U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report 50-244/94-05 **License: DPR-18**

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

Inspection: February 8 through March 8, 1994

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

Approved by: W. J. Lazarus, Chief, Reactor Projects Section 3B — 4/5/94 Date

INSPECTION SCOPE

Plant operations, maintenance, engineering, and plant support.

INSPECTION EXECUTIVE SUMMARY

Operations

The plant operated at 98 percent power for the majority of the inspection period. On February 17, 1994, loss of offsite power circuit 751 caused a spurious turbine runback. By coincidence, the "A" EDG was operating in parallel with circuit 751 at the time. Although this prevented the associated 480-volt safeguard buses from being deenergized, the resultant undervoltage transient caused a momentary turbine runback. Reactor power was subsequently reduced to less than 90 percent, as required by technical specifications, while core axial flux distribution was stabilized. Full power operation was resumed later that day. Operator response to the transient was prompt and in accordance with procedure. Actions were well-focused on establishing and maintaining plant stability.

On March 4, 1994, the plant was shut down to commence the scheduled annual refueling outage. At the close of the inspection period, the reactor was in refueling shutdown mode, with reactor disassembly in progress in preparation for full core offload to support extensive service water, component cooling water, and residual heat removal system maintenance.

Maintenance

Corrective maintenance on spent fuel pool service water system components was well planned to optimize plant safety for a complete core off-load. Diagnostic testing on the Turbine Driven Auxiliary Feedwater Pump was effectively carried out to identify and evaluate off-normal operating parameters.

Engineering

On February 15, 1994, the licensee determined that the two manual containment isolation pushbuttons had not been periodically tested as required by technical specifications. The licensee requested, and was granted, enforcement discretion to defer testing until after shutdown for the refueling outage. In January, 1994, the licensee determined that two containment pressure instruments had been inoperable since June 1992 due to blockage of the common sensing line that connects the associated pressure transmitters with containment; as a result, the reliability of automatic initiation of certain safety features was degraded. These two conditions demonstrated that testing was not being appropriately performed, and constituted a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control."

Plant Support

On March 1, 1994, while purging the pressurizer to the volume control tank, valve seat leakage in the post accident sampling system resulted in minor radioactive contamination of water in the condensate storage tanks; the health physics technician who discovered the problem was also slightly contaminated. Licensee response to this minor radiological event was prompt and comprehensive. At the close of the inspection period, a root cause analysis of this event was in progress.

Safety Assessment/Quality Verification

In a meeting of the Nuclear Safety Audit and Review Committee, topics were candidly discussed and were presented with sufficient detail for board members to assess the safety significance of the agenda issues.

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DETAILS

1.0 OPERATIONS (71707)

1.1 Operational Experiences

At the beginning of the inspection period, the plant was operating at full power (98 percent). On February 17, 1994, a voltage transient on one of the two offsite electrical power supply circuits resulted in a five percent power reduction due to momentary, transient-induced actuation of the turbine runback functions. Operators subsequently reduced power to 89 percent, as required by technical specifications, while core axial flux distribution was stabilized. Full power operation was resumed later that day and continued until March 4, 1994, when a controlled shutdown was performed to commence the scheduled annual refueling outage. At the close of the inspection period, the reactor was in refueling shutdown mode, with reactor disassembly in progress in preparation for full core offload to support extensive service water, component cooling water, and residual heat removal system maintenance.

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 Spurious Actuation of Automatic Reactor Protection System Due To Offsite Electrical Transient

Offsite electrical power for the Ginna plant is provided by two independent 34.5 kilovolt supply lines, designated circuits 751 and 767. Each circuit supplies one of the two station auxiliary transformers, 12A and 12B. Along with normal site loads,.these transformers each supply two safety grade (1E) 480 volt electrical buses. Two emergency diesel generators (EDGs) serve as backup 1E power sources for the auxiliary transformers. The 1E electrical buses are safety significant in that they supply power to reactor safety/accident mitigation equipment and instrumentation.

On February 17, 1994, operators were conducting a monthly performance test of the "A" EDG, with the diesel loaded to 2000 KW. Since normally operating plant equipment does not provide this much load, the EDG was being operated in parallel with circuit 751. This electrical alignment is specified by the performance test and allows operators to establish the required EDG loading by backfeeding power through circuit 751.

Concurrent with the EDG testing, a mechanical problem had developed with one of the power distribution breakers at the offsite supply station (station 204) that supplies power for circuit 751. At about 2:20 PM, offsite power control initiated switching operations to isolate the affected circuit breaker. During this operation, malfunction of a bank of automatic close-in capacitors produced a loss of the circuit 751 supply bus. Since the "A" EDG was coincidentally operating in parallel with circuit 751, it assumed all of the electrical load upon loss of the normal power supply. This large increase in load caused the EDG voltage to drop below the undervoltage trip setpoint of the two 1E bus normal supply breakers. These breakers opened, thus isolating the 1E buses (buses 14 and 18) from circuit 751, with power continuing to be supplied to these buses by the "A" EDG.

Bus 14 supplies normal power to two of the four instrument buses which power one channel of the reactor protection system. One of these two instrument buses (bus "A") receives auctioneered power from the 125-volt DC 1E electrical distribution system, such that degradation or loss of a single power supply will not affect power at the instrument bus. The other instrument bus (bus "B") is powered only by bus 14. Therefore, while the "A" EDG was carrying circuit 751, the degraded voltage was translated to instrument bus "B". Voltage was sufficiently low to trip reactor protection system channel "B" protective function bistables. Since the reactor protection system turbine runback functions (overpower and overtemperature temperature difference) require only one signal to satisfy the system logic, a turbine runback occurred during the approximately four seconds of degraded voltage operation.

The automatic turbine runback decreased plant power to approximately 93 percent. Although this was a relatively small power reduction, a xenon buildup complicated the operators' efforts to maintain allowable core flux distribution. Operators were not successful at maintaining axial flux difference within the target band, and consequently initiated a further reduction in power to less than 90 percent, as required by technical specification 3.10.2.9. The power reduction was halted at 89 percent and axial flux difference was stabilized within the target band.

Stable offsite power was restored to circuit 751 within two minutes of the transient. After discussion with the load dispatcher, operators transferred the affected 1E electrical buses back to circuit 751 and shut down the "A" EDG. Reactor power was slowly escalated, due to end-of-cycle core physics constraints, with full power operation being achieved at 10:10 PM, February 17, 1994.

The inspector arrived at the control room several minutes after the transient started and observed good operator response to the transient. Actions per abnormal procedure (AP)-TURB.2, "Turbine Load Rejection," were promptly carried out. The Head Control Operator effectively maintained focus on verifying that the necessary equipment was operating and that conditions were stable. Reactor power was promptly reduced when axial flux difference exceeded the target band. NRC notification was completed as required by 10 CFR 50.72.

Although good procedural adherence was observed, the inspector questioned whether the directions in PT-12.1, "Emergency Diesel Generator 1A," for operation of the EDG voltage regulator and speed governor, were adequate. During this test, EDG voltage and speed control are selected for manual control to facilitate operation of the generator in parallel with the grid. The procedure contains a precaution to return these controls to automatic if a safety injection signal were to occur during conduct of the test. The basis of this precaution is that the normal (offsite power) feed breakers would open in response to a safety injection signal, and the generator would become the sole source of power to the associated safeguard buses. Although loss of circuit 751 had produced the same result, operators left the EDG voltage and speed control in manual, because the precaution was specific to safety injection. The inspector discussed this question with the licensee. The licensee agreed that the precaution for returning the EDG voltage and speed control to automatic should be extended to a loss of offsite power. The inspector had no additional concerns on this matter.

1.4 Plant Shutdown For Cycle 24 Refueling Outage

The inspector observed portions of the power reduction and plant shutdown that were conducted on March 4, 1994 for the Cycle 24 refueling outage. The inspector observed that the power reduction was well controlled. Strict procedural adherence and good communications, including repeat-backs of directed procedural steps, were observed. Low power operations, pre-outage turbine testing, and reactor shutdown were well coordinated. Management involvement in operations was evident during preparations for, and conduct of, turbine testing. The reactor shutdown and transition to plant cooldown were conducted deliberately and without incident. The inspector had no additional concerns in this area.

2.0 MAINTENANCE (62703, 61726)

2.1 Preventive/Corrective Maintenance

2.1.1 Routine Observations

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

- Work Order (WO) 19320990, "Disassemble/Inspect/Replace V-4622 (Spent fuel pit (SFP) heat exchanger "A" service water outlet isolation valve), observed February 22, 1994
  - This is a Crane model 143½ globe valve; as discussed in inspection report 50-244/93-12, the licensee determined that these valves are susceptible to stem/disc separation due to failure of the stem/disc lock weld. This maintenance revealed that the lock weld on this valve had failed, but that there was still full stem/disc

engagement. Additionally, the seat ring guide (fits around the lower valve stem to help keep the disc centered) was found to be worn. A non-conformance report (NCR 94-009) was issued by the Quality Assurance department to document the deficiencies identified during this maintenance and to authorize interim use until November 30, 1994.

-- The inspector considered that conducting this maintenance prior to the refueling outage was prudent, for the following reasons:

  - Maintenance was coordinated with other service water system maintenance which required both trains of SFP cooling to be secured to provide isolation;

  - SFP cooling was secured for maintenance when the heat load was low as possible (approximately 10 months after the last refueling outage and just prior to the current refueling outage);

  - With a full core off-load to be performed during the current refueling outage, maintenance performed prior to the outage improved system reliability.

-- The inspector considered that deferral of valve replacement as specified by NCR 94-009 would be of minimal safety significance.

- WO 19400816, "Turbine Driven Auxiliary Feedwater Pump - Repair Outboard Pump Bearing," observed February 25, 1994

-- During routine monthly performance testing on February 24, 1994, technicians noted that the turbine driven auxiliary feedwater (TDAFW) pump outboard bearing cartridge temperature increase was greater than expected. The pump was declared inoperable, pending further investigation. The following day, after changing the bearing oil and inspecting the bearing cartridge, the pump was operated for several hours while bearing oil and cartridge temperatures were monitored. Although bearing cartridge temperature was still higher than expected, the long monitored run time demonstrated that oil temperature eventually stabilized within the band specified in the vendor's manual. Additionally, pump vibration was monitored periodically until oil temperature stabilized, and indicated normal operation. Based on these results, the TDAFW pump was declared operable on February 25, 1994.

-- The inspector considered that this maintenance activity was well executed. The inspector considered that the licensee's action to declare the TDAFW pump operable was adequately supported by the test results.

- WO 19400660, "Perform DP Testing on MOV-4663 (Air conditioning service water isolation)," performed per M-64.1.2, "MOVATS Testing of Motor Operated Valves," revision 20, effective date February 15, 1994, observed March 1, 1994

  -- The technicians were knowledgeable of test methods and procedural requirements. No deficiencies were noted.

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)-2.1M, "Safety Injection System Monthly Test," revision 10, effective date December 30, 1993, observed February 17, 1994

- PT-12.1, "Emergency Diesel Generator 1A," revision 72, effective date October 26, 1993, observed February 17, 1994

- PT-50.3, "Differential Pressure Testing of Containment Spray Valves MOV-860C and MOV-860D," revision 1, effective date April 28, 1990, observed February 23, 1994

- T-18C, "Turbine Overspeed Trip Test," revision 16, effective date June 4, 1993, observed March 4, 1994

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

3.0 ENGINEERING (71707)

3.1 Failure to Test Containment Isolation Manual Push Buttons

By letter dated February 15, 1994, RG&E requested that the NRC staff exercise discretion to not enforce compliance with the required actions of Technical Specification (TS) Table 4.1.2, Item No. 9, for testing the manual containment isolation push buttons, because testing at power could potentially challenge plant engineered safety features. RG&E had informed the NRC by telephone on February 14, 1994, that it had determined that the two control room push buttons, which can be used by operators to manually actuate the containment isolation system, had not been tested as part of the routine surveillance testing of that system. On the basis of the submitted documents, the NRC staff concluded that postponement of performing this test until

after the plant is in cold shutdown, beginning March 7, 1994, involves minor safety impact. Therefore, discretion was exercised to delay testing until the refueling outage and not to enforce immediate compliance with the requirement of TS Table 4.1.2, Item No. 9, from 10:00 AM on February 16, 1994 (the time that the limiting condition for operation for this requirement expired) to 12:00 AM on March 7, 1994, when the plant would be in cold shutdown and the TS requirement would be no longer applicable. Testing of the manual containment isolation function will be performed prior to resuming power operations.

The NRC staff has reviewed relevant plant procedures and supporting documentation, including Licensee Event Report 94-04, addressing the functional testing of both containment isolation push buttons. Dedicated surveillance testing of this manual function had not been performed as required by Technical Specifications and as such, represented failure to implement a testing program as required by 10 CFR 50, Appendix B, Criterion XI, "Test Control." Criterion XI states, "A test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents." Contrary to this requirement, dedicated testing of the manual containment isolation function was not incorporated into procedures and implemented. (50-244/94-05-01)

3.2 Containment Pressure Transmitters Inoperable Due to Blockage of Pressure Sensing Line

As documented in Inspection Report 50-244/94-01, in January 1994, a control room operator observed that one of the narrow range (0-60 psig) containment pressure instruments, PI-947, was reading slightly lower than the other two, PI-945 and PI-949.

Troubleshooting revealed the cause to be a blockage in the sensing line between containment and the pressure transmitter, PT-947. The portion of the sensing line within the containment penetration was found to be made of carbon steel; this was the location of the blockage, which was later determined to be rust. Because this sensing line is shared with containment pressure transmitter PT-948, two channels of containment pressure instrumentation had been inoperable. Review of computer-archived data revealed that this condition had existed since June 1992.

The apparent cause of the blockage was that water had historically been used as the process fluid during annual instrument calibrations. This testing was performed by isolating the detector and then attaching the pressure source to a test connection within the detector isolation boundary. Upon restoration from testing, residual water would drain from the detector, through the sensing line, and into containment. Exposure of the horizontal run of carbon steel tubing within the containment penetration to this runoff water caused rust, which, after years of service, plugged the line. Existence of the blockage went undetected for a long period (1) because the scales of the associated meters were too large to show significant deflection as a result of normal containment pressure variations, and (2) because verifying communication through the sensing line, from the transmitters root valves to its end point inside containment, was not included in performance testing.

The result of this problem was that it degraded the reliability of automatic initiation of certain safety features, with the two-out-of-three (2/3) logic being reduced to two-out-of-two (2/2). Specifically, the 2/3 logic required for a safety injection signal based on a 4 psig containment pressure would have been reduced to a 2/2 logic with the inoperability of P-947. However, the diverse actuation circuitry for the safety injection signal has three additional means of actuation (steam generator low steam pressure, pressurizer low pressure, and manual). None of these diverse means was affected by the inoperability of P-947.

The 2/3 logic required for steam line isolation actuation based on a 18 psig containment pressure was reduced to a 2/2 logic with the inoperability of P-948. The diverse actuation circuitry for steam line isolation has three additional means of actuation (high steam flow, high-high steam flow with safety injection, and 2/4 low T-average with safety injection, and manual). None of these diverse features were affected by the inoperability of P-948.

The 2/3 plus 2/3 logic required for containment spray actuation based on a 28 psig containment pressure was reduced to a 2/2 plus 2/2 logic with the inoperability of P-947 and P-948, however, manual actuation was available if required.

Subsequent to identifying the plugging, the affected channels were tripped until the line was cleared and licensee management tasked the operations and engineering staffs to evaluate the safety implications and implement corrective actions to preclude a recurrence. Results of these efforts are documented in LER 94-02, submitted to the NRC on March 4, 1994.

In reviewing LER 94-02, the inspector identified two shortcomings in the licensee's scope of corrective action and safety evaluation. First, the licensee failed to address test program inadequacies that resulted in a failure to promptly identify line blockage and inoperable pressure sensing channels. This incident is similar in nature to that described in section 3.1 above, in which containment isolation pushbuttons were not tested, and represented a second example of a violation of the requirements of 10 CFR 50, Appendix B, Criterion XI, "Test Control" (see Detail 3.1).

The second shortcoming was that an evaluation of the effect of the loss of one (circuit 751) of two offsite power sources on the remaining operable pressure channels was not addressed. Automatic containment spray initiation could be compromised by a loss of circuit 751 in certain situations because such a loss could temporarily deenergize safety bus 14 and associated instrument bus "B", which has no backup power supply. Instrument bus "B" powers one set of pressure sensing channels (PI-946 and PI-949). Therefore, loss of instrument bus "B" could cause the loss of an additional two channels of containment pressure instrumentation. The licensee acknowledged this design vulnerability and will address this evaluation in a supplement to LER 94-02.

The inspector reviewed the licensee's immediate corrective actions taken in response to this incident including: placing the affected pressure channel relays in the tripped position, clearing the sensing line, daily trending narrow range containment pressure indications on the plant computer, revising the instrument calibration procedure to use air rather than water as the process fluid, and scheduling inspection of the remaining containment pressure sensing lines during the refueling outage. The inspectors had no further questions at this time.

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.

4.1.2 Post Accident Sampling System Material Condition

On March 1, 1994, operators established a purge of the pressurizer steam space to the volume control tank, through the post-accident sample system (PASS). The purpose of this purge was to reduce the hydrogen concentration in the pressurizer in preparation for the refueling outage. While this purge was in progress, a health physics (HP) technician prepared to perform a water flush of the PASS deionized water header. The PASS is configured such that these two operations can be performed simultaneously; however, as preparations for the flush progressed, the HP technician observed steam coming from a flexible hose in the DI water header. A portable radiation survey instrument in the area of the steam discharge alarmed, indicating that the pressurizer was the likely source of the steam. The HP technician isolated the flexible hose and then informed the control room operators of the problem. Venting of the pressurizer through the PASS was secured.

Extensive radiation and contamination surveys were performed. The HP technician was found to be contaminated with short-lived radioactive gases, and was decontaminated. Radiation levels in the vicinity of the steam leak were normal. Some loose surface contamination was detected on the floor in the area of the leak; the area was roped off, and subsequently cleaned and decontaminated. Since the deionized water header cross-connects to several other radiologically clean water systems, all connecting water systems were sampled for radioactive contamination. Small concentrations of radioactive gases and particulates were found in the condensate storage tanks. The concentrations were so low as to not pose a radiological concern for normal use. No significant contamination was detected in the remaining deionized water systems associated with this event.

In response to this event, the licensee initiated a root cause analysis investigation. The affected portions of the PASS were removed from service, pending results of this investigation and determination of corrective action. Multiple valve seat leakage through the ½-inch line was an apparent contributor to this event. The inspector examined the material condition of the PASS. The inspector noted that the existing installation of the air operator for valve AOV-10017 (PASS sample cooler outlet AOV to PASS liquid and gas sample panel), a valve that is normally shut, could have allowed for some seat leakage. This, and several minor material discrepancies, were addressed to the licensee.

The inspector assessed the licensee's response to this radiological event to have been good. Based on the nature and duration of the discharge, as well as the measured contamination levels, the inspector assessed that the radiological significance of this event was minimal.
At the close of the inspection period, the licensee's root cause investigation was in progress. The inspector had no further questions at this time.

4.1.3 ALARA Planning For Outage

The inspector reviewed the ALARA planning packages that will be used to support core offload/refueling operations and motor operated valve testing during the 1994 outage. Through this review, the inspector determined that the licensee has proactively addressed measures to reduce exposure to personnel performing these tasks. These measures included mock-up training, job site decontamination, shielding installation, equipment pre-staging, and work package/procedure development. The inspector concluded that these measures reflected attention-to-detail in job planning and preparations to minimize 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.

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.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

5.1 Periodic Reports

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

-- Monthly Operating Reports for January and February 1994

-- Semi-annual Radioactive Effluent Release Report (July-December 1993)

No unacceptable conditions were identified.

5.2 Licensee Event Reports

Licensee Event Reports (LERs) submitted to the NRC were reviewed to determine whether details were clearly reported, causes were properly identified, and corrective actions were appropriate. The inspectors also assessed whether potential safety consequences were properly evaluated, generic implications were indicated, events warranted additional onsite follow-up, and applicable requirements of 10 CFR 50.72 were met.

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

- 94-001, Radiation Monitor R-32 (Main Steam Line) Not Properly Calibrated. R-32 output was one decade low due to a technician's mathematical error. (January 19, 1994)

- 94-002, Containment Pressure Transmitters PT-947/PT-948 Inoperable Due to a Blocked Sensing Line (February 2, 1994)

The inspector concluded that LER 94-001 was accurate, met regulatory requirements, and appropriately identified the root causes. Shortcomings identified in LER 94-002 are addressed in section 3.2 of this inspection report. In response, the licensee will submit a supplement to LER 94-002.

5.3 Nuclear Safety Audit and Review Committee Meeting

On February 24, 1994, the inspector attended a meeting of the Nuclear Safety Audit and Review Committee. Topics included review of recent plant events, technical specification improvement program status, a presentation by the modification subcommittee including discussion of recent PASS modifications, review of licensee event reports, an outage overview presentation, and a review of QA/QC subcommittee activities. The inspector determined that the licensee satisfied the requirements of technical specifications 6.5.2 regarding committee membership composition and quorum. The inspector concluded that topics were candidly discussed and were presented with sufficient detail for board members to assess the safety significance of the agenda issues.

5.4 Regional Staff/RG&E Management Meeting

On February 17, 1994, RG&E management met with the NRC staff in the Regional office to discuss proposed changes to the licensee's Quality Assurance Plan, including implementation of a peer inspection program. Additional topics discussed were 1994 refueling outage plans, maintenance rule implementation status, and quality improvement initiatives. Attendees at this meeting are identified in Attachment I. Handouts provided by the licensee are included as Attachment II to this report.

6.0 ADMINISTRATIVE (71707, 30702, 94600)

6.1 Deep Backshift Inspection

During this inspection period, deep backshift inspections were conducted on February 21, February 27, March 5, and March 6, 1994.

6.2 Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of inspections. The exit meeting for the current resident inspection report 50-244/94-05 was held on March 14, 1994.

ATTACHMENT 1

REGION I/RG&E MEETING
QA PROGRAM CHANGES AND 1994 REFUELING OUTAGE PLANS
FEBRUARY 17, 1994

NAME	TITLE
RG&E	
Steven Adams	Superintendent, Support Services
Charles Anderson	Manager, QA
John Cook	Manager, Planning and Scheduling
Thomas Marlow	Manager, Quality Performance
Robert McMahon	QC Engineer-Operations
Joseph Widay	Plant Manager-Ginna
George Wrobel	Manager, Nuclear Safety & Licensing
NRC	
Suresh Chaudhary	Senior Reactor Engineer, DRS
Allen Johnson	Project Engineer, NRR
William Lazarus	Chief, Reactor Projects Section 3B, DRP
James Linville	Chief, Projects Branch 3, DRP
Michael Modes	Chief, Materials Section, DRS
Thomas Moslak	Senior Resident Inspector, Ginna

ATTACHMENT 2

REGION I/RG&E MEETING
QA PROGRAM CHANGES AND 1994 REFUELING OUTAGE PLANS
MEETING SLIDES
FEBRUARY 17, 1994

RG&E/NRC MEETING

February 17, 1994

I.	Opening Remarks	J. Widay	5 Min.
II.	Quality Verification Program		
	■ Purpose	S. Adams	5 Min.
	■ Program Description	R. McMahon	20 Min.
	■ CFR 50.54 Change Basis	C. Anderson	10 Min.
	■ Questions/Open Discussion	All	15 Min.
III.	Quality Improvement Initiatives	T. Marlow	15 Min.
IV.	1994 Refueling Outage Plans	J. Cook	15 Min.
V.	Maintenance Rule Implementation Status and Plans	S. Adams	15 Min.

QUALITY VERIFICATION PROGRAM

PURPOSE

<u>Improve Quality of Work Accomplished</u>

- Enhances ownership of work accomplished
- Clarifies accountability of work
- Enhance pride in workmanship

<u>Improve Efficiency</u>

- Eliminate waiting for inspector

QUALITY VERIFICATION

Background

- Quality standards traditionally assigned to the Quality Control organization.

- Maintenance expressed interest in performing "quality" verifications.

- Quality Performance screening of selected inspection hold points with pertinence to ANSI and other recognized and appropriate engineering codes and standards.

- Based on importance, complexity, and training.

QUALITY VERIFICATION

Definition

Quality Verification (QV) - Checks or process monitoring performed and documented to assure task acceptability by an individual who is trained and qualified to perform the task, but did not perform the task being verified.

QUALITY VERIFICATION

Specific Applications

	Torquing	Cleanliness
Class 1	quality inspection	quality inspection
Class 2 & 3	quality verification	quality verification for cleanliness level B, C & D

EXAMPLE

Cleanliness Inspection Procedural Change to Quality Verification

M-37.10 "Grinnell Diaphragm Valves, Air Operated, Maint."

During work planning within the shops if Quality Control and Maintenance concur that an existing Quality Control hold point is for an ASME Class 2 or 3 component requiring Cleanliness level B, C or D then Quality Verification would be applicable.

step 5.3 QV/Q.C. HOLD POINT

step 5.3.1 QV/Q.C. to perform cleanliness inspection in accordance with QVP-5/QCIP-5 on all parts prior to assembly.

QV/QC ___________

QUALITY VERIFICATION

Personnel Qualifications

Attribute	Quality Verification	N 45.2.6 Level II
Education	H.S. Graduate or equivalent	H.S. Graduate or equivalent
Experience	4 yrs. related plus qualif. per N18.1	3 yrs. related or 1 yr. as a Level I
Physical	near vision - annual color vision - initial	near vision - annual color vision - initial
Requalification	3 yrs. maximum	3 yrs. maximum

- Quality Verification requirements meet or exceed the N45.2.6 Level II requirements.

- Quality Verifier training includes instructions on duties and responsibilities of a quality verifier and demonstrated proficiency.

QUALITY VERIFICATION

Independence

- Quality Verifier did not perform the specific task being verified.

- Consistent with N45.2 QA Program requirements
  - ☐ organizational structure
  - ☐ verification of conformance

- Effectiveness by QA/QC oversight.

QUALITY VERIFICATION

Reporting

- Verifier reports to Line Organization

- Documentation of discrepancies.

Tracking and Trending

- Assessment results will be tabulated and trended by QC.

- Discrepancies will be tracked by Maintenance.

QUALITY VERIFICATION

MILESTONE	TCD	
Selection of activities	08/01/93	Completed
Define Quality Verification	12/13/93	Completed
Interview line organization	12/15/93	Completed
Presentation of program to GPC and endorsement	01/07/94	Completed
Presentation of program to Maintenance and endorsement	01/07/94	Completed
Write and approve implementing Administrative procedure	01/14/94	Completed
Write and approve guidelines that direct torquing and cleanliness	01/28/94	Completed
Provide an assessment plant of QV during the 94 Outage	02/01/94	Completed
Approval of changes to A-503 & A-1603.3	02/02/94	Completed
Revision to QAM Sect. 10 and Glossary	02/07/94	Completed
10CFR50.54 Analysis	02/10/94	Completed
Revise QCIP-1 (Inspection Instructions)	02/15/94	
NRC introduction meeting to QV	02/17/94	
Training of Maintenance personnel	02/28/94	

QUALITY VERIFICATION

Oversight

- QA/QC personnel
- Sample plan
- Specific criteria assessed
- Weekly progress meetings
- Updates to NAM and Line Management
- Final Assessment

10 CFR 50.54 CHANGE BASIS

Impact on Traditional QC Inspection

- Scope Limited - routine, repetitive tasks

- Complexity Modest - witness, check

- QC Involvement Remains Extensive

CONSISTENCY WITH ANSI/IEEE/APPENDIX B

- Standards recognize requirement variability e.g. N45.2.8

- Screening criteria based on variability for:

  - ☐ Risk
  - ☐ Complexity
  - ☐ Inspector Training

- QV selections consistent with criteria

- QV approach - consistent with Appendix B, II (control extent consistent with Importance to Safety)

EVALUATION - Comparison of Control

(Quality Inspection vs Quality Verification)

METHOD - Similarity

- Attribute definition
- Acceptance Criteria Specified

PERSONNEL

- Education and Experience
- Structured Training
- Demonstrated Proficiency
- Near and Color Vision
- Qualification Documented

INDEPENDENCE

- Verifier not responsible
- QA/QC Oversight

UNCHANGED ELEMENTS

- Total QC/QV Hold Points Unchanged

- Quality Inspections remain QC cognizance

- QV - Independent Verification Similarity

SUMMARY AND CONCLUSION

<u>Based on</u>:

- Personnel qualifications
- Independence
- QA/QC Oversight

Ginna Safety and Reliability Enhanced

Commitments Not Reduced

RG&E/NRC REGION I MEETING

February 17, 1994

I. Introduction, Goals, and Milestones

II. Quality Assurance Program Revision

III. Nuclear Directives

IV. Audit Program Frequency and Comprehensive Assessments

V. Procedure Review Periodicity

VI. Licensing Documents Interface

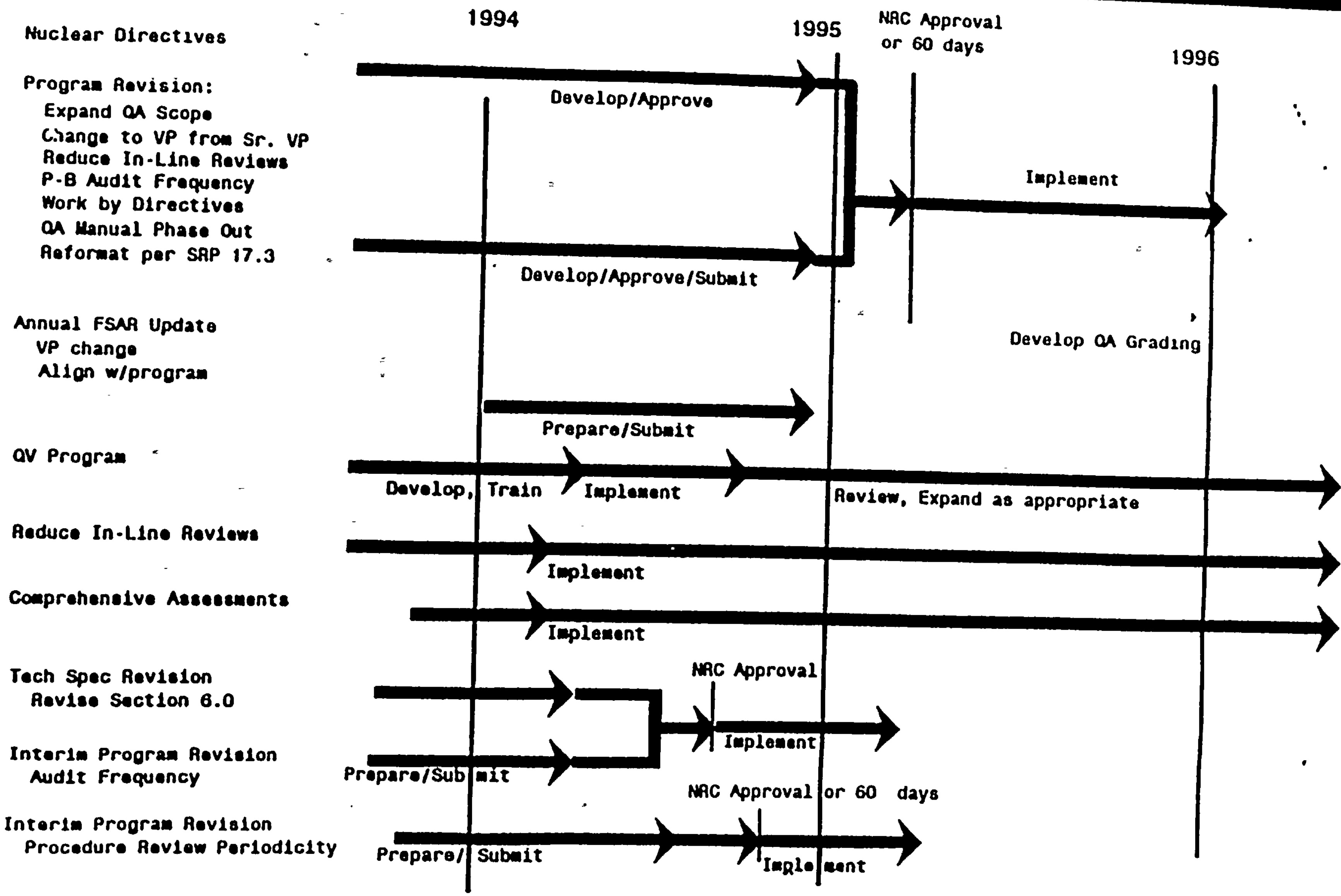
VII. Quality In-Line Review Phaseout

VIII. Grading of QA Requirements

IX. Future Plan for Quality Verification/Inspection

Quality Improvement Initiative Milestones

Attachment 2



QUALITY ASSURANCE PROGRAM FOR STATION OPERATION

QAPSO REVISION

- <u>Modeled after SRP 17.3</u>

- <u>Focus Areas</u>
  - ☐ Management
  - ☐ Performance
  - ☐ Assessment

- <u>Capture QIP Initiatives</u>

GINNA NUCLEAR DIRECTIVES

- Contain Existing Appendix B QA Criteria

- Nuclear Directives Will Replace QA Manual

- Ownership of QA Policy/Directives by Vice-President

- Corporate Responsibility for QA Program Shifting from Senior Vice-President to Vice-President

- Will be Included in QA Program Submittal, End of 1994

COMPREHENSIVE ASSESSMENTS

- Performance Based Assessments

- Transition to Proactive Oversight versus Mandated Audits

- Determine Assessment Scope and Process

  - Effective Scoring System

  - Areas of Concentration

  - Past Performance Dictates Priority, Frequency, Importance, History

- Overall Results Determine Need for Audit

PROCEDURE REVIEW PERIODICITY

- Symptom Based, Event Driven Procedure Review Will Continue

- Reviews Replaced With Programmatic Controls Based Upon Procedure Usage and Alternative Procedure Control Programs

- Periodic Review Requirements for Certain Procedures Deleted

  - Administrative

  - Technical

LICENSING DOCUMENTS INTERFACE

- Plans to Upgrade to Improved Technical Specifications

Evaluate Administrative Controls Section 6.0 of Existing T.S.		
Section	**Description**	**Relocate/Change**
6.5.1	PORC	Relocate to QA, or UFSAR Emergency, and Security Programs
6.5.2	NSARB	Relocate to QA, or UFSAR Emergency, and Security Programs
6.8	Procedures	Relocate review and approval process of procedure changes to QA Program or UFSAR.
6.10	Record Retention	Relocate to QA Program or UFSAR

- Relocation of changes to UFSAR would be submitted to NRR along with TS Amendment
- Relocation to QAPSO will require interim submittal (March)
- Potential mid-year QAPSO submittal - procedure review
- End of year major revision to QAPSO
- UFSAR Chapter 17 will contain QAPSO
- Changes required to Chapter 13 of UFSAR

QUALITY IN-LINE REVIEW PHASE OUT

- Establish Transfer Plans
  - Procedures
  - Approvals
  - Training
  - Define Oversight Methodologies

- Transfer Processes to Line Organizations

- Implement Oversight

- Discontinue Low Value-Added Reviews

Grading of QA Requirements

- **<u>Industry Initiative</u>**

- **<u>Evaluation Aspects</u>**

  - ☐ Documentation
  - ☐ Control
  - ☐ Verification

- **<u>Example - Checklists/Signoffs</u>**

Grade 1	Grade 2	Grade 3
All Steps	N/A	N/A
Verifications	Yes	N/A
Hold Points	N/A	N/A
	Final Signoff	Final Signoff

QUALITY VERIFICATION FUTURE PLANS

- Goal is to maximize worker responsibility for quality while assuring optimum utilization of resources.

- Three year program to integrate traditional QC into line organizations.

- Existing QC personnel transferred into Operating Departments.

- Department personnel trained and qualified to same standards as present QC personnel.

- Results reporting shifted to line organizations.

1994 OUTAGE PRESENTATION

I. <u>Outage Objective</u>

II. <u>1993/1994 Performance Indicators</u>

III. <u>Critical Path Overview</u>

IV. <u>Major Outage Activities</u>

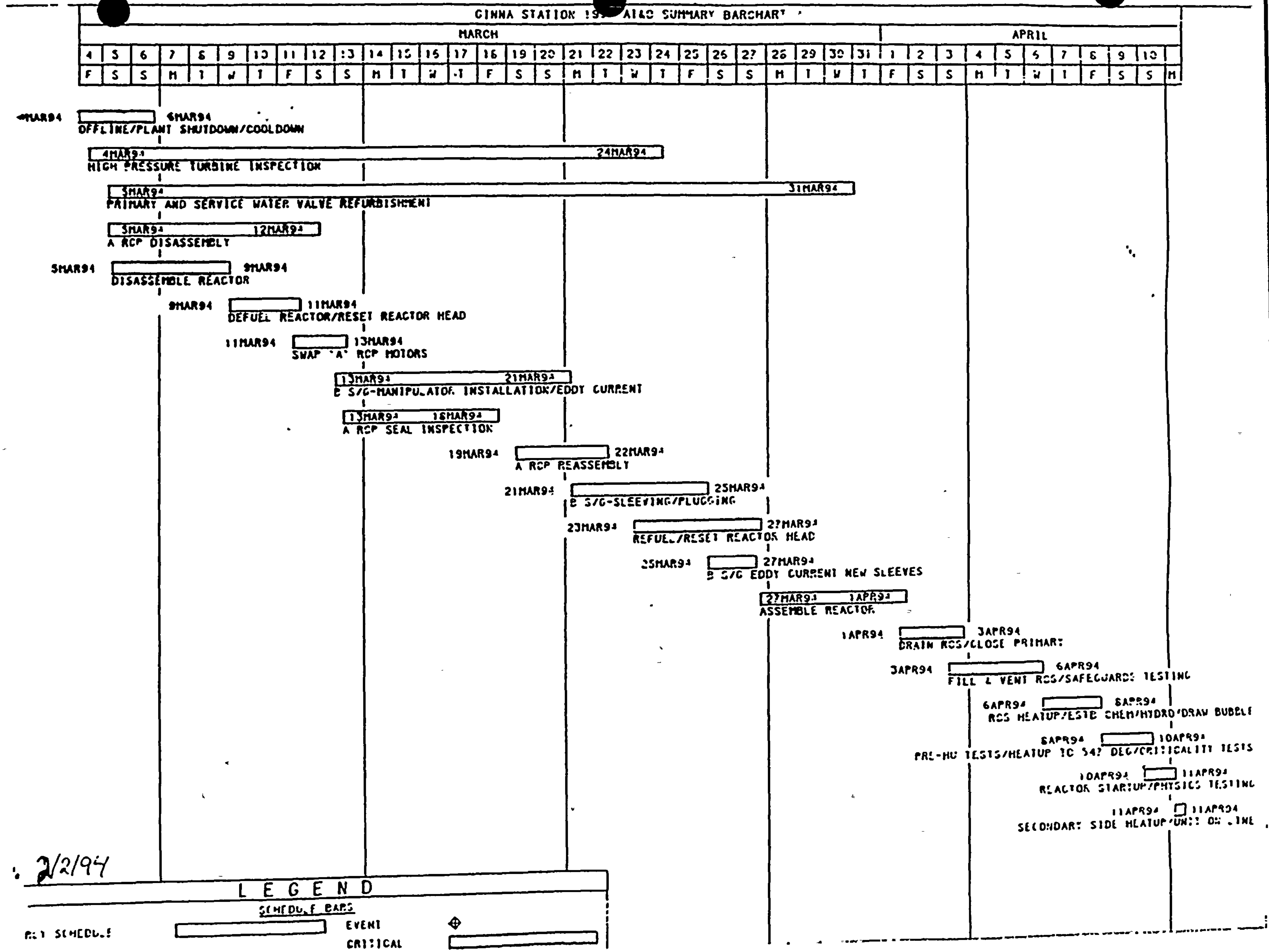
V. <u>Outage Risk Management</u>

1994 OUTAGE OBJECTIVE

RG&E TEAMWORK

SAFETY **QUALITY**

SCHEDULE


GINNA STATION
SUMMARY BARCHART
MARCH
APRIL
4MAR94 6MAR94 OFFLINE/PLANT SHUTDOWN/COOLDOWN
4MAR94 24MAR94 HIGH PRESSURE TURBINE INSPECTION
5MAR94 31MAR94 PRIMARY AND SERVICE WATER VALVE REFURBISHMENT
5MAR94 12MAR94 A RCP DISASSEMBLY
5MAR94 9MAR94 DISASSEMBLE REACTOR
9MAR94 11MAR94 DEFUEL REACTOR/RESET REACTOR HEAD
11MAR94 13MAR94 SWAP 'A' RCP MOTORS
13MAR94 21MAR94 B S/G-MANIPULATOR INSTALLATION/EDDY CURRENT
13MAR94 18MAR94 A RCP SEAL INSPECTION
19MAR94 22MAR94 A RCP REASSEMBLY
21MAR94 25MAR94 B S/G-SLEEVING/PLUGGING
23MAR94 27MAR94 REFUEL/RESET REACTOR HEAD
25MAR94 27MAR94 B S/G EDDY CURRENT NEW SLEEVES
27MAR94 1APR94 ASSEMBLE REACTOR
1APR94 3APR94 DRAIN RCS/CLOSE PRIMARY
3APR94 6APR94 FILL & VENT RCS/SAFEGUARDS TESTING
6APR94 8APR94 RCS HEATUP/ESTB CHEM/HYDRO/DRAW BUBBLE
8APR94 10APR94 PRE-HU TESTS/HEATUP TO 547 DEG/CRITICALITY TESTS
10APR94 11APR94 REACTOR STARTUP/PHYSICS TESTING
11APR94 11APR94 SECONDARY SIDE HEATUP/UNIT ON LINE
LEGEND
SCHEDULE BARS
EVENT
CRITICAL

2/2/94

OUTAGE PERFORMANCE INDICATORS

** SAFETY **	1993 GOAL	1993 ACTUAL	1994 GOAL	·1994 BUSINESS PLAN
Lost Time Accidents	0	0	0	0
Person-Rem Exposure	210	155	140	190
Contaminations	140	96	100	130
Rad Waste Generation	1000 cu. ft/wk	980 cu. ft/wk	900 cu. ft/wk	9,000
** QUALITY **				
Preventive Maintenance	90%	96.4%	95%	---
Corrective Maintenance	90%	93.8%	95%	---
Inspections	90%	99.1%	95%	---
Rework	3%	0.9%	1%	---
** REGULATORY **				
License Event Reports (LERs)	3	1	3	8
NRC Significant Events	0	0	0	0
** PLANT IMPROVEMENTS **				
Modification Work	90%	100%	95%	---
** OPERABILITY **				
Startup Problems	0	1	0	---
Continuous Run	60	60	60	---
** CORPORATE **				
Outage Length	55	45.3	39	49

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1994 AI&0 OVERVIEW

Major Activities

- Defueling
- HP Turbine Minor Inspection and Preseparator Pipe Wall Repair
- PORV Refurbishment
- A RCP Seal Inspection
- A RCP Motor Swap
- Service Water Outage of A and B Loops
    - Valve Replacement/Refurbishment
    - A Service Water Header Inspection

1994 AI&0 OVERVIEW

Major Activities (cont'd)

- Refurbishment of 101XU's
  - ☐ Service Water
  - ☐ CCW
- Primary Side Valve Inspection
  - ☐ CV 842 A&B
  - ☐ CV 867 A&B
- S/G Inspection and Repair
- Rod Control System Card Replacements & Minor Modifications
- Rx Compartment and Bus Duct Cooler Replacement
- # Work Orders Planned for Outage

☐	I&C	338
☐	Mechanics	118
☐	Pipe	276
☐	HVAC	49
☐	Electricians	147
	TOTAL	928

OUTAGE RISK MANAGEMENT

- Use of PRA to Evaluate Outage Configuration
- Delayed Installation of S/G Nozzle Dams Until After Defueling
- Improve PORC Overview of Outage Activities
- Fire Protection Review of Outage Activities
- Added NSL Personnel to Outage Safety Assessment Team

GINNA STATION

MAINTENANCE RULE IMPLEMENTATION

I. Current Status

II. Training

III. Peer Group Involvement

IV. Project Team Composition

V. Major Milestone Schedule

I. Current Status

- Reorganization in November to dedicate one Manager full time to Maintenance Rule implementation efforts.

- Project Team formed - 1st meeting 2/10/94

- EOP review for "Non-Safety SSCs in EOPs" in progress (Operations)

II. Training

80 key players briefed (10 sessions) including

- (Company-Wide) 31 affected Mgrs & key supervisory personnel
- System Engineers
- Operations (4 of 6 shifts)
- Craft training planned after project completion

III. <u>Peer Group Involvement</u>

- Westinghouse Two Loop Group

- MR Info. Sharing Committee Mtg. (NMP1, NMP2, Fitzpatrick, Ginna)

- Region 1 Utilities

IV. Project Team

Project Manager
John Fischer, Director Maintenance Rule

Design Engineering
Len Sucheski, Supervisor, Structural Engineering

Instrumentation & Control and Electrical
Robert Popp, I&C/Electrical Station Engineer

Materials Engineering & Inspection Services
Frank Klepacki, ISI Engineer

Nuclear Safety & Licensing (Programs)
David Wilson, Associate Engineer

Nuclear Safety & Licensing (License Renewal)
John Jorgensen, Senior Nuclear Engineer

Operating Experience
Frank Puddu, Operating Experience Specialist

Project Team (cont'd)

Operations

Doug Peterson, Operations-Maintenance Liaison
(Shift Supervisor)

Preventive & Predictive Maint./RCM/NPRDS/Root Cause Analysis

Tom Plantz, Maintenance Systems Manager

Performance Testing

Gregg Joss, Results & Test Supervisor

Scheduling

John Cook, Planning & Scheduling Manager

System Engineers & Modifications

Jeff Wayland, Lead Engineer - Systems Engineering

Substations

Terry Walter, Manager, System Design Engineering
Jeffrey Fiske, Supervisor, Substation Design

V. Major Milestone Schedule

2/94	Majority of the data gathering in place
5/94	Complete MR scoping Determine risk significance
6/94	Identify affected processes
10/94	All SSC performance criteria complete All affected processes modified
4Q94	NUMARC assist visit
4Q94	RG&E QA Audit
1Q95	NRC non-enforceable inspection
7/95	RG&E Goal MR Implementation Deadline
7/96	10CFR50.65 Legal MR Implementation Deadline