U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/93-16 **License: DPR-18**

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

Inspection: August 1 through September 11, 1993

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Approved by: for 10/7/93
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INSPECTION SCOPE

Plant operations, maintenance, engineering, and plant support.

INSPECTION OVERVIEW

Operations

On August 29, 1993, alert watchstanding and decisive operator action averted a significant plant transient, when a rapid power reduction to 70 percent was performed after an auxiliary operator noted oil/water leakage from the "B" heater drain tank pump motor. While repairs were in progress, power was further reduced to just below 50 percent to plug main condenser tube leaks. Full power operation resumed on August 31, 1993.

The plant operated at full power for the balance of the inspection period.

A program to upgrade plant valve tagging was approximately 96 percent complete.

Maintenance

Good concern for the failed pressurizer relief tank level indication, a plant indication not required by technical specifications, led to installation of a temporary modification to restore this indication.

Inadequate electrical safety precautions during maintenance on a component cooling water pump discharge pressure instrument led to a technician receiving an electrical shock. Although the individual was not seriously injured, the incident was not promptly reported to the control room; as a result, a tripped instrument bus breaker that affected the redundancy of an ESF function was not promptly identified.

(INSPECTION OVERVIEW CONTINUED)

The Maintenance Procedure Upgrade Program was approximately 60 percent complete, and was generating procedures of exceptional quality.

Engineering

Difficulty with service water system ultrasonic flow instrumentation led to identification of a problem with the existing transducer mounting arrangement.

The licensee's procedures for implementation of 10 CFR 50.59 requirements were reviewed and found to be thorough.

Plant Support

Comprehensive corrective action was implemented in response to an automatic roll-down fire door being obstructed.

Good radiological control practices were observed during the on-site portion of the annual emergency radiation injury drill. However, one minor deficiency was noted, in that daily source checks had not been performed for two unattended portable radiacs.

A joint emergency preparedness meeting was constructive in discussing the roles of the represented state and county agencies when responding to various emergency action levels.

The inspector reviewed the licensee's program to provide employees, who wish to raise safety issues, alternate paths to express these concerns without fear of retribution. The existing program for employees to confidentially report issues was not well managed; actions were being taken to improve its effectiveness.

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DETAILS

1.0 OPERATIONS (71707)

1.1 Operational Experiences

The plant operated at full power (approximately 98 percent) throughout the inspection period. On August 29, 1993, plant power was reduced to 70 percent (the limit for operation with a single heater drain tank pump in service) due to impending failure of the "B" heater drain tank pump motor. Power was subsequently reduced to just below 50 percent for correction of main condenser tube leaks. Following completion of repairs, full power operations resumed on August 31, 1993. There were no other significant operational events during the inspection period.

1.2 Control of Operations

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

1.3 "B" Heater Drain Tank Pump Motor Oil Cooler Service Water Leak

On August 29, 1993, an auxiliary operator observed a mixture of oil and water coming out of the "B" heater drain tank (HDT) pump motor upper bearing oil cooler fill line. The auxiliary operator informed the control room, and the shift supervisor responded to the scene. When the shift supervisor observed the situation, he immediately directed that a rapid plant power reduction be commenced. Reactor power was reduced at the rate of one percent per minute to the point at which two HDT pumps were no longer required (70 percent), and the "B" HDT pump was secured. As a result of this transient, reactor axial flux difference (AFD) exceeded the target band, as defined in technical specification 3.10.2.8, for a period of 39 minutes. This was an expected consequence of such a rapid downpower transient, and was allowed for by technical specification 3.10.2.10.a; because AFD remained within the limits prescribed by this technical specification, no operational restrictions were incurred.

The "B" HDT motor was removed for repairs. Electrical testing indicated that the motor insulation was not damaged. The rotor and stator were sent to a local vendor to be steam cleaned and dried. The cause of the problem was found to be a service water leak in the upper motor bearing oil reservoir heat exchanger. Ultrasonic examination of the copper piping indicated that approximately 50 percent thinning had occurred; this was consistent with the degree of thinning experienced in other plant components of similar age that use copper piping

in service water applications. The pinhole leak had developed from a small dented area on the pipe. Based on previous metallurgical analysis of a similar copper piping failure, the licensee concluded that the cause of failure had been a combination of age-related wall thinning and localized oxidation in the area of the dent, caused by sodium hypochlorite (which is added to the service water system for control of biofouling). The leak was repaired by silver soldering. During reassembly, new motor bearings were installed and the pump mechanical seal was replaced. The "B" HDT pump was returned to service on August 31, 1993.

Routine chemistry monitoring had previously identified minor circulating water leakage in the main condenser 1A2 waterbox. The licensee further utilized the period of reduced power operation to search for the source of this leakage. Power was reduced to just below 50 percent and the 1A2 waterbox was removed from service. Two leaking tubes were identified, one by applying plastic wrap to both tubesheets (vacuum translated from the main condenser through the leak causes the wrap over the affected tube to rupture), and one by the tracer gas method. With the leaking tubes plugged, the 1A2 waterbox was returned to service prior to completion of the "B" HDT pump maintenance.

The inspector observed portions of the power changes required for the HDT pump and main condenser maintenance. Control room personnel demonstrated good operational control and procedural compliance. The inspector concluded that alert action by the auxiliary operator in identifying the "B" HDT pump motor problem and prompt control room response to rapidly lower plant power averted a significant plant transient by precluding pump failure. The inspector had no additional concerns on this matter.

1.4 Valve Tagging Program

Through discussions with operations management, piping and instrumentation diagram (P&ID) review, and system walkdowns, the inspector observed that the licensee's valve tagging program was nearing completion. The program, beginning in 1989, was designed to replace numerical valve tags with color coded tags of a ruggedized (phenolic) material containing the alpha numeric valve designator, a brief functional description, and, in specific cases, a symbol to identify if the valve was to be locked open or locked close. To date, 15,309 tags (about 96%) have been replaced of a total of 15,989 valves. Remaining were valve tags on the hydrogen seal oil unit for the main generator (176 tags), certain valves in containment that were difficult to access (119 tags), and valve tags awaiting final verification before installation (385 tags). The licensee projects these to be completed in 1994.

Through walkdowns, the inspector determined that certain valves tags on high temperature steam lines were susceptible to warping and discoloration. The licensee was addressing this concern by examining tag condition during the weekly system walkdowns performed to verify that valve position on P&IDs conform to the as-left position identified in the governing procedure, and through routine operational tours. Damaged tags were subsequently replaced.

The inspector concluded that the licensee had made reasonable progress in upgrading and maintaining valve tagging to assure clear identification of components.

2.0 MAINTENANCE (62703, 61726)

2.1 Corrective Maintenance

2.1.1 Routine Observations

The inspector observed portions of maintenance activities to verify that correct parts and tools were utilized, applicable industry code and technical specification requirements were satisfied, adequate measures were in place to ensure personnel safety and prevent damage to plant structures, systems, and components, and to ensure that equipment operability was verified upon completion. The following maintenance activities were observed:

- Work Order 9320677, "Perform Inspection and Maintenance on "B" Spent Fuel Pool Heat Exchanger," (opening of the heat exchanger and eddy current testing), performed in accordance with Maintenance Procedure (M)-110, "Inspection and Refurbishment of 1A/1B Spent Fuel Pool Heat Exchangers," revision 4, dated June 23, 1993, observed August 16-18, 1993

- Work Order 9301279, "Heater Drain Tank Pump "B", Repair Motor/Cooler," (motor reassembly), performed in accordance with M-45.0, "Mechanical/Electrical Inspection and Maintenance of Ginna Station Motors (Excluding Crane Chem-Pumps)," revision 5, dated March 25, 1993, observed August 30, 1993

- Work Order 9301319, "2% Deviation Alarm Adjust Isolation Amplifier NM-305 and Monitor," (connection of test leads and data collection) observed September 10, 1993

2.1.2 Pressurizer Relief Tank Level Instrument Failure

At approximately 1:00 a.m. on September 8, 1993, the pressurizer relief tank (PRT) level instrument failed. As a result, the associated main control board (MCB) meter failed off-scale low, and MCB annunciator F-17, "PRT Level [low-high]," alarmed. The PRT receives discharges from the pressurizer relief and safety valves, and from the low pressure letdown relief valve; failure of the PRT level instrument was of particular concern because the annunciators that indicate high downstream temperature (intended to provide rapid, alarm indication that the associated valve has actuated) for these valves were all in a state of alarm due to minor leakage past the pressurizer relief valves. Other instrumentation (such as PRT temperature) was still available to provide indication of a fast-breaking situation (such as a failed-open relief valve), and operation without PRT level indication did not violate any technical specification requirement; nonetheless, the licensee was concerned that this combination of malfunctions constituted a degradation of reactor coolant system (RCS) leakage monitoring capability that was unacceptable for long-term operation.

Maintaining proper level in the PRT was a concern from several aspects. The nominal PRT level of 70 percent was based on providing an adequate quench volume (that is, a volume of relatively cool water to suppress the pressure increase that would occur due to steam formation if RCS coolant were discharged to an empty tank) for discharges from the pressurizer relief valves, while reserving adequate volume to accept discharge produced by the worst case RCS overpressure transient. Too little quench volume or not enough volume to accept a discharge could result in the tank being pressurized to the point of failure of the rupture disc. Additionally, were the tank to get too full, even normal RCS leakage could eventually cause a rapid pressure increase and result in rupture of the tank rupture disc. Therefore, operations department management developed guidance for control of PRT level while the level indicator was inoperable. Historic data from the plant computer indicated good correlation between PRT level and pressure. Based on this, the PRT was to be drained as necessary to maintain PRT pressure between 2.0 and 5.0 psig. Additionally, while the PRT level indication was inoperable, no credit was taken for PRT discharges in determining RCS leakage; although not a factor in determining total leakage, this did result in an increase in unknown leakage by reassigning previously identified PRT in-leakage as unidentified.

Initial electrical troubleshooting indicated that the source of the problem was either the level detector or its associated controller. Both of these components are located in the vicinity of the PRT, in the containment building. At-power radiation levels in this area range from several hundred millirem to several rem per hour. Licensee management determined that the importance of PRT level indication warranted an attempt to repair while at power. The resultant corrective action plan consisted of two possible repair activities. The first would replace the amplifier circuit card in the level detector controller. This was considered to be the most likely cause of controller failure, and, if successful, would result in the lowest radiation exposure. If this did not restore level indication, a differential pressure (d/p) detector would be connected, in parallel with the installed level detector, as a temporary modification.

A containment entry was conducted on September 9, 1993, to replace the suspect amplifier circuit card, as well as to target the d/p detector installation. When installation of the new circuit card failed to correct the problem, focus shifted to preparation for installing the temporary modification. It was determined that the d/p detector could be mounted on the lower support bracket for the normal level detector. Because the temperature of the PRT is normally well below the boiling point of water, condensation would not provide a reliable means of maintaining water level in an external reference leg; consequently, it had been decided to use a dry reference leg. To prevent condensation from collecting in the reference leg and thereby degrading detector output, an inverted loop seal would be used to divert condensation back to the PRT. The technician obtained measurements for fabrication of the reference leg, and took photographs of the area for any additional preparations that might be required.

The PRT temporary level detector was installed on September 10, 1993. Two technicians required approximately two hours in containment to complete the installation. Approximately one man-rem of radiation exposure was expended in the effort. When placed in service, the indicated level corresponded well with the anticipated level and tracked as expected during a test discharge from the PRT.

The inspector participated in the containment entry on September 10, 1993, and observed portions of the temporary PRT level detector installation. The inspector observed that the necessary materials were properly staged and that the work progressed rapidly. The workers demonstrated good ALARA and heat stress awareness. No deficiencies were noted.

The inspector concluded that the licensee had responded appropriately to loss of PRT level indication. Interim measures were promptly established for operations personnel to track PRT level, and parallel development of repair strategies minimized the period of operation without level indication. The maintenance activity was well planned and executed. The inspector had no additional concerns in this matter.

2.2 Surveillance Observations

2.2.1 Routine Observations

Inspectors observed portions of surveillances to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operation (LCOs), and correct system restoration following testing. The following surveillances were observed:

- Performance Test (PT)-12.2, "Emergency Diesel Generator 1B," revision 73, dated May 27, 1993, observed August 4, 1993

- PT-2.1M, "Safety Injection System Monthly Test," revision 9, dated January 22, 1993, observed August 18, 1993

- PT-16M-T, "Auxiliary Feedwater Turbine Pump - Monthly," revision 5, dated July 1, 1993, observed August 24, 1993

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

2.2.2 Component Cooling Water Pump Discharge Pressure Instrument Maintenance

On August 19, 1993, the "B" component cooling water (CCW) pump was placed out of service to perform work order 9320650, "States Deck Addition for PIC-617." This maintenance was the result of a technical support request, TSR-92-020, to install a states deck in the component

cooling water discharge pressure instrument controller (PIC-617) to facilitate routine testing. The installation was to be accomplished in association with calibration procedure CPI-PC-617, "Calibration of Component Cooling Water Pumps Discharge Pressure PIC-617 and Suction Gages," (revision 5, effective date June 18, 1993) as directed by procedure change request (PCN) 93T-660. With the CCW system in operation, it was not possible to completely deenergize PIC-617; installation of the states deck would require working with 120 volt AC energized equipment.

In the course of performing the states deck installation, the instrument and control (I&C) technician was required to install a ring terminal on the end of an energized lead. These terminals are attached by crimping a barrel fitting over the conductor. The technician realized that the lead he was working on was energized, but believed that the plastic sleeve around the barrel of the ring terminal would provide adequate insulation. At 8:09 a.m., when the technician attempted to crimp the terminal barrel, he received an electrical shock from the energized lead through the crimping tool. The technician was able to release the crimping tool, which then came in contact with the PIC-617 mounting post and continued to short-circuit for about 10 seconds. The technician did not appear to have been injured, and therefore, the station medical emergency procedure was not initiated by others at the scene. When supervisory personnel were informed, however, the technician was examined by the site nurse and later taken to a hospital for further examination and observation. He was found to have suffered no serious effect from the electrical shock.

In the control room, operations personnel were not immediately aware that a problem with the PIC-617 maintenance had occurred. Their first indication of a problem came approximately 14 minutes later, when chemistry personnel inquired as to why steam generator blowdown had been secured. Investigation revealed that the steam generator blowdown isolation valves had closed. About 30 minutes after the incident, control room personnel were informed and joint troubleshooting with I&C personnel commenced. Within 40 minutes, the end result of the PIC-617 short-circuit was found to be that an associated supply breaker had tripped open. The breaker (breaker number 11, powered from instrument bus 1D) was the supply for the M-2 miscellaneous relay rack. After establishing the scope of equipment and components affected by the deenergization, and verifying that reenergizing the M-2 relay rack would not produce any negative operational effects, power was restored to the M-2 relay rack at 10:17 a.m.

The licensee determined that several reactor protection system/ESF functions had also been made less reliable by the inadvertent deenergization of the M-2 relay rack. Of these, only one was a protective function required by technical specifications, that being the automatic start of the motor driven auxiliary feedwater (MDAFW) pumps on low-low steam generator water level. Deenergizing the M-2 relay rack removed power from the MDAFW pump auto start relays in one of the two trains of the reactor protection system. Although the remaining reactor protection system train was unaffected and would have caused both MDAFW pumps to start on low-low steam generator water level (through two identical relays in the M-1 miscellaneous relay rack), redundancy of this function was eliminated while the M-2 relay rack was deenergized. Technical specification table 3.5.2 states requirements for the number of input channels for ESF

functions (in this case, for example, there are normally three channels per steam generator of water level indication that provide input signals to the "MDAFW auto-start on low-low steam generator water level" ESF function) and specifies actions in cases where these requirements cannot be met; it does not, however, address loss of a single function output to a train of the reactor protection system.

Later on the same day, the plant operations review committee (PORC) met to review the event and consider the technical specification implications. They concluded that loss of the "MDAFW auto-start on low-low steam generator water level" ESF function from one train of the reactor protection system did not place the plant in an unanalyzed condition, in that table 3.5.2 prescribes required actions for loss of input channels, up to and including loss of all input channels, for this function. Since loss of all input channels is functionally equivalent to loss of the function output to both trains of the reactor protection system, it was concluded that the loss of function output to one train was bounded by a defined condition. Furthermore, because this condition had existed for a period of time shorter than the prescribed action statement for such a worst-case condition (just over two hours of a six hour action statement), the PORC concluded that no violation of technical specifications had occurred.

The licensee initiated a human performance evaluation system (HPES) review of the electric shock incident. At the close of the inspection period, the results of this evaluation, including recommended corrective actions, were still under preparation. Several corrective actions, including I&C department training and recommendations for expanded general employee training on electrical safety and use of the station medical emergency procedure, had already been initiated.

Through review of the work package, event report, and PORC meeting minutes, and through discussions with personnel, the inspector concluded that no violation of technical specifications or reporting requirements had occurred as a result of the inadvertent deenergization of the M-2 relay rack. The inspector considered the licensee's immediate actions to identify underlying training and procedure weaknesses to be appropriate.

2.2.3 "B" Emergency Diesel Generator Performance Testing

On September 7, 1993, the licensee attempted to conduct PT-12.2, "Emergency Diesel Generator 1B." After the engine was started, parameters were recorded per data sheet 1, "Local Panel 'Initial' Readings at No-Load Condition." Lube oil pressure (at 86 psig) was found to be in the high required action range (greater than 85 psig), and the "B" EDG was consequently declared inoperable at 9:35 a.m. Although lube oil pressure had lowered to within specification (apparently due to the oil warming up) before the engine was secured, the operability determination was not changed. As required by technical specification 3.7.2.2.b, operability of the "A" EDG was verified within one hour of the "B" EDG being declared inoperable.

As the first step in troubleshooting, calibration of the "B" EDG lube oil pressure gauge, PI-2858, was checked. Accuracy was found to be within the normal range of acceptability, and no adjustment was made. To provide backup indication, a test gauge was installed in parallel with the normal lube oil pressure gauge, and the performance test was again attempted. Both lube oil pressure gauges indicated pressure in the acceptable range during this second performance of PT-12.2. The "B" EDG was declared operable at 7:31 p.m., September 7, 1993.

The inspector considered that declaring the "B" EDG inoperable had been a conservative action, particularly in that, during the same period of engine operation, lube oil pressure subsequently lowered to within specification. The inspector had no additional concerns on this matter.

2.3 Maintenance Procedure Upgrade Program Review

The inspector reviewed the status of the licensee's Maintenance Procedure Upgrade Program, that was initiated in mid-1991. The inspector determined that the upgraded corrective and preventive maintenance procedures reflected exceptional procedure quality. These component-specific procedures, which require verbatim compliance with step-by-step technician sign-offs, included detailed vendor drawings, illustrations, and specifications. Prior to implementing certain maintenance procedures, sign-offs by the Shift Supervisor were required to assure that the initial plant conditions (identified in the procedures) were met and that the system isolation boundaries are established. Also specified in the body of the procedure were post-maintenance operability testing requirements, system re-alignment guidance, and requisite Quality Control Hold Points with stated acceptance criteria. To date, 513 of a projected 890 procedures have been rigorously developed using equipment analysis, task analysis, and functional analysis techniques; followed by a pre-PORC multi-discipline review and final PORC approval. In-place procedures requiring updating based on the latest vendor manual changes or product bulletins were expeditiously identified through an electronic data link and revised accordingly.

From this review, the inspector concluded that the licensee had made steady progress developing and implementing a comprehensive maintenance procedures program.

3.0 ENGINEERING (71707, 92701)

3.1 Service Water Pump Performance Testing

On August 31, 1993, the inspector observed a portion of PT-2.7.1, "Service Water Pumps," revision 8, procedure change notice 93T-716, dated July 29, 1993. Testing is performed individually on each of the four service water pumps. The pump under test is used to supply its associated SW supply header (two supply headers, each served by two SW pumps); header flow is then adjusted to a specified value by throttling flow to one of the associated heat exchangers. Once flow has been adjusted, pump discharge pressure must fall within a specified band. In this case, the required header flow could not be established when testing the "A" SW

pump. Based on comparison with other SW system parameters that had been recorded during earlier testing of the "B" SW pump, it was concluded that the ultrasonic flow measuring instrument was the probable source of the problem.

Following discussions with the flow instrument vendor and additional testing, the licensee determined that the low indicated flow had been due to a performance problem associated with the ultrasonic flow instrument transducer. This instrument determines flow by measuring the time required for sound to travel through a moving medium across a known distance. This measurement can be obtained by either 1) reflection, using a combined transmitter and receiver (transducer) which transmits sound into the pipe and then receives the echo that is reflected from the opposite side, or 2) directly, using a separate transmitter and receiver (in actuality, two transducers, with each performing only one function) that are mounted on opposite sides of the pipe. As originally installed, the flow instrument used the reflection method. During troubleshooting of the "A" SW pump indicated low flow, decreased signal strength and signal waveform analysis showed that the reflect site had degraded; although the mechanism was not determined, this was the apparent cause of the problem. By performing flow measurements on the "A" SW pump using the direct method, the licensee demonstrated that its discharge pressure was, in actuality, consistent with the other three SW pumps under the same test conditions. In addition, direct measure flow determination was performed on the "C" SW pump to check the accuracy of measurements made using the standard reflect method; the result confirmed that the reflect mode was producing satisfactory results for the remaining SW pumps.

As corrective action, a new baseline discharge pressure was established for the "A" SW pump using the two transducer direct method for flow measurement. The licensee plans to convert flow instrumentation for the remaining three SW pumps to the two transducer arrangement and establish new baseline discharge pressures prior to the next scheduled performance of PT-2.7.1.

The ultrasonic flow instrument has been used for SW pump quarterly performance testing for approximately one year. A problem with this instrument occurred during testing on February 25, 1993, which required baseline discharge pressure for the "C" SW pump to be redetermined; details are presented in inspection report 50-244/93-03. In both cases, the inspector considered that subsequent licensee actions adequately demonstrated that the pump in question was operable.

3.2 Implementation of 10 CFR 50.59 Requirements

Allowances for licensees to deviate from requirements of the final safety analysis report (FSAR) are addressed in 10 CFR 50.59, "Changes, Tests and Experiments." The inspector reviewed the licensee's procedures for implementation of 10 CFR 50.59 requirements. The following procedures were reviewed:

-- Administrative procedure A-303, "Preparation, Review and Approval of Safety Analysis," revision 10, effective date August 28, 1992

-- Engineering procedure QE311, "Preparation, Review and Approval of Safety Analyses," revision 6, effective date April 22, 1987, through procedure deviation request number 0677

-- A-601.8, "Procedure Change Control - 10 CFR 50.59 Review," revision 6, effective date April 9, 1993

A-303, a station procedure, applies to minor modifications, technical evaluations, temporary modifications, and special tests; QE311, a corporate engineering procedure, applies to major modifications, technical evaluations, and special tests, that are accomplished under engineering work requests; and, A-601.8, also a station procedure, applies to procedures. The inspector determined that these procedures adequately addressed the circumstances under which 10 CFR 50.59 was applicable, and fully implemented the specified criteria for examination. In addition, the following 10 CFR 50.59 evaluations were reviewed:

-- Engineering work request 4951, "Replace TDAFW Pump Recirc Check Valve," revision 2, dated March 3, 1993

-- Procedure change notice 93T-726 to PT-2.7.1, "Service Water Pumps," revision 8, dated July 29, 1993

-- Nonconformance report 93-222, "Valve 4618 Bonnet Bolting Has Insufficient Thread Engagement," dated August 12, 1993

No deficiencies were noted. The inspector concluded that safety analyses were being performed for items required by, and in the manner prescribed by, 10 CFR 50.59. The licensee's program for implementing these requirements was determined to be thorough. The inspector had no additional concerns on this matter.

4.0 PLANT SUPPORT (71707)

4.1 Radiological Controls

4.1.1 Routine Observations

The inspectors periodically confirmed that radiation work permits were effectively implemented, dosimetry was correctly worn in controlled areas and dosimeter readings were accurately recorded, access to high radiation areas was adequately controlled, survey information was kept current, and postings and labeling were in compliance with regulatory requirements. Through observations of ongoing activities and discussions with plant personnel, the inspectors concluded that the licensee's radiological controls were generally effective.

Additionally, the inspector made the following observations:

-- On August 18, 1993, the inspector accompanied a health physics technician during a portion of a routine weekly radiation and contamination survey of the auxiliary building basement. No deficiencies were noted.

-- On two occasions during the inspection period, the inspector came upon unattended portable radiacs in the auxiliary building for which daily source checks had apparently not been performed. Although documentation indicated that they had not been in use, the inspector considered the immediate availability of uncalibrated radiacs to be an instance of weak control of in-use instrumentation.

4.1.2 Corporate ALARA Committee Meeting

On September 7, 1993, the inspector attended a meeting of the RG&E corporate ALARA committee. The meeting addressed implementation status of revised 10 CFR 20 requirements, source term reduction technique evaluations, contamination control enhancements, and steam generator replacement ALARA issues. The inspector determined that the licensee is effectively integrating corporate and site resources to programmatically reducing collective personnel dose.

4.2 Security

4.2.1 Routine Observations

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

4.3 Fire Protection

4.3.1 Routine Observations

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

On August 16, 1993, the inspector observed maintenance to replace a valve in the auxiliary building upper level; this maintenance involved welding approximately 10 feet above the floor and adjacent the east end stairway. Although the hot work permit specified "contain all sparks," sparks were freely falling to the upper level floor. The inspector considered that fire watch coverage was adequate to ensure safety. During subsequent discussion with the licensee fire protection engineer, the inspector was informed that two additional fire watches (for a total of

three) had been assigned to cover this work after it had been determined that it would not be possible to contain the sparks caused by welding. The inspector concluded that action taken by the fire protection department when the original requirements of the hot work permit could not be satisfied were timely and appropriate.

4.3.2 Obstructed Automatic Roll-Down Fire Door

During a routine plant tour on August 10, 1993, the inspector noted that two cooling fans had been set in door S-36 such that they would prevent full closure of its associated automatic roll-down fire door. The inspector informed the shift supervisor and an auxiliary operator was dispatched to correct the problem. The two fans were promptly relocated clear of the roll-down fire door.

Door S-36 is an infrequent access door between the turbine building and the intermediate building (cold side). The fans had been placed there to improve cooling of the rod control system cabinets, an effort associated with troubleshooting of a recent rod control system problem (see inspection report 50-244/93-12). Because the door sill is approximately two feet above the floor, the two box-fans had been placed on the sill to better draw air through the door. The automatic roll-down fire door itself is a recently added fire protection feature of door S-36.

The licensee initiated the following corrective action:

-- Increased fire watch supervision tour frequency;

-- Initiated additional fire watch and site personnel training regarding fire barrier limitations;

-- Informed other licensees via the Nuclear Network and the licensee's operational assessment division; and,

-- Will include an article in the Ginna newsletter to reiterate fire barrier concerns.

The inspector considered that these corrective actions were appropriate.

4.4 Emergency Preparedness

4.4.1 Annual Emergency Radiation Injury Drill

On September 1, 1993, RG&E conducted its annual emergency radiation injury drill. The drill was initiated with a simulated two-person accident caused by a steam leak in the auxiliary building basement. Injuries were simulated to be so severe as to require treatment before the patients could be moved out of the contaminated area. After site medical emergency personnel

and an off-site contract physician had responded, the patients were transported by ambulance to Rochester General Hospital (one of two participating area medical facilities). Off-site drill performance was evaluated by the Federal Emergency Management Agency (FEMA).

The inspector observed the on-site portion of the drill and attended the post-drill critique. The inspector noted no deficiencies during conduct of the drill. Emergency personnel generally demonstrated good perspective in maintaining radiological controls consistent with the overriding priority of dealing with the medical emergency. The post-drill critique was self-critical and generated good recommendations for improving site response to medical emergencies.

4.4.2 Joint Emergency Preparedness Meeting

On September 9, 1993, the inspector attended a meeting of state, county and RG&E emergency preparedness representatives. The purpose of the meeting was to review the roles of the organizations in response to the various Emergency Action Levels and discuss the actions taken when implementing Protective Action Recommendations. The meeting provided an effective forum to improve an understanding of the roles played by the participating organizations when responding to various emergency action levels.

4.5 Employee Concerns Program Review (TI 2500/028)

The inspector reviewed licensee measures to provide employees, who wish to raise safety issues, alternate paths from their supervisor or normal line management to express these concerns and to encourage people to come forward with their concerns without fear of retribution. As identified in the RG&E Employee Handbook, the licensee promotes two primary communication channels for elevating safety concerns to management: an "Open Door Policy," in which each employee has the right to communicate directly, including use of a Superintendent's Hotline, with any level of management; and, "The Gateway Program," in which employees can confidentially contact management about any work-related problems. Through interviewing various members of the licensee's workforce, the inspector concluded that, generally, employees feel comfortable discussing issues with RG&E management face-to-face. However, workers were generally unaware of the existence of the Gateway (confidential) program and the Superintendent's Hotline. The inspector confirmed that Gateway reporting forms were not available in the plant, and that the Superintendent's Hotline was not answered upon placing a call.

In discussing these findings with licensee management, the inspector was informed that the RG&E Employee Relations Department is presently revamping its employee concerns program. Additionally, several initiatives are being planned to foster employee communications, including periodic breakfast meetings between selected workers and senior management, and implementing a Senior Management Plant Tour procedure. The Appendix A form, Employee Concerns Program, is attached.

4.6 Periodic Reports

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

-- Monthly Operating Report for August, 1993

-- Semiannual Radioactive Effluent Release Report

No unacceptable conditions were identified.

5.0 ADMINISTRATIVE (71707, 30702, 94600)

5.1 Senior NRC Management Site Visits

During this inspection period, four senior NRC managers visited Ginna Station. On August 18, 1993, Mr. Walt Butler, Director of Project Directorate I-3 of the Office of Nuclear Reactor Regulation, attended a plant operations review committee (PORC) meeting and met with senior licensee management. Three region I Deputy Division Directors (Mr. Wayne Lanning, Division of Reactor Projects; Mr. Charles Miller, Division of Reactor Safety; and, Ms. Susan Frant Shankman, Division of Radiation Safety and Safeguards) toured the site and met with senior licensee management.

5.2 Backshift and Deep Backshift Inspection

During this inspection period, a backshift inspection was conducted on August 30, 1993. Deep backshift inspections were conducted on September 6 and 11, 1993.

5.3 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 inspection report 50-244/93-13 (engineering programs review, conducted June 14-18 and August 30 - September 3, 1993) was held by Mr. Harold Gregg on September 3, 1993. The exit meeting for inspection report 50-244/93-16 was held on September 15, 1993.

ATTACHMENT A

EMPLOYEE CONCERNS PROGRAMS

PLANT NAME: R. E. Ginna LICENSEE: Rochester Gas and Electric Corporation
DOCKET#: 50-309

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. PROGRAM:

1. Does the licensee have an employee concerns program? (Yes or No/Comments) **Yes. An Open Door Policy is the primary means of communicating concerns to management. A confidential program (the Gateway program) and a superintendent's hotline are in place; but are not publicized and are essentially inactive.**

2. Has NRC inspected the program? **Report No. 93-16. No, but 93-16 will capture TI 2500/028 effort.**

B. SCOPE: (Circle all that apply)

1. Is it for:

   a. Technical? (Yes, No/Comments) **Yes. In addition to an Open Door Policy, the Employee Assistance Program (EAP) and Potential Conditions Adverse to Quality (PCAQ) are mechanisms to address technical concerns.**

   b. Administrative? (Yes, No/Comments) **Yes. EAP - through referral.**

   c. Personnel issues? (Yes, No/Comments) **Yes. EAP - through referral.**

2. Does it cover safety as well as non-safety issues? (Yes or No/Comments) **Yes**

3. Is it designed for:

   a. Nuclear safety? (Yes, No/Comments) **Yes. Not specifically but concerns can be referred to responsible departments.**

   b. Personal safety? (Yes, No/Comments) **Yes. Director contact with safety coordinators. EAP - through referral.**

c. Personnel issues - including union grievances? (Yes or No/Comments) **Yes. The absence of a union has fostered a teamwork approach to resolving differences.**

4. Does the program apply to all licensee employees? (Yes or No/Comments) **Yes**

5. Contractors? (Yes or No/Comments) **Yes**

6. Does the licensee require its contractors and their subs to have a similar program? (Yes or No/Comments) **Yes. Through contractual agreements in the area of industrial safety concerns.**

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns? (Yes or No/Comments) **Yes**

C. **INDEPENDENCE:**

1. What is the title of the person in charge? **Site Gateway Coordinator reports to Corporate Director of Compensation Administration.**

2. Who do they report to? **Director of Employee Relations.**

3. Are they independent of line management? **Yes**

4. Does the ECP use third party consultants? **On a limited basis. Wm. Mercer and Company has conducted an independent employee opinion survey.**

5. How is a concern about a manager or vice president followed up? **No formalized mechanism.**

D. **RESOURCES:**

1. What is the size of the staff devoted to this program? **3, but ECP is a collateral duty.**

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)? **None specific. Short term in-house courses have been provided on supervisory skills; e.g., interviewing skills.**

E. **REFERRALS:**

1. Who has followup on concerns (ECP staff, line management, other)? **Plant Referral to the cognizant department and responsible manager.**

F. CONFIDENTIALITY:

1. Are the reports confidential? (Yes or No/Comments) Yes

2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)? (Circle, if other explain) **He can remain anonymous or be known to any or all of the above.**

3. Can employees be:

   a. Anonymous? (Yes, No/Comments) Yes

   b. Report by phone? (Yes, No/Comments) **No. Superintendent's Hotline no longer works.**

G. FEEDBACK:

1. Is feedback given to the alleger upon completion of the followup? (Yes or No - If so, how?) **Yes. A confidential answer can be mailed to their home or a personal meeting can be arranged with management.**

2. Does program reward good ideas? **Yes. Employee Suggestion Box is a separate mechanism.**

3. Who, or at what level, makes the final decision of resolution? **Based on the nature of the concern, at the appropriate management level, normally the Plant Manager.**

4. Are the resolutions of anonymous concerns disseminated? Yes

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)? **All of the above.**

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program? **By the frequency of recurrence of the same issue.**

2. Are concerns:

   a. Trended? (Yes or No/Comments) No

   b. Used? (Yes or No/Comments) Yes

3. In the last three years how many concerns were raised? Of the concerns raised, how many were closed? What percentage were substantiated? **This information was not readily available.**

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)? **An independent Employee Opinion Survey was conducted to identify management areas of concern.**

5. How frequently are internal audits of the ECP conducted and by whom? **None performed.**

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure? (Yes or No/Comments) **No**

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)? **General Employee Training and RG&E Employee Handbook.**

ADDITIONAL COMMENTS: **(Including characteristics which make the program especially effective, if any.)**

Overall, the Gateway (confidential) program and Superintendent's Hotline have fallen into disuse. Workers are generally unaware of their existence. Reporting forms are not readily available, telephone hotline numbers are not answered, and a sampling of the work force indicated that the Open Door Policy is the most effective approach. Workers feel that they can freely communicate concerns to all levels of management.

As a result of the recent Employee Opinion Survey, RG&E management is implementing several initiatives including: eliminating the Gateway Program, establishing a new hotline program, scheduling Senior Management/Worker Breakfast Meetings, and formalizing Senior Management Plant Tour Procedures.

NAME:	TITLE:	PHONE #:	
Tom Moslak	SRI	315-524-6935	9/10/93