit card replacements in the rod control cabinet. The problem was ultimately traced to a circuit card malfunction; however, troubleshooting had been complicated by a second malfunction that was introduced by the replacement step counter module. Correction of this problem delayed the reactor startup by approximately one day. The technicians demonstrated a high level of technical competence; however their initial troubleshooting efforts lacked a systematic approach to a resolution of the root cause and resulted in a time delay (approximately 24 hours) in restarting the reactor plant. System engineering and maintenance management eventually became involved in the troubleshooting efforts and a prompt resolution was achieved. The inspectors considered that earlier involvement by system engineering and maintenance management may have provided better overall direction, a more systematic approach to the troubleshooting, and a more prompt resolution.

## 2.2 Surveillance and Testing Activities

### 2.2.1 Routine Observations (IP 61726)

Inspectors observed portions of surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operation (LCOs),

and correct post-test system restoration. The following surveillances were observed:

- M-72.1.1, "Reactor Coolant Loop RTD [Resistance Temperature Detector] Integrity Check," observed February 7, 1996

  -- Testing of loop A average temperature (Tavg) hot leg (Th) RTD, TE-401A, performed because the associated instrument was indicating lower than the three other channels. This item is discussed further in section 3.2 of this report.

- Performance Test (PT)-12.2, "Emergency Diesel Generator B," observed February 15, 1996

- Instrument Calibration Procedure (CPI)-SPAN-5.10, "Calibration Alignment of Delta T Dana Amplifier at 70% Power or Greater, Channel 1, Loop A," observed February 15, 1996

  -- Performed to compensate for drift in Tavg/ΔT RTD element TE-401A, as discussed in section 3.2 of this report

- PT-32A, "Reactor Trip Breaker Testing - "A" Train," observed March 1, 1996

  -- Included troubleshooting for R-29 (containment high range radiation monitor) spiking, noted during previous reactor trip breaker testing; troubleshooting is on-going

- PT-16Q-B, "Auxiliary Feedwater Pump B - Quarterly," observed March 9, 1996

  -- Partial, retest for the CV-4009 repairs

- PT-6.2, "N.I.S. [Nuclear Instrumentation System] Intermediate Range Channels N-35 and N-36," observed March 9, 1996

  -- N-35 calibration check

The inspectors determined through observing the above surveillance tests that operations and test personnel adhered to procedures, that test results and equipment operating parameters met applicable acceptance criteria, and that redundant equipment was available during testing for emergency operation.

### 2.2.2 A-Emergency Diesel Generator Fuel Oil Transfer Pump Failed Surveillance

On February 1, 1996, during quarterly in-service (ASME Section XI) performance testing (PT-12.6, "Diesel Generator Fuel Oil Transfer Pump Tests") of the A-Emergency Diesel Generator (EDG) fuel oil transfer system, the fuel oil transfer pump failed to achieve the required discharge pressure and flow (16 psig and 23.27 gpm achieved; vs. 17.7-20.9 psig and 25.8-29.9 gpm acceptable). As a result, the A-EDG was declared inoperable, placing the plant in a seven day Limiting Condition for Operation (LCO). Subsequent troubleshooting by operations and maintenance personnel concluded that the apparent cause of the pump's low discharge pressure was failure of the pump recirculation valve

SOV-5907A to tightly close, resulting in pressure and flow losses during filling of the day tank.

Since the failed valve was original plant equipment and a replacement was not readily available, operations and engineering evaluated the impact on plant safety and A-EDG reliability. As a precautionary measure, the fuel oil transfer system was temporarily modified by securing SOV-5907A in the open position. In this configuration, flow to both the day tank and fuel storage tank (recirculation flow) will result when filling the day tank. This condition is acceptable since the positive displacement transfer pump can still deliver the minimum required flow to the day tank (>2.62 gallons per minute, as stated in the Updated Final Safety Analysis Report, section 9.5.4). To confirm adequate flow, PT-12.6 was performed following deenergizing the valve; a discharge pressure of 15 psig and a flow of 20.23 gpm were obtained. Accordingly, the A-EDG was returned to service on February 3, 1996.

Prior to performing this reconfiguration, the proposed Temporary Modification Permit (96-007) and supporting Safety Evaluation (SEV 1059) were reviewed and approved by system engineering, operations, and the Plant Operations Review Committee (PORC). Reconfiguring was considered precautionary since it was postulated that the degraded valve could cause an electrical failure that could fail the control fuses and disable the entire A-EDG fuel oil transfer system. The temporary modification disconnected the power leads for SOV-5907A, isolated the valve from the control circuit, and eliminated the possibility of fuse failure due to coil degradation. To reestablish A-EDG operability, the licensee used guidance contained in Generic Letter 91-13, Technical Guidance 9900 "Operability." Where the ASME Section XI acceptance criteria is more conservative than the regulatory limit, this guidance states that the corrective action may be an analysis to demonstrate that the specific degradation does not impair system operability and the component will still fulfill its function.

The licensee purchased a commercial grade replacement valve since an identical valve was no longer manufactured. Therefore, the dedication process was used to qualify the replacement valve and the solenoid operator. Procurement engineering completed a comparative analysis, establish valve performance requirements, and identified the critical attributes that the quality assurance department would verify prior to accepting the replacement valve for installation. Receipt inspection of the part number, voltage, power rating, dimensions, and coil resistance was to provide assurance that the item ordered was the item received.

On February 13, 1996, the failed valve (ASCO model 8210A35) was replaced with an ASCO model HC8210C35. The inspector observed the installation of the replacement valve and post-installation testing of the fuel oil transfer system. Relevant documentation reviewed included the work package, commercial grade dedication technical evaluation for the replacement valve (TE 96-505), temporary modification permit, tagging order (to remove the system from service), ACTION report, and UFSAR section 9.5.4.

Mechanical maintenance personnel installed the valve in a professional manner, using foreign material exclusion controls on open piping, complying with

procedural requirements for bolt tightening, flange fit-up and closely coordinating procedural hold point verifications with the quality control inspector. I&C technicians reterminated solenoid wiring with the control circuit using skill-of-the-craft techniques. Following installation, Results and Test (R&T) technicians had operations personnel realign the system for testing. Testing was conducted in conformance with the test procedure and system performance parameters met acceptance criteria.

Although the performance criteria of PT-12.6 were met during post-installation testing, during system recirculation, high pump discharge pressure (44 psig) caused the system relief valve (RV-5959) to lift. This condition did not compromise system operability; however, it indicated that SOV-5907A had been in a degraded condition (that is, not fully closing) prior to the IST baseline parameters for the FO transfer pump being established in 1992. An ACTION report (96-0088) was generated to document and resolve this condition.

Subsequent to returning the fuel oil transfer system to service, the inspector interviewed the procurement engineer regarding the commercial grade dedication of the replacement valve. Through this discussion, the inspector determined that a prompt and thorough evaluation was completed for suitable replacement components. The engineer adhered to the relevant engineering and administrative procedures in establishing critical valve performance attributes and by identifying quality control receipt inspection criteria.

Additionally, the inspector interviewed the cognizant system engineer regarding installation of the temporary modification following the initial valve failure. Through this discussion and review of the supporting documentation, the inspector concluded that the fuel oil transfer system was capable of performing its intended safety function following deenergizing SOV-5907A. Upon identifying that SOV-5907A had failed, prompt and extensive actions were initiated by the operations, maintenance, and engineering departments, to evaluate the condition from a safety and regulatory perspective, to restore the A-EDG to service by installing a temporary modification, to qualify a suitable replacement for the failed valve, and to expeditiously install/test the replacement. These activities were effectively coordinated with appropriate management and QA oversight.

### 2.2.3 Motor Driven Auxiliary Feedwater Pump Anomalous Discharge Flow

On February 12, 1996, the licensee performed monthly surveillance testing on the B-MDAFW pump. Approximately one-half hour after the pump was secured, a control room operator noted that the two main control board instruments for B-MDAFW pump discharge flow were showing erratic indication. The operator documented the condition in a work request/trouble report (WR/TR 013045).

The following day, the inspector noted the WR/TR concerning the B-MDAFW flow indication. The inspector reviewed archived data from the plant computer and noted that, although erratic, both flow instruments showed the same pattern at the same time. About one-half hour after the pump was stopped, flow went from zero to about 25 gallons per minute for about 20 minutes, and then returned to zero. The inspector considered that this indicated that flow had actually occurred, as opposed to the condition being the result of coincident

instrument failures. The inspector discussed this situation with the licensee, and the licensee initiated an ACTION report (96-0086) to investigate the problem.

Further review of archived data by the licensee revealed that the same indications that were observed on February 12, 1996, had been occurring for at least several months with both MDAFW pumps. The licensee assessed this condition as not affecting MDAFW pump operability. At the close of the inspection period, the licensee planned further investigation of this condition, to be performed during normally scheduled surveillance testing.

The inspectors considered that the licensee did not initially respond aggressively to the B-MDAFW pump anomalous flow indication, in that a condition that potentially affected the operability of a safety system was not promptly entered into the corrective action system. Subsequent licensee actions appeared to be appropriate, and the licensee's corrective action process will track the condition through appropriate resolution.

## 3.0 ENGINEERING

### 3.1 (Update) Steam Generator Replacement Project (IP 50001)

#### 3.1.1 Project Status

RG&E's project to replace both steam generators (SGs) during the next refueling outage (April 1996) is currently on schedule and onsite preparation activities are ongoing. Overall, the project continues to be well managed and coordinated between RG&E and Bechtel.

#### 3.1.2 Observations

The inspectors reviewed documentation and observed various phases of the preparation for the replacement of the steam generators, including reinstallation of liner on the training mockup, training of welders on the automatic welding machine, qualification of the "cadweld" rebar splicing process and crews, splice installation, and receipt inspection of both new steam generators at the site.

The inspectors observed the following activities:

- The welding of the liner reinstallation in the "mockup" had not been completed; however, welding of two sides had been finished. The two radiographs on the completed weldments disclosed some rejectable defects (lack of fusion) in the root, although the fit-up appeared satisfactory. The licensee was in the process of evaluating and resolving the discrepancy and developing a fix to eliminate such defects from the liner welding process.

- The inspectors observed the training of welders on automatic welding machines. There were six machines onsite. Five out of the six were being used for training and one was kept as a backup. Ten crews of three persons each were being trained on the machine in two shifts.

- Eight cadweld splicers had been qualified. Each splicer had made two splices in horizontal, and two splices in vertical/slope position. The qualification splices had been visually examined by Bechtel quality control (QC) and the vendors representative/trainer, and were found acceptable. The inspectors observed the tensile testing of the splices in the onsite universal testing machine. All the tested splices met or exceeded the acceptance criterion of the splices.

- Both new steam generators were delivered to the site on January 7 and 17, 1996. A temporary work facility was erected near the station warehouse to house the generators during preparation for installation. The steam generators were receipt inspected, and installation of the upper support ring and the preparation of pipe nozzles for welding is in progress.

- The Lampson Transilift crane assembly was completed and a load test was performed on March 21-22, 1996. The test load was 440 tons, and the load was raised and lowered through the full range of the main boom and over the path that will occur when the steam generators are lifted. The inspectors observed the operation of the crane during the load test, and the survey of the crawlers and main boom while under load. The test was satisfactory and no deficiencies related to the crane assembly were noted.

The inspectors concluded that the licensee's planning, preparation, and related activities in the area of engineering and construction well support the steam generator replacement in the coming refueling outage starting April 1, 1996. Overall, RG&E's management of the steam generator replacement has been excellent. Although some welder qualifications have been behind schedule, overall coordination and preparation for the project has been very good and on time.

### 3.2 Reactor Coolant System Average Coolant Temperature Instrument Drift (IP 37551)

Over a period of several months, operators noted that one channel of reactor coolant system (RCS) average coolant temperature (Tavg) and differential temperature (ΔT) was indicating slightly lower than the other three. This was a potential operational concern because Tavg is used as an input to the automatic rod control system, and potentially affected the reactor protection system (RPS) as well. Tavg and ΔT are inputs for determining the overtemperature and overpressure differential temperature (OTΔT and OPΔT) reactor trip setpoints.

Instrument and Control (I&C) personnel investigated the condition and noted that the RCS loop A hot leg temperature detector (TE-401A) for the affected Tavg/ΔT channel (RPS channel 1) had shown some minor inconsistency during the previous annual calibration check. Although the detector had been within allowable tolerance, they had initiated action to replace TE-401A during the next refueling outage. To assess the detector's current condition, I&C technicians performed precision measurements of the RCS loop A Tavg RTDs per M-72.1.1, "Reactor Coolant Loop RTD Integrity Check." This test showed that TE-401A was indicating about 7.0°F lower than the other loop A Tavg hot leg RTD (TE-405A). Testing at the beginning of the operating cycle showed that

TE-401A indicated about 4.5°F lower than TE-405A; therefore, it was concluded that TE-401A had drifted about 2.5°F lower since the beginning of the operating cycle.

Nuclear Engineering Services performed an operability assessment of the RPS channel 1 temperatures. The assessment determined that the effect of the TE-401A drift on the OTΔT and OPΔT setpoints was in the non-conservative direction, but that the resultant values were still within the UFSAR limits. The assessment concluded that channel 1 OTΔT and OPΔT were still operable and that an existing MCB alarm (annunciator F-24), "RCS Delta T Deviation 3°F," should be used to indicate that the limiting acceptable value of drift had been reached. The assessment further recommended that a delta T span adjustment be performed for RPS channel 1. This would not affect the temperature indication provided by TE-401A, but would reduce the non-conservative drift effect from the calculated values of OTΔT and OPΔT. The calibration was satisfactorily performed on February 15, 1996.

The inspectors reviewed the licensee's assessment of the RPS channel 1 temperatures and evaluation of OTΔT and OPΔT setpoint margin, and noted no discrepancies. To further assess the licensee's evaluation of instrument drift, the inspector reviewed design analysis DA-EE-95-0109, "Evaluation of 24 Month Instrument Surveillance Intervals." The licensee performed this design analysis to provide justification for extending surveillance intervals in support of an 18 month operating cycle. The design analysis was performed pursuant to the guidance of Generic Letter 91-04, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle." The inspector noted that the licensee's method for projecting instrument drift was different than the methods contained in Instrument Society of America (ISA) Standard S67.04, "Setpoints for Nuclear Safety-Related Instrumentation." Conformance to this standard is not a requirement; however, in most cases that the inspector reviewed, the licensee's method was adequately conservative for assessing instrument drift.

The inspector concluded that nuclear engineering services provided timely, conservative support in resolving the TE-401A drift problem. TE-401A will be replaced during the 1996 refueling outage. The inspectors had no additional concerns on this matter.

### 3.3 Instrument Bus Inverter A Failure (IP 37551)

At 2:23 p.m. on March 12, 1996, a failure of instrument bus inverter A occurred. Operators were alerted to the condition by MCB annunciator E-3, "Inverter Trouble." As designed, power transferred automatically through the automatic static transfer switch to the associated constant voltage transformer, so power to instrument bus A was not lost. Failure of the A inverter placed the licensee in a 72 hour shutdown action statement per TS 3.8.7.

Investigation revealed that the inverter output fuses had blown and that there were numerous failed solid state electrical components in the inverter, including diodes and silicon controlled rectifiers (SCRs). The damaged components were replaced and the inverter operated satisfactorily; however,

after about 45 minutes, the output fuses blew again. During subsequent troubleshooting, a vendor representative noted that the inverter output voltage was slightly high. This was due to a group of capacitors whose capacitance had decreased with age, together with other capacitors that were replaced during the 1995 refueling outage. By the vendor's direction, the total capacitance was reduced to reduce the output voltage. This appeared to correct the problem, and the inverter was declared operable at 10:29 p.m. on March 14, 1996. However, at 10:48 a.m the following day, the inverter failed again. The licensee reentered TS action statement 3.8.7 with 15 hours and 54 minutes of the original 72 hours remaining.

Through the use of sophisticated monitoring equipment during subsequent troubleshooting, I&C technicians were able to capture and record an event in which inverter output frequency went from 60 Hz to 120 Hz and inverter current doubled. The cause of this event was traced to a defective integrated circuit (IC) chip on an oscillator board. The oscillator board was replaced and the inverter operated satisfactorily. Inverter A was declared operable at 2:11 a.m. on March 16, 1996, with 31 minutes remaining in the action statement.

The problem with inverter A was determined to be the defective IC chip that was randomly initiating the inverter startup sequence. The inverter initially starts up with a 120 Hz output (60 Hz during normal operation) and does so by doubling the normal SCR firing rate. The resultant high current when this occurred during normal operation caused the inverter output fuses to blow. Shop testing later demonstrated that the problem was temperature induced. This complicated troubleshooting, which was performed with the cabinet open and therefore at relatively cool temperatures. An earlier attempt to use infrared thermography for troubleshooting had shown the chip to have a "hot spot," but it was not recognized as the source of the problem, partly because there was no baseline information to compare it to.

The inspectors considered that the licensee's response to the inverter A failure was excellent with very good management direction and involvement. The vendor was promptly consulted and appropriately utilized during the extensive troubleshooting effort. The use of sophisticated monitoring equipment made it possible for I&C technicians to record a short duration event that led to identification of the problem. The inspector had no additional concerns on this matter.

## 4.0 PLANT SUPPORT

### 4.1 Emergency Preparedness (IP 82701)

#### 4.1.1 Conduct of Emergency Preparedness (EP) Activities

The inspectors reviewed the effectiveness of various licensee controls to maintain and manage the EP program. The inspectors conducted interviews, reviewed documentation, and investigated specific activities to assess this aspect of the licensee's performance.

The inspectors reviewed the licensee's efforts associated with the EP support to the steam generator replacement project (SGRP). Prior to this inspection,

the inspectors reviewed an inter-office memo from the Onsite Emergency Planner (OEP) to the Corporate Nuclear Emergency Planner (CNEP), Manager - Nuclear Assessment (MNA), and the Radiation Safety Communications Coordinator that discussed several contingencies which were planned for EP's involvement in the SGRP. The contingencies addressed scenarios including a fire, a radioactive release, mass casualty, steam generator drop, adverse weather, isolating containment penetrations, and loss of electrical power. The licensee's planning for these contingencies included procedures, equipment and facilities, personnel, and offsite support. The inspectors concluded that the licensee was proactive in this effort and had properly considered and satisfactorily planned to support the SGRP effort.

The inspectors reviewed the licensee's 1996 business plan (dated March 1, 1996) and identified several EP projects that were included. The plan includes such items as developing joint EP capabilities with other utilities, benchmarking the Nuclear Emergency Response Plan (NERP) public information program, utilizing an auto-dial system for off-hour call-outs, supporting the SGRP, implementing a severe accident management program, conducting "train the trainer" sessions for Nuclear Emergency Response Plan (NERP) instructors, and improving the process for tracking NERP responder qualifications. Based upon the review of the business plan, the inspectors concluded that licensee management has addressed EP functions and needs in its plan.

The inspectors reviewed the Commitment and Action Tracking System (CATS) and the EP items currently in the system. There were 15 open items (nine were from the December 1995 exercise) and none were overdue. All items were assigned to the low priority status, except for an item about the Reactor Vessel Level Indicating System. The inspectors agreed with the assigned priorities and had no concerns or questions regarding the use of CATS for EP items.

The inspectors reviewed the licensee's activities regarding a licensee-identified problem pertaining to its call-out drills. The call-out drills implement three Emergency Plan Implementing Procedures (EPIPs) (1-5, Notifications (Onsite); 3-6, Corporate Notifications; and 4-5, Public Affairs Notifications) to notify responders via a telephone tree. During the last NRC inspection of the licensee's EP program (Inspection Report No. 50-244/95-10), the licensee was modifying its notification process to place one-hour responders earlier in the telephone tree so that they could meet the one hour response goal. Since that inspection, the licensee conducted three quarterly call-out drills without fully satisfying all of the intended objectives. In each drill, there was a different reason for not meeting the drill objectives. In one, certain responders exceeded the one hour goal by several minutes and in the others, portions of the telephone tree were not completed due to a mis-communication and an individual failing to follow procedures. The inspectors did not consider these failures to be individually significant, but were concerned that the licensee continues to be unsuccessful in meeting objectives for this drill. The licensee plans to implement an auto-dialer system before the end of 1996 to notify the responders in a more timely and reliable manner. This will be reviewed in a future inspection (IFI 50-244/96-01-03).

The inspectors concluded that the licensee was actively involved in the EP function. Sufficient controls were implemented to monitor and assess EP group performance. The EP group is responsive to assigned CATS items and was appropriately self-critical regarding the call-out drill problems. Overall, the licensee's performance in this area was assessed as satisfactory.

4.1.2 Status of EP Facilities, Equipment and Resources

The inspectors conducted an audit of emergency equipment in the Station Control Room, Technical Support Center (TSC), Operations Support Center (OSC), Survey Center (SC), Assessment Facility (AF) and Emergency Operations Facility (EOF). The inspectors also reviewed records of various equipment inventory activities and test surveillances conducted during the past year and reviewed the capabilities of the licensee's communication system.

The inspectors checked several emergency equipment kits and emergency cabinets in the emergency facilities and found them to be appropriately stocked as directed by the licensee's procedures. The inspectors verified that survey meters, personnel dosimetry and respirator canisters were calibrated and were operationally ready.

The inspectors reviewed equipment inventories and surveillance test reports for 1995 and determined that equipment inventories were conducted at specified frequencies and checklists were properly completed and reviewed. Inventory lists included identified deficiencies and corrective actions were well documented.

While touring the EOF, the inspectors examined the survey team closet that contained radiological instrumentation, thermoluminescent dosimeters (TLDs) and field emergency kits. It was noted that five TLDs used for survey team members were in close proximity to an unshielded Cs-137 radioactive point source used for instrument response checks. The inspectors discussed with the licensee the potential exposure to the TLDs from the point source, possibly causing erroneous dose results. The licensee committed to placing the point source in a lead shield to prevent exposing the TLDs while in storage.

The Assessment Facility (AF) is located in the licensee's Training Center East. It has a sample preparation laboratory and a counting laboratory with a whole body counter, an alpha/beta gas flow proportional counter and a high resolution gamma spectrometry system with two detectors. The AF is routinely used as an environmental laboratory during normal plant operations. However, in accordance with the Nuclear Emergency Response Plan (NERP), Section 6.3.9, the AF is to be used for receiving and analyzing environmental samples collected by field survey teams during an emergency and, per Section 4.3.12, serves as a backup laboratory for analyzing post-accident sampling system (PASS) samples, if the in-plant laboratory should become inaccessible. In discussions with members of the chemistry department, the inspectors determined that, while the licensee's instrumentation in the AF is calibrated to analyze a PASS sample, there were no procedures for activating this facility as a radiological laboratory during an emergency nor were there procedures for analyzing radioactive samples in the AF. Further discussions with the OEP revealed that the following activities have never been exercised

at the AF in an emergency drill: 1) transporting potentially contaminated offsite environmental samples from the SC to the AF; 2) analyzing offsite samples; and 3) handling, transporting and analysis of a PASS sample. The lack of procedures and failure to exercise this facility are violations of 10 CFR Part 50.47(b)(8) and (14) which require emergency facilities and equipment be provided and maintained, and periodic exercises be conducted to evaluate major portions of the emergency response capability. **(VIO 50-244/96-01-04).**

The inspectors reviewed the licensee's communication system capabilities by interviewing the Manager, Communications Design and Support. The purpose of the interview was to obtain additional information for NRC evaluation on the communication systems and to follow-up on information gathered during the previous EP program inspection. The licensee's system appeared to be sufficiently redundant to ensure that a communication link could be maintained with offsite agencies during severe natural conditions.

The CNEP's and OEP's direct program oversight has resulted in an excellent equipment inventory and surveillance test program. With the exception of the violation regarding the AF, the emergency facilities and equipment were maintained in a state of operationally readiness.

**4.1.3 EP Procedures and Documentation**

The inspectors reviewed recent NERP and EPIP changes to assess the impact on the effectiveness of the EP program. The inspectors also assessed the process which the licensee uses to review EPIPs and changes made to them.

The inspectors reviewed recent changes to the licensee's NERP and EPIPs and determined that the changes did not reduce the effectiveness of the program. The inspectors randomly selected an EPIP that had been changed and reviewed it against the licensee's 10 CFR 50.54(q) review process, as well as the process described in administrative procedure A-205.2, "Emergency Plan Implementing Procedures Committee." The inspectors found that the licensee also performs a 10 CFR 50.59 safety review for procedure changes. No problems were identified.

The inspectors also reviewed NERP and EPIP changes in the regional office. Those are listed in Attachment 1. The inspectors determined that none of the changes decreased the effectiveness of the NERP.

The inspectors also reviewed the frequency of NERP and EPIP reviews against Section 7.2 of the NERP, Annual Review and Revision of the Plan and Procedures and A-601.4, "Procedure Control - Periodic Review." The inspectors verified that the licensee conducts annual reviews of the NERP and that PORC has reviewed the EPIPs within a five year period. However, the inspectors identified that the wording in the NERP was misleading with respect to the frequency of EPIP reviews and should be clarified to reflect the intended review cycle. The licensee agreed.

The licensee's NERP and EPIPs are sufficient to implement the EP program. The changes made to those documents and the change review process were acceptable. Overall, this area was assessed as satisfactory.

4.1.4 Staff Knowledge and Performance in EP

The CNEP and OEP have two opportunities annually to broaden their EP experiences. Both had recently visited other licensees to participate in audits or peer evaluations and had attended industry seminars pertaining to EP to maintain their proficiency.

The inspectors interviewed four TSC directors to assess the quality of NERP training that these individuals received. The inspectors had each director classify four events and explain their responses to making protective action recommendations (PARS) under changing plant conditions and how RVLIS values corresponded to core uncovery. The directors answered all of the questions correctly.

4.1.5 Staff Training and Qualification in EP

The inspectors reviewed EP training records, training procedures, lesson plans, EPIPs and the licensee's NERP to evaluate the licensee's EP Training Program. The inspectors also reviewed chemistry procedures and training records for operating the Post Accident Sampling System (PASS).

Using the ERO list, the inspectors randomly selected 50 individuals' training attendance records from the Training Department files. The records indicated that all of the selected ERO personnel had received their annual training and were qualified to fill their assigned emergency response positions. The inspectors verified that the CNEP had removed individuals from the ERO list who failed to meet training requirements, and that new ERO members had received the required training. The inspectors reviewed various EP lesson plans and determined that they met the objectives set forth in the Nuclear Emergency Response Plan Training Program Procedure, TR C.22.

The inspectors reviewed training agendas provided by the licensee and their contractor to local hospitals, township fire departments, sheriff offices and ambulance services against NERP, Section 7.1.4, Special Training for Participating Agencies, and found them to be very comprehensive. State and local agencies appear to be kept well informed of any NERP changes. The licensee also participated in numerous town meetings providing support to local agencies.

The inspectors also reviewed chemistry procedures for operating the PASS and found them to be comprehensive. The training records indicated that chemistry technicians received both classroom and hands-on training annually. In addition, the chemistry supervisor recently began to test technicians monthly on operating the PASS to maintain their proficiency. In 1995, the licensee conducted a semi-annual Health Physics drill to specifically test the adequacy of the PASS and found performance to be acceptable. Also, in October 1995, the NRC performed a radiological confirmatory measurements inspection (NRC

Inspection Report No. 50-244/95-18). During that inspection, the inspectors observed the licensee successfully taking a PASS reactor coolant sample.

The inspectors determined that the licensee maintained a good onsite training program and noted that the licensee is very diligent in providing training, conducting drills and maintaining an excellent rapport with state, local and emergency support entities. The licensee was fully capable of operating the PASS and technicians were well trained.

4.1.6 Organization and Administration

The licensee's EP organization and ERO have remained essentially stable since the last program inspection when a corporate reorganization had occurred. There were no changes in the management reporting chain for the EP group. The OEP, who has been in his position for over a year, reports to the CNEP, who reports to the MNA who then reports to the Vice President Nuclear Operations. The inspectors interviewed the CNEP and the MNA separately regarding the EP program, program initiatives and significant issues. All responses were consistent; therefore, the inspectors concluded that good communications exist within the EP group.

Neither the MNA or the CNEP has been assigned additional responsibilities since the last inspection. However, the inspectors observed a minor discrepancy in the organization chart in Figure 7.1 of the NERP. The chart in the NERP does not include Process Improvement as a reporting function to the MNA. The inspectors determined this to be insignificant and the licensee agreed to revise the NERP chart.

According to the CNEP, offsite personnel and organizations remained the same except that the director of the State's emergency management organization was replaced. The individuals who report to the director have remained the same. The inspectors concluded that offsite support has not been significantly effected by personnel changes.

The inspectors found that there were no changes to personnel in key ERO positions since the last EP program inspection and each ERO position is staffed with at least three qualified individuals. Overall, staffing of the licensee's organization and offsite entities have been stable.

4.1.7 Quality Assurance in EP Activities

The inspectors reviewed Audit Reports AINT-1996-0001-NAB and AINT-1995-0007-GFS, of the EP Department, conducted in 1996 and 1995, respectively. The inspectors also reviewed audit plans, checklists, procedures and interviewed personnel from the QA Department regarding the process for conducting a program audit.

Based on document review and interviews, the inspectors determined that the audits were conducted utilizing an audit plan and checklists and that the audit team included a technical specialist from another nuclear utility. The 1996 Audit Report stated that program deficiencies identified in 1995 were corrected with the exception of the licensee failing to keep telephone lists

current. The licensee is currently working to resolve this matter and it has been entered into the tracking system. Overall, the audits addressed the areas specified in 10 CFR 50.54(t).

However, the inspectors identified that QA had never audited the contractor used to audit, train, and provide radiological medical consultations to local hospitals, although other licensee contractors had been audited. The inspectors stated that an audit of the EP contractor, although not a requirement, would be beneficial to the program.

While interviewing the QA Manager and the Independent Assessor, the inspectors were informed that pre-audit interviews were conducted with the supervisor of the departments being audited. In accordance with QA Procedure QA-1803, "Performance of Quality Assurance Audits," the pre-audit conference with the supervisor is intended to "solicit scope additions and management concerns." According to the QA Manager, this conversation is used to solicit additional information, such as department deficiencies and problems, and is then added to the audit plan and checklist. The inspectors reviewed the audit plans and checklists from 1996 and 1995, and could not determine if information from the pre-audit interview was added to either the audit plan or checklist or what portion of the audit focused on the identified deficiencies or problems. The licensee stated that the pre-audit interview makes them aware of already existing problems which serves to better utilize the time spent in an audit.

The guideline in Section 4.3 of ANSI/ASME N45.2.12-1977, states that, "a brief pre-audit conference shall be conducted with the cognizant organization manager. The purpose of the conference shall be to confirm the audit scope, present the audit plan, introduce auditors, meet counterparts, discuss audit sequence and plans for the post-audit conference, and establish channels of communications." Also, Section 4.3.2.2 states, "objective evidence shall be examined for compliance with quality assurance program requirements." The inspectors agreed that a pre-audit conversation to discuss the scope of the audit is an acceptable practice, but having the audited supervisor identify deficiencies and problems could raise questions about the capability of the audit team to identify program problems independently. Also, the inspectors questioned the audit team's capability of remaining objective in reaching its conclusions if an issue has already been characterized as a problem by the supervisor prior to the audit.

While the contents of the audit reports satisfied 10 CFR 50.54(t) requirements, the inspectors was not able to determine if the audit was unduly biased by the pre-audit interview. Although the QA Manager believes this practice to be acceptable, he agreed to review the matter.

### 4.1.8 Miscellaneous EP Issues

<u>Updated Final Safety Analysis Report (UFSAR) Inconsistencies</u>

Since the Ginna UFSAR does not specifically include EP requirements, the inspectors compared licensee activities to the NERP, which is the applicable document. The following inconsistencies were noted between the emergency plan and licensee activities by the inspectors.

1. The inspectors reviewed Section 8.1 of the licensee's NERP describing recovery and noted that the Plant Operations Review Committee (PORC) is responsible for evaluating plant conditions, reviewing decontamination activities and necessary repairs prior to giving approval for plant reentry. The inspectors reviewed the PORC charter and noted that it did not mention their recovery phase responsibilities. Also, per the NERP, members of the recovery organization will be given recovery training annually.

   The inspectors discussed exercising recovery actions with the licensee. The licensee stated that at the conclusion of every exercise, the recovery manager discusses recovery actions with his staff. Additionally, the inspectors determined that recovery training is included in the annual emergency response requalification training. However, the licensee could not provide assurance that all PORC members are part of the ERO, and therefore, are receiving the emergency response requalification training. The licensee stated that the ERO and the training records would be reviewed to determine whether all PORC members receive the necessary training regarding their recovery phase responsibilities and the PORC Charter will be revised to be consistent with the NERP.

2. The Nuclear Emergency Planning Organizational Chart listed on NERP Figure 7.1 was compared to the EP departmental organization chart and it was determined that a minor discrepancy existed (See Section 4.1.6).

3. The licensee has never exercised the Assessment Facility for analyzing both onsite and offsite samples during an emergency. Also, the licensee does not have procedures for using this facility as a radiological laboratory. These are required by Section 7.1.5 and Section 6.3.9 of the NERP (See Section 4.1.2 and Notice of Violation).

<u>(Closed) IFI 50-244/95-19-01 Reactor Vessel Level Indication System (RVLIS) Discrepancies</u>

During the December 1995 exercise, confusion arose among participants pertaining to RVLIS. Specifically, it was uncertain what RVLIS value corresponded to the top of the fuel. The lead inspectors called two licensee personnel to obtain the correct value. The inspectors was given three different RVLIS values for the top of the fuel - 1) 42 percent was the value from the licensee's Emergency Response Data System (ERDS); 2) 55 percent was from an engineering drawing; and 3) 68 percent was from the emergency operating procedures (EOPs) setpoint book when in adverse containment conditions. The lead inspector asked the licensee to resolve the confusion and to ensure that the concept of adverse containment conditions, and its implication for all instrumentation readings, were understood by engineers in the TSC and EOF. The licensee agreed to correct the ERDS RVLIS value and to review all ERDS parameters to ensure accuracy. The licensee also agreed to ensure that the correct values and the concept of adverse containment condition values would be properly incorporated into all procedures.

Since that time, the licensee conducted training and revised the core damage procedure and appropriate EAL basis to clarify the issue. The value to be

used for the top of the fuel is 68 percent, which is the value used in the EOPs and which incorporates instrument uncertainties associated with adverse containment conditions. During this inspection, the inspectors verified the effectiveness of the licensee's training by questioning four TSC directors about RVLIS. Their answers were correct and consistent with licensee expectations. The licensee also revised EPIP 2-16, "Core Damage Estimation," by cautioning users to utilize the setpoints and instructions found in the EOPs and to consider core exit thermocouple temperatures, in addition to water level, when analyzing core conditions. The licensee also added an engineering diagram depicting RVLIS values to their corresponding reactor vessel location to assist personnel in assessing core uncovery. The licensee changed the wording in several emergency action level basis documents to clarify minimum level for core cooling. The licensee is currently reviewing and revising its ERDS data point library to ensure that RVLIS and other values are correct. Based upon the licensee's corrective action to this issue, this item is closed.

(Closed) URI 50-244/93-18-02 Untimely Protective Action Recommendation

During the November 1993 exercise, an area for potential improvement was noted regarding a failure to issue a timely PAR. When a General Emergency (GE) is declared, a PAR is to be issued with the 15-minute notification. The licensee's notification form listed four choices for PARs: 1) There is no need for protective actions outside the site boundary; 2) Need for protective action is under evaluation; 3) Sheltering recommended; and 4) Evacuation recommended. During the exercise, the GE was declared at approximately 10:15 a.m. At 10:25 a.m., the licensee issued the PAR - "Need for protective action is under evaluation." The licensee was prepared to issue a PAR based on plant conditions at the time of the GE declaration; however, prior to making the offsite notifications, plant conditions changed such that the PAR also changed. The licensee took time to evaluate the latest plant and radiological conditions to make the appropriate PAR, and correctly issued the PAR to shelter at 10:55 a.m. This was 40 minutes after the GE had been declared and did not meet the 15 minute goal.

During inspection 94-21, the inspectors determined that the licensee deleted "Need for protective action is under evaluation" as a PAR option. This removed the implication that PAR issuance can be delayed. Also, the inspectors reviewed requalification training lesson plans and confirmed that the objective of issuing a PAR within 15 minute of the GE declaration had been emphasized to potential decision-makers. However, due to the potential public impact of delaying a PAR, this issue remained open pending the timely and accurate PAR issuance by the licensee during an NRC evaluated exercise.

During the licensee's December 6, 1995 full-participation exercise (Inspection Report 95-19), the licensee successfully demonstrated the timely and accurate issuance of PARs. Due to an administrative oversight, this item was not closed at that time. The inspectors determined that the licensee's performance during the December 1995 exercise was sufficient to close URI 50-244/93-18-02.

## 4.2 Radioactive Liquid and Gaseous Effluent Control Programs (IP 84750)

### 4.2.1 Management Controls

Program Changes

The inspector reviewed the organization and administration of the radioactive liquid and gaseous effluent control programs. The inspector determined that there were no changes to the radioactive effluent control programs since the last inspection conducted in July 1994. The Chemistry Department has primary responsibility for conducting the radioactive liquid and gaseous effluent control programs. Other responsible groups for the programs are: 1) Operations, 2) Instrument and Controls (I&C), 3) System Engineers, 4) Results and Test (R&T), and 5) Radwaste Operations.

Quality Assurance (QA) Audits

The inspector reviewed the 1995 QA audit report (Report No. AINT-1995-0010 -GFS), required by Section 6.5.2.8 of the technical specifications (TS). The QA audit covered eight areas, including radioactive liquid and gaseous effluent control programs, radiation protection, and the Radiological Environmental Monitoring Program. There were no audit findings or deficiencies identified by the 1995 audit team for the effluent control programs. Based on the 1995 audit report review, the inspectors determined that the licensee met the TS requirement.

Review of Semiannual/Annual Radioactive Effluent Reports

The inspector reviewed the 1994 semiannual and the 1995 annual radioactive effluent release reports. These reports provided data indicating total released radioactivity for liquid and gaseous effluents. These reports also summarized the assessment of the projected maximum individual and population doses resulting from routine radioactive airborne and liquid effluents. Projected doses were well below the TS limits. The inspector determined that there were no obvious anomalous measurements or omissions in the reports.

### 4.2.2 Review of Off-Site Dose Calculation Manual (ODCM)

The inspector reviewed the licensee's current ODCM (effective date February 24, 1996). The ODCM provided descriptions of the sampling and analysis programs that are established for quantifying radioactive liquid and gaseous effluent concentrations and for calculating projected doses to the public. All necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, site-specific dilution factors, and dose factors, were listed in the ODCM. The licensee adopted other necessary parameters from Regulatory Guide 1.109.

Based on the above review, the inspector determined that the licensee's ODCM contained all necessary information and instruction to establish and implement the radioactive liquid and gaseous effluent control programs and the Radiological Environmental Monitoring Program.

### 4.2.3 Radioactive Liquid And Gaseous Effluent Control Programs

To determine the implementation of the TS and the ODCM requirements, the inspectors toured the plant, reviewed the following selected licensee's procedures, and reviewed selected radioactive liquid and gaseous discharge permits:

- CH-RETS-Minipurge
- CH-RETS-Purge-CV
- CH-RETS-PV-Release
- CH-RETS-GDT-Release
- CH-RETS-LIQ-Release

During the tour, the inspector noted that all effluent radiation monitoring systems (RMS) were operable at the time of this inspection. During the review of the above radioactive liquid and gaseous effluent procedures, the inspector noted that the procedures were easy to follow and contained sufficient level of detail.

The inspector also determined that the reviewed discharge permits were complete and met the TS/ODCM requirements for sampling and analyses at the required frequencies and met the lower limits of detection established in the ODCM.

### 4.2.4 Steam Generator Blowdown Tank and Spent Fuel Pool Leakages

This portion of the inspection evaluated the licensee's efforts to accurately quantify and characterize suspected leakage from the steam generator blowdown tank and the spent fuel pool system, and potential dose consequences of any releases to the environment. This evaluation focused on the licensee's actions and their results in this area since January 1996 and future plans with respect to the steam generator blowdown tank and the spent fuel pool system.

<u>Steam Generator (S/G) Blowdown Tank Leakage</u>

On January 5, 1996, the licensee noted that small amounts of iodine-131 (I-131) and iodine-133 (I-133) were measured in grab samples taken from the turbine building retention tank and the intermediate subbasement ground water in-leakage. Further licensee investigation results revealed that the origin of the leakage was from the discharge piping of the steam generator (SG) blowdown tank. The retention tank, also known as the turbine building drains tank, is located in the turbine building and collects drainage from miscellaneous drains such as roof drains and floor drains. The licensee was not able to determine the leak rate, because there is no flow measurement instrument installed for measuring the flow rate downstream of the blowdown tank. Therefore, the total amount of leakage to the soil under the turbine building floor was not known. The licensee speculated that the leakage was small, because iodine activities from the retention tank and the intermediate subbasement ground water in-leakage were very low. During the outage in April 1996, the licensee plans to modify the discharge piping, which is expected to stop this leakage pathway.

The licensee took routine grab samples from the SG blowdown tank and analyzed them for gamma emitters and tritium. The licensee also performed the projected dose assessment, as required by the TS and the ODCM. The inspector reviewed the analytical results and the projected dose assessment results, which were calculated based on the total release of the SG blowdown tank for the period of January to February 1996. Major gamma emitters were radioiodines with range of 1E-6 to 1E-7 μCi/cc. Tritium activity was about 1E-4 μCi/cc. The maximum projected thyroid doses for January and February was 1.99E-2 mrem and 2.58E-2 mrem, respectively. These values were well below regulatory limits. The licensee suspects that a small fraction of radioiodines (mainly I-131 and I-133) may be deposited in soil under the turbine building floor, while tritium may be migrating into ground water.

Based on the above reviews and short half-life of radioiodines, the inspectors determined that the leakage was not currently of sufficient magnitude to affect public health and safety or the environment.

Spent Fuel Pool Leakage

During previous inspections (Inspection Report Nos: 50-244/95-20 and 95-21), an NRC inspector reviewed the licensee's investigation results for the suspected fuel pool leakage, including planned future actions.

There are three on-site environmental wells located northeast (Well C), southeast (Well B), and southwest (Well A) of the plant. Analytical results of tritium at Wells A and B suggested that tritium activities had not increased since November 1995. But tritium activities at Well C had increased since September 1995, as shown in Table 1.

Table 1 - Analytical Results of Tritium for On-Site Environmental Wells

Unit: μCi/cc

| Date | Well A | Well B | Well C |
|---|---|---|---|
| 9-1-95 | No Measurement | No Measurement | 1.76E-6 |
| 10-16-95 | No Measurement | No Measurement | 6.90E-7 |
| 11-8-95 | 1.74E-8 | 4.98E-7 | No Measurement |
| 11-17-95 | 6.31E-8 | No Measurement | 2.02E-7 |
| 11-28-95 | -3.80E-8 (*) | 3.45E-7 | -1.74E-7 (*) |
| 12-15-95 | 6.58E-7 | 1.96E-6 | 2.05E-6 |
| 1-18-96 | No Measurement | No Measurement | 4.16E-6 |
| 1-25-96 | No Measurement | No Measurement | 3.40E-6 |
| 2-7-96 | No Measurement | No Measurement | 1.53E-5 |
| 2-23-96 | No Measurement | No Measurement | 1.75E-5 |

*Below the minimum detection level. Normal environmental background is approximately 1E-7 $\mu$Ci/cc.

Well C was the optimum location to monitor possible environmental release through ground water due to the prevalent northeasterly direction of ground water flow. Analytical results of Wells A and B were used as environmental background, since they are upstream of the underground water flow.

During this inspection, the inspector discussed the site hydrology with the licensee and a consultant. The consultant (Dr. R. Poreda, Associate Professor, University of Rochester) presented tritium underground migration study results, and described the underground water mixing ratio. The high-mixing ratio indicated relatively low underground water movement. The mixing ratio at the Well C was the highest and suggested that the underground water movement was slow at this location. This study supports the slow tritium increase seen at Well C, as illustrated in Table 1.

The depth of Well C is about 20 feet from ground level. In order to assess the underground water movement better, a new deep well adjacent to Well C has been recommended by the licensee's consultant to obtain better characterization and representation of suspected leakage to the environment.

**4.2.5 NRC Assessment and Planned Licensee Action**

Based on reviews of limited analytical data and interviews with the licensee and its contractor, the inspector made the following conclusions:

- The sources of contamination at Well C may be multiple, such as leakage from the spent fuel pool and SG blowdown tank. Routine discharge pathways, such as condenser air ejector effluents, might also contribute to the tritium activity at Well C; and,

- The suspected leakage from the spent fuel pool and the SG blowdown tank, do not currently impact public health and safety and the environment.

In an effort to provide for assessment of suspected leakage, the licensee plans to:

- Install a deeper monitoring well (or a multi-level monitoring well) adjacent to Well C and analyze ground water samples;

- Continue to monitor and analyze samples from on-site Wells A, B, and C;

- Continue to monitor and evaluate the ground water movement; and,

- Determine actions for resolution of remediation of suspected leakage.

- Apply an epoxy coating to the bottom of the fuel transfer canal to stop leakage through the foundation bolts supporting the fuel transfer cart rails.

The inspector found the licensee's current action plan to be appropriately scoped.

4.2.6 Calibration of Effluent/Process RMS

The inspector reviewed the most recent calibration results for the following effluent/process RMS to determine the implementation of the TS requirements:

- RE-10A, Containment Iodine Gamma Detector
- RE-12, Containment Gas Detector
- R-12A, Containment Purge (SPING-4)
- R-14A, Plant Vent (SPING-4)
- R-15A, Condenser Air Ejector (SPING-4)
- RE-17, Component Cooling Water Detector
- RE-18, Liquid Waste Disposal
- RE-19, Steam Generator Blowdown
- RE-20 A&B, Spent Fuel Pit Service Water Detectors

The I&C Department and the RP/Chemistry Department had the responsibility to perform electronic and radiological calibrations, respectively, for the above radiation monitors. All reviewed calibration results were within the licensee's acceptance criteria.

The inspector discussed the maintenance of operability/reliability with the members of the I&C and RP/Chemistry staff. From these interviews, the inspector determined that these individuals had good knowledge of the RMS relative to operability requirements and performance history. The inspector noted that the RMS read-out devices in the control room were replaced with digital devices. Consequently, calibration results are more reliable because more accurate readings can be obtained. The inspector also noted that the licensee performed daily trending analysis for the above RMS in the main control room. The licensee plots RMS readings twice in a day on the control charts to track any changes. The inspector stated that the tracking of RMS readings was an excellent effort to verify the system operability and reliability.

Based on the above reviews, the inspector determined that the licensee's performance and achievements, relative to calibration of the RMS and the upgrading projects, were sufficient to demonstrate good operability and reliability of the system.

4.2.7 Air-Cleaning Systems

<u>Air-Cleaning Systems Required by the Technical Specification</u>

The inspector reviewed the licensee's most recent surveillance test results to determine the implementation of TS requirements for the: 1) control room emergency air supply systems, and 2) containment air recirculation system. The inspector reviewed the following surveillance test results:

- Visual Inspection
- In-Place HEPA Leak Tests

- In-Place Charcoal Leak Tests
- Air Capacity Tests
- Pressure Drop Tests
- Laboratory Tests for the Iodine Collection Efficiencies

All test results were within the licensee's TS acceptance criteria. The inspector had no further questions in the above surveillance tests.

Air-Cleaning Systems Described in the Updated Final Safety Analysis Report (UFSAR)

During the reviews of other air-cleaning systems committed by the UFSAR, the inspector noted that the licensee's procedure did not have acceptance criteria for the airflow capacity test and resulted deviations from the UFSAR commitments. The current industry practice for the acceptance criteria of the airflow capacity test is ±10 percent of the designed flow. These acceptance criteria are also listed in ANSI N510-1986. The following was noted:

- UFSAR 6.4.2.2.1: Airflow capacity for the Control Room during the normal operation is 8,045 cfm.

  Surveillance Results: 2-5-94: 12,821 scfm
  4-13-95: 10,431 scfm

- UFSAR 12.3.3.2: Airflow capacity for the Plant Vent is 75,000 cfm. The value is being used for the setpoint calculation, as defined in the ODCM.

  Surveillance Results:

  | | | |
  |---|---|---|
  | 3-31-92: | 66,554 scfm for A-Train | |
  | | 68,819 scfm for B-Train | |
  | 3-8-94: | 67,364 scfm for A-Train | |
  | | 75,662 scfm for B-Train | |
  | 3-21-95: | 63,139 scfm for A-Train | |
  | | 68,247 scfm for B-Train | |
  | 10-5-95: | 61,660 scfm for A-Train | |
  | | No data for B-Train | |

- Auxiliary Building Ventilation System: No airflow capacity was defined in the UFSAR. Therefore, the licensee assumed, based on nominal air flow per filter (84 HEPA filters x 1,000 cfm per filter = 84,000 cfm).

The inspector noted that the UFSAR did not provide any acceptance criteria for the air capacity test, and the listed values for the above systems were vague relative to design requirements. Although these apparent discrepancies between surveillance tasks and the values listed in the UFSAR do not have a significant impact on public health and safety and the environment, the inspector stated that: 1) airflow capacity test procedures should be updated to follow the industry practice; 2) design-base airflow capacity should be retrieved from the original design basis, rather than assumed (e.g., auxiliary

building ventilation system); and, 3) UFSAR should be reviewed and updated to reflect the current plant designs and configurations. This item is considered unresolved pending further review (URI 50-244/96-01-05). The licensee stated that the UFSAR is being reviewed and will be updated.

### 4.3 Radioactive Waste Storage, Processing Systems, and Equipment (IP 71750)

The Waste Disposal System (WDS) at the Ginna Station consists of three subsystems used to collect and process all potentially radioactive liquid, gaseous, and solid waste. All the equipment for these subsystems has been in place since original plant construction, except for the a liquid waste evaporator that was removed from service and abandoned in place in 1990 and an ultra filtration unit physically removed from the plant in 1980. Radioactive fluids entering the WDS are collected in sumps and tanks until a determination is made on the type and level of treatment necessary. The fluids are sampled and analyzed to determine the level of radioactivity before any discharge is made. Liquid wastes requiring cleanup before release are collected and processed by a vendor supplied demineralization system. All solid waste is packaged and stored on site until they are shipped offsite for disposal. Gaseous waste is pumped to a gas decay tank where it is held for a suitable decay period. The gases are then discharged intermittently at a controlled rate through a monitored plant vent. The principle components of the WDS include the following:

1) Miscellaneous Waste Disposal System (radio chemistry laboratory drain tank and discharge pump; laundry hot shower tanks; intermediate building sump pump)
2) Liquid waste drains, waste holdup tank (auxiliary building equipment and floor drains)
3) Spent resin tanks and cubicle
4) Liquid waste evaporator and waste condensate tanks (abandoned in place, no maintenance required)
5) Reactor coolant drain tank
6) Gas waste disposal system (gas compressors, compressor moisture separators and compressor seal heat exchangers, and gas decay tanks)

The inspector discussed the radiological conditions present in the WDS equipment with the principle health physicists at the station. There are currently no hot spots or high exposure areas that are accessible to personnel, and no spills of radioactive material have occurred from the WDS since an incident in 1983. No residual effects from that incident appear to remain. No excess personnel exposure or contamination incidents have occurred in recent years from the use of these systems.

The system engineer for the waste disposal systems conducts quarterly walkdown inspections. For each walkdown, the engineer documents the condition of the equipment and identifies any deficient conditions that require corrective action follow-up. The most recent walkdowns were performed in February 1996 and no conditions requiring immediate maintenance were identified. Minor discrepancies were noted and were scheduled for routine maintenance. Portions of the radwaste systems already have established performance criteria since they will fall within the scope of 10 CFR 50.65 (Maintenance Rule) in July

1996. The system engineer performed a two year historical evaluation of these systems and documented the amount of corrective maintenance and the modifications made over that period. The inspector reviewed this documentation and determined that the amount of corrective maintenance and the number of modifications have not been significant.

The inspector reviewed the P&IDs for these systems and conducted visual inspections of all accessible equipment. Overall, these systems are well maintained and do not appear to represent a significant radiological hazard to plant personnel. All areas and equipment observed are serviced by the filtered ventilation system for the auxiliary building, and fire protection systems also were present in these areas. Section 1.2.6 of the UFSAR for the Ginna Station contains a brief description of the purpose and use of the Waste Disposal System. The description indicates that the system collects and processes for disposal all potentially radioactive liquids, gaseous, and solid waste resulting from reactor operation and cleans up all effluents released to the environment to concentration levels below those required by 10 CFR 20. Operating procedures are designed to limit normal effluents to within the limits required by 10 CFR 50, Appendix I. Solid wastes produced at the Ginna Station are packaged and shipped for disposal at authorized locations. The inspector concluded that no inconsistencies appear to exist between the UFSAR description of the waste disposal system and its use, and the system installed and used in the plant. The inspector also determined that there does not appear to be a need for enhanced inspection of these systems beyond the routine inspections currently performed.

Contaminated Storage Building (CSB)

The licensee maintains a separate facility at the Ginna Station with a controlled environment for storing contaminated and reusable tools and equipment. Equipment that can be decontaminated to less than 8 mR/hr on contact is stored in containers that protect the equipment and personnel. The general area background levels inside the CSB are currently about 1 mR/hr. The CSB also contains a specially designed work area for decontaminating the stored items after they are used. The work area contains the appropriate facilities for filtered ventilation and collection sinks for capturing liquids and solids removed during the decontamination work. The inspector toured the CSB and observed the arrangement of stored equipment and plant personnel handling and processing materials and equipment returning to storage. The radiological controls in place appeared to be effective and the general state of housekeeping in the CSB was very good.

Video Inspection of Spent Resin Tank Room

The two spent resin tanks at Ginna are located inside a cubicle in the lower level of the Auxiliary Building adjacent to the charging pump room. The cubicle has been blocked off to personnel access since late 1970 due to the high radiation levels present inside the cubicle after the first plant operating cycle. An unsealed concrete block barrier completely fills the inner doorway into this area and provides shielding from the high radiation inside. The outer doorway in front of the concrete blocks is maintained as a locked high radiation area. The cubicle was last entered for a radiological

survey in 1993 after all spent resin stored onsite was shipped away for disposal. The cubicle contains two 150 $ft^3$ capacity resin tanks and associated piping to store contaminated spent resin from the CVCS purification system demineralizers.

Routine entries for surveys are not made into the cubicle since all valves and operator controls for the equipment are located outside the cubicle. However, on March 20, 1996, the licensee removed one row of concrete blocks at the top of the doorway to gain access for a remote radiation survey, and for a remote color video inspection. The inspector observed the inspection on a remote monitor and noted the material condition of the cubicle. Most areas were visible to the camera except directly under the two tanks. One tank contained approximately 40 $ft^3$ of spent resin and was creating a radiation field of 400 mR/hr just on the inside surface of the block wall. Both tanks and all of their associated piping are stainless steel. The equipment also appeared to be in very good condition, and was not deteriorating. There were no signs of current leakage of any liquid or resin from any of the piping or tanks. The walls and floors of the cubicle were dry. A padlock and small piece of sheet metal were noted on the floor; however, the cubicle was otherwise clean, and was not being used to store any waste material in barrels or other containers. Overall, the cubicle appeared to be in very good condition and did not represent a potential hazard to personnel. The 40 $ft^3$ of spent resin in one tank represents the total stored inventory onsite at the present time.

The auxiliary building also contains a "DI Vault" which houses several deionization vessels used in the CVCS purification system, the SFP cleanup system, and other purification systems in the plant. This vault was also blocked off to personnel access in 1970 due to the very high radiation levels inside. The last radiological survey available for this vault was taken in February 1988 and indicated that tank surface contact readings varied from 2 - 10 R/hr. The survey also indicated the presence of a small amount of water on the floor that was apparently leaking from a pipe in the overhead of the vault. The licensee was not able to confirm whether there is currently any water present in the vault, or if any maintenance was performed on interior piping in 1988. However, the inspector observed that the block wall in the access doorway was not sealed, and there was no water present at the exterior base of the wall. The licensee agreed to perform a remote video inspection of the vault during the current refueling outage, and will document the general condition of equipment and the radiation levels in the room.

## 4.4 Steam Generator (SG) Replacement Security Program

### 4.4.1 Plant Modifications

The inspector reviewed the licensee's proposed security program modifications necessary for the SG replacement program. The modifications were designed to include devitalizing the containment vessel for a period during the SG replacement project, and then revitalizing the containment after its integrity is reestablished and appropriate verifications of systems and equipment are complete.

The containment is being devitalized because the SG replacement project requires cutting large holes into the top of containment (a vital area barrier). Implementation of adequate compensatory measures for the degraded barrier was deemed impractical.

The containment devitalization program requires the installation of a new door to provide a new access route to containment that does not require passing through other vital areas. In addition to the installation of a new door, temporary barriers installed around the containment personnel entry area were intended to separate the de-vitalized area from adjacent vital areas. At the conclusion of the inspection, the installation of the door was not complete and the installation of the temporary barriers had not begun; however, the inspector's walkdown of area to be modified and review of the proposed modifications identified no apparent weaknesses in the proposal.

### 4.4.2 Procedures

The inspector reviewed security post orders developed for the security posts at the containment personnel hatch. The post orders were developed for use when the containment is vital and also when it is devitalized. No weaknesses were noted in the post orders.

The modifications to the NRC-approved security plan for the SG replacement program were submitted to the NRC, in accordance with the provisions of 10 CFR 50.54(p), on January 15, 1996. The NRC notified the licensee by letter, dated March 18, 1996, that the changes had been reviewed and were determined to be consistent with the provision of 10 CFR 50.54(p) and were acceptable for inclusion in the security plan.

### 4.4.3 Security Organization

The inspector's review determined that the licensee had augmented the existing security organization with eight temporary security officers to support the SG replacement project. The inspector reviewed the training records for four of the eight officers and determined that they had been trained and qualified as unarmed guards, in accordance with the provisions of the NRC-approved security training and qualification plan.

No weaknesses were noted during the review of the training records of the temporary officers.

## 5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (IP 71707)

### 5.1 Reactor Fuel Receipt Inspection

The licensee received four separate shipments of new reactor fuel on February 22 and 27, and March 1 and 8, 1996. A total of forty new fuel assemblies were delivered with ten assemblies in each shipment. On February 28 and March 1, 1996 the inspectors observed receipt inspection of new assemblies by a QC inspector during unpacking from the shipping containers and during temporary storage. After being unpacked, each assembly was placed into a designated storage rack inside an enclosure designed specifically for

new fuel storage. The enclosure was maintained locked for restricted access and foreign material exclusion controls were in effect with fuel present. Each shipping container was inspected for damage, seal and shock mount integrity, tight closure hardware and clamps, and the internal accelerometers were verified to be unactuated. Each assembly was carefully rigged out of its container, unwrapped, and set into its storage rack prior to receipt inspection.

A detailed visual examination of each assembly was performed by the QC inspector to verify the assembly identification and ANSI numbers, the lack of physical distortion or damage, the lack of foreign material, and the condition of the assembly grid straps. The QC inspector identified two fuel assemblies (F56 and F72) with bent tabs on their grid straps during the receipt inspection. It did not appear that the bent tabs caused damaged to any of the adjacent fuel pins, but they did not allow for the required gap around each pin. The QC inspector documented these conditions and initiated an ACTION Report to initiate corrective actions. The condition was not significant enough to reject the assemblies; however, a fuel vendor representative came to the Ginna Station on March 1, 1996 to perform a repair of the tabs. After the repair was made, a complete receipt inspection was reperformed with satisfactory results on the two assemblies.

The inspectors reviewed the QC records after the receipt inspection was completed on all assemblies. The documentation was accurate and complete. Overall the receipt inspection process for the new fuel was thorough and well controlled.

## 5.2 Periodic Reports

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

- Monthly Operating Reports for January and February 1996

No unacceptable conditions were identified.

## 5.3 Licensee Event Reports

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

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

- LER 96-001, Inservice Test Not Performed During Refueling Outage, Due to Inadequate Tracking of Surveillance Frequency, Resulted in Violation of Technical Specification (May 4, 1995)

This event represented a violation of the technical specification requirement to implement an inservice test program. In this case, the violation was of a condition of a relief request, which specified that the valve at issue be disassembled for the purpose of IST every other year during a refueling outage; although the valve had been disassembled for this purpose less than two years earlier, it had not been done during a refueling outage. The licensee noted that the valve at issue was in an IST group with a maximum acceptable inspection interval of six years. This violation is not being cited because it was of minimal safety significance, and the valve was inspected within a two year interval. This event is further discussed in Section 2.1.1 of this report. LER 96-001 is closed.

## 6.0 ADMINISTRATIVE (IP 71707)

### 6.1 Senior NRC Management Site Visits

During this inspection period, two senior NRC managers visited Ginna Station. On March 4, 1996, Mr. Richard W. Cooper, Director of the Division of Reactor Projects, Region I, toured the site and met with senior licensee management. On February 12-14, 1996, Mr. Lawrence T. Doerflein, Chief of Reactor Projects Branch No. 1, Region I, toured the site and met with senior licensee management.

### 6.2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. Inconsistencies were noted between the wording of the UFSAR and the plant practices procedures, and/or parameters observed by the inspectors in the areas of emergency preparedness and air cleaning systems as described in sections 4.1.8 and 4.2.7, respectively.

### 6.3 Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of inspections. The exit meeting for the steam generator replacement project engineering preparations (section 3.1 of this report, conducted February 5-9, 1996) was held by Mr. Suresh Chaudhary on February 9, 1996. The exit meeting for the effluents monitoring program inspection (section 4.2 of this report, conducted March 4-8, 1996) was held by Mr. Jason Jang on March 8, 1996. The exit meeting for the emergency preparedness program inspection (section 4.1

of this report, conducted March 11-14, 1996) was held by Mr. David Silk on March 14, 1996. The exit meeting for the current resident inspection report 50-244/96-01 was held on March 29, 1996.

## ATTACHMENT 1

## REVIEW OF THE NERP AND EPIPs

An in-office review of revisions to the NERP and EPIPs submitted by the licensee was completed. A list of the specific revisions reviewed are included in Attachment 1. The inspectors concluded that the revisions did not reduce the effectiveness of the NERP and were acceptable.

| Procedure No. | Procedure Title | Revision(s) |
|---|---|---|
| | Nuclear Emergency Response Plan | 15 |
| EPIP 1-0 | Ginna Station Event Evaluation and Classification | 21,22 |
| EPIP 1-5 | Notifications | 25 |
| EPIP 1-9 | Technical Support Center Activation | 7 |
| EPIP 1-10 | Operational Support Center (OSC) Activation | 5 |
| EPIP 1-11 | Survey Center Activation | 10 |
| EPIP 1-14 | Station Call List | 8 |
| EPIP 2-2 | Obtaining Meteorological Data and Forecasts and Their Use in Emergency Dose Assessment | 7 |
| EPIP 2-3 | Emergency Release Rate Determination | 8 |
| EPIP 2-4 | Emergency Dose Projections - Manual Method | 9 |
| EPIP 2-6 | Emergency Dose Projection - Midas Program | 7 |
| EPIP 2-9 | Administration of Potassium Iodine KI | 2 |
| EPIP 2-16 | Core Damage Estimation | 6 |
| EPIP 2-18 | Control Room Dose Assessment | 8 |
| EPIP 3-3 | Immediate Entry | 3 |
| EPIP 3-6 | Corporate Notifications | 22 |
| EPIP 4-1 | Public Information Response to an Unusual Event | 5 |
| EPIP 4-3 | Accidental Activation of Ginna Emergency Notification System Sirens | 6 |
| EPIP 5-2 | Onsite Emergency Response Facilities and Equipment Periodic Inventory Checks and Testing | 12,13 |
| EPIP 5-3 | Testing the Ability to Notify Primary NERP Responders | 14 |
| EPIP 5-4 | Emergency Plan Implementing Procedure (EPIP) Training Program | 15 |