U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	50-244/91-80
Docket No.	50-244
License No.	DPR-18
Licensee:	Rochester Gas and Electric Corporation 89 East Avenue Rochester, New York 14649
Facility Name:	Ginna Nuclear Power Station
Inspection Conducted:	May 6 through June 7, 1991
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Inspection Summary: Inspection on May 6 through June 7, 1991
Report No. 50-244/91-80

Areas Inspected: Announced team inspection by regional and contract personnel to review the functionality of the electrical distribution system.

Results: As described in the Executive Summary.

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EXECUTIVE SUMMARY

During the period between May 6 and June 7, 1991, a Nuclear Regulatory Commission (NRC) inspection team conducted an Electrical Distribution System Functional Inspection (EDSFI) at Ginna Nuclear Power Station. The inspection was performed to determine if the Electrical Distribution System (EDS) was capable of performing its intended safety functions as designed, installed, and configured. The team also assessed the licensee's engineering and technical support of EDS activities. For these purposes, the team performed plant walkdowns and technical reviews of studies, calculations and design drawings pertaining to the EDS, and interviewed corporate and plant personnel.

Based upon the sample of design drawings, studies and calculations reviewed and equipment inspected, the team determined that the electrical distribution system at Ginna Station is capable of performing its intended functions. In addition, the team concluded that the engineering and technical support staff, both at the Ginna Station and at the corporate offices in Rochester, New York, provide adequate support for the safe operation of the plant. The inspection also identified one violation, two deviations, and three unresolved items, as discussed in the paragraphs below. In addition, one previously identified item (Violation 50-244/89-81-06) was closed, as discussed in paragraph 4.2.2.

The licensee has implemented controls to maintain the electrical system configuration. Equipment inspected was observed to be well-maintained and an effective fuse control program was evident. The development of a molded case circuit breaker test program is ongoing. The testing attributes being addressed are comprehensive and thorough. A deficiency was identified in handling the as-found data of the protective relay testing. The dropout voltage settings of three protective relays drifted below the Technical Specification limits during the 1991 refueling outage yet no evaluation was performed as required by station procedures.

The corporate and site technical engineering and modification support personnel are adequately staffed with competent personnel and are very familiar with the EDS and its support systems. Effective interfaces exists between station and engineering personnel. Communications between the various engineering and technical support organizations were found to be good. Engineering support to operating and maintenance activities was determined to be good. The team determined that the licensee has an aggressive self assessment program and considered this to be a strength.

The licensee has a good program to investigate deficiencies, identify root causes and to complete appropriate corrective actions in a timely manner. Technical training and Quality Assurance Programs were found to be adequate.

The team observed several examples of a lack of attention to detail in the design calculation process. The examples included power demand calculations for the diesel generators, circuit breaker coordination calculations, battery room ventilation and hydrogen concentration calculations and use of incorrect fuel oil storage requirements. Corrections of these calculations were

completed during the inspection except for circuit breaker coordination which is an unresolved item. Part of this weakness was due to the fact that the licensee's engineering personnel had generated a large volume of design calculations within a short time before this inspection.

Increased management involvement to improve the existing design control process and quality of engineering work was demonstrated by the completion of P&ID Update Program, Electrical Configuration Controlled Drawing Program, Engineering Work Request (EWR) Procedure upgrades, ongoing Design Basis Reconstitution Program and Configuration Management Control Program. Improvement in the licensee's design control and modification process was noted during this inspection.

The inspection findings are summarized as follows:

One Violation	Discussed in Paragraph	Item Number
Protective relay settings drifted below Technical Specification limits and were not evaluated	4.3.3	50-244/91-80-04
Two Deviations		
1. Onsite power supply not meeting the single failure criterion	2.2	50-244/91-80-01
2. Redundant control cables of component cooling water pump control circuits were not adequately separated	2.2	50-244/91-80-02
Three Unresolved Items		
1. Completion of a comprehensive coordination analysis for all circuit breakers	2.8	50-244/91-80-06
2. Degraded voltage effects on Class 1E Motors	2.5	50-244/91-80-05
3. Completion of dynamic response analysis of emergency diesel generator loading	2.4.2	50-244/91-80-03

Three Observations

1. Unprotected diesel generator output cables	2.4.6
2. Undersizing of certain circuit breakers	2.7
3. Lack of loss of field protection for emergency diesel generators	2.4.5

One Weakness (lack of attention to detail in the design calculation process) examples:

1. Power demand calculation for the diesel generator	3.1
2. Circuit breaker coordination calculations	2.8
3. Battery room ventilation and hydrogen concentration calculations	3.3.5
4. Use of incorrect fuel oil specific gravity in calculating the fuel oil storage requirements	3.2.1

1.0 INTRODUCTION

During inspections in the past years, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants in the county, the functionality of related systems had been compromised by design modifications affecting the electrical distribution system (EDS). The observed design deficiencies were attributed, in part, to improper engineering and technical support. Examples of these deficiencies included: Unmonitored and uncontrolled load growth on safety related buses; inadequate review of design modifications; inadequate design calculations; improper testing of electrical equipment; and use of unqualified commercial grade equipment in safety related applications.

In view of the above, the NRC developed an Electrical Distribution System Functional Inspection (EDSFI) program for operating plants. There are two objectives for the EDSFI. The first objective is to assess the capability of the electrical distribution system's power sources and equipment to adequately support the operation of safety related components. The second objective is to assess the performance of the licensee's engineering and technical support in this area.

To achieve the first objective, the inspection team reviewed calculations and design documents. Particular attention was paid to those attributes which ensure that quality power is delivered to those systems and components which are relied upon to remain functional during and following a design basis event. The review covered portions of onsite and offsite power sources and included the 34.5 kV offsite power grid, station auxiliary transformers, 4.16 kV power system, emergency diesel generators, 480 V Class 1E buses and motor control centers, station batteries, battery chargers, inverters, 125 Vdc Class 1E buses, and the 120 Vac Class 1E vital distribution system.

The team verified the adequacy of the emergency onsite and offsite power sources for the EDS equipment by reviewing regulation of power to essential loads, protection for calculated fault currents, circuit independence, and coordination of protective devices. The team also assessed the adequacy of those mechanical systems which interface with and support the EDS. These included the air start, lube oil, and cooling systems for the emergency diesel generator and the cooling and heating systems for the electrical distribution equipment.

A physical examination of the EDS equipment verified its configuration and ratings and included original installations as well as equipment installed through modifications. In addition, the team reviewed maintenance, calibration and surveillance activities for selected EDS components.

The team's assessment of capabilities and performance of the licensee's engineering and technical support covered organization and key staff, self assessment program and technical training, temporary and permanent plant modifications, operating procedures for EDS, root cause analysis and corrective action programs and engineering support in design and operations and their interface.

In addition to the above, the team verified general conformance with General Design Criteria (GDC) 17 and 18, Systematic Evaluation Program (NUREG 0821 and Supplement 1), and appropriate criteria of Appendix B to 10 CFR Part 50. The team also reviewed the plant's Technical Specifications, the Updated Final Safety Analysis Report and appropriate safety evaluation reports to ensure that technical requirements and licensee's commitments were being met.

The details of specific areas reviewed, the team's findings and the applicable conclusions are described in Sections 2 through 5 of this report.

2.0 ELECTRICAL SYSTEMS

The characteristics of the power system electrical grid to which the Ginna plant is connected were reviewed to assess the adequacy of important parameters such as voltage regulation, short circuit contribution, protective relaying, surge protection, control circuits, stability, and reliability. The station auxiliary (startup) transformers were reviewed in terms of their kilo-volt-amperes (kVA) capability, their connections to the safety buses, protection, and voltage regulation. The emergency diesel generators (EDGs) were reviewed to assess the adequacy of the kilo-watt (kW) rating, the ability to start and accelerate under assigned safety loads in the required time sequence, the voltage and frequency regulation under transient and steady state conditions, compliance with single failure criteria, and the applicable separation requirements. The 480 V safety buses and their connected loads were reviewed to assess load current and short circuit current capabilities, voltage regulation, protection, adequacy of cable connections between loads and buses, compliance with single failure criteria, and applicable separation requirements.

The team reviewed the regulation of the EDS loads, the overcurrent protection, and coordination of protective devices for compliance with regulation, design engineering standards, and accepted engineering practices. The review included system descriptions, station Updated Final Safety Analysis Report (UFSAR), equipment specifications, licensee event reports (LERs), operating procedures, one line diagrams, and equipment layout drawings.

The team also reviewed procedures and guidelines governing the EDS design calculations, design control and plant modifications, and EDS single line diagrams and wiring schematics. A simplified single line diagram of the Ginna EDS is shown on Attachment 2.

2.1 Offsite Power and Grid Stability

The Ginna Station receives its power from two independent 34.5 kV circuits (circuit 751 and circuit 767). Circuit 751 receives 34.5 kV direct from the RG&E station 204 and circuit 767 receives 34.5 kV from the Ginna switchyard station 13A via the 115 kV to 34.5 kV stepdown transformer No. 6.

Four 115 kV lines (908, 911, 912, and 913) connect to substation 13A through the breaker-and-a-half technique of switching. This arrangement provides the versatility of dual feed for each line and the ability to remove any breaker or transmission line without deenergizing any other part of the substation.

The Ginna electrical power system was initially designed with a single auxiliary (startup) transformer 12A but a spare transformer 12B was added after the beginning of commercial operation. However, the station continued to operate with only one auxiliary transformer feeding all safety related loads. To increase the availability margin in the event of a single system failure, the 34.5 kV bus was split and the system was re-configured in 1989 to its present state.

Each of the auxiliary transformers is rated 34500-4160-4160 V, 28-41.8 MVA. These two transformers have two load ratings associated with them, the OA (oil-air) and the FA (forced-air) rating. All safety loads are supplied by the these transformers, however, according to 'Load flow and voltage profile analysis' Document No. EEA-03001, Revision 0, each of these feeders is capable of supplying the entire load. The worst case loading for the 12A and 12B transformers occur when the main generator trips and when all auxiliary loads are connected to the offsite grid. Maximum system loading is 29.6 MVA, split evenly between the two secondaries. The safety related buses do not have access to either the main generator output system or the 115 kV network.

The safeguards or 1E distribution is divided into two redundant and completely independent trains, A and B. Train A and B are each made up of two safeguards 480 V buses. Train A consists of buses 14 and 18 while train B consists of buses 16 and 17.

2.2 Bus Alignment During Startup, Normal and Shutdown Operation

During normal operation, the main generator feeds electrical power at 19 kV through an isolated bus to a 19-120 kV stepup transformer. The bulk of the power required for auxiliaries is supplied by unit auxiliary transformer 11, connected to a 19 kV isolated phase bus.

During normal shutdown all auxiliary loads are transferred to the station auxiliary transformers 12A and 12B.

During startup operation all station loads are energized from auxiliary transformers 12A and 12B. Bus 11B is connected to bus 12B and bus 11A is connected to bus 12A. After successful startup the operator manually transfers buses 11A and 11B to the main generator.

When the main generator trips, the plant auxiliary loads from the transformer are automatically transferred to buses 12A and 12B by closing tie breakers BTB-B and BTA-A. Upon loss of offsite power the loss of voltage relay on 480 V emergency buses 14, 16, 17 and 18 will start the emergency diesel generators DG A and DG B and connect them to their respective buses.

While reviewing the emergency buses configuration, the team identified a design deficiency in the emergency tie breaker arrangement between buses 17 and 18 in the screenhouse. Bus 17 (train B) and bus 18 (train A) are tied with a single breaker (BT17-18). Interlocks are provided to prevent closure of the tie breaker if more than one AC power source were serving the Class 1E buses. To close the tie breaker, either (a) both diesel breakers must be tripped and one offsite breaker tripped, or (b) both offsite source breakers must be tripped and one diesel breaker must be tripped.

While the interlocks preventing closure of the tie breaker were redundant, only one control circuit for the breaker was provided within the switchgear; therefore, spurious closure of the breaker due to a fault in the control circuit could be postulated during an event requiring onsite power sources. If this occurs when both EDG's are running out of phase, buses 17 and 18 plus one of buses 14 and 16 could be lost (assuming one of the EDG breakers trips before tiebreaker BT17-18, because of a lack of a comprehensive breaker coordination program). The team concluded that this design deficiency constitutes a deviation from paragraph 3.1.2.2.8 of Ginna Updated Final Safety Analysis Report (UFSAR), General Design Criterion 17, which states, in part, "the onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure" (50-244/91-80-01).

In response to the team's concern, the licensee withdrew the tiebreaker to the test position, so that the tiebreaker cannot be closed inadvertently during plant operation. The licensee also revised the affected procedures to accommodate this new configuration.

While reviewing the control logic for the component cooling water (CCW) pump operation, the team identified that 125 Vdc control circuit conductors from Train A and Train B Component Cooling Water Pumps shared the same four-conductor cable. The cable was routed within a relay cabinet, through a conduit, and into a cable tray. This deviates from UFSAR Paragraph 8.3.1.4.2, Separation of Redundant Circuits, which states, in part, "All components requiring redundant cabling, as well as the cabling for redundant components, have been identified and the redundant power, instrumentation, and control cables are run separately." This constitutes a deviation (50-244/91-80-02). The licensee stated that this deficiency will be corrected during the next refueling outage.

The above separation deficiency combined with the ground detection procedure (Procedure M-38.23) could cause operational problem of the CCW system. According to Procedure M-38.23, removal of grounds in the DC system is not mandatory, and could permit a ground to persist for a long time. Suppose two conductors of the unseparated cable are shorted to the conduit (this may be due to cable insulation deterioration). If this condition is not isolated and corrected and a second ground develops somewhere in the DC system negative side (either in Train A or Train B), a hidden potential problem will be created. The CCW system would appear to function normally until a postulated accident occured. When this happened, assuming the EDG's started, all CCW pumps would be de-energized initially (per load sequencing requirements). When restart of the CCW pumps is later required, the short-to-ground would blow (and continue to blow) the fuses of the control circuits, causing both CCW pumps to be inoperable. According to the licensee, the plant had about 12 to 18 grounds per year in the DC system.

In response to the team's concern, the licensee checked with the plant to confirm that no ground currently existed in the DC system. The licensee also initiated a revision of Procedure M-38.23 to strengthen isolation and correction of detected grounds in the DC system. The licensee also conducted a comprehensive analysis to determine if other similar situations exist in the design. The team had no further questions.

2.3 Bus Transfer Schemes

The team reviewed the transfer schemes to ensure that transfer occurs without any inrush in the system and without adversely affecting any class 1E equipment.

The team noted that during any maintenance work on transformer 12A or 12B, the loads are normally transferred to the unaffected side by closing either breaker 12AX or 12BY as required. The operator follows procedure 0-6.9.2 "Establishing and/or transferring offsite power to bus 12A/bus 12B." The team was concerned that the procedure did not address the maximum permitted phase angle shift between the two sources. Since the transfer is 'make before break' the out of phase transfer could cause high inrush currents and high transient torques at the motor shaft.

The licensee stated that its preliminary analysis indicated that the maximum phase shift between buses 11A and 11B, 12A and 12B, and PPSX and PPSY will not exceed 15 degrees, based on simulations that considered reasonable contingency conditions. The team determined that this response is acceptable based on the fact that 1) During normal operation the Class 1E buses are lightly loaded and hence the voltage drop on these buses will not be very significant; 2) A 15 degrees phase difference will not cause an appreciable inrush current.

2.4 Emergency Diesel Generators (EDG)

The EDGs consist of two Alco 16 cylinder Model 251F engines coupled to a Westinghouse 1950 kW (continuous rating), 0.8 power factor, 900 rpm, 480 Vac generator. The team reviewed the licensee's steady-state and dynamic loading

analyses for EDG 1A, since these analyses indicated that EDG 1A had lower loading margins than EDG 1B. The acceptance criteria for these analyses were that the short-time ratings would not be exceeded and the minimum voltage and frequency recovery requirements of Regulatory Guide 1.9 would be met. The team reviewed the licensee's assumptions, analytical procedures, and results with respect to those criteria. Protection of the EDGs was also reviewed. This is discussed as follows.

2.4.1 Steady State Loading Analysis

The team reviewed the Licensee's Design Analysis EEA-01002, "Diesel Generator 1A Steady State Loading Analysis", Revision 0, dated May 6, 1991 to ensure that the loading was within the capability of the EDG rating.

The team identified two discrepancies. The first involved an incorrect determination of brake horsepower for the residual heat removal pumps and the safety injection pumps. The effect of this error was to add 20.6 kW to the load on each EDG. The Licensee updated the data base accordingly during the inspection, and demonstrated that there was no substantial effect on the existing load margin. This issue is also discussed in Paragraph 3.1.

The second discrepancy in the steady-state calculation involved the licensee's incorrect and nonconservative assumption that "The EDG can be loaded to its two-hour rating immediately after it has been loaded to its 30 minute rating". This assumption for short-time rating is not permissible by Regulatory Guide 1.9 and IEEE Standard 387-1984, which defines the short time rating as: "The electrical power output capability that the diesel generator unit can maintain in the service environment for 2 hours in any 24 hour period, without exceeding the manufacturer's design limits and without reducing the maintenance interval established for the continuous rating." Based on the above, the team concluded that the 2 hour rating could not be applied again for at least 22 hours.

During the inspection, the licensee re-evaluated some of its conservative assumptions, and re-adjusted the operating time of the safety injection pump to 58 minutes instead of 2.5 hours. They demonstrated that the short-term and continuous loading of the EDG does not exceed the EDG rating at any time. The team did not have any further questions.

2.4.2 Dynamic Loading Analysis

The team reviewed the licensee's Design Analysis EEA-01001, "Diesel Generator Dynamic Loading Analysis," Revision 0, dated May 6, 1991. The licensee had identified this analysis as an interim use document for providing reasonable assurance that the EDGs were properly sized to meet their loading requirements. The licensee stated that they intended to revise and refine the analysis as more data became available from field testing.

On the forgoing basis, the team concluded that the licensee's general approach to the analysis was acceptable. However, the licensee had identified several unverified assumptions in the analysis. These included unvalidated model software, unknown constants for the exciter and the governor, and unretrievable values for speed-torque curves and motor inertia. The licensee committed to complete the final dynamic loading analysis, including justification of the unverified assumptions, by May 1992. This is an unresolved item pending NRC review of the final analysis (50-244/91-80-03).

2.4.3 Emergency Diesel Generator Protection

The team reviewed the co-ordination curves for breakers EG1A1, EG1A2, EG1B1, 1B3, and EG1B2 which provide the protection for the EDG.

The team observed that the co-ordination study did not contain sufficient information to evaluate the adequacy of the protective devices. The curves lacked the following information: 1) The maximum and minimum loads on the generator breakers; 2) The maximum and minimum fault currents; 3) The cable I^2t curves; 4) The generator damage curve; 5) The decremental characteristic of the EDG and the time/current charasteristic of voltage control overcurrent relay (51V).

During the inspection the licensee provided additional information to support the coordination of the EDG breakers. They demonstrated that the EDGs were adequately protected. The licensee agreed to include this information into the coordination analysis program discussed in Section 2.8. The team concluded that the EDGs were adequately protected against overloads and did not have any further questions.

2.4.4 Emergency Diesel Generator Field Ground Fault Protection

The team reviewed the EDG wiring diagram and was concerned that the field was not protected against ground faults nor was there any alarm to warn the operator of a fault situation.

The generator field circuit is ungrounded. Thus a single ground fault will not result in equipment damage, or affect the operation of the generator. If, however, a second ground fault should occur, there will be an unbalance in the rotor magnetic field. This unbalance may be enough to develop destructive vibrations within the generator.

The licensee acknowledged this concern and stated that the probability for the field circuit to have a second ground was very low and that this was not a safety issue since in the case of the loss of one EDG, there was still another EDG available. The team had no further questions.

2.4.5 Emergency Diesel Generator Loss of Field Protection

The team observed that the EDG did not have loss of field protection for the EDG nor was there an alarm to warn the operator of this condition. This protection is of value when the EDG is being tested and connected in parallel with the grid. Should a generator lose its field excitation during testing, it will continue to operate as an induction generator obtaining its excitation from the grid. This causes the generator rotor to quickly overheat due to induced slip frequency currents. The licensee stated that this type of protection is not generally provided on 480 V generators. However, in nuclear power plants, where the availability of safety support system is of importance, this feature would minimize failures during testing.

This is not considered a safety issue because only one EDG would be affected at a time.

2.4.6 Unprotected Cables Connected to the Emergency Diesel Generators

The team reviewed the AC Electrical System One Line Diagram, Drawing Number 33013-2409 and found that the two cables feeding 480 V buses 14 and 18 were directly connected to the EDG without any protection. The team was concerned with the potential for a fault at the end of the unprotected long screenhouse feeder cables since the cables are buried underground and are susceptible to water exposure. Normally such cables are prone to faults and a fault could remain undetected for a long period of time. If a ground fault develops, it can cause the loss of two emergency buses. The licensee stated that these cables have not been a problem. Furthermore these cables are meggered annually per procedure M15.1. The team observed that a fault could occur between the testing periods.

2.4.7 Emergency Diesel Generator Droop Mode Alarm

During periodic testing of the EDGs, the EDG has to be switched in the "Droop" (parallel) mode so as to enable it to be paralleled to the grid. The team noted that the switch position in Parallel mode is not alarmed in the control room. The team was concerned that after the test is over, the operator may inadvertently leave the switch in the droop mode, affecting the availability of the EDG during a loss of offsite power event.

The licensee responded by stating that the monthly test procedures PT 12.1 and PT 12.2 require the Unit/Parallel switch be placed in the "Unit" mode prior to procedure completion. The team had no further questions.

2.4.8 Safety Injection Signal While Testing Emergency Diesel Generator

The team noted that when the EDGs are tested every month, they are operated in the parallel mode (parallel with the grid). If a safety injection (SI) signal occurs at this stage, the following takes place:

- The two Class 1E buses associated with the EDG under test are isolated from the offsite power;
- The SI signal does not bypass the 'Test' mode;
- All non-class 1E loads are tripped;
- All non-sequenced Class 1E loads are tripped;
- The sequencer is initiated and loads are connected to the EDG in a predetermined sequence;

Since the EDG is in the parallel mode, the generator terminal voltage is not automatically regulated. As the load increases, the frequency and voltage drops, causing the generator to trip on overload.

In response to the team's concern, the licensee stated that this deficiency was known to them and had existed since the plant was built. They had raised a PCAQ (Potential Condition Adverse to Quality) to correct this deficiency (PCAQ # 91-029 was subsequently issued on June 3, 1991 for this problem).

The team concluded that this is not a safety issue since only one EDG is tested at a time. The other EDG is available to carry the sequenced load.

2.5 Degraded Voltage on Class 1E Buses

The team reviewed Document No. EEA-03001, Rev. 0, dated April 27, 1991, "Loadflow and Voltage Profile Analysis" and Document No. EWR 4525-2, Rev. 1, dated July 24, 1990, "Adequacy of Electric System Voltages". The team noted that each safeguards bus (14,16,17 and 18) had four undervoltage relays to sense both a complete loss of voltage and also a degraded offsite source. The four relays were divided between type 27D, which was used to detect a complete loss of voltage, and type 27, which detected abnormally low voltage. Any one of the four undervoltage relays could start the EDG associated with its train. However, two relays were required to cause tripping of the bus breaker. The degraded voltage relays on Class 1E buses 14,16,17 and 18 were set to trip at 418 V, and loss of voltage relays were set to trip at 372 in 0.5 seconds.

The team noted that the analysis did not include the effect of degraded voltage on some of the Class 1E motors. The licensee provided preliminary computer results indicating expected voltages on some of the Class 1E motors. During worst case conditions with LOCA loads on the system, if the grid voltage dips to 116.47 kV, the Class 1E bus 14 could be at 418 V. This may not cause tripping of the degraded voltage relay. This condition may result in motors

operating at a degraded voltage at the motor terminal. In response to the NRC concern, the licensee carried out a preliminary study for large motors and found that there was no concern except for the RHR pump motor. The study revealed that the voltage at the terminal of RHR pump 1A could be as low as 413 V. The threshold operating voltage limit for this motor is 414 V. Below this voltage the motor could get overheated causing degradation of the motor winding insulation. However, the team concluded that 413 V is close to the threshold voltage of 414 V and this degraded voltage condition will not last long enough to cause damage to the motor winding.

However, the team was concerned about degraded voltages at some of the Class 1E MCCs. For example MCC 1C could have a degraded voltage of 411 V. The study did not analyze the voltage levels at the terminals of all vital loads supplied from Class 1E MCCs that are required to operate during accident conditions. Therefore, the team could not determine if such motors could operate safely under the degraded voltage condition. The licensee committed to complete the analysis of the degraded voltage situation, on a motor by motor basis, by June 1992. This is an unresolved item pending an NRC review of the analysis (50-244/91-80-05).

2.6 Over-Voltages on Class 1E Motors

The team reviewed Document No. EEA-03001, Rev. 0, "Load Flow and Voltage Profile Analysis ", to determine if any of the Class 1E loads could be subjected to a high voltage during lightly loaded conditions or grid voltage fluctuations. The team noted that there were no restrictions on overvoltage operation in the Ginna Station Technical Specification or UFSAR. The team observed that the maximum voltage seen at bus 17 could be as high as 496 V. The team was specially concerned about the 300 HP Service Water Pump which would be subjected to voltages beyond its rating (440 V +10 % = 484 V) while operating in the 1.15 service factor (SF) range (EWR 4232, Revision 0, dated May 9, 1980 " Insitu Motor Load Determination " indicated that the above motor could operate in the 1.15 SF range during a design basis accident).

The licensee presented a letter dated January 21, 1980, from Westinghouse Electric Corporation (WEC) stating that the average temperature rise of the above motor was 68°C at 500 V and 72°C at 515 V, which is below the 90°C temperature rise (above 40°C ambient) allowed for a Class B insulation system. The team however noted that the letter did not specify if the temperature rise calculations were done for a service factor of 1 or 1.15.

The licensee gave further clarification of the WEC letter stating that the temperature calculations were based on the maximum winding resistance temperature immediately after starting the motor and not the steady state winding resistance. With continuous operation this temperature will decrease. The team did not have any further concern with this issue.

2.7 AC System Short Circuit Review

The team reviewed EWR 4525-1, "Fault Current Analysis of Power Distribution System", Revision 1, dated July 27, 1990, to determine if the Class 1E equipment was properly sized to withstand the available short circuit current.

The team noted the interrupting current ratings of the Class 1E 480 V circuit breakers are as follows:

Bus	Type	Rating (Amps sym.)
14 & 16	DB-50	50,000
17 & 18	DB-25	30,000

The team observed that the fault currents were significantly above the breaker ratings when either EDG was running in the test mode. The test mode configuration required EDG 1A to be paralleled with both its 1E buses (14 & 18). Similarly, the test mode configuration for EDG 1B required it to be paralleled with both of its Class 1E buses (16 & 17). The calculated fault currents were as follows:

Bus	Without EDG	With EDG
14	39,099	55,337
16	39,463	56,418
17	24,336	51,148
18	22,260	48,879

The licensee stated that they had evaluated the probability of such an fault current occurring and found it to be very low ($3x10^{-7}$ per year).

2.8 Protection of Class 1E Motors

The team reviewed Amptector Response Characteristics for several large Class 1E motors and was concerned that the curves did not include the motor characteristic for degraded voltage situations. In some cases the margin between the motor full load current and the lower band of the pickup current was very narrow. This could cause tripping of a motor at degraded voltage conditions while attempting to start or while operating in the service factor zone during an accident condition. The industrial practice is to set the pickup at 115-125% for motors with a 1.00 service factor and 125-140% for motors with a 1.15 service factor. The team was specially concerned about the Containment Recirculation Fans and the Service Water Pumps where the margin between the full load current of the motor and the lower band of the relay pickup set point was very small. The licensee provided preliminary calculations which indicated that there was no cause for concern. However, the acceleration time was based on an Electrical Transient Analyzer Program (ETAP) that modeled these two motors, since the acceleration time characteristics at various voltages were not available from the manufacturer.

The licensee stated that a comprehensive coordination analysis is being prepared to document the basis for all Amptector setpoints. Since this document is not yet complete all factors for setpoint changes have not been evaluated. The licensee committed to complete the coordination analysis of the 480 V and 4160 V breakers by November 1992. This is an unresolved item pending NRC review of the coordination analysis and the evaluation of the factors for setpoint changes (50-244/91-80-06).

2.9 Selection and Sizing of Power Cables

The team reviewed document EDG-4A, Revision 0, dated April 9, 1991, "Cable sizing analysis for cables installed in conduit and cable trays". The team noted that the document was very recent and was intended for new installations. A similar document did not exist in the past. The team found that the analysis was adequate and considered the effect of short circuit current that could damage the cable, cable routing requirements, cable construction requirements, cable capacity and the necessary derating factors. However, the analysis did not address the maximum allowable voltage drop in the feeder or the review of the cables for voltage drop during starting of motors.

The team conducted a spot check of recent modifications and did not identify any improperly sized cables.

2.10 Electrical Penetration Sizing and Protection

UFSAR 8.3.1.3 stipulates GDC 50, IEEE Std 317, and Regulatory Guide 1.63 as the design bases. In addition, the UFSAR cites manufacturer's fault tests and studies conducted in support of SEP Topic VIII-4, "Electrical Penetrations". The team selected a penetration analysis package for review. This analysis was documented in the licenee's SEP Technical Evaluation Topic VIII-4 Report, "Evaluation of Selected Penetrations to Withstand Low Magnitude Faults", dated June 3, 1981.

The I^2t values for the silver brazed and soft solder penetrations were calculated based on the equivalent of I. M. Onderdon's fusing current-time equation for copper conductors and connections. An adiabatic thermal process was assumed. The initial temperature of the penetrations was assumed to be the LOCA temperature. A review of the protection analysis using short circuit values from more recent calculations did not identify any protection concerns for the sample reviewed.

The team identified that several of the original Standard Evaluation Plant (SEP) commitments for backup protection had not been implemented. The licensee explained that subsequent NRC staff guidance allowing exceptions for backup protection, where the circuit is Class 1E qualified or where the circuit is isolated, resulted in eliminating the need for backup protection in some cases. On that basis, this was acceptable to the team for the penetrations reviewed during the inspection (480 Vac penetration CE-21 serving containment recirculation fan A motor).

No anomalies were found for the review of the 4160 Vac penetration CE-25 (Reactor Coolant Pump 1 A), and a field check of a sample of protective relay settings did not identify any deficiencies.

2.11 120 Vac Instrument Bus System

Section 8.3.1.1.5 of the UFSAR and the licensee's drawing 03201-0102, 120 Vac Instrument Bus One-Line Diagram", Rev. 0 dated April 20, 1991 describes the design basis and configuration of the 120 Vac Class 1E system. Only three of the buses supporting the four channel protection system instrumentation are Class 1E, and only two of the Class 1E buses are battery-backed. In addition to the four instrument buses, one channel each of certain engineered safety features actuation system (ESFAS) instrumentation is served from a separate inverter. The licensee's one-line diagram indicated that this additional inverter was served by battery A (which is also the source for instrument bus 1A), but the loads were identified as Instrument Channel D.

2.11.1 System Configuration

The team asked the licensee to demonstrate that the use of a non-1E power source for one channel did not compromise the independence of the four instrument buses. The licensee' analysis indicated that the power feeder for instrument bus 1D shared the same conduit as the power feeder for instrument bus 1C. The licensee stated this was acceptable under the original design basis and was supported by the failure analysis provided during the inspection.

The team identified to the licensee that the UFSAR provided a commitment that the instrument buses meet separation criteria of IEEE Std 384-1974. Based on the foregoing description of the configuration of the buses, the design does not conform to IEEE Std 384. The licensee agreed, and stated that this was an error in the UFSAR that occurred during the FSAR update, and that a correction to the UFSAR had been identified to delete this commitment.

The team concluded on the foregoing basis that the system configuration appeared to conform to the original design basis as reviewed by the NRC staff, although the design did not conform to more recent standards and practices with regard to qualification, independence and separation.

2.11.2 Loading and Continuous Ratings

The licensee monitored the loading of the instrument buses for normal operating conditions; the values for known additional loads of instrumentation being retrofit and the margins for normally de-energized loads were determined. The values were totalled to determine the system loading. The licensee determined that the existing loading on buses 1A and 1C was acceptable, but that future additions of loads should be restricted until a load monitoring program is established.

2.11.3 Fault Protection and Coordination

The licensee's analysis indicated that the existing breakers used in the 120 Vac distribution system (Buses 1A and 1C) have adequate interrupting ratings for

the maximum available short circuit currents. The analysis evaluated coordination of all breakers in the Bus 1A and Bus 1C panels, and determined it was adequate. In the instances where coordination could not be demonstrated, the analysis showed that the lack of coordination was bounded by the system failure analysis. Based on a review of the foregoing analyses, the team concluded that fault protection and coordination was adequate on buses 1A and 1C.

2.12 125 Vdc Class 1E System

The 125 Vdc Class 1E system is divided into two buses. Each bus contains two battery chargers (200 amp and 150 amp). Each of the 200 amp chargers was sized to recharge its battery within 24 hours while carrying its load.. Two 60-cell, lead-acid, batteries are provided for supporting control power, emergency lighting, and the instrument bus inverters. The team reviewed the battery capacity, load profile, fault protection and coordination, and voltage drop analyses to determine the design adequacy. The results are discussed as follows.

2.12.1 Battery Capacity and Load Profile

The batteries were replaced approximately five years ago. The team reviewed the licensee's confirmatory Design Analysis EEA 09004, Rev. 0, dated May 4, 1991, and EWR 3341 Design Analysis No. 5, "DC System Load Survey", Rev. 1, dated February 3, 1988. The analysis confirmed adequate battery capacity in accordance with IEEE Std 485-1983. The analysis established the basis for battery sizing for a four hour station blackout (SBO) event pursuant to 10 CFR 50.63. The licensee was aware that the UFSAR describes an 8 hour duty cycle as the basis for sizing. The licensee indicated that the UFSAR would be revised to reflect the SBO four hour duty cycle as the limiting condition.

The team reviewed the analysis assumptions, the basis for individual load contributions to the profile, and performed an independent check of cell sizing.

The team noted that each battery load profile depended on automatic shedding at twelve minutes of a significant load (for non-safety related DC lube oil pump of the main feedwater pump) by a timer that was not in the surveillance program. The timer was replaced during the last outage with a qualified timer in order to provide a reliable load setting. The setting of the timer had been verified to be less than twelve minutes as part of the post maintenance test. The team was concerned about the possibility that the load would not be shed within twelve minutes, thus affecting the reserve capacity of the battery. In response, the licensee agreed to include the timer setting in their surveillance program.

2.12.2 Fault Protection and Coordination

The team reviewed the licensee's Design Analysis EEA-09005, Rev. 0, dated April 29, 1991, supplemental data on panel ratings, and EWR 3341 Design Analysis No. 10, "Fuse Isolation and Coordination", Rev. 1 dated February 12, 1988. The 125 Vdc system uses fuses as protective devices except for a small

number of load side breakers. The team also reviewed the DC one-line diagram 33013-1036 Sh. 2, Rev. 5 dated March 1, 1990. The team concluded that available short circuit currents were acceptable for the fuses and panels installed and that a fault on any Class 1E or non-class 1E branch circuit would not result in a main fuse degradation.

2.13 Conclusion

Based on the team's review of the EDS design, the team concluded that the Ginna electrical distribution system is capable of performing its intended function. The team also noted that the licensee had carried out major modifications to the 34.5 kV bus to increase the availability margin in the event of a single off-site power system failure.

However, the team identified two deficiencies in the EDS:

1) A single short in the control logic or a single mechanical malfunction (although unlikely) could cause the EDS to lose three emergency buses; and

2) The redundant control cables for the two Component Cooling Water (CCW) pumps have no separation. This deficiency, combined with the existing ground detection procedure, could cause both pumps to be inoperable.

The team also identified three unresolved items which require further corrective actions by the licensee:

1) A comprehensive coordination analysis for all safety related circuit breakers;

2) Analyses of degraded voltage effects on the 480 V MCC motors;

3) Completion of the dynamic loading analyses of the EDG did consider the scenario where the CS pump and the third SI pump could occur as random load on the EDG.

In addition, the team made three observations:

1) Unprotected output cables from emergency diesel generators.

2) Undersizing of circuit breakers of buses 14, 16, 17, and 18.

3) Lack of loss of field protection for the emergency diesel generators.

With the exception of specific findings, observations and unresolved issues identified in the report, the EDS components were adequately sized and configured.

3.0 MECHANICAL SYSTEMS

To determine the functional ability of mechanical systems to support the EDGs during postulated design basis accidents, the team reviewed sample documentation and conducted a walkdown of the fuel oil storage and transfer, lubricating oil, starting air, and diesel heating and cooling equipment. The team also reviewed equipment associated with the heating, ventilation and air conditioning (HVAC) of the diesel generator buildings, service water screenhouse, relay room, battery rooms, control room, and selected EDG and HVAC design modifications. The team also reviewed the power demand for major loads (selected pumps) for input into design basis calculations.

3.1 Power Demands for Major Loads

The team reviewed the power demands for the major pump motors powered by the EDGs following a loss of offsite power during LOCA conditions.

The team noted that the peak Residual Heat Removal (RHR) pump loading occurs at runout condition and peak Safety Injection (SI) pump loading occurs prior to runout. The RHR pump brake horsepower (bhp) based on the manufacture's pump curve for the flow of 2500 gpm near runout condition was 173 and the motor power demand was 139.2 kW. The EDG loading calculation EEA-01002, Revision 0, May 6, 1991 assumed the RHR pump bhp as 165 and the motor power demand 132.8 kW. For the SI pumps, the maximum bhp based on the manufacturer's pump curve corresponding to a flow of approximately 400 gpm was 367 and the motor power demand was 289.7 kW. The EDG loading calculation assumed 358 bhp for the SI pump and 282.6 kW for the motor power demand. Based on the team's findings, the licensee agreed to revise the EDG loading calculations to correct these loads.

In summary, as a result of the team's finding, the automatic and steady state loads will be increased by 20.6 kW (6.4 kW for the RHR pump, 7.1 kW for the SI pump and 7.1 kW for the SI swing pump) from the existing loading calculations. The licensee incorporated this new power demand into the EDG loading calculations, resulting in a load increase of about one percent. This issue was also discussed in Paragraph 2.4.1.

3.2 Diesel Generator and Auxiliary Systems

The team reviewed the licensee's calculations, procedures, and other documentations to determine the design adequacy of diesel generator cooling, air start system, fuel oil storage and transfer system. These are discussed as follows.

3.2.1 Diesel Generators Cooling

Two Alco 16 cylinder model 251F turbocharged and aftercooled diesel engine generator sets are provided to generate the required emergency power for all the engineered safeguards equipment. Each diesel generator has a continuous rating of 1950 kW, a two hour rating of 2250 kW and a 30 minute rating of 2300 kW.

The team reviewed performance trending data from May 15, 1990 to April 21, 1991 for both EDGs. The trending program was utilized to measure jacket water and lube oil outlet temperatures to verify the EDG cooling function. The team noted that these temperatures must be maintained within a normal range as defined in plant procedures PT-12.1 and PT-12.2. However, if a measurement was obtained which was outside the specified range, remedial action would be taken. Within the scope of this review, no unacceptable conditions were identified.

According to the UFSAR, Section 8.3.1.1.6.4, and technical specification, Section 3.7.2, an onsite diesel fuel oil inventory at all times was maintained to assure the operation of both EDGs carrying design load of all the engineered safeguards equipment for at least 40 hours. Technical specification, Section 3.7.1, stated that the reactor would not be maintained critical without two EDGs operable with an onsite supply of 10,000 gallons of fuel oil available.

The team noted that calculation ME-91-0011, Revision 0, dated May 2, 1991, "Diesel fuel oil minimum onsite storage requirements, PECAQ 91-0010", used a fuel oil specific gravity of 0.89 which was not conservative for evaluating the technical specific onsite fuel oil storage requirements since the fuel consumption was converted from lb/hr to gallons/hr. The licensee agreed that fuel oil could be at a specific gravity as low as 0.82 and still satisfy all other fuel oil specification requirements. The licensee determined that the specific gravity of the fuel oil used in the fuel consumption test was 0.865 and after applying correction factor for the higher heating value for the lower specific gravity fuel oil, the net effect of minimum fuel oil specific gravity would be an increase of 3.5% in the onsite fuel oil storage requirement. In addition, the increase in EDG loads mentioned in Section 3.1 would have an effect of further increasing the onsite fuel oil storage requirement by about 1%.

The licensee provided preliminary calculations to include the effect of minimum fuel oil specific gravity and the increased EDG loads on onsite storage requirement which indicated that to assure the operation of both EDGs at design load of all the engineered safeguards equipment for 40 hours, an onsite fuel oil storage capacity of about 10,600 gallons would be required.

The team reviewed calculation EWR 4526 ME-23, Revision 0, dated April 30, 1991, "Diesel Generator Fuel Oil Storage Tank Usable Volume" and noted that the usable capacity of the two fuel oil storage tanks was 5827 gallons each, giving a total capacity of 11,654 gallons.

The team also reviewed procedure 0-6.13, "Daily Surveillance Log," Revision 65, and noted that by following the procedure, the volume of onsite diesel fuel oil in each tank was maintained at the required value of 5,300 gallons. The licensee agreed to correct value of 10,000 gallons stated in the technical specification. This is one example of a weakness in engineering calculations.

3.2.3 Fuel Oil Transfer System

The team noted that there was no fuel oil transfer pump trip on low storage tank level. The licensee's response was that the Technical Support Center was mandated to be fully actuated within one hour of an accident. It would be the duties of the recovery staff to assure that enough diesel fuel was available or could be ordered and delivered in sufficient time to assure that a low level in the storage tank did not occur. In addition, operations personnel would be monitoring the diesels if they were running during an accident. The team had no further questions.

3.2.4 Fuel Oil Storage and Day Tank Vents

The team determined that the exposed fuel oil storage and day tank vents were not qualified to withstand tornado generated missiles. The licensee stated that in addition to having an inconsequential probability of a missile strike to the fuel oil tank vents, diversity was available in venting. As shown on P& ID's 33013-1239, sheets 1 and 2, each storage and day tank has independent venting as well as a common vent on each of the recirculation/overfill lines. Therefore, if a missile strike were to occur on any of the vents, venting capability would not be lost. The team had no further questions.

3.2.5 Air Start System

The team reviewed instrument calibration data sheet CP-I-DG-INSTR-64A, Revision 01 Page 236 of the data sheets indicated that the setpoint for the EDG low starting air pressure alarm was 90 psig. However, after the air boosters were installed in 1975, there was no test data to demonstrate that the EDG would be capable of starting and be ready to receive the load within 10 seconds with 90 psig starting air. The team reviewed CYGNA Energy Services calculation 92528-001, Revision 1, dated May 9, 1991, "Evaluation of the capacity of the Diesel Air Start System" and noted that after four starts, the air pressure in the receivers would be about 117 psig.

The licensee provided a copy of the Auxiliary Operator's Log sheet to the team and stated that the starting air receiver pressure log was performed twice per shift to ensure that the receiver pressure remained within the normal range of 225-260 psig.

The licensee also stated that the Alarm Response Procedure directed the Auxiliary Operator to verify that the air compressor was running and the correct valve aligned. The alarm response directed the Auxiliary Operator to notify the control room of the alarm and cause of the alarm. If the low air pressure condition could not be corrected immediately, the EDG would be declared inoperable and the other EDG would be started in accordance with Technical Specification, Section 3.7. The team had no further questions.

3.3 Heating, Ventilation and Air Conditioning HVAC Systems

The team reviewed the licensee' drawings, calculations and other documentations to determine the design adequacy of the EDG room HVAC system, Screenhouse Ventilation System and Battery Room ventilation. These are discussed as follows:

3.3.1 Emergency Diesel Generator Rooms Temperature

According to the UFSAR, Table 3.11-1, all equipment in the EDG rooms was designed for operation at 104°F when the diesels were not in operation. However, the ventilation system for the EDG rooms was designed to maintain the room temperature below 104°F, with the EDGs running, during summer with an outside air design temperature of 91°F. The team noted that the ventilation system for the EDG rooms would not start unless the EDGs were running and, therefore, the heat loads in the rooms could raise the temperature above 104°F.

In response to the team's concern, the licensee initiated a procedure change notice (PCN 91-3283) to revise procedure O-6:16 to monitor the room temperature and manually start the ventilation fans when the temperature reached 90°F. The team had no further questions.

3.3.2 EDG Rooms Ventilation System

The team noted that the calculation assumed an ALCO provided heat loss of 4 Btu/Bhp per minute from all the ALCO EDG and auxiliaries and electrical components excluding the heat load from the exhaust stack. However, the licensee could not provide the contributions from various heat sources to arrive at this value. Therefore, the team was unable to verify that all the EDG heat sources were included in the HVAC calculation. In response to the team's concern, the licensee contacted the EDG manufacturer, Canadian General Electric, to verify that all the EDG heat sources including the electric components but excluding the exhaust stack were in fact included to arrive at the 4 Btu/Bhp per minute heat rejection to the EDG room air.

Calculation ME-91-0010 indicated that the maximum predicted temperature in the EDG room would be 104.3°F. The team noted that the calculation had assumed an air density based on a temperature of 70°F, whereas the outside air design temperature was 91°F. Correcting for the air density, the maximum predicted EDG room temperature would be 104.8°F which was above the design temperature of 104°F. The licensee stated that NUMARC 87-00, Appendix F established a continuous temperature of 140°F for the EDG electronic governor which was the limiting piece of equipment. This provided reasonable assurance of continued functionality of the EDGs at the maximum room exhaust temperature of about 105°F for the GINNA EDG rooms.

3.3.3 Seismic Qualification of Steam Heaters and Associated Piping in the EDG Rooms

In response to the team's question regarding the seismic qualification of the steam heaters and the associated piping in the EDG rooms, the licensee stated that the heaters and the associated steam piping were evaluated using SQUG methodology during an interaction review of the EDG air start system. According to Section 4.5 of EQE report 42031-R-001, Revision 0, dated January 18, 1991, "Seismic Verification of the Diesel Air Start System at the Ginna Nuclear Power Station," the space heaters and piping were 'judged' to be adequate to maintain position and structural integrity during and after an SSE. The licensee further stated that they would conduct a seismic analysis of the steam line inside the EDG room to evaluate and confirm the SQUG finding. The analysis would be completed by July 31, 1991.

3.3.4 Screenhouse Ventilation System

The team reviewed the screenhouse HVAC calculation ME-91-0009, Revision 1, dated May 15, 1991. The team identified the following discrepancies:

(i) Air infiltration was assumed to be 1.25 room air change per hour whereas based on the ASHRAE recommended value of 0.6 cfm per sq. ft, the air infiltration would be 1.1 room air change per hour.

(ii) The calculation did not address the effect of the loss of non-1E powered ventilation fans on the screenhouse temperature during summer with the outside air temperature of 91°F.

In response to the team's concerns, the licensee revised calculation ME-91-0009, Revision 2, May 24, 1991. The revised calculation demonstrated that the screenhouse temperature could be maintained below the design value of 104°F by natural ventilation alone.

3.3.5 Battery Room Ventilation

There was no calculation to demonstrate that on loss of non-1E powered ventilation fans and air conditioning unit, the DC powered backup ventilation fan could maintain the hydrogen concentration in the battery rooms below the required limit of 2% and room's temperature below the summer design temperature of 104°F with the outside air at 91°F. In response to the team's concerns the licensee evaluated the flow split to the 'A' and 'B' battery rooms to demonstrate that the hydrogen concentration in the 'B' battery room (lower ventilation flow) would remain below the 2% limit. The licensee evaluated the battery room temperature to demonstrate that the maximum temperature would be within the design limit of 104°F. The fact that there were no calculations for the battery room temperature and hydrogen concentration before the team's arrival is an example of a weakness in engineering calculations.

3.4 Service Water System

The service water (SW) system takes suction from Lake Ontario and supplies cooling water to the EDG heat exchangers and other plant loads. The system discharges back into Lake Ontario via the discharge canal or via Deer Creek. The system consists of four vertical, two stage, centrifugal pumps rated at 5300 gpm each. The normal flow requirement is provided by two or three pumps, with the remaining pump(s) on standby.

Waterhammering can cause severe damage to the piping and other mechanical equipment in the SW system. There are two cases where waterhammering can occur: 1) SW pumps switching operation, and 2) loss of power to a SW pump. The licensee stated that both cases have occurred at Ginna Station. Service water Pump switching was a planned operation that occurred frequently; whereas, loss of SW pump power was an unplanned transient condition that had occurred a couple of times.

During any planned starting or stopping of the SW pumps, an operator is stationed in the Screen House Building to observe the operation. The operator was able to hear the check valve close and did observe minor pipe movement during the operation; however, no loud banging occurred and no major movement of the SW piping was noticed.

At least two occurrences of loss of power to SW pumps had occurred at Ginna since 1980 based upon a review of LERs.

Based upon the 20 years of operations experience accumulated to date in combination with the valve and support inspections routinely performed at the Ginna Station as part of the Inservice Testing (IST) and Inservice Inspection (ISI) programs, the flow-induced thermal hydraulic transients associated with SW pump discharge check valve slamming had not caused any observable damage to date to the check valves themselves or to the SW piping and its supports.

The licensee provided a summary of the waterhammer problems experienced in the SW piping to the Standby Auxiliary Feedwater (SDAFW) Pump Room Cooler, and included the status of activities performed to date to address the issue. The licensee stated that during the mid 1980's the plant experienced waterhammer in the 4" SW piping to the SDAFW Pump Room Coolers during performance of Plant Procedure PT-2.7. Observations and test data gathered during the performance of PT-2.7 indicated that pressure spikes were occurring in the 4" SW piping during the opening of SW valves 4616, 4735, 4615, 4734 after these valves had been closed for a period of time in excess of a couple of minutes. PT-2.7 required that these valves be closed prior to the performance of periodic testing of portions of the SW System. After completion of SW testing, the valves were stroked open from the control room. It was only during the opening of the valves after they had been closed for a long period of time that pressure spikes of a couple hundred psi were measured by temporary pressure transmitters connected to the vent valves on the 4" SW piping to the SDAFW Pump Room Coolers. Testing of stroking the valves closed followed immediately by stroking the valve open demonstrated that no severe pressure spikes were experienced.

As an immediate response, Plant Procedure PT-2.7 was revised to require that the four SW valves be manually opened to approximately the 50% position; and then stroked with the motor operator the remainder of the travel. This was to be done after the valves had been closed as part of the SW System alignment for performance of PT-2.7. Due to the longer time required to manually stroke these valves, the plant reports that the pressure spike previously experienced during the automatic valve openings had been eliminated.

On a long term basis, EWR-4612 was initiated on December 17, 1976 to evaluate changes to the SW System to alleviate the potential for water hammer due to the opening of the above service water valves.

The team had no further concerns in this area.

3.5 Conclusions

The team concluded that the appropriate technical staff was knowledgeable of the mechanical systems affecting the EDG. Sufficient information was available to review and assess the operability of these mechanical systems.

A number of issues were identified in the mechanical area with regard to the design and calculations. These issues indicated the need for establishing a thorough design review of the EDGs and associated equipment. These issues are considered by the team as examples of a lack of attention to detail in the original design calculations. The identified issues were fully addressed and resolved during the inspection. However, the team had no concerns regarding the operability of this equipment.

4.0 EDS EQUIPMENT

The scope of this inspection element was to assess the effectiveness of the controls established to ensure that the design bases for the electrical system is maintained. This effort was accomplished through the verification of the as-built configuration of electrical equipment as specified in electrical single-line diagrams, modifications packages, and site procedures. In addition, the maintenance and test programs developed for electrical system components were also reviewed to determine the technical adequacy.

4.1 Equipment Walkdowns

The team inspected various areas of the plant to verify the as-built configuration of the installed equipment. Areas inspected included the diesel generator, switchgear, battery, and electrical panel rooms. Transformer, protective relay and pump motor nameplate data were also examined. This information was collected to verify the completeness and accuracy of system calculations.

In summary, walkdown inspections indicated that adequate measures are in place to effectively control system configuration. The inspected equipment was found to be installed in accordance with design drawings. Equipment inspected was found to be well kept with surrounding areas clear of safety hazards.

4.2 Equipment Maintenance and Testing

The team reviewed various operations, maintenance and testing procedures for equipment such as diesel generator, switchgear, circuit breakers, batteries and battery chargers, inverters and protective relays. Licensee personnel were interviewed to ascertain their understanding of the testing programs. The team also reviewed the program established to control instrument setpoints during the calibration and testing process. The team's observations are described below.

4.2.1 Diesel Generator Testing

The team reviewed licensee periodic surveillance tests for the EDG units. The tests are performed in accordance with approved procedures which demonstrate the 1950 to 2250 Kw capability required by the technical specifications. The team reviewed test procedure PT-12.1, "Emergency Diesel Generator 1A" which provides instructions for performing surveillance testing of EDG 1A as required by the Technical Specifications.

The team witnessed a surveillance test performed on May 24, 1991. The team observed that the test procedure does not require the recording of the as-found no-load EDG voltage and frequency. This data is valuable since any abnormal readings could indicate that either the as-left settings were left incorrectly or the control knobs were adjusted subsequent to the previous test. The effect of such abnormal readings would be that the EDG may not be able to carry the design loads during required operation since the unit voltage and frequency are critical parameters for proper operation. In response to the team's concern, the licensee stated that verification and documentation of the as-found no-load voltage and frequency at the startup of the units would be evaluated for incorporation into station procedures.

The team observed that procedure step 6.12 requires that the EDG voltage be raised to approximately 5 volts higher than the running bus voltage prior to synchronizing with the offsite system. During the surveillance test, the EDG no-load voltage was observed to be approximately 10-15 volts higher than the bus voltage. The control room operator, nevertheless, closed the EDG output breaker onto the bus. In response to the team's question as to the acceptability of the operator's action, the licensee evaluated the voltage difference and concluded that a voltage difference of 0 to 25 volts would not exceed the generator or breaker capabilities. Nevertheless, the licensee stated that further operator guidance would be provided as to an acceptable voltage range prior to closing the output breaker.

The team had no further questions.

4.2.2 Molded Case Circuit Breaker Testing

A deficiency (Violation 50-244/89-81-06) pertaining to a lack of scheduled periodic testing of Class 1E 480 V molded case circuit breakers (MCCB) and the lack of established acceptance criteria for testing the 125 Vdc system undervoltage relay alarms was previously identified during a 1989 Safety System Functional Inspection (SSFI).

In response to the NOV, the licensee stated that it was developing appropriate test methods for MCCBs as part of the Reliability Centered Maintenance (RCM) program. Corrective Action Report 1985 was initiated to formally track and address the lack of MCCB testing. A corrective action plan was developed to systematically evaluate the identified violation. This consisted of:

- Evaluation of 10 CFR 21 notifications pertaining to MCCBs;
- Review of data of installed MCCBs to ensure proper setpoints and conditions;
- Investigation of industry methods for periodic testing of MCCBs;
- Development of a program for such testing; and
- Initiation of a program for periodic MCCB testing by the next refueling outage.

The licensee performed a failure mode analysis to determine attributes for the MCCB testing program. Maintenance Work Requests, industry experience and practices, vendor manuals and Ginna station procedures were reviewed in this effort. This resulted in recommended items to address the considered failure modes. These recommendations included performing periodic electrical exercising of overload devices and instantaneous tripping units of the circuit breakers. In addition, it included performing periodic inverse-time characteristic tests.

Presently, program development is ongoing with completion expected by the end of 1991 and implementation expected by 1992. Through discussions with the licensee staff, the team concluded that although the program is still being developed, the expected program attributes address the requirements of periodic testing of MCCBs.

With respect to the lack of established acceptance criteria for the dc undervoltage relay alarms, the licensee has revised test procedure PT-11, "60-Cell Battery Banks 'A' & 'B'" to explicitly define the acceptance criteria for the undervoltage relay alarms. As part of the corrective actions, the licensee revised PT-9.1, "Undervoltage Protection - 480 Volt Safeguard Busses" to incorporate explicit acceptance criteria.

The team concluded that the corrective action plan initiated to address the lack of MCCB testing was comprehensive and addressed the essential elements to develop an effective testing program. Based on the licensee's continuing MCCB test program development and the revision of appropriate test procedures, this violation is closed.

4.2.3 Inverter Testing

The 120 V instrument buses 1A and 1C are provided with uninterruptible power supplies from a separate inverter, regulating transformer (Constant Voltage Transformer - CVT), and static switch combination. These combination units ensure reliable power to Class 1E instruments. Normal power to these units is from Class 1E battery systems. A static switch is provided to transfer to the alternate AC power supply from respective MCCs on a loss of inverter output.

As stated in the UFSAR, the maximum transfer time, including sensing time, is 1/4 cycle. The automatic static-switch transfer is initiated by one of the following conditions:

- Inverter failure
- Overcurrent beyond the static switch
- Inverter output undervoltage
- Manual

The team reviewed maintenance procedure M-38.2, "1-A Inverter/CVT Maintenance or Repair", Revision 14 which provides instructions for preventive and corrective maintenance for the 1A inverter/CVT. Through review of the procedure and discussions with licensee personnel the team concluded that there had been no initial or subsequent testing to verify that in fact the static switch would be able to transfer from the normal to the alternate power source within 1/4 cycle.

The licensee stated that the static transfer switch capability was not a safety function since the failure of the auto transfer would result in de-energizing an instrument bus and therefore protective devices would fail to the safe mode. The licensee stated that the manufacturer's operating manual lacks sufficient instructions for testing the transfer capabilities. An additional manual will be procured and existing procedures will be revised to demonstrate the transfer switch capabilities.

4.2.4 Class 1E Battery Testing

The Ginna Technical Specification (TS) Surveillance Requirement 4.6.2 requires that each 125 Vdc battery be subjected to load (service) and discharge (performance) tests. Additional maintenance requirements are also specified in the TS. The team reviewed surveillance test procedures PT-11 "60 Cell Battery Banks 'A' & 'B'" and PT-10.2 "Station Battery 1B Service Test." Within the scope of this review no discrepancies were identified.

4.2.5 Other Electrical Equipment

The team reviewed test procedures for other Class 1E electrical equipment. This review included battery chargers, circuit breakers and relays. The procedures reviewed were determined to be technically adequate with applicable acceptance criteria.

4.3 Protective Device Setpoint Control and Calibration

The team reviewed the licensee's program for controlling protective device setpoints to assure that equipment will operate at predetermined levels. In addition, instrument calibration procedures and records were also reviewed to determine whether the contents of procedures and test results were acceptable. These are discussed as follows.

4.3.1 Protective Relay Setpoint Control

The licensee provides control of protective device setpoints through the Engineering Work Request (EWR) process and applicable design output documents. Once a design change to protective device setpoints has been determined to be required, an EWR is initiated to assure adequate review and control. Documents generated during the review and approval process include: Design Criteria, Safety Analysis, Design Analysis, and Design Verification.

The team examined the installed equipment to assess the control of protective device setpoints and system configuration. As-found settings for overcurrent relays, circuit breakers and undervoltage relays were compared against controlled documents. The team also verified the installed fuse sizes and types in several control circuits. The installed fuses were the same as that specified in wiring diagrams.

No discrepancies were identified.

4.3.2 Engineered Safety Feature (ESF) Load Sequencing Timers

The team reviewed procedure RSSP-2.7 "Safety Injection Sequence Timers Train A and B". This procedure is used to set the individual ESF load sequencing timer. The procedure describes the initial conditions, precautions, and instructions for the performance of the test. The test results provide verification that the timers have not drifted significantly from the previous as-left values. This assures that the ESF loads will load onto the respective 480 V buses at appropriate time intervals to preclude the EDGs from being overloaded. The as-found times for each individual timer is recorded and evaluated against specified values. These values are derived from Engineering Work Request (EWR) 4960-1 "Time Delay Relay Setpoints ESFAS System", Revision 4. The EWR analyzed the individual timers considering instrument drift and ESF motor acceleration times. Although the times are derived from the EWR, the as-found values are compared against the UFSAR. The procedure requires that any timer which does not fall within the specified required time band be evaluated to ensure full compliance with the values specified in UFSAR Table 8.3-2. The UFSAR table lists the individual ESF load running times, which are the times by which each individual motor is required to have reached full speed.

The team noted that MOVs 871-A/B have individual timers to ensure proper closing upon receipt of a safety injection (SI) signal and are included in procedure RSSP-2.7. However, the MOVs are not listed in the UFSAR Table 8.3-2 and therefore cannot be evaluated against the UFSAR. This was evident from the review of records for a test performed in April 1990. In this instance, the procedure specified time band for the timers were exceeded. However, these values were not evaluated since they are not specifically listed in the UFSAR table. The MOV required times are based on the capability of the swing SI pump 1C to operate. These times, as well as those for other timers listed in the UFSAR table, have been analyzed with the required times summarized in EWR 4960-1. The team asked why the procedure required evaluation of the

as-found timer values against the UFSAR load running times instead of the established timer setpoints in EWR 4960-1 since the EWR already has considered the UFSAR values in the analysis. Use of the setpoints from the EWR would ensure that all loads, including the subject MOVs, are properly evaluated. The licensee agreed that the EWR criteria will be incorporated into the RSSP-2.7 procedure. The out-of-band MOV timer values were subsequently evaluated and were determined to be adequate such that the swing SI pump 1C would still have been able to operate during an accident since there was sufficient margin in the setpoint value.

The team had no further questions.

4.3.3 Undervoltage and Degraded Voltage Relays

Ginna Station Technical Specifications (TS) Section 2.3 specifies the Limiting Safety System Settings for Protective Instrumentation. Section 2.3.3.1 specifies that 480 V undervoltage relays will be tested to ensure that they operate in accordance with their design characteristics. Figure 2.3-1 identifies the loss of voltage and undervoltage relay operating ranges. In accordance with TS Table 4.1-1, each channel is required to be tested on a monthly basis and calibrated every refueling outage.

Ginna Station procedure PT-9.1 "Undervoltage Protection - 480 Volt Safeguard Busses" provides instructions for testing the operability of the loss of voltage and degraded voltage relays associated with 480 V Safeguard buses 14, 16, 17, and 18. This procedure implements the TS monthly surveillance test requirements. Procedure PR-1.1 "Protective Relay Calibration 480 V Undervoltage and Ground Alarm Scheme For Buses 14, 16, 17 and 18" provides instructions for the calibration of protective relays. It implements the refueling outage TS Surveillance requirement.

Review of procedure PR-1.1 calibration results performed during the 1991 refueling outage (March 1991) indicated that three (3) as-found relay values were below the TS limits specified in TS Figure 2.3-1. Specifically, the as-found relay dropout voltage settings were less than the TS limit of 103.5 V (equivalent to 414 V at the 480 V buses). These are denoted below.

Relay	As-Found Dropout [V]	Voltage at 480 V Bus
27B/14	103.39	413.6
27/16	103.07	412.3
27B/18	103.38	413.5

Although the above as-found values were below the TS limits, the results review performed by the licensee did not identify this condition. Therefore, no evaluation was performed to determine whether safety-related motors would still have been able to operate at reduced voltages prior to the relays dropping out. In response to the team's concern, the licensee performed an evaluation and determined that no adverse effect on the safety related motors would result due to the small voltage deviation. In addition, the licensee initiated a

Ginna Station Event Report to document and evaluate the above condition for reportability.

Procedure PR-1.1 "Protective Relay Calibration 480 V Undervoltage and Ground Alarm Scheme for Buses 14, 16, 17 and 18", section 5.3 requires an I&C/Electrical Equipment Failure Safety Related Report be prepared to evaluate those relays that exceed the calibrated tolerance.

Failure to prepare the I&C/Electrical Equipment Failure Safety Related Report for the protective relays described above constitutes a violation of Ginna Technical Specifications, Section 6.8.1, which requires that written procedures be established and implemented for surveillance and test activities of safety related equipment (50-244/91-80-04).

4.4 Conclusion

The licensee has implemented controls to maintain electrical system configuration. Equipment inspected was observed to be well-maintained and an effective fuse control program was evident. The development of the molded case circuit breaker test program is ongoing. The testing attributes being addressed are comprehensive and thorough. A deficiency was identified in handling the as-found data of the protective relay testing. The droupout voltage settings of three protective relays drifted below the Technical Specification limits during the 1991 refueling outage yet no evaluation was performed as required by station procedures.

5.0 Engineering and Technical Support

The team assessed the capability and performance of the licensee's organization to provide engineering and technical support by examining the interfaces between the technical disciplines internal to the engineering organization and the interfaces between the engineering organization and the technical support groups responsible for plant operations.

The team also reviewed a sampling of the licensee's Potential Conditions Adverse to Quality (PCAQ) reports, Nonconformance Reports (NCRs), Licensee Event Reports (LERs), major, minor and temporary modification programs, training, quality assurance (QA) audits, root-cause investigation and corrective action programs, and self assessment programs.

5.1 Organization and Key Staff

The Engineering and Technical support for the Ginna Station is provided by the Corporate Nuclear Engineering Services staff at Rochester, New York, the Site Technical Engineering group and Site Modification Support group.

The Corporate Nuclear Engineering Services group is headed by the Manager, Nuclear Engineering Services. The Corporate Engineering support for the electrical distribution system is provided by the Electrical Engineering group within Nuclear Engineering Services Division. The Site Technical Engineering

group and Modification Support group are responsible for providing site engineering support to plant operations, maintenance and design support.

The corporate engineering staff performs all major engineering design, and the Ginna Station performs all minor modifications. Engineering consultants are used only to supplement the in-house capabilities, on an as needed basis. The team noted that the Nuclear Engineering Services Department Staff has been increased from 68 to 104 from 1989 to present to improve the engineering support for the station. Throughout the inspection, the corporate and site engineering staff provided timely and thorough responses to the team members. The team concluded that the engineering positions are adequately staffed with knowledgeable personnel.

5.2 Root Cause Analysis and Corrective Action Programs

The team reviewed several Licensee Event Reports, Potential Conditions Adverse to Quality (PCAQ) documents, Non-Conformance Reports (NCRs), Corrective Action Reports (CAR) and QA Audits to assess the effectiveness of the licensee's root cause analysis and corrective action program.

The NCRs reviewed by the team indicated that corrective actions were appropriate to address the problems identified in the NCRs and in accordance with procedure QE-1501. Engineering dispositions and applicable 10 CFR 50.59 and Part 21 reviews were found to be thorough.

Several PCAQ reports in accordance with Procedure QE-1603 were reviewed to determine whether safety concerns were properly identified, reported and corrected. The team noted that in all cases, the licensee promptly identified potential safety concerns, made accurate operability and preliminary safety assessments, reportability evaluations, and necessary corrective actions were initiated. Quality Assurance audits reviewed were found to be adequate and addressed various elements of engineering organization design control and surveillance programs. Corrective actions and response to the audit findings were prompt and proper engineering management attention was noted as evidenced by the minimal outstanding open audit findings.

The team also reviewed selected LERs to assess the adequacy of engineering organization involvement in NRC reporting requirements (in accordance with 10 CFR, Parts 20, 21, 50.72, 50.73 and 50.36) and to determine the adequacy of root cause analysis and corrective actions. Corrective actions were generally broad in scope to address the root and contributing causes. The root cause investigation process was thorough and self critical to identify weaknesses. This was evidenced during the review of LER 87-008, inoperable circuit breakers for "1B" RHR and "1B" safety injection pump and LER 90-005, low safeguards bus voltage during start of "A" RCP. The team noted that a corrective action group working for the manager tracks and initiates corrective action reports for LERs and any potential safety concerns identified by the station. The sample review of open CARs indicated that CARs were closed out in a timely manner.

The team determined that the licensee has a good program to identify and investigate discrepancies and root causes and to complete corrective actions in a timely manner.

5.3 Self Assessment Programs

The team reviewed the licensee's self assessment programs to assure that safety issues are properly identified and corrected. The team noted that the licensee had performed an electrical distribution system functional inspection to make an independent assessment of the EDS. The independent assessment covered electrical and mechanical design review, operations, testing and modifications. The assessment was comprehensive and several technical issues were identified in the report. The corrective actions to resolve these issues were being pursued at the time of inspection.

Another self assessment program reviewed was the licensee's Potential Conditions Adverse to Quality (PCAQ) Program which identifies and resolves safety significant issues with appropriate engineering and station personnel review. Several potential safety concerns were identified by the licensee during this year. The review of sample PCAQ indicated that potential safety concerns were reviewed in a timely manner to determine operability and safety concerns and were found to be thorough.

The quality assurance area was also reviewed by the team to evaluate the involvement of QA personnel in assessing the quality of engineering services. The team concluded that QA audits and QA involvement in monitoring engineering effectiveness were adequate.

The team noted that the licensee had performed internal and independent assessments to assess the capability and quality of output generated by their Nuclear Engineering Services Division. These comprehensive self assessments were performed to address design control and engineering assurance weaknesses identified during previous NRC SSFI Inspection (No. 89-81). The team noted that in order to improve the Ginna Station's performance, licensee management has committed to implement configuration management engineering projects such as P&ID Upgrade, Electrical Controlled Configuration Drawing (ECCD) upgrade, Q list, Design Basis Documents, Programs and Commitment Tracking Systems. Some of the projects such as P&ID upgrade, Q list document and ECCD upgrade were completed and the remaining configuration management projects are scheduled to be completed by 1994.

The team concluded that the licensee's self assessment program efforts were thorough and aggressive and considered to be a strength for achieving the licensee's nuclear mission goals for attaining outstanding performance in all aspects of operation and safety of the Ginna Station.

5.4 Equipment Modifications

The team reviewed the program for plant design changes and modifications to ascertain that they were performed in conformance with the requirements of the Technical Specifications, 10 CFR, FSAR, and applicable procedures.

The RG&E modification process is categorized into major-mods and minor-mods. Major modifications are performed through the licensee's Engineering Work Request (EWR) process and are performed by the Corporate Engineering group. The major modifications are either mostly safety related changes or non-safety related plant changes that are complex in nature. Minor modifications are performed by Ginna Station Technical Engineering group and are either generally non-safety related changes to the plant or safety related changes which are minor in nature. All minor modification requests (TSR process) are reviewed by the RG&E corporate office to determine whether modifications are classified approproately in accordance with procedures QE 322 and A 301.1 and also to provide corporate engineering oversight in the Modification Process.

The major and minor mods reviewed are identified in Attachment 2 and include a variety of permanent plant changes to the electrical distribution and support systems.

The team noted that engineering procedures for modification process were prescribed in several individual, "QE" procedures. No single procedure exists describing the whole modification process. The modification packages reviewed (1984-1990) indicated that design criteria, design verification, design input and safety evaluation thoroughness and technical review could be improved. For example, (1) EWR 3891-Design criteria for DC battery replacement did not consider guidance for cell sizing, design margin, charger capacity; the safety analysis did not consider hydrogen evolution; the increase in short circuit current contribution did not coordinate and design a verification appeared to be more administrative in nature rather than a technical verification. (2) EWR 2929-Safety analysis and design verification did not appear to identify the potential for degrading the coordination of system protection when back up protection is applied to electrical penetrations.

However, recent analyses reviewed by the team indicated that these aspects have since been identified and addressed. The team observed that the documentation of completed modification packages were not kept in one specific location and were difficult to retrieve. Numerous weaknesses were identified with respect to design documentation and calculations during the previous NRC SSFI (inspection Report No. 89-81). The team noted that in order to address all the design control plant modifications process deficiencies, the licensee had performed a comprehensive internal and independent assessment of the above area.

Increased management involvement to improve the existing design control process and quality of engineering work was observed by the the team during this inspection. As a result, Nuclear Engineering Services modification design process standard and flow chart describing the integrated design modification process were developed and in the final stages of approval. Several "QE" procedures were revised to provide a better understanding of the existing design process and appropriate procedure training were completed. A sampling of work orders for the EDS completed in 1990-1991 was reviewed to assure that maintenance activities did not result in design changes. No unintended design changes were identified.

During this inspection, the team observed that several calculations were developed by the licensee in a very short time duration. The team determined that technical review and thoroughness of some of the calculations could have been improved.

The team interviewed several members of the engineering staff (both corporate and site) to determine their understanding of the design control and modification process. The engineering staff were found to be knowledgeable and have a good understanding of the modification process. The team noted that a design basis reconstitution program and configuration management controls are being implemented to enhance the documentation so that it more accurately reflects as-built conditions and to better assure that the Ginna plant is operated and modified within its design basis.

The team observed a positive improvement in the design modification process, engineering procedures and EDS calculations. However, the team concluded that the effectiveness of licensee's design control and modification process cannot be determined at the present time since most of the proposed corrective actions for the identified weaknesses are yet to be completed.

5.5 Temporary Modification Program

Temporary modifications for electrical systems (Bypass of Safety Function and Jumper Control) are administered and controlled by procedures A-1402, 1405 and 1406. These procedures identify the controls for use of bypass features on safety related and non-safety related equipment. The team's evaluation of selected temporary modifications revealed that they contained appropriate review and approval by the Technical manager and the Shift Supervisor and appropriate safety evaluations/reviews were performed to meet the intent of the 10 CFR 50.59 requirements. However, the team noted that the procedures do not require a detailed formal 50.59 review or safety evaluations. The licensee state that temporary modification procedures are being updated to address all program weaknesses as part of the procedure update program. The team noticed that four of the non-safety related modifications were found to be approximately six years old. The licensee stated that these temporary modifications are being replaced by permanent plant modifications through their EWR/TSR modification process and are scheduled to be worked in accordance with the priority assigned to the modifications. The licensee also stated that the Ginna Station's goal is to closeout the temporary modifications before the end of one year.

The team reviewed the log kept in the control room for tracking temporary mods and interviewed control room supervisors. The review indicated that open temporary mods are reviewed periodically and tracked. The team determined that the licensee has an adequate program for controlling temporary modifications and bypasses in the plant.

5.6 Engineering Support/Interface

The team reviewed the involvement and effectiveness of the engineering staff to support design functions, operations, maintenance and other organizations at the site. The team noted that the licensee has an integrated prioritization system for controlling and assessing engineering work activities. The interface between station and engineering personnel at Ginna was found to be effective as evidenced by the presence of technical engineering, modification support staff and corporate staff, at the site, to support the engineering/technical needs of the plant. A close working relationship between the engineering and operations personnel was noted during this inspection. Several corporate, plant engineering, maintenance and operations staff were interviewed during the course of the inspection to understand the communication channel/interface established for Ginna Station. The licensee has established morning and afternoon meetings to discuss plant activities pertaining to design, operation and maintenance action items. The active participation of management representatives from different organizations for these meetings exhibits the effective interface between engineering and plant organizations.

Furthermore, the team observed that the licensee was able to provide required design documents and calculations within a short time indicating a good coordination between different organizations and the Ginna Station. The team found the engineering staff to be very knowledgeable of the EDS. The team that interacted with the NRC inspection team indicated a good familiarity with their area of responsibility. A good interface between support organizations was noted during this inspection.

5.7 Technical Staff Training

The team reviewed the licensee's technical training program to evaluate the adequacy of training given to the corporate and site engineering staff.

The training program is conducted in accordance with licensee's procedure No. QE 102, "Indoctrination and Training." This procedure provides instructions for the control and documentation of indoctrination and training for Nuclear Engineering personnel for their specifically assigned functions. The training program consists of initial and continuing training. The initial training program depends on the qualification and experience of the individual. The initial training program extends up to 2 years. The continuing training program is an ongoing program and it covers at least 4 - 8 hours of classroom training per quarter. The Ginna training center provides adequate training in several courses such as System Engineering, 50.59/safety evaluations, LER process, modifications process, industry events and simulator training. Furthermore, the technical staff is required to attend administrative and engineering procedures training in addition to the normal required reading assignments. The team noticed that training documents are properly maintained and tracked in the computer data base and updated periodically to maintain an effective training program. The team also noted that the licensee engineers

actively participate in industry groups and programs, and are aware of technical issues. The team concluded that the licensee has an adequate training program for the technical staff for performing engineering and design functions and for providing adequate technical support for the plant's operational activities.

5.8 Conclusion

The corporate and site technical engineering and modification support personnel are adequately staffed with competent personnel and are very familiar with the EDS and its support systems. Effective interfaces exist between station and engineering personnel. Communications between the various engineering and technical support organizations were found to be generally good. Engineering support to operating and maintenance activities are generally good with an effective interface evidence in many areas of projects. The team determined that the licensee has an aggressive self assessment program. This program is considered to be a strength.

The licensee has a good program to investigate deficiencies, identify root causes and to complete appropriate corrective actions in a timely manner.

Technical training and Quality Assurance Programs were found to be adequate.

The team observed several isolated examples which indicate that the thoroughness of technical reviews and attention to detail could be improved in the design calculation/modification process. Increased management involvement to improve the existing design control process and the quality of engineering work was evidenced by the completion of P&ID update program, Electrical Configuration Controlled Drawing Program, EWR Procedure upgrades, ongoing Design Basis Reconstitution Program and Configuration Management Control Program. Improvement in the licensee's design control and modification process was noted during this inspection.

6.0 Unresolved Items, Weaknesses and Observations

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items or violations. Unresolved items identified during this inspection are discussed in detail, Paragraphs 2.42, 2.5 and 2.8. Weaknesses and observations are conditions that do not constitute regulatory requirements and are presented to the licensee for their evaluations.

7.0 Exit Meeting

The inspector met with licensee corporate personnel and licensee representatives (denoted in Attachment 1) at the conclusion of the inspection on June 7, 1991. The inspector summarized the scope of the inspection and the inspection findings at that time.

Attachment 1

Persons Contacted

1.0 Rochester Gas and Electric Corporation (RG&E)

S. Adams, Technical Manager
C. Anderson, Manager, Quality Assurance
B. Carrick, Mechanical Engineer
R. Carter, Mechanical Engineer
G. Daniels, Electrical Engineer
B. Flynn, Engineer, Nuclear Safety and Licensing
C. Forkell, Manager, Electrical Engineering
B. Hunn, Electrical Engineer
M. Kennedy, CM Program Directory
M. Lilley, Manager, Nuclear Assurance
D. Markowski, Mechanical Engineer
R. Mecredy, Vice President, (Ginna) Nuclear Production
J. Metzger, Senior Mechanical Engineer
T. Miller, Electrical Engineer
*R. Morrill, Operation Experience Coordinator
T. Newberry, Mechanical Engineer
J. Pacher, Electrical Engineer
L. Rochino, Lead Mechanical Engineer
W. Roeltger, Electrical Engineer
J. Sargent, Electrical Engineer
E. Smith, Mechanical Engineer
L. Sucheski, Supervisor, Structural Engineering
P. Swift, Electrical Engineer
C. Vitali, Mechanical Engineer
*G. Voci, Manager, Mechanical Engineer
*T. Weigner, Technical Assistant to Dept. Manager
P. Wilkens, Dept. Manager, NES
J. Widay, Superintendent, Ginna Production
G. Wrobel, Manager, Nuclear Safety Licensing

2.0 Niagara Mohawk Power Corporation

F. Constance, Electrical Engineer
D. Goodney, Lead Electrical Engineer
*A. Julka, Supervisor, Nine Mile 2 Electrical
A. Pinter, Licensing Engineer
*T. McMahon, Supervisor, Nine Mile 1 Electrical

3.0 United States Nuclear Regulatory Commission

C. Anderson, Chief, Electrical Section, DRS
M. Hodges, Director, Division of Reactor Safety
A. Johnson, Project Manager NRR
R. Wessman, Project Director PDI-3, NRR
N. Perry, Ginna Resident Inspector

*denotes those not present at the exit meeting on June 7, 1991.

ATTACHMENT 2 - GINNA ELECTRICAL DISTRIBUTION SYSTEM