U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/93-03 **License: DPR-18**

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

Inspection: January 27 through March 9, 1993

Inspectors: T. A. Moslak, Senior Resident Inspector, Ginna
E. C. Knutson, Resident Inspector, Ginna

Approved by: W. J. Lazarus, Chief, Reactor Projects Section 3B — 3/18/93 Date

INSPECTION SCOPE

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

INSPECTION OVERVIEW

Plant Operations: There were no significant operational challenges during this inspection period. The plant operated at 98% power until commencing a one percent per day coastdown on March 2, 1993. The plant will enter the cycle 23 refueling outage commencing March 12, 1993.

Radiological Controls: No deficiencies were noted in the licensee's preparations for offsite shipment of irradiated reactor fuel. The shipment occurred on February 4, 1993 and completed without incident on February 24, 1993. An ALARA subcommittee meeting demonstrated commitment to reducing exposure through integrated engineering support for controlling the source term.

Maintenance/Surveillance: Troubleshooting and corrective maintenance on a service water pump motor and the turbine driven auxiliary feedwater pump was prompt and well coordinated. The licensee demonstrated an effective predictive maintenance program in discovering and correcting high resistance electrical contacts on a 1E electrical bus normal power supply transformer. PORC was effective in evaluating equipment operability and assessing the impact of potential corrective actions.

Security: Response to a forced access incident at a nuclear facility in Pennsylvania was prompt and conservative. A planned security system outage was well planned and executed; appropriate compensatory measures were effectively implemented. The inspector and the licensee reviewed the procedures to deal with a land vehicle bomb threat.

Emergency Preparedness: The licensee completed installation of a digital seismic monitor.

(INSPECTION OVERVIEW CONTINUED)

Engineering/Technical Support: The offsite power distribution system was realigned to provide more reliable power to the instrument buses.

Safety Assessment/Quality Verification: Bottled hydrogen storage was examined. The licensee is re-evaluating the safety implications of their hydrogen storage. An erosion/corrosion subcommittee meeting demonstrated a systematic approach to erosion/corrosion concerns.

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DETAILS

1.0 PLANT OPERATIONS (71707)

1.1 Operational Experiences

The plant operated at 98 percent power from January 27 to March 2, 1993. The plant commenced a coast down power reduction at approximately one percent per day on March 2, 1993. At the end of the inspection period, the plant was operating at 89 percent power, continuing power coast down to the March 12 start of the cycle 23 annual refueling outage. There were no significant operational challenges 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 consistently 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.

2.0 RADIOLOGICAL CONTROLS (71707)

2.1 Routine Observations

The inspectors periodically confirmed that radiation work permits were effectively implemented, dosimetry was correctly worn in controlled areas and dosimeter readings were accurately recorded, access to high radiation areas was adequately controlled, 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 radiological controls were conscientiously implemented.

2.2 Shipment of Irradiated Reactor Fuel (86740)

As discussed in inspection reports 50-244/92-15 and 92-20, the licensee has prepared selected fuel rods from test fuel assemblies for offsite laboratory examination. During this inspection period, the resident inspectors, with the support of a regional senior radiation specialist, examined the cask shipment preparations. This review verified that documentation was properly completed, that the exclusive-use vehicle was properly inspected, that radiation/ contamination levels were below regulatory limits, that the cask was firmly secured to the trailer, and that drivers were properly trained and qualified. Upon confirming that the cask was safe for

shipment, the cask left site on February 4, 1993, reaching its port-of-call on February 5, 1993, and arriving safely at its final destination on February 24, 1993. Specific details of the pre-shipment inspection are presented in inspection report 50-244/93-01.

2.3 ALARA Subcommittee Meeting

On March 2, 1993, the inspector attended a meeting of the licensee's corporate As Low As Reasonably Achievable (ALARA) subcommittee. The purpose of the meeting was to review radiological controls effectiveness and evaluate additional measures that could be used to minimize worker exposure and personnel contaminations. Meeting topics included performance indicator trend review, status of source term reduction initiatives, review of reactor cavity decontamination plans, implementation status of revised 10 CFR 20 requirements, and implementation status of a laser disk surrogate tour system. Additionally, site health physics management described efforts to further reduce station cumulative exposure to below the all-time low achieved during calendar year 1992, 261 person-rem. The inspector concluded that the meeting reflected an aggressive approach by RG&E corporate management to assess engineering controls to minimize worker dose by integrating corporate engineering support into the routine site radiological controls program.

3.0 MAINTENANCE/SURVEILLANCE (62703, 61726)

3.1 Corrective Maintenance

3.1.1 "A" Service Water Pump Motor High Bearing Temperature

During a routine control room inspection on January 29, 1993, the inspector noted that an abrupt temperature increase had recently occurred on the "A" service water (SW) pump motor lower radial bearing, as indicated on the temperature monitor strip chart recorder. The inspector informed operations department personnel, who verified that the pump had been in service long before the temperature increase (i.e., this was not simply the expected temperature rise that would occur following pump motor startup) and that there had been no operational transients (such as SW system realignment or variations in supply bus electrical parameters) that would account for the change. Although the temperature rise was small (from 88°F to 109°F) and the final temperature was well below the alarm setpoint (180°F), the abruptness of the initial rise and lack of any apparent cause were abnormal; given the plant's recent history of SW pump motor failures, the licensee initiated an investigation.

The electrical maintenance department, in coordination with the corporate electrical engineering staff, conducted diagnostic testing of the pump motor. Motor vibration was checked and found to be consistent with previously determined values. Extensive testing of the motor windings showed no degraded conditions. However, the motor's power output was found to have increased from 300 horsepower (as determined during original acceptance testing) to 343

horsepower. From these results, the cause was suspected to be impending failure of the lower radial bearing (i.e., that bearing failure was producing the observed higher temperatures and bearing drag was resulting in the additional motor power requirement).

The lower radial bearing for the "A" SW pump motor was replaced on February 4, 1993. The replaced bearing showed no visible sign of wear or degradation. There was no heat-induced discoloration of the races, the grease appeared clean, and the bearing turned freely and without excessive play. Subsequent testing of the "A" SW pump motor demonstrated that bearing replacement had not corrected the problem; both the elevated bearing temperature and the excessive motor power requirement persisted. However, motor load measurements taken with the pump uncoupled were found to be consistent with values obtained during acceptance testing. This, along with the results of electrical testing conducted prior to the bearing replacement, indicated that the motor was not the source of the problem. While in cold shutdown during the upcoming refueling outage, the licensee plans to install the "D" SW pump motor on the "A" SW pump, and thereby conclusively establish whether the pump or the motor is the source of the problem.

The inspector considered that the licensee's investigation of elevated bearing temperature on the "A" service water pump motor has been conservative and thorough.

3.1.2 "B" Motor Driven Auxiliary Feedwater Pump Oil Pump Failure

While conducting performance test (PT)-16Q-B, "Auxiliary Feedwater Pump B - Quarterly," on February 9, 1993, a problem developed with the pump's associated AC oil pump motor. When the operator started the "B" AFW pump from the main control board, the ON and OFF indicating lights for the "B" AFW pump AC oil pump began to cycle rapidly. Additionally, main control board annunciator H-28, "MDAFW Oil Pump Off," began to go rapidly into and out of alarm. In response, the operator secured the "B" AFW pump within 10 seconds. The on-off cycling of indicators in the control room suggested that the oil pump electrical controller was cycling. After verifying that brief operation of the AFW pump without its associated oil pump in operation would cause no equipment damage, and with maintenance personnel positioned to observe the controller locally, the "B" AFW pump was again started. When the oil pump controller was observed to be cycling, the AFW pump was promptly secured. The "B" AFW pump was declared inoperable at 3:27 p.m., February 9, 1993, placing the licensee in a seven-day action statement per technical specification (TS) 3.4.2.1.

Later that same day, an auxiliary operator noted that the glass in the oil cooler sightglass associated with the "B" AFW pump AC oil pump was broken. Although suspected to have occurred during the earlier oil pump troubleshooting, the cause could not definitely be established. In itself, this problem also rendered the "B" AFW pump inoperable.

The suspected cause of the AC oil pump electrical problem was degradation of the start solenoid in the controller main line contact assembly. Testing of the start solenoid showed its electrical resistance to be lower than expected. As a result, the main line contact assembly was replaced.

During the course of this work, a loose wire was also discovered on one of the two DC control power fuses. The wire was tightened, and on completion of the main line contact assembly replacement, the controller was tested satisfactorily. Subsequent shop testing showed the replaced main line contact assembly to operate properly, indicating that the loose fuse wire had been the source of the problem.

The section of piping containing the oil sightglass was removed and cleaned to eliminate broken glass and any other foreign material. The gear box was inspected and no damage to the gears was noted. Additionally, inspection of the service water side of the heat exchanger and the service water strainer showed these components to be clean. The broken glass was replaced and the piping was reinstalled. All repairs were completed and the "B" AFW pump was returned to service on February 12, 1993.

Through observation of the maintenance and operations department's response to the pump failure, the inspector concluded that prompt actions were effectively coordinated to expeditiously return the pump to service.

3.1.3 Elevated Tap Temperatures on Emergency Bus 16 Transformer

Infrared thermography is a technique that senses infrared radiation (heat) from an object and processes it as a photograph in which the colors represent the temperature of the object. Since high temperature is frequently an indicator of impending component failure, this technique has proven useful in predictive maintenance. It is particularly useful in examining electrical components; problems that may only be evident while components are under load can be detected without physical contact, thereby enhancing personnel safety.

In preparation for planning preventative maintenance during the upcoming outage on the class 1E electrical bus 16, an infrared thermographic inspection was performed of its major components on March 4, 1993. As a result of this inspection, the licensee discovered that the tap connecting links for the normal power supply transformer were developing high temperatures (about 200°F above normal) when operating under high load. Bus 16 is one of four class 1E 480 volt electrical buses that power nearly all reactor safety/accident mitigation equipment and instrumentation.

The licensee evaluated the impact of transformer repair on plant operations to determine if this maintenance should be conducted while the plant was at power or deferred until the refueling outage. Following extensive review by the plant operations review committee, the conclusion was that repair could be performed while at power without impacting plant operating safety. Bus 16 would be maintained energized by the "B" emergency diesel generator (EDG), thus allowing the normal supply transformer to be deenergized and isolated for repair.

Maintenance activities began on the afternoon of March 5, 1993. Troubleshooting revealed that electrical resistance readings across the tap connecting links, although all low, did vary slightly, and that the variations correlated with the temperature readings (that is, the link with the lowest

resistance had been the coolest, and the link with the highest resistance had been the hottest). The three links were removed and cleaned to achieve uniformly low electrical resistance. Subsequent load testing and thermographic examination demonstrated that this had corrected the high temperature problem. All actions were complete by the evening of March 5, 1993.

Through attendance of the PORC meeting, discussions with personnel, review of the work package, and observation of maintenance activities, the inspector concluded that the licensee's actions in discovering, assessing, and correcting high temperature connections on the bus 16 normal power supply transformer were conservative and well planned. Discovery of the problem demonstrated an effective predictive maintenance program. PORC review of the proposed maintenance was thorough and included evaluation of technical specification requirements, operational impact, and contingency planning. The transfer of power to bus 16 from its normal supply to the "B" EDG was particularly well planned; after a successful trial run on the plant simulator, the actual transfer was executed in a highly professional manner. Plant management, health physics, engineering, and quality assurance personnel were immediately available and effectively integrated in the maintenance activity. The inspector had no additional concerns on this matter.

3.2 Surveillance Observations

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

- PT-32A, "Reactor Trip Breaker Testing - "A" Train," revision 14, procedure change notice (PCN) 93T-078, effective date January 15, 1993, observed on February 23, 1993

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

3.2.1 Turbine Driven Auxiliary Feedwater Pump Low Recirculation Flow

On February 17, 1993, the inspector observed the conduct of PT-16Q-T, "Auxiliary Feedwater Turbine Pump - Quarterly," revision 4, effective date February 5, 1993. A portion of this test verifies operability of the pump recirculation flow path. Recirculation flow is important in that it provides pump cooling under low discharge flow conditions. However, in that recirculation flow represents wasted pumping capacity under normal flow conditions, a flow control valve is used to regulate recirculation flow based on pump discharge flow. In this case, recirculation flow was found to be low out of specification (17 gallons per minute (gpm), as opposed to the minimum allowable of 58 gpm) with pump discharge flow throttled to 50 gpm (from full flow of 200 gpm).

Valve alignment in the recirculation flow path was checked and found to be correct. Recirculation line flow meter calibration was verified using an independent ultrasonic flow meter. Having verified that low recirculation flow actually existed, the licensee declared the turbine driven auxiliary feedwater (TDAFW) pump inoperable on February 17, 1993, and entered a 72-hour action statement per TS 3.4.2.2.a.

Through subsequent PORC review of pump operability considerations, the licensee concluded that the pump could be operated with the recirculation line out of service. This evaluation was based on operational considerations, in that the TDAFW pump is not normally operated with discharge flow throttled to the point where recirculation flow is necessary to protect the pump. Short of an equipment failure that would, in itself, make the TDAFW pump inoperable, the only way such low discharge flow could be achieved is through operator action. Additionally, no credit is taken for pump recirculation capability in the AFW system safety analysis. As a result of this review, the licensee declared the TDAFW pump operable on February 18, 1993. As an added precaution while the recirculation flow path was out of service, an operator aid tag was placed on the main control board directing that the pump should be tripped if discharge flow is less than 100 gpm.

The licensee suspected the cause of the low recirculation flow to be failure or blockage of the associated recirculation line check valve, CV-4023. With this type of valve, disc travel is perpendicular to the valve seat. Seat/disc alignment is maintained by a guide stem that fits through the center of the disc and threads into the valve bonnet. A spring, concentric with the guide stem, holds the disc against the valve seat under no-flow conditions. Radiographic examination of the valve internals confirmed that the guide stem had backed out of the valve bonnet and become cocked, thus preventing disc travel to the full open position.

Repair of CV-4023 was performed on February 19, 1993, under work order 9320233, "Inspect/Repair TDAFW Pump Check Valve V-4023." Per maintenance (M) procedure M-37.129, "Inspection and Operability Verification of Check Valve V-4023," revision 2, effective date August 7, 1992, the valve was disassembled and the guide stem was rethreaded into the valve bonnet using a thread locking compound. Valve reassembly was completed using a new disc spring and body-to-bonnet gasket. All repairs and acceptance testing were completed on February 19, 1993.

In summary, the licensee effectively integrated the operations, maintenance, engineering, and nuclear safety/licensing organizations to evaluate pump operability, to provide detailed guidance to operators regarding pump limitations, and to expedite repairs. Through attendance at the dedicated PORC meeting and review of supporting documentation, the inspector concluded that the licensee had soundly justified that, with reduced recirculation flow, the TDAFW pump remained capable of fulfilling its design function as an engineered safety feature.

3.2.2 "C" Service Water Pump High Discharge Pressure

On February 25, 1993, the inspectors observed the conduct of PT 2.7.1, "Service Water Pumps," revision 3, PCN 93T-081, effective date February 11, 1993. This quarterly test verifies that the service water (SW) pumps are capable of developing design discharge pressure and flow rate. Beyond this, pump and system performance is checked for possible degradation by comparing test results to established baseline data. As established by American Society of Mechanical Engineers (ASME) code, the amount of deviation from baseline dictates the requirements for corrective action. In this case, discharge pressure for the "C" SW pump (62.8 psid) was in excess of the baseline value (59.6 psid) that was previously established by the licensee's test program.

Technical specification 3.3.4.1 requires operability of at least two service water pumps, powered from separate electrical buses, for plant operations above cold shutdown. Any time that these conditions cannot be met, TS 3.3.4.2 requires that the plant shall be placed in hot shutdown within six hours and in cold shutdown within an additional 30 hours. The "A" SW pump had been declared inoperable on February 1, 1993, as a result of the high motor bearing temperature problems discussed in section 3.1.1 of this report. Although two SW pumps ("B" and "D") remained unaffected, they are both powered from the same electrical bus. Therefore, as of the completion of testing the "C" SW pump at 9:30 a.m., the shift supervisor considered the "C" SW pump to be inoperable (as specified in PT 2.7.1, Inservice Test Sheet, Note 3) and entered the six hour action statement of TS 3.3.4.2.

Operability determination based on degraded pump performance (such as low discharge pressure or low flow) is largely based on the premise that, due to degrading material condition, the pump may not be able to perform its intended function when required. Operability determination based on pump performance in excess of baseline values is more based on concern that 1) some other component in the system has failed or is in a degraded condition, or 2) test equipment did not provide accurate data, either for the baseline determination or for the test in question. In either case, other parameters (such as component temperatures) indicated that the SW system was, at least, able to perform its intended function under the existing plant conditions. Consequently, the licensee responded by generating a procedure change notice, PCN 93T-084, that waived the ASME criteria until the test could be reperformed using a newly calibrated discharge pressure gauge.

Early on the afternoon of February 25, 1993, PORC convened to discuss operability of the "C" SW pump. Following review of historic performance test data and current system parameters, the committee concluded that the "C" SW pump was (and always had been) operable. The most likely cause of the problem was determined to be that the baseline value of the "C" SW pump discharge pressure was incorrect. In performing this test, pump flow is adjusted (by throttling system flow) to a specific value, at which point, pump discharge pressure is measured. PT 2.7.1 had recently been revised to incorporate an acoustic flow measuring device as the means of determining pump discharge flow; the previous performance of this test (November 11, 1992) had been used to establish baseline values. Since then, the test points that couple the flow

detector to the pipe had been permanently attached to the "C" SW pump discharge piping. A slight difference in coupling, most likely due to slightly different placement of the test points, introduced a difference in the flow indication; since a proportionality exists between flow and pump discharge pressure, this produced the observed difference in discharge pressure. Normal SW system operation, test results from the remaining SW pumps, and results from the reperformance of the "C" SW pump test, all supported that the baseline value of pump discharge pressure for the "C" SW pump was the sole source of the problem. As a result, an interim baseline value for the "C" SW pump was established using the first test results from February 25, with a final value to be established following further testing and evaluation.

Through observation of testing, attendance of the PORC meeting, review of data, and discussions with personnel, the inspector concluded that the "C" SW pump operability determination was proper, and that the decision to establish a new baseline value for pump discharge pressure was appropriate. The inspector had no additional concerns on this matter.

4.0 SECURITY (71707)

4.1 Routine Observations

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

4.2 Response to Forced Access Incident at a Nuclear Facility

On the morning of February 7, 1993, an unauthorized forced access incident occurred at a nuclear facility in Pennsylvania. In response to notification by the NRC of this event, RG&E implemented security reinforcements pending determination of the nature and scope of the incident. These reinforcements included increased access road surveillance, fortification of perimeter gates, and increased in-plant and site perimeter monitoring.

The situation at the facility in Pennsylvania was resolved by afternoon of the same day. Although there were no apparent indications of conspiracy to gain access to other nuclear facilities, RG&E maintained the enhanced security measures until the morning of February 8, 1993. The inspector considered that the licensee's actions had been prompt and properly addressed the anticipated threat. The inspector had no additional concerns on this matter.

4.3 Planned Security System Outage

The licensee is in the process of implementing an extensive site security system upgrade program. During this inspection period, preparations for installation of new equipment required that the security access system computer be relocated. As a result of the computer outage, the normal system of vital area access control would be temporarily disabled. Prior to the outage,

the inspector reviewed the licensee's preparations for relocating the computer. The inspector concluded that the proposed compensatory measures were adequate and that scheduling the system outage for a holiday weekend was appropriate.

The security door access system was deenergized on the morning of February 13, 1993. During the outage, the inspector examined vital area access control to verify that compensatory measures were being properly implemented. No deficiencies were identified. Computer relocation was completed and the system was returned to operation on the evening of February 13, 1993. The inspector had no additional concerns on this matter.

4.4 Response to World Trade Center Bombing Incident

As a result of the February 26, 1993, bombing of the World Trade Center complex in New York City, the inspector reviewed the licensee's precautions against a land vehicle bomb event. The Ginna Station Physical Security Plan lists specific implementing criteria and response requirements. In light of the World Trade Center bombing incident, the licensee has addressed the need for heightened security awareness among the security force. The inspector considered this action to be appropriate.

5.0 EMERGENCY PREPAREDNESS (71707)

5.1 Seismic Monitor Upgrade

Nuclear power plants are required, by 10 CFR 100, Appendix A, to have suitable instrumentation so that the seismic response of plant features important to safety can be determined promptly to permit comparison of such response with that used as the design basis. During this inspection period, the licensee completed an upgrade of their seismic monitoring instrumentation. The previously installed seismic detector recorded data on photographic film; processing this record imposed a significant delay on obtaining even the raw data for quantifying a seismic event. The newly installed seismic detector utilizes a digital accelerometer to generate computer-ready data. After downloading to a portable computer, the information can be quickly processed.

The capabilities of this new equipment were inadvertently demonstrated on February 16, 1993. At 8:15 a.m., an auxiliary operator found the monitor in the alarm state and informed the control room. Although suspected to be an anomalous condition, actions were taken in accordance with site contingency (SC) procedure SC-5, "Earthquake Emergency Plan." A survey revealed no plant structure or equipment damage, and reactor coolant system leakage was determined to be normal. Nearby seismic monitoring stations were contacted and indicated no corresponding seismic activity. Information processed from the seismic detector indicated that a single event with a peak acceleration of approximately 0.5 g and 0.2 second duration had occurred at 7:39 a.m. This corresponded to the time that a worker had been moving equipment

in the area of the seismic monitor. Based on the short duration and frequency spectrum of the event, the licensee concluded that the seismic monitor had been bumped and that no seismic event had occurred.

The inspector concluded that the actions taken by the operations and emergency preparedness departments demonstrated a strict procedure adherence philosophy and a conservative safety attitude.

6.0 ENGINEERING/TECHNICAL SUPPORT (71707, 92701)

6.1 Alignment of Offsite Electrical Supplies

Electrical power for Ginna station is provided by two offsite supply lines. These two independent sources, circuits 751 and 767, are each capable of supplying all site electrical loads. During power operations, however, loads are normally split. Circuits 751 and 767 each supply one train of the safety grade (class 1E) electrical system, and normal loads are divided between the two offsite sources and the output of the main generator. The number of power sources available, along with a system design which includes alternate feeds and bus ties, provides a great deal of flexibility in aligning the offsite power distribution system.

On December 24, 1992, circuit 751 deenergized due to a short circuit that occurred offsite. As discussed in inspection report 50-244/92-20, this caused a momentary loss of instrument power which produced an unnecessary automatic 20 percent turbine runback. During this inspection period, the licensee shifted the offsite power distribution system lineup to provide more reliable power to the instrument buses. In the present lineup, loss of circuit 751 will not cause any instrument buses to be deenergized. Although deenergizing circuit 767 will still result in loss of an instrument bus and produce an unnecessary turbine runback, this offsite supply is more reliable (both by design and operating history) than circuit 751. Additionally, the reactor protection system function that produces the turbine runback upon loss of one instrument bus has been demonstrated to be unnecessary and will be eliminated during the upcoming refueling outage.

7.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (90712, 90713, 92701, 40500)

7.1 Periodic Reports

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

-- Monthly Operating Report for January 1993

No unacceptable conditions were identified.

7.2 Bottled Hydrogen Storage

The inspector reviewed in-plant storage of bottled hydrogen to verify that it does not pose a direct hazard to safety-related equipment. The principle storage location for bottled hydrogen is the hydrogen storage area, a small building adjoining the north side of the turbine building. The two emergency diesel generator buildings also adjoin the north side of the turbine building, separated from the hydrogen storage area by a forth adjoining structure, the turbine oil storage area. The inspector was concerned that a postulated explosion in the hydrogen storage area could constitute a threat to EDG operability.

The hydrogen storage area is a building approximately 48 feet long and 13 feet wide. The wall that adjoins the turbine building is 12-inch thick concrete block, and the turbine oil storage building adjoining wall is 12-inch thick reenforced concrete. Both of these walls have fire resistance ratings that exceed three hours. The two outside walls and the roof are sheet metal. The floor is 12-inch thick concrete, separated from compacted backfill by a two-foot crawl space. There is one access door and one roll-up door, both through the sheet metal walls. The building has no installed fire suppression system. The majority of bottled gas storage is along the concrete wall that is shared with the turbine oil storage area (east wall). Gas bottles are stored vertically in nine adjoining storage racks, each of which will hold up to 10 compressed gas bottles. Storage along the east wall is designated for hydrogen and carbon dioxide. Cage and rack storage along the west (sheet metal) wall, will accommodate approximately 80 gas bottles, and is designated as miscellaneous gas storage. Four bottles each of hydrogen and carbon dioxide are located along the south concrete wall and are attached to respective turbine building supply headers.

Due to physical configuration, any plausible accident scenario originating with a fire/ explosion in the hydrogen storage area and ultimately affecting EDG operability would have to involve either the turbine oil storage area or the diesel fuel oil storage tanks. The turbine oil storage area building is approximately 48 feet long and 33 feet wide. The wall that adjoins the turbine building is 12-inch thick concrete block; the three remaining walls are 12-inch thick reenforced concrete. All walls have fire resistance ratings that exceed three hours. The roof is a metal deck. There is one access door from the turbine building, which has a fire resistance rating of 1.5 hours, and an outside access door through the north wall. The building contains two 25,000-gallon turbine lube oil storage tanks and bulk quantities of maintenance lubricants. The building is protected by an automatic deluge water spray system, designed to deliver 0.5 gallons per minute per square foot, and actuated by a rate-of-rise heat detection system.

The two diesel fuel oil storage tanks are located under ground, with approximately one half of each tank being located beneath the west side of the hydrogen storage area. The tanks are approximately eight feet in diameter and 16 feet in length, with a volume of 6,000 gallons each.

They are oriented horizontally, with the tops of the tanks about one foot under ground. Sheet metal doors at ground level provide access to a manway on each tank. The tanks are constructed of 5/16-inch carbon steel.

The inspector reviewed the station Fire Protection Evaluation (Gilbert Associates, Inc. Report Number 1936, dated March 1977). Section 4.12, "Hydrogen Storage Area," concludes that "this area presents no hazard to the continued safe operation or safe shutdown of the plant," however, it does not discuss possible involvement of the diesel fuel oil storage tanks. The licensee agreed to re-evaluate the safety implications of their hydrogen storage.

7.3 Erosion/Corrosion Subcommittee Meeting

On January 29, 1993, the inspector attended the quarterly meeting of the RG&E Erosion/ Corrosion (E/C) Integrated Management Team. Management representatives from the licensee's corporate engineering, maintenance, quality assurance, chemistry, and materials engineering and inspection services (MEIS) participated. Agenda topics included updates on the small bore piping program, revisions to quality engineering (QE) procedure QE-333, "Erosion/Corrosion Control Monitoring for Carbon Steel Piping," scope of the 1993 E/C program, review of the replacement of the 16-inch extraction steam line from the "A" and "B" preseparators, and chemistry program updates. The inspector determined that the meeting was well coordinated in that in-depth discussions addressed areas where the E/C program could be enhanced and where repair/replacement strategies could be optimized.

The inspector concluded that the licensee is aggressively and systematically addressing E/C concerns.

7.4 Engineering Support and Pre-Outage Meeting

A meeting was held on February 8, 1993, in the NRC Region I offices between RG&E and NRC management to discuss the scope of the 1993 annual refueling outage and current engineering support activities. Attachment 1 to this report lists meeting attendees. RG&E management discussed the outage schedule, planned maintenance activities, modifications to be completed and licensing activities. Handouts from the meeting are included as Attachment 2 to this report.

8.0 ADMINISTRATIVE (71707, 30702, 94600)

8.1 Backshift and Deep Backshift Inspection

During this inspection period, a backshift inspection was conducted on February 26, 1993. Deep backshift inspections were conducted on the following dates: February 13, 15, 26, 27, and March 6, 1993.

8.2 Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of inspections. The exit meeting for inspection report 50-244/93-04 (radiological environmental monitoring and effluent control programs, conducted February 8-12, 1993) was held by Mr. Jason Jang on February 12, 1993. The exit meeting for inspection report 50-244/93-03 was held on March 10, 1993.

ATTACHMENT I

RG&E ENGINEERING SUPPORT/PRE-OUTAGE MEETING
FEBRUARY 8, 1993

NAME	TITLE
RG&E	
Steven Adams	Technical Manager/Outage Director
Charles Forkell, Jr.	Manager Electric Engineering
Michael Kennedy	Director, Configuration Mgn. Program
Richard Marchionda	Superintendent Support Services
Delray Morgan	Lead Mechanical Engineer
Thomas Newberry	Lead Mechanical Engineer
Eugene Voci	Manager Mechanical Engineering
Thomas Werner	Director, Technical Process
Joseph Widay	Plant Manager
Paul Wilkins	Manager, Nuclear Engineering Services
NRC	
Joseph Carrasco	Reactor Engineer, Division of Reactor Safety (DRS)
Wayne Hodges	Director, DRS
Al Johnson	Project Engineer, NRR
William Lazarus	Chief, Reactor Projects Section 3B, Division of Reactor Projects (DRP)
James Linville	Chief, Projects Branch 3, DRP
Thomas Moslak	Senior Resident Inspector, Ginna
Brenda Whitacre	Reactor Engineer, DRS

Attach to Insp Rpt
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NRC REGION I MEETING
FEBRUARY 8, 1993

10:00 AM - 12:00 AM

Introduction	P. Wilkens	5 min
Performance Indicators/Management Initiatives	J. Widay	10 min

ENGINEERING SUPPORT ACTIVITIES

Process Upgrade	T. Werner	10 min
Configuration Management	M. Kennedy	10 min
Instrument Setpoints	C. Forkell	10 min

1993 OUTAGE ACTIVITIES

Outage Schedule and Overview	S. Adams	20 min
Maintenance Activities and Reliability Centered Maintenance Program	R. Marchionda	15 min
Modifications Activities	P. Wilkens	10 min
Containment Fan Cooler Replacement	E. Voci	5 min
Preseparator Header Replacement	D. Morgan/ T. Newberry	5 min
Licensing Issues	P. Wilkens	10 min

BREAKOUT TOPIC

Preseparator Header Repair

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PERFORMANCE INDICATORS
MANAGEMENT INITIATIVES

1992 PERFORMANCE RESULTS

ACCREDITATION TRAINING STATUS

HUMAN PERFORMANCE ENHANCEMENT/ROOT CAUSE ANALYSIS

ALARA REDUCTION

EMPLOYEE ACHIEVEMENT/BETTERMENT

RGE

February 8, 1993

PERFORMANCE INDICATORS MANAGEMENT INITIATIVES

1992 NUCLEAR PERFORMANCE RESULTS DECEMBER 1992

Performance Indicator	Target Level Annual	YTD	Actual
Capacity Factor, %	81.5%	81.5%	84.32%
Equivalent Forced Outage Rate %	3.0%	3.0%	2.26%
Unplanned Auto Scrams While Critical	1	1	2
Fuel Reliability (x10-3 μCi/gm	2.00	2.00	1.37
Solid Radwaste (Cubic Feet)	3000	3000	2163.4
OSHA Reportable Accidents	5	5	7
Lost Time Accidents	1	1	2
Collective Radiation Exposure (person-rem)	330	330	261.2
Contamination Incidents	220	220	220
O&M Expenditures ($1000s)	61,200	61,200	57,687
Capital Expenditures (1000s)	32,500	32,500	37,181

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PROCESS UPGRADE PROGRAM

PROGRAM GOAL

To develop and implement enhanced Nuclear policies, procedures and practices which will assure conformance with regulatory and technical requirements, provide engineering assurance, and optimize work flow and process control.

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PROCESS UPGRADE PROGRAM

WHY?

Inability of individuals, both new hires and outside agencies, to follow the engineering processes using the existing procedures

Growth of Nuclear Engineering Services Department

Need to revise governing procedures for clarity and compliance with changing industry standards and programs

Assessment identified weaknesses in Engineering Assurance

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PROCESS UPGRADE PROGRAM

OVERALL APPROACH

Initiated January, 1992

Seeking Process Improvements
(Eliminate, Simplify, Integrate, Divisionalize, and Formalize)

Major Commitment of Division Resources

10 Focus Teams - Specific Functional Areas

Multi-Departmental Focus Teams

Overall Plan and Schedule tied to Business Plan

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PROCESS UPGRADE PROGRAM

WORK IN PROGRESS

REVISED WORK PRIORITIZATION PROCESS

- Modification and Major Programs
- Large and Small Activities

COMPUTERIZED WORK TRACKING SYSTEM (EWTS)

- Visible Work Prioritization
- Tracking of Estimated vs Actual Manhours
- Schedule Adherence [Target vs Actual]

NES PERFORMANCE MONITORING SYSTEM

- Monitor Efficiency "How well are we doing"
- Monitor Effectiveness "Are we doing the right things"
- Monitor Quality "Are we meeting the customer's expectations"
- Trend Analysis - Backlog, Work Initiated/Completed

PROJECT PLANNING, MANAGEMENT AND IMPLEMENTATION

- e.g. Project Plan Concept - Lessons Learned -

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PROCESS UPGRADE PROGRAM

PROGRESS TO DATE

NEW PROCESSES

- "Short Form" EWR
- Team based "Integrated Design Process"
- Integrated Assessment
- NES Procedures Enhancements
  - User friendly procedure format
  - Procedure ownership concept
  - Issued new manual
  - Initiated procedure rewrites

INTERIM CHANGES

- Improved "In-Process" Document Control
- Enhanced control of vendor documents
- Enhanced calculation control/retrieveability

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PROCESS UPGRADE PROGRAM

NEXT STEPS

STREAMLINE ENGINEERING PROCESSES
(Focus Team Activated)

DEVELOPMENT OF PROJECT PLAN/DESIGN PACKAGE
(Focus Team Activated - Work product in draft format

OVERALL RESOURCE UTILIZATION PLAN
(EWTS testing initiated)

COMPLETE REVISION OF NES PROCEDURES

FINALIZE PERFORMANCE MEASURES/INDICATORS

PROGRAM COMPLETION - THIRD QUARTER, 1993

PROCEDURES COMPLETION - THIRD QUARTER, 1993

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CONFIGURATION MANAGEMENT PROGRAM

OVERVIEW

- Integrate Existing/Proposed Projects
- Develop Consistent Project Scopes
- Establish Data/Technical Interfaces Among Projects
- Develop Effective Work/Change Control Processes

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CONFIGURATION MANAGEMENT PROGRAM

PROJECTS MANAGED WITHIN CM PROGRAM

- P&ID Upgrade Project
- Electrical Controlled Configuration Drawing Upgrade Project
- Structural Controlled Configuration Drawing Upgrade Project
- Ginna Plant Equipment Safety Classification Project (Q-List)
- Vendor Technical Manual Upgrade Project
- Design Basis Document Development Project
- Setpoint Verification Project
- Configuration Management Information System Project
- Maintenance Procedures Upgrade Project
- Calibration Procedures Upgrade Project
- Document Control System Upgrade
- Enhanced Change Control Process
- Ginna Work Control Process Improvements

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CONFIGURATION MANAGEMENT PROGRAM

COMPLETED PROJECTS

PROJECT	DELIVERABLE
P & ID Upgrade	189 Drawings ME Equipment Database
ECCD	3,800 Drawings
Structural CCD	200 Drawings
VTM	2,931 Technical Documents
Instrument Index	Instrumentation Database
CP Procedures	360 Procedures
Q-List	> 30,000 Components Classified Ginna Master Equipment Database
Work Control	On-Going
Change Control	On-Going
Document Control	Seek Database Updated

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CONFIGURATION MANAGEMENT PROGRAM

MAJOR MILESTONES

PROJECT	ACTIVITY	DATE
Setpoint Verification	Complete Contracted Scope	3/94
	Complete RG&E Scope	12/94
Configuration Management Information System	Complete Interim System Training	7/93
	Turn-on Interim System (Nucleis/IDMS)	9/93
	Complete Development Nucleis/Oracle	2/95
	Turn-on Final System (Nucleis/Oracle)	3/96
Design Basis Documentation	Complete Licensing Database	1/93
	Determine Detailed Program Scope	8/93
	Begin Document Indexing	7/93
	Begin Topical and System DBDs	9/93
Maintenance Procedures	Complete Project	8/94

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INSTRUMENT SETPOINT VERIFICATION PROJECT

NEED FOR PROJECT

PILOT PROJECT

SCOPE

METHODOLOGY

SCHEDULE

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INSTRUMENT SETPOINT VERIFICATION PROJECT

NEED FOR PROJECT

- Existing Design Basis Documentation Was Not Consistent
- Setpoint and Calibration Issues Identified During SSFI and EDSFI Inspections
- Commitment to Configuration Management Program

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INSTRUMENT SETPOINT VERIFICATION PROJECT

PILOT PROJECT

- Consisted of Two Instrument Loops
- Means to Refine Methodology
- Establish a Basis for Resources (Manpower, Funding)
- Allowed Development of a Bid Document

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INSTRUMENT SETPOINT VERIFICATION PROJECT

SCOPE

- Safety Related and Safety Significant Instrument Loops
- Loops Were Selected Based on Review of:
  - Technical Specification
  - Updated Final Safety Analysis Report
  - Regulatory Guide 1.97 Equipment
  - Environmentally Qualified Equipment
  - Emergency Operating Procedures
- Time Delay Relay Setpoints and Undervoltage Relay Setpoints Covered by Other Initiatives

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INSTRUMENT SETPOINT VERIFICATION PROJECT

METHODOLOGY

- Assemble data package
- List and justify assumptions if required
- Document performance requirements (also seismic, EQ)
- Describe and document existing loop design
- Verify and document that the instrument loop is properly designed and calibrated
- Document loop uncertainty and evaluate adequacy of setpoint/indication for performance requirements
- Describe any discrepancies or problems
- Provide recommendations if required
- Conclusions

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INSTRUMENT SETPOINT VERIFICATION PROJECT

SCHEDULE

1991
- Developed Preliminary Setpoint Verification Methodology
- Performed Pilot Project
- Reviewed Pilot Project Results and Refined Methodology

1992
- Developed Procedure Controls
- Awarded Contract
- 17 Instrument Loop Evaluations Being Finalized

1993
- Complete 49 Unique Instrument Loops

1994
- Complete Remaining Instrument Loops

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1993 OUTAGE PRESENTATION

OUTAGE OBJECTIVE

1992/1993 PERFORMANCE INDICATORS

CRITICAL PATH OVERVIEW

MAJOR OUTAGE ACTIVITIES

OUTAGE RISK MANAGEMENT CHANGES

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1993 OUTAGE PRESENTATION

1993 OUTAGE OBJECTIVE

SAFETY

QUALITY

SCHEDULE

RGE

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1993 OUTAGE PRESENTATION

1993 OUTAGE PERFORMANCE INDICATORS

**SAFETY	1992 GOAL	1992 ACTUAL	1993 GOAL	1993 BUSINESS PLAN
Lost Time Accidents	0	1	0	1
Man-rem Exposure	305	223	210	240
Contaminations	188	152	140	180
Radwaste Generation	900 CU. FT/WK	1197 CU. FT/WK	1000 CU. FT/WK	14,300
QUALITY				
Preventative Maintenance	90%	91.9%	90%	-
Corrective Maintenance	90%	92.3%	90%	-
Inspections	90%	100%	90%	-
Rework	5%	0.2%	3%	-
REGULATORY				
Licensee Event Reports (LERs)	3	1	3	9
NRC Significant Events	0	0	0	0
PLANT IMPROVEMENTS				
Modification Work	90%	99.4%	90%	-
OPERABILITY				
Startup Problems	0	0	0	-
Continuous Run	30	30+	60	-
CORPORATE				
Outage Length	49	45.4	55	55

1993 ELECTRICAL OUTAGE BAR CHART

10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	1	2	3	4	5	6	7	8	9	10	11	12	13	14
W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T	W	T	F	S	S	M	T	W

Mar 14 5:00 — Mar 14 21:00
PERFORM PM ON BUS 13 PER M-48.1

Mar 16 4:00 — Mar 17 17:00
LOW LOOPLEVEL INTEGRITY

Mar 18 7:00 — Mar 23 17:00
1A DIESEL GENERATOR ANNUAL MAINT INSP

Mar 20 9:00 — Mar 20 10:00
INSTALL SPARE IN PLACE OF MCC 1C SUPPLY BRKR

Mar 22 14:00 — Mar 22 15:00
REPLACE ORIGINAL MCC 1C SUPPLY BREAKER

Mar 24 7:00 — Mar 24 17:00
RSSP-2.3 1A DIESEL GENERATOR ANNUAL TRIP TEST

Mar 25 5:00 — Mar 25 21:00
INSPECT/CLEAN BUS 11A & BUS 12A PER M-49.1

Mar 26 5:00 — Mar 26 21:00
INSPECT/CLEAN BUS 11B & BUS 12B PER M-49.2

Mar 27 7:00 — Apr 2 17:00
1B DIESEL GENERATOR ANNUAL MAINT INSP

Mar 28 5:00 — Mar 29 21:00
BUS 16 & MCC 1D OUTAGE

Mar 30 7:00 — Mar 30 13:00
PERFORM PM ON MCC 1J

Mar 31 8:00 — Mar 31 16:00
PERFORM PM ON MCC 1M

Apr 3 7:00 — Apr 3 17:00
RSSP-2.3 1B DIESEL GENERATOR ANNUAL TRIP TEST

Apr 8 13:00 — Apr 10 3:00
LOW LOOP LEVEL INTEGRITY

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1993 OUTAGE PRESENTATION

1993 AI&O OVERVIEW

MAJOR ACTIVITIES

- Defueling
- ILRT
- Containment Recirc Fan Cooler Replacements
- LP-2 Turbine Rotor Major Inspection/ Stationary Blade Replacement
- B RCP Seal Inspection
- Service Water Outage of B Loop (Defueling or flooded condition required)
- A & B RCP Diffuser Bolt Inspections (Defueling required)
- Reactor Vessel Specimen Pull
- Reactor Vessel Internals Inspection with Mini Rover (Defueling required)

1993 OUTAGE PRESENTATION

1993 AI&O OVERVIEW

MAJOR ACTIVITIES
(continued)

- MSR Relief Valve Refurbishment (6 of 6)
- Main Steam Safety Valve Inspections/Refurbishment
- Incore Thimble Cleaning & Eddy Current
- Main Generator Voltage Regulator Replacement
- B D/G Voltage Regular Inspection
- # Work Orders Planned for Outage

I&C	391
Mechanics	116
Pipe	376
HVAC	53
Electricians	140
TOTAL	1076

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1993 OUTAGE PRESENTATION

OUTAGE RISK MANAGEMENT CHANGES

REVISION TO OUTAGE SAFETY ASSESSMENT

- Based upon NUMARC 91-06
- 1992 Outage Experience

ADDITION OF EXPERIENCED STAFF TO OUTAGE GROUP

- Larry Smith
- Held SRO License/33 Years Experience with RG&E
- Former Operations Supervisor

ADDITIONAL RESPONSIBILITIES GIVEN TO OUTAGE COORDINATORS

- Review all holds
- Approve all Temporary PCNs
- Attend Shift Turnovers to Enhance Communications
- On-Call to Assist Shift Supervisors During Transients

COMMUNICATE ESTIMATED HEAT-UP/BOIL TIMES DURING LOW LOOP LEVEL

- Update Status Board Each Shift
- Include "Time to Boil" and "Time to Core Uncovery"

1993 OUTAGE PRESENTATION

GINNA OUTAGE SAFETY ASSESSMENT

REACTIVITY		SUBTOTAL	CONDITION	SCORE
1. SR Instrumentation operable (0-2)	____	0-1	RED	0
2. Fuel movement not in progress	____	2	ORANGE	1
3. Number of boration paths avail (0-2)	____	3-4	YELLOW	2
4. RCS boron > 2000 ppm	____	5-6	GREEN	3
Reactivity Subtotal	____			
NOTE: Reactivity assessment is not required when all fuel is in SF Pit				
CORE COOLING		**SUBTOTAL**	**CONDITION**	**SCORE**
5. Number of S/G avail. for decay heat removal (0-2)	____	0	RED	0
6. Refueling cavity flooded	____	1	ORANGE	1
7. No. of RHR trains available (0-2)	____	2	YELLOW	2
8. RCS level above reduced inventory ≥ 64"	____	3-5	GREEN	3
Core Cooling Subtotal	____			
NOTE: Core Cooling Assessment is not required when all fuel is in SF Pit				
POWER AVAILABLE		**SUBTOTAL**	**CONDITION**	**SCORE**
9. Offsite power sources available to bus 12A (0-2)	____	0-2	RED	0
10. Offsite power sources available to bus 12B (0-2)	____	3	ORANGE	1
A D/G operable (2)	____	4-6	YELLOW	2
B D/G operable (2)	____	7-8	GREEN	3
Power Available Subtotal	____			
CONTAINMENT		**SUBTOTAL**	**CONDITION**	**SCORE**
13. Refueling Integrity (or CNMT Int) set	____	0	RED	0
14. Closure cability in < 2 hrs.	____	1	ORANGE	1
15. Fuel movement not in progress	____	2	YELLOW	2
16. RCS not in low loop level condition	____	3-4	GREEN	3
Containment Subtotal	____			
NOTE: Containment Assessment is not required when all fuel is in SF Pit				
INVENTORY		**SUBTOTAL**	**CONDITION**	**SCORE**
17. Pressurizer level > = 13% w/Rx Head on	____	0-1	RED	0
18. Rx Cavity flooded	____	2	ORANGE	1
19. Rx Vessel level > = 64"	____	3-4	YELLOW	2
20. No. of RCS borated water makeup paths available (0-4)	____	5-6	GREEN	3
Inventory Subtotal	____			
NOTE: Inventory is not required when all fuel is in SF Pit				
SPENT FUEL PIT COOLING		**SUBTOTAL**	**CONDITION**	**SCORE**
A1. SF Pit level > low level alarm	____	1	RED	0
A2. A SF Pit cooling system available	____	2	ORANGE	1
A3. B SF Pit cooling system available	____	3	YELLOW	2
A4. Standby SF pit cooling system available within 2 hours	____	4	GREEN	3
SF Pit Cooling Subtotal	____			
SF Pit cooling assessment only applies when core is full off loaded				
OVERALL SAFETY CONDITION	**TOTAL SCORE** ____			

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RELIABILITY CENTERED MAINTENANCE (RCM)

PROJECT/PROGRAM HISTORY

EPRI Large Scale Demonstration Project

- Started in early 1988
- 26 of 48 identified plant systems
- By project's end in mid-1991 a printed summary of each system analysis had been delivered
- Total of 460 recommendations to make additions and/or deletions to:
  - Add preventive maintenance tasks
  - Delete preventive maintenance tasks
  - Perform technical evaluation of structures and components
  - Perform plant modifications
- Consultant cost of about $1,600K

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RELIABILITY CENTERED MAINTENANCE (RCM)

PRESENT SITUATION

A. PROJECT RECOMMENDATIONS

- 137 of the 460 original EPRI RCM Project recommendations have been dispositioned at a calculated cost of $315K
- Dispositioning the remaining recommendations is projected to be completed by the end of 1994
- Considering resource reallocation to improve implementation schedule

B. "LIVING PROGRAM"

- Four Preventive Maintenance Analysts (Electrical, Mechanical, Valve/Pipefitter and Instrument & Control) review all completed work packages (including both preventive and corrective involving their area of responsibility
- The RCM analyses was performed on a system basis, but ongoing hardware responsibilities are assigned on a discipline/lead shop/component type basis

RELIABILITY CENTERED MAINTENANCE (RCM)

PRESENT SITUATION
(continued)

- PM Analysts verify RCM analysis summary for component involved is complete and accurate and updated:
  - Failure Codes and Effects Summary
  - Industry Experience Report
  - Ginna Maintenance History Summary
  - Surveillance Testing
  - Preventive Maintenance Program
  - Rationale Summary

- The PM Analyst also goes through the RCM analysis stair step questions to determine additional information presented provides sufficient justification for changing a PM task frequency or for initiating a plant modification, maintenance procedure revision or some other change.

- The PM Analysts review plant modification documentation and industry experience reports and ensure that appropriate changes are made to applicable PM tasks and the RCM analysis summaries are updated accordingly.

- The analysis summaries are currently referenced and updated manually in their hardcopy form by the PM Analysts.

RELIABILITY CENTERED MAINTENANCE (RCM)

PRESENT SITUATION
(continued)

- The analysis summary information is being loaded into a personnel computer local area network database. This should take much of the administrative overhead of accessing and updating of the analysis information out of the "living program." This is expected to be at a workable stage by mid-1993.

C. COSTS/BENEFITS

- The direct cost to RG&E of the consultant's involvement in the initial EPRI project and currently as part of the Maintenance Procedure Upgrade Project (MPUP) can be readily assessed. However, it is at this point that the "cost" of implementing RCM becomes fuzzy. Quite often it is impossible to differentiate between actions associated with RCM implementation and actions that would otherwise have been done anyway.

- Reduction of PM tasks will result in cost savings but will not always be immediately apparent due to:

    - Interval length (five years)
    - Resources not reduced
    - Parts reduction, PM to CM shift
    - Past system/component reliability

RELIABILITY CENTERED MAINTENANCE (RCM)

PRESENT SITUATION
(continued)

- The benefit of RCM is that it is a methodical, logical approach to developing a basis and rational for what preventive maintenance is and/or is not performed.

- Appropriate course corrections are made as new information arrives and the system is inherently self correcting and adaptive to changing conditions.

- Much of the cost benefit potential for Ginna lies in shifting from calendar based equipment disassembly for inspection/overhaul to effective employment of predictive maintenance technologies (vibration analysis, oil analysis, acoustic analysis, thermography, motor current and insulation condition analysis) to determine when major inspections or overhauls should be performed.

- This will be achieved when deterioration of a component's condition can be detected while it is still acceptable and reasonable predictions can be made as to when the component condition will become unacceptable and/or failure will occur. The PM Analysts have been tasked with developing and integrating the use of these predictive technologies into the PM Program.

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RELIABILITY CENTERED MAINTENANCE (RCM)

FUTURE/INTENTIONS

A. ADDITIONAL SYSTEM ANALYSES

- An additional 8 systems are to be analyzed as part of the Maintenance Procedure Upgrade Project (MPUP).
- Analyses of Radiation Monitoring and Extraction Steam Systems are in progress as is the selection of 6 of the remaining plant systems.
- These 8 systems analyses are expected to be completed by mid-1993.

B. MAINTENANCE RULE

- NUMARC draft implementation guide has been reviewed and the NUMARC pilot implementation project report(s) will be reviewed when they are received (expected early 1993).
- RG&E is participating in a 2-loop owner's group. Maintenance Rule implementation and RCM involvement are seen as topics to be pursued in this forum.
- Maintenance Rule focus is on plant/system level performance and condition monitoring. Introduction of a system engineer functional organization is being considered to provide coherency and continuity of focus at the plant system level.

RELIABILITY CENTERED MAINTENANCE (RCM)

FUTURE/INTENTIONS
(continued)

C. CONFIGURATION MANAGEMENT INFORMATION SYSTEM

An integrated database information system is being developed with full implementation expected by 1996. RCM living program functionality is to be evaluated for an appropriate level of incorporation.

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RELIABILITY CENTERED MAINTENANCE (RCM)

GINNA PLANT SYSTEMS
(continued)

Legend: Steam Generators were considered to have already been sufficiently analyzed.
BOLD - Systems analyzed as part of EPRI project
ITALIC - Systems of which 6 of will be analyzed as part of the MPUP
NORMAL - Systems currently being analyzed as part of MPUP

1. STEAM GENERATOR
2. **REACTOR COOLANT**
3. **REACTOR PROTECTION**
4. **ENGINEERED SAFETY FEATURES**
5. **RESIDUAL HEAT REMOVAL**
6. **DIESEL GENERATOR**
7. **CHEMICAL VOLUME & CONTROL**
8. **SAFETY INJECTION**
9. **MAIN FEEDWATER**
10. **ELECTRICAL DISTRIBUTION - DC**
11. **CONTROL ROD DRIVE**
12. **AUXILIARY FEEDWATER**
13. **ELECTRICAL DISTRIBUTION - AC**
14. **NUCLEAR INSTRUMENTATION - EXCORE**
15. **MAIN STEAM**
16. **FIRE PROTECTION**
17. **CONTAINMENT**
18. **TURBINE GENERATOR**
19. **SERVICE WATER**
20. **CONTAINMENT SPRAY**
21. **NUCLEAR INSTRUMENTATION**
    CORE EXIT THERMOCOUPLES AND INCORE FLUX MONITORS
22. **ELECTRICAL DISTRIBUTION - MCC**
23. *FUEL HANDLING*
24. **CIRCULATING WATER**

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RELIABILITY CENTERED MAINTENANCE (RCM)

GINNA PLANT SYSTEMS

Legend: Steam Generators were considered to have already been sufficiently analyzed.
BOLD - Systems analyzed as part of EPRI project
ITALIC - Systems of which 6 of will be analyzed as part of the MPUP
NORMAL - Systems currently being analyzed as part of MPUP

25. RADIATION MONITORING
26. **CONDENSATE**
27. *HEATING, VENTILATION & AIR CONDITIONING*
28. **STANDBY AUXILIARY FEEDWATER**
29. *RADIOACTIVE WASTE DISPOSAL - GAS*
30. **INSTRUMENT AND SERVICE AIR**
31. *RADIOACTIVE WASTE DISPOSAL - LIQUID*
32. **COMPONENT COOLING WATER**
33. EXTRACTION STEAM
34. *WATER TREATMENT*
35. *NUCLEAR SAMPLING*
36. *ELECTRICAL DISTRIBUTION - UVP*
37. *POST-ACCIDENT SAMPLING*
38. *ELECTRICAL PENETRATION & PRESSURIZATION*
39. *PENETRATION COOLING & N2 PRESSURIZATION*
40. *FEEDWATER HEATER DRAINS & RELIEFS*
41. *SPENT FUEL POOL COOLING*
42. *SUMPS AND DRAINS*
43. *METEOROLOGICAL*
44. *ALL VOLATILE TREATMENT*
45. *(HOUSE) HEATING STEAM & CONDENSATE*
46. *CONDENSER AIR REMOVAL & PRIMING*
47. *GLAND SEALING WATER*
48. *CHEMICAL ADDITION*

February 8, 1993

1993
NON-OUTAGE MODIFICATIONS/TECHNICAL SUPPORT

SECURITY SYSTEM MODIFICATIONS

USI A-46, SQUG

INTERMEDIATE BUILDING HVAC SYSTEMS

FIRE DAMPER & BARRIER WORK

BORON CONCENTRATION REDUCTION

PROGRAM SUPPORT
(Erosion/Corrosion, IST, MOVs)

February 8, 1993

1993
OUTAGE MODIFICATIONS/TECHNICAL SUPPORT

1993 MODIFICATIONS SIMILAR IN MAGNITUDE TO 1992

EXPECT 30,000 CRAFT HOURS

WORK MANAGED BY RG&E WITH EXPERIENCED CONTRACTOR

February 8, 1993

1993
OUTAGE MODIFICATIONS/TECHNICAL SUPPORT

SERVICE WATER

Containment Fan Cooler

SW Fouling

Temporary Cooling

Valve Refurbishment Support

PIPING

Valve Replacements

IST Vents & Drains

Steam Generator Replacement Walkdowns

February 8, 1993

1993
OUTAGE MODIFICATIONS/TECHNICAL SUPPORT

ELECTRIC AND I & C

Recorder Replacement

Generator Exciter Voltage Regulator

Solonoid Valve Replacement

ADFCS Upgrade

CONTAINMENT "MANSAFE" SYSTEM

ILRT STRUCTURAL INSTRUMENTS

PRESEPARATOR DRAIN HEADERS

RGE

February 8, 1993

CONTAINMENT RECIRCULATING COOLERS

LEAKING COOLERS

RESTRICTIVE ACCESS FOR INSPECTION/REPAIR OF COOLERS

HEAT REMOVAL CAPABILITY MARGIN IMPROVEMENT

RESTRICTIVE TECH SPEC ON CRC

February 8, 1993

CONTAINMENT RECIRCULATING COOLERS

LIMITATIONS & DESIGN REQUIREMENTS

SCHEDULE
(Support March '93 Outage)

ACCESS TO REMOVE AND REPLACE COOLER COILS

DESIGN BASIS REQUIREMENTS

- Maximum Heat Removal Capacity Limit (LOCA)
- Minimum Heat Removal Capacity Limit (MSLB)
- Air Flow Limits (Iodine Removal)
- Effect on SWS Hydraulic Balance
- Zebra Mussels
  (Biofouling Control & Water Chemistry)
- Seismic Design

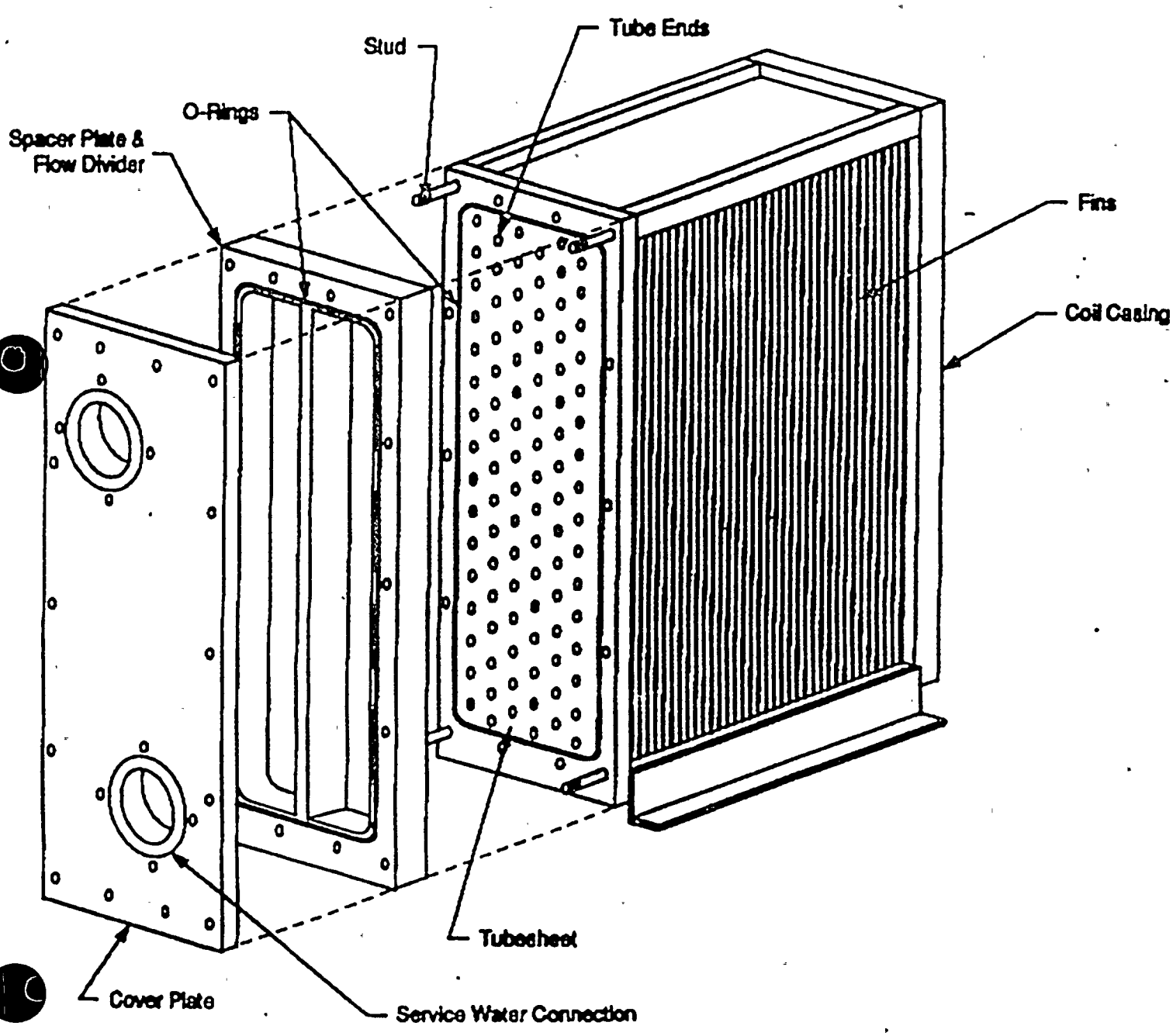
CONTAINMENT RECIRCULATING COOLERS

SUMMARY OF IMPROVEMENTS FOR ENHANCED DESIGN

- 17% Heat Transfer Margin (Accident Conditions)
- AL-6XN Tube Material
- Resistant to Erosion and Corrosion
- Compatible with Velocities for Zebra Mussel Control
- Lower Water Velocity Reduces Potential for Erosion/Corrosion
- Waterbox Design
- Water-Side Access for Inspection, Cleaning, and Repair
- Plugging Margin

CONTAINMENT RECIRCULATING COOLERS

ENHANCED CRFC COIL DESIGN CONCEPT



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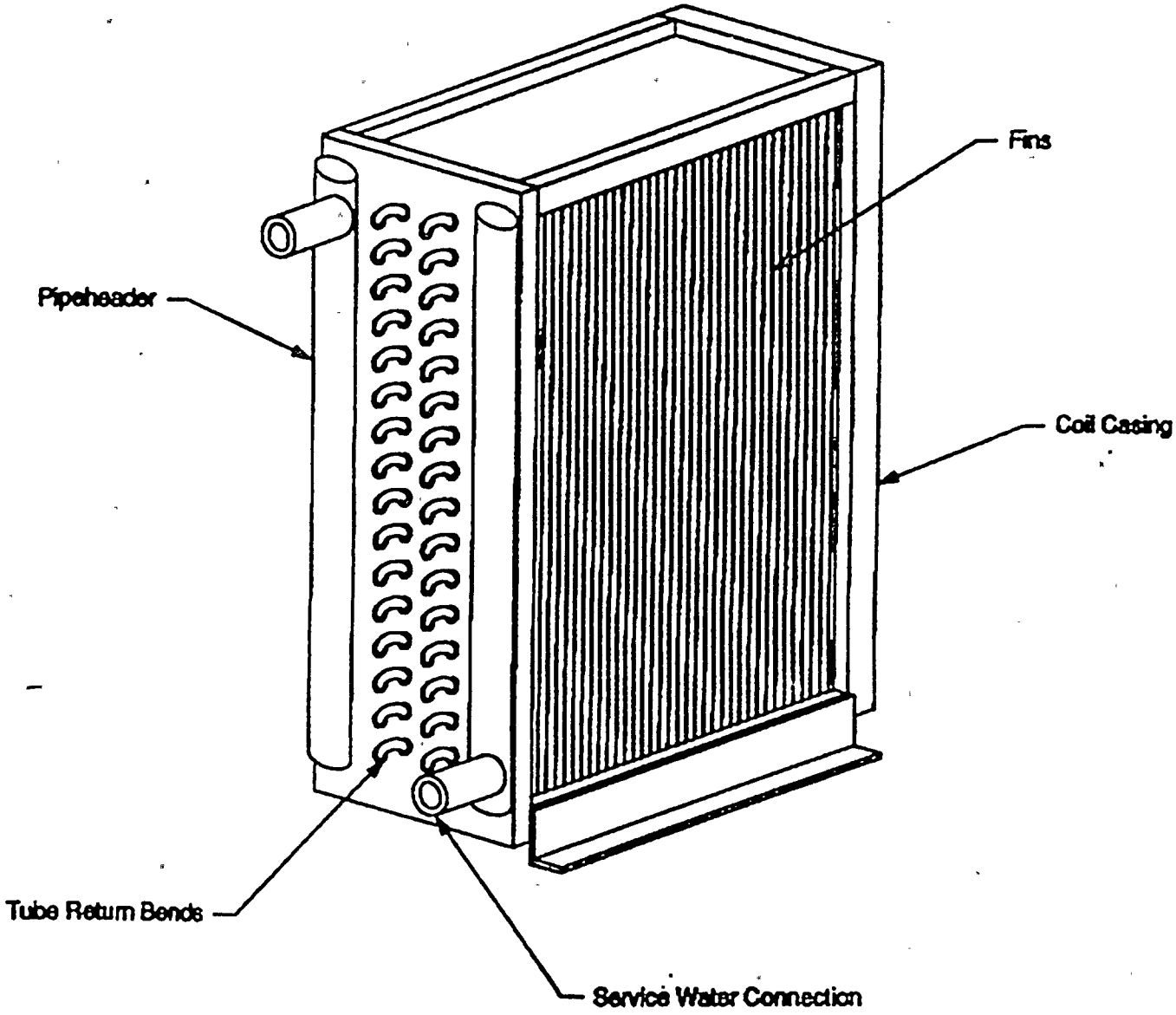
CONTAINMENT RECIRCULATING COOLERS

EXISTING CRFC COIL DESIGN CONCEPT



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PRESEPARATOR DRAIN HEADER

OVERVIEW & STATUS

ISSUE:

June 1992 Fishmouth Rupture of "A" preseparator drain header. No injury resulted or damage to other equipment.

WHAT ARE PRESEPARATOR DRAIN HEADERS?

- In line moisture collection headers for extraction steam of the 4A feedwater heater.
- **Note:** These are downstream and remote from Preseparator devices which are located in the HP turbine exhaust nozzle.

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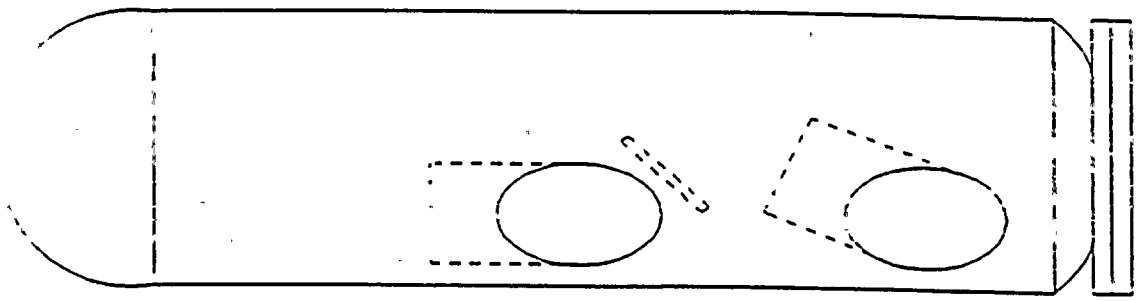
PRESEPARATOR DRAIN HEADER

INSPECTION & REPAIR FOLLOWING RUPTURE

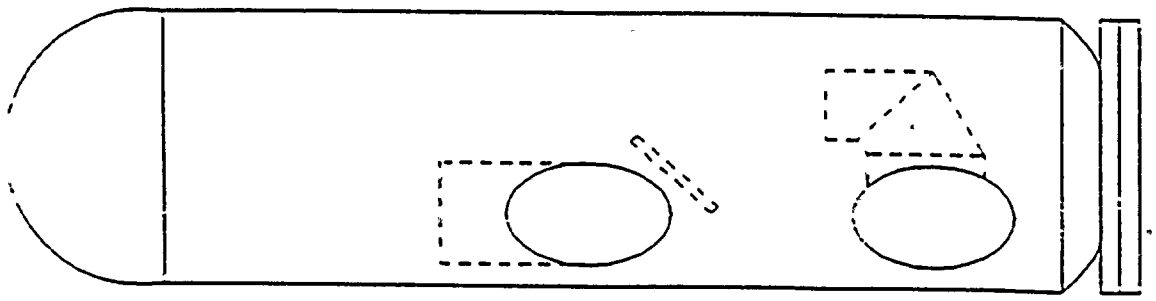
- Inspections were done on Both A & B preseparator drain headers.
- Engineering basis was established.
- A combination of A-36 plate & weld overlay in thinned area was used for repairs.
- Repair made was for the short term.
- The analysis was submitted to NRC.
- There were issues & questions raised in NRC Inspection report 50-244/92-09.
- RG&E has responded to questions raised in November 1992 response submittal.

February 8, 1993

PRESEPARATOR DRAIN HEADER



EXISTING "A" HEADER



NEW "A" HEADER

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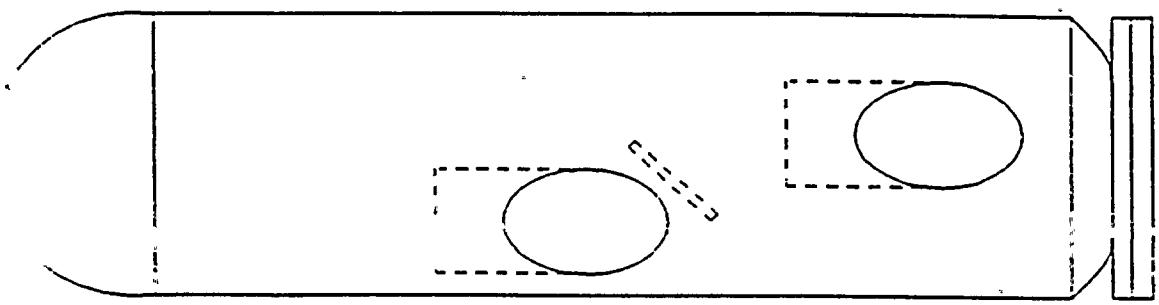
PRESEPARATOR DRAIN HEADER

EXISTING AND NEW "B" HEADER



February 8, 1993

PRESEPARATOR DRAIN HEADER

PRESEPARATOR A & B DRAIN HEADER REPLACEMENT

- New piping header designed, fabricated and to be installed in accordance with appropriate Codes/Standards during 1993 Refueling outage

IMPROVED FEATURES

- New headers are Chrome Moly with partial Stainless Steel Internals
- New headers are 1/2" wall instead of 3/8".
- New A header redirects nozzle to avoid direct impingement on side wall of header.
- Headers increased in length by 6" to ease constructability, and has the effect of reducing steam energy on end of header.
- Baseline UT to be performed on areas of header with potential for future wear. Headers are now included the E/C program.

February 8, 1993

NRC LICENSING ISSUES

REGULATORY GUIDE 1.97

BORON REDUCTION TECH SPEC

REVISED ECCS ANALYSIS - UPI

SQUG/IPEEE

PRA/IPE

DBDs