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Licensee: Carolina Power and Light Company
P. O. Box 1551
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Docket Nos.: 50-325 and 50-324 License Nos.: DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: February 29 - March 4, 1988 and March 14 - March 18, 1988

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## EXECUTIVE SUMMARY

The Brunswick Steam Electric Plant consists of two General Electric Boiling Water Reactors of the BWR-4 design with Mark I containments. It is located in Southport, NC. The plants received their operating license in 1975 and 1977. Design generating capacity is 821 MWE each.

The Brunswick Steam Electric Plant (BSEP), PRA, which was developed by Carolina Power and Light Company (CP&L), includes an analysis of both units as they existed on October 1986, and was completed over the period of October 1986 through June 1987. The BSEP PRA is mainly a level 1 PRA, which deals with core-melt scenarios as a result of various internal event initiators. In addition, some limited level 2 PRA analyses of containment responses are also given in the BSEP PRA. The study identified the dominant accident sequences by their severity and provided insights into the contributing or mitigating plant design and operating features. The total core damage frequency from internal events for Brunswick Unit 2 was calculated to be 2.5E-5/yr.

The NRC reviewed 11 dominant accident sequences and an inspection plan was developed to focus attention to those areas which represent the greatest contributors to these dominant accident sequences.

The inspection was performed February 29 - March 4, 1988 and March 14-18, 1988, by 11 NRC inspectors with different areas of specialization with the an exit meeting held on March 18, 1988. No violations were identified in this assessment.

BSEP has established an Onsite Nuclear Safety Group (ONS) which reports to managers who are neither located onsite nor a part of the plant staff. This group has taken responsibility for the PRA, analysis of the results and initiation of suggestions and actions based upon its results. Many of the high importance issues identified by the NRC, for inclusion in the inspection plan had already been evaluated by ONS. ONS maintains a long term view of plant safety without getting involved in the day-to-day plant activities.

The areas inspected and the inspectors' observations are summarized below. Each area is more thoroughly discussed in the appropriate section of the report.

The electrical distribution system from the off-site source to the emergency buses was inspected. A plant walkdown including the switchyard was conducted. Observations made included:

- Battery surveillance activities indicate that the station batteries were well maintained.

- Although battery duty cycle studies had been performed, the studies for the 125/250 VDC batteries did not include station blackout scenarios as modeled in the PRA.

- The DC interrupting rating of the THFK circuit breakers used in the vital DC circuits may be marginal for the available current.

- The inclusion of a directional power relay in the plant design to protect the emergency diesel generators while in the test mode is a good design.

Examinations of the Nordberg Emergency Diesel Generators (EDG) performance, the results of a recent task force study on EDG availability, and plant walkdowns resulted in the following observations:

- The plant aggressively pursues resolution of EDG problems to improve availability and reliability.

- Low jacket water temperature had been recently noted by the licensee while performing the monthly load test. The temperature was 40°F below that allowed by the manufacturer. An engineering evaluation was not completed by the time this inspection ended on March 18, 1988. This matter will be followed up during a future inspection.

- The predictive maintenance trending program exceeds the manufacturer recommendations.

Maintenance practices were examined relative to HPCI, RHR, and ADS valves. Observations based on this examination are as follows:

- The maintenance practice for ADS valves results in unnecessarily high risk of common-mode failure. The pilot valves of all ADS valves are refurbished by the same vendor technician. The procedure does not require independent verifications of this activity.

- Deficiencies were observed in valve installation and assembly involving installation of fasteners, valve location, and valve orientation.

- The current valve backseating procedures may result in Technical Specifications valve closure times being exceeded.

- The Automatic Maintenance Management System (AMMS) used for planning and documenting certain aspects of maintenance provides an efficient, readily accessible means for planning, scheduling, and documenting maintenance.

- Maintenance records are complete, retrievable and provide verification of satisfactory maintenance performance.
- The PRA and expertise gained from its development are being used to improve maintenance practices.

- Excellent capabilities have been developed and implemented for analysis and assessment of equipment failures.

- Maintenance procedures appear very good with regard to technical content and human factors. Minor problems were noted such as item numbers in figures were illegible and a lack of signoffs in procedure sections.

Inservice Testing was examined relative to HPCI, RHR, and ADS valves and HPCI pumps. Observations based on this examination are as follows:

- The procedure for stroke testing ADS valves does not contain all of the acceptance criteria required by the testing program.

- The testing procedures are excellent from a human factors and technical standpoint.

- The records are complete, retrievable and provide verification of satisfactory performance of the procedures.

Emergency Operating Procedures were reviewed for important operator actions that were identified by the PRA. EOPs were also reviewed for incorporation of the BWR Owners Group Emergency Procedure Guidelines, Rev. 2. Findings from the review and from interviews with plant personnel were:

- The licensee's EOPs included important operator activities identified by the PRA.

- The EOPs included steps and cautions of the BWR Owner Group EPGs, Rev. 2.

- Operator training could be strengthed in the areas of: Manual operation of RHR MOVs during emergency situations, and DC load shedding to extend battery life during a station blackout.

- To provide guidance for control room operators should station AC power fail, indicators on the labels of the affected instruments are provided to show failure direction; upscale, downscale or as-is-failure. This is a good from a human factors standpoint.

Accessibility of plant equipment during station blackout was reviewed. Observation were:

- The security card readers would prohibit ready access if the nonessential DC loads were shed from the batteries. An interim resolution agreement calls for keys to be distributed to operators before shedding DC loads.

- Emergency lighting in some areas may be insufficient for manual manipulation of equipment.

Instrumentation and Controls procedures were reviewed for components shown to have a high importance measure in the PRA. Observations from the review and from interviews with plant personnel were:

- The I&C procedures were recently upgraded. A good feature is the calibration summary sheet explaining impact on plant operation that is given to operations when permission to perform the test is granted.

- The instruments used for detecting condensate in the condensing pots for the steam supply to RCIC and HPCI do not have consistent test frequency requirements. In some cases, the interval has exceeded manufacturer's recommendations.

Walkdowns were performed for the Diesel Building HVAC and the Control Building HVAC. The PRA identifies these systems as important contributors to risk scenarios. Interviews with the system engineer and Onsite Nuclear Safety Group were conducted. Observations included:

- When the PRA identified a potential problem with the Diesel Generator Building HVAC system that could have resulted in the diesels being unavailable in a station blackout, immediate action was taken. This problem was aggressively resolved.

- The inspectors' walkdown identified a problem that could "short-circuit" the DG HVAC air flow path and result in a reduced heat removal capacity.

- A potential common mode failure was identified in the Control Building's instrument air supply to the HVAC. A common header feeds dampers for both divisions. An air failure could result in the inability to start the Control Room emergency ventilation system until dampers were manually repositioned. This situation is not covered by current procedures.

A walkdown of the Service Water System was performed during this inspection. A possible common mode failure was noted that could result in loss of cooling water to all four diesels. The location of the water headers in the diesel tank building may cause them to be susceptible to a single credible event causing loss of all three headers.

A walkdown of the SLSC was conducted, including a sampling of valve line-ups, labeling of components and examination of material condition. Interviews with the PRA and QA groups were conducted. The following observations were made:

- The PRA model does not reflect a possible recirculation mode if a relief valve fails and the pumps operate. The consequence is that insufficient flow may be provided to the reactor vessel to achieve successful operation of this system. Relief valve failures at low pressures have been observed at other similiar plants.

- Testing does not assure that the piping/valve segment from the SLC storage tank to the first T joint is not plugged from crystallization of the borated solution.

- The drawings show that the SLC tank level indicator uses instrument air which will be interrupted during a station blackout. This could provide a false indication of flow.

- Pump valve spring failures have been observed. Metallography results were not conclusive, however, the tools used to install the springs may have contributed to their failure. Also, it is noted that the PRA pump failure rate may not be indicative of a positive displacement pump, since generic failure data may reflect centrifugal pump failures.

To assess effectiveness of emergency operating procedures in responding to PRA events, several transients were simulated on the plant simulator. The EOPs were used to respond to and recover from selected accidents. Observations made included:

- The simulator is designed for normal and abnormal operations and is not able to replicate severe accident sequences as identified in the PRA study. Operator training on severe accident scenarios must be accomplished by other means.

- Inaccurate thermalhydraulic modeling displayed by the simulator adversely impacts the effectiveness of operator training.

A review was performed of the station procedures for containment venting. The vent path and the procedures were walked down. Interviews were conducted with plant operators and with engineering personnel. The following observations were made:

- Even though the review procedures indicated specific entry conditions to containment venting, interviews with Operations indicated the final decision would lie with the personnel in the Technical Support Center.

- All venting actions are performed at either the main control panel or at the back panels. This has the advantage of increasing personnel safety during the venting procedure if power is available.

- The procedure does not address venting during a station blackout. Venting would prove impractical for many of the vent paths due to inaccessibility to manually operate the valves.

- The walkdown of the vent path indicated a weakness in the expansion joints located on each side of the fans. The licensee has not completed an analysis to determine the pressure that the joints could withstand or would be subjected to during venting.

## SUMMARY

Scope: This special PRA-based operational safety, announced inspection was in the areas of Operations, Maintenance, Administration and Training. Items inspected were determined to be of high importance to the dominant accident sequences identified in the plants Probabilistic Risk Assessment (PRA) study. Details are discussed starting in Section 5.0.

Results: No violations or deviations were identified.

REPORT DETAILS

1.0 Persons Contacted

Licensee Employees

*M. A. McDuffie, Senior Vice President - Nuclear Generation
*P. W. Howe, Vice President - Brunswick Nuclear Project
*C. R. Dietz, General Manager - BSEP
*J. D. E. Jeffries, Manager - Corporate Nuclear Safety
*R. E. Helme, Director - Onsite Nuclear Safety
*F. A. Emerson, Project Engineer - Onsite Nuclear Safety
*J. G. Titrington, Principal Engineer - Operations
*A. S. Hegler, Operations Superintendent
*K. E. Enzor, Director - Regulatory Compliance
*E. R. Eckstein, Manager - Technical Support
*L. E. Jones, Director - QA/QC
*A. G. Cheatham, Manager - E&RC
*S. H. Callis, Jr., Onsite Licensing
*M. J. Pastva, Jr., Specialist - Regulatory Compliance
*J. O'Sullivan, Manager - Maintenance
*J. W. Moyer, Manager - Training
*G. P. Barnes, Project Specialist - Licensing
*W. B. Geise, Project Specialist - Simulator
*B. S. Strickland, Project Specialist - Operations
*K. B. Altman, Principal Engineer - Maintenance
*J. A. Smith, Director - Administration
*R. M. Poulk, Jr., Project Specialist - Regulatory Compliance
C. Schacher, Project Engineer, Maintenance Programs Group
G. Thompson, Project Engineer, Systems Engineering Group
W. Martin, Principal Engineer, Onsite Nuclear Safety
P. Bernard, Project Engineer, Onsite Nuclear Safety
J. Nikitas, Project Engineer, Technical Support Group
J. Gee, Project Leader, As-Built Drawing Group
W. Shade, Senior Electrical Systems Engineer, Technical Support Group
T. Fiorenza, Electrical Systems Engineer, Technical Support Group
S. Boyse, Project Engineer, Technical Support
R. Creech, Instrumentation and Control Supervisor (Unit 2), Maintenance
C. Patterson, Inservice Inspection Project Engineer, Technical Services
L. Wheatley, Inservice Inspection Project Engineer, Technical Services
R. Kitchen, Mechanical Supervisor (Unit 2), Maintenance
P. Musser, Project Engineer, Maintenance (Procedures)
J. Kueck, Project Engineer, Independent Review Unit, Corporate Nuclear Safety Section
J. Lane, Responsible Plant Engineer, Technical Support
E. Harrelson, Engineering
W. Mauney, Senior Specialist, Maintenance

Other Organizations

H. Rockhold, EG&G Idaho Incorporated, Pump and Valve Test Program Reviewer Under Contract to NRC
P. Berry, Electrical Engineer, Cafer Associates
C. Pierce, System Operations Dept. CP&L Wilmington Office
P. Smith, Relay Maintenance, CP&L Wilmington Office

Other licensee employees contacted included craftsmen, engineers, technicians, operators, mechanics, security force members, and office personnel.

NRC Resident Inspector

*W. Ruland, Senior Resident Inspector

*Attended exit interview

2.0 Exit Interview

The inspection scope and findings were summarized on March 18, 1988, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings. No dissenting comments were received from the licensee. The following new items were identified during this inspection:

IFI 324, 325/88-11-01, Vent Path Model, Section 6.2
UNR 324, 325/88-11-02, Stroke Time for Backseated Valves, Section 8.3 b.(2)
IFI 324, 325/88-11-03, Electrical System Design Review SAT and 5kV Cable, Section 10.3
IFI 324, 325/88-11-04, Compliance With GDC 17 and Related TS Change Request, Section 10.3
IFI 324, 325/88-11-05, Deficiencies Identified During Walkdown of Electrical Equipment, Senerio 10.5(d)
IFI 324, 325/88-11-06, Blackout Services Battery Duty Cycle Study, Section 10.7
IFI 324, 325/88-11-07, DC Voltage Profile Study, Section 10.7.1
IFI 324, 325/88-11-08, THFK Breaker Rating, Section 10.7.1
IFI 324, 325/88-11-09, Stroke Time Testing for ADS Valves, Section 11.4
UNR 324, 325/88-11-10, EDG No. 3 Operation With Low Jacket Water Temperature, Section 12.2(2)
IFI 324, 325/88-11-11, Overspeed Testing of the EDG, Section 12.2(5)

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

## 3.0 Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

## 4.0 Unresolved Items

Unresolved items identified during this inspection are discussed in Sections 8 and 12.

## 5.0 Introduction

Carolina Power and Light Company performed a Probabilistic Risk Assessment (PRA) over a period of October 1986 through June 1987. The PRA represents the plants as they existed in October 1986. The PRA was a level 1 PRA, performing an analysis of core damage potential, and part of a Level 2 PRA looking at limited containment response to core damage. The PRA does not contain an analysis of radionuclide release from the core or its behavior within containment. It also will include an examination of internal flooding, internal fire, or seismic events when complete.

For several years the NRC has been using PRA as an input to direct its inspection efforts. Based upon the systems, events, and components identified as high risk contributors to the dominant PRA accident sequences, PRAs allow inspectors to focus on items of greater significance to public safety.

These PRA based inspections also lead the inspectors to examine some areas beyond the normal scope of inspection for the NRC. Many times non-safety systems and accidents not considered part of the licensing analysis are the dominant contributors to the PRA's core melt frequency. These areas were examined to determine if adequate attention is being directed toward reducing risk from these items.

The NRC obtained limited portions of the Brunswick PRA results upon which to base inspection plans. The PRA indicated Anticipated Transient Without Scram (ATWS) and Station Blackout (SBO) as dominant contributors to the core melt frequency. The top eleven accident sequences were selected as the focus of the inspection. These included the number one sequence, SBO, contributing about 32% of the core melt sequence probability and six ATWS sequences totaling about 52% of the probability. The other sequences involved multiple failure of ECCS equipment or Reactor Pressure Vessel (RPV) rupture.

The eleven sequences were analyzed to determine the relative importance of events, equipment, and recovery actions taken by plant personnel. The results were tabulated and used as input into development of an inspection plan. The team consisted of inspectors with different backgrounds and specialties. The composition of the team and general areas of inspection were:

Team Leader - F. Jape
Operations/ Venting - R. Schin, L. Nicholson
Electrical - P. Fillon, E. Chow
Diesel/Mechanical - M. Thomas
Instrument and Controls/ Mechanical - R. Bernhard, T. Margulies
Mechanical/Pumps/Valves - E. Girard
Simulation - C. Casto

The inspection was conducted February 29, 1988 thru March 4, 1988 and March 14, 1988 thru March 18, 1988. The exit interview with the preliminary results was held March 18, 1988. During the entrance interview the inspectors explained the PRA based inspection concept and covered the areas to be inspected. Carolina Power and Light discussed their organization as it related to the PRA and application of PRA results.

5.1 Licensee Initiatives

Carolina Power and Light has an Onsite Nuclear Safety Group at BSEP which reports to an off-site manager. This group conducts independent safety reviews. The responsibility to ensure the PRA results are used to improve plant reliability and safety has been assigned to this group. The inspectors discovered that many of the areas of high importance selected to inspect had already been reviewed by this group.

Interviews with the onsite Nuclear Safety Group revealed several licensee initatives performed or in progress that should result in both reduced costs to the utility and an increase in public safety.

Examination of the PRA shows that decreasing scram frequencies is a major contributor to safety. A small improvement in the scram rate can be more significant than large improvements in other, less important items.

Brunswick has instituted an extensive Scram Reduction Program to address this area. A review of historical data was used to determine problem areas and systems causing the scrams. Historical data was used as the basis for improvements in procedures and systems to reduce scram rates. A scram reduction Task Force ranked the improvements in terms of effectiveness and costs for implementation. The most cost effective suggestions were added as action items for the plant's managers and supervisors. In addition, to avoid future scrams in areas that have a high susceptibility of occurring due to a single failure, a Single Failure Points Study was performed. This study constructed charts of scram sequences fault trees leading from RPS back to the primary causes. These points of single failure were identified as areas for improvement.

A significant reduction in the number of scrams has been observed as a result of the Scram Reduction Program and of the High Risk Scram Components and Single Failure Points Study and corrective actions. Continued management focus on these activities should lead to continued reduction in the scram rate.

For some systems highlighted by the PRA as significant contributors to the dominant sequences, the utility has performed SSFIs based upon

the NRC concept. Currently efforts are complete for HPCI and SLC, and the licensee mentioned ADS as a system targeted for an effort in the future. The inspectors' reviews of these SSFIs are discussed is Section 8.3 of this report.

5.2 Results

The report is organized by major areas inspected. The results in each area are summarized in that section of the report. Figures and Tables are located within each section of the report. Documents reviewed are listed in Section 19.0

## 6.0 Containment Venting

Effective containment venting for elevated containment pressure and combustible gas control is a means to mitigate a challenge to containment integrity in severe accidents. The Brunswick PRA further recognizes venting as a final means of decay heat removal in preventing core damage. The intent of this inspection was to evaluate the method and verify that containment venting could be realistically and effectively achieved, if needed. The controversial matters of when and under what conditions venting should occur remains outside the scope of this inspection effort.

To attain this inspection objective, various containment venting pathways were evaluated for availability and practicability of venting operations. Control room local equipment operations were inspected by walkdown simulations and procedural reviews, as well as evaluation of any available alternate means of operation.

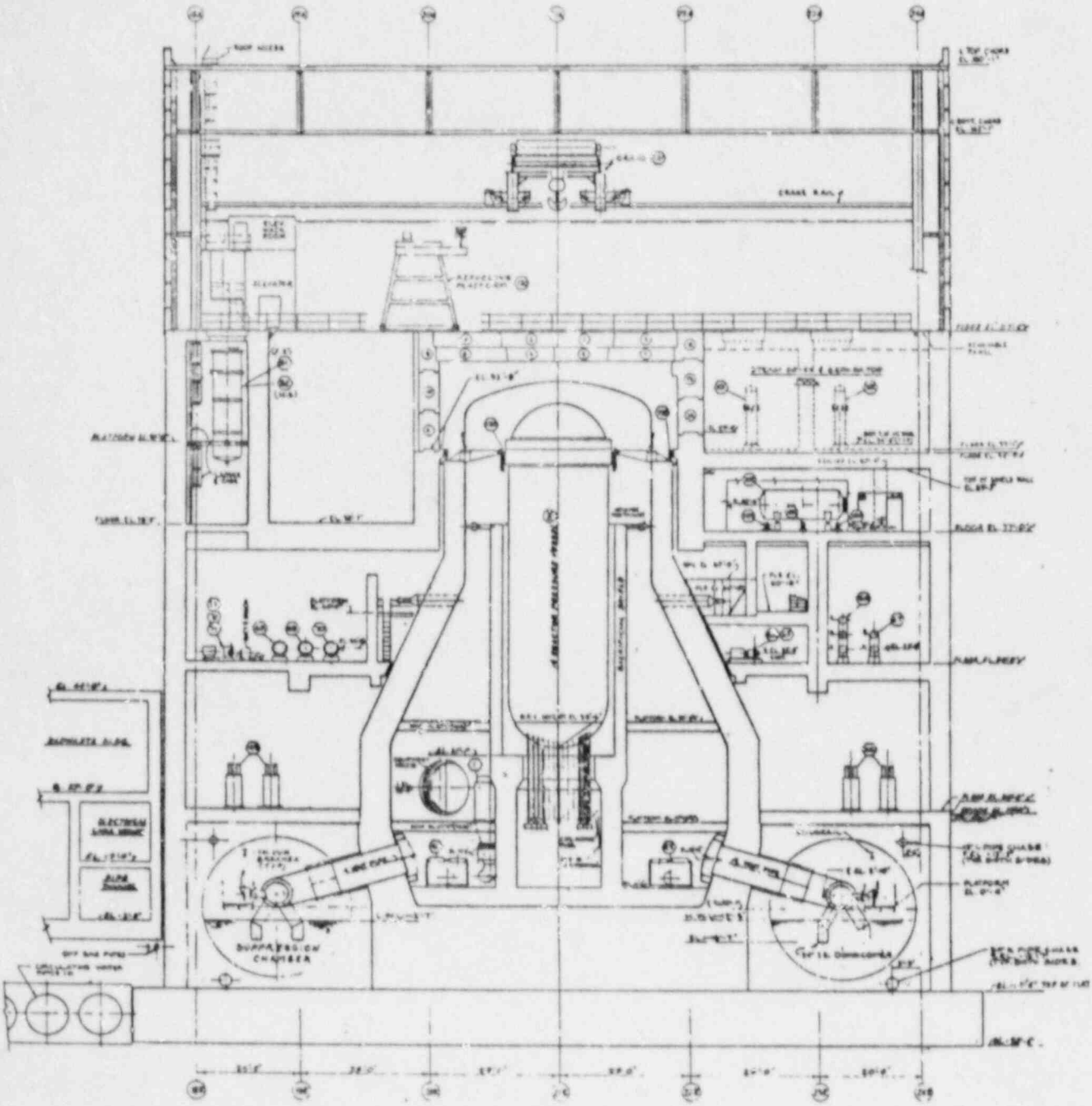
The primary containments at Brunswick are Mark 1 pressure suppression systems which house the reactor vessel, the reactor coolant recirculating loops, and the other branch connections to the RCS. Design pressure of the containment is 62 psig. The inverted lightbulb, steel-lined drywell is surrounded by several feet of reinforced concrete everywhere except the drywell head. Unlike other Mark 1 designs, no gap exists between the steel shell and the concrete, The torus or suppression chamber (steel-lined) is also surrounded by several feet of reinforced concrete and is approximately 40% filled with water. The general arrangement of the primary containment is shown in Figure 6.1.

### 6.1 Containment Venting Procedure

The evolution of containment venting is currently prescribed in Emergency Operating Procedure (EOP) EOP-01-CCP, "Containment Control Procedure", Revision 5, dated June 5, 1987. This procedure was based on Revision 2 of the BWR Owner's Group Emergency Procedure Guidelines (EPGs). The licensee also provided the inspector a draft copy that incorporates the proposed Revision 4 to the EPGs. Although the entry conditions differ in the revisions, the method for venting remains the same.

EOP 01-CCP-PCP-, "Primary Containment Pressure", is the section of the above procedure that invokes containment venting. Initial entry conditions into this section is primary containment pressure above 2 psig, with the initial actions attempting to troubleshoot and control containment pressure using the more conventional methods. If the suppression chamber pressure exceeds 58 psig, then the procedure states to evacuate the reactor building and begin a sequence of opening valves to vent the containment out the stack, see Figure 6.2. The procedure states to secure the vent when suppression chamber pressure can be maintained below 58 psig without venting.

Figure 6-1 General Arrangement of Primary Containment



Although the above procedure contains specific initiating conditions that require venting the primary containment, discussions with licensed operators indicated that they expect the final decision to vent would be made from the Technical Support Center (TSC). Senior station management supported this philosophy and commented that a large number of issues must be considered prior to initiating a containment vent to the atmosphere.

The initial primary containment pressure limit of 58 psig was selected based on the 62 psig design pressure of the containment. The licensee stated that this pressure was selected to assure that all equipment would perform as desired during the evolution. A draft of the proposed EOP, based on Revision 4 to the EPG, changes the primary containment pressure limit to 70 psig. This increased pressure was developed considering the following parameters:

- Pressure capability of the containment.

- Maximum containment pressure at which vent valves can be opened and closed.

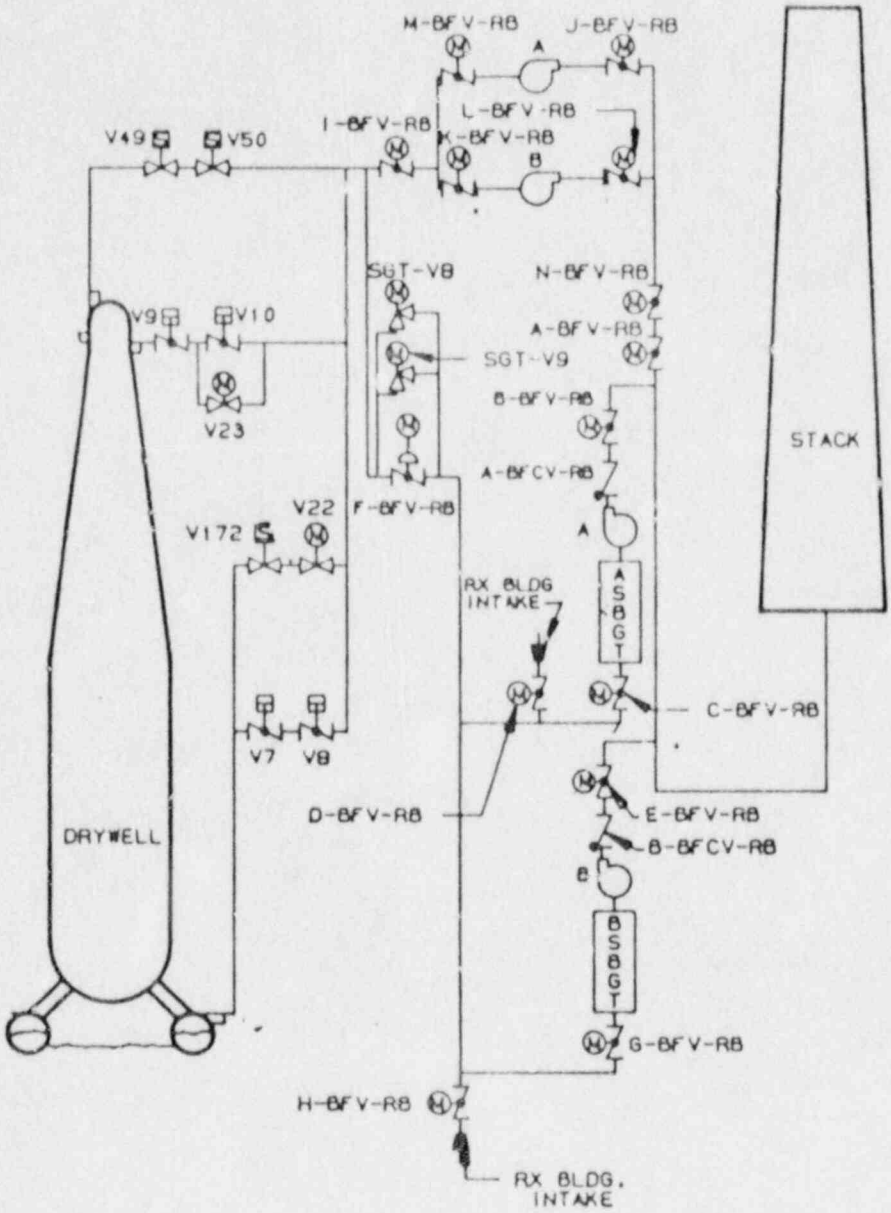
- Maximum containment pressure at which the SRVs can open and remain open.

- Maximum containment pressure that vent valves can be opened and closed to vent the reactor pressure vessel.

The licensee considers the maximum containment pressure at which the SRVs can operate to be the limiting factor for deriving the 70 psig pressure limit. Instrument air pressure of these Target Rock valves was assumed to be 95 psig with a 25 psi differential pressure across the actuators required for the valves to open. An engineering evaluation was also performed that stated that operation of the large butterfly valves (V7,8, 9, & 10) would be questionable at containment pressures exceeding 70 psig. The inspectors noted that a formal analysis had not been performed to ensure that the applicable motor operated valves (V22 & 23) could open with the worst case differential pressure. Initial indications are that adequate design margin exists to permit these valves to operate, yet only one of the four valves (2 per unit) have had the actual running load and torque switch settings verified. The licensee acknowledged this item and stated that additional evaluation and field testing of the MOVs would be forthcoming.

The draft revision to the EOP also contains an additional entry condition to vent containment when drywell or suppression chamber hydrogen concentration reaches or cannot be determined to be below 6% and drywell or suppression chamber oxygen concentration reaches or

Figure 6.2 Containment Vent Paths



cannot be determined be below 5%. The draft procedure also contains provisions to evluate the suppression chamber level prior to selecting a vent path to preclude venting a line that is filled with water.

No specific precautions are included in the venting procedure regarding NPSH problems for pumping during venting. As the suppression pool temperature approaches saturation, the margin on NPSH for the pumps that take suction from the suppression pool is reduced. The venting procedure states to initiate venting at 58 psig and secure and the vent when pressure can be maintained below 58 psig. The inspector discussed with the licensee the benefits of including in the vent procedure a precaution to the operators that a rapid depressurization of the suppression pool may result in loss of NPSH and cause pump damage. The NPSH curves for these pumps were observed to be readily available to the operators in the main control room with guidance included elsewhere in the procedures.

The sequence that was selected to open the vent valves is shown in Table 6.1. All but the initial vent path is through the purge exhaust fans and out the stack. The initial path is from the wetwell to the one-half inch needle valves (SGT-V8 & 9) and through the standby gas treatment (SBGT) filters to the stack. Although this path has the obvious benefits of venting from the wetwell and utilizing the SBGT filters, it's effectiveness in controlling containment pressure would be limited by the small size of the needle valves. Subsequent vent paths bypass the SBGT filters in an effort to preserve these filters for reactor building cleanup. The remaining vent sequence was selected using the small lines first to limit the off-site release rate and protect the low pressure duct near the purge exhaust fans.

6.2 Walkdowns Of Containment Vent Paths

The inspector conducted a walkdown with a senior reactor operator of both the main control room using the venting procedure and the in-plant vent paths that are to be used. All planned venting actions are performed at either the main control room board or the back panels. Adequate scale was provided for containment pressure indications. The switches and jumpers that are required to override the containment isolation signal and open the valves were all correctly labeled and staged. The following items were noted during the walkdowns:

- Performing a vent of the primary containment during a station blackout has not been specifically addressed and would be very difficult. Containment pressure indications and combustible gas concentrations would not be readily available to the operator in

the main control room. These indications would be available from the remote shutdown panel; however, the override and valve controls are not available at the remote panel. The effectiveness of venting through the only valves that could be operated by DC power during a blackout (V49 & 50 which are 3" dia.) would be limited due to their small size. In addition, manual operation of several of the motor operated valves during a blackout would be difficult due to poor accessibility. The licensee considers any actions to vent the containment during a blackout to be a recovery operation dictated by the circumstances at the time, therefore, no contingencies have been developed to perform venting during blackout.

- As stated above, all planned venting actions are performed from the main control room. The licensee has not developed contingency actions should the initial attempt to vent fail. Manual operations of several of the valves would be prohibitive due to their location and the expected radiation levels during an accident.

- The entire vent path is hard piping with the exception of a small section of duct at the purge exhaust fans. This duct contains what appears to be field fabricated expansion joints on each side of the fans that would be susceptible to failure during a vent. The licensee agreed with this comment and could not provide a design pressure rating for the joints.

- Development of a system model to determined the worst case flow and pressure in the vent path has been initiated but not yet completed. The completion of the model should enable a better understanding of the system performance and limitations. The inspector reviewed a preliminary analysis that indicated adequate venting could be achieved with a minimal pressure surge in the vent path by partially opening only the large suppression chamber butterfly valves (V7 & V8). This would have the added advantage of accomplishing all venting from the suppression pool. The preliminary results also indicated that relatively high pressures (approximately 40 psig) may be experienced at the purge exhaust fans during certain system configurations. A review of the final system model and the resulting system performances will be the subject of further inspection and is identified as an Inspector Followup Item 324,325/88-11-01, Vent Path Model.

- An analysis has not been performed to evaluate the effects of a release during venting from potential failure points in the vent path. Discussions with operators indicated the worst case scenario of a release at the purge exhaust fans could result in the loss of a standby liquid control train due to the proximity of the motor control center for this equipment.

TABLE 6.1

CONTAINMENT VENT PATHS

| VENT LINE | | VALVES | MINIMUM DIAMETER (inches) |
|---|---|---|---|
| 1. | STANDBY GAS FILTERS | SGT-V8 & 9 | 1/2 |
| 2. | SUPPRESSION POOL PURGE EXHAUST BYPASS | V22 & 122 | 2 |
| 3. | DRYWELL PURGE EXHAUST | V9 & 23 | 2 |
| 4. | DRYWELL HEAD PURGE EXHAUST | V49 & 50 | 3 |
| 5. | SUPPRESSION POOL PURGE EXHAUST | V7 & 8 | 20 |
| 6. | DRYWELL PURGE EXHAUST | V9 & 10 | 18 |

## 7.0 Simulation Activity

### 7.1. Introduction

The team reviewed the eleven most dominant accident sequences in the Brunswick PRA study, and from these, two were selected for simulation on the Brunswick simulator. To ascertain effectiveness of plant operations and operational readiness, the ability of the plant operational staff was observed in responding to and recovering from the selected accident sequences on the simulator.

Two accident sequences were simulated and the following activities were considered.

- Demonstration of equipment and system operations.
- Utilization of station normal, abnormal, alarm, and emergency operating procedures.
- Ability of the plant specific simulator to duplicate these events.

The blackout sequence and MSIV isolation followed by a failure of long-term cooling were selected. The blackout sequence is the most dominant accident sequence which contributes 30% to the total core melt probability and the MSIV transient contributes 2%. The ATWS events account for more than 50% of the total sequences, but was not selected because previous, successful demonstrations were observed during operator license examinations.

### 7.2 Preparation

Simulator scenarios were developed based on the PRA study. The sequences were reviewed for specific component/system failures and these were collated into scenario events. Plant conditions assumed in the sequences were duplicated to the extent feasible on the simulator. The simulator Cause & Effect document was used to develop the component overrides and determine the plant response to events. The Emergency Operating Procedures (Rev. 4) were used to predict operator response to the scenarios and the expected responses were documented for use by the inspectors.

Currently the plant is operating with Rev. 2 of the General Electric Owners Group Emergency Procedures Guidelines. For this simulation the draft Rev. 4 of these procedures were used in responding to accident sequences. It is expected that this revision will be placed into service later in 1988. Training has not been completed on this revision, therefore, the crew was selected from individuals who are

licensed, and are familiar with Rev. 4 due to their work on implementation of these procedures. The crew consisted of one Shift Foreman, one Senior Control Operator, two Control Operators and one Shift Technical Advisor. The crew was briefed on their tasks and was then asked to respond to the simulations. The simulator exercise lasted about five hours.

Confidential pre-exercise discussions, and table top simulations of the proposed scenarios were conducted with training department personnel. These discussions were conducted to allow the facility to review and comment on the predicted plant/operator responses to events. Collectively, the inspectors reviewed the expected responses of the plant/operators on the simulator, familiarizing themselves with the control board layout and the roles of the various operators involved.

7.3 Station Blackout Sequence

The blackout event was initiated by severe weather conditions, triggering a loss of ac power, followed by emergency diesel generator failures. The contributing event of the core melting is a failure to restore the off-site power within four hours and thus depleting station battery.

The Station Blackout Sequence was as follows:

Tornado warning, followed by switch yard destruction and off-site power loss.

Safety Relief Valve failed open.

Emergency Diesel Generator (EDG) four failed to start.

Emergency Diesel Generator (EDG) three output breaker tripped after one minute.

Observations from the SBO simulation scenario:

(1) Flow path three does not direct the shutdown of EDGs which are not feeding the bus and that have lost service water. The licensee is changing the procedure to incorporate this step.

(2) The procedure does not direct manual opening of residual heat removal valve F007 (pump minimum flow line) after a loss of power with subsequent pump start. A similar problem has been identified for Westinghouse plants as referred to in NRC Information Notice No. 87-59: Potential RHR pump loss.

(3) The facility does not have a thorough procedure to shed loads from the batteries. To conserve battery power the operators

requested a load study from the Technical Support Center during the event. Prior consideration of the loads which may be vital or non-vital may prevent the need to conduct these engineering evaluations during severe events.

(4) Station blackout scenarios are not a part of the established simulator training program. The facility does train the operators on loss of site power events.

7.4 MSIV Closure Without Bypass Valves

The MSIV transient is initiated by CRD loss and loss of condenser vacuum, which results in turbine bypass valve failures. The contributing event of the core failure is subsequent inability of removing the decay heat.

A MSIV closure without bypass valves sequence was as follows:

HPCI pump tagged for maintenance.

B Control Road Drive Pump tagged for maintenance.

RCIC tripped on auto start signal.

Running Control Rod Drive Pump trips.

Loss of condenser vacuum.

MSIVs fail closed.

Observation from the MSIV transient scenario:

A series of steps in the End Path Procedure for Reactor Level control may cause a delay in taking action to enter Local Emergency Procedure 1. The steps allude that reactor vessel level must drop '0' inches before action is to be taken. During this waiting period, inventory is lost through the SRVs while removing decay heat. The procedure does not specify prompt action upon recognition of a loss of high pressure feed. Due to problems related to the thermo-hydraulic modeling of the simulator this step could not be evaluated under "real life" conditions, and therefore, a complete assessment of procedure adequacy could not be accomplished.

7.5 Other Findings

(1) A loss of high pressure feed was initiated as part of the MSIV closure sequence. The thermohydraulic modeling of the simulator did not match the expected plant response. The simulator

displayed an excess of inventory, and inaccurate response to depressurization. As a result, the operators may have been misled and the procedure not executed properly. This condition eliminated one alternate method of high pressure injection (SLC), and directed the operators into a normal plant cooldown during adverse conditions. Had the simulator responded correctly, this alternate means of injection may have been addressed by the EOPs and a rapid depressurization of the reactor vessel would have possibly been initiated. The inaccurate modeling of thermohydraulic conditions is a generic flaw in the simulator which may impact the simulation of design bases events.

(2) Accurate modeling of Thermohydraulic response by the core is essential for initial and continuing training of the plant operations staff. Specifically the inability to fully and accurately simulate design bases events, and/or events required by 10 CFR 55.59(a)(2)(ii) could lead to negative training and subsequent degradation of the operator's proficiency. Additionally, this condition could potentially effect renewal of part 55 licenses. During this assessment it was noted that the licensee has identified modeling problems with the simulator and corrective actions are being implemented to resolve these deficiencies. The licensee intends to acquire consultant support and had allocated resources to this effort.

(3) Recognizing that the simulator was not designed to model core melt sequences, the sequences selected were beyond that expected for the simulator capability. The longer term decay heat removal operations, and core-melt conditions were not incorporated due to this limitation.

(4) The simulator capability for overrides is very extensive. All desired overrides were accomplished without difficulty.

(5) Simulator configuration control with the plant control room was thorough. No discrepancies were noted.

(6) The team recognized the facility initiative to involve operations personnel in programs affecting operations, e.g., control room furniture, LCO data base construction, implementation of the Emergency Operating Procedures.

(7) The operators involved in the simulation were not aware of the PRA study results, and they were not trained for the events which could lead to containment venting.

(8) In completing the EOP revision the facility has initiated a thorough task analysis of procedure steps for operator training.

## 8.0 High Pressure Coolant Injection System (HPCI)

The safety objective of the HPCI system is to provide sufficient core cooling to prevent excessive fuel cladding temperatures in the event a loss of coolant accident (LOCA) in which reactor pressure stays high enough to supply a source of steam. It is designed to maintain core coverage at high pressures. The HPCI pump is steam turbine driven and includes a booster pump to provide sufficient discharge pressure for injection into the reactor vessel. Either the condensate storage tank or the suppression pool may be used as a suction source. Steam to drive the pumps is provided by the reactor via a line from a main steam line. The pumps discharge into a feedwater line which directs its flow into the reactor.

### 8.1 Purpose of NRC Inspection

The maintenance and testing of HPCI items needed for HPCI pumps to begin performing their function was selected for NRC inspection because the license's PRA identified the failure of the HPCI pumps to start (performing their safety function) as a major contributor to a dominant accident sequence for core melt. This event and three related events were described in the PRA as follows:

| Failure Event Description | PRA Identification |
|---|---|
| Turbine driven pump fails to start | HPC-TDP-FS-HPTDP |
| Turbine driven pump in test or maintenance | HPC-TDP-TM-HPTDP |
| MOV F001/MOV F006 fail open | HPC-MOV-CC-F001/F006 |

### 8.2 Areas Inspected

NRC inspection of this area examined the adequacy of the licensee's maintenance and testing in assuring that their HPCI pumps will start when called on to perform their safety function. Specific hardware items addressed were the HPCI pumps and selected examples of check valves (F005 and F019) and motor operated valves (F001 and F006) that must function satisfactorily for the pumps to begin performing their safety function.

Valve F001 is a normally closed, DC motor operated valve located in the steam line to the turbine. Its safety function is to open to admit steam to the HPCI turbine. Valve F006 is a normally closed, DC motor operated valve located in the HPCI injection line. Its safety function is to open so that cooling water may be injected into the reactor via the feedwater piping. F006 also serves as a containment isolation valve.

Valves F005 and F019 are check valves located, respectively, in the pump suction and discharge lines. Both valves must open to cause

coolant flow to the reactor. Valve F019 must close when suction is changed from the condensate storage tank to the suppression pool. This precludes flow from the suppression pool into the condensate storage tank.

8.3 Details

The inspector examined the adequacy of the licensee's maintenance and testing of the HPCI pumps and valves in assuring against the above listed failure events. The examination was conducted through a review of procedures, records and other documents, interviews with responsible licensee personnel and observation of pumps. The documents reviewed are listed in Section 19.0. Details of the examination and findings are described below:

a. Interviews

Responsible engineering, maintenance and test personnel were interviewed relative to HPA followup activities, maintenance testing, failure history and corrective actions.

Due to the importance of the HPCI system as noted in the PRA, various activities had been instituted by the licensee to monitor and increase its reliability. Actions taken by the licensee that were verified by the inspector included.

- A reliability evaluation was performed and documented by the On-site Nuclear Safety staff.
  The inspector examined but did not perform a detailed review of the evaluation.

- A Safety System Functional Inspection (SSFI) was conducted on HPCI using NRC guidelines.
  The inspector examined but did not perform a detailed review of the SSFI report.

- Participation in an Institute for Nuclear Power Operations (INPO) Safety System Unavailability Program which included HPCI. The inspector reviewed a report from on-site Nuclear Safety to Plant Management describing the unavailability findings.

- Increased HPCI testing frequency to reduce unavailability. The inspector verified that the specified test frequency in the HPCI System Operability Test (PT 9.2) had been increased from once each 92 days to once each 46 days. The added tests are only partial tests, as only minimum pump flow and discharge head capabilities are verified. Full ASME Section XI testing continues to be performed at the 92 day frequency.

- Installation of precautionary signs around the HPCI pumps to caution individuals working in the area to use care in avoiding accidental damage to HPCI items.

In response to questions by the inspector as to the past failure history of important HPCI valves, responsible licensee engineers informed the inspector that failures had been experienced in pump discharge valve F001, which must open to permit injection of HPCI cooling water for core cooling, and pump steam turbine supply valve F006, which opens to provide steam to drive the HPCI turbine. The cause of the F001 failure was still under investigation. Responsible personnel consider that a possible cause is pressure locking. The F006 failure was attributed to high voltage spikes, which caused the valve motor insulation to break down. The inspector discussed the failure of F006 valve with the Project Engineer from the licensee Corporate group that was responsible for the failure investigation. The Project Engineer described in detail the investigation conducted and the proposed corrective actions. The inspector noted, based on the discussion, that the investigation appeared thorough and complete and that the licensee appeared to have excellent capabilities for performing such failure investigations.

b. Review of Maintenance Procedures and Records

The inspector reviewed examples of corrective maintenance procedures and some of the associated records. Procedures reviewed are listed in Section 19. The subject procedures are applicable to equipment in many systems, not just to HPCI. The procedures reviewed were: MP-14A, which specifies the use of the Automated Maintenance Management System (AMMS) that is currently used to initiate prescribe, and document to a limited degree all maintenance work; SP-85-066, for backseating valves to stop excessive leakage; OCM-M0001, which is currently used for maintenance stroking motor operated valves; MP-16-21, the predecessor of OCM-M0001; and five procedures covering maintenance and troubleshooting/failure analysis on various models of Limitorque motor operators for valves OCM-M0500, M0501, M0502, M0503 and M0003 and MP-57. Records reviewed were two examples of backseating of valves, documented by Work Request/Job Orders (WR/JOs) FI901 and HU901, and an example of troubleshooting/failure analysis, documented on WR/JO 87BMTI1. The procedures were reviewed for adequacy of technical content and human factors. The records were reviewed to verify that they adequately documented the required procedural operations. The inspectors' findings with regard to the procedures and records are as follows:

(1) MI-16-21, March 16, 1987, is the predecessor of OCM-M0001 February 1, 1988. While both versions were reasonably well

written, OCM-M0001 appeared better both from human factors and technical content considerations. For example, Figure 1 in MI-16-21 has some areas that become illegible in reproduction; whereas, in OCM-M0001 the figure is wholly satisfactory.

(2) Concerns regarding valve backseating practices were described in NRC Information Notice (IN) 87-40. The inspectors' review of the licensee's backseating procedure (SP-85-066) found that it contained controls which adequately assured against the concerns expressed in the IN. SP-85-066 is an Operations procedure used by Operations and Maintenance personnel. From a human factors stand point the inspector noted that it appeared better than the normal maintenance procedure, in that it contained individual signoffs of the steps in the procedure and associated independent verifications where appropriate.

The inspector noted a recent change to the procedure dated, October 5, 1987. A note was added following step 6.10, which permits omission of stroke time testing to assure that backseating does not cause TS stroke times to be exceeded. An explanation of how the license assures that stroke times are met when backseating is performed is identified as UNR 325,324/88-11-02, Stroke Times for Backseated Valves.

The records examined were found properly completed and retrievable, and indicated a control of the backseating process consistent with procedural requirements.

(3) The Limitorque Valve Failure Analysis procedure appeared to provide a good approach to root cause determination of motor operated valve failures. The record example examined by the inspector was in-process and the failure cause had not been determined since the investigation was in-process.

(4) Limitorque Operator Corrective Maintenance procedures OCM-M0500, M0501, M0502, M0503 and M0003 appeared to be excellent from both a technical and a human factors stand point with minor exceptions. These exceptions were that M0003 references MP-16-21 which was replaced by OCM-M0001 and M0500, M0501, M0502 and M0503 all contain figures with some item numbers that are illegible or nearly so.

The inspector reviewed the procedure describing the licensee's preventive maintenance program (MP-10) and two preventive maintenance work procedures, one for lubrication of Limitorque Limit Switch Assemblies (OPM-M0004) and one

for Torque Switch Contact Inspection (MI-10-25). In addition, the inspector had the licensee utilize the AMMS to indicate the planned preventive maintenance for the HPCI valve 2-E41-F006 and RHR valve 2-E11-F00B. The preventive maintenance scheduled for each valve was procedure MI-10-25 which is to be performed on a three year frequency.

The inspector found that the preventive maintenance procedures, like the other licensee maintenance procedures, were generally satisfactory in technical content and human factors. MI-10-25, which was approved May 25, 1985, is judged not to be quite as good from a human factors standpoint as is OPM-M0004 (June 25, 1987 revision). The latter procedure's precautionary notes, for example, were presented in a more attention getting form. Neither procedure has individual signoffs for procedure steps as they are performed. The use of individual sigroffs is not a requirement but a good practice used to aid in assuring steps are not missed. The licensee uses this practice in their Operations procedures.

c. Review of Inservice Testing Procedures and Records

The inspector reviewed PT 9.2, the licensee's procedure for performing ASME Section XI and TS 4.0.5 inservice testing of the HPCI pumps and valves. In addition, the inspector reviewed the following records of the testing conducted since January 1985:

- Graphic plots of Unit 1 and 2 HPCI pump test data
- Graphic plots of stroke time data for Unit 1 and 2 motor operated valves F001 and F006
- Data sheet records of Unit 2 stroke testing of motor operated valves F001 and F006, check valves F005 and F019, and the HPCI pumps

The graphic plots referred to above were prepared by the licensee in accordance with procedure, ENP-16.1, which was also reviewed by the NRC inspector.

To aid in his review of the licensee's stroke time data, the inspector tabulated the stroke times and calculated means and standard deviations for the data from each of the motor operated valves. These tabulations are depicted in Tables 8-1 and 8-2. HPCI pump differential pressure (DP) and vibration measurements were also tabulated and are given in Table 8-3. Pump measurement means and standard deviations were not determined, as it did not appear that they would be useful. The values in the Tables are listed by test date. For the valve data, known valve failure dates are indicated. The licensee is performing precise

measurements of valve performance using Motor Actuator Characterization, or MAC tests, on their HPCI MOVs in response to NRC Bulletin (IEB) 85-03. Stroke times from this testing are included in the inspector's Tables. The inspector discussed the related data with an engineer involved in the testing. Based on a review of the licensee's procedures and test results, and a discussion with the cognizant engineer, the inspector's findings are as follows:

(1) The stroke time data for tests preceding the valve failures was not useful in predicting the failures. No trends or abnormal stroke time results were noted in the test data that preceded the two failures which occurred for Unit 1 valve, 1-E41-F001, or the failure of valve 2-E41-F006.

(2) Specialized MAC diagnostic testing of valve 1-E41-F001 about six months prior to its second failure did not indicate any conditions that might have resulted in the failure. MAC testing performed following the second failure, both with and without a differential pressure of 1000 psig across the valve, did not reveal any adverse conditions.

(3) The licensee has no criteria for recognizing or addressing abnormal stroke times. They respond to stroke time abnormalities that exceed the ASME Section XI specified limits that trigger an increase in testing frequency. As a consequence, testing errors and impending valve failures may go unrecognized. This deficiency was cited relative to other valve tests in NRC Inspection Report 325, 324/88-06.

(4) The licensee's graphs of stroke time data do not have failures recorded. Although they do indicate when the recorded values are from post maintenance testing, the type and extent of maintenance is not indicated. Inclusion of failure points and summary information on maintenance with the graphs could aid in identifying valve degradation. In some instances it may be desirable to indicate test conditions, such as whether a differential pressure existed across the valve during testing.

(5) The licensee's graphs of pump test data have much data presented in a small space, making recognition of trends difficult. Also, as for their valve test, the licensee relies principally on ASME Section XI criteria for assessing the test data. They do not attempt to characterize normal versus abnormal test values as possible indicators of pump performance. The inspector is aware of no published engineering basis for use of the ASME Section

XI test criteria as a predictor of failure and cautioned the licensee against excessive reliance on the Section XI criteria.

(6) The graphing procedure, ENP 16.1, appeared to have been satisfactorily followed by test personnel. However, it appeared technically inadequate, in that it did not provide for addressing abnormal pump or valve operation. As noted above, it did not present all of the information that appeared to be useful in evaluating individual data points and trends. Licensee test personnel informed the inspector that they had plans to change their trending procedure.

(7) Licensee data indicated proper testing of check valves F005 and F019, except that the closure function of F019 was not tested. A cognizant licensee engineer informed the inspector that this deficiency had been recognized, that a request for NRC approval of disassembly on a sampling basis at refueling outages had been submitted, and that valve 2-E41-F019 was scheduled for the disassembly during the current outage. The inspector verified that relief had been requested (November 24, 1987 submittal, request VR-20) and reviewed a data sheet WR/JO87-BISE1 that indicated that valve disassembly had been performed on January 26, 1988.

(8) The HPCI test procedure (PT. 9.2), which is an Operations procedure, appeared satisfactory technically, and with regard to human factors.

(9) The inspector was unable to draw any conclusions from his tabulation of pump data. No basis for the apparent test value abnormalities that occurred on March 4, 1987, and February 25, 1987, were given on the graphs or were described in the data sheet.

d. Review of Failures of Valves 2-E41-F006 and 1-E41-F001.

The inspector reviewed LERs 2-87-001 and 1-87-023 for the January 1, 1987 failure of 2-E41-F006 and the December 31, 1987 failure of 1-E41-F001. The inspector found that the information provided was consistent with the related data he reviewed and that it appeared to represent an excellent presentation of events and licensee followup.

With the aid of licensee personnel, the inspector searched the AMMS for failures of the subject valves. Records of followup work were readily identified and retrieved. Subsequently, the inspector reviewed WR/JOs 87-BMTI2 and BMTI1 relating to the December 31, 1987 failure of 1-E41-F001 and WR/JOs 87-AAJY1 and 87-AAJZ1 relating to the January 5, 1987 failure of 2-E41-F006.

The records were technically complete and indicated that the work was properly performed and documented.

e. Review of Procedures for Identification of Repetitive Failures

In response to questioning regarding the licensee's practices in addressing repetitive failures, the inspector was informed that two methods are now in use. In one, repetitive failure is defined as a failure that recurs within 18 months on the same tag number equipment, on either Unit 1 or Unit 2. In the other, the repetitive failure is defined as use of four or more of the same replacement part in the past 18 month period. The Maintenance Principal Engineer is responsible for assuring that repetitive failures receive proper corrective action and also provides the plant Nuclear Safety Committee with periodic reports. The inspector verified that both methods of addressing repetitive failures were described in Maintenance Procedure SOP-02.40RO. The method based on equipment tag number was also described in part in the AMMS procedure (MP-14A).

The inspector reviewed the licensee's most recent report of repetitive failures, issued February 13, 1988. It contained seven items identified on the basis of equipment tag number and three based on part numbers. All but one of the ten items involved diesel generator associated equipment or parts. The remaining item was a pump pressure gage.

f. Review of Instructions for Verification of Maintenance Work and Work Requests

The inspector questioned responsible Maintenance Engineering personnel as to how they assured that work records entered on the AMMS were accurate and, therefore, useful in checking for repetitive failures. The inspector was shown and reviewed the licensee's "Post Maintenance Work Inspections" instruction, which specifies weekly Maintenance Engineering checks of randomly selected completed work requests. The work and work requests are required to be audited using a Post Maintenance Audit Checklist.

g. Review of Vendor Manual Availability

In order to verify that maintenance personnel had ready access to appropriate vendor manuals, the inspector requested a planner to retrieve the Limitorque manual, FP20243, which was referenced in a licensee maintenance procedure. The manual was readily retrieved through the computerized Equipment Data Base System (EDBS) and appeared complete and up-to-date. It was not clear whether there were sufficient microfiche readers present to afford maintenance personnel ready access to the manuals. This was identified as a problem by the licensee in their SSFI.

h. Walkdown of the HPCI Pump

The inspector observed the general condition of the Unit 2 HPCI pump during a tour of the reactor building and observed no evidence of any adverse conditions. Housekeeping appeared good and signs were displayed cautioning against possible damage to the equipment when working in the area.

TABLE 8-1

HPCI VALVE STROKE TIME DATA
VALVES 1-E41-F001 and 2-E41-F001

Valve size and type: 10 inch Gate Valve
Actuator: MOV (Limitorque, 250 VDC, SMB-1) Body: Cast Iron
Normal position: closed Safety position: open
Function: Opens to supply reactor steam to power HPCI pump.

| Unit 1 - Opening | | Unit 2 - Opening | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/23/88 | 16.6 | 10/9/87 | 16.4 |
| 2/21/88 | 17.6 | 7/16/87 | 15.3 |
| 1/8/88 | 17.2 | 4/25/87 | 14 |
| 1/2/88 | 16.8 | 3/14/87 | 14 |
| 1/2/88 | 15.2 | 1/27/87 | 15.9 |
| 10/9/87 | 15.8* | 11/2/87 | 16.1 |
| 7/17/87 | 13.4 | 8/15/86 | 15.6 |
| 6/14/87 | 14.5 | 6/26/86 | 14.9 |
| 6/2/87 | 16.6 | 11/18/85 | 16.3 |
| 1/30/87 | 15 | 8/16/85 | 16.3 |
| 11/6/86 | 15.5 | | |
| 10/9/86 | 16.5 | | |
| 8/14/86 | 16.4# | | |
| 2/11/86 | 15.1 | | |
| 10/28/85 | 15.4 | | |

| | | | | |
|---|---|---|---|---|
| mean | = 15.8 | mean | = 15.5 | Unit 1-Closing MAC = 15.63 |
| sd | = 1.00 | sd | = 0.87 | Unit 2-Closing MAC = 14.49 |
| MAC | = 15.84 | MAC | = 14.34 | |
| (5/17/87) | | (1/15/88) | | |

# - Valve motor failed 10/6/86 during a refueling outage

* - Valve failed in attempt to actuate to open during HPCI operability testing on 12/31/87. Motor found burned out.

MAC- Indicates precise measurements of stroke time determined with the licensee's Motor Actuator Characteristic (MAC) program.

TABLE 8-2

HPCI VALVE STROKE TIME DATE
VALVES 1-E41-F006 AND 2-E41-F006

Valve size and type: 14 inch Gate Valve Carbon Steel Body: Cast Iron
Actuator: Motor operator (Limitorque SMB-3, 250 VDC)
Normal position: closed
Safety position: open and closed
Function: Opens to provide cooling water flow from pump discharge into feedwater line into reactor vessel. Closes to provide reactor vessel isolation

| Opening Times | | | | Closing Times | | | |
|---|---|---|---|---|---|---|---|
| Unit 1 | | Unit 2 | | Unit 1 | | Unit 2 | |
| Date | Time | Date | Time | Date | Time | Date | Time |
| 2/23/88 | 17.5 | 1/2/88 | 16.8 | 2/23/88 | 15.9 | 1/2/88 | 16.8 |
| 2/21/88 | 18.2 | 10/9/87 | 15.7 | 2/21/88 | 16.4 | 10/9/87 | 15.1 |
| 1/8/88 | 18 | 7/16/87 | 17 | 1/8/88 | 14.5 | 7/16/87 | 14.5 |
| 11/1/87 | 17.4 | 4/25/87 | 15.8 | 11/1/87 | 17.1 | 4/25/87 | 13.7 |
| 10/9/87 | 16.4 | 4/7/87 | 16.4 | 10/9/87 | 15.8 | 4/9/87 | 14.5 |
| 7/17/87 | 13 | 3/19/87 | 17.5 | 7/17/87 | 14.6 | 3/14/87 | 14.6 |
| 6/14/87 | 15.4 | 1/27/87 | 15.8 | 6/14/87 | 17. | 1/27/87 | 14.9 |
| 6/7/87 | 16 | 1/13/87 | 18.7 | 6/7/87 | 14.2 | 1/13/87 | 13.4 |
| 6/2/87 | 16.8 | 1/19/87 | 16.6 | 6/2/87 | 14.5 | 1/9/87 | 14.5 |
| 1/30/87 | 14.2 | 11/2/86 | 15.3 | 1/30/87 | 16 | 11/2/87 | 15.5 |
| 11/6/86* | 17.4 | 8/14/86 | 14.2 | 11/6/86 | 15.8* | 8/14/86 | 14.3 |
| 8/14/86 | 15.4 | 6/26/86 | 17 | 8/14/86 | 16.5 | 6/26/86 | 15.4 |
| 5/17/86 | 15.9 | 5/26/86 | 16.3 | 5/17/86 | 17 | 5/26/86 | 15 |
| 2/11/85 | 18.9 | 11/18/85 | 14.1 | 2/11/86 | 15.1 | 11/18/85 | 15 |
| 10/28/85 | 17.3 | 8/16/85 | 14 | 10/28/85 | 14.9 | 8/16/85 | 13 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| means = | 16.5 | mean = | 16.1 | mean = | 15.0 | mean = | 14.7 |
| sd = | 1.52 | sd = | 1.27 | sd = | 0.96 | sd = | 0.89 |
| MAC = | 15.42 | | | MAC = | 15.60 | | |
| | (5/31/87) | | | | (5/31/87) | | |

* Valve failed to open in recovery following scram on 1/5/87.

MAC - Indicates precise measurements of openings stroke time determined using Motor Actuator Characteristic (MAC) program. The licensee had not performed MAC testing on the Unit 2 valve but plans to in the near future. Thus, there were no MAC times for the Unit 2 valve.

TABLE 8-3

HPCI UNIT 2 PUMP TEST DATA

| | Pump Diff. Pressure | | Main Pump Vibration | | Booster Pump Vibration | |
|---|---|---|---|---|---|---|
| Date | Measured | Acceptable | Measured | Acceptable | Measured | Acceptable |
| 10/9/87 | 1008 | 963 - 1057 | 1.0 | 0 - 1.46 | 0.7 | 0 - 1.46 |
| 7/16/87 | 1000 | 963 - 1057 | 0.35 | 0 - 1.46 | 0.55 | 0 - 1.46 |
| 4/25/87 | 976 | 963 - 1057 | 0.4 | 0 - 1.46 | 0.5 | 0 - 1.46 |
| 3/14/87 | 1060 | 963 - 1057 | 1.0 | 0 - 1.46 | 1.0 | 0 - 1.46 |
| 1/27/87 | 1050 | 963 - 1057 | 0.6 | 0 - 1.46 | 0.7 | 0 - 1.46 |
| 11/2/86 | 1017 | 963 - 1057 | 0.38 | 0 - 1.46 | 0.32 | 0 - 1.46 |
| 8/15/86 | 1040 | 963 - 1057 | 0.46 | 0 - 1.46 | 0.24 | 0 - 1.46 |
| 6/26/86 | 1002 | 963 - 1057 | 0.6 | 0 - 1.46 | 1.0 | 0 - 1.46 |
| 11/18/85 | 1053 | 963 - 1057 | 0.35 | 0 - 1.46 | 0.5 | 0 - 1.46 |
| 8/16/85 | 1032 | 963 - 1057 | 0.40 | 0 - 1.46 | 0.3 | 0 - 1.46 |
| 5/17/85 | 1005 | 963 - 1057 | 0.21 | 0 - 1.46 | 0.18 | 0 - 1.46 |
| 4/23/85 | 1007 | 963 - 1057 | 0.7 | 0 - 1.46 | 0.5 | 0 - 1.46 |
| 2/27/85 | 1036 | 1130 - 1239 | 0.56 | 0 - 1.12 | 0.9 | 0 - 1 |
| 2/26/85 | 1026 | 1130 - 1239 | 0.7 | 0 - 1.12 | 0.6 | 0 - 1 |
| 2/18/85 | 1130 | 1130 - 1239 | 0.08 | 0 - 1.12 | 0.07 | 0 - 1 |
| 2/16/85 | 988 | 1130 - 1239 | 0.8 | 0 - 1.12 | 1.2 | 0 - 1 |

## 9.0 Residual Heat Removal System (RHR)

RHR valves F007A and B, F024A and B, F028A and B and F048A and B were selected for NRC inspection because the licensee's PRA identified their importance in recovery actions and in failure events involving dominant accident sequences for core melt.

### 9.1 Description and Functions of RHR Valves

For the actions and events under consideration, the principal safety concern is that the RHR valves function to accomplish suppression pool cooling. Although all of these valves have motor operators, it is important that they be capable of being operated manually if motor operation proves impossible. The F007 valves must open to provide a pump minimum flow path to preclude pump damage from overheating when the pump is operating with its discharge path isolated.

The F028 and F024 valves open for the RHR pumps to recirculate suppression pool water through the RHR Heat Exchangers (HXs) for cooling. They are normally closed valves that lie in the path from the HX to the suppression pool.

The opening of F024 is of lesser importance, since an alternate path through F027 is available. The F048 valves close to assure the recirculating flow does not bypass the HXs.

### 9.2 Details

The inspector examined the adequacy of the licensee's maintenance and testing of these RHR valves to assure against the events of concern. The examination was conducted through inspection of the valves, interviews with responsible licensee personnel and review of the procedures, records and related documents. The documents reviewed are listed in Section 19. Details of the inspector's examination and findings are described below.

NRC inspectors, aided by a licensed operator, closely examined Unit 2 (unit in refueling ) and Unit 1 (unit in operation) of F007, F024, F028 and F048 valves in loops A and B. The inspectors examined the valves to determine their apparent condition and whether they could be readily accessed for manual actuation should motor actuation fail. The inspectors findings were as follows:

(1) Chesterton Live Load Packing had been installed on Unit 2 valves F024A, F028A, and F048A to increase packing life as part of a packing improvement program.

(2) A number of discrepancies were noted regarding valve orientation, fasteners, and position indication. These were discussed

with the license for their review and disposition. Several of the items were observed during maintenance and final disposition had not yet been completed.

(3) Unit 1 F007B valve was found to be missing the handwheel.

The ability to manually operate valve F007B in a timely manner during an emergency is considered of high importance by the PRA. A work request to repair the valve handwheel issued February 19, 1988, was on file. The handwheel had been found while performing other maintenance above the RCIC turbine in the overhead. Valve F007B is located about 15 feet above the RCIC turbine area. The licensee could not determine when the handwheel had fallen off. The last recorded maintenance on this valve had been an EQ inspection on October 27, 1987. Unit 1 had completed an outage and had been restarted on February 19, 1988.

The work request had been evaluated as not affecting operability of the valve (no LCO) and a maintenance priority 3 had been assigned. At the request of an inspector, the valve was cycled electrically from the control room, and it operated properly. The inspector agreed with the priority 3 assignment. The handwheel repairs would be scheduled to be accomplished during the next shutdown of Unit 1 and RHR Loop B, which was scheduled for the week of April 9, 1988.

Licensee's schedule for physical inspection of this valve operator was reviewed. For system configuration alignment checks, the licensee uses control room position indication, and does not physically inspect the valve operator. The maintenance department has an 18 month PM schedule for physically inspecting all MOV operators. Other nonroutine inspections are done by operations, maintenance, engineering, and others but it is possible that a missing MOV handwheel or gearbox cover could go undetected for as long as 18 months.

9.3 Interviews

Responsible engineering, maintenance and test personnel were interviewed relative to general information on control circuitry, failure history and corrective actions, maintenance and testing of the RHR valves. Significant information gained from these interviews indicated that the site personnel were knowledgeable and familiar with plant design and equipment performance.

(1) The valves are Limitorque AC motor operated. Valve opening actuation is controlled by a limit switch and closing by torque switch. Torque switch and overload protection are bypassed over most of valve travel to aid in assuring valve operation for performance of safety functions. The licensee's engineers provided valve circuity drawings which depicted the stated controls.

(2) F007 and F028 are gate valves and F024 and F048 are globe valves.

(3) The valves have not experienced significant failures or required any special maintenance because of degradation, except that F024 had excessive leakage that required corrective maintenance.

(4) RHR system unavailability for containment cooling is being monitored and reported quarterly. The NRC inspector verified that quarterly tabulations are prepared by the licensee from LCO data.

9.4 Maintenance Procedures and Records Review

Maintenance procedures, reviewed by the NRC inspector, relative to HPCI valve maintenance, are applicable to maintenance on the RHR valves. Maintenance procedures specifically applicable to RHR valves were for the installation of live load packing on Unit 2 RHR valves; F024A, F0228A and F048A. The inspector found that the procedures were adequate and that actual installation appeared in conformance with the procedure.

Maintenance related records reviewed by the NRC inspector and the findings with regard to records were as follows:

(1) The work histories for Unit 2 valves F024A and F007A were examined for significant failure and maintenance. The inspector found no indication of failures other than the excessive valve leakage on F024A that was described in interviews. Two WR/JOs were examined to verify that work was properly performed and recorded. These were WR/JO 86-AHGT1 which involved inspection of the F007A valve for concerns identified in NRC IN 86-03 and WR/JO 87-BGIC1 which involved inspection and correction of a packing leak on valve F024A.

The inspector found that the required information was properly recorded on the WR/JOs and that it indicated satisfactory work performance, including post maintenance stroke time test for F024A.

(2) Records of Plant Modifications (PMs) 84-060 and 84-061 were selected for review because abnormal stroke times occurred for some valves during testing following the PMs. The PMs installed redundant fuses in the control circuits for valves F028B and F048B in both Units. Opening times for the F048B valves appeared larger than normal for testing conducted on April 22, 1987 for Unit 1 and October 29, 1987 for Unit 2. The licensee and the inspector found no basis for stroke time increase. Subsequent periodic tests resulted in times consistant with previous test results.

(3) The AMMS was checked to determine if the licensee had scheduled preventive maintenance for valve 2-E11-F007B. The inspector found that MI 10-25 was scheduled. The MI will perform a check of the torque switch contacts.

9.5 Review of Testing Procedures and Records

The inspector reviewed the licensee's procedures for performing ASME Section XI, and TS. 4.0.5, testing of the RHR valves, and reviewed the records of testing. The procedures reviewed were PT 8.2.2b, for loop B valves, and PT 8.2.2c, for loop A valves. The records reviewed were for the stroke time testing of the valves, as recorded on graphs, and in the procedure data sheets. The graphs are the same kind as those referred to for HPCI valves in an earlier section. To aid in his review of the data, the inspector tabulated the stroke times and calculated means and standard deviations for the data from each of the valves. The tabulations are found in Tables 9-1,-2,-3, and -4 for RHR valves F007, F024, F028 and F048, respectively. The data are listed by test date. Stroke times that differ from the calcuated means by more than 3 standard deviations are considered abnormal and are identified in the Table by asterisks. In some instances the inspector's review and analysis of the data identified possible explanations for abnormal stroke times and these are identified by the symbol (#) in the Tables. No failures of the valves were identified and, therefore, none are identified in the tables. Based on this review and analysis of the data, the inspector's findings with regard to the licensee's testing are as follows:

(1) The licensee has no criteria for addressing abnormal stroke times unless the times are so large as to be considered valve failures. As a consequence, testing errors and possible indications of significant valve degradation may go unrecognized. Further, the licensee may miss an opportunity to recognize and understand maintenance and operating affects on the valves that may aid in assuring continued operability. Instances where stroke times of valves have been significantly affected by conditions not recognized and explained by licensee personnel are denoted by * and # in Tables 9-1 and -3.

(2) The records indicated that the licensee's performance of stroke time tests are performed at the test frequency specified by ASME Section XI and that the results are recorded as required by Section XI.

(3) The licensee's procedures for performing the stroke time testing of the these RHR valves appear excellent from both a technical and human factors standpoint.

## TABLE 9-1

### RHR VALVE STROKE TIME DATA
### VALVES 1-E11-F007A & B AND 2-E11-F007A & B

Valve size and type: 4 inch Gate Valve
Body: Carbon Steel
Actuator: Motor [illegible] 3Ph., 33HP, Limitorque SMB-000
Normal position: [illegible]
Safety Position: Open and Closed
Function: Open to provide pump protection against overheating

Opening Times - Unit 1

| 7A Date | 7A Time | 7B Date | 7B Time |
|---|---|---|---|
| 2/18/88 | 21.4 | 1/22/87 | 21 |
| 12/22/87 | 19.6 | 10/30/87 | 21 |
| 10/3/87 | 19.6 | 10/18/87 | 21.8 |
| 10/2/87 | 21.2 | 8/7/87 | 20.8 |
| 8/3/87 | 21.3 | 7/25/87 | 21.2 |
| 08/03/87 | 19.6 | 07/25/87 | 18.8 |
| 5/29/87 | 21.4 | 5/27/87 | 20.7 |
| 5/2/87 | 20 | 5/1/87 | 21.1 |
| 12/23/86 | 22.6 | 12/20/86 | 21.4 |
| mean = | 20.9 | mean = | 21.1 |
| sd = | 0.99 | sd = | 0.33 |

Opening Times - Unit 2

| 7A Date | 7A Time | 7B Date | 7B Time |
|---|---|---|---|
| 12/27/87 | 21.3 | 10/30/87 | 17.7 |
| 12/24/87 | 21.5 | 10/29/87 | 20.8 |
| 11/25/87 | 22.4 | 10/27/87 | 19.5 |
| 10/3/87 | 22.7 | 8/8/87 | 19.6 |
| 7/11/87 | 21.2 | 5/16/87 | 20.8 |
| 07/11/87 | 19.7 | 05/16/87 | 19. |
| 6/9/87 | 21.4 | 2/22/87 | 17.4 |
| 4/17/87 | 21.3 | 2/19/87 | 19 |
| 1/25/87 | 21.3 | 12/3/86 | 19 |
| mean = | 21.6 | mean = | 19.2 |
| sd = | 0.54 | mean = | 1.17 |

Closing Times - Unit 1

| 7A Date | 7A Time | 7B Date | 7B Time |
|---|---|---|---|
| 02/18/88 | 18.9 | 01/22/88 | 18.4 |
| 12/22/87 | 18.3 | 10/30/87 | 19.3 |
| 10/03/87 | 21.3 | 10/18/87 | 18.9 |
| 10/02/87 | 19.9 | 08/07/87 | 18.3 |
| 03/03/87 | 19.6 | 07/25/87 | 18.8 |
| 05/29/87 | 19.8 | 05/27/87 | 18.5 |
| 05/02/87 | 18 | 05/01/87 | 21 |
| 12/23/86 | 19.6 | 12/20/86 | 18.2 |
| 09/21/86 | 20.1 | 10/02/86 | 19.1 |
| 06/21/86 | 19.6 | 01/02/88 | 19.1 |
| 03/20/86 | 19.9 | 04/16/86 | 19.1 |
| 12/02/85 | 20 | 12/29/85 | 19.2 |
| 09/18/85 | 19.7 | 09/14/85 | 18 |
| mean = | 19.6 | mean = | 18.9 |
| sd = | 0.80 | sd = | 0.73 |

Closing Times - Unit 2

| 7A Date | 7A Time | 7B Date | 7B Time |
|---|---|---|---|
| 12/27/87 | 20 | 10/30/87 | 17.4 |
| 12/24/87 | 20 | 10/29/87 | 19 |
| 11/25/87 | 19.8 | 10/29/87 | 18.8 |
| 10/03/87 | 19.7 | 08/08/87 | 19.8 |
| 07/11/87 | 19.7 | 05/16/87 | 19 |
| 06/09/87 | 19.5 | 02/22/87 | 19.2 |
| 04/17/87 | 19.9 | 02/19/87 | 18.9 |
| 01/25/87 | 18.9 | 12/03/86 | 19 |
| 11/17/86 | 20.4 | 09/04/86 | 19.5 |
| 08/26/86 | 20.3 | 05/20/86 | 20 |
| 06/25/86 | 20.4 | 10/06/85 | 18.8 |
| 10/13/85 | 20 | 09/12/85 | 19 |
| 07/03/85 | 14.8 | | |
| mean = | 19.9 | mean = | 19.0 |
| sd = | 0.38 | sd = | 0.62 |

## TABLE 9-2

### RHR VALVE STROKE TIME DATA
### VALVES 1-E11-F024A & B AND 2-E11-F024A & B

Valve size and type: 16 inch Globe
Body: Cast carbon steel
Actuator: Motor, 460 VAC 3Ph, 5.2.HP. Limitorque SMB-3
Normal position: Closed
Safety position: Open and Closed
Function: Open to permit flow from RHR HX into Torus

Opening Times - Unit 1

| 24A | | 24B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 74.6 | 1/22/88 | 76.5 |
| 12/22/87 | 69.9 | 10/30/87 | 76 |
| 10/3/87 | 75.3 | 10/18/87 | 76.2 |
| 10/2/87 | 73.5 | 8/7/87 | 76.8 |
| 8/3/87 | 75.4 | 7/25/87 | 75.8 |
| 7/4/87 | 75 | 5/27/87 | 76.9 |
| 5/29/87 | 75.5 | 5/1/87 | 76.8 |
| 5/2/87 | 76.3 | 3/17/87 | 77 |
| 12/23/86 | 75.2 | 12/20/86 | 78.7 |
| mean = | 74.5 | mean = | 76.7 |
| sd = | 1.87 | sd = | 0.80 |

Opening Times - Unit 2

| 24A | | 24B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/24/87 | 72.7 | 10/30/87 | 74.7 |
| 12/23/87 | 71.3# | 10/29/87 | 73.8 |
| 10/3/87 | 76.8 | 08/08/87 | 74.2 |
| 10/1/87 | 76.9 | 5/23/87 | 74.8 |
| 7/11/87 | 77.2 | 5/11/87 | 74.5 |
| 6/9/87 | 76.5 | 2/22/87 | 74.7 |
| 5/22/87 | 79.1 | 2/19/87 | 74 |
| 4/17/87 | 77.2 | 1/29/87 | 74 |
| 1/29/87 | 76.6 | 1/11/87 | 70.8 |
| 01/25/87 | 76.8 | 12/03/86 | 75 |
| mean = | 76.1 | mean = | 74.1 |
| sd = | 2.19 | sd = | 1.16 |

Closing Times - Unit 1

| 24A | | 24B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 70.3 | 1/22/88 | 74 |
| 12/22/87 | 69.5 | 10/30/87 | 73 |
| 10/3/87 | 70.3 | 10/18/87 | 73.3 |
| 10/2/87 | 70.5 | 8/7/87 | 73.7 |
| 8/3/87 | 70.2 | 7/25/87 | 73.5 |
| 7/4/87 | 70.5 | 5/27/87 | 74 |
| 5/29/87 | 70.2 | 5/1/87 | 73.5 |
| 5/2/87 | 70 | 3/17/87 | 73 |
| 12/23/87 | 70.2 | 12/20/86 | 73.7 |
| 9/21/86 | 70.2 | 10/2/86 | 73.5 |
| 6/21/86 | 70.2 | 7/02/86 | 76.6* |
| 3/20/86 | 70.4 | 4/16/86 | 73.5 |
| 12/12/85 | 70.4 | 3/27/86 | 73.7 |
| 10/19/85 | 70.2 | 12/29/85 | 73.7 |
| 9/12/85 | 73.2* | 10/27/85 | 73.8 |
| | | 9/14/85 | 72.6 |
| mean = | 70.4 | mean = | 73.7 |
| sd = | 0.60 | sd = | 0.83 |

Closing Times - Unit 2

| 24A | | 24B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/24/87 | 71.5 | 10/30/87 | 71.9 |
| 12/23/87 | 77.1*# | 10/29/87 | 71.5 |
| 10/3/87 | 71.4 | 08/08/87 | 71.3 |
| 10/1/87 | 71.6 | 5/27/87 | 71.3 |
| 7/11/87 | 73.1 | 5/16/87 | 71.1 |
| 6/9/87 | 72.9 | 2/22/87 | 70.9 |
| 5/22/87 | 72.8 | 2/19/87 | 71.6 |
| 4/17/87 | 72.4 | 1/29/87 | 71.8 |
| 1/29/87 | 73.1 | 1/11/87 | 70.8 |
| 1/25/87 | 72.5 | 12/3/86 | 72 |
| 11/17/86 | 72.5 | 09/04/86 | 72.1 |
| 8/26/86 | 72.6 | 5/20/86 | 63.1* |
| 7/13/86 | 72.7 | 11/6/85 | 71.1 |
| 5/25/86 | 75.4 | 9/12/85 | 71 |
| 10/13/85 | 74.9 | | |
| 8/12/85 | 74.9 | | |
| mean = | 73.2 | mean = | 70.8 |
| sd = | 1.51 | sd = | 2.18 |

#Change in stroke time coincides with tightening of packing gland nuts.

* Denotes values differing from mean by more than 3 standard deviations. It appears from these data that the opening and closing times recorded may be reversed.

TABLE 9-3

RHR VALVE STROKE TIME DATA
VALVES 1-E11-F028A & B AND 2-E11-F028A & B

Valve size and type: 16 inch Gate Valve
Body: Cast Carbon Steel
Actuator: Motor, 460VAC 3PH, 3.35 HP. Limitorque SMB-1
Normal position : Closed
Safety position: Open and Closed
Function: Open to permit flow to Torus from RHR HX. Closes to isolate torus.

Opening Times - Unit 1

| 28A | | 28B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 70.7 | [illegible] 88 | 74.8 |
| 12/22/87 | 65.9 | [illegible] 30/87 | 75 |
| 10/3/87 | 70.5 | 10/18/87 | 73.2 |
| 10/2/87 | 71.5 | 8/7/87 | 75.5 |
| 9/25/87 | 69 | 7/25/87 | 75.5 |
| 8/3/87 | 70.7 | 5/27/87 | 76 |
| 6/8/87 | 60.5* | 5/1/87 | 75.3 |
| 5/29/87 | 70.5 | 3/17/87 | 75 |
| 5/2/87 | 70.5 | 12/20/87 | 71.3*# |
| 9/29/86 | 70.5 | 10/2/86 | 75.5 |
| 6/21/86 | 70.3 | 7/02/86 | 75.2 |
| 3/20/86 | 70.8 | 4/16/86 | 75.2 |
| 12/12/85 | 67.1 | 3/27/86 | 77.2 |
| 9/18/85 | 70.8 | 12/29/85 | 75.2 |
| | | 9/14/85 | 75.4 |
| mean = | 69.2 | mean = | 75.2 |
| sd = | 2.86 | sd = | 1.17 |

Opening Times - Unit 2

| 28A | | 28B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/24/87 | 74.1 | 11/12/87 | 74.5 |
| 10/3/87 | 71.3 | 10/30/87 | 74.6 |
| 7/11/87 | 75.6 | 10/29/87 | 74.7 |
| 4/17/87 | 75.4 | 8/8/87 | 74.7 |
| 1/25/87 | 75.6 | 5/16/87 | 74.7 |
| 11/17/86 | 75.7 | 2/22/87 | 74.5 |
| 8/26/86 | 75.8 | 2/19/87 | 74.7 |
| 7/14/86 | 75 | 12/3/86 | 75 |
| 5/25/86 | 75.5 | 9/04/86 | 75 |
| 10/13/85 | 74.7 | 5/20/86 | 80.1 |
| 7/1/85 | 75.8 | 10/6/85 | 74.7 |
| | | 9/12/85 | 76 |
| mean = | 75.0 | mean = | 75.3 |
| sd = | 1.26 | sd = | 1.51 |

Closing Times - Unit 1

| 28A | | 28B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 67.9 | 1/22/88 | 72.9 |
| 12/22/87 | 65.8 | 10/30/87 | 73 |
| 10/3/87 | 67.1 | 10/18/87 | 72.6 |
| 10/2/87 | 67 | 8/7/87 | 73.4 |
| 9/25/87 | 62 | 7/25/87 | 73.5 |
| 8/3/87 | 67.5 | 5/27/87 | 73.2 |
| 6/8/87 | 66 | 5/1/87 | 72.9 |
| 5/29/87 | 67.1 | 3/17/87 | 73 |
| 5/2/87 | 61 | 12/20/86 | 75.5*# |
| 12/23/6 | 67.1 | 10/2/86 | 72.6 |
| 9/29/86 | 67.3 | 7/2/86 | 72.8 |
| 6/21/86 | 67.2 | 4/16/86 | 72.8 |
| 3/20/86 | 67.6 | 3/27/86 | 72.9 |
| 12/12/85 | 70.8 | 12/29/85 | 73.1 |
| 9/18/85 | 67.6 | 9/14/85 | 73.6 |

Closing Times - Unit 2

| 28A | | 28B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/20/87 | 70.7 | 11/12/87 | 70.5 |
| 10/3/87 | 71.6 | 10/30/87 | 72 |
| 7/11/87 | 73 | 10/29/87 | 72.1 |
| 4/17/87 | 72.7 | 8/8/87 | 72.1 |
| 1/25/87 | 72.7 | 5/16/87 | 72.3 |
| 11/17/86 | 72.9 | 2/22/87 | 72.6 |
| 8/26/86 | 73 | 2/19/87 | 72.6 |
| 7/14/86 | 69 | 12/3/86 | 73 |
| 5/25/86 | 73.2 | 9/4/86 | 72.5 |
| 10/13/85 | 72.7 | 5/20/86 | 72.6 |
| 7/1/85 | 73 | 10/6/85 | 72.3 |
| | | 9/12/85 | 72 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| mean | = | 66.6 | mean | = | 73.2 | mean | = | 72.2 | mean | = | 72.2 |
| sd | = | 2.27 | sd | = | 0.68 | sd | = | 1.24 | sd | = | 0.59 |

* Denotes values differing from mean by more than 3 standard deviations (sd)

# It appears that the opening and closing times recorded may be reversed.

## TABLE 9-4

### RHR VALVE STROKE TIME DATE
### VALVES 1-E11-F0408A & B AND 2-E11-4048A & B

Valve size and type: 20 inch Globe Valve
Body: Cast Carbon Steel
Normal Positions: Open
Safety Position: Open and Closed
Fuction: Opens to permit bypassing of RHR HX. Closes to prevent bypassing of RHR HX.

Opening Times - Unit 1

| 48A | | 48B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 100.6 | 1/22/88 | 93.8 |
| 12/22/87 | 99.7 | 10/30/87 | 94 |
| 10/3/87 | 100.4 | 10/18/87 | 94.3 |
| 10/2/87 | 100.4 | 8/7/87 | 93.9 |
| 8/3/87 | 100.6 | 7/25/87 | 94.2 |
| 5/29/87 | 100.5 | 5/27/87 | 95.8 |
| 05/01/87 | 98.7 | | |
| 5/2/87 | 100 | 4/22/87 | 105 |
| 12/23/87 | 100.4 | 12/20/86 | 94.2 |
| mean = | 100.3 | mean = | 96.0 |
| sd = | 0.29 | sd = | 3.51 |

Opening Times - Unit 2

| 48A | | 48B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/24/87 | 99.3 | 10/30/87 | 100 |
| 10/3/87 | 99.5 | 10/29/87 | 106.3 |
| 10/1/87 | 103.1 | 10/29/87 | 106.2 |
| 7/11/87 | 101.1 | 8/8/87 | 104.2 |
| 6/09/87 | 100.2 | 5/16/87 | 99.8 |
| 4/17/87 | 99.7 | 2/22/87 | 101.3 |
| 01/25/87 | 99.8 | 02/19/87 | 100.5 |
| | | 12/3/87 | 103 |
| mean = | 100.4 | mean = | 102.7 |
| sd = | 1.24 | sd = | 2.50 |

Closing Times - Unit 1

| 48A | | 48A | |
|---|---|---|---|
| Date | Time | Date | Time |
| 2/18/88 | 100.7 | 1/22/88 | 101.5 |
| 12/22/87 | 99.6 | 10/30/87 | 96 |
| 10/3/87 | 100.5 | 10/18/87 | 98.8 |
| 10/2/87 | 100.6 | 8/7/87 | 96 |
| 8/03/87 | 100.2 | 7/25/87 | 96 |
| 5/29/87 | 100.6 | 5/27/87 | 102.3 |
| 5/2/87 | 100 | [illegible]/1/87 | 94.2 |
| 12/23/86 | 100.5 | [illegible]/22/87 | 101 |
| 9/21/86 | 100.3 | 12/20/86 | 95.9 |
| 6/21/86 | 100.5 | 10/2/86 | 101.3 |
| 3/20/86 | 101.2 | 7/2/86 | 98.6 |
| 12/12/85 | 101.1 | 4/16/86 | 98.2 |
| 9/18/85 | 100.7 | 1/30/86 | 101 |
| | | 12/29/85 | 95.9 |
| | | 09/14/85 | 100.8 |
| mean = | 100.5 | mean = | 98.5 |
| sd = | 0.41 | sd = | 2.58 |

Closing Times - Unit 2

| 48A | | 48B | |
|---|---|---|---|
| Date | Time | Date | Time |
| 12/24/87 | 97.9 | 10/30/87 | 99.7 |
| 10/03/87 | 98.5 | 10/29/87 | 101.7 |
| 10/1/87 | 97.7 | 10/29/87 | 101.2 |
| 7/11/87 | 99.1 | 8/8/87 | 104.2 |
| 6/9/87 | 99 | 5/16/87 | 99.1 |
| 4/17/87 | 99 | 2/22/87 | 100.6 |
| 1/25/87 | 98.7 | 2/19/87 | 99.9 |
| 11/17/86 | 99.1 | 12/03/86 | 99 |
| 11/16/86 | 97 | 9/4/86 | 100 |
| 8/26/86 | 100 | 6/22/86 | 99.3 |
| 7/14/86 | 101.8 | 6/3/86 | 99.2 |
| 5/25/86 | 99.1 | 5/23/86 | 99 |
| 10/13/85 | 103.1 | 5/20/86 | 100.7 |
| 8/12/85 | 98.5 | 10/6/85 | 100.8 |
| | | 09/12/85 | 100 |
| mean = | 99.2 | mean = | 100.3 |
| sd = | 2.34 | sd = | 1.32 |

## 10.0 Electrical Distribution Systems

There is one unit auxiliary transformer (UAT) and one startup/standby transformer (SAT) for each of the two units. See Figure 10.1, One Line Diagram. The UAT is tapped from the generator isolated phase bus duct, and supplies power for plant auxiliaries during normal operation. The SAT connects the 230 kV switchyard with the plant 4160 V system, and supplies power for unit startup as well as shutdown mode. When operating with the UAT or SAT, power flows to the emergency buses through balance-of-plant (BOP) buses. The feeders from the BOP buses to the emergency buses have circuit breakers at both ends so that, should a fault occur on the feeder cable, the fault can be quickly disconnected from the emergency bus.

In general, the distribution systems for the two units do not have any interconnections between units upstream of the emergency buses. Each unit is connected to a 230 kV switchyard that is electrically separate from the other unit's switchyard. The only exception to this separation is that the plant common buses can be fed from either SAT. Interconnections do, however, exist between the emergency buses of the two units via tie buses and breakers, but these are considered to be reserved for maintenance purposes only. The FSAR describes some limited sharing of safety-related equipment, such as pumps between units.

There are four emergency diesel generators for the two units. The 4160 V and 480 V systems are high-resistance grounded systems. Each unit has two separate 125/250 VDC systems and two separate 24/48 VDC systems. The latter system is not classified Class 1E, but does feed loads considered important to safety.

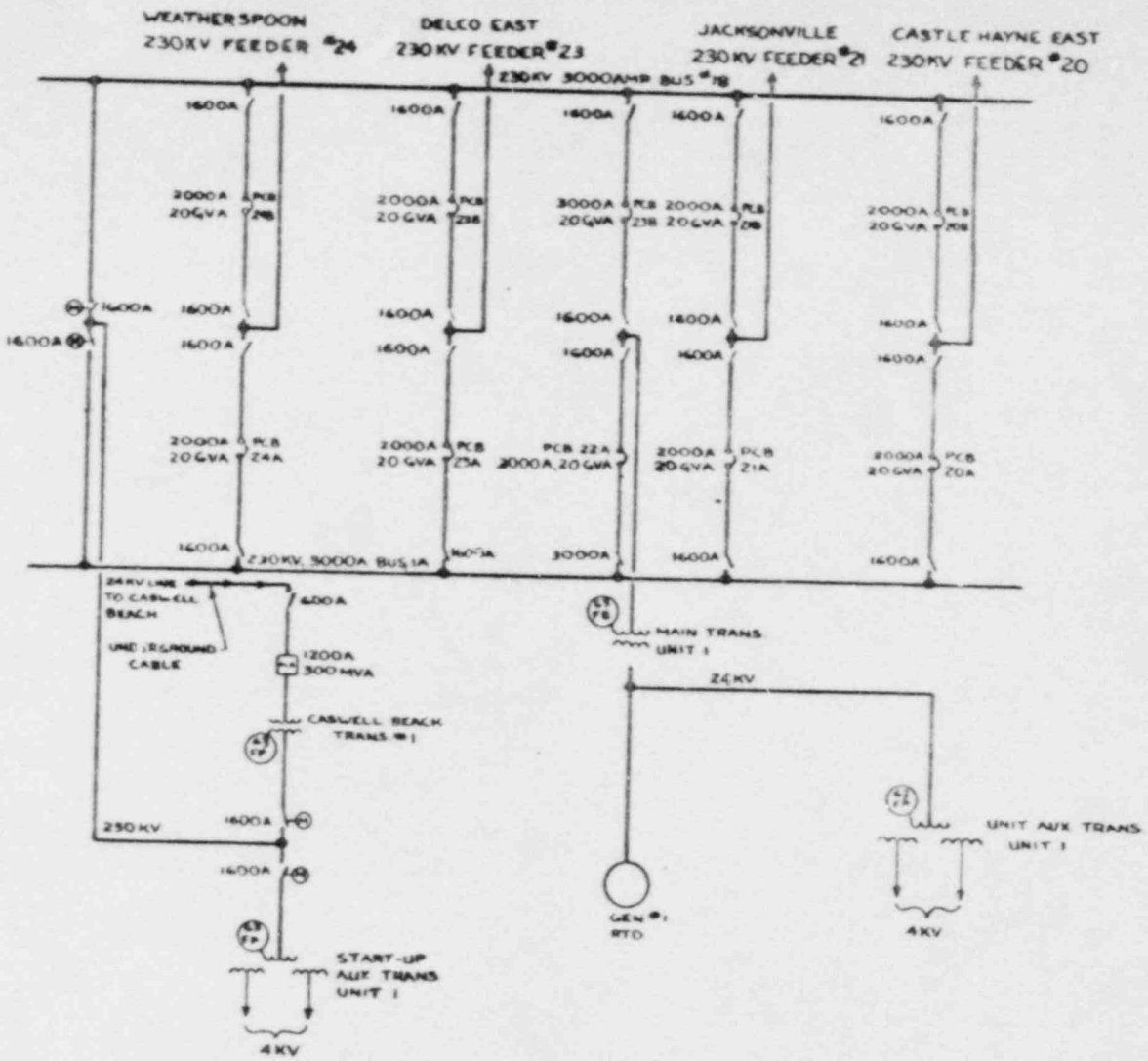
### 10.1. Scope of the Inspection

The scope of the electrical inspection covered portions of the engineering, design, maintenance, and operations areas. Interviews were conducted with licensee personnel working in each of these areas. The personnel were asked questions deemed relevant to system reliability, and probabilistic risk assessment conclusions were stressed during the interviews. Plant walkdowns were carried out to assess equipment layout, human factors, and equipment condition. The location of intra-plant communications equipment was assessed during the walkdowns. Nearly all specific items reviewed and all significant findings are discussed in this Section.

### 10.2 Auxiliary Distribution System - PRA Considerations

A blackout of the transmission grid followed by failure of the four emergency diesel generators is obviously a severe scenario, but it has sufficient probability of occurring to significantly contribute to the total core melt frequency value. Furthermore, the PRA study showed that loss of specific buses has particular significance. In order of decreasing importance, these buses are MCC2CA, 4160 V bus E3 and 480 V bus E7.

Figure 10.1 One Line Diagram




BRUNSWICK STEAM ELECTRIC PLANT UNITS 1 & 2
Carolina Power & Light Company
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN ONE LINE DIAGRAM
230 KV & 24 KV SYSTEMS
SHEET NO. 1

FIGURE 8.2.1 2

Equipment mandated by 10 CFR 50.62 to be installed in order to reduce the risk from anticipated transient without a scram (ATWS) scenarios has not been considered by the PRA. The Alternate Rod Injection System was installed on Unit 2 during the outage that was ongoing at the time of this inspection. Modifications to the recirculation pump trip circuit and the Standby Liquid Control System (SLC) were also accomplished during this outage. Certain facets of the Brunswick design for the ATWS modifications are under review by the NRC. The NRC prefers two trip coils rather than one trip coil for the recirculation pump trip circuit, and greater diversity of sensors for the Alternate Rod Injection System. These issues should be resolved in the near future. The same modifications will be installed on Unit 1 before the end of the 1988 fall refueling outage. ATWS scenarios are a major contributor to the core melt frequency value. However, the Brunswick PRA results will substantially change as a result of implementation of the mandated ATWS modifications. This is because Brunswick already had a form of recirculation pump tripping and the PRA took credit for manually scramming the reactor upon an ATWS event. The SLC system is discussed in Section 14.

10.3 Design Considerations Related to the PRA Conclusions

In accurate and out-of-date electrical drawings can lead to problems when attempting to implement system modifications, therefore the NRC inspector inquired as to the licensee's drawing update program. The licensee's program calls for updating elementary diagrams and wiring interconnection diagrams within 15 days after the modification is declared operational. The resolution of discrepancies between drawings and the actual installation is proceduralized in Procedure ENP-25. In order to obtain confirmation that the drawing update program was working well, the NRC inspector selected three plant modifications at random to use as examples. Two plant modifications implemented in the summer of 1987 outage and one modification associated with the present outage were chosen. Randomly selected drawings, which were revised for the chosen modifications, were updated witnin 15-35 days of the modification operational date. This is slightly longer than the program goal,. but certainly acceptable timeliness. The licensee had an interactive computer program to track drawing status and plant modification packages. The NRC inspector was satisfied that the drawing update program was working well.

The inspector also reviewed operational considerations based upon electrical system design.

The start-up transformer windings are connected grounded wye on both the primary and secondary sides without a buried delta winding. Transformers having this connection configuration and constructed on three cores can be troublesome. As stated in Reference 1 Section

19.0, unbalanced conditions result in zero- sequence flux, which travels from one end yoke to another through the transformer tank. During a secondary single line to ground fault, the short-circuited secondary coil on one leg will not tolerate flux in the faulted leg. Therefore, almost the full magnitude of normal core leg flux is forced out of the yoke into the tank. Severe heating of the tank wall and core clamping parts results from eddy current and hysteresis losses. Because the 4160 V system at Brunswick is a high-resistance grounded system, there may be a temptation to continue operation with one phase grounded for an extended period of time, especially during postulated accident conditions. The licensee could not confirm during the inspection whether the transformer was of the three, four or five-legged core construction.

As stated previously, with a high-resistance grounded system, there may be a tendency to continue operation with one phase grounded for an extended period of time. It was noted that receipt of one 4160 V ground fault alarm was treated as a simple trouble ticket. This capability can increase reliability, but the trade-off is that line-to-line voltage will appear on the ungrounded phases. This overvoltage can be tolerated for an extended period of time if the cable and potential transformers have insulation rated for line-to-line voltage rather than line-to neutral voltage. Drawings indicate that the potential transformers are rated 4160 V, and therefore, would pose no problem. The NRC inspector inquired about the thickness of insulation for the cable used in the 4160 V system, however, the licensee could not answer during the time of the inspection.

In summary, if the SAT is of the three-legged core construction, the licensee should be aware of the consequences of operating for extended periods of time with a faulted phase, i.e transformer tank heating may be a problem. One reason the NRC inspector believes the SAT has three-legged construction is that FSAR Section 8.2.1.6 states the following: "The transformers are of core type construction with the third harmonic eliminated by allowing the third harmonic currents to circulate in the transformer tank. The thermal capacity of the transformer tank has been designed to eliminate overheating." Unfortunately the FSAR does not mention the zero sequence flux associated with faulted conditions. If the 5 KV cable has 90 mils of insulation, it would be overstressed during faulted conditions. Again the licensee would want to be aware of the consequences of continuing to operate with a faulted phase. Fortunately each 5 kV feeder has a ground fault detection relay wired to trip an annunciator. Therefore, faults could be quickly disconnected if procedures so stated. Susceptibility to overvoltages due to fault conditions does not exist on the 480 V system because the equipment is rated 600 V.

Due to the unanswered question on the SAT construction and the 5 KV cable insulation wall thickness this matter is an Inspector Follow-up Item 325,324/88-11-03, Electrical System Design SAT and 5 KV cable.

Technical Specification 3.8.1.1 states: "As a minimum, the following AC electrical power sources shall be OPERABLE: a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and..." This LCO has an associated surveillance 4.8.1.1.1.b. The NRC inspector asked the licensee to identify the two independent circuits mentioned in the Technical Specifications, and to explain how the surveillance was accomplished. The licensee replied that the required independent circuits described in the current Technical Specification are the transmission lines. The NRC inspector responded that the transmission lines do not connect the transmission network and the onsite Class 1E distribution system. The matter could not be resolved during the inspection.

The licensee has submitted a request to delete surveillance 4.8.1.1.1.b. by letter dated February 29, 1988. The change request is predicated on the licensee's definition of the two independent circuits, which implies that no actual switching is necessary to demonstrate operability.

Apparently, the original Technical Specification did not mention two independent sources of offsite power nor does the FSAR specifically mention them. Standard Technical Specifications, approved in 1977 (two years after initial operation), contained the LCO and surveillance mentioned above. By letter dated August 31, 1982, the licensee requested to delete surveillance 4.8.1.1.1.b. However, this request was withdrawn by letter dated February 14, 1984.

Obviously the SAT provides one source of offsite power to the emergency buses. Another source of power could be through the generator step-up transformer (in step-down operation). However, before the generator step-up transformer could be used as a source of power for the emergency buses, the generator would have to be disconnected from the isolated phase bus, and several generator protective relays would have to be disabled. This work would take from 8-12 hours to accomplish. Another potential source of offsite power is the SAT of the other unit, through the buses of the other unit and the interunit tie buses. The licensee stated that this source of power could not supply emergency loads of two units and maintain a proper voltage profile. The NRC will review the Brunswick design with respect to the requirement to have two independent sources of offsite power. In order to track this review effort, this matter is identified as Inspector Follow-up Item 325,324/88-11-04, Compliance With GDC 17 and Related TS Change Request.

The NRC inspector inquired as to how the diesel generator is protected from overload in the event that the transmission grid is lost while the diesel generator is in test mode feeding into the grid. The licensee stated that he has installed a directional power relay to protect against this event. The relay is enabled whenever the diesel generator is in manual mode. The licensee stated that once during the history of the plant the transmission grid went down while the diesel generator was in test mode. The power relay operated to trip the generator breaker before the diesel became overloaded, there was no overspeeding following the load shed, and the emergency diesel generator returned to standby mode.

Various design features were reviewed from the point of view of being a potential cause of de-energizing any of the high importance electrical buses These features are itemized below:

(a) The automatic transfer circuit which controls the fast transfer of power from the UAT to the SAT upon a generator trip has performed reliably. It has operated satisfactorily about 20 times in the last five years with no failures.

(b) The plant does not have any swing buses or automatically transferred buses in the Class 1E systems.

(c) Feeder breakers at the 480 V switchgear which control motor control center feeders are equipped with instantaneous trip units. There have been problems at Brunswick where the switchgear breaker did not coordinate with the individual feeder breakers at the motor control centers. The licensee stated that a coordination review was ongoing to confirm system selectivity at motor control centers. This effort is scheduled for completion in October 1988.

(d) It was confirmed that a Lighting Protection System is installed to protect plant areas against direct lighting strokes.

10.4 Operations and Maintenance

Operations Procedure (OP) 50 Paragraph 5.6, Transferring Auxiliary Power from the SAT to the UAT, was reviewed. It was noted that the procedure calls for the operator to confirm that the SAT breaker is open after the transfer, thus guarding against parallel operation should auxiliary contacts fail to automatically trip the breaker.

The licensee stated that a procedure is available for feeding the emergency busses from the generator step-up transformer, should that become necessary. The procedure involves disconnecting the generator from the isolated phase bus and disabling several generator protective relays. This method was demonstrated once during a refueling outage.

Organization of the Maintenance Department was reviewed and discussed. Individual work crews were assigned in a logical manner. There appeared to be sufficient number of personnel for the electrical work. The preventive maintenance program activities and their frequency were discussed with the first line managers, and appeared to be adequate.

Maintenance work orders (referred to as trouble tickets at Brunswick) are tracked and trended using an interactive computer program and other administrative tools. The NRC inspector spent 4 or 5 hours reviewing various trending reports, and calling up work order data on the computer terminal. The licensee had identified a few repetitive failures of particular relays, however, the review did not reveal any other significant trends or problems in the areas of electrical maintenance, except the bolt problem described in Section 10.7.4.

10.5 Walkdown of Equipment Areas

Over the course of the electrical inspection, several walkdowns were conducted which included the following areas: 4160 V switchgear rooms, 480 V switchgear areas, motor control center areas, power transformer yard, emergency diesel generator room, cable spreading room, control room and back panels, the service water pump house, and the isolated phase bus.

The following potential contributors to equipment unavailability were identified:

(a) At motor control center 2CA (or 2CB) in the cable spreading room, five of the contactor status lights were not lighted.

Having both contactor status lights (green for deenergized, red for energized) not lighted could indicate a loss of control power, and therefore, an equipment unavaibility condition. Procedures called for auxiliary operators to check contactor status lights during daily operator rounds. The motor control centers had spare lamps attached so that burned-out lamps could be immediately replaced. Perhaps an explanation for the condition was that the plant was in an outage during the inspection.

(b) At the control room/reactor building wall penetration area some cables had what appeared to be sharp bends as they exited the conduit bushings (less than minimum recommended bend radius). The accompanying licensee representative made note of the possible adverse condition for later review and followup.

(c) In the service water pump house, corrosion of equipment was observed. The safety-related lube water pumps were corroded, and a non-safety-related cable tray had one section completely

corroded away. The internals of three motor controls center starters, selected at random, were inspected for corrosion. At one of the starters (MCC 2PA Compt 2- E08) corrosion was beginning to take place on wire terminals and the contactor coil. The other two starters did not have any visible corrosion.

(d) In the area of the startup transformers, cable trench covers were broken and gaps in the covers could allow rodents to enter. Rodents could damage the cable jackets or insulation of switchyard control cables in the trenches. This type of damage could ultimately lead to control cable short-circuits, especially since the cables were sitting in water. Failure of a current transformer lead, for example, could lead to a loss-of-offsite power event.

Housekeeping in general was adequate throughout the plant and excellent in some areas.

The NRC plans to inspect the corrective actions for these items during future inspections. Therefore, this matter is identified as Inspector Follow-up Item 324,325/88-11-05, Deficiencies Identified During Walkdown of Electrical Equipment.

10.6 230 KV Equipment - PRA Considerations

In the PRA study, a generic value was used for the probability of occurance of the loss-of-offsite power initiator. There was no detailed modelling of the transmission grid, the Brunswick switchyard or the switchyard/plant interconnections. The spare SAT mentioned in the FSAR was not factored into the PRA study.

Certain features of the 230 KV and auxiliary equipment not mentioned in the FSAR but related to hardware strengths or weaknesses are discussed in this section. All of the 230 KV circuit breakers are sulfur hexafluoride type manufactured by ITE Corporation. The primary transmission line protective relays are electromechanical MHO type distance relays manufactured by General Electric Company. The primary relays are used in conjunction with a power line carrier signal which serves to block tripping of circuit breakers for faults outside the defined zone. The backup transmission line protective relays are the same type as the primary, but they are applied in a zone protection arrangement. In addition, there are breaker failure relays, bus differential relays and backup overcurrent relays. Fault analysis equipment is important to recovery from line outages or loss-of-offsite power events. The relay houses contain two fault analyzers for each unit which are capable of printing out oscillograms of current and voltage waves and time scaled breaker position indications.

One bus tap (short overhead line) connects the 230 kV buses to the SAT and the Caswell Beach pumping station transformer. One set of lightning arrestors protects both of these transformers. The bus tap can be aligned to one or the other 230 kV bus bar through non-load break disconnect switches. The bus tap has its own differential protection. Should relays sense a fault on the bus tap or in the transformers, they would operate to clear the appropriate 230 kV bus while the other bus would remain in service. The SAT has a non-load break disconnect switch on the primary side, and the Caswell Beach transformer has a load break switch on the primary side. The load break switch is a combination circuit switcher and disconnect switch and is manufactured by S&C Electric Company. The point of the above discussion is that the connection of the Caswell Beach transformer to the transformer bus tap should have little or no effect on the overall reliability and availability of the SAT as power source.

10.6.1 Operations and Maintenance of 230 kV Equipment

DC control power for the switchyard is supplied by the plant safety related batteries. Primary and backup relaying have independent power supplies. Each of the DC distribution panels has a manual transfer switch to select feeder cables from the two batteries. If one of the transfer switches were left in the wrong position, the system would appear to work properly but the redundancy of power supplies would be lost. Therefore, the NRC inspector confirmed that position of the transfer switches is periodically checked.

Maintenance and surveillance of the 230 kV and relay house equipment is shared between Nuclear Operations and the Transmission/Substation Group. The NRC inspector reviewed the individual maintenance and surveillance activities, and compared them to activities at other sites having similar equipment. The activities themselves and their frequency of performance appeared to be in line with accepted industry practice. The only comment made in this area was that the Auxiliary Operator Daily Check Sheets called for checking relay targets and other items in the relay house, but not the breaker status lights. A deenergized breaker status light could indicate a broken trip circuit. The licensee is considering adding this check to the operation check sheets.

The SF6 circuit breakers and other equipment have operated without faults over the years, the last having occurred in 1974.

Relay operations at the relay house will trigger annunicators at the dispatch center and at the nuclear units' main control room. The dispatcher and the plant operator can communicate via commercial telephone lines, CP&L's microwave system, or radio.

10.6.2 Walkdown of Equipment Areas.

Walkdowns were conducted of the Unit 2 switchyard and relay house to look for any possible adverse conditions such as corrosion, moisture inside panels, poor wiring workmanship, or lack of emergency lighting, fire detectors or fire extinguisher. The walkdowns did not generate any significant comments.

10.7 DC Distribution System - PRA Considerations

Batteries and battery charges, together, if properly maintained, will supply an uninterrupted and most reliable source of power for certain critical functions such as circuit breaker control, emergency lighting, and instrumentation power supplies. When battery charger output is lost either due to malfunction of the charger itself or due to failure of the 60 cycle input, the battery will supply power for certain critical loads. Should a loss-of-offsite power (LOOP) event occur, there will be a blackout of AC power for about 10 seconds until the diesel generator comes on line. The battery can supply power for this 10 second period, and the battery power is needed to flash the generator field and close the generator breaker. If the LOOP event is followed by failure of the diesels themselves, battery power is needed to power instruments, lighting and certain valves. The PRA study models the failure of specific components in the DC System, and these failures are in event scenarios leading to core damage.

When considering the failures of specific components in the DC system, the PRA study shows the relative order of importance to be (higher to lower): battery 2A2, battery 2B1, panel 4A, panel 4B, battery 2A1, other components. The PRA assumed the battery could supply the necessary load for four hours in a blackout scenario. The licensee had performed extensive studies of battery duty cycles for design basis events. However, the licensee did not have battery duty cycle studies corresponding to the blackout scenarios defined in the PRA for the 125/250 V battery. Inspector Follow-up Item 324,325/88-11-06, Blackout Scenario Battery Duty Cycle Study, will be used to review any studies the licensee may provide in this area. The load on each of the 24 V battery is about a constant 10-15 Amperes. Battery performance data shows that the 600 AMP-Hour batteries could deliver 16 Amperes for 36 hours.

10.7.1 DC Distribution System - Design Features Related to the PRA Conclusions

The NRC inspector asked to review the licensee's voltage profile study for the DC system. Such a study would demonstrate that each DC device could operate within its rated voltage range when battery voltage varies from 105-140 V. The licensee could not

provide the study during the inspection. This matter will be followed up during a future inspection. IFI 324,325/88-11-07, DC Voltage Profile Study.

A 125/250 VDC System Coordination Study dated December 15, 1975, was reviewed by the NRC inspector from the viewpoint of the interrupting rating of the circuit breakers versus the short-circuit current that the battery can deliver. The study concluded that the available current was about 10,000 amps. A copy of the manufactures' application data including a table of DC interrupting ratings was presented. However, the table and its associated notes did not define the interrupting rating for the THFK circuit breaker for a 250 V, 2 pole, ungrounded system application.

The THFK breakers interrupting rating will be inspected during a future inspection. This matter is identified as Inspector Follow-up Item 324,325/88-11-08, THFK Breaker Rating.

10.7.2 Operations and Maintenance

Brunswick has two sets of lead calcium 125/250 Volt batteries to supply safety-related and non-safety-related loads. The batteries are the original batteries, except for a small percentage of the individual cells that have been replaced over the years as needed. In capacity tests conducted during the March 1988 Unit 2 outage, each of the batteries was shown to have over 100% capacity. There are also two sets of 24/48 V batteries. The original lead antimony batteries were replaced in 1987 with lead calcium batteries. Procedures were revised to meet the requirements of the new batteries.

Auxiliary operators, using check sheets, monitor the battery charger output current and voltage once per shift. There are battery charger trouble alarms in the main control room. A "battery charger trouble" annunciator represents five possible problems with the battery charger. The licensee has a detailed annunciator response procedure to cope with the annunciator.

A total of 24 battery surveillance data sheets for the 125/250 V batteries, sampling all the types of surveillances, was reviewed by the NRC inspector.

Surveillance procedures and the manufacturer's instruction book were also reviewed. Basically there were no comments on the battery surveillances except for the following two items:

(a) The quarterly check; dated December 8, 1987, of all cell voltage and specific gravity on battery 2A-1 shows that the

voltage of many cells deviated more than 0.05 V from the all cell average, indicating a need for equalizing. The NRC inspector confirmed by review of Work Request No. 87-BLSQ1, dated December 23, 1987, that the equalizing was carried out.

(b) The licensee performs a monthly check of all cell voltage and specific gravity. The performance of this check on a monthly frequency is more often than required by the Technical Specification and is considered an indication of a strong battery surveillance program.

FSAR Section 8.3.1-10 refers to an automatic transfer switch for alternate power supplies to the DC power bus in the D/G control panels. When the inspector asked about the operation of the transfer switch, the licensee stated that the automatic feature has been defeated. The FSAR should be revised in this regard.

Battery surveillances are conducted by the Unit 2 Electrical Plant Modification Crew. This group is staffed by ten people, and records show that battery work is rotated among the members. Corrective maintenance records related to the DC System were reviewed by the NRC inspector, but no significant trends could be detected.

10.7.3 Walkdown of Equipment Areas

A walkdown was conducted of the two Unit 2 battery rooms. Each battery room contains the 125/250 V battery, 24/48 V battery, battery chargers, RPS motor generator set, uninterruptible power supply cabinet, DC distribution panels, cable trays and HVAC ducts.

The NRC inspector noticed that cell jar 2B1-30 had noticeable bowing. The long side of the jar was bulged out approximately 3/8 inch from true flat.

The side of the jar was restrained from further expansion by the battery rack and Styrofoam spacer. Several other cells had noticeable bowing to a lesser degree. The NRC inspector called GNB Battery Inc, the battery manufacturer, at their Langhorne, PA factory/office to obtain their opinion on the significance of the observed bowing.

The originally furnished cell jars were made of PVC. Cell jars made of this material exhibited a small degree of bowing at the time of manufacture due to the hydrostatic pressure of the electrolyte. Slight bowing of the jar does not have any effect on the performance of the battery. Replacement cells, furnished

later in plant life, were made of Styrene-Acrylonitrile Plastic which remains flat in the application. It was concluded that the bowing observed in cell 2B1-30, and to a lesser degree in other cells does not constitute any adverse condition. This is because slight bowing is a characteristic of the battery as designed, and increased bowing is limited by the intercell spacer material.

10.7.4 Bus Bar Bolt Failure

On February 19, 1988, shortly before the PRA inspection, the licensee reported the finding of broken bolts used to connect bus bars together and cable lugs to the bus bars in AC and DC motor control centers (MCC). Since this identified common mode failure had obvious implications vis-a-vis the PRA study, the PRA inspection team ascertained the nature of this problem. In order to put the bus bar bolt failures into proper context, the following construction details of the MCCs at Brunswick are described.

Each AC MCC has three sets of bus bars corresponding to the three electrical phases, and each DC MCC has three sets of bus bars for the positive, negative, and center points. Each set of bus bars consists of two horizontal copper bars at the top of the MCC which run the entire length of the structure, and one vertical copper bar in each vertical section. The vertical to horizontal connections were made with two square neck type 5/16" diameter x 1½" long silicon bronze carriage bolts, a Belleville washer, lock washer and nut. The same type bolts were also used to connect cable lugs to the main bus bars, and to splice the bus bars at shipping splits. Spacer plates were used at the connection points as required to achieve the proper clearance between the horizontal and vertical bus bars.

Failed bolts were either sheared off or exhibited cracking at the head/square interface point. In at least two MCCs, 35% of the bus bar connection bolts had failed. Nearly all MCCs had numerous failed bolts. At several of the MCCs, both bolts making up an individual connection had failed. These may be assumed to have been loose or high resistance connections. If the MCCs with these high-resistance connections had been subjected to full load current even for short periods of time, the heat generated at the poor connection point could have lead to failure of the entire MCC. Lower level currents for extended periods of time could also ultimately have lead to complete failure of the MCC. In addition, the ability of the MCCs to withstand a design basis earthquake was indeterminate due to the failed bolts.

The history of the failed bolt problem, how the problem was discovered by the licensee, defining the magnitude of the problem, and the description of corrective actions taken are discussed in Licensee Event Report 1-88-006 and NRC Inspection Report 50-325/88-05. The licensee will attempt to determine the root cause of the bolt failure, and findings will be reported in a supplemental LER. Had the common mode failure potential represented by the failed bus bar connection bolts continued uncorrected, the failure rate of the electrical distribution system assumed in the PRA would not have represented the actual case at Brunswick. However, since the problem is being corrected, the PRA results are not affected by this problem.

10.7.5 Summary of DC Distribution System Inspection Results

The importance of the DC Distribution System cannot be overstated because it plays a critical role in nearly all PRA accident scenarios. What was observed during this inspection, especially in the licensee's treatment of battery surveillances, tends to support assumptions made in the PRA about performance of the DC Distribution System. However, the voltage profile study could not be reviewed. If the study was never performed, questions about the basis for modifications to the DC Distribution System may not be properly answered. A question remains about the application of the molded-case circuit breakers. On the one hand, review of technical literature, Reference 2, Section 19.0. suggest that 24, 48, 250 V devices may be far less reliable than 125 V devices. On the other hand, this equipment has been in service for over ten years, and the maintenance trending program has not brought any repetitive failures of this class equipment to light.

## 11.0 Automatic Depressurization System (ADS) Valves

These valves were selected for NRC inspection because the Brunswick PRA identified an ADS failure event as a major contributor to a dominant accident sequence for core melt. The subject ADS failure event was described as follows:

| Failure Event Description | Identifier No. |
|---|---|
| Two or more SRVs fail to open because of O-ring leakage or other dependent failure mechanisms | ADS-CCF-LK-ORING |

The safety objective of the ADS is to serve as a backup to the High Pressure Coolant Injection System (HPCI). In the event of a loss-of-coolant accident (LOCA) and the failure of HPCI, ADS is designed to depressurize the nuclear system such that low pressure systems can operate to assure adequate core cooling. Depressurization is accomplished through actuation of seven of the 11 safety relief valves, which are designated as ADS valves. The ADS valves are identified (proceded by a 1 or 2 Unit designation) B21-F013A, C, D, H, J, K and L. All of the SRVs are flange mounted, two stage valves manufactured by Target-Rock Corporation. Each valve has a single-stage pilot section and a main valve section. ADS valve actuation is accomplished through a solenoid control valve which admits instrument air to an air operator which opens the valves. A backup pneumatic supply is provided by the Backup Nitrogen System. The ADS valves are normally automatically actuated but may be actuated manually.

### 11.1 Scope of Inspection

The inspector examined the adequacy of the licensee's maintenance and testing of the ADS valves in assuring against common-mode or dependent failures. The examination was conducted through a review of procedures, records and other documents, interviews with responsible licensee personnel and observation of the ADS valves (and other SRVs) installed in Unit 2. The documents reviewed are listed in Section 19. Details of the examination and findings are described below.

### 11.2 Interviews

Cognizant Project Engineers were interviewed regarding descriptive and functional information on the valves, maintenance and test practices, failure history, and corrective actions. Significant information obtained in the interviews included the following:

(1) The pilot assembly of every SRV (including all seven ADS valves) is reworked each refueling outage. The rework includes disassembly, inspection, refurbishment as needed, and testing

(response, set point, re-seat and leakage). The rework is performed by one Target-Rock Corporation technician and is done at Wyle Labs. The work is performed using a Target-Rock procedure. The SRVs are tested by Wyle Labs following the work. Additional details are discussed in Section 11.3(2).

(2) Two of 11 complete SRVs (main stage, pilot and base) are reworked each refueling outage by Target-Rock at Wyle Labs.

(3) As power operated valves, the ADS valves are required by TS 4.0.5 to be stroke time tested in accordance with ASME Section XI requirements. The inspector later verified that procedure PT 11.1.2 accomplished stroke time testing.

(4) In response to questioning regarding past failures of the ADS valves the inspector was informed of the following:

- There is an ongoing problem with set point drift, common to all BWRs using two stage TR valves, and is being addressed by the industry. Corrective actions thus far have not been fully effective. In the last SRV testing at Brunswick many of the SRVs continued to fail the test requirements but evaluations have indicated that safety requirements would have been met.

- In mid 1987 two SRVs failed when the solenoids would not actuate. Investigation found that the solenoid plungers and bonnet tubes had become glued together by excess Loctite used to fix the valve plunger nuts in place. The Loctite had been applied when the valves were reassembled during the previous refueling outage.

11.3 Maintenance Procedure Reviews

The inspector reviewed two procedures used for maintenance on the ADS valves. They were procedure MI-16-626 for removal, inspection and installation of the SRVs, and the Target-Rock (vendor) procedure 2025K for disassembly, inspection, refurbishment and related testing of the SRVs. Details of the reviews of the procedures are as follows:

(1) Procedure MI-16-626

This procedure was reviewed for adequacy of technical content and human factors. The inspector found that it appeared to contain adequate technical content, that it was generally clear and easy to follow, that the individual procedure steps did not contain excessive verbage or operations, and that it provided for recording of appropriate data. Hold points or second party verifications were included for cleanliness and bolt torquing. The following minor weaknesses were noted in the procedure:

- There was no provision for checking off (e.g. by initializing) steps as they were completed within the procedure. This is not a requirement but a good practice used to aid in assuring steps are not missed. The licensee uses this practice in their Operations procedures.

- Portions of Figure 7 were illegible or nearly so.

The inspector discussed the above weaknesses with the responsible Maintenance Project Engineer and was informed that:

- A decision had been made to put required signoffs only in data sheets at the end of the procedures.

- The concerns regarding legibility had been recognized, and as the procedures are being revised, improved line drawings are replacing the previous figures. This results in satisfactory reproduction quality.

(2) Target-Rock Procedure 2025K

This procedure was reviewed for adequate technical content, human factors and for procedural changes to assure that excessive Loctite is not used in valve re-assembly. (Problems caused by use of excessive Loctite are mentioned above in 9.2(4). The inspector found that the procedure appeared to contain adequate technical content, was clear and easy to understand and contained adequate provisions for recording important data. As a correction to prevent valve failures due to use of excessive Loctite, a procedural change provided specific instructions for the amount of Loctite to be applied, the location of application and inspection for excess Loctite. Previously the procedure had contained a caution note stating not to use excessive Loctite. This note had been added in 1982, following Loctite induced valve failures essentially identical to those that occurred at Brunswick in 1987 (Reference GE SIL 196, Supplement 1, April 1981). Failures of SRVs resulting from use of excessive Loctite were also described in NRC IN 84-53 and IEB 80-25

The NRC inspector found that while the procedure was generally satisfactory clear, it contained the following apparent weaknesses:

- There were no provisions for any QC inspections or other independent verifications of important procedural steps such as tightening, bolting or applying Loctite. For example, torquing of bolting in Section 3.2.13 required no independent verification. The addition of independent inspections or verifications would aid in reducing the risk of dependent, common mode failures.

- Some of the individual procedural steps contain too many operations and there is no signoff beside each operation as it is performed. Section 3.2.13 of the procedure contains six unseparated operations.

The failure to have independent verification or QC checks of important assembly actions is especially significant in view of the fact that the same technician rebuilds all of the SRVs. A common mode of failure can be created because a single human error (e.g., use of excessive Loctite) could make all 7 ADS valves inoperative at the same time.

This was discussed with the licensee for evaluation and disposition.

11.4. Test Procedure Reviews

The inspector selectively reviewed licensee procedures which described testing performed to meet TS 4.0.5 and ASME Section XI requirements for the ADS valves. Included in the review was the licensee Engineering Procedure ENP-17, that specifies their program for testing pumps and valves. Also reviewed was periodic test procedure PT 11.1.2, which implements stroke time testing specified for ADS valves by ENP-17.

ASME Section XI (as implemented TS 4.0.5) requires stroke time testing for power operated valves like the ADS valves. ENP-17 indicates that the licensee has requested the NRC to grant relief from the ASME requirement. The relief request, described in ENP-17 as VR-07, states that the true stroke time of the valves will not be measured but that they will be stroked open and closed at least once each 18 months. It states that an abrupt change in turbine bypass valve position or steam line flow (per TS 4.5.2.b) within 5 seconds will be adequate to demonstrate valve operability. The licensee's relief requests are in NRC review and the inspector verified that the NRC is expected to issue its evaluation shortly.

The inspector reviewed PT 11.1.2 for appropriate technical and human factors content. The procedure appeared to provide good implementation of technical and human factors and provided a satisfactory verification of the stroking of the ADS valves. However, it was noted that the procedure contains neither the ASME required stroke timing nor the relief request provisions for acceptance verification that an abrupt change in BPV position or steam flow occurs within 5 seconds of valve actuation. The adequacy of testing with the omission of time requirements require further NRC evaluation will be followed up. IFI 325,325/88-11-09, Stroke Time Testing for ADS Valves.

## 11.5 Visual Observation of Unit 2 SRVs

The inspector entered the Unit 2 drywell and examined the 11 SRVs to aid in understanding their location and installation configuration and to look for any conditions which might adversely affect their operability (e.g., improperly installed fasteners, damage to valves or associated lines, etc.). The inspector did not note any adverse conditions.

### 11.5.1. Failure and Work History Records for SRVs

The inspector reviewed records of SRV deficiencies identified in the LERs and in AMMS to ascertain the adequacy of corrective actions and historical information.

NRC files were examined for LERs related to the SRVs (and ADS valves) 1985 to present. Problems described in the LERs were setpoint drift (LER 1-87-011 and 2-86-001) and SRV failures due to excess Loctite (LER 1-87-020). Both of these problems were discussed with the inspector during interviews. Setpoint drift deficiencies have not been fully resolved, the inspector acknowledged that the problem was being attended to satisfactorily. Further, the setpoint drift did not appear to have resulted in an inability to perform the safety function. The excessive Loctite causing the ADS valves to be inoperable was more serious and represented an example of the dependent failure of concern based on the PRA. As described in above, the inspector did not consider that the licensee adequately addressed the common mode aspects of this problem.

AMMS is used to initiate, prescribe and document corrective maintenance including troubleshooting. The record of corrective maintenance contained in AMMS is maintained and used to obtain historical failure information. The system contains information from 1985 to present. Prior to 1985 historical hardware information was not maintained in a retrievable manner. Information from AMMS is brief, but the WR/JO is identified and it can be located on microfilm for obtaining details.

The inspector reviewed procedure MP-14A, which implements and prescribes the methods for using AMMS. Its use aids in work planning and engineering evaluations. Work history records for the SRVs were reviewed.

The degraded o-ring problem described to the inspector during interviews with Project Engineers was located in the AMMS. Subsequently, the inspector reviewed details of the

work in record copies of Unit 2 Work Request/Job Orders (WR/JO) 86-BSEZ1 (10/26/86) and 86-BSFE1 (10/26/86). The o-rings involved are located between the solenoid and the adapter block on the pilot valve. The inspector found that the work history on the AMMS and the actual records of the work performed were well-documented and satisfactorily provided needed information for the conduct of and verification of corrective maintenance. The inspector agreed with the licensees engineer that the o-ring failures had not been serious enough to be reported as an LER and that corrective actions taken were adequate.

An investigation of ADS valve failures due to excess Loctite was performed by the licensee's failure analysis lab. The failure is described in LER 1-87-02. The inspector reviewed the investigation report, MSL No. 12-186, and found that it presented a detailed and thorough investigation of the event. The report recommended review and correction of the Target-Rock procedure for assembly of the valves. As noted in Section 9.3(2), the inspector found that the Target-Rock procedure had been revised to provide more specific instruction on the use of Loctite.

The inspector reviewed the records of functional testing of the SRVs at Wyle Labs, reported in Unit 2 Report No. 48099-0, January 21, 1986, and in Unit 1 Report No. 48607-0, April 24, 1987. Based on these reports the valves appeared satisfactorily tested and the required data properly recorded.

## 12.0 Emergency Diesel Generators

The Standby AC supply and distribution system for the two units consists of four Nordberg Emergency Diesel Generators (EDGs) and four 4.16 KV Class IE Buses. The EDGs provide onsite redundant sources for emergency AC power in the event of loss of normal AC power.

The EDGs were selected because of their importance in reducing core melt frequency in the station blackout accident sequence. Recovery of the EDGs will lead to recovery from a station blackout. For this reason, the inspector focused on EDG availability. The inspector reviewed the documentation associated with EGD reliability evaluations; EDG maintenance and failure history data; and EDG surveillance and operating procedures.

### 12.1 EDG Reliability Evaluation

The licensee formed a task force to evaluate EDG reliability as result of EDG failures occurring from October 1987 through January 1988. Information contained in the evaluation for each EDG event included a description of the event, root cause evaluation, failure significance, recommendations, similar historical failures, and a failure rate plot. The evaluation also contained graphs showing EDG unavailability for 1986, 1987, and the period covering the recent EDG failures. EDG unavailability for these periods was higher than the value assumed in the PRA. The PRA value was based on EDG data for the period 1981- 1985.

One of the EDG task force's findings was that some of the recent EDG failures were repetitive and that past solutions had not been effective in reducing the frequency of failures. Recommendations in the EDG reliability evaluation were presented to the Plant Nuclear Safety Committee (PNSC) for consideration as action items. Actions to resolve some of the findings in the EDG reliability evaluation had been implemented prior to presentation of the evaluation to the PNSC. The PNSC identified as action items other recommendations in the EDG evaluation, and assigned responsibility to various plant groups for followup and resolution.

After reviewing the EDG reliability evaluation, and after discussions with licensee personnel concerning the recent EDG failures, it appeared that the licensee is aggressively pursing resolutions to the various EDG problems in order to improve EDG availability and reliability.

### 12.2 EDG Maintenance Review

The inspector reviewed documentation associated with maintenance on the EDGs. This review included Maintenance Work Requests (WRs), Nuclear Plant Reliability Data System (NPRDS) input, EDG failure

history data from 1975 to 1987, maintenance procedures and programs, vendor technical manual, trending programs, surveillance and operating procedures, and Technical Specifications (TS). In addition to the documents reviewed, the inspector held discussions with responsible licensee personnel concerning the above and performed walkdowns of the EDG rooms.

Review of WRs, NPRDS, and the EDG failure history data were useful for determining the various problems and maintenance performed on the EDGs. The information compiled by the licensee in the EDG failure history was very good. This aided the inspector in obtaining an accurate picture of the EDG machinery history. The records indicated there have been various problems which have resulted in EDG failures. There have not been any major mechanical problems associated with the EDG failures. Some of the items discussed with licensee personnel included the following:

(1) The inspector noted that low control air pressure due to moisture and corrosion buildup in the EDG starting air/control air system has been a problem in the past. Previous corrective actions included increased preventive maintenance (PM) and blowdown of the system to remove moisture. The corrective actions implemented were chosen over modifications to the system, such as adding air dryers. The increased PM and blowdown of the system were considered to be as effective and less costly than modifications to the system. Daily blowdown of the starting air system for each EDG was recommended. EDG failures due to low control air pressure were not experienced for several years. One of the recent EDG failures was for low control air pressure on EDG No. 4. Although the EDG was in standby at the time the condition was found, the control air pressure was lower than the minimum pressure required to start the EDG. Current procedures reviewed by the inspector specify blowdown of the starting air system weekly for each EDG. The EDG task force found that the system design, system blowdown, and preventive maintenance were all considered to be less than adequate, and probable contributors to the failure. The task force recommended that plant personnel evaluate the need for increased EDG starting/control air blowdown and to consider other locations for blowdown and frequency of blowdown. Engineering Work Request EWR 06-249 was initiated to resolve this concern. This item was under review by plant personnel at the conclusion of the inspection.

(2) The inspector reviewed a number of WRs associated with the EDGs. This included outstanding and completed WRs. Open WRs were reviewed for the EDG engine control system, fuel oil system, lube oil system, jacket water system, starting air system, air intake and exhaust system, and the service water system. The review was performed to obtain an accurate picture of current problems associated with the EDGs.

While reviewing outstanding WRs for the jacket water system, the inspector questioned licensee personnel concerning work request WR 88-AACY1. The WR stated that during E-Bus load stripping testing, the jacket water temperature for EDG No. 3 was 80°F with the engine running. The cause of the low jacket water temperature appeared to be failure of the jacket water outlet temperature control valve. Periodic Test PT-12.2C, No. 3 Diesel Generator Monthly Load Test, was being performed at the time the low water temperature was observed. The inspector asked if an evaluation had been performed to determine if the low jacket water temperature had any affect on the EDG. The analysis should consider thermal stresses on the engine which could affect operability. The EDG vendor technical manual states that conditions which are not necessary for starting, but required for proper operations are lube oil temperature above 110°F, and jacket water temperature above 120°F. The EDG lube oil is cooled by jacket water. Other questions raised by the inspector included: what were the lube oil and jacket water temperatures prior to starting the EDG; how long did the EDG operate with the low jacket water temperature; was the EDG loaded at the time; and what was the lube oil temperature during the time the EDG was operating. Licensee personnel had not provided answers to these questions at the conclusion of this inspection. Licensee resolutions to these questions will be reviewed during future inspections. This item will be tracked as UNR 324/325/88-11-10, EDG No. 3 Operation With Low Jacket Water Temperature.

(3) The licensee is evaluating recent problems experienced with Allen Bradley pneumatic time delay relays. Actions being considered by the licensee include determining the root cause failure mode and replacing the relays. Replacement of the relays is being considered based on the failure trend developed over the past year. There have been maintenance activities performed to correct various problems associated with Allen Bradley relays. Since June of 1987, four relays have been replaced because of failures. The remaining pneumatic timing units would be replaced over the next 15 months.

(4) The NPRDS information reviewed included some of the same information contained in the EDG reliability evaluation and the EDG failure data. Data in the latter two documents were compiled by ONS. Licensee personnel responsible for entering information for Brunswick in the NPRDS data base stated that the NPRDS is very helpful in obtaining industry information on various component problems. For example, through NPRDS the licensee has found that Brunswick is the only plant experiencing failures of Allen Bradley relays within the EDG system.

Licensee personnel also stated that they do a monthly NPRDS equipment failure analysis and compare component failures at

Brunswick to the industry average for the same component. This information is provided to appropriate plant management personnel and project engineers.

(5) The inspector reviewed the vendor requirements for routine preventive maintenance as specified in the vendor Technical Manual FP-20322 Nordberg Diesel Engine Instruction Manual. The inspector reviewed the licensee's program for corrective, predictive, and preventive maintenance and compared it to the vendor's recommended maintenance program to ensure that all items were covered. With the exception of one item, the licensee met or exceeded the vendor's recommended maintenance program.

One item which the licensee does not appear to be performing in accordance with the vendor's recommended frequency is to check the operation of the EDG mechanical overspeed safety shutdown. The vendor's Technical Manual recommends checking the overspeed safety shutdown weekly. Licensee personnel stated that they do not check the overspeed safety shutdown weekly because that requirement is intended for a diesel engine that is in continuous operation. The EDGs at Brunswick are used as a standby source of power and each is operated approximately two hours each month. Operation of the EDGs as they are being used at Brunswick would require testing the overspeed safety shutdown approximately once every seven years or 168 hours of operation, whichever comes first. The inspector questioned the licensee as to whether actual overspeed tests of the EDGs had been performed to verify that the overspeed safety shutdown worked properly. The licensee stated that they were not aware of any actual overspeed test being performed on the EDGs since they were installed at Brunswick approximately 15 years ago. The hours of operation for the four EDGs at Brunswick range from approximately 788 to 878 hours. The manufacturer performed overspeed tests on the EDGs, and verified that the overspeed safety shutdown worked properly prior to installing the EDGs at Brunswick. Licensee personnel also stated that, while they have not performed any actual overspeed test on the EDGs, the electrical overspeed trip logic is tested once every 18 months and verified to work properly for each EDG. Licensee personnel further stated that a test procedure has been approved which will physically test the overspeed safety shutdown. The decision to test the overspeed safety shutdown was in response to NRC Information Notice 86-07, Lack of Detailed Instruction and Inadequate Observance of Precautions During Maintenance and Testing of Diesel Generator Woodward Governors. Licensee personnel stated that plans are to test the EDGs over the next several months. Results of the overspeed tests for each EDG will be reviewed during future inspections. This item will be tracked as IFI 324/325/88-11-11, Overspeed Testing of the Emergency Diesel Generators.

(6) The licensee discussed their maintenance trending programs for the EDGs. The licensee has a very good program for monitoring and trending EDG parameters. Any abnormalities can be detected early and appropriate corrective actions implemented to reduce the possibility of significant damage. The licensee's program for monitoring EDG parameters exceeds the requirements recommended by the EDG manufacturer. Information that is being collected and trended includes the following:

- Engine performance data once per month
- Lube oil data once per month
- Wear particle analysis one per month
- Spectrography of oil (performed by Cooper Industries) once per quarter. NOTE: Nordberg, which is the EDG manufacturer, was purchased by Cooper Industries. Cooper Industries provides any support that the licensee may need with regard to the EDGs.
- Review of firing pressure, vibration, and ultrasonics on each engine cylinder once per quarter.

Licensee personnel stated that they have also implemented a program where they trend repetitive failures of components. Any two failures similar in nature which occur within an 18 month period are being tracked as repetitive. Repetitive problems are flagged by the maintenance planner. When the WR is given to craft personnel for implementation, emphasis is placed on it being a repetitive problem. After the WR is completed, it is sent to a designated individual who tracks repetitive component failures. The trend data is based on WRs entered in the licensee's Automated Maintenance Management System (AMMS). This trending program has been implemented for slightly over one year. Licensee personnel stated that there are approximately 160 items on the repetitive failures list. Ten of those items are related to the EDGs.

(7) The inspectors discussed maintenance training with maintenance personnel. It was stated that there are two special crews trained to perform maintenance work on the EDG engines. These are the only crews assigned to perform maintenance on the engines.

During the inspection period, the inspector performed walkdowns of the EDG rooms. Piping and instrumentation drawings were used to verify as-built locations and component labeling. The inspector also observed the general condition of equipment, environmental conditions, accessibility for maintenance, administrative controls related to fire protection and housekeeping, and availability of emergency lighting. All areas inspected appeared to be satisfactory.

12.3 Surveillance

The inspector reviewed selected EDG surveillance and operating procedures to verify that adequate measures exist for determining EDG availability and operability, and that surveillance testing met the requirements specified in Technical Specifications. The procedures reviewed are included in the list of documents reviewed in Section 19.

12.4 Conclusion

The inspector considers the licensee's maintenance and surveillance programs to be adequate. The EDGs have shown to be reliable in that there have not been any major mechanical problems experienced with either the engines or auxiliary systems. The EDG failures experienced have not been the result of major problems. However, the inspector noted one area which may need more improvement. Appropriate actions should be taken to resolve the finding of the EDG task force regarding recent EDG failures that were repetitive where past solutions have not been effective in reducing the frequency of failures. In order for EDG reliability and availability to improve this concern must be resolved. The licensee has implemented a program for trending repetitive failures. This program should be reviewed to determine if corrective actions have been adequate or whether additional maintenance measures need to be taken.

12.5 Balance of Plant Relay Concern

The inspector followed up on a concern where Sargent and Lundy informed the licensee that failure for a balance of plant relay in the turbine building would cause the loads on the emergency bus to block start instead of sequence on. The relay, 2-2D-AD5-27-1, senses undervoltage on the offsite power buses that feed the four emergency buses. If the relay contacts fail to open when offsite power is lost coincident with a LOCA, the logic will allow the LOCA unit's loads to start simultaneously with the closing of the EDG output breaker on the emergency bus. There are four relays affected, one for each bus.

The inspector reviewed plant Modification PM-86-025, which involved eliminating the block loading of emergency loads on the emergency buses if a LOCA signal is received and offsite power is avavaible. After the modification the loads will be sequenced on the emergency buses. This modification will resolve the concern associated with the HFA relay. The modification was being performed on Unit 2 during this inspection and is scheduled for Unit 1 later. Although the modification has not been completed for Unit 1, the concern over excessive instantaneous load on the Unit 1 EDGs has been addressed in that testing has been performed where the EDGs experienced block loads of greater amounts than that which would be experienced if the relays were to fail. This item is discussed in more detail in NRC Inspection Report 50-324,325/88-05.

13.0 Service Water System (SWS)

An inspection was conducted of Brunswick's Service Water System in August and September of 1987. The results were reported in Inspection Report numbers 50-324/87-29 and 50-325/87-29. The current inspection walked down those portions of the SWS not previously walked down. A brief review was also performed of system modifications performed to restrict flow through the Reactor Building Closed Cooling Water Heat Exchargers. This item will be addressed in the Resident Inspector's Report.

The areas of service water walked down included a revisit to the service water pumphouse, the service water piping for the Diesel Generators in the Diesel Day Tank Building, and the service water piping in the Diesel Building. The housekeeping in the service water pumphouse was better than on previous inspections. Some items showing corrosion on the last visit had been cleaned and painted. General area appearance was good considering the environmental conditions and the quanity of water being handled.

The Day Tank Building piping arrangement appears to be susceptible to a common mode failure. Pipes from the service water system enter the building and are connected to three large headers located next to each other. All three are supported by common large supports attached to the wall and ceiling. The three headers are the unit two essential header, the unit one essential header, and the return header. Each hanger supports all three headers. All are located within a few feet of the diesel day tanks. Each tank holds a four day supply of fuel. A fire or explosion in any of the bays containing the day tanks, or a failure of the supports could potentially disable all four diesels from receiving cooling water. There appears to be enough support from the through-wall penetrations to limit header movement in the event of a hanger failure.

The piping in the Diesel Building was walked down. An area of recent repair was examined. Through wall leaks at a weld seam had required a section of pipe to be replaced. General housekeeping seemed good.

The one weakness found during the service water walkdown was the difficulty that would be experienced inspecting the large, cement lined headers in the day tank area. Inspections would be limited to looking for leaks. The piping is cement lined inside and covered with grout like insulation material outside. Visual inspection inside the pipe would be difficult due to lack of accessibility. Leaks in the discharge header would probably require both plants to shutdown to allow repair, as all four diesel would be out of service.

14.0 Standby Liquid Control System (SLC)

The Standby Liquid Control System consists of two positive displacement high pressure pumps, a sodium pentaborate storage tank, a demineralized

water test tank for system performance tests, and the piping, valves and associated equipment to provide for injection of sodium pentaborate into the vessel at high pressure. The system is designed to provide positive reactivity addition to safely shut the reactor down in the event of control rod drive system failure.

A review was performed of the SSFI performed by the licensee on the SLC system. The SLC system was modified in the outage underway at the time of the inspection to meet the requirements for the BWRs Anticipated Transient Without a SCRAM (ATWS) Rule, 10 CFR 50.62. The inspectors performed a system walkdown on all system components and piping outside the drywell. All instrumentation located locally with the tanks and pumps was examined. System design assumptions and calculations were reviewed. System drawings were reviewed. Details of the inspection follow.

A system modification has been performed to change the circuitry to start both SLC pumps, instead of the single pump required in the original design. The inspectors asked for the net positive suction head calculations for the condition of both pumps running. The inspectors were provided a letter from General Electric, dated September 9, 1987, that included a recalculation of pump NPSH available assuming two pumps running. Carolina Power and Light calculation ID#PID-0149A-01, SLCS NPSH Analysis, Two Pump Operation From the Test Tank, was also reviewed. The inspectors reviewed the calculations and examined vendor test information including the NPSH requirements of the pumps. The calculations indicated adequate NPSH margin was available. The calculations were based on as-built measurements on the system. Proper compensation for use of a sodium pentaborate solution of the concentration used in the system was made in the acceleration calculations. The calculations included the required acceleration components of NPSH needed for a positive displacement pump.

A system walkdown was performed using the system piping diagram D-02547, Revision 16, Standby Liquid Control System, Unit 2. The drawing was the piping diagram reflecting the system prior to modification. The only discrepancies noted were those additions made by the system modifications. Revision 19 of the drawing was reviewed and the changes had been incorporated. One additional minor discrepancy was noted and brought to the licensee's attention for incorporation in future drawing revisions. The general areas observed were clean, the equipment had a well maintained appearance, and valves and major equipment were clearly and correctly marked.

Discussions with plant personnel indicated that in a recent overhaul the SLC pump had valve springs that had to be replaced because the springs were broken when removed from the pump. The inspectors reviewed a Metallurgy Unit Memorandum, MSL 12-74, analysing the springs by the Carolina Power and Light lab. The lab, based upon examination of two of the five damaged springs, advised spring replacement on all four pumps, two for

each of two units. The springs used for the replacement were to have more active coils then originally furnished with the pump. The springs are scheduled to be replaced after every 300,000 spring cycles or about 13 hours of pump operation. The spring failures were of interest to the inspectors, since they can be an indication of inadequate NPSH available to the pumps. The metallurgical report included in the possible causes "Pump/Valve malfunctions resulting in spring overloading". If the periodic replacement of the springs does not fix the failure, actual measurements may have to be taken during pump operation to determine actual NPSH available at the pump suction.

As part of the system review, power and air supplies for the system equipment were verified. The SLC storage tank instrumentation is a bubbler type, with instrument air constantly supplied and bubbled into the tank near the bottom. The back pressure on the air line is measured, and used to determine the weight of fluid above the line, and therefore, the level in the tank. It was determined that the source of air for the bubbler will slowly bleed down during a loss of offsite power (LOOP), due to loss of the compressor. The instrumentation is supplied from an electrical power source that is not interrupted on loss of offsite power. This combination will result in operators receiving and indication of decreasing level on LOOP. This fact is not covered in operator training or in the system procedures. Decreasing tank level is used as one the verifications of proper pump operation and adequate system flow, as there is no system instrumentation available for monitoring flow into the vessel.

The G.E System Design Specification, 22A1342 R4, was reviewed. Under 4.5, Controls and Instrumentation, it is specified that electrical power shall be available to the system instrumentation in the event of power failure. Instrument air is not addressed. The bubbler is not required for the system to operate in the event of a power failure. The design specification is therefore not violated. Training or a note in the procedure about the failure mode may be appropriate.

The ATWS modification provides increased flow to the vessel through existing piping. Increasing flow will result in higher head losses through the system piping. In order to verify adequate head to inject into the vessel after increased pressure losses, the inspectors reviewed SP-85-110, SLCS 2-Pump Flow Test, performed to measure system pressure losses with both pumps running. The inspectors compared the results to the head loss calculations performed for two pumps running. The results closely agreed.

The Quality Assurance (QA) group had previously addressed the question of only a single squib valve firing, creating additional backpressure. Operations is required to shut off one pump if both squib valves do not fire.

QA had also raised questions on a portion of SLC not tested during the system functional checks using demineralized water from the test tank. The portion of system piping from the stroage tank to the tee from the test tank not checked for obstruction. If crystalization of sodium pentaborate were to occur in this pipe, it would not be noticed.

Review of the modification package for plant MOD 86-034 indicated the system relief valves' setpoint was to be increased to avoid their lifting during two pump operation. The relief valves are connected to the pump discharge line and relieve back to the pump suction line. BWRs have, in the past, reported problems with these relief lifting early, providing a recirculation path for the pumps. In the event that SLC was called upon to perform its function, this relief valve flow path could reduce injection. With a simultaneous LOOP, an operator monitoring the system operation would note the pumps on, the squib continuity circuits out (indicating squib firing), and a decreasing tank level. This would falsely indicate system success. Reactor power would not be decreasing. With relief valve setpoint drift, a slow injection may be underway and a slow decreasing power level would be noted. INPO notified the industry of the history of SLC relief valve problems and the implications in 1986. Brunswick has experienced setpoint drift on these relief valves in the past. The surveillance intervals for these RV should be reviewed in light of the increased setpoint to 1450 psig and the smaller margin to system operating pressure with two pumps running. The failure rate of the relief valves should be adjusted in the PRA analysis to reflect past performance of these valves and this failure mode.

The PRA reliability numbers for the SLC pumps and relief valves are based upon industry numbers for generic high pressure pumps and for relief valves in continuous service. Industry numbers reflect centrifical pump reliability data and the SLC pumps are positive displacement pumps. The reliability of the pumps and relief valves may not be as high as the industry numbers.

A review of the Union Pump data sheets show that as pump output pressure increases, electrical demand increases. With the new increase in back-pressure due to an increase in flow, and with the new higher relief valve setpoints, the pumps will be running at higher than their nameplate motor horsepower under some conditions. Testing of the relief valves involves throttling a discharge valve until the reliefs lift. Pump serial number 281324 will be operating at 42 horsepower at the upper limit of the relief valve setpoint. Its nameplate rating is 40 horsepower. An engineering evaluation of this and of motor adequacy should be performed and documented.

A review of the GE purchase specification for the squib valves indicates a 1400 psig design pressure rating is required and operating pressure is expected to be 1190 psig (reference 21A9335, Explosive Valves, Standby Liquid Control System, Revision 0 and data sheet 21A9335AB). Hydrotesting

is required at 1.5 times to design pressure. Increasing the system design pressure from 1400 psig to 1500 psig should be reflected in these purchase documents. Conax Corporation, the valve manufacturer, hydrotested the valves currently in stock to 2800 psig (reference P. O. number 307906, MRR number 362475), however, the purchase specification should be updated to reflect the increased requirements.

The review of the system showed almost all questions asked by the inspectors had been addressed by the licensee prior to this inspection. The personnel interviewed were knowledgeable about the system. Questions asked were answered quickly and documentation produced to verify the answers. The SSFI concept has been performed for HPCI, and a less detailed SSFI without the massive manpower effort, for SLC.

The inspectors reviewed system drawings as part of the SLC inspection effort. The drawings reviewed are listed in Section 19.0.

## 15.0 HVAC Systems

The PRA assigned high importance to the Diesel Building HVAC and to the control building HVAC. The inspector discussed system configuration, past problems and outstanding issues with the system engineer. A walkdown was performed on both the Diesel HVAC and Control Building HVAC.

### 15.1 Diesel Building HVAC

As a result of the PRA, a potential common mode of failure was identified by the licensee for the Diesel Building HVAC, that had the potential to result in Diesel Generator failure. The identified sequence was: loss of offsite power; start of the diesels; non-essential, interruptible instrument air bleeds off; dampers in the supply lines to the Diesel Building fail closed due to lack of instrument air; with no suction source , the exhaust fans cannot maintain adequate cooling to the diesel bays; the EDGs overheat and shutdown. Upon discovery of this potential sequence of events, the licensee took prompt action to block open the dampers involved, and since the dampers function was that of a fire barrier, establish a firewatch. At the time of the inspection, the fire watch was still in progress. Plans had been mode to change the loss of air failure mode for the dampers to fail open, and to provide a back-up air supply. Testing was performed to prove adequate ventilation to the diesel bags could be provided by the exhaust fans if the doors to the building were blocked open and the equipment bay doors opened. Another proposed solution would involve installing fire doors that are normally open, and would close during a fire by the melting of a fusable link. Prompt action was taken in response to the PRA concern for a temporary solution. The permanent fix has yet to be implemented.

A walkdown of the Diesel Building HVAC system was performed. High differential pressure was noted between the diesel bays and the other areas of the building with the normal HVAC in operation. When the walkdown was performed one of the supply fans was being torn down for maintenance. The supply fans feed a common plenum and the duct work for the individual building areas is ducted from the plenum. The fire isolation dampers are located in the ductwork after the common plenum.

In the walkdown it was noted the exhaust fans had two discharge dampers. One damper vents to the outside of the building. The other, for cold weather operation, permits recirculation of the exhaust air back into the area where the supply fans take suction. Some of these recirculation dampers appeared inoperable. They had failed in the open position, providing a "short circuit' for the air back to the supply intake. This would impair heat removal from the building. It could not be determined from observation if the failure mode of the dampers was open or closed. The conditions of these dampers could effect HVAC operability in hot weather.

The system engineer indicated that the supply fans, although originally built to safety standards, are not addressed in the FSAR or Tech Specs, so have not been maintained as safety related equipment. Specific criteria for Diesel HVAC operability decisions are not available to operations. Operability questions are directed to the HVAC system engineer. Analysis should be performed to determine minimum system configuration to have the HVAC system operable. Minimum configurations should be documented and available for operations to make decisions. Variables to be considered for operability are: position of the various systems dampers, exhaust fan condition, supply fan conditions, and status of the fans to the switchgear areas.

One of the actions required in the event of HVAC failure is the blocking open of doors. The inspection of the Diesel Building did not reveal any readily available method to block the doors open.

15.2 Control Building HVAC

The Control Building HVAC is important because it provides cooling to the switchgear and provides Hydrogen removal from the battery rooms. The system was designed with redundancy and employs dual trains to allow operation on loss of a diesel. While performing the system walkdown, the inspector noted all air operated equipment was supplied from a common air header, regardless of the division of electrical power the train belonged to. There are two air compressors and two air storage tanks, but these input to a single header. Isolation between the tanks is provided by check valves. The compressors are not on a regular preventative maintenance program and the check valves are not tested. The common air header is a design that would allow loss of control building and control room HVAC with a single failure of the header. This common mode failure had not been identified by the PRA.

In response to questions by the inspector, the System Engineer indicated that loss of air would cause most dampers to fail closed. The Recirculation fan dampers would fail as-is. If the loss of header pressure happened when the system was not in the emergency mode, the damper failures would prevent the starting of the emergency HVAC system to the Control Room. Currently operations personnel are not trained on this event. Contingency procedures directing manual operation of the dampers to allow starting the emergency fans have not been provided.

15.3 Summary

Based upon the interview with the system engineer, HVAC is receiving greater attention than it had in the past. Equipment is being reviewed for applicability of PMs. Equipment repair is more timely, and HVAC availability should improve with the increased attention.

## 16.0 Instrumentation and Controls

The inspector reviewed instrumentation indicated to have high importance to the PRA. The review included Reactor Protection System (RPS) instrumentation, Residual Heat Removal (RHR) instrumentation, and High Pressure Coolant Injection (HPCI) instrumentation.

The RHR instrument controls a valve which permits minimum recirculation flow through the RHR pumps. Failure of the instrument could result in pump damage or loss of injection water.

The HPCI instrument insures condensate is not allowed to accumulate in the HPCI's steam supply piping. Accumulation of condensate could result in pump damage.

### 16.1 Reactor Protection System Instrumentation

The inspector reviewed the requirements of Technical Specification 4.3.1, Reactor Protection System Instrumentation Surveillance Requirements. Licensee personnel were interviewed concerning the verification of surveillances used to meet the requirements of TS 4.3.1. The computer tracking system for cross referencing and tracking these requirements was demonstrated to the inspector.

In addition, a test was selected for review. The RPS High Reactor Pressure Instrument Channel Calibration, IMST-RPS23R, dated 01/11/88, Revision 3 was reviewed. Observations from the review were:

1) All circuit restoration was double verified. Lifting of leads was not double verified. Errors in the lifting of leads may cause unnecessary challenges to safety systems.

2) After the Shift Supervisor gives permission to start the calibration, operations is not involved again until the system is restored. The calibration involves a potential LCO and the bringing in and dropping out of alarms. Operations should be more involved in the timing of the out of service instrument loop and determining the LCO requirement.

3) The procedure was well written. The steps were concise and clear. Results and data were well documented on the attachments. A very good feature was the dated summary sheets given to operations by the technician describing the test and the limitations it will impose on the plant.

### 16.2 Residual Heat Removal Instrumentation

The inspector performed a review of OPIC-DPS-001, Calibration of ITT Barton Model 581A-0, Differential Pressure Indicating Switch,

Revision 4, dated 10/15/87 and Attachment 3, Revision 4, for the RHR pump discharge control. This instrument inputs to the control circuit of E11-F007B, the RHR minimum flow valve. Failure of this valve to function would result in the RHR pumps dead-heading and possible damage to the pumps. The procedure was well detailed, QC hold points were clearly marked, and data sheets were well laid out. The Process Instrument Calibration Summary Sheet clearly describes what will be inoperable during the testing. The inspector has the same concerns with this procedure as those discussed in the previous section on RPS. The potential for permanent damage to the RHR pumps exists if they are run without minimum flow. Operations should be informed of the removal of automatic valve actions just prior to that step being performed, and again immediately after restoration. The possibility of pump damage should be listed as a caution or warning on the Summary Sheet. A prerequisite should be that no testing that will run the RHR pumps is conducted during the time of the test. Operations should have guidelines telling them to shut down the pumps if they autostart but are not injecting.

In addition to the procedure, the following prints were reviewed:

D-02526, Sheet 2B, Rev. 40, Piping Diagram RHR

LL-92037, Sheet 48, Rev. 7, Miniflow Bypass Valve

I-E11-F007B, Control Wiring Diagram

I-FP-50017, Sheet 7, Rev. K, 791E418RL, Sheet 7, RHR System Elementary Diagram and Sheet 16, Revision G

Examinations of the prints showed that improper termination of the two leads lifted in steps 7.1.14.1 and 7.1.14.2 of the procedure would not result in any system changes that could be noted until the valve was required to respond to the pumps running. Currently double verification is used to assure quality. Performing this calibration just prior to a RHR surveillance that required the corresponding pumps to operate would provide a functional check to back up the double verification. At no extra cost, an additional safety margin could be obtained.

16.3 High Pressure Coolant Injection Instrumentation

The inspector performed a review of MI-03-3M7, Revision 3, 1/19/88, Calibration of E41-LSH-N014-1 and E51-LSH-N010-1, FCI Model HT66, Liquid Level Switch, Functional Check of E41-LE-N014 and E51-LE-N010. This calibration procedure checks the level switches for both the HPCI and RCIC condensing pots. The inspector also reviewed the associated vendor manual, 2-FP-81284, Revision 0, Model HT66, Liquid Level Switch Instruction Manual. The system drawings were reviewed

to verify the instrument loop configuration. These included D-02523, Piping Diagram High Pressure Coolant Injection, Sheet 1, Revision 29 and Sheet 2, Revision 28; LL-9046, Sheet Z90, HPCI Steam Line Drain Pot Level Control, Control Wire Diagram, Revision 0, LL-9364, Sheet 12, Unit No. 2, Annunciator, H12-P601A Control Wire Diagram, and 1-FP-50039, Sheet 8, Revision G, 791E420RL, Elementary Diagram, HPCI System.

Discussions with licensee personnel revealed that the level switches had been replaced in the last several years with RTD type level switches. The replaced switches detect a change in thermal conductivity in the pipe or volume indicating a change in level. Fluid will draw heat away from the heated RTD circuitry faster than will steam or air. The sensitivity and response time of the instrument are adjustable. The solid state device is highly reliable, has no moving parts, and active components are not exposed to the fluid. The switches are used in HPCI, and RCIC, and a similar model is used on the CRD Scram Discharge Volume Instrument Volume. The circuit is wired such that high level or an inoperative instrument will result in an alarm. Operations procedure 2-APP-A-01, Rev. 12, 02/18/88, an alarm response procedure, involves actions including verification of valve operation and insuring restoration within five minutes. If the alarm has not cleared, instructions are given to initiate a work order to check for circuit trouble.

The inspector reviewed MI-03-3M7. The procedure checks normal circuit function by disconnecting the lead to the heater in the device. This causes the RTDs in the circuit to equalize and simulates a wet condition. The procedure does not explain the reason for lifting the wire or its function or what its removal simulates. The explanation is provided in the vendor's manual. The vendor's manual also includes a method of trouble shooting the element not included in the procedure. The procedure does contain steps indicating the I&C Foreman should be notified if the instrument does not respond or calibrate normally. More details in the procedure involving the 'why' behind the actions would help in troubleshooting and understanding limitations.

The vendor manual recommends a recalibration six months after installation and annually after that. Unit 2 had the instrumentation installed in 1984 and was last calibrated 07/16/87. Calibration was attempted again in December 1987, but procedure problems resulted in the calibration not being completed. A trouble ticket was written to provide for calibration upon procedure revision. A procedure dated 01/19/88 is now available. The trouble ticket is a Priority Three and has not yet been worked. Unit 2's RCIC instrument E51-LE-N010 has a similar history. Unit 2 has a six month interval in the maintenance planning computer for the required test interval. Unit 1's instruments were installed in 1986. The last calibration on

record is 09/09/86 for the HPCI drain level, and 10/15/86 for the RCIC instrument. There is no required calibration frequency in the planning system for the Unit 1 instruments. The PRA identifies the failure of the HPCI steam line condensing pot level instrument as an event of high significance to the dominant accident sequences. Normal calibration of these instruments in accordance with manufacturer's recommendations would lessen the likelihood of failure of the instruments. It was also noted that a process instrument summary sheet was not included as part of this procedure. This sheet is used effectively with other procedures to notify operations of the impact of the calibration on their activities.

In addition, HPCI system flow instrument calibration was examined. Procedure OPIC-DPT001, Revision 7, Calibration of Rosemount Model 1153 Differential Pressure Transmitter, dated 02/04/88 and Attachment 3, Rev. 6, were reviewed. The steps are detailed, QC hold points are well documented, and the data sheets are well laid out.

## 17.0 Operations

The Brunswick PRA revealed many plant activities that had high measures of importance in recovering from key accident scenarios. Plant Emergency Operating Procedures (EOPs) were reviewed to insure that they included all of the important actions for the significant PRA recovery items.

The following is a brief description of those items examined:

| Item | Description |
|---|---|
| a | Switchgear room door opening |
| b | Manual opening of RHR MOVs using stem |
| c | Manual opening of RHR MOVs from control room after PT instrument failure |
| d | Manual opening of RHR MOVs using stem after command failure |
| e | Manual opening of one of two RHR MOVs using stem |
| f | Manual opening or closing of RHR MOVs using stem after depressurization failure |
| g | Recovery of off-site power within 1/2 hour |
| h | Recovery off-site power within 5 hours |
| i | RPS scram failure; mechanical and electrical |
| j | High pressure water level control |
| k | Low pressure water level control |
| l | Removal of decay heat |
| m | SLC actuation failure |

The EOPs were also reviewed to assure that they contained important recovery actions for the following dominant accident sequences:

| Item | Description |
|---|---|
| a | Blackout sequence (LOP/AC/DC) |
| b | Transient (MSIV CL/BPV/Long Term Decay Heat) |

The licensee's EOPs were inspected in the following manner:

a. The basis guidelines for writing the licensee's EOPs were determined, and also the NRC approval status of those guidelines.

b. Each guideline required to be used for the above PRA identified recovery items and accident sequences was identified. Then approximately 30% of the steps and cautions in each guideline were selected and traced into the licensee's EOPs, to insure that each guideline step/caution was adequately covered in the EOPs.

c. Individual recovery items identified by the PRA (i.e., Switchgear room door opening) were located in the licensee's EOPs, to insure that they were adequately covered in the appropriate procedures.

d. Licensed and non-licensed plant operators were interviewed about recovery actions not specifically covered in the EOPs. This was done to determine that operator knowledge in these areas was adequate, and also that licensee's operator training program contained adequate coverage of these areas.

The basis guidelines used to write the licensee's EOPs was BWR Owner's Group Emergency Procedure Guidelines, Rev. 2. These guidelines were approved by the NRC for use by the licensee in writing EOPs. Procedural guidance for writing EOPs, covering format and writing style, was included in a Procedure Generation Package (PGP) submitted by the licensee to the NRC for approval. That PGP has not yet been approved by the NRC, and was not used in this inspection.

Comparison of licensee's EOPs to the EPGs involved a review of the following plant procedures:

OI-37, Preparation and Review of the Plant Specific Technical Guideline, Rev. 1
EOP-01-FP-01, Path 1, Rev. 3
EOP-01-LPC, Level/Power Control, Rev. 4
EOP-01-LEP-03, Alternate Boron Injection, Rev. 2
OI-13, Valve and Electrical Lineup Administrative Controls, Rev. 19
EOP-01-FP-4, Path 4, Rev. 3
EOP-01-FP-5, Path 5, Rev. 3
EOP-01-EPP-2A, End Path Procedure 2A, Rev. 3
EOP-01-CCP, Containment Control Procedure, Rev. 5
EOP-01-SRP-AEP, Auxiliary Electrical Power System Recovery, Rev. 3
EOP-01-LRP, Level Restoration Procedure, Rev. 4
EOP-01-LEP-01, Alternate Coolant Injection, Rev. 3
EOP-01-LEP-02, Alternate Control Rod Insertion, Rev. 2

Approximately 30% of the steps and cautions from the EPGs were checked for adequate incorporation into the licensee's EOPs. All of these EPG steps/cautions checked were found to be adequately included in the EOPs. Also, all of the significant individual recovery items identified in the EOPs were included with the exception of manual opening of RHR MOVs (PRA recovery items b, c, d, e, f) and DC electrical load shedding to external battery life (The inspector looked for this as part of PRA recovery item h).

Also, there appeared to be a lack of plant information on the timing of certain key events during a station blackout accident, such as battery life or, reaching drywell temperature limit. These are important factors affecting operational decisions, such as containment venting. A plant study on the blackout scenario has not been done.

Interviews of licensed and non-licensed operators were conducted (2 SROs, 2 ROs, and 2 AOs).

Manual opening of RHR MOVs (PRA recovery items 4, 5, 6, 7, 8) was covered. The licensee considers manual operation of RHR MOVs a simple task and has not embodied this recovery action into procedures. The inspector determined that operators had an adequate knowledge of manual operation of RHR MOVs for normal plant conditions. However, considering the high importance of proper operation of the RHR MOVs, the inspector identified several questions that might be advantageous to have been previously considered to cope with an event. These are:

a. Should the operator be sent directly to the valve, or should he or she check the breaker thermal overloads first?

b. Should the breaker for the valve motor be opened, or left closed during manual operation of the MOV?

c. How long does it take to manually operate MOVs, and in consideration of that, should 1 AO or 2 AOs be sent?

d. If a minimum flow valve (RHR F007) failed to open after the related RHR pump started on an ESF signal, how long would it take for the pump to burn out? Should the pump be stopped, or left running while an attempt to manually operate the valve is made? During simulator drills, a situation actually occurred where an RHR pump started but its minimum flow valve did not open - this was caused by electrical power for the pump and valve being supplied by two different emergency diesel generators.

To ascertain if provisions have been provided to extend battery life during a blackout, DC electrical load shedding was discussed during interviews with operators. There are no plant procedures for load shedding beyond the shedding of 4 DC lube oil pumps. One operating instruction includes a list of DC loads that could be used as a guide. However, the inspector concluded that additional licensee review and training in this area would be beneficial, including:

a. Should additional DC loads be stripped?

b. Who would decide which loads to strip, and on what basis would this decision be made?

Another point of note that came out of the interviews of operators was:

- Flashlights are needed by operators (especially AOs) during blackout conditions. The licensee does not require operators to carry flashlights, but most of them do. Availability of extra flashlights in the plant was questioned. The licensee agreed to consider requiring operators to carry flashlights.

Revision 4 to the BWR Owner's Group Emergency Procedure Guidelines of March 1987, is now being reviewed by the NRC for approval. The licensee

has already written new EOPs based on the EPG, Rev. 4, and has scheduled to implement these new procedures by the end of this year. The Rev. 4 EPG provides several improvements over Rev. 2:

a. Containment venting guidance is more detailed, including new guidance on primary containment pressure limits prior to venting.

b. Hydrogen control guidance is included, where there was none in Rev. 2.

c. Level control guidance is different, allowing lower reactor vessel level to be used to reduce reactor power during ATWS.

d. Fewer cautions are used in Rev. 4. Many were incorporated into action steps or were removed and are now covered only in the training program.

e. Containment flooding guidance is given in Rev. 4, replacing the alternate shutdown cooling in Rev. 2

Overall strengths observed by the inspector in this area included:

a. EPGs appeared to be well incorporated into EOPs.

b. The procedure writer was very knowledgeable about all plant operating procedures.

c. The licensee is taking the initiative in writing revised EOPs based on the EPG, Rev. 4 instead of waiting for final NRC approval of the Rev. 4 EPGs.

Observations for licensee consideration include:

a. A blackout scenario plant study, including timing of such things as battery life.

b. Additional training for operators in emergency manual operation of MOVs, DC load shedding, and security door key availability.

c. AOs being required to carry flashlights.

17.1 Security Door Keys

On loss of electrical power to the plant security system, the normal key cards cannot be used to open security doors throughtout the plant. This could present a significant problem of access to locked areas in emergency situations, by operators. Thus important recovery actions by operators could be impeded.

The inspector reviewed the requirements and existing conditions by:

a. Reviewing of NRC requirements, including regulations and letters to the licensee.

b. Reviewing of the licensee's security plan in this area, proposed revisions submitted to the NRC and NRC approval status of those proposed revisions.

c. Reviewing security system power supplies and loss of power failure condition of doors.

d. Reviewing metal door keys, including physical inspection and testing in doors.

e. Interviewing licensed and non-licensed operators.

The NRC requirements in the area of security doors and emergency access are found in the Miscellaneous Amendments rule change to 10 CFR parts 73 and 50, which became effective on September 3, 1986. According to that regulation, the access authorization system must be designed to accommodate the potential need for rapid ingress or egress of individuals during emergencies. Additionally, the licensee has authority to suspend safeguards measures during safety emergencies. In response to the Miscellaneous Amendments rule, and subsequent NRC correspondence, the licensee has submitted a proposed revision to the site security plan. The proposed security plan revision is under review by the NRC. The existing security plan for door keys does not permit operations personnel to carry mechanical keys.

Until the change to the security plan is fully implemented, the licensee agreed to issue mechanical keys to appropriate operators before power to the card reader system is removed from the battery during a station blackout. This provides access during plant emergencies.

Electrical power for the door security system is from an uninterruptible power supply, which is battery powered. Thus, on a station blackout, the security door system would remain operable for as long as the battery lasted. However, other hazards (fire, steam) could cause an electrical loss of security doors. On loss of electrical power the doors would fail closed. Exit from vital areas would be possible but entry without a key would not be possible. Mechanical keys are available in the control room to open vital area doors. Under the existing plan, an operator would need to have a key sent to him from the control room or obtain assistance from a roving guard with a key in order to get through secured doors.

The inspector verified the door key availability in the control room area, checked that all keys were identically cut (and individually identified), and successfully tested one key in two of the plant security doors.

Interviews with plant operators (2 SROs, 2ROs, and 2AOs) revealed that they knew how the security door system was powered, and how the doors fail on loss of power. They also knew that some guards have mechanical door keys. However, some operators were not aware of the availability of mechanical keys in the control room area.

17.2 Failure of Containment Nitrogen Inerting Line and Consequent Intrusion of Sand Into the Torus and Drywell

In early January 1988 a failure occurred in the Containment Atmosphere Control line that supplies nitrogen for torus and drywell inerting. The line passes underground prior to entering the reactor building. It was in this underground portion that the failure occurred. Sand entered the break and was carried into the torus and to vacuum breaker containment isolation valves located in the lines.

Routine leak rate testing being performed for the scheduled Unit 2 refueling outage on January 19, 1988 identified excessive vacuum breaker valve leakage. There was concern that this leakage might have been caused by the sand introduced into the system through the nitrogen line break. The NRC inspector reviewed the matter with licensee personnel and concluded that the excessive leakage did not appear to have been caused by sand and was therefore not related to the nitrogen line break. There was concern that the line break might result in serious damage inside safety-related structures. The inspector questioned responsible licensee maintenance personnel regarding their knowledge of the failure and how recurrence would be avoided. They expressed confidence in the current temporary fix, an above ground low temperature service plastic pipe replacement line. No additional information was provided to the inspector prior to the end of this inspection (about two weeks passed) by the maintenance personnel. However, the above ground temporary plastic piping failed and was replaced. It was not clear that the licensee's corrective action was yet effective. The inspector informed the plant manager that their corrective actions in this matter had not been prompt and it was still not clear that they were efiective. Additional followup on this matter is being performed by the NRC Resident Inspector and will be described in the March 1988 Inspection Report.

## 18.0 ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AC | Alternating Current |
| ADS | Automatic Depressurization System |
| AMMS | Automated Maintenance Management System |
| AMP | Amperes |
| AO | Auxiliary Operator |
| ASME | American Society of Mechanical Engineers |
| ATWS | Anticipated Trip Without Scram |
| BOP | Balance of Plant |
| BWR | Boiling Water Reactor |
| CRD | Control Rod Drive |
| DC | Direct Current |
| DP | Differential Pressure |
| ECCS | Emergency Core Cooling System |
| EDG | Emergency Diesel Generator |
| EER | Engineering Evaluation Report |
| EOP | Emergency Operating Procedure |
| EPG | Emergency Procedure Guidelines |
| ESF | Engineered Safeguards Feature |
| EWR | Engineering Work Request |
| FSAR | Final Safety Analysis Report |
| GE | General Electric |
| GDC | General Design Criteria |
| GPM | Gallons Per Minute |
| HPCI | High Pressure Coolant Injection |
| HVAC | Heating/Venting Air Conditioning |
| HX | Heat Exchanger |
| I&C | Instrument and Control |
| IEB | Inspection and Enforcement Bulletin |
| IFI | Inspector Followup Item |
| IN | Information Notice |
| INPO | Institute for Nuclear Power Operations |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |
| LOCA | Loss of Coolant Accident |
| LOOP | Loss of Offsite Power |
| MAC | Motor Actuator Characterization |
| MC | Motor Control |
| MCC | Motor Control Center |
| MI | Maintenance Instruction |
| MOV | Motor Operated Valve |
| MP | Maintenance Procedure |
| MSIV | Main Steam Isolation Valve |
| MSL | Metalurgical Service Lab |
| MST | Maintenance Surveillance Test |
| MWE | Mega Watt Electric |
| NPRDS | Nuclear Plant Reliability Data System |
| NPSH | Net Positive Suction Head |
| NRC | Nuclear Regulatory Commission |

| | |
|---|---|
| OI | Operation Instruction |
| ONS | On-Site Nuclear Safety |
| PGP | Procedure Generation Package |
| PM | Plant Modification or Preventive Maintenance |
| PNSC | Plant Nuclear Safety Committee |
| PRA | Probabilistic Risk Assessment |
| PSI | Pounds Per Square Inch |
| PSIG | Pounds Per Square Inch Gage |
| PT | Performance Test |
| QA | Quality Assurance |
| QC | Quality Control |
| RCS | Reactor Coolant System |
| RHR | Residual Heat Removal |
| RPS | Reactor Protection System |
| RPV | Reactor Pressure Vessel |
| RO | Reactor Operator |
| SAT | Standby/Startup Transformer |
| SBGT | Standby Gas Treatment |
| SBO | Station Blackout |
| sd | Standard Deviations |
| SIL | Service Information Letter |
| SLC | Standby Liquid Control |
| SLSC | Standby Liquid System Control |
| SRO | Senior Reactor Operator |
| SRV | Safety Relief Valve |
| SSFI | Safety System Functional Inspection |
| SWS | Service Water System |
| TR | Target Rock |
| TS | Technical Specification |
| UAT | Unit Auxiliary Transformer |
| UNR | Unresolved Item |
| V | Volts |
| WR/JO | Work Request/Job Order |

19.0 Docments Reviewed


1. IEEE Paper, Transformer Connections in Three-Phase Distribution Systems, L. W. Long, Part of IEEE Tutorial on Application of Distribution and Power Transformers, 76 CH1159-3-PWR, page 16

2. IEEE Paper, Selection of System Voltages for Power Plant DC Systems, J. F. Montalbano, H. L. Bush, IEEE Transactions on Power Apparatus and Systems, Vol PAS-101, No. 10 October 1982, pages 3820-3829

3. IEEE Paper, Considerations for Ground Fault Protection Medium Voltage Industrial and Cogeneration Systems, D. J. Love, N. Hase hmi, Presented at IEEE Industry Application Society 1986 Annual Meeting

4. IEEE Paper, Field Installation and Maintenance of Oil-Immersed Transformers, D. C. Johnson 76 CH 1159-3-PWR, pages 74-76

5. NUREG-0666, A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plants

6. NRC Inspection Report 50-325/88-05 Section 10, Silicon Bronze Bus Bar Bolts, pages 8 and 9

7. Procedure, 125 VDC Battery Weekly Operability Test. No. 2MST - BATT11W, Rev. 4, dated November 17, 1987

8. Procedure, 125 VDC Battery Monthly Operability Test No. 2MST - BATT11M, Rev. 2, dated December 29, 1985

9. Procedure. 125 VDC Battery Quarterly Operability Test No. 2 MST-Batt 11Q, Rev. 5, January 27, 1988

10. Procedure, 125 VDC Battery Service Capacity Test, No. 2MST-BATT11R, Rev. 2, February 5, 1987

11. Procedure, 125 VDC Battery Performance Capacity Test, No. 2MST-BATT11FY, Rev. 2, dated December 30, 1987

12. Design Basis Document for 125/250 Volt DC Load Study. No. 7579-139-02, Rev. 0, dated June 27, 1984

13. Monthly Emergency Core Cooling System Work Order Report (trending document) November 1987 - May 1986

14. General Electric Co. Publication, Molded - Case Circuit Breakers Application and Selection, GET 2779G page 32

15. Letter, CP&L to NRC, on Revision to Technical Specifications Electric Power Systems, dated August 31, 1982

16. Letter, CP&L to NRC, on Withdrawal of Request for Licensee Amendments, dated February 14, 1984

17. Letter, CP&L to NRC, on Request for Licensee Amendment Alternate/ Normal Power Testing, dated February 29, 1988

18. Instruction Manual for Stationary Batteries, GNB Incorporated Publication

19. Annunicator Response Procedure, 250 V Battery B Charger Trouble, 2APP UA-23 Rev. 11, pages 36, 37

20. Unit 2 Turbine Building Auxiliary Operator Daily Check Sheet, Part of BSEP/Vol VII/OI-03.4, pages 115, 123 and 124, Rev. 10.

21. Unit 0 Outside AODCS, pages 155, 156, 160, 161, 168, 169, 176

22. Electrical Lineup Prestartup Checklist for DC Electrical System, from 2 OP-51, Rev. 17 page 109.

23. Startup Procedure, Transferring Auxiliary Power from the SAT to the UAT, from 1 OP-50, Rev. 7, pages 30-32

24. Organizational Chart for the Maintenance Department, dated November 25, 1987

25. Periodic Test Procedure, 230 kV Pneumatic Circuit Breaker Check, No. 12.1, Rev. 6, dated December 27, 1987

26. Letter, G. W. Morris, Westec Services, Inc. to J. H. Bellack, Cleveland Electric Illuminating Co. on Battery Service Discharge Test, Cell Specific Gravity, Battery Contribution to DC Short-Circuit Current, dated March 10, 1987

27. Letter, J. H. Bellack to G. W. Morris, Response to Morris Oct 87 letter, dated April 16, 1987

28. Licensee Event Report, Docket No. 50-325, LER 1-88-006, Bolt Head Failures of 5/16 inch x 1 1/2 inch Silicon Bronze Carriage Bolts in Bus Bar Connections of Electrical Switchboards.

29. Coordination Study, 125/250 VDC System, Rev. 2, dated December 15, 1975, pages 1 and 2

30. Drawing, Unit No. 2 Emergency Key One Line Diagram 4160 V, 480 V, 120/208 V, 120/240 V AC and 24/48 V, 125/250 V DC, DWG No. F-3026 Rev. 4

31. Drawing, Unit No. 1 Auxiliary One Line Diagram 4160 Volt System SWGR 1B, 1C, 1D, and Common A, Dwg No. F-30002 Rev. 1 (Dwg No. F-3002 Rev. 16 for Unit 2)

32. Drawing, Units No. 1 and 2 Auxiliary One Line Diagram 4160 Volt Emergency System SWGR E1, E2, E3 and E4, Dwg. No. F-03004 Rev. 11 F-03003 Rev. 11

33. Drawing, Unit No. 1 Single Line Diagram 125-250 Volt D-C System Distribution Switchboards 1A and 1B Dwg No. F-30006 Rev. 24 (Dwg No. F-03006 Rev. 24 for Unit 2)

34. Drawing, Units No. 1 and 2 Three Line Diagram 24/48 Volt D-C System Distribution Panels, Dwg No. F-3028 Rev. 17

35. Drawing, Units 1 and 2 Main One Line Diagram 230 kV and 24 kV Systems Sheet No. 1 and 2 Dwg No. F-03000 Rev. 15 and F-3001 Rev. 18

36. Drawing, 4160 V SWGR E1 Compt AE6 Incoming Line SWGR 1D Control Wiring Diagram, Dwg No. 9527-LL-9111 Sh 8, Rev. 5; Sh 8A, Rev 9; Sh 8B, Rev. 1

37. Drawing, Unit No. 1 - 460 Volt Switchgear "1D" Compartment "1-AD1" Emergency Switchgear E1 Fdr Bkr Control Wiring Diagram, Dwg No. 9527-LL-91004 Sh 8 Rev. 4

38. Drawing, Unit No. 1 and 2 4160 Volt Swithgear "E1" DIV I Relaying and Metering Three Line Diagram Dwg No. F-03077 Sh 1, Rev. 10; Sh 2, Rev. 14

39. Drawing, 4160 Volt Switchgear E1 Compartment AE9 Emergency Diesel Gen No. 1 Bkr Control Wiring Diagram, Dwg No. 9527-LL-9111 Sh 12, Rev. 6; Sh 12A, Rev. 7; Sh 13, Rev. 3; Sh 13A Rev. 7 Sh 13B Rev. 3

40. Drawing, 230 kV Switchyard - Unit No. 1 Caswell Beach Transformer Circuit Switcher 89-T1 Control Wiring Diagram, Dwg. No. LL-9012 Sh 8, Rev. 4

41. Drawing, 230 KV Switchyard - Transformer Area Trenches and Conduits Sheet 1 Dwg No. 9527-F-3559, Rev. 10

42. Drawing, Reactor Building - Unit No. 2 Plan Grounding Elevation 117'-4" and Roof, Dwg. No. 9527-F-3386 Rev. 6 [Shows details of lightning protection equipment]

43. System Description SD-19R12 (December 28 1987), High Pressure Coolant Injection System

44. HPCI/RCIC Reliability Evaluation Report dated December 12, 1986, and partially updated May 15, 1987

45. HPCI Safety System Functional Inspection completed May 15, 1987

46. Memorandum from R. Helme To M. Hill, INPO Pilot Program, June 18, 1987 (transmital of unavailability data on HPCI)

47. Periodic Test Procedure (PT) 9.2R52 (January 19, 1988) HPCI System Operability Test

48. Maintenance Procedure MP-14A, R7 (Febuary 9, 1988), Corrective Maintenance (Automated Maintenance Management System)

49. Maintenance Instruction MI-16-21R10 (March 20, 1987), Motor - Operated Valve Stroking Procedure

50. Corrective Maintenance Procedure OCM-M0001R3 (February 5, 1988), AC and DC Motor Operated Valve Stroking Procedure

51. NRC Information Notice (IN) 87-40 (August 31, 1987), Backseating Valves Routinely to Prevent Packing Leaks

52. Special Procedure SP-85-066 R3 (October 6, 1987), Backseating of Valves Using the Motor Operator

53. Record - WR/JO 85-FI901 completed, July 10, 1985 for backseating valve 2-B21-F002

54. Record - WR/JO 85-HU901 completed July 12, 1985 for backseating valve 2-E41-F016

55. Corrective Maintenance Procedure OCM-M0500R0 (February 13, 1987), Repair Instructions for Limitorque Motor Operator Model Numbers SMB-5 and SMB-5T

56. Corrective Maintenance Procedure OCM-M0501R4 (September 25, 1987), Repair Instructions for Limitorque Motor Operator Model Numbers SMB-0 through 4, SMB-4T, SB-0 through 4

57. Corrective Maintenance Procedure OCM-M0502R2 (March 30, 1987), Repair Instructions for Limitorque Motor Operator Model Number SMB-000

58. Corrective Maintenance Procedure OCM-M0503R1 (October 20, 1987), Repair Instructions for Limitorque Motor Operators Model Number SMB-00 and SB-00

59. Corrective Maintenance Procedure OCM-M0003R0 (March 20, 1987), Limitorque Limit Switch Rotor Replacement Procedure

60. Maintenance Procedure MP-57R2 (December 9, 1987), Limitorque Valve Failure Analysis and Troubleshooting Procedure

61. Record - Preliminary failure analysis of January 5, 1988, for valve 1-E41-F001 contained in WR/JO 87-BMTI1

62. Maintenance Procedure MP-10R28 (December 2, 1986), Preventive Maintenance Program

63. Preventive Maintenance Procedure OPM-M0004R1 (June 25, 1987), Limitorque Limit Switch Assembly Lubrication Procedure

64. Maintenance Instruction MI-10-25RO (May 15,1985), Torque Switch Contact Inspection of Q-List Limitorque Operations

65. Records - Current in-process plots of HPCI Unit 1 and 2 pump test data and Unit 2 stroke time data for valves F001 and F006

66. Records - Data sheets for Units 1 and 2 stroke testing for HPCI valves F001, F005, and F006 and F019 and for testing the HPCI pumps (performed since January 1985)

67. Engineering Procedure ENP-16.1R4 (November 15, 1985), Pump and Valve Graphing

68. Letter from R. Richey (Licensee) to NRC dated November 24, 1987 (Serial NLS-87-261) containing revised Inservice Testing Program for Pumps and Valves

69. Standard Operating Procedure (Maintenance) SOP-2.40RO (January 12, 1988), Repetitive Failure

70. Report of Repetitive failures dated February 13, 1988

71. Project Guidelines - Post Maintenance Work Inspections (Post Maintenance Work Audits), Revision 1 (July 1987)

72. Drawing: - Reactor Building Piping Diagram, High Pressure Coolant Injection System, Unit 2, D-02523 Sheets 1 and 2 (R26 and R25)

73. Drawing: Valves 1-E41-F005 and 2-E41-F005, Foreign Print 6325

74. Drawings: Valves 1- and 2-E41-F019, Foreign Print 6310

75. Drawing: Valves 1- and 2-E41-F006, Foreign Print 6027

76. Drawing: Valves 1- and 2-E41-F001, Foreign Print 6313

77. Licensee Event Report 2-87-001, Automatic Reactor Scram Due to Main Turbine Control Valve Fast Closure Resulting from Loss of Main Generator Excitation Voltage

78. Licensee Event Report 1-87-023, Inoperability of High Pressure Coolant Injection System (E41) Due to Failure of HPCI Turbine Steam Inlet Isolation Valve E41-F001

79. Refer to HPCI Documents (6) through (8), (13) through, (18), (20) through (22), (25) through (27) and (29) which are also applicable to RHR valve maintenance and testing

80. System Description SD-17R11 (December 28, 1987), Residual Heat Removal System

81. Periodic Test (PT) 8.2.2c R13 (September 11, 1987), LPCI/RHR System Operability Test - Loop A

82. PT 8.2.2b R17 (June 24, 1987), LPCI/RHR System Operability Test - Loop B

83. Records - Current graphs and related data sheets for stroke time tests on valves F007, F024, F028 and F048 (both loops and both units)

84. Record - WR/JO 86-AHGT1 completed February 27, 1986 for inspection of valve 2-E11-F007A relative concerns expressed in NRC IN 86-03

85. Record - WR/JO 87-BGIC1 completed December 22, 1987 for correction of valve 2-E11-F024A packing leak

86. Records - Plant Modifications 84-060 and -061 for installation of redundant fuses in Units 1 and 2 valve control circuits

87. Drawing: Reactor Building Piping Diagram, Residual Heat Removal System - SH. 1A, Unit No. 1, D-25025, SH.1A

88. Drawing: Reactor Building Piping Diagram, Residual Heat Removal System, Unit No. 1, D-25025, SH.1B

89. Drawing: Reactor Building Piping Diagram, Residual Heat Removal System - System SH. 2A Unit No. 1, D-25026 SH. 2A

90. Drawing: Reactor Building Piping Diagram, Residual Heat Removal System - SH.2B, Unit No. 1, D-25026 SH. 2B

91. Drawing: Reactor Building Piping Diagram, Residual Heat Removal System SH.1B, Unit No. 2, D-02525, SH.1B

92. Drawing: Valves 1-and 2-E11-F007A and B, Foreign Print 6152

93. Drawing: Valves 1-and 2-E11-F02A and B, Foreign Print 6157

94. Drawing: Valves 1-and 2-E11-F028A and B, Foreign Print 6151

95. Drawing: Valves 1-and 2-E11-F048A and B, Foreign Print 6156

96. Drawing: Min. Flow Byp. Vlv. 1-E11-F007A, Control Wiring Diagram, LL-92036R5, SH.53

97. Drawing: RHR Containment Spray Valve 1-E11-F024A Control Wiring Diagram, LL-92036R4, SH.65

98. Drawing: RHR Containment Spray Valve 1-E11-F028A Control Wiring Diagram, LL-92036R8, SH.71

99. Target Rock Corporation Procedure No. 2025K (8/21/87), "Assembly and Test Procedure, 3-Way Solenoid Valve Assy Instructions"

100. Licensee Event Report (LER) 1-87-011, Safety Relief Valves Setpoints Exceeded During Testing at Wyle Laboratories

101. LER 1-87-020, Failures of Reactor (B21) Safety Relief Valves B21-F013J and L to Open as a Result of Excess Loctite on the Interior of the Valves Solenoid Bonnet Tubes

102. Engineering Procedure ENP-17R3 (7/17/87), Pump and Valve Inservice Testing (IST)

103. Periodic Test (PT) 11.1.2 R19 (2/10/87), Automatic Depressurization System and Safety Relief Valve Operability Test

104. Maintenance Instruction MI-16-626R8 (4/30/87), Target-Rock Safety Relief Valves, Two Stage, Model 7567F

105. System Description SD-20 R12 (11/12/86), Automatic Depressurization and Safety/Relief Valve System

106. NRC IE Bulletin 80-25 (12/19/80), Operating Problems with Target Rock Safety-Relief Valves at BWRs

107. NRC Information Notice 84-53 (7/5/84), Information Concerning the Use of Loctite 242 and Other Anaerobic Adhesive/Sealouts

108. Maintenance Procedure MP-14A, R7 (2/9/88), Corrective Maintenance (Automated Maintenance Management System)

109. Record - WR/JO 86-BSEZ1 completed 10/29/86 for repair of air leak between solenoid and adapter on pilot for valve 2-B21-F013H

110. Record - WR/JO 86-BSFE1 for repair of air leak between solenoid and adaptor block on valve 2-B21-F013E

111. Carolina Power and Light Company - Metallurgy Unit Memorandum dated 2/29/88, MSL No. 12-186, Brunswick - Safety Relief Valve Solenoid Investigation

112. OMP-11 Preventative Maintenance Program

113. OMP-14A Corrective Maintenance Automated Maintenance Management System

114. OMP-59 Control of Maintenance on the Emergency Diesel Generator System

| | | |
|---|---|---|
| 115. | OPDM-ENG507 | Diesel Engine Analysis Nordberg Model FS-1316-HSC |
| 116. | OPM-ENG501 | Instruction for Testing and Adjusting of the Woodward Overspeed Dump Valve |
| 117. | OSPP-ENG508 | Diesel Engine Analysis Nordberg Model FS-1316-HSC |
| 118. | FP-20322 | Nordberg Diesel Engine Instruction Manual |
| 119. | OPT-12.2A | No. 1 Diesel Generator Monthly Load Test |
| 120. | OPT-12.2B | No. 2 Diesel Generator Monthly Load Test |
| 121. | OPT-12.2C | No. 3 Diesel Generator Monthly Load Test |
| 122. | OPT-12.2D | No. 4 Diesel Generator Monthly Load Test |
| 123. | OPT-12.3.1 | Emergency Diesel Generators Inspection |
| 124. | 1MST-DG11R | DG-1 Loading Test |
| 125. | 1MST-DG12R | DG2 Loading Test |
| 126. | 1MST-DG13R | DG3 Loading Test |
| 127. | 1MST-DG14R | DG4 Loading Test |
| 128. | 1MST-DG21R | DG-1 Trip Bypass Logic Test |
| 129. | 1MST-DG22R | DG2 Trip Bypass Logic Test |
| 130. | 2MST-DG11R | DG-1 Loading Test |
| 131. | 2MST-DG12R | DG2 Loading Test |
| 132. | 2MST-DG13R | DG3 Loading Test |
| 133. | 2MST-DG14R | DG4 Loading Test |
| 134. | 2MST-DG21R | DG3 Trip Bypass Logic Test |
| 135. | 2MST-DG22R | DG4 Trip Bypass Logic Test |
| 136. | OP-39 | Diesel Generator Operating Procedure |
| 137. | OI-03.3 | Auxiliary Operator Daily Surveillance Report |
| 138. | OI-03.4 | Daily Check Sheets |
| 139. | SD-39 | Emergency Diesel Generator System |

140. NRC Information Notice 86-07, Lack of Detailed Instruction and Inadequate Observance of Precautions During Maintenance and Testing of Diesel Generator Woodward Governors

141. NUREG/CR-4440, A Review of Emergency Diesel Generator Performance at Nuclear Power Plants

142. 9527-D-2266 Sheet 2A, Starting Air for Diesel Generators

143. 9527-D-2266 Sheet 2B, Starting Air for Diesel Generators

144. 9527-D-2269 Sheet 2A, Fuel Oil to Diesel Generators

145. 9527-D-2269 Sheet 2B, Fuel Oil to Diesel Generators

146. 9527-D-2271 Sheet 2A, Diesel Generator Lube Oil System

147. 9527-D-2271 Sheet 2B, Diesel Generator Lube Oil System

148. 9527-D-2273 Sheet 2A, Diesel Generator Jacket Water System

149. 9527-D-2273 Sheet 2B, Diesel Generator Jacket Water System

150. 1-FP-05835 Rev. C, Standby Liquid Control System Elementary Diagram, Unit 1

151. LL-93041 Rev. 16, Unit 1, Emergency Power System 120/208 Volts AC Distribution Panel and 1AB, Sheet 6

152. 9527-LC-93041 Rev. 8, Unit 1, Emergency Power System 120/208 Volts AC, Power Distribution Panel 1E5-HGO, Sheet 19, 20 (Rev. 7)

153. D-25047 Reactor Building Piping Diagram, Standby Liquid Control System, Unit No.1, Rev 19

154. D-72008 Piping Diagram, Instrument Air Supply System, Reactor Building - Sheet No. 5, Unit No. 1, Rev 16

155. D-70029 Reactor Building Piping Diagram Instrument Air Supply System SH.2B, Unit No. 1, Rev. 31.