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Report No.: 50-261/87-06

Licensee: Carolina Power and Light Company
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Docket No.: 50-261 License No.: DPR-23

Facility Name: H. B. Robinson

Inspection Conducted: March 9 - April 15, 1987

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SUMMARY

Scope: This special, announced Safety System Functional Inspection (SSFI) was performed to provide an in-depth assessment of the operational readiness of the emergency power systems including the emergency diesel generators. The adequacy of on-site electrical power sources to support safe plant shutdown was

also evaluated. The licensee's operational readiness and management controls were evaluated in five functional areas, primarily as they related to the emergency power systems. The functional areas reviewed were:

- Operations
- Surveillance
- Maintenance
- Quality Assurance
- Design Changes and Modifications

Inspection Objective: The objective of the team inspection at H. B. Robinson was to assess the operational readiness of the emergency power systems. This assessment will include a determination of the following:

- capability of the systems to perform the safety functions required by its design basis;

- adequacy of testing to determine that the systems would perform all of their safety functions required;

- adequacy of systems maintenance (with emphasis on the Emergency Diesel Generator) to ensure system operability under postulated accident conditions;

- adequacy of operator and maintenance technicians' training to ensure proper operations and maintenance of the system;

- adequacy of human factors considerations relative to the emergency power systems (e.g., accessibility, labeling of valves, layout of controls) and the systems supporting procedures to ensure proper system operation under normal and accident conditions;

- adequacy of management controls including procedures to ensure that emergency electrical systems will fulfill their safety functions required by their design bases.

Summary of Significant Inspection Findings

Inadequate Implementation of Appendix R Dedicated Shutdown

The licensee committed to implement dedicated shutdown and manual operator actions in lieu of the originally proposed plant modifications to comply with 10 CFR 50 Appendix R. The deadline for compliance with Appendix R for this facility was February 1986, and the licensee indicated to the Commission that they were in compliance by July 1985. Walkthroughs of the dedicated shutdown procedures with licensed individuals and review of associated procedures and training, indicated significant deficiencies. The procedures contained technical errors and human factors deficiencies, and had not been the subject of adequate validation, verification, and

safety evaluation. The initial operator and maintenance training was less than adequate, and no retraining had been conducted. In addition, the communications system utilized to support dedicated shutdown was inadequate and the emergency DC lighting was deficient in certain plant areas. Given the inadequate procedures, training, communications, and emergency lighting, there is serious doubt that the licensee could have reasonably assured the ability to perform a safe plant shutdown under the fire and station blackout conditions as required by Appendix R. Additional details on this area are contained in paragraph 3.a.(1) of this Inspection Report.

Emergency Diesel Generator Failures

The "B" emergency diesel generator (EDG) scavenging air blower failed during a surveillance test on March 10, 1987. The "B" EDG also tripped on high crankcase pressure on March 13 and again on March 23, 1987. These failures, particularly the blower failure on March 10, may have been prevented by evaluation and corrective actions in response to vendor recommendations and indicators of possible potential failure. The indicators of potential problems and failure included the failure of similar blowers at other facilities, signs of rubbing in the "B" EDG blower, a two-hour unloaded EDG "B" run, and a failed "B" EDG scavenging air blower temperature test. Although these indicators occurred over a three-year period, the licensee initiated minimal corrective actions until the failures of the "B" EDG in March 1987. The licensee also failed to comply with approved procedures requiring blower clearance checks and restricting the maximum water content of EDG lube oil. EDG operation with a degraded and leaking lube oil cooler resulted in the EDG high crankcase pressure trips and may have caused damage to the piston and cylinder liners. This could have resulted in EDG failure during design basis emergency operation. Additional details on this area are contained in paragraphs 3.c.(1) and 3.c.(2) of this Inspection Report.

Inadequate Electrical Switchgear Coordination

The licensee did not, under Electrical Distribution System Modification 860, ensure that the 480 volt switchgear and motor control centers serving engineered safety feature circuits were properly sized and coordinated to permit safe operation under short circuit conditions. This failure is contrary to the licensee's commitments in Section 8.3.1.1.4 of the FSAR. The licensee also failed to implement controls to assure overload capacity calculations, testing, and the installation of equipment associated with the DC electrical system including batteries, inverters, and breakers were adequate. Additional details in this area are contained in paragraph 3.e of the Inspection Report.

Other major areas of concern identified during this inspection include the following:

Operations; Paragraph 3.a

- Inadequate Emergency Diesel Generator Load Indication

  Indication of emergency diesel generator (EDG) kilowatt load was not provided in the control room. This lack of indication could result in an operator manually adding excess loads and overloading the EDG during emergency operations; paragraph 3.a.(3)(a).

- Emergency Diesel Generator Trip Potential

  There is a potential that an EDG being operated in parallel with the system would trip on an automatic start signal (loss of offsite power) due to a transfer of station loads and the resultant EDG overload. The surveillance procedure did not address this potential or the actions needed to reset the EDG breaker and the overspeed trip; paragraph 3.a.(3)(b).

- Emergency Diesel Generator Human Factors Deficiencies

  Human factors concerns were identified in relationship to local operations of the EDGs. These concerns included inadequate DC emergency lighting, communications, and control panel labeling; paragraph 3.a.(6).

Surveillances; Paragraph 3.b

- Inadequate Battery Load Testing

  The safety-related "A" and "B" batteries failed the first five-year load test in 1984. In response to this failure, the licensee installed a third non-safety grade battery and transferred non-safety-related loads to this new battery. The inspectors reviewed the presently approved station battery test surveillance procedure and noted that it did not address all DC loads that could be added to the "A" battery, did not apply a temperature correction factor to the test current, did not address minimum acceptable DC equipment voltage, and did not require trending or extrapolation of test results to ensure that the battery could supply sufficient capacity through the next five-year interval; paragraph 3.b.(1).

- Emergency Diesel Generator Vendor Recommendations Not Incorporated

  The licensee did not implement vendor recommendations requiring the checking of EDG scavenging air blower clearances or the alternative actions of limiting unloaded operation to less than five minutes or ensuring that the blower temperature differential temperature did not exceed 100°F. These recommendations were based on the overheating and

failure of similar EDG blowers at two other facilities in 1985 and 1986. A vendor recommendation to step unload the EDGs following loaded testing to dissipate heat was also not incorporated; paragraph 3.b.(2)(a).

- Emergency Diesel Generator Governor Problems

  The inspectors observed surveillance testing of the "A" EDG in which the generator appeared to lose KW load requiring the operator to make manual adjustments to restore load. The licensee attributed this load reduction to EDG operation in parallel with the system, but indicated that the governors would be checked during the outage; paragraph 3.b.(2)(b).

- Emergency Diesel Generator Fuel Oil Testing

  The licensee does not perform quality testing on fuel oil prior to or after delivery to the Unit 1 light-off tanks. Fuel oil is transferred from these tanks to the 6000-gallon IC turbine tank and eventually to the EDG fuel oil tank. Although the fuel oil is tested prior to transfer from the IC turbine tank to the EDG fuel oil tank, the oil in the IC turbine tank is not quality tested. Since the licensee frequently takes credit for the 6000 gallons of oil in this tank toward the 25,000 gallons required for 7-day operation, this storage is an extension of the EDG fuel oil system and should be subject to the same degree of quality control; paragraph 3.b.(2)(c).

- Demonstration of Emergency Diesel Generator Operability

  Technical Specifications require that if one EDG is inoperable, the remaining EDGs will be demonstrated to be operable on a daily basis. The licensee's surveillance procedure requires a weekly surveillance operation of 60 minutes, which is also the test period required by Standard Technical Specifications to demonstrate operability under the limiting condition for operations (LCO). Instead of utilizing this surveillance procedure to demonstrate operability under the LCO, the licensee utilizes an operations work procedure requiring only a 30-minute loaded operation; paragraph 3.b.(2)(d).

Maintenance; Paragraph 3.c.

- Not All Emergency Diesel Generator Instrumentation Included in Calibration Program

  EDG instrumentation such as expansion tank level switches, standby lube oil temperature controllers, and diesel jacket water thermostatic controllers were not included in the licensee's calibration program; paragraph 3.c.(4).

- Potential Emergency Diesel Generator Room Ventilation Failure

- The EDG room ventilation dampers could fail closed on a loss of the non-safety-related instrument air system. Under these conditions, the EDG rooms could exceed the 104° maximum temperature the equipment is environmentally qualified for, resulting in a potential loss of all emergency onsite power; paragraph 3.c.(5).

- Potential Auxiliary Building Ventilation Failure

  On a loss of instrument air and closure of the EDG ventilation dampers, the auxiliary building ventilation system could also be lost. Without the auxiliary building ventilation system, a negative building pressure may not be maintained creating the potential for an untreated radiological release; paragraph 3.c.(6).

Quality Assurance; Paragraph 3.d

- Inadequate QA Nonconformance Report (NCR) Implementation

  In lieu of the QA nonconformance reporting system, the licensee frequently utilizes the deficiency tagging and maintenance work request system to disposition significant deficiencies associated with safety-related equipment and activities. Unlike the NCR system, the maintenance work request does not ensure an adequate level of management evaluation, root cause identification, corrective actions, and reporting. Examples were identified associated with deficiencies and failures involving EDGs, transformers, and batteries; paragraph 3.d.

Design Changes and Modifications; Paragraph 3.e

- Controls and Retrievability Over Design Calculations

  The licensee has not established comprehensive controls over original calculations which form the design and operating basis for the plant. The lack of retrievability of design basis calculations could impede the correct translation into plant specifications, drawings, procedures, and instructions; paragraph 3.e.(1)(a).

- Validation of Electrical System Design

  The licensee's design control activities did not ensure that adequate design analyses were performed to validate the electrical system design. Examples included the lack of voltage regulation studies for the spare startup transformer which has a lower impedance than the installed startup transformer; voltage regulation studies on backfeed through the main unit transformers through the unit auxiliary transformer; and short circuit calculations for safety-related motor control centers, paragraph 3.e.(2)(a).

- Inadequate Formal Design Analysis

  The licensee did not have formal design analyses in place to validate that the design of the electrical system is capable of performing its intended function and to document design bases and design conditions for the plant; paragraph 3.e.(2)(b).

- Inadequate Breaker Fault Current Interrupt Capability

  The inspectors identified the potential that the Westinghouse DB-50 breakers and the Westinghouse Molded Case Circuit Breakers may have inadequate fault current interrupt capability. The licensee's calculations associated with the currents to which these breakers could be subjected did not consider the worst case conditions. Since these breakers were not certified or tested to interrupt the current levels that could be seen, the potential exists for catastrophic breaker failure and damage to adjacent breakers and buses; paragraphs 3.e.(3)(b)1 and 2

Four violations, one unresolved item, and twenty-one inspector followup items were identified as follows:

Violation 50-261/87-06-01 - Failure to adequately implement the requirements of 10 CFR Part 50 Appendix R III.G and III.L., Dedicated Shutdown; paragraph 3.a.(1)(g).

Violation 50-261/87-06-08 - Failure to have adequate procedures to test the battery; paragraph 3.b.(1)(a).

Violation 50-261/87-06-11 - Failure to provide adequate procedures to control EDG fuel oil in the IC tank; paragraph 3.b.(2)(c).

Violation 50-261/87-06-13 - Failure to adequately implement the requirements of 10 CFR Appendix B in activities affecting the quality of safety-related equipment; paragraphs 3.c. and 3.d.

Unresolved Item 50-261/87-06-20 - DB-50 circuit breakers not properly coordinated electrically and the acceptability of using a PRA in lieu of equipment changeout. paragraph 3.e.(3)(b)1.

Inspector Followup Item 50-261/87-06-02 - Revision of breaker verification checklist to address power operation breaker alignments; paragraph 3.a.(2).

Inspector Followup Item 50-261/87-06-03 - Emergency diesel generator loading indication in the control room; paragraph 3.a.(3)(a).

Inspector Followup Item 50-261/87-06-04 - Resolution of concerns and recommendations associated with IE Notice 84-69, Operation of Emergency Diesel Generators; paragraph 3.a.(3)(b).

Inspector Followup Item 50-261/87-06-05 - Resolution of concerns associated with electrical trip/reset buttons on 480 volt emergency bus breakers; paragraph 3.a.(6)(b).

Inspector Followup Item 50-261/87-06-06 - Adequacy of DC emergency lighting in emergency diesel generator rooms; paragraph 3.a.(6)(c).

Inspector Followup Item 50-261/87-06-07 - Adequacy of communications in the emergency diesel generator rooms; paragraph 3.a.(6)(c).

Inspector Followup Item 50-261/87-06-09 - Implementation of emergency diesel generator vendor recommendations; paragraph 3.b.(2)(a).

Inspector Followup Item 50-261/87-06-10 - Emergency diesel generator load drift; paragraph 3.b.(2)(b).

Inspector Followup Item 50-261/87-06-12 - Sixty-minute versus thirty-minute emergency diesel generator operability testing; paragraph 3.b.(2)(d).

Inspector Followup Item 50-261/87-06-14 - Setpoint differences on EDG instrumentation; paragraph 3.c.(3).

Inspector Followup Item 50-261/87-06-15 - Calibration of EDG instrumentation; paragraph 3.c.(4).

Inspector Followup Item 50-261/87-06-16 - Potential failure of EDG room ventilation system; paragraph 3.c.(5).

Inspector Followup Item 50-261/87-06-17 - Potential loss of auxiliary building ventilation system and radiological release; paragraph 3.c.(6).

Inspector Followup Item 50-261/87-06-18 - Control of calculations and technical staff awareness that the FSAR is not a design basis document; paragraphs 3.e.(1)(a) and 3.e.(1)(b).

Inspector Followup Item 50-261/87-06-19 - Evaluation of additional licensee emergency switchgear short circuit current studies; paragraph 3.e.(2)(b).

Inspector Followup Item 50-261/87-06-21 - Review of licensee's evaluation of molded case circuit breaker interrupting capability; paragraph 3.e.(3)(b)2.

Inspector Followup Item 50-261/87-06-22 - Performance of analysis of required EDG fuel oil storage capacity; paragraph 3.e.(4)(c).

Inspector Followup Item 50-261/87-06-23 - Review concerns in the EDG starting air system and the "as-built" plant configuration; paragraph 3.e.(4)(d).

Inspector Followup Item 50-261/87-06-24 - Review of licensee's seismic analysis to modification on EDG air start line; paragraph 3.e.(4)(e).

Inspector Followup Item 50-261/87-06-25 - Review of battery concerns; paragraph 3.e.(5)(b).

Inspector Followup Item 50-261/87-06-26 - Review of licensee evaluation of DC breakers short circuit calculations; paragraph 3.e.(5)(c).

TABLE OF CONTENTS
FOR
REPORT DETAILS

REPORT DETAILS

1. Persons Contacted

   Refer to Appendix A.

2. Exit Interview

   The inspection, scope and findings were summarized on March 27, 1987, and on April 15, 1987, with those persons indicated in Appendix A. The inspectors described the areas inspected and discussed in detail the inspection findings. No dissenting comments were received from the licensee. No proprietary material is contained in this report.

   On April 15, 1987, the licensee also briefed the NRC staff on their initial followup efforts to the preliminary findings of the team. The material presented during this briefing is included as Appendix B to this report.

3. Detailed Inspection Findings

   a. Operations

      The inspectors reviewed Operations activities and procedures related to the electrical system, and the licensee's ability to effectively mitigate the results of major electrical transients such as an emergency diesel generator trip, a loss of all offsite power, or a total station blackout. The inspection consisted of a review of related procedures, drawings, logic diagrams, training, human factors, and response to events and licensee event reports (LERs). In addition, the inspectors walked a group of licensed operators and senior operators through selected dedicated shutdown procedures, which are designed to bring the plant to hot standby and cold shutdown under fire and loss of all AC power conditions.

      (1) Dedicated Shutdown (Appendix R) Capability

         Title 10 CFR Part 50, Appendix R, Item III.G.2, requires that facilities provide fire protection and separation of cables and equipment important to the safe shutdown of the plant. In the licensee's March 16, 1982 submittal, they proposed to meet these requirements through significant plant modifications designed to provide additional remote shutdown capability. In a supplemental submittal dated February 6, 1984, the licensee proposed replacing most of the plant modifications with manual operator actions and post-fire repair procedures. This change to utilize dedicated or alternate shutdown capability in lieu of item III.G.2 is allowed by items III.G.3 and III.L. of Appendix R.

In addition to the plant life-cycle cost savings of not installing the proposed modifications, the licensee cited several other reasons for the revised approach, including: minimizing extensive electrical modifications to the plant; reducing modifications to plant cable trays and penetrations; reducing the negative impact on plant security created by remote control panels; and reducing personnel exposure to radiation during modification installation.

Due to the increased reliance on complex manual operator actions and equipment repairs to achieve safe shutdown, the licensee made commitments to upgrade related capabilities. These commitments included improvements to communications, emergency DC lighting, and provision to access keys for entry into security and radiation areas. The licensee also committed to develop and implement the necessary procedures and training to ensure that the plant could be shut down in accordance with Appendix R, Item III.L. This requirement includes achieving hot standby conditions, followed by cold shutdown conditions within 72 hours. The Dedicated Shutdown Procedures (DSPs) developed by the licensee included operating procedures to achieve the required hot standby conditions, and the operating and post-fire repair procedures necessary to achieve the cold shutdown conditions. These procedures were developed by a contractor and included the following:

- DSP-001, Hot Shutdown Using The Dedicated/Alternate Shutdown System
- DSP-002, Hot Shutdown From The Control Room With A Fire In The Charging Pump Room
- DSP-003, Hot Shutdown From The Control Room With A Fire In The Component Cooling Water Room
- DSP-004, Hot Shutdown From The Control Room With A Fire In The North Cable Vault
- DSP-005, Hot Shutdown From The Control Room With A Fire In The South Cable Vault
- DSP-006, Cold Shutdown Using The Dedicated/Alternate Shutdown System
- DSP-007, RHR Pump Power Repair Procedure
- DSP-008, RHR System Flow Indication Repair
- DSP-009, Steam Generator PORVs Control Repair
- DSP-010, RHR System Temperature Indication Repair
- DSP-011, Pressurizer PORV Control Power Repair
- DSP-012, RHR Flow Control Valves Repair

The repair procedures, DSP-007 through DSP-012, are required to support DSP-006 in achieving cold shutdown within 72 hours. These procedures restore necessary power for control and indication which are lost through fire damage or through intentional operator actions required in DSP-001.

A Safety Evaluation Report (SER) was issued by the NRC to the licensee on August 8, 1984, addressing the acceptability of the alternate safe shutdown capability. In a letter accompanying this SER, the NRC made the following request:

> "Because of the multiple and complex manual actions that may be required as a result of your revised alternate shutdown approach, we request that written procedures for accomplishing cold shutdown, within 72 hours following a fire event and using onsite power only, be available for our review in advance of your July 31, 1985, commitment for compliance with Appendix R, III.B.3 and III.L requirements."

It appears that this review of the approved DSPs prior to implementation did not occur. A Regional based Appendix R inspection conducted February 4-8, 1985 (and documented in report 50-261/85-07), included a review of dedicated shutdown capability. The DSPs were not reviewed because they were still in draft form.

As part of this SSFI pertaining to the licensee's ability to safely shut down the plant under loss of offsite power conditions, the inspectors reviewed the procedures, equipment, and training associated with dedicated shutdown. The basis for this review was that in certain cases these procedures require the operators to deliberately separate the plant from all offsite and onsite AC power, including the tripping of the emergency diesel generators and associated emergency buses. Under these conditions, the only AC power source would be the dedicated shutdown diesel generator and associated dedicated shutdown bus. This diesel generator and shutdown bus supply the minimum equipment necessary to achieve hot standby and cold shutdown including the "A" Component Cooling Water Pump; "A" Charging Pump; one RHR Pump; "D" Service Water Pump; and specific valves. Power to the RHR pump requires utilizing repair procedures to connect temporary cables from a selected pump to a spare breaker on the dedicated shutdown bus.

On March 24 and 25, 1987, the inspectors conducted walkthroughs of DSP-001 and DSP-006 with licensed members of the plant operating staff. These walkthroughs, combined with a review of the procedures, resulted in a number of significant concerns. Deficiencies were noted in the technical accuracy of the procedures, in the associated communications, human factors, emergency lighting, training, staffing, and entry conditions. These concerns are discussed below:

(a) Technical Accuracy

Dedicated Shutdown Procedure DSP-001, Revision 0, was observed to contain several technical errors.

- The transfer sequence provided for transferring MCC 5 from the normal source of power, emergency 480 volt bus E1, to the dedicated shutdown bus was incorrect, and would not have resulted in restoration of AC power to MCC 5. This deficiency was resolved by a temporary change to DSP-001 on March 25, 1987.

- The directions to adjust the steam driven auxiliary feedwater pump speed controller provided no acceptance criteria and no local instrumentation was provided. In addition, indications are that to adjust this controller without first removing control air could result in physical damage to the controller.

- In DSP-011, Pressurizer PORV Control Power Repair, the associated cable routing diagram was incorrect for the existing plant configuration.

The licensee needs to perform a comprehensive review of all the dedicated shutdown procedures to ensure the technical accuracy.

(b) Communications

The walkthrough of DSP-001 and DSP-006 indicated that the portable radio system utilized was totally inadequate to support the required local operations and communications. These radios did not have an installed repeater, thus radio to radio communications through walls and obstructions was unsatisfactory. Operators were observed attempting extreme measures in order to communicate including climbing up a ladder several floors, and running from corner to corner of rooms.

The dedicated shutdown procedures require frequent communications on plant status for interrelated or prerequisite actions. The licensee's Appendix R submittal indicated that dedicated shutdown procedure communications would be accomplished utilizing the public address (PA) system and portable radios. The AC power supply to the PA system, however, is deenergized early in the use of DSP-001 and not restored. Another submittal indicated that the daily use of the radio system for plant operations had demonstrated the radios to be adequate to support dedicated shutdown. The licensee indicates that they had determined three specific locations in the plant where these radios could be utilized to communicate clearly. However, these locations are not compatible with the implementation of the dedicated shutdown procedures.

(c) Human Factors

A number of human factors deficiencies were noted during the review of dedicated shutdown procedures and associated systems and equipment. While these deficiencies would probably not of themselves prevent conduct of the procedures, they did appear to cause delays and confusion, and given the stress of fire and/or station blackout, could have impeded safe shutdown. General examples of human factors deficiencies included:

- Titles of valves were not addressed in procedures, just valve numbers.

- No listing of electrical breaker compartment numbers were provided in the procedures. Breaker compartment numbers could expedite location of safe shutdown breakers particularly on MCCs which contain large numbers of breakers.

- No color coding or other type of distinctive labeling was provided for breakers and valves associated with dedicated shutdown.

- "Response Not Achieved" directions for required actions and verifications were not contained in procedures.

- Assembly area was not defined, except "as appropriate."

(d) Emergency Lighting

Appendix R, Item III.J. requires that emergency lighting units with at least an eight-hour power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto. The inspectors did not review the adequacy of the emergency DC lighting for safe shutdown in detail. There were areas observed during the conduct of the walkthrough, however, that appeared not to be in conformance:

- The dedicated shutdown diesel (DS) enclosure contains no battery packs or other emergency lights. One of two DS control panels and the trip reset are located inside the engine enclosure.

- The Auxiliary Feedwater Pump (AFW) local speed controller had no emergency lighting provided.

- The access ladder area from the turbine deck to the auxiliary feedwater control valves appears to lack adequate emergency lighting.

The licensee indicated that they had performed blackout testing and determined the emergency lighting to be adequate to meet Appendix R. In a submittal dated January 16, 1985, the licensee requested an exemption from the requirements of Item III.J. for the access path to the safety injection room and the service water intake structure. The exemption request proposed the utilization of flashlights, but has apparently never been granted.

(e) Training

The licensee committed to complete the training associated with the dedicated shutdown procedures by July 31, 1985. 10 CFR 50.48 required this training to be completed prior to the end of the February 1986 refueling outage. The initial training for operators on these procedures was conducted in May and June of 1985 by the contractor who wrote the procedures. The inspectors could not review the lesson plans and materials associated with this training because the contractor apparently retained this material. This initial training was completed on draft procedures, and the inplant walkthrough training was apparently less than an hour in duration for all 12 procedures. No operator training or requalification training on the approved procedures or inplant walkthroughs or drills had been conducted since this initial training in May of 1985, nearly two years earlier. Subsequent training and periodic requalification on dedicated shutdown had been identified as an inspector followup item (261/85-07-13) during an Appendix R inspection in February 1985.

Despite "practice" walkthroughs, prior to the walkthrough by the inspectors, the lack of training and retraining on dedicated shutdowns was notable on March 25, 1987. In addition, the training for maintenance personnel on the dedicated shutdown repair procedures was not accomplished by the licensee until May of 1986, nearly one year after the commitment and implementation of the procedures. The licensee submittal had indicated that operators would "direct" the cold shutdown and repair activities, but it was indicated during the walkthroughs that they were not trained or prepared to do so.

This lack of adequate training and retraining is of particular concern considering the number, complexity, and severity of manual actions required, and the extreme conditions under which these actions would need to be accomplished.

(f) Staffing

The licensee's original submittal indicated that a maximum of four operators would be necessary to achieve hot standby conditions following a fire. Three operators would be needed to energize and control hot shutdown equipment from the dedicated shutdown stations. A fourth operator would be required to investigate and/or mitigate possible spurious events. The requirement of the fourth operator was later retracted, and dedicated shutdown to hot standby was scheduled on time-lines to be completed by only three operators. During this period other licensed operators required by Technical Specifications would be assigned to fire brigade duties.

DSP-001 requires concurrent actions by three operators including a turbine building operator, an electrical operator, and an auxiliary building operator. Under present staffing levels, the dedicated shutdown procedures require the shift foreman (SRO) to double as the electrical operator while achieving hot standby conditions. This doubling up of responsibilities results in several concerns. DSP-001 is not designed for this utilization of manpower as it requires the electrical operator to notify the foreman of actions on several occasions. In addition, the licensee's submittal indicated that the dedicated shutdown activities would be directed by an SRO stationed in the most central area available. "The shift foreman will station himself in the most central control area available, determine the magnitude of the fire, and decide on the appropriate response."

Having witnessed the walkthrough on May 25, 1987, it is not clear how the shift foreman could effectively accomplish the numerous activities required of the electrical operator, while at the same time maintaining an awareness of the overall plant conditions, and making the critical decisions required of an SRO under fire and blackout conditions.

The licensee's submittal also indicated that the number of operators would be increased to ten in order to direct post-fire repairs and to achieve cold shutdown following achievement of hot standby. These operators would be supplied by offshift personnel who would be called in. The licensee indicated at the time of this inspection and the walkthroughs that the operators were not prepared or responsible for directing these activities as stated in the submittal, but that this was a maintenance responsibility.

Indications were that the level of training provided to maintenance personnel was also not adequate to ensure that these repair procedures could be effectively implemented to achieve cold shutdown within the required 72 hours.

(g) Entry Conditions And Initial Actions

The dedicated shutdown procedures, particularly DSP-001, require operators to take deliberate and drastic actions to mitigate the potential loss of control and electrical sources due to fire. Among the actions required early in the conduct of DSP-001 during a shutdown from outside of the control room are:

- de-energization of all offsite power
- de-energization of both emergency 480 volt buses
- tripping both emergency diesel generators
- de-energizing DC power panels associated with the control of safety-related controls, breakers, and valves.

These actions intentionally place the plant in a station blackout, with reliance for safe shutdown placed on a single dedicated shutdown diesel generator and manual operator actions. This is a condition outside the existing FSAR analysis. The licensee elected not to develop a series of procedures, such as DSP-001, which would be progressively more serious in required actions and overall effect on the plant. With progressive procedures, implementation would depend on the degree of loss of power and control due to fire.

The DSPs exceed the emergency operating procedures (EOPs) in the gravity of operator actions and in the potential adverse effects if incorrectly implemented. Despite this potential, the DSPs were not subjected to the level of formal evaluations, validation, and quality control as provided for EOPs. The validation process was apparently primarily the responsibility of the contractor, and was not well documented. In view of the noted deficiencies in the DSPs, this validation process appears to have been less than adequate.

The entry conditions to DSP-001 include only the following:

- notification of a fire, and
- inability to restore plant control using the EOPs.

The licensee's EOPs are not designed for use outside the control room, and control room inaccessibility is not addressed in the EOP flowcharts. Without an established interface between the EOPs and the DSPs and inadequate symptom based entry conditions, the potential existed for operators to enter the DSPs when unwarranted. Any fire which required evacuation of the main control room would meet the DSP-001 entry conditions and could result in the operator implementing an intentional station blackout even though electrical and control power may not be degraded. A control room inaccessibility Abnormal Operating Procedure, AOP-004, Revision 0, 1984, also provides directions for shutdown from outside the control room in the event of smoke, toxic gas, or bomb threat.

There was not an established interface between the DSPs, the EOPs, or AOP-004, and no well defined entry conditions to ensure the correct decision by operating personnel. In addition, once an operator has committed to enter DSP-001, there were no symptom based decision points established prior to critical actions such as de-energizing all offsite power and tripping the emergency diesel generators. These deficiencies indicated that adequate management controls had not been established to ensure that predictable, and desired decisions and actions would be made by operators under Appendix R conditions, and that plant safety would not be jeopardized by incorrect or premature decisions.

The DSP-001 walkthrough on March 25, 1987, supported these concerns. Operations management had been pre-informed that the scenario would include a current transformer fire inside the control room reactor control panel resulting in dense smoke and evacuation of the control room. Under these conditions, the licensee predicted the SRO would elect to enter AOP-004 to perform a routine boration shutdown from outside the control room. The licensee refers to AOP-004 as a "mild" control room evacuation procedure because it does not require the drastic actions contained in DSP-001.

When told of the scenario, the SRO decided not to enter AOP-004 or DSP-001, but to utilize respirators and remain in the control room with EOPs. This contingency was not addressed in plant procedures. The inspectors escalated the scenario by indicating to the operators that the smoke was worse and the control board physically hot. At that time the SRO elected to enter DSP-001 and to intentionally blackout the station. Clear, symptom based

entry conditions and directions did not exist to ensure the predictable and desired response, and to ensure orderly transfer between EOPs, DSPs, and AOPs. Clearly defined symptom based entry conditions and predictable responses are essential to post-TMI Emergency Operating Procedures and should also be applicable to Dedicated Shutdown Procedures which replace the EOPs during control room inaccessibility.

- Title 10 CFR Part 50, Appendix R, Item III.G, requires that fire protection features shall be provided for structures systems, and components important to safe shutdown. Item III.G.2 requires adequate separation of cables and equipment, including associated non-safety circuits, to ensure that one of the redundant trains necessary to achieve and maintain hot shutdown is free of fire damage. Item III.G allows alternative or dedicated shutdown capability for fire zones where the separation criteria of III.G.2 cannot be met.

- Title 10 CFR Part 50, Appendix R, Item III.L., requires that an alternate or dedicated shutdown capability provided for a specific fire area shall be able to (a) achieve and maintain subcritical reactivity conditions in the reactor; (b) maintain reactor coolant inventory; (c) achieve and maintain hot standby conditions; (d) achieve cold shutdown conditions within 72 hours; and (e) maintain cold shutdown conditions thereafter.

- Appendix R Item III.L.3 requires that procedures shall be in effect to implement this capability.

- Appendix R Item III.J. requires that emergency lighting units with at least eight-hour battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.

- Title 10 CFR Part 50.48 requires the licensee to have the modifications, administrative controls, and the training associated with Appendix R and dedicated shutdown in place by the refueling outage in February 1986.

- Technical Specification 6.5.1.1.1.f requires that written procedures shall be established, implemented, and maintained for the Fire Protection Program.

Contrary to the above, the licensee did not provide adequate plant modifications, procedures, training, communications, or lighting to reasonably assure that the requirements of Appendix R could be successfully implemented prior to the established date. This will be a violation (VIO 50-261/87-06-01).

It appears that, despite the serious implications associated with implementation of these procedures, they were accepted from the contractor without an adequate validation and verification process. The safety analysis for the procedures, which have the potential to place the plant outside the analyzed conditions in the FSAR, was very general and generic to all 12 procedures. It appears that the licensee's representatives who assumed responsibility for dedicated shutdown did not consider these conditions to be a credible event, and as a result there was inadequate effort devoted to ensuring the technical accuracy of the procedures, and the adequacy of supporting training, communications, and lighting.

In addition, the licensee's failure to develop adequate dedicated shutdown procedure entry conditions or decision points, and adequate EOP/DSP/AOP interfaces, placed excessive reliance on operator judgement. Under specific plant conditions, this failure created at least the potential for confusion and the unwarranted implementation of DSP-001, and the resultant intentional station blackout transient, an unanalyzed condition.

(2) Electrical System Procedures

The inspectors reviewed several procedures associated with the plant electrical system including the following:

- General Operating Procedure GP-002, Revision 21, Cold Shutdown to Hot Subcritical at No Load T-avg
- General Operating Procedure GP-003, Revision 10, Normal Plant Startup From Hot Shutdown to Critical
- General Operating Procedure GP-005, Revision 11, Power Operation
- Operating Procedure OP-603, Revision 7, Electrical Distribution

This review identified a deficiency in the licensee's methodology for verifying and documenting proper breaker and valve alignments under various modes of plant operation. Attachment 9.1 of OP-603 provides an electrical lineup sheet for breakers

including those associated with motor operated valves (MOVs) and motor control centers (MCCs). The breaker positions established by Attachment 9.1 are those required prior to plant heat-up. In addition to utilizing Attachment 9.1 of OP-603 for breaker alignments prior to heatup, the licensee utilizes the same attachment for alignment verifications while at power operation. While the required positions for many breakers remain the same for pre-heatup and power operation, there are several safety-related breakers and the associated valves which are repositioned prior to the plant exceeding 1000 psig. Examples of breaker positions which change include the following:

(a) General Procedure (GP)-002 requires the use of Operating Procedure (OP)-603, Attachment 9.1 to align the plant electrical distribution systems. This operating procedure is to be completed within two weeks of the heatup, and also reviewed within 24 hours prior to commencing heatup. Technical Specification 3.3.1.1.g requires that the breakers for MOVs 878 A and B (safety injection discharge pump cross connects) be open with the breaker control power removed prior to the plant exceeding 1000 psig. However, Attachment 9.1 lists the required breaker position for these MOVs as being closed, with no caveat concerning the availability of control power. A placard on the front of MCC 5 indicated that the valves should be open, with the control power removed, as per the Technical Specifications. Independent review by the inspectors determined that the Technical Specification requirements were complied with, and the breakers were open, but that Attachment 9.1 to OP-603 was signed off as closed during power operations.

(b) GP-002 also requires valve position verification and sign-off for all valves listed in Technical Specification 3.3.1.1.g (13 valves) prior to exceeding a plant pressure of 1000 psig (step 5.1.2.67). This establishes the required breaker and control power conditions required for plant operation in accordance with the Technical Specifications. This also establishes a variance from the positions required in OP-603, Attachment 9.1 for MOVs 878 A and B, as described in the preceding paragraph.

(c) Using OP-603, Attachment 9.1, the inspectors compared other required breaker positions with actual in-plant breaker positions. The following breakers which were required to be racked out by Attachment 9.1 were found racked in, but in the open position. Racked in and open is the proper Technical Specification position for these breakers while at power operation.

- Containment Spray Pump "A" Breaker 52/19A -

- SI Pump "A" Breaker
- SI Pump "C" Breaker
- Containment Spray "B" Breaker

(d) GP-003 and GP-005 list in the Precautions and Limitations Sections a requirement for the electrical distribution system to be aligned in accordance with OP-603. However, GP-002 is completed prior to GP-003 and GP-005, and prior to a plant pressure greater than 1000 psig, the written prerequisite conditions directed for these procedures (GP-003 and GP-005) are not met. The conditions required to operate the plant in accordance with the Technical Specifications is complied with, however, the variance between the pre-heatup procedural breaker position requirements and the breaker position required at power operation is not addressed.

These deviations between the breaker positions required by Attachment 9.1 of OP-603 for pre-heatup alignment, and the breaker positions required at power operation have also caused confusion for QA auditors performing valve and breaker alignment verifications. The Quality Assurance (QA) group performed surveillances on May 24, 1985 (Quality Assurance Surveillance Report (QASR) No. 85-086); August 16, 1985 (QASR No. 85-132): and November 22, 1985 (QASR No. 85-180); in the electrical area. Attachment 9.1 of OP-603 was used during these surveillances for the breaker lineup verification. In all three instances the positions of breakers for MOVs SI-878 A and B were listed as having been closed. Contrary to this verification the breakers were open. QASR 85-132 and QASR 85-180 did show that the breakers were actually open, however, only QASR 85-132 noted in the comments section why the breakers were open.

QASR 85-086 did not note that breakers for MOVs SI-878 A and B were open, however, the open positions were marked while the required positions were circled indicating that the discrepancy had been noticed. No supporting or explanatory information was placed in the comments section of QASR 85-086.

Although the procedure breaker checklist required positions did not match the actual breaker positions, all three QASRs indicated that all safety equipment circuit breakers were actually verified in their proper positions. During a review of OP-603, Attachments 9.1 and discussions with QA personnel, it was noted that no guidance was given to identify which breakers were for safety-related equipment, or which breakers in Attachment 9.1 change required position at power operation.

In response to this deficiency, the licensee committed to revise the Attachment 9.1 breaker verification checklist in OP-603 to notate the proper breaker alignment at greater than 1000 psig. The appropriate revision of this procedure and resolution of the issues will be an inspector followup item (IFI 50-261/87-06-02).

(3) Emergency Diesel Generator (EDG) Loading

(a) Maximum Load Control EDG

When the EDG is loaded following an actual plant event such as a loss of offsite power or safety injection (SI), the operator must maintain the total EDG loading at or below 2750 KW, the Technical Specification load limit. Exceeding the load limit during the manual addition of other essential loads could result in an EDG overload and loss of vital equipment. It is essential therefore, that the control room operator remain constantly abreast of the loads on each EDG and the remaining KW availability.

The inspectors identified several significant concerns regarding the control room operators ability to maintain this awareness under transient or accident conditions including the following:

- No KW load meters are provided in the main control room for the EDGs. The only EDG load indication provided in the control room is an ammeter. There is no information provided to the operator to correlate EDG ammeter load to the EDG KW load limit.

- The Emergency Operating Procedure (EOP) flowpath (1) does not indicate the 2750 KW Technical Specification EDG load limit.

- The present communications between the control room and the EDG local control panel during EDG operation are extremely poor especially during diesel operation.

These concerns all indicate that the control room operator may not be provided with adequate indication, procedures, or communications to ensure that the EDGs are not overloaded during a plant emergency. This item will be identified as inspector followup item (IFI 50-261/87-06-03) pending completion of the following:

- The licensee's control room evaluation and corrective action under NUREG 0700, Control Room Design Review -

- Implementation of the licensee's improved communication system

(b) Response to IE Notice 84-69, Operation of Emergency Diesel Generators (EDGs)

IE Notice 84-69, Supplement 1, Operation of Emergency Diesel Generator (EDG), was generated to alert licensees of potential significant safety problems related to operation of the EDG in modes other than standby service mode. When an EDG is operated in parallel with the offsite power supply system or non-vital loads, disturbances on the offsite and/or non-vital buses can adversely affect the emergency power supply system. The onsite emergency power supply system is no longer independent of the offsite power systems and therefore a disturbance on this system could result in both a loss of the offsite power and a disabling of the onsite emergency power supply. The inspectors reviewed licensee actions taken to address the following concerns:

- Availability of the EDG for subsequent emergency demands if a fault develops when feeding non-emergency loads.

- Operation of the load sequencer and EDG trip functions during the above event.

- Operation of the load sequencer if the open output circuit breaker fails to open.

- The vulnerability of the EDG to trip signals which are bypassed for emergency starts but are operable for manual starts and during testing of EDG.

The generator protective relays provided with the EDG are intended to protect the generator against abnormal electrical conditions. The inspector determined that upon occurrence of an electrical disturbance, that the EDG output breaker was provided with adequate trips.

Discussions with licensee technical staff members indicated inadequacies in operating staff knowledge concerning reset of the EDG following a trip. The licensee's internal response to IE Notice 84-69 indicated that if a loss of offsite power occurred while operating an EDG in parallel for surveillance testing, that EDG would probably trip. This trip would be due to overload resulting from an

automatic transfer of non-emergency loads to the EDG. This would result in a trip of the EDG breaker overload device and an overspeed trip of the EDG. Restoration of the EDG to service would then require resetting the breaker overload trip by opening and reclosing the breaker, and then manually resetting the EDG overspeed trip. The potential for this trip to occur and the necessary actions required to restore the EDG operability were not addressed in the operating surveillance procedure for the EDGs. This deficiency could conceivably delay the availability of the EDG for subsequent service if required.

The inspectors verified that with the EDG output breaker closed, the blackout sequence logic is disabled. Subsequent to this, if the EDG does not separate from the emergency (E)-bus, sequential loading of the blackout loads does not occur. Those blackout loads that were previously energized from the E-bus will remain energized unless the feeder breaker should trip because of a fault condition. The disabling of the blackout sequence logic is shown on Controlled Wiring Diagrams (CWD) Sheet 890 wherein an auxiliary "a" contact of the EDG output breaker is used to energize an alarm relay (device 74). A "b" contact from this alarm relay is then used to isolate the E-bus undervoltage protective relay (CV-7) circuit as shown on CWD Sheets 274 and 275 for 480V Bus E-1.

Initiation of a Safety Injection (SI) signal with the EDG output circuit breaker closed does not inhibit safeguard sequencing of loads on to the E-bus. This situation is applicable for an SI signal coincident with a Loss of Offsite Power or an SI signal occurring independently. The inspector reviewed the vulnerability of the EDG trip signals that are bypassed when in the standby service mode, but which are operable during manual starts and test runs. The concern is that the EDG would be more susceptible to these trips during testing, which could adversely affect availability upon emergency demand. The inspector determined that during performance of the EDG weekly operational surveillance test, OST-401, the EDGs are manually started with the trips defeated. However, in accordance with updated FSAR Section 8.3.1.1.5.1, the trips are then enabled to allow testing of the EDGs without excessive equipment risk if a valid non-emergency trip signal was to be received. Although this test mode provides a window of trip vulnerability to the EDG during weekly surveillances, it is permitted by the licensee's Technical Specification (TS) and FSAR commitments.

Based on review of the applicable sheets of CWD 19062B, and discussions with licensee technical and training staff, the inspector determined that licensee management had taken action in response to IE Notice 84-69, but that these actions were incomplete. Recommendations made by the Onsite Nuclear Safety (ONS) staff, including the addition of the EDG protective relays to the plant calibration program to assure greater equipment reliability, had not yet been implemented by plant management. Additionally, the ONS recommendation that E-bus breakers 52/18B and 52/28B be included in the periodic inspection and testing program applicable to the other E-bus breakers, have not been acted upon by plant management. Resolution of concerns and recommendations associated with IE Notice 84-69 will be an inspector followup item (IFI 50-261/87-06-04).

(c) IE Notice 84-38, Loss of Offsite Power to Nuclear Facilities

In response to NRC Inspection and Enforcement (IE) Notice 84-38, Loss of Offsite Power to Nuclear Facilities, the licensee's System Operations Department initiated a study in 1984. The Systems Operations Department is responsible for the maintenance of CP&L's offsite electrical transmission facilities. The inspectors reviewed the licensee's response to this IE Notice and the internal study. The study was designed to review facility design, maintenance, and operations programs and practices that could result in a loss of offsite power at the facility. An associated probabilistic risk analysis (PRA) performed by the licensee determined that major modifications to the electrical switchyard were not justified, based on the resultant reduction to core melt frequency. Seven improvement actions items were identified, however, as follows:

- Review substation maintenance program and practices.
- Perform audit of 115 kilovolt (KV) and 230 KV switchyards.
- Review relay maintenance standards and practices and develop operational testing procedures for 115 KV and 230 KV switchyard equipment.
- Perform relay equipment walkdown inspection.
- Review switchyard equipment maintenance and operational testing procedures and equipment labeling.
- Review start-up transformer source reliability.

- Provide switchyard fencing to restrict vehicular and personnel traffic through the switchyard.

Item (f) above identified a need to modify the switchyard configuration to allow alternate offsite feed to the single startup transformer from the 230 KV switchyard. The present configuration provides for only a 115 KV offsite power source to this transformer. This modification is planned for a near-term refueling outage. The licensee had completed implementation of all of the other action items listed above and which are designed to improve the reliability of offsite power.

Also, as a Result of IE Notice 84-38 and the above review, the Systems Operations Department has provided a standby startup transformer onsite. This transformer is stored onsite, unconnected, in close proximity to the in-service startup transformer. Should the startup transformer fail, the licensee estimates a minimum of 18 to 24 hours would be required to install the standby transformer. This estimate includes the transport of the moving crew and equipment from Raleigh, NC, security clearance of workers and equipment, disconnection and movement of the failed transformer, and movement, installation, and testing of the standby transformer. Two hours of this time were estimated to be required for the plant security access of crew members and equipment. This time could be reduced by pre-badging the workers, and by escorting vehicles as done with fires and emergencies.

The inspector reviewed the procedures and equipment associated with the installation of the spare startup transformer, and interviewed responsible System Operations Department personnel. Due to experience of the line crews in replacing similarly sized transformers, the licensee is confident that the startup transformer could be removed and the spare transformer installed and tested within the 18 to 24 hours indicated. The System Operations Department is only responsible for installation of the spare transformer and the connections and testing associated with the primary side of the transformer. The plant Electrical Section is responsible for the procedures and equipment associated with the secondary side of the transformer.

(4) Licensee Event Report (LER) 86-005, Loss of Offsite AC Event, Corrective Actions

On January 28, 1986, with Unit 2 at 80 percent power, the licensee experienced a loss of one of the two emergency buses, E-2, resulting in a high pressurizer pressure reactor trip.

Unit auxiliaries then shifted to the startup transformer, but a west 115 KV bus lockout deenergized the single startup transformer. This placed the plant in a loss of offsite power condition with only one of the two onsite emergency AC power sources available and an unusual event was declared.

On March 6, 1986, during refueling shutdown, two station service transformers were removed from service for maintenance on the common supply breaker. While energizing emergency bus E-2 from emergency bus E-1, the supply breaker opened due to degraded voltage relay actuation. This again placed the plant in a loss of offsite power condition with only one of the two emergency buses energized.

The licensee's initial investigation determined that the loss of offsite power and the loss of emergency bus E-2 resulted from two separate, independent conditions; susceptibility of the startup transformer primary side current transformers (CTs) to DC saturation, and the vulnerability of the emergency bus undervoltage relays to the blowing of fuses.

As a result of these events as described in Licensee Event Report 86-005, Rev. 2, "Loss of Offsite AC Event," the licensee made modifications to the differential relay protection scheme for the 115 KV/4.16 KV startup transformer. The proposed modifications include:

- A spare current transformer (CT) on the 115 KV side of the startup transformer with the secondaries of two CTs wired in parallel.
- An interim ten-cycle delay between the output of the transformer differential relay and actuation of the lockout relay.
- Replacement of the CTs on the 4.16 KV side of the startup transformer, with new CTs of a higher accuracy class.

The inspectors reviewed the adequacy of the licensee's corrective actions, and the testing performed by the licensee on the startup transformer differential protection after the modifications were made and before placing equipment back into service. The inspectors held discussions with personnel from the Systems Operation Department who were primarily responsible for analyzing this event. The discussions centered around the following points:

- A bushing CT on the startup transformer
- A "special design CT" on the 4.16 KV side of the transformer
- Oscillograms of current and voltage recorded during a test.

The bushing CT on the startup transformer is used in the 115 KV bus differential protection. This CT has a ratio of 1200-5 amperes, and therefore would not be prone to saturation for through faults or during motor bus transfer.

LER 86-005 refers to a special design CT to be installed on the 4.16 KV side of the transformer protection. Actually this is a standard CT manufactured by Westinghouse.

Oscillograms of CT current and voltage were recorded during a test performed as part of the analysis. The oscillograms indicated that the motor bus transfer dead time was in the area of six to seven cycles. The oscillograms also indicate that the motor bus was about 180 degrees out of phase with the system at the moment of breaker closure. However, this was seen to be a result of very light load conditions at the time of the test (shutdown mode), rather than a condition that would exist during an emergency bus transfer.

In general, transient currents that occur during motor bus transfers (assuming 6 cycle dead time) are lower values than peak short-circuit currents. But, the DC offset time constant is significantly longer for motor bus transfer than short-circut transients. This phenomena lead to the loss-of-offsite power event.

The inspector inquired about tests that were performed on the transformer differential protection after the CT modifications were made. The licensee responded that the following tests were performed:

- Ratio test
- Excitation test
- High potential test
- At full load, record all current inputs (and phase angles) to the differential relay.

The inspectors' review of this area concluded that the licensee's corrective actions to the LER were adequate.

(5) Control Room Electrical Drawings

A review of controlled drawings in the control room indicated that Piping and Instrumentation Drawings (P&IDs), Controlled Wiring Diagrams (CWDs), and logic diagrams are provided for Operations personnel. Conspicuously absent from the control room were the electrical one-line drawings, including safety-related electrical drawings. The licensee indicated that protective tagging for work orders is accomplished utilizing a

combination of the general one-line diagram provided as an installed operator aid, and the electrical load list attached to System Description SD-16, Electrical System. The operator aid (attached to an operating panel) is a very general representation of the electrical system and does not include individual load breakers. This operator aid is also not subject to the stringent revision controls applicable to controlled plant drawings. SD-16 provides a list of breakers, however it does not contain one-line drawings or information related to protective devices or transformers. The licensee indicated that one-line electrical drawings have not been requested for the control room. Operations personnel indicated, however, that they had been requested several times, and would be useful. Selected one-line drawings would provide the control room operators with valuable reference material for protective tagging, as well as both normal and emergency electrical operations. In response to this concern, the licensee provided selected one-line electrical drawings in the control room prior to completion of the inspection.

(6) Human Factors

(a) Procedure GP-001, Fill and Vent of the Reactor Coolant System, Step 5.1.2.67, requires that nine valves be verified OPEN, with their control power switches in the DEFEAT position. These valves are, SI-862 A and B, SI-863 A and B, SI-864 A and B, SI-866 A and B, and SI-869. The purpose of step 5.1.2.67 of GP-001 is to ensure Technical Specification 3.3.1.1.g is complied with (valves OPEN with control power REMOVED), while retaining valve position indication at both the local and remote locations. In order to place these breakers in the DEFEAT position, an operator must take the individual defeat switch, located in the back of the control room Reactor Turbine Generator Board (RTGB), for each breaker, to the DEFEAT position; locally, the control power switch is left in the ON position.

Field inspection of the local and remote operators and indications for these, and other valve breakers, identified several human factors concerns.

- Locally, the Motor Control Centers on which the breakers with defeat switches are located do have an operator aid in the form of a plastic sign. The wording, however, on this aid is such that an operator could confuse the availability of control power with

the positioning of the valve, and thus be uncertain of both. This is possible since the control power switch is in the ON position and position indication is not available.

- Locally, the operator aid which is utilized for the valves listed above is also used as a cue for the operators concerning the positioning of valves SI-865 and SI-878. These valves, however, are not provided with the DEFEAT switch available on the other SI valve breakers. This results in the control power switches being in the OFF position and the indication power being unavailable for these valves at both the local and remote locations. The disparity between these two valves and the nine valves listed above could cause confusion to the operator, since the same operator aid is used locally for all of the valve breakers.

- Remotely, there were no operator aids which would cue the operator to the unique indications (position indication without control power availability) for these valves. This places an excessive burden on the memorization capabilities of the operator.

- The back panel of the RTGBs at which the operator implements the DEFEAT positioning of the SI valves is key controlled, along with the other RTGB back panels. However, the components which are inside each of these back panels are not identified on the outside of the RTGB doors. This can result in difficulty in quickly locating the proper door for implementing the DEFEAT position, or for operating any of the other components in the RTGB back panels. The inspector observed one operator try four different doors before locating the correct panel containing the defeat switches.

- The 878 and 865 valve breakers were opened with orange defeat signs, but the breakers have no defeat switches or local indication of control power.

(b) The inspectors walked down the electrical system including 480 and 4160 volt AC, 115 KV, 120 volt vital AC, and 125 volt DC. A number of human factors concerns were also noted in these areas as follows:

- The dedicated shutdown diesel remote control panel had several control power lights inoperable due to missing or burned out bulbs. The panel is utilized on a

weekly basis by operators to conduct a surveillance test of the diesel. Although the licensee responded to the inspectors' concerns by replacing the control power lights, this dedicated shutdown diesel board should be the subject of increased licensee attention. Past QA audits of the electrical system also noted numerous control power lights burned out. These lights are essential to ensure the control power necessary to operate essential equipment when required, and should receive increased attention.

- The dedicated shutdown diesel cabling loading to the 4160/480 volt transformer has a loading limitation of 2400 KW with 300 amps. These limits are indicated in the applicable operating procedures, but were not marked on the remote or local control board KW meters and ammeters. Indicating these limits would help ensure that the cable limits are not exceeded during emergency operations.

- Motor Control Centers (MCC) contain both 480 volt safety-related and nonsafety-related "balance of plant" (BOP) breakers. The safety-related breakers are not provided with any unique identification i.e., color coding or special labels. This type of identification could help identify to personnel safety-related equipment, particularly during emergency breaker operations.

- The 480 volt breakers on safety-related buses E-1 and E-2 have electrical trip/reset buttons in addition to the mechanical trip button. Operations personnel were confused over whether these electrical trip/reset buttons were operable with the breaker in the "connected position." In the "connected position," the breaker is racked in fully and connected to the bus. A review of applicable drawings with Engineering indicated that only two of the electrical trip resets on the supply breakers to MCC 5 and MCC 6 were operable in the "connected position." The electrical trip resets on the remainder of the E-1 and E-2 breakers are operable only in the "test position." In the "test position," the breaker is partially racked out, and not connected to the bus. Procedures and operator training needs to be upgraded to reflect this logic. Operator aids located next to the electrical trip buttons on each breaker would also be useful. Resolution of this concern will be an inspector followup item (IFI 50-261/87-06-05).

(c) A number of human factors concerns were noted by the inspectors regarding the EDGs. Examples of human factors concerns were:

- Emergency Lighting - The inspectors assessed the emergency DC lighting in the EDG rooms and found it to be less than adequate. During the inspection, a partial loss of AC power occurred due to a fault in a lighting panel. The inspectors noted that the A EDG electrical control panel was dark, as were the areas behind the EDG where the starting air system and fuel oil day tank are located. This lack of emergency lighting would make monitoring of certain operating parameters of the EDG difficult during a loss of AC power. This concern will be an inspector followup item (IFI 50-261/87-06-06).

- Communications - During the inspection, the inspectors reviewed the capability of the communications network between the main control room and the diesel room and found it to be also less than adequate. The present primary means of communication between the main control room and the diesel room are by use of the public address (PA) system. With the EDG operating, it is extremely difficult to hear the PA system announcements. In addition, communication with the control room over this system is very poor due to background noise. The licensee does have portable radios, but once again communications are very poor due to background noise and the lack of radio headsets plus the current system does not have a repeater. This concern will become inspector followup item (IFI 50-261/87-06-07).

- Labeling - Labeling on the control panels in the EDG room was difficult to read, and adequate labeling was not provided on the local EDG electrical control panels. In some instances, labels with an incorrect setpoint have been affixed to the EDG engine control board below their respective meters.

b. Surveillance

The inspectors reviewed surveillance testing associated with the safety-related batteries and the emergency diesel generators (EDGs). This review included inspection of related surveillance procedures and completed surveillances, as well as observation of surveillance tests conducted by Operations and Maintenance.

(1) Battery Surveillance

The safety-related "A" and "B" replacement batteries were installed in 1978 and first tested in 1979. At that time, test procedure PT-20.3, Revision 4, dated September 5, 1979 was used as the basis for the 1979 acceptance test.

Safety-related batteries are required by Technical Specification 4.6.3.5 to be load tested every five years. When subjected to its first five year test in 1984, the "A" battery failed to maintain the load above the acceptance criteria. This test was performed per Test Procedure EST-012, Station Battery Load Test, (a renumbered revision to PT-20.3), Revision 1, April 20, 1984. Corrective action taken following the battery test failure consisted of immediately removing the non-safety-related DC motor loads (modification M-831) from the battery, and placing these loads on a newly installed non-safety-related C battery.

It does not appear that an attempt was made to evaluate the original loads compared to the rated capacity of the "A" battery to determine whether or not an unsafe condition had occurred during plant operation. Indications of this failure indicates that the battery was improperly sized in 1968 and probably would have failed to meet its design load whenever the battery room temperature dropped below 60°F. The daily surveillance procedure accepts a minimum temperature of 50°F.

(a) The inspectors reviewed the existing surveillance procedure EST-012, Station Battery Load Test, Revision 2, November 22, 1985, and identified the following four concerns:

- The load profile did not address all the DC circuits that could add loads to the "A" battery. EST-012 has interpreted the load to consist of only those loads listed in FSAR Table 8.3.2-1, Major Battery Loads. Failure to have an adequate procedure to perform this surveillance is identified as a violation (VIO 50-261/87-06-08).

- No temperature correction factor was applied to the test current to correct for either the battery's temperature at the time of the test, or to prove the battery could perform its required safety function at the permissible minimum battery temperature.

- The acceptance criteria of 105 volts did not address the minimum acceptable voltage of the supplied DC equipment, and any voltage drop that may exist between the battery terminals and the loads. As an example, the instruction manual for the safety-related inverter cautions that voltages below 105 volts at the inverter, would probably result in clearing the semiconductor fuses.

- The present procedure did not require any trending or extrapolation of the test results to establish if the battery would provide sufficient capacity during the next five-year interval. The licensee has also not committed to perform a battery capacity test (as described in IEEE 450, Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries), which could assist in making this determination.

Therefore, the present test procedure can not prove the capability of the battery to deliver its required load at the minimum permissible temperature. The results also cannot be used to trend the battery's capacity with age, as evidenced by the "A" battery just barely passing the 30-minute original acceptance testing period, and failing the first 5-year capacity test.

Modification M-831 removed the turbine auxiliary DC motors from the "A" battery, lowering the 30-minute profile which permitted the battery to pass the lower test requirement. This change also had the effect of moving the critical discharge period from 30 minutes to 3 hours. The inspectors also noted that the original 1979 test on the "A" battery apparently required lowering the discharge current prior to recording the voltage at the 3-hour mark. The revised test performed with the lower profile (SP-630, Rev. 0) in 1984, correctly recorded the battery voltage at the new critical 3-hour mark prior to reducing the discharge current. The 1984 test to the present FSAR profile, but not compensated for temperature, resulted in a 9.2 volt margin. However, because no earlier testing existed to this profile, no record was maintained of the actual test temperature and no performance capacity testing was performed. It is not possible with the existing test results to accurately estimate the amount of battery degradation or to extrapolate if sufficient capacity remains during the next five-year interval until the scheduled battery capacity test is performed in January 1990.

The inspectors have estimated that when breaker control circuits and other missing loads are identified, the B safety-related battery may not pass a service discharge test at the minimum temperature permitted by the surveillance procedure, MST-902, Battery Test Daily.

The inspectors reviewed a draft copy of MST-920 which, when approved, will replace the existing test procedure EST-012. The existing draft procedure does not address the concerns identified above.

It is the inspectors' understanding that a plant improvement has been approved to add heating to the battery room to maintain the minimum temperature above 60°F. This modification (M-909) should be expedited by the licensee to ensure adequate battery room temperature and battery capacity.

(b) Battery specific gravity readings are taken as part of the daily, monthly and five-year surveillance procedures. The daily surveillance procedure MST-902, which is used during all plant conditions, specifies a minimum specific gravity of 1.205 for the battery surveillance requirements. This is consistent with the manufacturer's requirements which specify a fully charged acceptable specific gravity of 1.205 to 1.225 when the electrolyte is at full level. The monthly surveillance test procedure, MST-903, includes an evaluation of specific gravity to assess if an equalizing charge is required. Contrary to the corrections required in the daily and five-year surveillance (EST-012) procedures, this procedure does not include a correction to specific gravity for electrolyte level. In addition, procedure EST-012 accepts a minimum specific gravity of 1.180. This does not meet the manufacturer's requirements. The inspectors acknowledge that the load discharge test procedure is used only during plant shutdown, and the low specific gravity value would be evaluated prior to a battery discharge test.

The correction for electrolyte level in MST-902 and EST-012 is referenced to the electrolyte high level mark on the cells. To compound the confusion over acceptable minimum specific gravity, the inspectors found that the battery racks were not installed level. Because of this, the electrolyte level would indicate higher in the front of the cell than in the back by almost one-half-inch. This error could account for a corrected specific gravity measurement approximately 10 points higher than actual.

The inspector witnessed the maintenance staff performing maintenance surveillance test procedure MST-902, Battery Test, Daily, 5 Days Per Week, Rev. 7, on March 23 and 24, 1987. The staff appeared to comply with the requirements of the procedure. During the test, the inspectors observed broken thermometer parts inside three different battery cells. The resident inspector will follow up on this item.

(2) Emergency Diesel Generator (EDG) Surveillance

(a) The EDG vendor, Fairbanks Morse, in August of 1986, sent the licensee a letter updating the technical manual. Among other items covered in the letter, the vendor addressed their recommended shutdown procedure. The vendor recommended that when securing the engine that a specific sequence of steps be taken to prevent EDG overheating including the following:

- load be first reduced to approximately 50-60 percent (this would promote cooling prior to complete electrical unloading)
- remove all electrical loads
- open the output breaker
- run the engine unloaded for 3-5 minutes (promote further cooling of the diesel prior to shutdown)
- secure the engine.

At the time of this inspection, it was noted that the licensee had not implemented these recommendations. The inspectors witnessed several diesel runs performed under operations procedure, OST-401, Diesel Weekly Surveillance, and observed operators removing all loads in one rapid step, and then running the engine unloaded in excess of five minutes. Review of the licensee's program to evaluate vendor recommendations will be identified as inspector followup item (IFI 50-261/87-06-09).

(b) The inspectors observed, during several surveillance runs on the "A" EDG, a definite inability in the unit to maintain a set kilowatt load.

OST-401, Diesel Weekly Surveillance, requires the diesel be started and the generator loaded to 2500 KW. Once the generator was connected to the system and loaded to 2500 KW, the inspectors noted a definite ramp decrease in kilowatts on the generator.

The licensee was questioned concerning this condition. Their response, at first was that no problem existed and the load drift was due to the generator being operated parallel to the system. Later in the inspection, following further questioning by the inspectors, the licensee stated that the load drift may in fact be caused by the EDG governor control system. The licensee further stated that the EDG governors would be examined and tested during the upcoming refueling outage. This item will be identified as inspector followup item (IFI 50-261/87-06-10).

(c) The inspectors examined the following procedures which implement the respective Technical Specification (TS) surveillance requirements:

-	OMM-008, Rev. 27, 12/16/86	TS 4.6.2
-	OST-403, Rev. 6, 3/10/87	TS 4.6.2
-	OST-402, Rev. 4, 7/21/86	TS 4.6.2

The following comments are made in reference to the above mentioned items:

Procedure OMM-008, Minimum Equipment List, verifies the requirements of TS 4.6.2 for minimum fuel oil storage of 19,000 gallons in the EDG fuel oil storage tank, and 6,000 gallons in the IC Turbine fuel oil storage tank during each shift turnover. OST-402, Diesel Fuel Oil System Flow Test, Quarterly, is referenced as an additional procedure verifying the requirements of TS 4.6.2. OST-402, however, does not specifically verify 19,000 gallons in the EDG fuel oil storage tank and 6,000 gallons in the IC Turbine fuel oil storage tank, but rather verifies that at least 25,000 gallons of fuel oil is available for emergency diesel generator use. This minor discrepancy needs to be corrected to reflect the requirements of TS 4.6.2.

All fuel oil is received by the Operations personnel at Unit 1 (Fossil). It is receipted for and stored in the Light-Off Tank(s) in the Unit 1 complex. No receipt testing is done at this time (either prior to or after the tanker discharge). There are provisions to receive fuel oil directly from a tanker to the Unit 2 EDG fuel oil storage tank, but this is considered to be an infrequent operation. In this case, sampling and testing of the fuel oil is conducted prior to discharge from the tanker. However, if the specifications of the fuel oil are not met, the fuel oil is directed to be placed in the Unit 1 Light-Off Tanks.

The Robinson FSAR, Chapter 8.3.1 and the Technical Specifications, Paragraph 3.7.1.d, require that 25,000 gallons of fuel oil (7-day supply) be available; this fuel oil is to be stored in the EDG fuel oil Tank, with the exception that 6,000 gallons may be stored in the IC Turbine fuel oil tank (Unit 1). Credit for the IC tank storage is continually exercised by the facility since the maximum possible capacity of the EDG fuel oil tank is 25,000 gallons. The IC Turbine Storage Tank is filled by transfer from the #1 Light-Off Tank. There is no record of, or requirement for, contents testing prior to this transfer. Normal filling of the EDG fuel oil tank is made by transfer from the IC Turbine Tank. Quality testing prior to the transfer is required by procedure OP-909, Fuel Oil System.

The Robinson FSAR, Chapter 8.3.1-5 requires the EDG to utilize No. 2 Fuel Oil, as prescribed per ASTM D-975; this requirement is reiterated in OP-909. Testing prior to transfer operations to the EDG fuel oil storage tank is conducted for viscosity, water and sediment, and American Petroleum Institute (API) specific gravity. Additionally, monthly tests of the tank's contents are conducted for the above and for cloud point. Testing of the fuel oil for impurities or the other properties of Table 1 of ASTM D-975, or Regulatory Guide 1.137 was not evident.

Insufficient testing of fuel oil appears to occur prior to transfer and during storage within the EDG fuel oil tank. Quality testing is performed by the licensee on the IC Turbine Tank content, which is, in fact, an extension of the EDG fuel oil storage system and, therefore, requires the same level of testing and verification as the EDG fuel oil. During an emergency seven-day run of the EDGs during which time credit for additional fuel oil delivery is not taken, the contents of the IC turbine tank might be required to meet the seven-day commitment. If the oil were tested at the time and determined to be out of specification, the seven-day commitment could not be met. This is a definite possibility, since "out of specification" fuel oil is procedurally accepted into the Light-Off Tank(s), which are the makeup source for the IC Turbine Tank.

In addition, IE Notice 87-04, Diesel Generator Fails Test Because of Degraded Fuel Oil, details the failure of an EDG at Arkansas Nuclear One Unit 2. The EDG experienced fuel starvation due to the plugging of a strainer located

between the day tank and the engine. A laboratory analysis indicated that a high concentration of particulates in the fuel oil caused the strainer fouling. These particulates were the result of oxidation and biological contamination. Samples for particulates and biological contamination do not appear to be included in the licensee's EDG fuel oil sampling program. When combined with the omission of any quality testing for the 6000 gallons taken credit for in the IC turbine bank, the potential appears to exist for the same type of EDG failure, including during a actual emergency run.

The licensee's EDG fuel oil storage and quality testing practices related to the IC tank, is identified as a violation (VIO 50-261/86-06-11).

(d) Technical Specification, 3.7.2.d., requires that if one emergency diesel generator (EDG) is inoperable that the remaining EDG will be demonstrated to be operable on a daily basis. Operations Surveillance Test OST-401 is normally utilized to perform the weekly surveillance test of the diesel generators. This surveillance procedure requires the diesels to be operated for 60 minutes each week to ensure continued operability. When the diesel generator becomes inoperable, however, the licensee does not utilize this surveillance procedure to demonstrate the remaining diesel operable on a daily basis. An operation work procedure, OWP-007, is used instead to prove operability. This procedure only requires a 30-minute run time or one-half of that required by the OST. This reduced testing time was utilized during the first week of this inspection to test the "A" EDG when the "B" EDG was declared inoperable due to the failure of the scavenging air blower.

The utilization of a procedure other than the normal surveillance test procedure to demonstrate operability under a Technical Specification action statement appears to deviate from standard industry experience. IE Notice 84-69 Supplement 1, Operation of Emergency Diesel Generators, included typical diesel Technical Specifications. These typical Technical Specifications which are similar to Standard Technical Specifications include an action statement which requires the normal EDG surveillance test to be conducted to prove redundant EDG operated at or above rated load for at least 60 minutes. The licensee has provided no acceptable supporting basis for not utilizing the normal surveillance procedure (OST) to prove operability under the

action statement and to support the 30 minute test period. Resolution of this issue is identified as an inspector followup item (IFI-50-261/87-06-12).

c. Maintenance

The inspectors reviewed maintenance activities related to the emergency diesel generators (EDGs). In response to several "B" EDG failures during the course of the inspection, the efforts were primarily focused on the circumstances surrounding these failures including the licensee's associated maintenance, testing, root cause analysis, quality assurance, and corrective actions.

On March 10, 1987, during a test run on the "B" (EDG), the scavenging air blower failed. The vendor technical representative on site at the time stated that the most likely cause of failure was due to overheating of the blower. Experience at other facilities indicated this overheating was a result of running the engine unloaded for extended periods of time.

Had the licensee exercised adequate quality assurance controls over the operability of the "B" EDG, and taken prompt corrective action in response to failures at other facilities and indications of equipment degradation, this EDG failure that occurred on March 10, 1987, could probably have been prevented. Indications of potential degradation of the "B" EDG scavenging air blower included a failed temperature test, indications of blower rubbing, and a two-hour unloaded run in February, 1986. The lack of corrective actions included a failure to check the blower clearances in response to the vendor recommendations, and maintenance procedural requirements, lack of evaluating the impact of the two-hour unloaded run, and the failed blower temperature test. In addition, a formal safety evaluation of the implications of the failed temperature test, and the potential effect on EDG operability, should have been performed and corrective actions taken as warranted. The single major basis provided by Operations and the PNSC for not responding to these indications and the vendor recommendations was the EDG past performance record. In view of the failures of similar EDG blower failures at other facilities, and indications of potential degradation of the "B" EDG scavenging air blower, particularly the failed temperature test, past performance was inadequate justification for failure to take corrective action.

On March 9, 13, and 23, 1987, the "B" EDG tripped on high crankcase pressure during operability testing. These EDGs trips on high crankcase pressure on three separate occasions, indicate an additional example of inadequate corrective actions and inadequate root cause identification by the licensee. The licensee was aware that the water levels in the EDG "B" lube oil were in excess of those allowed by procedures but did not take corrective action or perform further

analyses. Despite their awareness that the lube oil cooler integrity was degraded, the licensee did not perform a hydrostatic test at the 150 psig required by the approved procedure CM-201. Following a subsequent 30-hour EDG test run, the licensee failed to perform an oil sample to ensure that water from the degraded cooler, with a large number of plugged tubes, had not again leaked into the lube oil. Early indications were that the leaking oil cooler may have contributed to the damage to the EDG cylinder liners and pistons which could have caused a loss of the EDG under emergency conditions. In addition, the high crankcase pressure trips on March 9 and March 13 appeared to have been caused by this leaking and degraded lube oil cooler, as was the high crankcase pressure trip on March 23, 1987. This imposes a serious question as to whether the B EDG was actually operable to support the unit restart on March 20, 1987.

10 CFR Part 50, Appendix B, Criterion II, requires the implementation of a quality assurance program to provide control over activities affecting the quality of safety-related equipment.

10 CFR 50, Appendix B, Criterion XI, requires that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. Test results shall be documented and evaluated to assure that test requirements have been satisfied.

Criterion XVI requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective equipment and material, and nonconformances are promptly identified and corrected. In the cases of significant conditions adverse to quality, such as failures, malfunctions, defective material and equipment, nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management.

Criterion V requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished with these instructions, procedures, or drawings.

Instructions, procedures, or drawings, shall include appropriate quantitative and qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, the licensee failed to adequately implement the Quality Assurance Program to properly evaluate failed test results to identify root causes of failures, to implement approved procedures, and to implement corrective actions to identified deficiencies in activities related to the operability of the "B" EDG during a period extending from 1984 through March 1987. This failure to adequately implement the requirements of 10 CFR Appendix B in activities affecting the quality of safety-related equipment will be a violation (VIO 50-261/87-06-13).

The specific sequence of events related to the "B" EDG scavenging air blower failure on March 10, 1987, and the high crankcase pressure trips on March 9, 13, and 23, 1987, are as follows:

(1) March 10, 1987, "B" EDG Scavenging Air Blower Failure Chronology

(a) In November 1984, the licensee received INPO Safety Evaluation Report (SER), 78-84. This SER detailed the scavenging air blower failure at the Duane Arnold facility. After receiving the SER, the licensee contacted INPO and requested additional information. A preliminary copy of a vendor service information letter (SIL) was sent to the licensee from INPO in December of 1984.

(b) Also in November 1984, the vendor, Fairbanks-Morse, issued the same SIL detailing the blower failure at the Duane Arnold facility and recommendations on how the licensee could prevent the similar problems. The vendor recommended blower to housing clearances be checked during annual outages, and to limit no load operation to less than five minutes. The licensee stated that the date the SIL arrived onsite could not be determined because the letter bypassed the vendor recommendation review program. This error resulted in Maintenance and Operations procedures not being revised to reflect vendor recommendations.

(c) In January 1986, a second scavenging air blower failure occurred. The failure was at the Peach Bottom facility and occurred after 51 hours of light load operation.

(d) In January 1986, the Robinson "B" EDG ran unloaded for approximately two hours during an actual plant event. Despite the previous SIL, the INPO SER and blower failures at the Peach Bottom and Duane Arnold facilities, the licensee elected not to initiate any inspections to insure their equipment was in satisfactory condition.

(e) In February 1986, while performing PM-008, EDG Inspection, No. 2, the licensee noted there was evidence of rubbing on the "B" EDG scavenging air blower. A nonconformance report (NCR) was not generated on the condition, and the step was signed off as complete with no clearances or corrective action taken. An NCR was written a year later during this inspection, however the NCR only addressed the failure to follow procedures and not the physical condition of the blower.

(f) In June 1986, the licensee received supplement No. 1 to INPO SER 78-84. The supplement detailed the blower failure at the Peach Bottom facility.

(g) In July 1986, a second SIL was issued by the vendor concerning the blower failures. Once again the licensee indicated that the date the SIL arrived onsite is unknown due to the SIL bypassing the vendor recommendation program. The SIL recommended to avoid thermal failure, the blower be modified to achieve the required clearances, or as an interim measure, the licensee could:

1 conduct a temperature test to ensure the differential temperature across the scavenging air blower, does not exceed 100°F, or

2 limit no load operation to less than five minutes.

(h) In accordance with the supplement number (1) to INPO SER 78-84, the licensee's Onsite Nuclear Safety Group assigned five action items in July, 1986. These action items were sent to various site groups including:

1 Operations: They were tasked with reviewing the need to revise operations procedures to limit no load operation to less than five minutes. This revision was not completed until March 1987, following the failure of the "B" EDG scavenging air blower, and at the request of NRC inspection team members.

2 Maintenance: They were to ensure that scavenging air blower clearances are taken every time PM-008, Emergency Diesel Generator Inspection Number 2, is performed. This was a task they had failed to complete on two previous occasions, once in April 1984, and again in February 1986.

3 Regulatory Compliance: Determine whether the EDG scavenging air blower issue at Robinson was reportable under 10 CFR 21.

4 Technical Support: They were tasked with developing a special procedure to install temperature indicators to monitor the differential temperature across the scavenging air blower in accordance with the vendor recommendations.

5 Training: They were tasked with incorporating diesel generator loading limitations into the Operator Training Program.

(i) In August 1986, the vendor sent to the licensee a letter updating the technical manual. Among other items covered, the letter discussed the vendor's recommended shutdown procedure. To reduce the heat load on the EDG blower, the vendor recommended when securing the unit following a test run that:

1 EDG load first be reduced to approximately 50-60 percent,
2 remove all EDG load
3 open the output breaker
4 run the engine unloaded for 3-5 minutes
5 secure the unit

At the time of this inspection, the licensee had not implemented these recommendations. They were continuing to rapidly remove full load in one step, and to run the engine unloaded for five to ten minutes, which is five minutes longer than the vendor recommendations.

(j) In September 1986, the Plant Nuclear Safety Committee (PNSC) met and determined that even though the EDG scavenging air blower were similar in design to Peach Bottom and Duane Arnold, this issue was not reportable under 10 CFR 21. At the meeting the licensee did state that Engineering was developing a special procedure to measure the differential temperature across the EDG blowers. The PNSC indicated that the results of this test would determine if any further action was necessary.

(k) In October 1986, special procedure (SP-722) was performed to determine the differential temperature. The intent of the test was to run the engine unloaded for 15 minutes while taking temperature readings every minute. The test was started on the "B" EDG and after approximately one minute the differential temperature was 117°F, 17°F greater than the vendor recommended. Although not documented, the licensee indicates that operators continued to monitor the blower temperatures for another five minutes and the

temperature continued to rapidly increase exceeding 125°F. The test was suspended and the engine was loaded to reduce blower temperatures. There was no NCR written on the failed test, and no corrective actions taken.

(l) In November 1986, the PNSC met again and reviewed the data from the failed temperature test. The PNSC closed action item 86-06. Their decision to close the action item was based on a history of successful operation of the EDGs under a no-load condition, and the fact that the blowers would eventually be replaced with units having the required clearances. The decision of the PNSC not to take immediate corrective action appeared to disregard the failed temperature test, a test on which they had committed to base the need for any additional corrective action. The PNSC also failed to address:

1. the vendor letter referencing step unloading
2. the failure to check clearances during the February 1986 inspection
3. the possible impact on the diesel blowers from the two-hour unloaded run in January 1986.
4. the evidence of rubbing in the B EDG scavenging air blower in February 1986.

(m) In 1986, Operations submitted a letter entitled "Rejection of Manufacturer's Recommendations on the EDG." Despite the fact that (a) the letter was never signed, (b) the lack of recorded blower clearances, (c) the failed temperature test, and (d) vendor recommendations were not incorporated, the letter was provided by Operations as the licensee's justification for not revising Operations procedures to the vendor recommendations. The letter stated that preventative maintenance inspections of the EDGs indicated that the components were in satisfactory condition, even though during the February 1986 inspection evidence of rubbing was noted on the "B" EDG blower.

(2) High Water Content In "B" EDG Lube Oil Chronology

(a) The licensee, on March 12, 1987, while continuing work on the replacement of the "B" EDG scavenging air blower, obtained oil samples on the "B" Emergency Diesel Generator. These samples were found to contain water levels of approximately 1900 ug/g and 2000 ug/g. These levels exceed the limit specified in PM-001, Equipment Lube Oil Sampling, of 1000 ug/g.

The high water content was initially attributed to the engine "keep warm" heaters being deenergized and condensation forming. In response to this lube oil moisture content in excess of procedural requirements, the licensee did not generate an NCR, and no corrective action was initiated.

(b) On March 13, following the blower replacement, the engine was tested for operability without changing the oil. The engine was started and subsequently tripped on high crankcase pressure. At this point, the licensee performed a preliminary inspection and determined that the most probable cause of the crankcase pressurization was due to damaged pistons and liners.

(c) On March 14, maintenance began work to replace the damaged components. As the work progressed on the piston/liner replacement, it was determined that the condition of the pistons, rings, and cylinder liners would not have significantly contributed to the crankcase pressure problem. The licensee then determined that the most likely cause was due to water in the oil. An inspection of the jacket water system was conducted and the final conclusion was that the source of water leakage was the lube oil cooler. A leak test was performed on the lube oil cooler and 28 tubes were found to be faulty. The tubes were plugged. The leak test, when performed initially was at a considerably lower pressure than called for in the Maintenance Procedure CM-201, Safety-Related Heat Exchanger Maintenance. The licensee indicated to the inspectors that they wanted to treat the cooler "gingerly" since they thought it was in a degraded condition.

(d) Between March 18 and 19, 1987, the engine rebuild was completed, the lube oil replaced, and the engine started for the manufacturers run-in procedure. Following the run-in procedure, no additional lube oil samples were taken even though the licensee had reason to believe their cooler was in a degraded condition.

(e) On March 23, 1987, during a surveillance test on the "B" EDG, the engine once again tripped on high crankcase pressure. As in the earlier case, the licensee attributed this condition to a high water level in the oil. The lube oil cooler was disassembled and another leak test at 50 psig was performed. At this point, 15 more leaking tubes were noted and plugged. The licensee conducted a second leak test to 75 psig. This test resulted in an additional plugging of five more tubes.

(f) On March 26, 1987, the "B" EDG was started for an operability test but a loose flange leaked, dumping a significant amount of oil in the area requiring a shutdown of the EDG.

(3) EDG Associated Instrument Setpoints

During the inspection, it was noted that there appeared to be a lack of control over setpoints for certain instrumentation associated with the EDGs.

Specifically, it was noted that the air compressor on the "A" EDG starting air system was cycling between 200 and 220 psig. Contrary to this, both the original pre-operational test and system description require compressor cycle points of 220 and 250 psig.

A second example was related to the EDG lube oil low pressure shutdown switches. During a tour of the diesel room, it was noted that the lube oil switches were being calibrated for 16 psig decreasing. Contrary to this, the vendor technical manual recommends 18 psig.

The licensee indicated that this setpoint change occurred years earlier in response to a vendor recommendation, and that the lower pressure setting would not adversely effect engine operation. The licensee further committed that the switch setting on the lube oil system would be changed to reflect the recommended higher value.

Resolution of the EDG air compressor cycle setpoints and implementation of the low lube oil pressure setpoint procedural change will be identified as an inspector followup item (IFI 50-261/87-06-14).

(4) Calibration of Associated EDG Equipment

Under the licensee's Calibration Program, certain instruments which are associated with emergency diesels may not be calibrated, even though these devices perform important system functions. These functions include maintaining the diesels in a ready to start mode, and alarm indication to alert the operator of adverse system conditions which could inhibit or degrade system performance.

Technical Support Management Manual, TMM-003, Q-List Control Procedure, Revision 19, identifies structures, systems and components that are designed primarily to prevent or mitigate the consequences of postulated accidents. Maintenance Management Manual Procedure, MMM-006, Calibration Program,

Revision 6, establishes the methodology to assure that active safety-related instrumentation are properly controlled and calibrated. This procedure contains two appendices. Appendix "A" is a master listing which identifies the equipment addressed by the program. Appendix "B" contains the calibration data sheets for the equipment in the calibration program. However, some instrumentation associated with emergency diesel generators which perform important system functions are not considered safety-related by the licensee (i.e., not included on Q-List and not in calibration program) and do not appear to be calibrated or maintained commensurate with their importance. The inspectors are concerned that the safety system may not function as intended during anticipated transients or design basis events. The following are examples of EDG instrumentation which are not included in the licensee's present Calibration Program:

- Emergency Diesel Generator Expansion Tank Level Switches (LS 1962 A-1, A-2, B-1, B-2) The expansion tank, is equipped with two low level switches. The uppermost of the two switches (LS 1962 A-1 and LS 1962 B-1) controls an automatic solenoid operated fill valve to replace lost coolant only when the engine is running. The lower of the two level switches (LS 1962 A-2 and LS 1962 B-2) gives a warning if the level falls to approximately four (4) inches from the bottom of the tank. This level switch actuates an alarm to alert the operator of low expansion tank level either if the engine is running or in a standby mode. Neither of these instruments are considered safety-related except from a pressure boundary point of view, and do not appear to be calibrated. The inspectors were informed that these switches are calibrated on an "as-needed" basis. There is a concern that the expansion tank may be in an undetected empty state, because of an incorrect or failed instrument.

  It should be noted that the solenoid operated by the upper level switch is powered from a safety-related AC source and that the alarm on low level operated by the lower level switch is powered from a 125 VDC safety-related source. It appears that it is the licensee's intent to ensure that these instruments remain operable.

- Standby Lube Oil Temperature Controllers (TC 4520 A and B) The standby lube oil pump is used to circulate oil to a 6 kw heater and back to the engine. A lube oil heater thermostat (TC 4520 A or B) controls a heater to maintain a lube oil temperature between 135°F and 140°F. The inspectors were informed that these controllers are calibrated on an "as-needed" basis. The inspectors were

concerned that one of these devices could be in an undetected failed state such that the lube oil is much colder than 135 degrees F. As a consequence, the diesel may require a longer starting time and may increase the likelihood of failure to start (i.e., diesel does not start within 10 seconds). If an event occurs which requires the operation of the diesels, one may fail to start (i.e., single active failure) and the other diesel may be slow to start or fail to start because of low lube oil temperatures.

It should be noted that the lube oil standby circulation pump and oil heater are powered from a safety-related AC source. It appears that it is the licensee's intent to ensure that these instruments remain operable.

- Diesel Jacket Water Thermostatic Controllers (TC 4515 A and B) Jacket water cooling system is primarily used to remove diesel heat of combustion; however, it is also used to maintain the diesel generators in a warm standby status. Jacket water is maintained between 100 and 110°F. The standby circulating coolant pump is used to circulate jacket water to a 15 kw heater and back to the engine. A thermostat (TC 4515 A or B) controls a 15 kw standby heater to maintain temperature between 100°F and 110°F. The inspectors were informed that these are calibrated on an "as-needed" basis. There is a concern that one of these devices could be in an undetected failed state such that the jacket water temperature is much lower that 100°F. As a consequence, the diesel may require a longer starting time and may increase the likelihood of failure to start (i.e., diesel does start within 10 seconds). If an event occurs which requires the operation of the diesels, one may fail to start (i.e., single active failure) and the other diesel may be slow to start or fail to start because of low engine temperatures.

It should be noted that the standby circulation coolant pump and standby heater are powered from a safety-related AC source. It appears that it is the licensee's intent to ensure that these instruments remain operable.

A number of other facilities have recently upgraded their "Q" lists to include equipment which is "important to safety" or "quality related." This upgrade helps ensure that support equipment necessary to ensure that safety-related equipment can adequately perform its intended safety function, is the recipient of adequate management controls and attention. The licensee should perform a review of their controls and calibration of non-Technical

Specification equipment important to safety, including the instrumentation noted above. If the equipment is essential to ensure the proper functioning of safety-related equipment, or to the operator's ability to access and respond to emergency conditions and transients, the Calibration Program should be reviewed to ensure adequate attention and operability. The calibration of instrumentation listed above, will be identified as inspector followup item (IFI 50-261/87-06-15).

(5) IE Bulletin 79-01, Environmental Qualification of Class 1E Equipment

IE Bulletin 79-01 requires that all Class 1E electrical equipment be environmentally qualified. An unanalyzed environmental condition can exist in the emergency diesel generator rooms which could exceed the design environmental conditions for diesel generator components.

The emergency diesel generator rooms are each provided with a ventilation system which consists of a supply subsystem and an exhaust subsystem. The subsystems contain air operated dampers which are actuated by air pressure from the plant instrument air system (a non-safety-related system). With starting of the diesels, both the supply and the exhaust subsystems are actuated to prevent excessive room temperature buildups. In addition, evaporative cooling systems cool air recirculated through the rooms.

Upon loss of instrument air pressure, which can be postulated since the instrument air system is non-safety-related, the dampers will close, blocking the ventilation air to and from the rooms. Such a loss can also incapacitate the ventilation system for the balance of the auxiliary building as described in 3.c.(6). of this report.

Electrical equipment in the diesel generator rooms is qualified for a mild environment, i.e., less than or equal to 104°F. It is likely that upon loss of ventilation to those rooms the temperature would exceed 104°F, particularly in summer conditions. The licensee has not performed an analysis to determine what the actual temperature in these rooms would be.

Normally the fire doors to the diesel generator rooms are left open which might allow some air exchange with the rest of the auxiliary building. However, an analysis has not been performed by the licensee to determine how that exchange might occur and what the temperature effects would be.

The licensee has maintained that upon loss of instrument air, operators would enter the auxiliary building to restore the system to service or to block open the dampers to the diesel generator rooms. However, as described in 3.c.(6), post accident radiation levels in the building may effectively prohibit such action. In addition, blocking open the diesel generator room dampers without restoring the balance of the auxiliary building ventilation may create an undesirable positive pressure in the building which could cause contamination releases that are unmonitored and potentially in excess of 10 CFR 100 limits as described in 3.c.(6).

The licensee has also maintained that upon loss of outside air flow through the diesel generator rooms, the ventilation system would recirculate air through the evaporative coolers (swamp coolers) which would maintain the room temperature at acceptable levels. However, no analysis has been produced which supports this hypothesis. The licensee's position on this issue is not considered credible in that with the system purely in the recirculation mode, with no outside air passing through the rooms, the air would become saturated with moisture from the coolers, at which point effective evaporation would cease.

This scenario also raises a question as to the qualification of the equipment in the room in a totally saturated environment. Operation of the diesel generator units at temperatures above the qualification temperature could reduce the life of certain components and conceivably could cause failure during an accident condition. This would be highly dependent upon the actual equilibrium temperature that would be reached with the ventilation out of service. This concern was the subject of IE Notice 87-09, Emergency Diesel Generator Room Cooling Design Deficiency.

Additionally, the above described loss of ventilation could affect both units, causing common mode failure and leaving the plant without emergency power. Further review of the EDG ventilation issue and licensee actions will be identified as inspector followup item (IFI 50-261/87-06-16).

(6) Potential Failure of the EDG Room and Auxiliary Building Ventilation Systems

The EDG ventilation system consists of a supply portion and an exhaust portion. The supply portion is composed of a belt driven supply fan, ductwork, and a fire damper which closes in the event of fire in the room. The exhaust portion includes a belt driven fan and a gravity damper which exhaust to the outside environs. There are no design features for monitoring for airborne contamination from this exhaust point.

The EDG rooms are located in the auxiliary building. Whenever the emergency diesel generators are started, the ventilation systems for the rooms are started. The supply portions are designed to supply more in to the rooms than the exhaust portion can exhaust, thereby creating a slightly higher pressure in the rooms then in the balance of the auxiliary building and causing excess air to flow from the rooms to the balance of the building. This is intended to ensure that any airborne contamination in the building does not exit through the unmonitored room ventilation exhaust.

Control of the ventilation flow for the EDG rooms and auxiliary building is accomplished with air operated dampers which are supplied from the instrument air system. The instrument air system is non-safety-related, non-Seismic Category I, and can be postulated to fail in an accident situation. Loss of this system will allow the ventilation system dampers to close, effectively shutting down auxiliary building ventilation.

The licensee has maintained that in this situation the operators would go into the auxiliary building and perform the necessary steps to restore instrument air and building ventilation. However, per the licensee's post accident radiation map of the auxiliary building, very high radiation areas exist in the locations where the operator may be required to work to restore these systems. This high radiation may effectively prohibit working in these areas.

With the Auxiliary Building Ventilation System shut down, the building cannot be maintained at a negative pressure. In this condition, untreated contamination can be released to the environs.

In the event of an emergency diesel generator actuation with subsequent actuation of the room ventilation systems and a single undetected failure in the supply portion of the systems, the affected room exhaust fans will continue to operate creating a low pressure area in the room and an unmonitored exhaust flow path from the auxiliary building, through the room, and to the outside environs could occur.

Although a failure of a supply fan motor or other electrical components of the supply portion of the system would probably be detected by the operator through control room alarms, other non-electrical failures such as bearing failure in the fan, blade thrown off, failure closed of the exhaust damper, etc., could go undetected.

The licensee has committed to performing an analysis of the offsite radiological effects of failures of the ventilation system. Review of this analysis will be identified as inspector followup item (IFI 50-261/87-06-17).

d. Quality Assurance

The inspectors reviewed the implementation of the licensee's Quality Assurance Program as associated with the emergency diesel generators (EDGs) and the electrical power system and activities. The review included an assessment of the effectiveness of the program in areas such as the identification and control of nonconforming conditions, corrective actions, and reporting.

10 CFR 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, Criterion XV requires that measures be established for identification, documentation, disposition and notification of affected organizations for nonconforming conditions in the plant. Criterion XVI sets forth the requirements for assuring that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected, and to assure that "significant conditions adverse to quality" are assessed as to cause and that corrective actions are taken to preclude recurrence. This criterion also requires that such conditions be documented and reported to appropriate levels of management.

10 CFR 50.72 and 50.73 describe the requirements for reporting to the NRC conditions that are a threat to plant safety or are outside the design bases of the plant.

It is the intent of these quality assurance regulatory requirements that unsafe or potentially unsafe conditions in nuclear power plants are promptly identified, are evaluated for safety significance in a systematic, traceable manner by appropriately qualified persons, are corrected in a timely manner, and are reported to the Commission where appropriate.

The licensee's approved QA program, delineated in section 17.2 of the updated FSAR, is required to provide controls over activities affecting the quality of structures, systems, and components to an extent consistent with their importance to safety. It also requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Additionally, for significant conditions adverse to quality, the root cause of the condition and corrective action taken shall be documented and reported to appropriate levels of management.

The deficiency reporting system is thus intended to assure that identified deficiencies are documented and reported to the appropriate levels of management to facilitate implementation of the corrective action program. Concurrently, this program is intended to assure that an assessment for significant nonconformances, independent reviews for root cause determination, impact on plant operability, nuclear safety significance, and NRC reportability requirements be conducted. Subsequent to completion of the above activities, a corrective action plan is developed to specifically address the root cause of the identified deficiency, and this plan is implemented to effectively resolve the nonconformance. Effective resolution means this particular deficiency will not recur.

The following procedures were reviewed by the inspector:

Corporate QA Department procedure QA-104, Nonconformance Control, Revision 0
Plant Operating Manual, Volume 1, Part 1
AP-002, Plant Conduct of Operations, Revision 5
AP-030, NRC Reporting Requirements, Revision 3
Plant Operating Manual, Volume 4, Part 1
MMM-014, Deficiency Tagging Program, Revision 5
MMM-003, Maintenance Work Requests, Revision 12
CP&L QA NCR Manual, Revision 9, Section 15
CP&L Maintenance Management System Procedure Manual, Revision 56, Section 3.

Procedure MMM-014 delineates the administrative controls for identification of plant deficiencies and cross references these deficiencies with written work requests. Upon identification of a plant deficiency, the initiator is required to apply a deficiency tag to the equipment, and to obtain a work request number to initiate repairs. Based on review of this procedure, adequate administrative controls have been established for a "Deficiency Tagging System."

Maintenance Work Requests (MWRs) are the administrative process established for documenting any of the following types of maintenance activity:

Corrective maintenance to plant equipment.
Calibration of plant control equipment, instrumentation, and portable M&TE.
Security system repairs.
Fire Protection systems repairs.
Welding of plant equipment, structures or components; this does not include modification related maintenance.

Maintenance Work Requests are prioritized according to six levels with the highest priority, level 1A, being applicable if a direct safety hazard exists to personnel and/or equipment.

Corporate QA organization procedure OQA-104 delineates the requirements for reporting, controlling, escalating and obtaining resolutions for safety and non-safety nonconforming items or activities, excluding the receipt inspection processes. A review for determination of significance conformance is performed by Corporate Quality Assurance for deficiencies dispositioned via this procedure. Additionally, independent reviews for root cause determination, nuclear safety significance, impact on plant operability, and NRC reporting requirements are performed for deficiencies identified as significant nonconformances.

The licensee's QA Program did not ensure that deficiencies associated with nuclear safety-related components were reviewed for significant nonconformance. Procedure AP-002, Plant Conduct of Operations, paragraph 5.4 Quality Assurance, requires that deficiencies identified by plant personnel shall be dispositioned using the QA procedure OQA-204. This procedure was however replaced by OQA-104, and AP-002 was never revised to incorporate this change.

The consequence of this error was the establishment of two separate and independent administrative processes for the identification and correction of deficiencies. The deficiency tagging and work request process used by plant staff does not provide for determination of significant nonconformance, and for the performance of the other required independent reviews. Numerous examples of deficiencies that should have been dispositioned via the NCR process were observed during this inspection.

Supporting examples that have led to this conclusion include the following:

- During an inspection of the "B" diesel generator scavenging air blower in February 1986, evidence of rubbing was documented on the maintenance work request. The licensee did not write an NCR, perform a management evaluation, report the deficiency to the Commission, or take any immediate corrective action. An NCR was finally written on this deficiency during the next inspection over one year later.

- In October 1986, the licensee conducted a special temperature test of the "B" diesel generator scavenging air blower. This test was recommended by the manufacturer and designed to ensure the blower would not overheat under no load or low load operation. The blower failed this temperature test but the licensee did not write an NCR, notify the Commission, or take any immediate corrective action.

- In March 1987, lube oil samples taken from the "B" diesel generator indicated water levels in excess of the procedurally allowed limits. The licensee did not write an NCR or take any immediate corrective action. The "B" EDG subsequently tripped twice on high crankcase pressure attributable to a leaking lube oil cooler and excess water in the lube oil.

- In August 1986, the licensee determined that the diesel generator fuel oil storage capacity was less than the seven-day fuel load supply stated in the FSAR. The licensee did not write an NCR or notify the Commission.

- In 1984, the licensee determined that during a LOCA, station service transformers 2A and 2C which supply offsite power to the emergency busses could be overloaded by as much as 47 percent. The licensee did not write an NCR or notify the Commission.

- In 1984, the safety-related "A" battery failed the five-year surveillance test. The licensee did not write an NCR or notify the Commission.

These examples of the failure to write NCRs, to perform management evaluations of safety-related deficiencies, and to take prompt corrective actions, are additional examples of failure to adequately implement the requirements of 10 CFR Appendix B as cited in violation (VIO 50-261/87-06-13).

Other observations in the area, but not related to the emergency diesel generators were as follows. Interviews with maintenance personnel corroborate the practice of plant personnel dispositioning deficiencies via the deficiency tag and work request system. The licensee's corrective action program for dispositioning identified deficiencies via the deficiency tag and maintenance work request system does not provide for a review to determine if equipment under repair is a significant nonconformance. Reviews are not required to be made to determine if corrective maintenance being performed on nuclear safety-related structures, systems, and components are significant nonconformances and that deficiencies are assessed by the appropriate levels of management for:

- Nuclear safety significance
- Impact on plant operations
- Root cause determination
- NRC reporting requirements
- Engineering evaluation

The inspectors reviewed several NCRs that were processed under the licensee's existing QA program including the following:

- NCR 86/036, March 13, 1986, Electrical Cable Tray Fill

- NCR 86/037, March 13, 1986, Auxiliary Cable Spreading Room
- NCR 86/041, March 13, 1986, Electrical Cable Routing
- NCR 86/052, April 2, 1986, Electrical Distribution.

The review indicated that the NCR system root cause determination, corrective action plans, timeliness of management response, and final disposition were adequate.

e. Design Changes and Modifications

Design control and modifications were reviewed in the disciplines of electrical, instrumentation and control, HVAC, mechanical and structural. This review focused on the emergency electrical distribution systems (both AC and DC). The emergency diesel generators and auxiliaries, and supporting systems such as the instrument air system, the diesel generator room ventilation system, and the battery room cooling system. The following are observations that were made in the course of this review:

(1) Design

(a) Control of Calculations

The licensee has established no comprehensive measures for controlling calculations which form the design and operating basis of the plant such that they can be conveniently and consistently retrieved. For this reason, the inspectors are concerned that the licensee cannot reasonably be assured of the correct translation of the design and operating basis calculations into specifications, drawings, procedures and instructions for the plant as required.

This lack of good retrievability is a product of a number of factors:

- There is no comprehensive calculation index.
- There is no central file or repository for calculations.
- There is no overall system for identifying calculations which lends itself to good retrievability.
- There are multiple organizations within and outside the licensee's organization which generate or potentially can generate calculations, each with its own system, or lack thereof, for controlling calculations.
- Many of the original design calculations are held by the original architect/engineer and/or are not available.

Design calculations must be retrievable in some reasonable fashion that relates to the structure, system, or component to which they are applicable, the subject of the calculation, the discipline, or some other pertinent classification. Without this ability to conveniently and consistently retrieve design calculations, the traceability of the plant design and operating basis ranges from difficult to virtually impossible. If design calculations cannot be retrieved with confidence, the user will resort to other sources of information which may be incorrect, incomplete, or inconsistent with the other features of the design. This can result in inadequate design or incorrect procedures which can jeopardize the safety of the plant.

(b) Final Safety Analysis Report (FSAR) as Design Document

The FSAR is intended to be a document which describes the commitments of the licensee on features and operations of the plant which are pertinent to nuclear safety. It is not necessarily a true and complete reflection of the design basis of the plant in that (1) it is often less conservative than the actual design basis, (2) it is often not complete with respect to the design features it does address, and (3) it does not address many of the design features and parameters for the plant. Although it is an important source of information, it should not be considered as the design basis for the plant unless it has been developed and maintained as such in a controlled manner.

The licensee's FSAR has not been developed or controlled as a design basis document. It does not accurately reflect the design basis of the plant as evidenced by two examples which were discovered during this inspection; the discrepancy between the FSAR statement on diesel generator fuel oil storage capacity and the actual capacity as described in Section 3.e.4.c; the listing of safety-related battery loads being incomplete as described in Section 3.e.5.b of this report.

The licensee's technical staff was using the FSAR as a design basis document, as evidenced through conversations with a number of the licensee's technical personnel and through references in design documents to the FSAR as a basis for the design. An example of incorrectly citing the FSAR as a source of design basis information is the incomplete safety-related "A" battery load listing noted above. This was used as design input for calculation EC-84-11 which addressed the load profile discharge rates.

Resolution of the licensee's control of calculations and technical staff's awareness that the FSAR is not a complete design basis document will be identified as inspector followup item (IFI 50-261/87-06-18).

(c) Modification Control

The licensee's modification and design control procedure MOD-5, Modification/Package Development and Revision, Revision 6, dated November 12, 1986 Section 5.2 states the requirements for the elements that must be included in all modification packages. Section 5.3 also lists other outputs of the modification process that are to be included in the package, if applicable. The procedure further requires that all of these elements be listed on a Contents and Distribution List which is a part of the package.

By imposing these requirements, the quality, completeness, and consistency of the modification packages can be expected to be improved over packages generated without these requirements.

Without control of the design output such as the licensee has imposed, elements that are necessary to make up a complete package can be overlooked at all stages of the process - the origination stage, the checking stage, the installation stage, and the closeout stage. The licensee's imposition of these design output requirements helps ensure that all elements of the plant design and operations that may be affected by a modification are appropriately accounted for.

(d) Drawing Discrepancies

The inspectors observed discrepancies in the design documents and drawings pertaining to the electrical distribution system as follows:

- Main one-line Drawing 5379-5372, Revision 9, was not listed as an affected document on Modification 851 due to apparent oversight. Modification 851 added 4160 volt bus 5 and 480 volt bus 5, which according to the licensee's engineering staff should be shown on the main one-line diagram.

- Drawing 5379-5372, incorrectly shows Emergency Diesel Generator (EDG) "B" as 4160 volts. EDG "B" is a 480 volt machine, same as EDG "A".

- Drawing G190625, Revision 3, incorrectly lists the secondary voltage rating of startup transformer No. 2 as 4.368 - 4.368 KVA vice KV.

- Drawing G-190625, does not indicate "L-L" or "X" to "Y" winding impedance for either the Startup Transformer No. 2 or the Unit Auxiliary Transformer No. 2. This information is available on the subject transformer nameplate. During walkdown of the startup transformer it was noted that the nameplate value for the "X" to "Y" winding impedance was 2% which is an inconsistent value for the industry.

The FSAR, design and reference documents should accurately depict and describe the station design to prevent potential errors when modifications are made to the plant design and procedures.

(2) Electrical System Design

(a) 115 Killovolt (KV) Voltage Regulation

An assessment of the adequacy of the electrical system voltages for different plant operating configurations was performed by the inspectors. Voltage drop and short-circuit studies were performed by use of the Auxiliary System Design Optimization Program (ASDOP) computer program. The basic requirement for maintaining acceptable operating terminal voltages for all equipment fed from the auxiliary electrical distribution system imposes restrictions on the permissible variation of the source voltage. The source voltage variation, 115 KV switchyard voltage limit and generator voltage range, under each plant operating condition is supplied by the Transmission Department. An evaluation of the electrical distribution system capability to support auxiliary system loads, therefore, determines the equipment voltage criteria for a particular operating condition. Five models were developed for different plant operating configurations and the source voltage limits were calculated. By selection of plant operating conditions that establish the most restrictive source voltage limits, a worst case source voltage limit was defined. The adequacy of the source voltage maximum and minimum voltage limits was then determined by comparison of the calculated values with the expected source voltage range provided by the Transmission Department.

Subsequent to a review of the post-modification test data, the inspectors identified initial voltage readings that were outside the test acceptance criteria limits. Subsequent test values were documented as being within the

acceptance limits. The inspectors conducted interviews with Nuclear Engineering Licensing Department (NELD) engineers to ascertain the cause of the higher than expected voltage readings and were informed that the discrepancy between measured and predicted voltage values were caused by the 115 KV switchyard voltage range having been changed to 116.5 KV - 117.5 KV. NELD engineers were not immediately aware of this change in the source voltage range.

This new voltage schedule of 116.5 KV off peak and 117.5 KV on peak is not in accordance with the values shown in chapter 8.0 of the FSAR. Also, because the analysis was not based on a source voltage range of 116.5 KV - 117.5 KV with existing transformer tap settings, the test acceptance voltage values were higher than that predicted by the ASDOP computer program. The inspectors further determined that NELD engineers are presently engaged in an ongoing effort to identify the cause of additional discrepancies between measured and predicted voltage values at the BOP buses. These buses have measured voltage values less than that predicted by the ASDOP computer program.

An independent verification of the predicted voltage at the emergency buses under LOCA run conditions was performed by the inspectors. A review of the results of the analysis was also performed to assess the adequacy of the auxiliary electrical distribution system voltage regulation. The inspectors determined that the expected source voltages are within the calculated source voltage limits for both voltage schedules. Equipment voltage criteria was determined to be satisfactory upon comparison with the predicted voltage produced by the ASDOP computer program. It is therefore expected that with appropriate changes to transformer tap settings, adequate voltage will be maintained at operating equipment terminals.

The inspectors reviewed logic diagrams and control wiring diagrams and verified that components operation is as described in licensee technical system description and the updated FSAR. The inspectors also conducted a review of the 4160V auto bus transfer logic which showed the various trip functions for different bus faults. Additionally, the inspectors conducted interviews with licensee engineering personnel to ascertain protection provided for clearance of faults on 4160 V bus 1. Based on discussion with these personnel and review of coordination curves of time overcurrent relays (device 51) associated with breakers 52/10 and 52/12, adequate coordination appears to exist at the 4160V level to ensure clearance of fault by the bus-tie circuit breaker.

(b) Electrical System Design Validation

The inspectors noted that design control activities did not ensure that design analyses were performed to validate the electrical system design. The electrical design had not been validated for various plant operating conditions, as described in the FSAR, as follows:

- Voltage regulation and short circuit studies were not performed for the use of the spare start-up transformer which has a lower impedance (approximately 9%) than the start-up transformer in use (impedance approximately 10%). Due to the lower impedance, additional short circuit current is available when the spare transformer is used, which was not documented and was therefore, not accounted for in any other analysis the licensee has performed. An example is that fault currents documented in a PRA to justify not upgrading the emergency bus switchgear interrupting rating (Engineering Evaluation No. 86-127 Transmittal Memorandum dated December 18, 1986) are understated by approximately 200 amperes.

  During the inspection the licensee performed preliminary voltage regulation and short circuit analyses for the use of the spare start-up transformer. Results of the preliminary voltage study indicate a slight overvoltage at non-safety-related 208 volt panels, but adequate voltage on safety-related buses.

- Voltage studies had not been performed for the condition during cold shutdown when the start-up transformer is not available and the station receives power backfed from the main transformers through the unit auxiliary transformer. Since the emergency buses E1 and E2 do not have an overvoltage alarm feature, an overvoltage during this condition could degrade safety-related equipment which would not be detected.

  The licensee performed a preliminary study during the course of the inspection which indicates that system voltages are acceptable.

- Short circuit current calculations for safety-related motor control centers had not been performed for conditions when the Emergency Diesel Generator is tested or for the return to offsite power condition post-LOCA/LOOP when the emergency bus is in parallel with the start-up transformer source. During the course of the inspection the licensee performed a -

preliminary estimate of the short circuit current at MCC 6 for normal operation and the emergency diesel generator in test, which identified a design deficiency of the circuit breakers utilized to interrupt faults for this condition. Also, formal short circuit calculations to account for the aforementioned conditions on Emergency Buses E1 and E2 were not performed, but the licensee had estimated the short circuit currents for these buses prior to the inspection. During the course of the inspection, the licensee committed to perform formal design calculations for the subject conditions for the emergency bus switchgear and motor control centers. These concerns will be evaluated when the short circuit studies are completed. Followup review of the short circuit studies is identified as inspector followup item (IFI 50-261/87-06-19).

- As described in the FSAR and Electrical System Description SD-016, Revision 21, a spare startup transformer is provided on-site should the normal startup transformer fail. According to the licensee the spare transformer can be placed in service within 24 hours.

- During a field walkdown the inspectors noted that the spare transformer H-L impedance was 9.1% on a 22,000 KVA base whereas the startup transformer in use had a H-L "X" winding impedance of 10.2% on a 22,000 KVA base. Also, the licensee was advised that the startup transformer "X" to "Y" winding impedance was noted as being 2% on a 22,000 KVA base according to the transformer name plate. This is an anomalous value. When questioned as to which value was used by the licensee in the electrical system studies it was noted that this item would be investigated to determine what should be the correct value.

Formal design analyses should be in-place to validate that the design is capable of performing its intended function and to document to engineering personnel the design bases and design conditions for the plant. The apparent lack of these analyses indicates a significant weakness in the licensee's performance of design activities.

(3) M-860, Electrical Distribution System Expansion

The team reviewed plant modification M-860, Electrical Distribution System Expansion. As a result of the review, significant design deficiencies and inadequate 10 CFR 50.59 -

safety evaluations were identified. A narrative description of Modification M-860, as well as the inspectors' findings, are presented below.

(a) Scope of M-860

The licensee management identified inadequacies in the electrical distribution system of the facility in that, under postulated LOCA conditions, station service transformers SST-2A and SST-2C would be overloaded. Each of these transformers provided a 480 V power supply to the 480 V emergency buses E1 and E2, and balance of plant (BOP) 480V buses 1 and 2. In addition, the 480 V Dedicated Shutdown Bus was fed from SST-2C. Worst case loading scenarios showed that the transformers would be carrying a load of 150% of their forced air rating, and their secondary feeder breakers and associated bus ducts would be carrying load current in excess of their ampacity rating.

Pursuant to the above deficiencies, M-860, was prepared and implemented to provide for the following:

- A reliable source of off-site power to the safety-related equipment fed from 480 V Emergency Buses E-1 and E-2
- An improvement in voltage regulation of the 480 V emergency buses E1 and E2
- A decrease in the available fault current on the 480 V system
- An increase in the capacity of the BOP buses
- A decrease of heat loading in the 4160 V switch gear room.

The scope of activities covered by M-860 involved the installation of two new three piece equipment lineups consisting of a non-fused load break disconnect switch, a current limiting reactor, and 4160 V to 480 V station service transformer. Each of these new station service transformers, SST-2F and SST-2G, provide a 480 V power supply to 480 V emergency buses E1 and E2 only, respectively. The transformer primary windings are fed from the same 4160 volt switchgear breaker compartments that presently feed SST-2A and SST-2C. Additionally, a fused load break disconnect switch with anti-single phasing system has been installed on the primary side of SST-2A and SST-2C to enable these transformers to be removed from -

services without disruption of service to the emergency buses. The fused load break disconnect switch also provides selective isolation for overloads and/or faults on the BOP system.

The undervoltage trip for 480 V breakers ensures that upon occurrence of an E-bus undervoltage, not only will the emergency bus incoming line breaker open, but the 480V BOP bus and other non-essential loads that may inadvertently be backfed by the EDG are isolated. Additionally, the emergency bus bus-tie breaker is also tripped on E-bus undervoltage thus ensuring electrical separation of both class 1E electrical trains. Logic will also ensure that offsite power cannot be closed onto an E-bus that is being fed from its respective EDG.

The basic function of the modification to the electrical distribution system is to ensure a reliable source of off-site power to the 480 V emergency buses E-1 and E-2 that meet specific performance requirements. The modified electrical distribution system, both with and without the temporary current limiting reactor, is designed to provide adequate voltage regulation.

The design basis and design analyses for M-860 were reviewed. The focus of the review was to evaluate whether the installed modifications to the electrical system adequately satisfy system design and performance requirements. Documents reviewed during the evaluation included the following:

- Design Basis Document (DBD) No. R84026, Revision 2
- System Design Calculations and Analyses for voltage regulation and short circuit currents
- Electrical System Description SD-016, Revision 21
- Electrical one-line diagrams.

(b) Design Deficiencies

Documentation reviewed indicated significant design deficiencies in the interrupting capability of the electrical protective devices utilized in the 480 volt emergency power system. Contrary to the updated FSAR, Section 8.3.1.1.4, paragraph 3, the 480 volt switchgear and motor control centers (MCCs) serving engineered safety feature (ESF) circuits are not properly coordinated electrically to permit safe operation of the equipment under short circuit conditions. In addition, a basic design function of the modifications to the electrical distribution system, as stated in DBD No. R84026, was to decrease the available

fault current on the 480 volt buses to within equipment ratings. In calculating the fault current available at the 480 volt emergency buses the licensee recognized IEEE standard 141-1976, IEEE Recommended Practice For Electric Power Distribution For Industrial Plants, as an engineering guide. Nevertheless, the equipment applied on the emergency buses does not have the rated capability to interrupt faults during various plant operating conditions, including a LOCA condition, as stated in the FSAR.

DBD No. R84026 specifically states that until the existing Westinghouse DB switchgear was replaced, (or upgraded) with switchgear having feeder breakers with at least 85,000 amps interrupting rating, the system design will include a temporary means to limit the maximum available fault current to be interrupted by an emergency feeder breaker to 50,000 amps symmetrical during non-loss of coolant accident (LOCA) operating conditions with worst case breaker lineup. The installation of a current limiting reactor was intended to ensure that the 50,000 amp symmetrical interrupting rating of the DB 50 feeder breaker would not be exceeded for a fault on the load side terminals of one of the feeder breakers during worst case lineup, non-LOCA operation. This design function has not been achieved. The following sections contain examples highlighting design deficiencies.

1 Westinghouse Type DB-50 Breaker Interrupting Capability

The licensee has performed design analyses to establish the short circuit current available in the emergency AC power system for various plant configurations, including normal operation and LOCA conditions. Although a formal study has not been performed, the licensee has estimated that during the load testing of an EDG, as prescribed in the Technical Specifications, the fault current available at a load breaker on 480 volt emergency bus E1 or E2, was 78,400 amperes symmetrical. The circuit breakers provided to interrupt this fault, Westinghouse type DB-50, have a published interrupting rating of only 50,000 amperes symmetrical. In other words, the fault current available at the DB-50 circuit breaker was over 55% greater than the circuit breaker symmetrical interrupting rating. Similarly, a computer fault analysis (I4431099 dated October 16, 1985) performed by the licensee showed that during a LOCA condition, with offsite power available, the available short circuit current at the DB-50 circuit breaker would be 59,536 -

amperes or 19% more than the breaker rated interrupting capability. For a post-LOCA/Loss of Off-site Power (LOOP) return to offsite power when the emergency bus is in parallel with the start-up transformer source, the licensee estimates that 88,400 amperes are available, or 76% more than the rated interrupting capability of the circuit breaker.

The licensee intends to submit a Probabilistic Risk Analysis (PRA) to the NRC which may attempt to justify not upgrading the switchgear interrupting capability. The inspectors reviewed the subject PRA and Engineering Evaluation No. 86-127 and the following error was identified. Appendix B, "Development of Specific Basis Events and Initiating Event," page 79, item B.3, "Power from unit auxiliary transformer," frequency value, incorrectly assumed that the electric power distribution system would be aligned to the unit auxiliary transformer only if the start-up transformer is out of service due to a failure. However, the unit auxiliary transformer normally provides power to the station regardless of the start-up transformer condition. The calculation in Appendix D, Core Melt Frequency Calculation Method, page 102, the term for case 7 included a term for the postulated failure of the start-up transformer. Case 7 condition, power from unit auxiliary transformer/emergency diesel generator in test, startup transformer failure, does not need to be postulated. However, by deleting the power from unit auxiliary transformer term, or 1.3E-02 from the case 7 core melt frequency calculation, the worst case core melt frequency for this case changes from 1.25E-07 (as noted on table 3.3 "Accident Analysis Results," page 11) to 9.6E-06. This change was considered to be a significant contributor to the core melt frequency. This case and other non-conservative assumptions identified by the inspectors are under review by the licensee.

The inspectors were concerned that should a DB-50 circuit breaker fail in attempting to interrupt a feeder fault, such as during the load testing of an EDG on the same bus, a catastrophic failure of Emergency Bus E1 or E2 could occur, potentially damaging or degrading the redundant emergency bus switchgear or other vital equipment such as the redundant vital inverters A and B and MCCs which are located in the area. This concern was also iterated in the licensee's engineering document Project Identification PID-86-070/00. The inadequacy of the DB-50 circuit breaker to interrupt faults on the

systems on which it is applied represents a deviation from FSAR Section 8.3.1.1.4 which states that the 480 volt switchgear "... is properly coordinated electrically to permit safe operation of the equipment under normal and short circuit conditions." This item will remain unresolved pending NRC review of the licensee's DB-50 circuit breakers not being properly coordinated electrically and the acceptability of performing a PRA in lieu of equipment change out. This item will be identified as an unresolved item (URI 50-261/87-06-20).

2 Westinghouse Type FA, FB And EHB Molded Case Circuit Breaker Interrupting Capability

According to licensee calculations (computer run I4431099 dated October 16, 1985), during LOCA conditions with offsite power available 14,532 amperes of fault current are available on safety-related MCC-5. The circuit breakers utilized on the MCC are Westinghouse type FA, FB and EHB and have a manufacturer's published interrupting rating of 14,000 amperes symmetrical. The licensee has performed an interrupting capacity evaluation, calculation set RN107-E-41-F, Revision 0, which determined that the interrupting capacity is acceptable. However, this evaluation only considered a current asymmetry due to a fault X/R of 6.6 or less. In discussion with the licensee, it was established that the fault X/R could be in the range of 8 to 16. For an X/R of 16, ANSI C37.13-1981 recommends using a multiplying factor on the calculated short circuit current between 1.11 and 1.15, to establish the required symmetrical current interrupting capability of the breaker. Using a 1.12 multiplying factor (for X/R=16), the required symmetrical capability is 1.12 X 14,532 or 16,275 amperes, which exceeds the rated symmetrical interrupting capability of the circuit breaker by 16%.

During the course of the inspection, the licensee performed a preliminary estimate of the available short circuit current at the subject breakers for normal full power plant operating conditions and the EDG in test. The licensee has estimated that during this condition over 19,000 amperes symmetrical fault currents are available on safety-related MCC 5 and 6. Adjusting this value for an assumed fault for X/R=16 produces a required symmetrical interrupting capability of 1.12 X 19,000 or 21,280 amperes. This required capability exceeds the breaker rated symmetrical interrupting capability by 52%.

Calculation set RN107-E-41-F, MCC 5/6 Breaker Interrupting Capacity Evaluation, is under review by the licensee as a result of the fault X/R issue identified above. Should the subject circuit breakers attempt to interrupt a fault during the conditions described, a catastrophic failure of the circuit breaker and MCC can result, leading to secondary effects such as fire. In the area of train A MCC 5, redundant train cabling is within approximately five (5) feet vertically. The B diesel generator non-segregated phase bus is within approximately thirteen (13) feet vertically. Train "B" MCC 6 is located in the Emergency Bus E1 and E2 switchgear room where various redundant safety equipment is located.

For a postulated failure of MCC 5 (which is utilized on Dedicated Shutdown through an alternate feed from the dedicated shutdown bus) during a LOOP, redundant safety train cabling and the B EDG feeder bus may be affected resulting in a loss of power to MCC 6. The inspectors are concerned that should the subject circuit breaker(s) fail in attempting to interrupt a feeder fault, such as during a LOCA or the load testing of an emergency diesel generator, a failure of the MCC could occur, potentially damaging or degrading the redundant shutdown train. The potential for damage to redundant train safety equipment during a LOCA is an unanalyzed condition.

The inadequacy of the subject circuit breakers to interrupt faults on the systems on which it is applied represents a deviation from FSAR Section 8.3.1.1.4 which states that the 480 volt motor control centers "... is properly coordinated electrically to permit safe operation of the equipment under normal and short circuit conditions." A review of the update by the licensee of MCC 5/6 Breaker Interrupting Capacity Evaluation will be an inspector followup item (IFI 50-261/87-06-21).

(4) EDG Design and Modification

(a) EDG Logic

The EDG provides 480V power to emergency buses E-1 and E-2 in the event of an emergency bus undervoltage signal being generated, or the initiation of a safety injection signal.

An assessment of the EDG start and loading sequence was performed to determine consistency with the FSAR descriptions, EDG load sequence and licensee system descriptions.

Based on this review, the inspectors determined that the SI sequence logic is as described in licensee technical system descriptions and the updated FSAR. Also, loading of the E-buses are in accordance with FSAR Table 8.3.1-5.

The inspectors reviewed the blackout sequence logic. A plant blackout is defined as a loss of offsite power (LOOP) to the emergency buses E-1 and E-2. Upon occurrence of a LOOP, the blackout sequence logic initiates an auto-start of the EDG. This causes the E-buses to isolate by tripping incoming feeder circuit breakers 52-18B and 52-28B, and 480V BOP buses 1 and 3 feeder circuit breakers (52-1B and 52-2B; and 52-16B and 52-15B). All loads on the 480V emergency buses are removed by tripping their feeder breakers with the exception of the feeder breaker for MCC-5 on Bus E-1, and MCC-6 on Bus E-2.

The EDG output breaker closes when output voltage has increased, and after a two seconds time delay to ensure that the E buses are de-energized. The blackout sequence logic is enabled upon loss of voltage to the E-buses. A block signal is also placed on the "A" and "B" auxiliary feedwater pumps by the LOOP to prevent their breakers from closing due to a loss of feed pumps or a low-low level in a steam generator.

(b) EDG Loading

A basic design criteria for the EDG is that they provide sufficient electrical power to engineered safety features equipment and equipment important to safety which must operate to mitigate the consequences of design basis accidents. Worst case EDG load profiles were reviewed and compared to the capacity of the EDG to verify that this design criteria had been met.

The facility has two safety-related EDGs manufactured by Fairbanks Morse Company with the following electrical ratings:

- Continuous load rating	2500 KW
- Overload rating	2750 KW
- 168-hour rating	3250 KW
- Output voltage	480 volts
- Diesel engine power	3500 HP (2611 KW)

The sum of the loads that are automatically sequenced onto the EDG upon receipt of a safety injection (SI) signal are equal to 2325 KW. Automatic initiation of a containment spray pump would add 166 KW, making a total of 2491 KW - automatically connected SI loads.

Due to loading considerations, the control logic does not permit both containment spray and component cooling water to operate simultaneously for a loss of offsite power with an SI condition. According to the emergency operating procedures, the operator would manually energize the component cooling water pump if a containment spray signal is not present since it is desirable to have the component cooling water system in operation for most scenarios. Component cooling water however, is not necessary during the injection phase of an SI sequence. When the operator adds a component cooling water pump to the automatically sequenced loads, the total EDG load would be 2616 KW. Besides the SI equipment, there are some safety-related as well as essential balance of plant equipment that represent a potential additional load of 331 KW for the EDG.

Of this 331 KW potential additional load, about 187 KW may only be energized by manual operator action and, 144 KW may be cycled on by process variables, without operator action, after the operator resets the SI actuation signal. The SI loads (2616 KW) plus the non-SI loads (331 KW) represent a maximum potential load for the EDG of about 2947 KW.

The time duration of the SI loads is dependent on the particular accident scenario (i.e., large break Loss Of Coolant Accident, LOCA, small break LOCA, etc.), and operator action to remove loads as the need for them terminates.

(c) EDG Fuel Oil Storage

During the inspectors' review of EDG fuel oil storage capacity the following were noted:

- The Fuel Oil Day Tanks for the EDGs are not anchored to the floor however, fuel lines and vent piping connected to the tanks are anchored to the EDG room wall. This arrangement could allow free movement of the day tank during a seismic event and possibly cause a failure in the fuel supply to the EDG. The licensee performed a seismic calculation prior to the inspectors' exit, which indicated that the tank was adequately mounted.

- Updated FSAR, Section 8.3.1.1.5.1 states that "A minimum of 25,000 gallons of fuel oil is maintained on site. This is sufficient to operate one diesel at full load for seven days". The actual fuel oil storage on site is in fact not sufficient to operate one diesel at full load for seven days.

- In memos within the licensee's organization (Ben Furr to Guy Beatty, dated October 10, 1969) and the licensee's architect/engineer's organization (H. Arendsee to E. Chao, Dated October 14, 1969), it was revealed that at the full load fuel consumption rate indicated by the factory tests (174 gallons per hour), the 25,000 gallon on-site fuel oil storage was sufficient for only 6.15 days at best of full load operation for one diesel generator. (Note: Inspector's calculation yields 5.99 days capacity at this consumption rate).

- This information was "rediscovered" by one of the licensee's engineers and brought to the attention of the licensee's Regulatory Compliance Group in August, 1986.

- Section 3.7 of the Technical Specifications addresses auxiliary electrical systems. The basis portion of this section states that "Therefore, total on-site diesel fuel storage capacity shall not be less than seven days for minimum safety feature equipment operation". Minimum safety feature equipment operation electrical loads may be less than full load for the diesel generator for the later stages of response to an accident situation. This statement is not consistent with the FSAR commitment to provide seven days capacity at full load operation.

- Even though seven days full load capacity is not available, the capacity to meet the potentially lesser Technical Specification requirement may exist. In fact, an informal calculation has been performed by the licensee showing this to be the case. This, however, has not been shown to be the case through formal testing or analysis by the licensee.

Having less than seven days capacity, in and of itself, may not be significant because of the availability of resupply sources. However, the concern over fuel oil sampling as identified in Section 3.b.(2)(c) increases the significance of the concern. The fact that this reduced capacity is not noted in the FSAR is significant since steps to effect resupply may be based on the FSAR statement and may not provide additional fuel in time before the on-site fuel supply is exhausted. Performance of an analysis or testing to verify the actual storage capacity needs and possible subsequent revision of the FSAR and Technical Specification to reflect these results will be identified as an inspector followup item (IFI 50-261/87-06-22).

(d) EDG Starting Air Systems

During the inspectors walkdown of the EDG, starting air systems drawing G-190204-A, revision 10, was used and found to be incorrect concerning the piping arrangement associated with Pressure Switches (PS-1961A and PS-1961B) and valves (DA-2A, DA-2B, DA-34A, and DA-34B). The pressure switches control the cycling points of both EDG starting air compressors insuring a sufficient supply of starting air is available. The drawing also shows two Pressure Indicators (PI-1961A and PI-1961C) which are not presently installed in the system.

In 1984, design modifications were made to the emergency diesel generator starting air system to eliminate short cycling of the air compressors and to add a boundary valve between the safety-related and non-safety-related portions of the system. Several drawing errors were made or perpetuated with these design modification packages. They are as follows:

- The starting air flow diagram, drawing number G-190204-A, Sheet 1 of 3, Rev. 10 shows the piping from the new receiver control taps and from the line taps being attached to the compressor control pressure switches, PS-1961 A and B, at two separate connections each. In actuality, the two lines join together and connect to each pressure switch with a common line. This same error is reflected in modification package M-763, Drawing R-A and B, page 66 of the package.

- Modification package M-585-2 adds second check valves, DA-33A and DA-33B, in each of the supply lines to the starting air receivers to provide redundant isolation between the Q and non-Q portions of the piping system. This change was not incorporated in control drawings A-190301, Sheets 1961A and B.

- Control drawings A-190301, Sheets 1961 A and B do not show the piping and valves associated with the line taps for controlling the air compressors.

- Flow diagram G-190204-A, Sheet 1, Rev. 10 has not been changed to reflect new valve numbers per DCN 763-1 dated September, 1984.

Drawings which do not accurately reflect the true plant design, particularly on safety-related systems, can contribute to errors in operations, engineering, maintenance etc., which can jeopardize the safety of the plant.

Review of the two concerns in the EDG starting air system will be identified as inspector followup item (IFI 50-261/87-06-23).

(e) Seismic Concern in Modification Packages

Design Modification Package M-585-2, Rev. 0 contains a calculation (84032-M-01F, Rev. 0) of the effects on seismic qualification of the addition of a second valve in each of the 3/4" lines between the diesel generator starting air dryers and the air receivers. These valves are intended to provide redundant isolation between the Q and the non-Q portions of the system. This calculation purports to show that the piping system is qualified with the addition of the new valve. Although there are no stated acceptance criteria in this calculation, the acceptance of the results of the calculation appears improper as described in the following paragraphs:

- This calculation addresses the static loading stresses in the piping as a result of the addition of the second check valve. It does not address the dynamics of a seismic event or the effects the addition of such a mass would have on the dynamic response of the piping. Such an addition could profoundly alter the natural frequency of the piping, potentially putting it in the frequency spectrum of the seismic event, in which case the accelerations could be significantly above those of the building response spectra.

- The static analysis that is performed in this calculation does not look at the actual stresses associated with the addition of the new valve, but rather at the percent change in stresses. It concludes that since the increase (for the static case only) is only six percent, "this is not considered significant". However, it does not address what the stresses were before the addition of the valve. Therefore, the conclusion that six percent more is satisfactory may not be valid. If the stresses before had been close to the allowable maximum, then a six percent increase could be greater than the allowable maximum.

- The calculation assumes that only the mass of the valves, fittings, and piping from the receiver to the vertical portion of piping is cantilevered from the receiver. Inspection reveals that, in addition, in the vertical direction, the vertical portion of piping

plus the air dryer and associated piping could also be cantilevered. This increases the mass to several times greater than that used.

In the present form this calculation does not show that this piping is seismically qualified. Possible failure of this piping in a seismic event could render the emergency diesel generator air starting system inoperable, thereby rendering the unit itself inoperable. Because this analysis is applicable to both units, such a failure could be a common mode failure in both units which would cause loss of all emergency AC power.

Subsequent to the inspectors' discovery of this problem, the licensee performed a reanalysis of the piping in question. The reanalysis indicated the piping system to be satisfactory. Review of the licensee's seismic analysis for the pipe connection to the air dryer will be identified as an inspector followup item (IFI 50-261/87-06-24).

(5) Direct Current (DC) Distribution System

(a) DC Hardware Installation

- Replacement safety-related batteries and racks were installed in 1978 under modification M-424. This package identified that the manufacturer's mounting instructions for the battery racks would be required for installing the racks. Only the battery rack assembly drawing could be located by the licensee and this only gave the location of the anchor bolt holes. No acceptable torque values were indicated for the anchor bolts. In response to the inspectors' concern, the licensee checked the as-installed anchor bolt torque and found that one of the bolts on the "A" battery rack turned freely. It is the inspectors' understanding that the licensee will perform an analysis to determine the adequacy of the battery rack mounting.

  The cells were installed on the seismic racks with an older style crushable spacer material placed between the cells to absorb seismic shock. The licensee had substituted plywood for these spacers between some of the cells. From previous experience the inspectors were aware that the battery manufacturer had performed

generic seismic qualification testing on this type cell and the initial test failures were attributed to the type spacer material presently installed at the facility. The manufacturer had substituted a spacer of a different material which would revert back to its original shape, and successfully retested these type cells. The inspectors noticed that the Class 1 batteries at the facility were not refurbished with these newer cell spaces. In addition to the plywood between some of the cells, the licensee apparently used sheets of marinite to fill the space between the end cells and the battery rack end stringers without justification.

The inspector was concerned that under a seismic event both Class 1 batteries may be damaged and may not be able to fulfill their safety requirements. In response the licensee contacted the vendor (Gould/GNB) who has advised the licensee that the failure experienced in 1980 (Referenced Wyle Test Report No. 44681) occurred at a substantially higher acceleration than that specified for the facility (6.0g vs. 0.5g). Therefore, this failure mechanism for the spacer material does not exist at the facility. However, the manufacturer recommended that the plywood and marinite spacers should be replaced.

- Modification M-831 added a nonseismic sheet metal penthouse to the roof of the Auxiliary building to house the new non-safety, nonseismic C battery. The battery consists of 58 NCX 1800 cells, each containing 7.6 gallons of electrolyte. The battery cells were installed on nonseismic racks with no cell restraints. The battery room floor (the auxiliary building roof) was not prepared with an acid resistant finish. In the event of a seismic disturbance, failure of the C battery could result in 440 gallons of electrolyte (containing sulfuric acid) attacking the auxiliary building roof. The inspectors were concerned that this might in turn compromise safety-related equipment in the building rooms below. It is the inspectors' understanding that, in response to this item, the licensee will apply an acid-resistant protective coating to the section of the auxiliary building roof that forms the floor of the C battery room.

- The manufacturer's outline drawing for the Class 1 battery inverters (5379-4645) states that three feet is required in front and behind the inverters to provide sufficient space for access and ventilation.

The manufacturer's instruction manual (I.B. 19-600-37) states that three inches must be provided around the inverter in order to provide sufficient space for ventilation.

The Class 1 inverters at Robinson are attached to the wall with essentially no clearance. While the team acknowledges that the major heat source in the cabinets (the voltage regulating transformers) had been removed early in the plant life, the team is concerned that it appears that the original installation ignored the manufacturer's ventilation requirements for this equipment. The licensee has advised the team that Westinghouse has verbally confirmed that no spacing is required since the Sola transformers have been removed from the inverter cabinets. The team believes that the earlier modification should be reflected in the plant's drawings and instruction manuals.

(b) Battery Load Design

The licensee replaced the original Class 1 batteries in 1978 with batteries of slightly larger capacity. The licensee failed to review the original requirements for adequacy or review the present loading to ensure that the new batteries would have sufficient capacity to perform their safety function based upon the assumption that the FSAR battery load table (8.3.2-1) was complete. The team identified a number of safety- and non-safety-related loads that were not included on the FSAR tables but would be a load on the dc system, including:

- Diesel generator control and field flashing
- 480 volt switchgear breaker control
- 4160 Volt switchgear breaker control

The FSAR battery load table lists loads in differing units hp, kVA, kW, and amperes. It does not include a figure describing the complete load profile. However, calculation EC-84-11 was prepared in 1984 following the transfer of the T/G auxiliary dc motors to the new non-safety-related "C" battery. Not only did this calculation use the FSAR table of dc loads as the design basis, but it incorrectly assumed the inverters to be constant load devices and did not assume any efficiency losses in calculating the required dc input currents. Inverters, being constant kVA loads, will draw higher currents as the voltage decreases at the start, and during, a battery discharge.

Although the 1984 calculation referenced IEEE standard 485-1978 "Recommended Practice for Sizing Large Lead Storage Batteries", it did not check the adequacy of the cell size that was selected in 1978. This standard recommends that correction factors be included for such things as aging and minimum electrolyte temperature. Available capacity decreases at temperatures below the nominal 77°F cell rating. The Robinson daily battery surveillance procedure (MST-902) accepts cell temperatures down to 50°F. Based upon the temperature correction tables in IEEE 485, this would account for a loss of capacity of approximately 19%. In their letter to the NRC (RNPD/85-907), CP&L stated that the battery vendor had demonstrated that sufficient capacity exists in the Robinson batteries to operate down to 38°F. However, the team confirmed that this was based on the latest FSAR load table which did not include all of the DC loads. It appears that the "A" Battery may now have sufficient margin to account for a lower than rated temperature because of the 1984 reduction in load. However, based upon the inspectors' estimate of the missing loads identified above, it is not clear that the "B" battery could support the required discharge at this minimum temperature. It is the inspectors' understanding that the licensee, has now assigned their Nuclear Engineering and Licensing Department to develop a comprehensive assessment of the dc loads on the safety-related batteries.

Corporate Nuclear Safety (CNS) performed a study to assess the ability of RNP-2 to withstand a blackout without a second startup transformer (CNS-86-204). As part of this study, CNS included a review of the capability of the safety-related batteries to today's standards (IEEE-485-1983). The study identified safety-related loads not included in the FSAR load table and therefore not included in earlier battery sizing calculations or Technical Specification surveillance testing. The one load group identified by CNS was the switchgear control close and trip currents. Because of the errors made in this appended battery study (battery capacity figures and minimum design temperature), it appeared to CNS that the present battery had sufficient capacity. The inspectors were concerned that the additional load identified in the study should have initiated an investigation into the acceptability of the existing FSAR load table and surveillance load discharge test profile. The inspectors are concerned with this lack of interface between different departments in the licensee's organization.

In order to maintain DC power on Bus "A" during the surveillance discharge test of battery "A", the tie breakers are closed between Buses "A" and "B." The load discharge test procedure, EST-012, Section 5.7, directs the operator to feed the "A" Bus from the "B" battery. This breaker lineup is only permitted during the cold shutdown discharge testing for the "A" or "B" batteries. However, it results in all the plant DC loads being fed from the "B" battery and battery charger. The loads on the "A" Bus alone require a battery three times larger than the "B" battery (1050 AH/340 AH = 3). In the event of a loss of offsite power during this time, the inspectors are concerned that the load on the "B" battery could be larger than the design and test loads. This is an unanalyzed condition. The inspectors' estimates that, given a loss of ac power, the battery voltage would immediately drop below 105 volts which could result in a trip of the instrument inverters and the loss of all plant instrumentation.

The preceding concerns identified in the battery area are identified as inspector followup item (IFI 50-261/87-06-25).

(c) DC Short Circuit Calculations

The inspectors reviewed the safety-related dc short circuit calculation which was performed as part of the dc coordination study (RN107-E-35-F, Rev. 0, 8/7/86). The inspectors found several erroneous assumptions in the calculations:

- The calculated battery short circuit capacity was less than the manufacturer's tested value;

- The battery short circuit capacity was not adjusted for maximum permitted cell temperature, neglecting this source of increased battery short circuit current; and

- The tie breakers were assumed not to be closed. However, FSAR Section 8.1.2.5, Technical Specification 3.7.3, and DC Operations Procedure, OP-601 indicated that the tie breakers must be closed during periods of battery charger maintenance. Closed tie breakers would result in combined short circuit contributions from both "A" and "B" batteries.

The original short circuit study concluded that the maximum short circuit was approximately 9700 amperes. With the appropriate corrections to the above errors incorporated into the short circuit calculation, the inspectors estimate-

that the dc short circuit will be at least 1000 amperes above the breaker ratings of 10,000 amperes. This will remain an inspector followup item (IFI 50-261/87-04-26) pending followup by NRC.

The non-safety-related "C" battery was added in 1984 to assume some of the "A" battery load. The team found that no short circuit studies were performed for the "C" battery. The "C" battery is rated approximately 70% larger than the "A" battery (1800 AH/1050 AH) with a corresponding higher potential short circuit current. The "C" panel board consists of Westinghouse type EB breakers which are only rated for 5000 amperes. The "C" panel board is connected directly to the battery terminals. The team considers this a potential personnel safety hazard with no nuclear safety significance.

Attachments:
1. Appendix A
2. Appendix B

APPENDIX A

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#G. Wiseman, Fire Protection Engineer

NRC Resident Inspectors

*#H. E. Krug
*R. M. Latta

*Individuals, other than team members, present at the exit on March 27, 1987.
#Individuals, other than team members, present at the exit on April 15, 1987

APPENDIX B

CAROLINA POWER AND LIGHT COMPANY
SSFI
FOLLOWUP INITIATIVES

PRESENTED TO
NRC REGION II
ATLANTA, GEORGIA

APRIL 15, 1987

CAROLINA POWER AND LIGHT COMPANY

SSFI

FOLLOWUP INITIATIVES

- o ELECTRICAL SYSTEMS
  - o DB-50 INTERRUPT CAPABILITY
  - o MOLDED CASE BREAKERS - INTERRUPT CAPABILITY
  - o DC SYSTEM - SHORT CIRCUIT ANALYSIS

- o STATION BATTERIES
  - o SIZING
  - o SURVEILLANCE

- o DIESEL GENERATORS
  - o SCAVENGING AIR BLOWER
  - o GOVERNOR OPERATION
  - o SUPPORT COOLERS
  - o VENDOR RECOMMENDATIONS

- o DEDICATED SHUTDOWN
  - o PROCEDURES
  - o COMMUNICATIONS
  - o EMERGENCY LIGHTING

CAROLINA POWER AND LIGHT COMPANY

SSFI

FOLLOWUP INITIATIVES

o ELECTRICAL SYSTEMS	
o DB-50 INTERRUPT CAPABILITY	W. J. FLANAGAN
o MOLDED CASE BREAKERS - INTERRUPT CAPABILITY	W. J. FLANAGAN
o DC SYSTEM - SHORT CIRCUIT ANALYSIS	W. J. FLANAGAN
o STATION BATTERIES	
o SIZING	J. M. CURLEY
o SURVEILLANCE	J. M. CURLEY
o DIESEL GENERATORS	
o SCAVENGING AIR BLOWER	J. M. CURLEY
o GOVERNOR OPERATION	J. M. CURLEY
o SUPPORT COOLERS	J. M. CURLEY
o VENDOR RECOMMENDATIONS	J. M. CURLEY
o DEDICATED SHUTDOWN	
o PROCEDURES	J. M. CURLEY
o COMMUNICATIONS	J. M. CURLEY
o EMERGENCY LIGHTING	J. M. CURLEY

ELECTRICAL SYSTEMS - DB-50 INTERRUPT CAPABILITY

OBJECTIVE: PRIOR TO RETURN TO POWER, ESTABLISH THE ADEQUACY OF THE EMERGENCY POWER SYSTEM TO BRING THE PLANT TO A SAFE SHUTDOWN FOLLOWING A DESIGN BASIS EVENT

PLAN: REVISE THE PRA ASSOCIATED WITH FAULTED OPERATION OF DB-50 BREAKER TO ADDRESS CONCERNS RAISED BY SSFI TEAM.

ELECTRICAL SYSTEMS - MOLDED CASE BREAKER INTERRUPT CAPABILITY

OBJECTIVE: PRIOR TO RETURN TO POWER, ESTABLISH THE ADEQUACY OF THE EMERGENCY POWER SYSTEM MOLDED CASE BREAKERS TO SUPPORT SAFE SHUTDOWN FOLLOWING A DESIGN BASIS EVENT

PLAN: DEMONSTRATE THROUGH CALCULATIONS THE ABILITY OF THE MOLDED CASE BREAKERS ON MCC-5 AND 6 TO SAFELY INTERRUPT SHORT CIRCUIT CURRENT.

ELECTRICAL SYSTEMS - DC SHORT CIRCUIT ANALYSIS

OBJECTIVE: PRIOR TO RETURN TO POWER, ESTABLISH THE ADEQUACY OF THE SAFETY RELATED DC ELECTRICAL SYSTEM TO BRING THE PLANT TO A SAFE SHUTDOWN FOLLOWING A DESIGN BASIS EVENT

PLAN:

- REVIEW DESIGN DOCUMENTATION
- FIELD VERIFY DESIGN
- GENERATE "AS-BUILT" SHORT CIRCUIT CALCULATIONS

STATION BATTERIES - SIZING

OBJECTIVE: PRIOR TO RETURN TO POWER, ESTABLISH THE ADEQUACY OF THE SAFETY RELATED BATTERIES TO BRING THE PLANT TO A SAFE SHUTDOWN FOLLOWING A DESIGN BASIS EVENT

PLAN:

- o REVIEW DESIGN DOCUMENTATION
- o FIELD VERIFY DESIGN
- o ESTABLISH "AS-BUILT" LOAD PROFILE
- o GENERATE "AS-BUILT" SIZING CALCULATIONS
- o DEMONSTRATE ADEQUACY OF BATTERIES

STATION BATTERIES - SURVEILLANCE

OBJECTIVE: STRENGTHEN BATTERY TESTING PROGRAM TO PROVIDE BATTERY PERFORMANCE TRENDING IN ADDITION TO THAT REQUIRED BY PLANT TECHNICAL SPECIFICATIONS. IEEE STANDARD 450 WILL BE USED FOR GUIDANCE IN THIS UPGRADE.

STATUS:

- o IDENTIFIED NEED TO DO SERVICE TEST THIS OUTAGE.
- o FUTURE TESTING, TO PROVIDE CONTINUED ASSURANCE OF BATTERY OPERABILITY, STILL BEING EVALUATED.

DIESEL GENERATORS - SCAVENGING AIR BLOWER

OBJECTIVE: TO ENSURE THAT THE SCAVENGING AIR BLOWER (SAB) ON EACH D/G IS OPERATED IN ACCORDANCE WITH VENDOR RECOMMENDATIONS PRIOR TO RETURN TO POWER

STATUS:

- o "B" SAB REPLACED WITH MODIFIED UNIT
- o "A" SAB ROTOR TO CASING CLEARANCE VERIFIED TO MEET VENDOR RECOMMENDATIONS
- o DAMAGED SAB (FROM "B" D/G) RETURNED FOR FAILURE ANALYSIS AND MODIFICATION
- o MODIFIED SAB TO BE SHIPPED 5-31-87 (CURRENT SCHEDULE)

DIESEL GENERATORS - GOVERNOR OPERATION

OBJECTIVE: ENSURE LOAD DROP-OFF OBSERVED WHEN RUNNING D/G PARALLELED TO GRID DOES NOT OCCUR WHEN D/G IS OPERATED AND SEPARATED FROM GRID. COMPLETE PRIOR TO RETURN TO POWER.

STATUS:

- o 15 MINUTE RUN (4-3-87) AT 400 KW SUCCESSFUL
- o 15 MINUTE RUN (4-12-87) AT 1000 KW SUCCESSFUL
- o ADDITIONAL TESTING TO BE DONE AT FACTORY

DIESEL GENERATORS - SUPPORT COOLERS

OBJECTIVE: REPLACE (3) SW SUPPORT COOLERS FOR EACH D/G DURING OUTAGE.

STATUS:

- o "B" LO COOLER REPLACED
- o 5 REMAINING COOLERS - DELIVERY WEEK OF 4-13-87
- o FAILURE ANALYSIS ON FAILED COOLER IN PROGRESS

DIESEL GENERATORS - VENDOR RECOMMENDATIONS

OBJECTIVE: TO REVIEW ALL CURRENT VENDOR RECOMMENDATIONS REGARDING OPERATION OF D/G's. IMPLEMENT APPLICABLE RECOMMENDATIONS PRIOR TO RETURN TO POWER. REVIEW CURRENT VENDOR RECOMMENDATION PROGRAM AND REVISE AS NEEDED.

STATUS:

- o 5 MINUTE NO/LOW LOAD RUN TIME LIMIT CURRENTLY IMPOSED ON "A" D/G
- o STEP LOAD REDUCTION RECOMMENDATION IMPLEMENTED

DEDICATED SHUTDOWN - PROCEDURES

OBJECTIVE: CONDUCT A REVIEW OF DS PROCEDURES "HOT SHUTDOWN USING THE DEDICATED/ ALTERNATE SHUTDOWN SYSTEM" AND "COLD SHUTDOWN USING THE DEDICATED/ ALTERNATE SHUTDOWN SYSTEM" FOR TECHNICAL CONTENT, HUMAN FACTORS AND PROCEDURE ENTRY REQUIREMENTS. UPGRADE PROCEDURES AND CONDUCT TRAINING FOR THOSE OPERATORS REQUIRED TO USE THE PROCEDURES PRIOR TO RETURN TO POWER

STATUS:

- o REVIEW IN PROGRESS

DEDICATED SHUTDOWN - COMMUNICATIONS

OBJECTIVE: ENSURE OPERATORS CAN CONDUCT REQUIRED COMMUNICATIONS TO SUPPORT DEDICATED (REMOTE) SHUTDOWN OF PLANT. COMPLETE PRIOR TO RETURN TO POWER

STATUS:

- o REPEATER TO ENHANCE OPERATION OF HAND HELD RADIOS (DS POWER SUPPLIED)
- o FCC LICENSE PENDING - JUNE 1987
- o CONTINGENCY PLAN FOR RETURN TO POWER USING EXISTING RADIO SYSTEM

DEDICATED SHUTDOWN - EMERGENCY LIGHTING

OBJECTIVE: PRIOR TO RETURN TO POWER, ENSURE SUFFICIENT LIGHTING IS AVAILABLE TO SUPPORT DEDICATED (REDUCED) SHUTDOWN OF PLANT

PLAN:

- o REVIEW EXISTING LIGHTING/COMMITMENTS
- o REVIEW TEST TO SATISFY APPENDIX R
- o DEVELOP LONG TERM/SHORT TERM CORRECTIVE ACTIONS AS NEEDED

SSFI INITIATIVES CURRENT SCHEDULE SUMMARY

PRIOR TO RETURN TO POWER

- o REVISE PRA FOR DB-50 BREAKER FAULTED OPERATION
- o ADDRESS MOLDED CASE BREAKER ISSUE
- o VERIFY DC SYSTEM SHORT CIRCUIT CAPABILITY
- o DETERMINE STATION BATTERY AS-BUILT LOAD PROFILE
- o CONDUCT STATION BATTERY SERVICE TEST TO VERIFY BATTERY CAPABILITY WITH NEW PROFILE
- o ENSURE D/G SCAVENGING AIR BLOWER OPERATION MEETS VENDOR RECOMMENDATION
- o VERIFY "A" D/G GOVERNOR OPERABILITY
- o REPLACE ALL D/G SW COOLERS
- o COMPLETE REVIEW OF D/G VENDOR RECOMMENDATIONS - DEVELOP PLAN FOR IMPLEMENTING ADDITIONAL RECOMMENDATIONS AS NEEDED
- o UPGRADE DS PROCEDURES (2) - CONDUCT TRAINING
- o PROVIDE FOR COMMUNICATION TO SUPPORT DS SHUTDOWN
- o AUGMENT EMERGENCY LIGHTING TO SUPPORT DS SHUTDOWN AS NEEDED

SSFI INITIATIVES CURRENT SCHEDULE SUMMARY

FUTURE (PROJECTED COMPLETION TARGET)

o DS COMMUNICATIONS FINAL UPGRADE	- JUNE 1987
o BATTERY SURVEILLANCE PROGRAM	- DECEMBER 1987
o REVISE VENDOR RECOMMENDATION PROGRAM AS NEEDED	- DECEMBER 1987
o REVIEW/UPGRADE REMAINING DS PROCEDURES	- DECEMBER 1987
o LONGTERM EMERGENCY LIGHTING IMPROVEMENTS (IF NEEDED)	- MID 1988
o REVIEW CORRECTIVE ACTION PROGRAM	- DECEMBER 1987