U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report No. 50-244/85-06

Docket No. 50-244

Licensee No. DPR-18 Priority -- Category C

Licensee: Rochester Gas and Electric Corporation
49 East Avenue
Rochester, New York 14649

Facility Name: R. E. Ginna Nuclear Power Plant

Inspection at: Ontario, New York

Inspection Conducted: March 1, 1985 through April 30, 1985

Inspectors: W. A. Cook, Resident Inspector, Ginna

L. T. Doerflein, Senior Resident Inspector, FitzPatrick

W. J. Lazarus, Project Engineer

Reviewed by _____ 5.28.85
D. F. Limoth, Project Engineer Date

Approved by: _____ 5/28/85
J. C. Linville, Chief, Reactor Project Section No. 2C, DRP Date

Inspection Summary:

Inspection on March 1, 1985 through April 30, 1985 (Report No. 50-244/85-06)
Areas Inspected: Routine, onsite, regular, and backshift inspection by the resident inspector (158 hours) and two regional inspectors (23 hours). Areas inspected included: plant activities during annual refueling outage and routine power operations; licensee action on previous findings; surveillance testing; plant maintenance; IE Bulletin Follow-up; refueling activities; ECCS Evaluation Model; reactor trip breaker modifications; Licensee Event Report review; and inspection of accessible portions of the facility during plant tours.

Results: Of the ten areas inspected, no violations were identified.

## DETAILS

1. Persons Contacted

The below listed technical and supervisory level personnel were among those contacted:

C. Edgar, Instrumentation and Control Supervisor
G. Larizza, Operations Manager
T. Meyer, Technical Manager
B. Snow, Plant Superintendent
S. Spector, Assistant Plant Superintendent
J. Widay, Reactor Engineer

The inspectors also interviewed and talked with other licensee personnel during the course of the inspection.

2. Licensee Action on Previous Inspection Findings

(Closed) Inspector Follow-up Item (84-03-02): Administrative Procedure A-205, does not reflect Technical Specification PORC quorum requirements. The inspector reviewed the latest revision to A-205, Revision 14, dated February 13, 1985, and discussed with the licensee the changes incorporated into the latest revision. PORC quorum requirements as defined in A-205 properly reflect Technical Specification criteria.

The inspector had no further questions.

(Closed) Violation (84-07-01): PORC quorum requirements were not met. The inspector reviewed the licensee's response to this violation, Kober to Murley letter, dated June 8, 1984, and determined that adequate clarification of Administrative Procedure, A-205, "Plant Operations Review Committee Operating Procedure" governing PORC quorum requirements has been incorporated into Revision 14, dated February 13, 1985.

The inspector had no further questions.

(Closed) Inspector Follow-up Item (84-22-03): Review cause of Rod Position Indication (RPI) power supply electrical fault. The 13 volt power supplies for analog meter biasing in the RPI system were replaced with a temporary power supply on September 28, 1984. Investigation by the licensee determined that the power supplies were not the cause of the fault and RPI cabinet circuitry became suspect. Troubleshooting in the RPI cabinet could not be performed at power and the licensee utilized the temporary power supplies for the remainder of the power run.

Subsequent troubleshooting during the 1985 refueling outage determined that three improperly connected and loose terminal board ring connectors

were the cause of the fluctuating meter indication. The condition was corrected, permanent power supplies were reinstalled and the RPI system was retested satisfactorily.

The inspector had no further questions.

3. Review of Plant Operations

a. Throughout the reporting period, inspectors reviewed plant operations. On March 2, 1985, the reactor was shutdown for the commencement of the annual refueling and maintenance outage. Outage activities in addition to the loading of twenty-four new Westinghouse Optimized Fuel Assemblies and four new Exxon Lead Test Assemblies with annular fuel rods, included: eddy current inspection of all steam generator tubes in both the inlets and outlets to at least the first tube support plate; subsequent steam generator tube plugging and sleeving; reactor coolant pump and motor maintenance; main steam isolation and check valve shaft replacements; incore thermocouple upgrade; vital battery and charger replacement; reactor trip breaker modifications; and low pressure turbine rotor replacement.

The outage was completed and the reactor taken critical for low power physics testing on April 5, 1985 at 11:43 P.M.. Power operations have continued throughout the remainder of this reporting period with the exception of the events discussed below:

-- On April 6, 1985, the reactor tripped from 5 percent power at 7:02 P.M. due to B steam generator low level (30%) coincident with a steam/feedwater flow mismatch. The cause of the trip was operator error. While feeding the steam generators manually by controlling the feedwater regulating valve bypasses, the operator permitted B steam generator level to drop below the 30% low level setpoint. A calibration of the B steam generator (S/G) feedflow instrument was in progress which requires manual tripping of the "B" S/G steam/feedwater flow mismatch bistable. With the coincident protective system logic satisfied the reactor tripped as designed. Imprudence in the authorization of the calibration while controlling steam generator levels manually was recognized by the licensee as a contributing factor in this reactor trip event.

-- On April 6, 1985, the reactor tripped from 12 percent power at 11:41 P.M. due to B steam generator 2/3 low-low level (17%). The cause of the trip was operator inexperience in controlling steam generator levels during manual feeding of the steam generators using the feedwater regulating valve bypasses. The turbine was latched at the time of the reactor trip, however, the turbine did not trip automatically when the reactor tripped. The turbine was tripped locally using the manual trip lever. Quick response by the control room operators to manually

close the main steam isolation valves, when the turbine failed to trip, prevented any appreciable cooldown of the reactor coolant system.

Investigation by the licensee determined that both the 20 ET and the 20 AST turbine trip solenoids failed to actuate. The 20 ET solenoid was replaced and tested satisfactorily. The 20 AST solenoid failure could not be reproduced and was inspected and retested satisfactorily. A subsequent failure of the 20 AST solenoid to actuate occurred on April 11, 1985. In this instance the control board turbine trip push button was depressed to actuate the 20 AST solenoid. The first time the push button was depressed the turbine did not trip. On the second attempt the turbine tripped. The 20 AST solenoid coil was replaced and on subsequent testing it was determined that a mechanical stop on the auto stop oil tripping beam was preventing full travel of the beam. The mechanical stop clearance was adjusted and the trip mechanism and 20 AST solenoid were retested satisfactorily.

-- On April 7, 1985, the reactor tripped from 13 percent power at 10:39 A.M. due to A steam generator 2/3 low-low level (17%). The cause of this trip was, again, operator inexperience and error in maintaining proper S/G levels. The reactor was returned to criticality at 3:15 P.M. and the generator synchronized with the grid at 6:45 P.M..

-- On April 8, 1985, the reactor tripped from 18 percent power at 5:36 A.M.. The reactor tripped on A steam generator 2/3 low-low level (17%), however, the B S/G was also near the low-low level reactor trip setpoint. The steam generator low water levels resulted from the trip of the one operating main feedwater pump and subsequent turbine trip. The B main feedwater pump tripped due to pressure perturbations in the condensate and feedwater system resulting in low seal water differential pressure. The condensate pressure transient was believed to have started upon the dumping of steam to the main condenser via actuation of the steam dumps while reducing turbine load. The transient was aggravated by the condensate bypass valve opening automatically due to being left in the auto" position after the performance of maintenance on the valve prior to plant startup. Operating procedures have been revised to ensure the bypass valve is kept in the closed position prior to exceeding 30% reactor power to prevent its undesirable actuation at low power levels.

-- On April 11, 1985, at 12:20 P.M. the reactor tripped from approximately 8 percent power due to low condenser vacuum. The cause of the low vacuum condition was attributed to significant condenser tube leakage.

Prior to the reactor trip, the turbine was on line with reactor power at approximately 25 percent and investigations in progress to determine the source of condenser in-leakage. Condenser hotwell level fluctuations were observed since 9:53 A.M.. The 1A1 condenser waterbox was isolated and in the process of being vented when condenser vacuum began to decrease. The turbine was manually tripped at 11:35 A.M. prior to condenser vacuum lowering to the automatic trip setpoint.

Reactor power was being reduced to transfer from the B main feedwater pump to the auxiliary feedwater pumps when condenser vacuum decreased to the P-9 permissive setpoint, (same as low vacuum trip setpoint) causing the reactor to trip as designed. The P-9 persmissive functions to prevent a reactor trip when the turbine trips provided nuclear power is less than 50 percent and steam dumps are operable. In order for steam dumps to be operable one of two circulating water pumps must be operating and sufficient condenser vacuum available.

Each reactor trip breaker logic train has a P-9 permissive logic circuit and associated relays which are independent of the other train. During this reactor trip event, only the B train P-9 permissive relays actuated and resulted in only the B reactor trip breaker opening as designed. Two independent condenser vacuum switches actuate their respective P-9 permissive logic circuit relays. Post-trip investigation by the licensee determined that the B train vacuum switch (PC-484B) trip setpoint was 21.7 inches mercury and the A train vacuum switch (PC-484A) trip setpoint was 20.3 inches mercury. Consequently, the B train P-9 permissive logic was satisfied prior to the A train, resulting in only the B reactor trip breaker opening.

The control room operators were not aware of this reactor protection system anomaly and when only the B reactor trip breaker was determined to be open, the A reactor trip breaker was manually tripped.

Licensee inspection of the condenser determined that the carbon steel baffle plate for the fourth pass feedwater heater drains in the 1A1 hotwell had fatigue failed and damaged 40 surrounding condenser tubes. The 40 tubes were plugged and the baffle plate was replaced with a stainless steel plate and provided with additional reinforcement.

The inspector determined that operator training will be provided to address the P-9 permissive logic circuit and any other reactor protection system anomalies found after a comprehensive review by the licensee. In addition, engineering will be reviewing the P-9 permissive circuit to determine if modifications are warranted. The licensee determined that the

condenser vacuum switches had not been calibrated since 1979 due to being categorized with a large portion of the secondary plant gauges and sensors not considered to be safety-related or Technical Specification designated. This category of guages and sensors is calibrated as manpower availability dictates. The inspector determined that the vacuum switches will be incorporated into Administative Procedure, A-1105, "Calibration and/or Test Surveillance Program for Instrumentation/Equipment of Safety-Related Components". In addition, a comprehensive review will be conducted to determine if other sensors or guages warrant incorporation into this program.

The reactor was returned to criticality at 10:52 P.M. April 11, 1985 to ensure adequate heat input to the secondary for steam generator blowdown chemistry correction. The turbine was synchronized with the grid at 6:22 P.M. on April 13, 1985. Power operations have continued through the end of this inspection period.

The inspector had no further questions.

b. During the course of the inspection, tours of the following plant areas were conducted:

- -- Control Room
- -- Auxiliary Building
- -- Intermediate Building (including control point)
- -- Service Building
- -- Battery Rooms
- -- Turbine Building
- -- Diesel Generator Rooms
- -- Screenhouse
- -- Yard Area and Perimeter
- -- Containment

c. The following areas were observed during the tours:

1. Operating logs and records. Records were reviewed against Technical Specifications and administrative procedure requirements.

2. Monitoring instrumentation. Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.

   On April 5, 1985, representatives from the Training and Instrumentation & Control Departments were conducting temperature instrument failure analysis for subsequent use in the development of the control room simulator software programs. Concurrent with this research, an approved calibration procedure

was being performed on another temperature channel. The reactor plant was in hot shutdown with all rods inserted and with both reactor trip breakers closed.

At 0954, coincident high Delta T trip signals were inadvertantly inputted as a result of both evolutions in progress. The reactor protection system overpower Delta T and overtemperature Delta T 2/4 logics were subsequently satisfied causing both reactor trip breakers to open as designed.

The inspector determined that although the temperature instrument failure analysis research was authorized and acknowledged by control room operators, no formal procedure to govern the research activities was drafted or approved. The inspector discussed this event and related informal trouble-shooting activities with licensee management who committed to review the need for formalized guidance in this area. (85-06-01)

3. Annunciator alarms. Various alarm conditions which had been received and acknowledged were observed. These were discussed with shift personnel to verify that the reasons for the alarms were understood and corrective action, if required, was being taken.

4. Shift manning. Control Room and shift manning were observed for conformance with 10 CFR 50.54, Technical Specifications, and administrative procedures.

5. Radiation protection controls. Areas observed included control point operation, posting of radiation and high radiation areas, compliance with Radiation Work Permits (RWP) and Special Work Permits (SWP), personnel monitoring devices being properly worn, and personnel frisking practices.

6. Fire protection. Fire detection and fire-fighting equipment and controls were observed for conformance with Technical Specifications (TS) and administrative procedures requirements.

7. Security. Areas were observed for conformance with regulatory requirements and implementation of the site security plan, inclusive of administrative procedures for vehicle and personnel access, and verification of protected and vital area integrity.

8. Plant housekeeping. Plant conditions were observed for conformance with administrative procedures. Storage of material and components was observed with respect to prevention of fire and safety hazards. Housekeeping was evaluated with respect to controlling the spread of surface and airborne contamination.

While conducting a tour on April 23, 1985, the inspector entered the air handling room in the turbine building and found scaffolding erected on top of the Control Room/Computer Room Heating Ventilation and Air Conditioning Unit, a Technical Specification controlled safety-related system. Investigation determined that the scaffolding was erected by station maintenance personnel at the request of contractors scheduled to conduct work in the overhead cable trays. Further inquiries determined that station management was not aware of the presence of this scaffolding and that no engineering considerations or controls were prescribed for its erection. The scaffolding had only been staged for a few days and was dismantled later in the day on April 23.

The inspector discussed this event with station management and expressed a concern that there is an apparent lack of appropriate control of the installation of temporary equipment in the vicinity of safety-related systems. The licensee stated that a committee review was currently being conducted to address this issue. The inspector will review the licensee's resolution of this issue in a future inspection report. (85-06-02)

9. Equipment lineups. Valve and electrical breakers were verified to be in the position or condition required by Technical Specifications and plant lineup procedures for the applicable plant mode. This verification included routine control board indication review and conduct of a partial systems lineup check of the Auxiliary Feedwater System on April 17 and, Safety Injection System on April 24.

10. Equipment tagging. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment in the condition specified.

The inspector had no further questions.

4. Surveillance Testing

a. The inspector witnessed the performance of surveillance testing of selected components to verify that the test procedure was properly approved and adequately detailed to assure performance of a satisfactory surveillance; test instrumentation required by the procedure was calibrated and in use; the test was performed by qualified personnel; the test results satisfied Technical Specifications and procedural acceptance criteria, or were properly dispositioned.

b. The inspector witnessed the performance of portions of the following tests:

Periodic Test, (PT)-32.1, "Plant Safeguards Logic Test A Train", performed on April 3, 1985.

PT-2.2, "Residual Heat Removal System", performed on April 3, 1985.

Refueling Shutdown Surveillance Procedure, (RSSP)-7, "Control Rod Drop Test", performed on April 4, 1985.

Turbine Test, (T)-18C, "Turbine Overspeed Trip Test", performed on April 9, 1985.

c. On April 18, 1985, while performing Calibration Procedure (CP)-408.10, "Calibration and/or Maintenance of Delta Temperature Setpoint 1 Channel 4", Revision 2, dated May 23, 1984, the procedure incorrectly specified the defeating of pressurizer pressure channel PT-449 for use as a simulated input signal to the Channel 4 Delta T setpoint controller. Pressure channel PT-449 is the selected controlling channel for RCS Pressure Controller PCV-431K which regulates pressurizer spray valves and heater operation. When a simulated pressure signal, below normal operating pressure, was selected per the calibration procedure, pressurizer heaters remained energized and both sprays valves remained closed resulting in a pressure excursion. The operators first became aware of this condition when the RCS high pressure alarm sounded at 2310 psig. Operators promptly took corrective action to lower RCS pressure and returned it to the normal operating band.

The cause of this event was a procedural error. When the controlling pressure channel for PCV-431K was switched to PT-449 from PT-429 in 1979, a revision to procedure CP-408.10 was overlooked. CP-408.10 was never performed at full power conditions until this event and therefore was never procedurally challenged to be accurate. The inspector verified that CP-408.10 was properly revised and that technicians and operators reviewed this event and lessons learned.

5. Plant Maintenance

a. During the inspection period, the inspector observed maintenance and problem investigation activities to verify compliance with regulatory requirements; compliance with administrative and maintenance procedures; required QA/QC involvement; proper use of safety tags; proper equipment alignment and use of jumpers; personnel qualifications; radiological controls for workers protection; and reportability as required by Technical Specifications.

b. The inspector witnessed the following maintenance activity:

-- Preliminary inspection and transfer of new fuel assemblies from the shipping casks to the dry storage area, conducted on February 28, 1985 in accordance with Refueling Procedure,

RF-4.0, "Site Removal of New Fuel Assemblies from the Shipping Containers and Handling of Shipping Containers", Revision 10, October 12, 1983.

The inspector found no discrepancies.

6. IE Bulletin Followup

The inspector reviewed licensee actions on the following IE Bulletin to determine that the written response was submitted within the required time period, that the response included the information required including adequate corrective action commitments, and that licensee management provided adequate dissemination of the bulletin and the response. The review included discussions with licensee personnel and observations of the items discussed below.

IE Bulletin 84-03: "Refueling Cavity Water Seals", and IE Notice 84-93, "Potential For Loss of Water From the Refueling Cavity". This Bulletin and Information Notice addressed concerns identified following the failure of the refueling cavity water seal at the Haddam Neck Plant on August 21, 1984. The refueling cavity water level (23 feet) decreased to the level of the reactor vessel flange within 20 minutes, which flooded the containment with approximately 200,000 gallons of water. The pneumatic seal assembly experienced a gross failure when it was displaced out of its normal position. No fuel was being transferred at the time of this failure. If, however, fuel had been in transfer at the time, it could have been partially or completely uncovered with possible high radiation levels, fuel cladding failure, and release of radioactivity. In addition, if the fuel transfer tube had been open, the spent fuel pool could have drained to a level that would have uncovered the top of the spent fuel.

The inspector reviewed the refueling cavity seal design at Ginna and the licensee's response to IEB 84-03 dated 11/28/84 to evaluate the potential for failure and to determine whether the licensee had:

-- Identified the worst credible failure;

-- Evaluated the consequences of such failure to determine if leakage rates are limited to less than makeup capacity;

-- Implemented procedures for mitigating the consequences of a seal failure prior to fuel movement.

The details of the refueling cavity seal at Ginna were described in the response letter. Additional details were supplied in subsequent telephone conversations between the Ginna Reactor Engineer and Region I staff on February 26 and 27, 1985.

The licensee identified that the worst credible failure would occur if the entire seal ring fell through the annulus. This would result in the fastest draining of the refueling cavity and the least time for operators to take corrective action.

The likelihood of a seal failure and the consequences of such a failure were reviewed; the following results were identified:

-- While seal type is the same as that of Haddam Neck, Presray Model PRS 585, the Ginna seal has the following advantages over the Haddam Neck seals:

  -- Smaller seal centerline diameter (172 1/2" vs. 256 1/8")

  -- Greater rigidity of the seal

  -- Full surface contact on the cavity liner and more surface contact on the RV flange side (2 1/2" vs. 1 5/8")

  -- The hardness of the rubber is 60 durometer for the Ginna seal. The hardness of the rubber was found to be a distinct advantage over other seals in tests. The greater hardness of the rubber increased the rigidity of the seal flanges and thereby makes deformation of this flange more difficult.

-- The smaller radius of the seal ring for the same gap to be sealed will result in a lower flow rate for the same degree of seal failure. Thus, flow rate is proportional to the gap area which, in turn, is proportional to the radius of the gap. The ratio of gap area at Haddam Neck to Ginna is 256 to 172, or 1.48. Therefore it will take 1.48 times longer for the same volume of water to drain from the Ginna Refueling Cavity. Assuming instant closure of the refueling canal valve and assuming that the entire seal ring falls through the annulus, the time required to drain the upper cavity to its lowest level, the top of the Reactor Pressure Vessel (RPV), would be 20.4 minutes. If the refueling canal valve is not closed during the discharge interval, the additional volume of water from the spent fuel pool (SFP) will be discharged to the same level. The total discharge time then would be 36.9 minutes. If the Haddam Neck failure (1/3 of seal length) is assumed, the total time of discharge would be 110 min. or 1 hour and 50 minutes. Sufficient time would be available for the operators to mitigate the consequences of the seal failure.

-- The Upper Cavity is recessed relative to the seal location near the top of the RPV. Draining of the Upper Cavity, therefore, will not result in exposure of the fuel elements stored in the upper cavity in the upright position or in the upender. Approximately one foot of water remains to cover the top of the vertical assemblies. If the water in the spent fuel pool were to be drained to the RPV flange level, approximately 8" would remain above the vertically

stored fuel elements. The only possible exposure to air of a fuel element would come from an element stored in the vertical position in the manipulator mast or the fuel pool crane. There should be enough operator time (see above) to take care of the fuel element, close the valve in the refueling canal and perform other mitigating actions.

-- The horizontal gap in the annulus varies from 2 inches to 2 9/16 inches. The maximum value represents a 1/16" offset from the nominal horizontal gap of 2-2.5". The 1/16" horizontal offset is not significant, based on reported test results.

-- A three foot test section of the Ginna type seal was hydrostatically tested in a mockup fixture by a licensee contractor. The hydrostatic pressure was applied to simulate actual seal loading conditions of 10 psi, equivalent to the normal head of 24 feet. Deflection measurements confirmed that there was minimal deformation at this pressure. Failure occurred when the test pressure was increased to 30 psi (70 foot water column) not because of actual seal failure, but because of the test rig. This indicates there is a substantial safety margin between the normal operating water level and the failure level.

-- The effect of a dropped fuel assembly impacting on the cavity seal was not addressed by the licensee. However, the assumption that the entire seal fails is more severe than a postulated puncture or extension of the seal by a dropped fuel assembly.

-- The inflation pressure at Ginna is procedurally regulated at 30 psig. To reduce the possibility of overpressurization, a relief valve set at 40 psig is employed.

An emergency procedure for the handling of a general seal failure, and consequent draining of the refueling cavity has been written, approved, and implemented. This procedure is included as Section 9.3.4 (Loss of Water from the Refueling Cavity) of RF-60, "Cycle XIV-XV Refueling Procedure, Rev. 0. The inspector reviewed this procedure for technical adequacy and found it to be acceptable. It was further determined that appropriate training had been conducted in the use of the procedure by the refueling crews.

Conclusions:

-- The Ginna cavity seal is much less prone to failure than the Haddam Neck cavity seal. Tests on a mockup confirm that there is a substantial safety margin to failure.

-- If the cavity seal did fail, the fuel in the reactor cavity and the spent fuel pool would remain covered by water without any operator action. A fuel assembly in the manipulation mast could become

uncovered, but operators have sufficient time to lower the fuel to a safe level and have appropriate emergency instructions and training in their use.

7. Refueling Activities

The inspector reviewed procedure RF 60, "Cycle XIV-XV Refueling Procedure", Revision 0, to verify that it was properly approved, technically adequate, and in compliance with the Technical Specifications. The procedure was prepared by Westinghouse Corporation and reviewed and approved by the licensee. The inspector also verified that the pre-refueling checklists contained in procedure RF60 and in procedure RF8.0, "Fuel Assembly and Core Component Movement Prerequisites and Precautions", were completed prior to starting fuel moves. On March 11 and 12, 1985, the inspector observed fuel movement activities (removal and insertion) from the refuel floor (including the refueling cavity manipulation crane), the control room and the auxiliary building. The refueling was performed by Westinghouse personnel under licensee supervision. During several containment entries, the inspector noted that the refueling activities were audited by a licensee Quality Control inspector. During the refueling operations, the inspector also noted that: all core alterations were directly supervised by a licensed Senior Reactor Operator; continuous communications were maintained between personnel on the refueling cavity manipulator crane and in the control room; the Source Range Monitors were continuously monitored whenever core geometry was changed; fuel moves were properly recorded on the refuel floor and in the control room; and tools and equipment on the refueling floor were properly controlled.

Based on a record review and discussions with licensee personnel, the inspector also verified that all surveillance testing required by Technical Specifications for fuel handling was completed. This included verification that: the primary coolant system boron concentration was maintained greater than 2000 ppm, water level was maintained greater than 23 feet above the top of the reactor vessel flange; one Residual Heat Removal loop was in operation; the Auxiliary Building ventilation was properly aligned and operating; and containment integrity was maintained.

No violations were identified.

8. Core Verification

The inspector viewed the core verification videotape and verified, for a sample of one half the core, that the fuel bundle position was in accordance with the core map contained in the Westinghouse refueling procedure and used in the Safety Evaluation for the Startup Test Report. The videotape was clear and the serial numbers on the fuel assemblies were adequately visible. The inspector noted that the core verification had been performed by Westinghouse personnel and a licensee Quality Control inspector. A separate review of the videotapes was performed by the Reactor Engineer.

No discrepancies were identified.

9. Exxon Fuel ECCS Evaluation Model

On March 15, 1985, one of the licensee's fuel suppliers, Exxon Nuclear Corporation (ENC), informed the NRC that a coding error was discovered in the program utilized to develop the Exxon Emergency Core Cooling System (ECCS) Evaluation Model. Upon further review by the NRC staff, three additional concerns in the ENC Loss of Coolant Accident (LOCA) Analysis were discovered.

In the Safety Evaluation Report prepared by the NRC staff and transmitted as an enclosure to Thompson to Kober letter, dated April 5, 1985, the staff concluded that the coding error and two of the LOCA Analysis concerns were not applicable to Ginna. The third concern, the assumed validity and applicability of applying the Westinghouse-derived K(z) curve to ENC fuel, remains unresolved pending further quantitative analysis in accordance with the requirements of Section I.A. of Appendix K to 10 CFR Part 50. However, a significant safety margin does exist regarding peak fuel clad temperature and in the event of a design basis LOCA the maximum fuel element cladding temperature will not exceed 2200 degrees F. The staff concludes, that although the K(z) curve for ENC fuel has not been verified using an ECCS evaluation model wholly in conformance with Appendix K, there is reasonable assurance that the Ginna plant satisfies the criteria of 10 CFR 50.46 and that the plant can be operated without undue risk to the public health and safety.

As stated in the April 5, 1985, Thompson to Kober letter, the licensee must submit a reevaluation based on an acceptable ECCS model by January 4, 1986. (85-06-03)

10. Licensee Event Report (LER's)

The inspector reviewed the following LER to verify that the details of the event were clearly reported, the description of the cause was accurate, and adequate corrective action was taken. The inspector also determined whether further information was required, and whether generic implications were involved. The inspector further verified that the reporting requirements of Technical Specifications and station administrative and operating procedures had been met; that the event was reviewed by the Plant Operations Review Committee and that continued operation of the facility was conducted within the Technical Specification limits.

85-03: "Inoperable Fire Detection System". On March 9, 1985 at 6:55 A.M., Fire Detection and Auto Pre-action Suppression System S-15, "Intermediate Building Basement East Cable Trays" was requested to be removed from service for grinding and welding activities in that detection zone. The operator responsible for deactivating the S-15 system misread the instructions and inadvertantly deactivated the S-05 "Cable Tunnel Smoke Detection System Auto Deluge" system instead. This error was not discovered until 2:30 P.M. when surveillance personnel discovered the S-05 system deactivated.

Technical Specifications require compensatory measures taken for deactivated fire detection or suppression systems. Proper measures were taken for the expected deactivation of the S-15 system, however, no compensatory action was taken for the inadvertant deactivation of the S-05 system. Automatic detection in the cable tunnel was still afforded via Heat Detection System Z-05 and manual actuation of the S-05 spray/sprinkler system was available upon receipt of the Z-05 alarm in the control room.

The inspector reviewed the licensee's corrective actions and discussed the event with licensee management. A Notice of Violation is not issued in response to this event for the following reasons: the event was licensee identified; the event was promptly reported to the NRC; and the licensee instituted a double verification for the deactivation of fire protection and suppression systems to preclude recurrence. In addition, the licensee is investigating modifications to the existing fire Detection and Protection Control System to enhance operator identification of systems status and to improve routine operation and control. Licensee corrective actions to address previous violations related to this system could not reasonably have been expected to prevent this event.

The inspector had no further questions.

11. Reactor Trip Breaker Modification (EWR-3698)

Reactor trip breakers were modified under Engineering Work Request (EWR) No. 3698 to satisfy one of the NRC requirements outlined in Generic Letter 83-28, "Required Actions Based on Generic Implication of Salem ATWS Events". This modification upgraded the Reactor Protection System and breakers to automatically trip the reactor trip breakers (RTB's) through the undervoltage and shunt trip coils, simultaneously. This modification was accomplished during the 1985 refueling outage. The inspector reviewed the following documents:

-- EWR No. 3698 "Diverse Trip Modification on Reactor Trip Breakers", Design Criteria, Revision 0, dated October 10, 1984 and Safety Analysis, Revision 0, dated October 15, 1984.

-- Station Modification Procedure, (SM)-2698.1 "Reactor Trip Breaker Upgrade", Revision 0, dated March 6, 1985.

-- SM-3698.2, "Reactor Trip Breaker Preoperational Testing", Revision 0, dated March 27, 1985.

-- Maintenance Procedure (M)-32.2, "DB-50 Reactor Trip Circuit Breaker Inspection, Maintenance and Test", Revision 7, dated March 27, 1985 for the 1A, 1B, By-pass and spare RTB's.

-- Periodic Test, (PT)-32.5, "Reactor Trip Breakers A and B Train Response Time Testing", Revision 2, dated March 20, 1985.

The inspector reviewed the RTB modification to verify the following:

-- The modification was reviewed and approved in accordance with 10 CFR 50.59.

-- The design changes were reviewed and approved in accordance with Technical Specifications and established QA/QC controls.

-- The design changes were controlled by established procedures.

-- The completed test procedures were properly reviewed and evaluated, and test results were within previously established acceptance criteria.

-- Maintenance procedures were revised and approved in accordance with Technical Specifications.

-- The as-built drawings were changed to reflect the modifications.

With the exception of station drawing No. 33013-673 not being updated, the inspector found no discrepancies.

The inspector determined that as-built Drawing No. 33013-673, "Reactor Trip Breaker Control Schematic (sheets 1 and 2)" was in final Revision at corporate engineering. Drawing No. 33013-673 is not a "controlled" drawing as defined by Station Administrative Procedure A-603, "Control of As-Built Drawings and Design Documents". "Controlled" drawings require updating concurrent with the modification turnover to the station.

The inspector determined that the station document control room does not track outstanding EWR modifications on "non-controlled" drawings. Consequently, all drawing revisions are identified and revised as a function of the EWR process, however, only station "controlled" drawings are earmarked by the station for revision during the modification process and are current as of the day of turnover to the station. Other than by informal methods, station personnel may not have drawings which accurately reflect as-built conditions for up to 30 days after a modification is completed, if the drawing is not a "controlled" document.

The inspector discussed this concern with licensee management and corporate engineers and determined that an ad hoc engineering committee is currently reviewing overall drawing control and station distribution methods. The inspector determined that this concern is being addressed and will review its resolution in a future inspection. (85-06-04)

The inspector determined that this diverse tripping modification was not performed on the by-pass reactor trip breaker. In addition, response time testing was not performed on the by-pass breaker. Discussion with the licensee determined that the interpretation of breaker modification and testing prescribed by Generic Letter 83-28 was not applicable to the by-pass breaker if testing of the by-pass breaker was performed prior to

placing it in service. The inspector verified that maintenance and testing procedure M-32.5 does include this requirement. However, final review of the licensee's response to Generic Letter 83-28 by the NRC staff is still pending. The inspector will review this item after final resolution and acceptance. (85-06-05)

12. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification 6.9.1 and 6.9.3 were reviewed by the inspector. This review included the following considerations: the reports contained the information required to be reported by NRC requirements; test results and/or supporting information were consistent with design predictions and performance specifications; and the validity of the reported information. Within the scope of the above, the following reports were reviewed by the inspector:

-- Monthly Operating Reports for February and March 1985.

13. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings.

Based on the NRC Region I review of this report and discussion held with licensee representatives on April 25, 1985, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.