UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W
ATLANTA, GEORGIA 3032

Report Nos.: 50-325/88-19 and 50-324/88-19

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket Nos.: 50-325 and 50-324 License Nos.: DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: June 27-July 1 and July 11-15, 1988

Inspectors: Bruce Breslau August 25 1988
B. Breslau, Team Leader Date Signed

Team Members:

W. Levis
P. Moore
T. O'Connor
W. Orders
C. Payne
C. Rapp
R. Schin
D. Starkey

Approved by: Caudle Julian for 9/2/88
M. Shymlock, Chief Date Signed
Operational Programs Section
Division of Reactor Safety


SUMMARY

Scope: This was a special announced Operational Performance Assessment (OPA). The OPA evaluated the licensee's current level of performance in the area of plant operations. The inspection included an evaluation of the effectiveness of various plant groups including Operations, Maintenance, Quality Assurance, Engineering and Training in supporting safe plant operations. Plant management awareness of, involvement in, and support of safe plant operation was also evaluated.

The inspection was divided into three major areas including Operations, Maintenance Support of Operations, and Management Controls. Emphasis was placed on numerous interviews of personnel at all levels, observation of plant activities and meetings, extended control room observations, and plant and system walkdowns. The inspectors also reviewed plant deviation reports and LERs for the current Systematic Assessment of Licensee Performance (SALP) evaluation period, and evaluated the effectiveness of the licensee's root cause identification; short term and programmatic corrective actions; and repetitive failure trending and related corrective actions.

Results: A review of past NRC inspections and reportable events indicated a troubled performance history at Brunswick. Weaknesses had been identified in the environmental qualification of equipment, operational procedural adherence, procedure adequacy, and operator attentiveness. Two of these issues involved potential escalated enforcement actions.

During this inspection, the NRC discussed the performance history with plant and corporate management. The licensee's entrance/briefing of their self initiated OPA results and the results of the NRC's OPA indicate that similar weak areas had been previously identified by management and that significant actions were under way to correct these problem areas.

In general, the licensee's programs in the areas inspected were found to be adequate. Several areas were considered to be strengths: the use of Annunciator Tracking sheets and System Status sheets were very beneficial to the Control Operator during the shift turnover process; the computerized LCO tracking system greatly increased the efficiency with which LCOs were processed and reviewed; the Daily Instruction sheet prepared by the Operations Engineers provided a good means of communicating planned maintenance activities to Operations personnel; SWFCG scheduling of maintenance; the AMMS computer system, with PM scheduling, EDBS, surveillance test scheduling, and LCO tracking; the scram reduction program and maintenance personnel error reduction program, which have shown positive results; the maintenance procedure upgrade program; the MOV project plan; and the MAC method of testing MOVs.

However, notable weaknesses included: HPCI unavailability continued to be high, with continued valve failures; no improvement has been made during this SALP period to reduce HPCI unavailability; the method used to identify Temporary Procedure Revisions when they were attached to the original procedure was confusing and could lead to operator error; failure to adequately control the posting of operator aids in the plant could lead to misinformation being used by operators; and the WR/JO priority system as proceduralized did not compare well with how planners actually prioritized their work. Also, there has been an apparent lack of management attention toward completing work requests in a timely manner as indicated by a large percentage of backlogged WR/JOs (68% were over 3 months old), including priority 2 WR/JOs; and the maintenance work request priority system included no guidelines for timeliness (except for priority 1), nor any requirement for management review of WR/JOs that were outstanding past a certain time period. Also, the maintenance procedure revision request backlog was large (approximately 1 year).

Additional weaknesses included: participation by attendees in the plant status meetings was minimal; the accuracy and adequacy of status information presented in meetings did not reflect actual plant status; and management assertiveness and control during management meetings varied widely dependent on the subject. Also, management's lack of direct involvement: in plant activities, in the resolution of identified deficiencies, and lack of aggressiveness with respect to the identification and/or the resolution of identified technical deficiencies were of concern.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

+ S. Smith Jr., Chairman/President
* K. Altman, Principle Engineer - Maintenance
+ H. Banks, Manager - Corporate QA
+ G. Beatty, Vice President - Robinson Nuclear Project
+ H. Bowles, Administrative Assistant to the Chairman/President
* C. Blackman, Jr., Operations Manager
* J. Brown, Resident Engineer - Engineering
* S. Callis, Jr., On-site Licensing Engineer
* A. Cheatham, Manager - Environmental and Radiation Control
* R. Creech, I&C Electrical Maintenance Supervisor (Unit 2)
+ A. Cutter, Vice President - Nuclear Engineering Department
+* C. Dietz, General Manager - Brunswick Nuclear Project
* K. Enzor, Director - Regulatory Compliance
+ L. Eury, Senior Vice President - Operations Support
+ B. Furr, Vice President - Operation Training & Technical Support
* R. Grover, Project Construction Manager
+* J. Harness, Plant General Manager - Designated - Brunswick Nuclear Project
* K. Harris, Regulatory Compliance Specialist
* R. Helme, Manager - Technical Support
+ M. Hill, Manager - Nuclear Staff Support Section
* J. Holder, Manager - Outage
+* P. Howe, Vice President - Brunswick Nuclear Project
* L. Jones, Director - QA/QC
* M. Jones, Director - Onsite Nuclear Safety
* T. Jones, Regulatory Compliance Specialist
* R. Kitchen, Mechanical Maintenance Supervisor (Unit 2)
+* M. McDuffie, Senior Vice President, Nuclear Production
* J. Moyer, Manager - Training
* J. O'Sullivan, Manager - Maintenance
* R. Poulk, Jr., Project Specialist - Regulatory Compliance
+ R. Richey, Manager - Licensing & Nuclear Fuel Department
* J. Smith, Director - Administrative Support
* S. Smith, Maintenance Planning
+* R. Starkey Jr., Manager - Nuclear Safety & Environmental Services
* S. Strickland, Shift Foreman
* J. Titrington, Principle Engineer - Operations
+* E. Utley, Executive Vice President
* M. Walker, Regulatory Compliance Specialist
+ R. Watson, Vice President - Harris Nuclear Project Department
* A. Worth, Engineering Supervisor
* H. Wright, Senior QA Specialist - Corporate QA
* T. Wyllie, Manager - Engineering and Construction

Other licensee employees contacted included Technicians, Operations personnel, Maintenance and Instrumentation & Control personnel, and office personnel.

Non-Licensee Employee

+ P. Jordan, Roxboro/Mayo Site Representative for N.C. Eastern Municipal Power Agency

NRC Representatives

+ J. Grace, Regional Administrator - Region II
+ E. Adensam, Director - Project Directorate II-1, NRR
+ P. Frederickson, Section Chief - Reactor Projects
+ A. Gibson, Director - Division of Reactor Safety
+ C. Hehl, Deputy Director - Division of Reactor Projects
+ G. Lainas, Assistant Director - Region II Reactors
+ W. Troskoski, Regional Coordinator - EDO
+* W. Ruland, Senior Resident Inspector

*Attended pre exit interview
+Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Operations (71707, 71710)

The inspectors performed extended observations of control room activities (including back shifts), observed shift turnovers, reviewed applicable operator logs, and toured the plant with non-licensed operators as they performed their duties. The inspectors monitored operations personnel performance, awareness of plant status, use of procedures, and the maintenance of required station logs.

Interviews were conducted with licensed operators, non-licensed operators, STAs, and Operations Department Management. The operations staff as a whole exhibited a professional, well disciplined attitude toward performance of their duties.

a. Control Room and Local Plant Operations

(1) Control Room Decorum

The inspectors observed control room operations with emphasis on the conduct of day to day activities, operator professionalism, annunciator response, procedure adherence, and control room access. All operators were conscientious in performance of their duties and were attentive to plant conditions.

The licensee maintained a professional control room atmosphere. The licensed operators remained in the controls area as required. When an operator requested relief, an adequate review of the board status and current work activities was performed with the relief operator. Access to the control room was limited to operations staff and individuals authorized to enter. The practice of obtaining authorization was generally adhered to by non operations staff. The number of individuals present in the control room immediately after shift turnover tended to be somewhat excessive especially after the morning turnover. The operations staff conducted the business of clearances and other maintenance activities at windows located at the perimeter of the control room which greatly assisted in minimizing distractions to the operators.

The inspectors were concerned about control room crowding following a major plant event such as a reactor scram. An example of this concern was observed on July 14, 1988, immediately following a manually initiated reactor scram necessitated by an LCO action statement. At that time there were eight operations personnel, in addition to the CO, at or near the CO's desk and operating panel. This number appeared to be excessive and could interfere with the performance of CO duties.

(2) Status of Control Board and Local Instrumentation

Procedure 0-AOP-32.0, Plant Shutdown From Outside Control Room, Rev 16 was reviewed for consistent terminology between the procedure and the remote shutdown panel, no discrepancies were noted. The panels contained all instrumentation required by Technical Specification 3.3.5.2 with the appropriate measurement range.

Control Board walkdowns were conducted as part of the inspection. A Control Room Design Review program was in effect and an implementation schedule had been submitted to the NRC. Also, approximately one year ago, the control room was remodeled by raising the floor level and installing new desks and book shelves. The new arrangement permitted a good view of the control panels from either the CO or SF work station.

During control board walkdowns several discrepancies were noted as listed below:

(a) Area Radiation Monitor recorders, D22-R600 and D22-R601, located on panel XV-41 Unit 1, had scale and stamp pad printing which were difficult to read. The recorders were being tracked as a plant modification and the scales are to be replaced by maintenance.

(b) Caution tags located on control switches for RHS-V32 and RHS-V31, drain valves off reactor feed pump, Panel XV-3, Unit 1, indicated that the switches/labels for these two valves are crossed. The problem was noted on the caution tag dated November 20, 1984, but had probably existed since the initial installation of these switches.

(c) Caution tags on RHS-V28 and RHS-V29 Panel XV-3 Unit 1, indicated the same problem as described in (b) above. An EWR 02308 had been written to correct this problem, but no time table had been set for action on the EWR.

(d) Caution tag located on the control switches for the CWIP stated that, "When starting any CWIP ensure RPS channel A or B is not on the alternate power supply. The alternate EPA breakers will trip when either CWIP is started". Engineering had been investigating this problem under PM 86-088. The problem was not yet solved.

There were several orange "caution tag" stickers placed near appropriate control devices on the control board. These stickers are numbered which permitted ready reference to the "Control Panel Temporary Caution Tag Sheets" located in orange binders at each main section of the control board. The caution sheets provided the operator with a detailed description of the cautioned conditions. The use of these caution sheets was noted as being a good method to organize caution tag information without cluttering the control panels.

The licensee tracked the number of lighted and disabled annunciators in the control room. A goal of no more than 13 lit or 30 disabled annunciators had been established. Review of the annunciator status for the past 1½ years indicated that the number of lighted annunciators were slightly higher than the set goal.

In general, control board configuration and instrumentation was good. Areas where changes were needed had been identified in the implementation schedule by the Control Room Design Review Team.

(3) Logs and Records

The SF and CO each maintained a log book. Information contained in those logs was adequate and provided sufficient data to recount plant events/evolutions. The SF log was provided with spaces to record reactor power, reactor temperature, generator load, reactor mode, torus level, number of safety related jumpers in use, and meteorological tower data.

The COs maintained the master copy of the "Auxiliary Operator Daily Check Sheet" which contained data collected by the AOs during their daily plant rounds. Each AO transfered this data from the field copy to the master copy prior to the end of each shift. These sheets contained one week of plant data and was readily available for review by control room personnel.

The inspectors reviewed the implementation and logs of the licensee's jumper/lifted lead control, system configuration control, and locked valve and key control programs. No discrepancies were noted.

(4) Shift Turnover Process

The inspectors observed shift turnovers for both the day and night shifts. These turnovers were accomplished efficiently and in accordance with turnover procedures. Operating Instruction OI-02, Shift Turnover Checklist, Rev. 25 provided guidelines and checklists for the shift turnover. Each working position conducted a separate turnover which included completion of a turnover check sheet and a control board walkdown. The individual turnovers were followed by a shift briefing conducted by the SOS. The SOS covered those topics most pertinent to the on-coming shift. The briefings observed were good.

The turnover sheets completed by the CO had attached to them a "Lighted Annunicator Tracking" sheet and a "System Status" sheet. These sheets were computer generated based upon information submitted by the CO prior to the end of his shift. The Lighted Annunciator Tracking sheet gave the reason for each lighted annunciator and corrective action taken, if appropriate. The System Status sheet included references to any major surveillances or maintenance evolutions in progress. Additionally, it listed major pieces of plant equipment and their operational status. These two sheets provided a useful tool for the CO during the turnover process. These status sheets were noted as a strength of the turnover process.

(5) Local Plant Operations

AOs were observed as they performed their routine tours of the plant on both the reactor building and balance of plant equipment. The inspectors concluded that the AOs were a conscientious and professional group. Communications with the unit CO were good. Any question or problem was quickly brought to the attention of the control room. Adherence to operation procedures and radiological controls was good.

(6) Technical Specification Compliance

During the inspection the licensee entered several LCOs. In each case a conservative approach was taken concerning the necessity for LCO entry. The licensee utilized a computerized LCO system to control equipment and track Technical Specification action items. Information contained in this system distinguished between those items which actually placed the plant into action statements and those which were "info," serving as a warning to the licensed operators that additional actions may force the plant into an action statement. LCOs were also entered in the SF log book, which was subsequently reviewed by licensed operators during shift turnover. LCOs contained in the computerized system were printed into hard copies on a daily basis as a backup for the computer. This computerized method of LCO tracking was noted a strength.

(7) Plant Evolutions

On July 13, 1988, at approximately 8:00 p.m., Unit 1 commenced a plant shutdown to meet the requirements of an LCO, in accordance with general plant operating procedure GP-05, Unit Shutdown, Rev. 27. During the course of the shutdown, difficulties were encountered with the RWM and the RSCS. At approximately 9:00 p.m., the RWM erroneously prevented rod movement. The licensee bypassed the RWM in accordance with step 3.5 of GP-05 and TS 3/4.1.4. In conjunction with this action, a second operator was assigned to verify that the rod sequence was followed. At approximately 11:30 p.m., the RSCS prevented rod selection. During the course of trouble shooting on the RSCS the SF and the SOS discussed with plant management the amount of time remaining before the LCO was exceeded and the possible courses of action, including manually scramming the reactor.

All discussions examined the situation with consideration for procedure and TS compliance and were held in conjunction with plant management. The RSCS was returned to service at approximately 3:30 a.m., on the July 14, 1988, when control rod 22-03 was bypassed to the full out position in the Rod Position Information System as permitted by TS. The unit shutdown continued until approximately 8:30 a.m., at which time the reactor was manually scrammed to allow sufficient time to cooldown to mode three prior to the expiration of the LCO.

b. Temporary Procedure Revisions

The inspector reviewed the methodology used by the licensee to make temporary revision changes to procedures. Section 5.6.4 of administrative procedure Volume 1, Rev. 3 described this process. Section 5.6.4.2B required that temporary changes be entered into the control room copy of the Operating Manual by stapling a copy of the revised page(s) over the existing page(s). This requirement had generally been interpreted by the licensee as stapling all of the revised pages together and attaching them to the front of the old procedure with the required temporary revision form on top. Copies of the newly revised procedure were made and put into a working copy file where the operator could retrieve a procedure if necessary. The working copy file contained examples where the old procedure pages had been replaced with the newly revised pages and also showed examples where all the new pages were stapled together at the front of a procedure.

The inspector observed an inerting evolution which was conducted in accordance with Special Inerting Procedure SP-88-021, Temporary Revision 88-203. In this instance the revised pages were all attached to the front of the procedure. The operator and had to constantly refer to the changed pages in the front during the inerting process. An operator should be able to use a procedure with the necessary changes already inserted so that attention can be directed to the evolution at hand rather than diverted by a convoluted procedure. Discussions with the licensee concerning this issue resulted in a commitment to revise the administrative procedure to ensure that temporary procedure revisions are properly controlled.

The licensee commitment to incorporate appropriate changes into their administrative procedures will be identified as IFI 324,325/88-19-01.

c. Surveillance Testing

The inspectors monitored several PTs as they were performed. In each case the operators performing those PTs appeared to be well prepared and knowledgeable of the test being performed. Two PTs were observed which contained either procedural errors or decision-making errors as noted in the following:

(1) 0-PT-9.2, HPCI System Operability Test, Rev. 55, Temporary Revision No. 88-219 was observed from the control room. After the PT was started, it was detected by the SF that the field copies of the procedure did not contain the temporary revision pages. The test was stopped until each person participating in the PT had a correct working copy. Those procedure steps affected by the temporary revision had not yet been entered at the time of the discovery. Upon review of the file where working copies of procedures were maintained, it was determined that all other file copies contained the proper revised pages.

A prerequisite of this PT was that the suppression pool level be between -31 inches and -27 inches. The actual level at the start of the test was approximately -28.5 inches. Approximately 32 minutes after the HPCI pump was started the test was terminated due to level approaching -27 inches. The licensee had not fully anticipated this rapid increase in torus level and therefore had not pumped down the torus prior to commencing the test. This failure to adequately preplan the PT necessitated the unnecessary expenditure of personnel, time, and equipment to perform the test a second time. It also extended the time the licensee remained in the LCO.

(2) 1-SP-88-012, Special Inerting Procedure, Rev. 2, Temporary Revision 88-202 was performed by the Unit 1 Auxiliary Operator and observed by the inspector. The AO momentarily stopped the test and consulted the control room when he discovered that a "caution" in the procedure referred to step 6.11.22. In fact, there was not such a step. The caution should have referred to step 6.11.18 instead.

d. Post Maintenance Testing

The inspectors reviewed the method by which PMTR were determined. As defined in Operating Instruction OI-39, Handling of Work Request/Job Orders, Volume VII, Rev. 008, the STA or licensed operator will determine any operational and/or technical specification which require post maintenance testing. Interviews with STAs indicated that the practice of STAs determining, from source documents, PMTRs were necessary appeared to be working satisfactorily. Adequate information appeared to be readily available to the STA to make PMTR determinations.

Once the PMTR was determined by the STA, a printed copy of the PMTR was attached to the work packages and forwarded to the SF for further disposition. If post maintenance testing could not be performed until a later date, the work packages were filed until such time as the testing could be completed. The inspector reviewed the PMTR file to determine the adequacy of review of the file by operations personnel. Only a few PMTRs were in the file cabinet, indicating a good review process, however two were found which could have been closed out, but were not. Those were:

- 1C Condensate Transfer Pump. Pump bearing replacement was completed May 27, 1988, and the pump was presently in a "standby" condition, although the PMTR documentation had not been completed.

- AOG system breaker for 1B refrigerant compressor. The breaker had been tripping when the pump was started. Work was completed May 17, 1988. The control room panel indicated that the pump was operable, although the PMTR remained unsigned.

In the above two examples, the SF stated that there was no reason these two items should not have been signed off. Later that shift the SF informed the inspector that these two PMTRs had been properly dispositioned.

The inspector observed post maintenance testing of 1-E21-F005A, Core Spray Inboard Valve. This post maintenance test was performed in accordance with PM 86-001, Rev 0, page E-219 to ensure that the new breaker was correctly wired for proper valve operation. No discrepancies were observed.

e. Tagging

Administrative Instruction AI-58, Equipment Clearance Procedure, Rev. 002 gives directions to ensure safe operating conditions exist while equipment is being cleared, maintained or returned to service.

The inspectors observed tagging operations and discussed with the Senior Operations Specialists and Operations Technicians how clearances were prepared. The Operations Technicians indicated that sufficient resource material was available in their work area to adequately prepare any clearance. Either the Senior Operations Specialist or the Operations Technician prepared the written clearance based on a request from Maintenance and a review of that request by the Operations Engineer. The individual preparing the clearance reviewed all outstanding work on the particular piece of equipment in order to optimize the work effort on the equipment and to eliminate repetitive clearances on the same item. Clearances were then reviewed by the SF and given to the CO who assigned a clearance number and arranged for an AO to hang the clearance. With the exception of the review by the SF and CO, all clearance preparation work was normally performed outside the at-the-controls area of the control room.

The majority of clearances were hung during the night shift in preparation for work to be performed on the following day shift. To assist in the dissemination of information regarding upcoming clearances and other related shift matters, the operations engineers prepared a "Daily Instruction" sheet which was placed in the control room and was part of shift turnover required reading material. This method of communicating upcoming plant maintenance to the control room staff was noted as a strength.

During the course of plant tours, the inspectors observed the restoration of equipment previously tagged out. The restoration of equipment to its required position was performed in accordance with the clearance. In situations where concurrent clearances prevented the equipment restoration, the control room was contacted and the clearance amended to reflect the as left condition. Equipment operators were knowledgeable of removal and restoration requirements including independent verification.

f. System Walkdowns

Two plant systems were walked down to assess the adequacy of alignment procedures, housekeeping and configuration control. A Unit 1 system alignment was verified using 1-OP-18, Core Spray System Operating Procedure, Rev. 11. System configuration and drawing accuracy were verified through comparison to drawing D-25024, Reactor Building Piping Diagram, Core Spray System, Unit No. 1, Rev. 20. Additionally, clearances 1-856, 1-857, 1-858, 1-859, and 1-865 were in effect on breakers and valves associated with the Core Spray system. Copies of these clearances were utilized in performing the walkdown to ensure the licensee was maintaining proper configuration control. No discrepancies were noted with respect to those valves that were verified. The drawing, clearances and checkoff procedure were determined to be accurate. The latest completed procedure was verified to be correctly filled out, initialed where required, and independently verified.

A walkdown of portions of the Service Water system in the Service Water building and the Diesel Generator building was performed with the licensee's system engineer to verify certain valve positions, assess the general material condition of the system and to test the knowledge level of a system engineer on his assigned system.

The inspector did not find any discrepancies related to valve position for those valves that were verified. The system engineer was very familiar with the system and was able to answer all of the questions asked by the inspector concerning the operation, proposed modifications, and current problems with the Service Water system.

The material condition of the area was poor. Specifically, a heavily corroded conduit support (1 example) and missing conduit support baseplate anchor bolts (3 examples were observed). The three support plates were designed for four anchor bolts each were observed. One plate was missing two bolts and the other two plates were missing one bolt each. Additionally, a severely corroded condulet cover was found in the Service Water building. The licensee evaluated these items to determine their effect on system operability and concluded that in all cases the system was operable as is.

g. Housekeeping

Inspectors conducted several tours of the plant in both the reactor building and balance of plant areas. There was ample evidence of recent painting and labelling activities having been performed. With the exception of the following observations, which were pointed out to the licensee, housekeeping was generally good.

- The Service Water Pump area, the Main Lube Oil Storage Tank area in Unit 1, and the Heater Drain Pump room in Unit 1 needed additional housekeeping.

- Nitrogen bottles on a wheel cart tied to piping approximately three feet from Standby Liquid Control Pump B represented a potential missile hazard. (Unit 2)

- Bookcases located behind main control boards were not secured.

- Suction valves to Condensate Booster Pumps 1A and 1B were chained to electrical conduit.

- Chain falls located in the RHR pump areas were secured to electrical conduit.

h. Operator Aids

Operator aids are defined in OI-41, Operator Aids, Rev. 002 as labels, sketches, markings, notes, graphs, instructions, drawings, etc. which are posted and used as memory or informational aids to the operators. The procedure states that all operator aids should be approved as specified by this procedure.

During plant tours the inspectors found four examples of unauthorized operator aids. These unauthorized aids are listed below:

- Flow diagram attached to control cabinet door on the instrument air dryer skid located on the 20 ft. elevation of the Unit 1 turbine building did not contain a signed authorization.

- Vessel Temperature Recorder, B21-TR-R007, contained an unauthorized aid attached to recorder door which listed the identity of the 12 points on the recorder. Located in Unit 2 reactor building, 20 ft. elevation.

- Unauthorized breaker identification listing attached to door of 120/208 Volt Lighting Distribution Panel 2R1 located in Unit 2 reactor building, 20 ft. elevation. (near recorder B21-TR-R007)

- Reactor Water Cleanup Panel 2-XV83, 80 ft. elevation, Unit 2 reactor building, had attached to the panel an unauthorized list of apparent part numbers for panel lights and lens covers.

Lack of control in the posting of operator aids is observed as a weakness. This item will be identified as IFI 324,325/88-19-02.

i. Independent Verification

The licensee noted at the entrance meeting presentation on June 27, 1988, that independent verification (the method for performing valve and electrical lineup verification) was an area needing additional improvement. Accordingly, OI-13, Valves and Electrical Lineup Administrative Controls, Rev. 021, dated June 29, 1988, was issued to add clarification to the independent verification requirements. The revised procedure appeared adequate. Additionally, the Manager - Operations stated that he had been meeting with each on-shift crew to discuss and answer questions concerning proper implementation of the procedure.

j. Overtime

The Brunswick Steam Electric Plant Operating Manual, Administrative Procedure, Volume I, Rev. 3, Section 4.4 provided guidance for the control of overtime for those personnel who were responsible for the correct performance of safety-related tasks. A random review of time sheets for Operations personnel revealed numerous examples of individuals exceeding the guideline which specified no more than 72 hours shall be worked in any seven-day period (not including shift turnover time). Deviation from this guideline in exceptional situations may be authorized in writing by the Plant General Manager. In each case noted, authorization was not given for these individuals to exceed the guideline hours.

This failure to follow procedures in the use of overtime for operations personnel during the six different time periods between February 12, 1988 and June 3, 1988, is an apparent violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, Brunswick Technical Specifications Section 6.8.1, and Brunswick Administrative Procedure, Volume 1, Rev. 3, Section 4.4.

The potential for exceeding the guidelines was identified by the licensee and addressed in a company memorandum from the Manager - Operations dated June 1, 1988. Since June 3, 1988, the licensee has maintained strict compliance to the procedure which requires documented prior approval before overtime hours are exceeded. Further review by the inspector indicated that the licensee is adequately administering the overtime guideline. Therefore this violation is not being cited and no response is required.

k. Organization and Staffing

The on-shift operations crew at Brunswick was headed by a SRO licensed SOS, and two SRO licensed Shift Foremen. The Shift Foremen were each assigned to one of the units. The crews were on twelve hour shifts (7:00 - 7:00) with six operating crews. Each member of the control room staff wore a badge with the title of their working positions.

Staffing appeared to be adequate with a low turnover rate among operations personnel. There were extra licensed personnel on duty on a routine basis, especially during major plant evolutions.

l. Management Involvement

Operations management appeared to be actively involved in day to day plant operations. The Manager - Operations, who has held the position for less than a month, was observed in the Control Room several times during the inspection and was accompanied by one of the inspectors during a plant walkdown. Involvement in plant operations by the Manager - Operations appeared to be good.

One area was identified that may require additional management attention. A review of control room records and inspector observations indicated that the Shift Foremen were not making plant tours as often as perhaps they could. OI-02, Shift Turnover Checklist, Rev. 25 states that Shift Foremen and SOS should perform plant tours if time permits. Additional emphasis should be placed on performing plant tours.

A positive management initiative has taken place within the last year with the implementation of a Bachelor's Degree Program for Nuclear Operators. This program is conducted through the University of Maryland and presently had 94 of 102 eligible personnel participating.

3. Emergency Operating Procedures (42700)

The Brunswick EOPs were reviewed to determine the usability of these procedures by plant operators. This review was accomplished by using the EOPs to walk through selected accident sequences with operators in the plant as well as observing actual EOP usage on the simulator during scheduled requalification training. Particular attention was given to the clarity of procedure steps, the availability of specialized equipment to perform procedure steps and the accuracy of nomenclature used in the procedure as compared to that used in the plant.

Additionally, the individual responsible for maintaining the EOPs was interviewed to verify the adequacy of required documentation. It was noted that the licensee was in the process of converting their EOPs from Rev. 2 to Rev. 4 of the BWROG ERG. The opportunity was taken to observe any improvements being made as a result of this revision as well as sampling to see if any weaknesses were carried over.

a. Flowpaths

Flowpath 1 (EOP-01-FP-1), Rev. 2 and Flowpath 4 (EOP-01-FP-4), Rev. 4 were reviewed and walked through in the plant with operators. It was noted that several steps in the flowpaths were not clear. The operators exhibited some uncertainty as to the intent of what the steps were directing the operator to do. Specific examples are given below.

Example 1 - Both flow paths contain a step which directs the CO to "Verify on or manually start diesels". Both operators interviewed stated they would perform a normal manual start of the diesel and manually tie it to the "E" bus. Starting the diesel in this manner places governor control in the "droop" mode and the operator must constantly monitor load to maintain diesel speed and voltage. Both operators recognized this problem and stated that the diesel should be started in the EMERGENCY mode.

Example 2 - Steps 073, 074 and 056 of Flowpath 4 direct the operator to "Verify closure of Groups 1, 2, 3, 6 and 8 isolation valves". One CO interviewed stated he would use several check sheets from an appendix to the User's Guide while another stated he would quickly walk down his boards then verify later with the check sheets.

Example 3 - Steps 061 and 159 of Flowpath 4 state "If other unit's instrument air header is normal open service air receiver cross tie SA-V7". It would be clearer if an acceptable value were stated (e.g. > 90 psig), thus eliminating any subjectivity as to whether air header pressure is "normal" or not.

Example 4 - Step 193 of Flowpath 4 asks if "HPCI running". Confusion existed as to whether this step meant that HPCI is actually injecting or just operating on recirculation.

Example 5 - One step of Flowpath 1 asked the operator to determine "Can the reactor be shutdown before Suppression Pool temperature reaches 110 deg F". This step required the SF to make a guess as to which direction he should be going since insufficient information exists as to whether reactor shutdown is imminent. During a time critical casualty, such as an ATWS, the SF should not be performing extraneous steps due to erroneously deciding that the reactor can be shutdown or delaying implementation of alternate shutdown activities such as boron injection.

Example 6 - Step 201 of Flowpath 4 asks "Reactor vessel level steady or increasing". No direction is given as to the preferred source of level indication during a Station Blackout. The User's Guide lists circumstances when certain indications are unreliable and these are supposed to be known by the operators. If a preferred instrument existed for use during a specific situation, that instrument should be specified on the flowchart to eliminate confusion.

The flowcharts were reviewed for clutter and ease of reading. While there did not appear to be any extraneous information on the flowcharts, concern exists about the amount of steps on Flowpath 4 (both revisions) and the quantity of individual branching lines on all the flowcharts. It was noted that Revision 4 consolidates individual branching lines into a single branching line, greatly improving the operator's ability to follow a particular flowpath. Additionally, the flowcharts are being significantly expanded in size, making the steps easier to read and the lines easier to follow. One concern rises though with the use of larger flowcharts. All the important charts and graphs (e.g. SP Heat Capacity Limit) are located under clear plexiglass on the EOP table top. The size of the flowcharts, when opened on the tabletop, made it difficult to access these vital diagrams. Also, the use of more than two charts was quite cumbersome with existing table top space.

Finally, the labeling to exit the flowpath was not consistent with the labeling on the tabs of the Revision 2 End Path Procedures. For example, one step directed the operator to "Go to the level restoration procedure in the Contingency Section of End Path Manual 1". However, the tab for this procedure in EPM-1 was labeled EOP-01-LRP. Time was lost as the operator thumbed through the tabs until he found the correct procedure. This inconsistency was also noted in the draft Rev. 4 procedures.

Also, consideration should be made for tabbing important sections of the User's Guide that provide clarifications of flowchart steps. For example, step 173 of Flowpath 4 inquires if there is an "EHC system malfunction". When asked, a CO could not state what constitutes an EHC malfunction except in a general sense. The operator stated clarification was provided in the User's Guide but could not locate it.

b. Local Procedures

Several local, normal, and emergency operating procedures were walked through with the operators. These procedures should be able to be performed in an expeditious manner under accident conditions. Observations are noted below:

Significant discrepancies were noted between the equipment designations used in the procedures and the actual labeling of the equipment in the plant. A detailed listing is provided in Appendix A. Also, confusion was exhibited by the operators as to which steps should be performed where and by whom. For example, Section 3 of LEP-03, Alternate Boron Injection required the coordinated actions of the Control Operator, the Auxilliary Operator and the Rad Waste Operator. Additionally, the SF stated he would give his copy of the procedures from the End Path [illegible] to the Senior Auxiliary Operator to use out in the plant. [illegible] at additional copies from the Control Room files wou[illegible] used in the plant so that he and the CO would have a copy to perform Control Room actions. These apparent inconsistencies should be reviewed and resolved.

LEP-02, Alternate Control Rod Insertion

When this procedure was walked through with a CO, he was unable to perform step 3 of Section 2 because he did not have the RPS test channel trip logic switch keys. He stated they were in the CO's desk drawer and that he would have remembered them in an actual emergency. There were many keys in the CO's desk drawer and the RPS test channel trip logic switch keys were not clearly labeled for easy identification during an emergency.

The operator was then asked to perform step 5 of Section 2 which required pulling the fuses to deenergize all scram pilot valve solenoids. This time the operator did not bring fuse pullers with him. He again stated he would have remembered them in an emergency. Fuse pullers were kept in two locations near the Control Room, neither of which was very accessible during an emergency. The pullers expected to be used in this situation were located in a locked drawer under the EOP table in the Control Room. The key to this drawer was maintained in the SOS office outside the Control Room. It was stated that this drawer was not routinely unlocked when the EOPs were entered, but "as needed". As a result, required equipment was not readily accessible to the operator for use during this procedure. The other location for fuse pullers was in the SOS office and was the most likely place they would be obtained; however, they were subject to availability.

The licensee should reconsider the logistics of handling equipment vital to the performance of Local Emergency Procedures. Additionally, consideration should be made for designating early in the procedure the equipment needed to satisfactorily perform its steps.

LEP-03, Alternate Boron Injection

Three of five alternate boron injection paths were walked through with plant operators per LEP-03. They were as follows:

- RWCU via SLC tank (Section 1)
- Condensate System (Section 2)
- HPCI/RCIC (Section 4)

Again it would be advantageous if resource requirements, including manpower, were specified at the beginning of the procedure or the beginning of each section. Also, if there is a preferred order in the use of alternate boron injection paths, it should be noted in the OPERATOR ACTIONS (Section C) and listed in order of preference. Detailed observations are outlined below.

RWCU via SLC Tank (Section 1)

Step 3 of this procedure directed placing the RWCU system in service per OP-14. There was a contradiction in the prerequisites of this operating procedure (reactor level > 118 inches) and the potential condition of the reactor during the performance of LEP-03 (reactor level < 112 inches). The operator interviewed expressed confusion as to the implications of this contradiction and stated that he would do nothing without first contacting his foreman for guidance. Clarification is needed between the use of LEP-03 and OP-14 during emergencies.

Step 10.f, open or verify open valve SA-V395, required the operator to stand on the Precoat Pump motor. No ladder or steps were available as an operator aid.

Steps 17-21 directed the operator to install a submersible pump into the SLC tank to pump its contents to the RWCU precoat tank. The top hatch to the SLC tank was locked and required a key only obtainable from the SOS's office. The operator was unaware that a key was required to open the hatch. The pump is quite heavy and cumbersome with about 50-75 feet of heavy duty rubber hose. While it was logistically possible for just one operator to perform the steps of this procedure, it could more quickly and effectively be performed by two operators working as a team.

Condensate System (Section 3)

Neither of the operators interviewed showed familiarity with this procedure and both expressed doubt at being able to effectively perform the steps listed without additional assistance. The operators thought some of the steps would be performed by the Rad Waste Operator but were not sure which ones they were.

Step 4 directed the operator to open SJAE Condensate Recirculation Valves and maintain pressure in a prescribed band. There was no indication at the controller and no telephone close at hand to allow communication with the CO in the Control Room. It was stated that the CO would call over the PA system when pressure was in the correct range.

Step 5.d directed the operator to verify that the Condensate Booster Pump's auxiliary oil pump was running. The pump ran so quietly and the background noise was so loud that the operator admitted he had no way of verifying this step.

Some confusion existed as to whether any other steps in this procedure besides step 13 would be performed by the AO.

HPCI/RCIC (Section 4)

This procedure required the stringing of approximately 250 feet of heavy duty rubber hose from the 50 foot elevation to the -17 foot elevation. Again, consideration should be made of the manpower resources needed to effectively perform this section.

Step 1.b directed the operator to connect one end of the hose to the SLC tank drain line. This line possessed a fitting that was incompatible with the fitting on the hose. This step also directed that the other end of the hose be connected to the HPCI/RCIC CST Suction Vent Valve via a (contaminated) pipe chase. The logistics of stringing this heavy hose over and under the maze of piping and other components in the RCIC room was severe at best. The licensee should consider the feasibility of an alternative path such as down the stairwell to the RHR Heat Exchanger Room to accomplish this alternate injection path. The operator also could not find the HPCI/RCIC CST Suction Vent Valve.

Local Start of the Emergency Diesels

One operator stated that in an emergency, he could not locally start the diesel until the Control Room manually transferred control to LOCAL. It was noted that ASSD procedures allow local starting of the diesels without the Control Room transferring control. The licensee should consider the desirability of directing local control in a manner similar to that in the ASSD procedures.

Restart RPS MG Sets

The SF interviewed stated that restarting the RPS MG sets would take only a couple of minutes since they were located just down the stairs from the Control Room. An AO was asked to walk through his actions if directed by the CO to "Restart the RPS MG sets" in an emergency. He attempted to locate the correct procedure but required assistance from the CO. When asked if he needed the procedure to do this operation in an emergency, the operator said he did because he didn't know the procedure well enough to perform by memory. Upon locating the correct procedure, the operator was able to walk through the steps in a satisfactory manner. However, the entire process required nearly 15 minutes to complete.

EOP-01-SRP-ISA

This procedure directed the recovery of the Instrument/Service Air System.

Step C.2 directed the operator to open service air valve SA-V7 which required the operator to climb on a service air pipe about 4 feet off the floor. No reach rod, steps, or ladder were available as an operator aid for this step.

Steps C.7-C.10 listed contingency steps for additional actions with an implied priority; however, the contingency sections exhibited poor human factors consideration in that they were not organized in the same priority order.

Overall the operator was able to locate and walk through the steps specified in Sections 1-3 of this procedure; however, his performance was severely hampered by imprecise directions such as "check closed the service air header isolation valves" without specifying a valve label and number so he could verify he was checking the same valve intended by the procedure.

c. Training

Requalification training on the plant specific simulator was observed on the use of the new Rev. 4 EOPs. While it is understood that this was the first use of these procedures by the operators, some concerns were noted.

During a full ATWS, the SF stopped all mitigation activities at step 051 of Path-1 and waited for LEP-02, Alternate Control Rod Insertion, to be performed prior to entering Level/Power Control and injecting Boron. Path-1 required entry into Level/Power Control if reactor power was greater than 3% but did not allow for first completing LEP-02. The operator waited approximately 5 minutes without seeing positive results from LEP-02 before continuing with Path-1 and entering Level/Power Control.

There appeared to be some lack of understanding as to the basis of some flowpath steps. For example, one CO did not understand why Core Spray was not to be used during an ATWS while another operator did not understand the step for controlling SRV cycling. Additionally, while performing the Flooding Procedure, step 10 directed the operator to terminate injection from all sources but the operators failed to consider CRD and SLC injection flows.

The simulator exhibited some modeling deficiencies during the training session. During an ATWS with a concurrent loss of High Pressure Coolant Injection, the simulator was unable to correctly model reactor vessel level and, when emergency depressurization was performed, the reactor pressure could not be reduced below 300 psig. It was also noted that Suppression Pool level indication was modeled as being powered from an incorrect electrical bus. Additionally, the plant computer simulation was unavailable and information had to be fed to the trainees by the instructor. All the above factors rendered the training effectiveness of this particular scenario marginal.

d. EOP Documentation

The Brunswick EOP basis documentation was reviewed and discussed with the site EOP engineer. The following deficiencies were noted.

Entry into the flow charts was via "any scram or any condition that should result in a scram". The operator would pick up any one of five flowpaths and, through a priority screening process, be directed to the correct flow chart. As a result, the site does not concurrently perform actions for power, level and pressure control according to the BWROG guidelines. There was no site documentation available that provided justification for why this method was a satisfactory exception. This item will be identified as IFI 50-324,325/88-19-03. This justification was requested by the NRC when the Procedure Generation Package was originally submitted for approval.

Under the current EOP revision (Rev. 2), primary and secondary containment control as well as radiation release control were not addressed until near the end of the flowpath. It was noted that Revision 4 will make each of these a separate flowpath to be performed concurrently with the main flow charts.

Documentation for converting BWROG guidelines to PSTG existed but the conversion from the PSTG to the flowcharts lacked any documentation. Steps that were accepted in the PSTG verbatim from the BWROG guidelines did not appear in the flowcharts and steps existed in the flowcharts that are not documented as to the overall safety impact on the flowchart organization. The licensee had recognized these deficiencies and had taken steps to fill the documentation gaps in Rev. 4. The adequacy of this documentation, now in draft, was not reviewed. This item will be identified as IFI 50-324,325/88-19-04.

Rev. 4 is scheduled to be implemented by mid December 1988. Incorporated in Rev. 4 are the most recent changes to the BWROG ERGs as well as improvements recommended by the plant operators and private consultants. It contains what the NRC considers significant improvements to the current method of diagnosing and mitigating plant emergencies. The licensee was encouraged to maintain or improve their planned timetable for conversion to Revision 4.

The concerns raised by this preliminary EOP assessment will be addressed in a comprehensive EOP inspection to be performed in the Fall of 1988.

4. Maintenance Support of Operations (62700, 62702)

The inspectors evaluated the licensees maintenance program, paying particular attention to the interface mechanism with the operations department, root cause analysis, and repetitive failure identification. During the inspection effort the inspectors: conducted interviews with workers and supervisory personnel; reviewed station maintenance procedures, work requests, maintenance backlog, completed maintenance work packages, and operating and maintenance experience reports; and analyzed the maintenance planning and scheduling process, the preventive and predictive maintenance programs, and HPCI system availability to determine the effectiveness of the licensee's maintenance activities in support of safe plant operations.

a. Maintenance Work Initiation and Planning

The licensee used a computerized work request system with terminals throughout the plant and offices. This ease of access fostered a participation in the correction of plant problems by nearly all levels of personnel. The inspectors reviewed the procedure for the use of this system: Maintenance Procedure MP-14A, Corrective Maintenance (Automated Maintenance Management System), Rev. 7. Under this AMMS system, all work performed by maintenance personnel was accomplished under a WR/JO, including preventive maintenance.

MP-14A required that any plant employee who discovered a nonconforming condition to plant equipment should initiate a troubled tag (part of which was hung on the equipment) and should initiate a WR/JO (by having information entered into a computer terminal). If a direct safety hazard was involved, the SF was to be immediately notified. A detailed description of WR/JO initiation, prioritization, planning, execution, and postwork action was included in MP-14A.

Maintenance planners had recently been reorganized into a separate group in the maintenance department. This was a result of the BNP Maintenance Planner/Analyst Review completed in August, 1987 by Manpower Planning & Analysis of CP&L. This review appeared to be quite thorough, and was primarily focused on efficiencies and manpower savings. The licensee made a number of observations and recommendations in the review, including:

- Voiding of WR/JOs: 16% of all tickets completed in 1987 had been voided, mostly due to duplicate tickets. Operations personnel need more training in initiation of WR/JOs, to avoid duplication.

- Prioritization: To keep down the backlog, planners plan easiest jobs first. Consider a better priority system for planners.

- Complete Planning: More than half of the planners felt that 50% or more of their WRs were not thoroughly planned. More planner field visits are needed.

- Parts: Parts information was not fully loaded into the EDBS, which is part of AMMS. Planners spend too much time on parts identification and sourcing. Expedite loading of all parts information into EDBS.

- Training: Planners need training in Q list, ISI, EQ. No established training program exists for planners in these areas.

- Source Documents: Vendor manuals are all on microfiche in the maintenance library - indexing and readability need improving.

The new planner foreman stated that he was formulating a plan and schedule for accomplishing the needed improvements.

Through interviews with planners, the inspectors observed weaknesses in WR prioritization and planner training. The order of processing WR/JOs by planners appeared to be based heavily on their judgement, and appeared to include the following factors:

- Verbal requests by the planner foreman or operations personnel.
- The plant system outage schedule.
- Q list items, which were receiving special management attention.
- Easiest to plan, to keep down backlog.
- Heavily weighted toward planner's judgement.
- Virtually the last consideration appeared to be the priority assigned to the WR/JO, as specified in MP-14A.

One planner had on his computer backlog of WRs to be planned one priority 2, many priority 3, and a few priority 4 WRs. The priority 2 WR was for a personnel safety cage to be installed on a ladder to the HPCI roof. The planner stated that he knew that no safety cage had been on that ladder for years, and planned to work on other priority 3 and 4 WRs ahead of that priority 2. Overall, the inspectors observed that the actual order of working on jobs did not seem to correspond to the priority numbering system described in MP-14A. Also, individual planner judgement seemed to be an important factor in selecting which jobs to work first vice the priority assigned to the job.

In summary, two weaknesses were observed in the WR/JO planning/scheduling area:

- The WR/JO priority system described in MP-14A did not compare well with how planners actually organized their work. A substantial amount of planner judgement was involved in selecting which items to work first.

- The licensee did not provide all planners with specific training in the areas of ISI, PMTR, work prioritization.

Resolution of these two weaknesses will be identified as IFI 50-324,325/88-19-05.

b. Maintenance Scheduling

Planners would print out copies of planned PM WR/JOs, per the computerized PM schedule, and copies of planned corrective maintenance WR/JOs and forward them to the maintenance crew foreman. The crew foreman would then make proposed work schedules for the next two weeks. These proposed work schedules were then reviewed and approved by the SWFCG. Also included in the SWFCG scheduling review were surveillance tests and plant modifications.

The inspectors attended a SWFCG meeting and reviewed SWFCG procedures, including: SWFCG Charter of Nov. 1986; Site Work Force Control Guideline 3, Scheduling of Work, Rev. 2; Site Work Force Control Guideline 4, Preapproving WR/JOs/Plant Modifications, Rev.0; and Site Work Force Control Guideline 5, Controlling Radiation Exposure and ALARA Documentation, Rev. 1. The SWFCG included representation from each of the following organizations: Operations, Maintenance, Technical Support, E&RC, Administrative Support, Outage Management, QA/QC, and Engineering Construction. Each representative was to be empowered to make commitments for their organization. The SWFCG meeting went smoothly, and the group appeared to be effective in scheduling the maintenance work. The fact that some improvement had been made in the large maintenance backlog over the last year was credited largely to the effectiveness of the SWFCG. The SWFCG scheduling of maintenance was considered to be an area of strength for the licensee.

c. Automated Maintenance Management System

This computerized system had been identified as an area of strength during the last SALP period. Since then, the system had been expanded to cover more than corrective maintenance work requests, machinery history, and repair parts inventory. Specifically:

- PM program coverage in AMMS had been completed. Now all PMs are in the computer memory, in work request form. Also, AMMS automatically scheduled PMs for their next due date;

- PMTR had been added to AMMS;

- EDBS information continued to be added, such as: equipment I.D., manufacturer, model no., technical manuals, drawings, technical manual parts list and CP&L part number. Information to be added included: EQ by Nov. 1988, Q list by mid 1989, and ISI by mid 1989.

- Maintenance procedure revision requests and temporary changes were in the computer, available for access by any procedure user.

- Surveillance Test scheduling was now done by the computer system.

- LCO tracking was also done by the computer system.

The AMMS computer system continued to be an area of strength for the licensee.

d. Maintenance Work Backlog

The inspectors reviewed maintenance department goals for the work request backlog, and performance during 1987/88 toward meeting those goals. Also, the WR/JO backlogs of two planners and one maintenance crew foreman were reviewed. The safety concerns with a large WR/JO backlog are twofold:

1. Regular review of outstanding WR/JOs could become difficult, and some important repairs to safety equipment could receive inadequate attention and as a result not be completed in a timely manner.

2. The accumulation of a large number of needed repairs to non-safety (not on Q list) equipment could cause some reduction in overall plant safety.

The maintenance department goal for WR/JO backlog was: "Achieve and maintain the percentage of outstanding non-outage work requests greater than three months old at or below the industry median of 52.9 percent." Maintenance department records for 1987/88 demonstrate that performance toward meeting this goal has been poor, and that no improvement has been made during this period. This information is contained in Appendix B.

As part of a plan for reducing the number of safety items in the WP/JO backlog, the maintenance department in 1987 charted WR/JO backlog for corrective maintenance on ECCS systems. This chart exhibited a decrease from approximately 590 in November 1986 to approximately 340 in November 1987. An accompanying chart of open ECCS WR/JOs greater than 3 months old showed no substantial improvement, from approximately 62% in Nov. 86 to approximately 78% in Dec. 86 to approximately 62% in Nov. 87. In 1988, the licensee changed the chart to track total Q list WR/JOs. The backlog started at 1163 in January, decreased sharply to approximately 900 in April, then decreased to approximately 852 in June 1988. An accompanying chart of Q list WR/JOs greater than 6 months old showed a decrease from 476 in January to 361 in April, then an increase to 390 in June 1988. The licensee stated that in July 1988 the monthly charts will be changed to show Q list WR/JOs greater than 3 months old.

Overall, the licensee appeared to have made some improvements in the numbers of backlogged Q list WR/JOs, and in the total WR/JO backlog. However, this backlog continued to be large and to contain a high percentage of old WR/JOs.

The inspector reviewed the items in the WR/JO backlogs for the unit 1 reactor systems I&C maintenance crew, the unit 2 reactor systems mechanical planner, and the unit 2 reactor systems electrical planner. These backlogs were tabulated by age (year initiated) and by priority. The licensee uses a priority system of 1 through 4, with 1 being the highest priority and 4 being the lowest. The priorities are described in procedure MP-14A. These figures are also contained in Appendix B.

The tables in Appendix B show a substantial number of old high priority (2) WR/JOs. The 14 oldest priority 2 WR/JOs from the unit 2 electrical planner were selected for further review. For safety related equipment with control or alarm functions, the inspector investigated further to determine current status.

| WR/JO No. | Equipment | Waiting for |
|---|---|---|
| 85-AJIF1 | CAD vaporizer B flow recorder | Ops to void |
| 85-AFWQ1 | RBCCW rad. monitor (to be worked under WR/JO 87-BCYR1, which is waiting to be scheduled. Meanwhile, ops is taking manual samples) | Ops to void |
| 86-BPMY1 | Total jet pump flow recorder | Parts |
| 86-BZYC1 | Reactor recirc. flow recorder | Parts |
| 86-BPMW1 | Reactor recirc. temp. recorder | Parts |
| 86-BNUG1 | Watt transducer for 2B recirc. pump MG set | EWR |
| 86-AULD1 | 2-E21-PI-R601A needs cal. for unit 2 S/U P.T.s (Ops uses temporary gages) | Ops clarification |
| 86-BBWU1 | Drywell pressure switch needs cal. | M.I. |
| 86-AQHL1 | Drywell pressure transmitter needs cal. (M.I. written for above 2 WR/JOs. These are not Q list, are redundant sensors, provide alarm and indication but no control function) | M.I. |

| | | |
|---|---|---|
| 86-BEGX1 | DGB door from SWGR room to airlock (doors 203 & 204 will not work electrically as designed) | EWR |
| 86-ARHX1 | Drywell H2 inlet flow transmitter (M.I. written. Not Q list) | M.I. |
| 86-BTWU1 | Vibration detector needs bracket | EWR |
| 86-BHDB1 | RCR MG sets winding temp. recorder | See repair inst. |
| 86-BSAK1 | RCR MG sets winding temp. recorder | Ops to void |

Of these 14 old priority 2 WR/JOs, none presented immediate safety concerns for plant operation. (However, a lack of management attention to old priority 2 WR/JOs was apparent).

The unit 2 mechanical planner backlog of old WR/JOs was scanned for items that might potentially present plant safety concerns. Three were selected:

| WR/JO No. | Equipment | Waiting for |
|---|---|---|
| 86-AWME1 | Drill hole in handwheel, so valve can be locked, as req'd by OP-24 (This WR/JO was initiated on 5/20/86. On 6/25/86, a mechanic went to work on it and found the valve locked, with a hole in the handwheel. The WR/JO was then sent to ops to be voided.) | Ops to void |
| 86-AMJI1 | Scram air header pressure high (The concern here was that this air is used in ASCO solenoid valves, which have been found to be susceptible to failure when exposed to high air pressure. Actual scram air header pressure in the plant was checked and found to be in the normal operating range. Maintenance history showed that the regulator had been adjusted by I&C maintenance.) | Parts |
| 86-BNEL1 | Bracket for E41-LSH-N015A missing a bolt and a hole. This is an NRC concern. (This level switch monitors torus level, and feeds an alarm and a valve interlock with the F042 valve - HPCI alternate suction. This instrument was not Q list, and was redundant with N015B.) | EWR |

No immediate plant operability safety concerns were identified in these three WR/JOs.

In summary, no immediate plant safety concerns were identified in the selected old work requests. However, some weaknesses in backlog management were identified:

1. An excessively large percentage of backlogged WR/JOs were old.

2. There had been an apparent lack of management attention toward completing work requests in a timely manner, including priority 2 WR/JOs.

3. The maintenance work request priority system includes no guidelines for timeliness (except for priority 1), nor any requirement for management review of WR/JOs that are old.

e. HPCI Reliability/Availability

During the previous SALP period, HPCI unreliability/unavailability was a continuing problem area. Safety related valve failures were the primary contributors to HPCI unavailability. During the current SALP period, HPCI unavailability due to valve failures has not improved. According to the licensee's records, the history of HPCI unavailability has been:

| Year | HPCI Unavailability Unit 1 | Unit 2 |
|---|---|---|
| 1982 | 7% | 21% |
| 1983 | 15% | 5% |
| 1984 | 20% | 34% |
| 1985 | 4% | 14% |
| 1986 | 15% | 29% |
| 1987 | 6% | 11% |
| 1988 (1st half) | 19% | 17% |

This unavailability included time out of service for maintenance and a calculated fault exposure time (half of the time from a failure to prior operability verification).

During this inspection, the licensee encountered several problems with HPCI valves, which contributed to HPCI unavailability.

| Valve | Problem |
|---|---|
| 2-E41-F002 | Operator error on 6/27 - Reactor operator reported valve inoperable due to thermal overload trip. Investigation showed there was no detectable mechanical or electrical problem with |

the valve, and no thermal overload trip occurred. Due to this reported problem and investigation, unit 2 HPCI was unavailable for about 3 days.

| | |
|---|---|
| 1-E41-F001 | Motor burned up on 6/30 - This motor had previously failed, and had been replaced, on several previous occasions, including: 5/28/88, 12/31/87, and 10/9/86. Cause of this failure was attributed to thermal binding, with contributing factors of design problems, including starting resistors. As a result of this valve failure, unit 1 HPCI was unavailable for about 4 days. |
| 1-E41-F006, 2-E41-F006 | Design inadequacies. After the F001 valve failure, a review of other HPCI valves for potential design inadequacies determined that the F006 motor was undersized, on both units. On 7/14, unit 1 was shutdown for installation of a larger motor on F006. Later in the month, unit 2 was shutdown, and a larger motor was installed on its F006 valve. |

The licensee had conducted an SSFI on the HPCI system during March 15 to May 15, 1987. The subsequent report was very detailed, and covered the areas of design, training, procedures, programs, reliability, maintenance, and testing. A total of approximately 179 items requiring further action or investigation were identified during the SSFI. Each item was prioritized and assigned to the applicable department for action and response by a specified due date. Additionally, each item was entered into the licensee's computerized CTS to facilitate followup. The inspectors selected seven of these items for review of current status. Of these items, four had been completed. The other three were past the original due date, and the due date had been extended. The seven items were:

| Item No. | Priority | Description | CTS Status |
|---|---|---|---|
| PGW-2 | 1 | Microfiche of tech. manuals not user friendly. Admin. action. | Closed. Better reader printer installed. |
| MW-11 | 1 | HPCI DC Bkr. PMs (over 50 amps) do not check thermal trips. Maint. action. | Closed. M-1 procedure revised. |
| DW-21 | 3 | IEB 85-03 calculations do not appear to account for voltage drop from battery bus to MOV. T.S. evaluate. | Due 4/30/88. Due date changed to 1/15/91. |

| | | | |
|---|---|---|---|
| DW-17 | 3 | UE&C study shows F008 torque less than 85% and used 10.8 H.P. for F007. T.S. evaluate. | Closed. OP-19 revised to minimize F008 dP. |
| DW-32 | 1 | Discrepancy between design basis and UE&C spec. for F012, F007, and F008 motors sizing. T.S. evaluate. | Closed. Reviewed, no prob. |
| DW-34 | 1 | Motors for F007, F008, and F012 potentially undersized. T.S. eval. | Due 5/31/88. Due date changed to 10/31/89. |
| DO-21 | 5 | FM-84-380 (381) did not consider industry exp. (SOER 84-07). T.S. evaluation(Plant mod moved F006 valve to inaccessible area. The SOER covered thermal and hydraulic binding of valves.) | Due 6/4/88. Due date changed to 12/8/88. |

The inspectors made further observations about the status of some of the above items:

1. Item PGW-2 was listed as closed. But the inspectors determined, through interviews and observations, that the current installation was not adequate. With only one microfiche reader-printer available for use by the entire maintenance department, delays were caused. Also, the quality of prints from the reader-printer was poor - some parts of the prints were illegible. The licensee stated that a larger maintenance library will be completed within the next three months. It will include two reader-printers and one hard copy of each technical manual. The other three items above (MW-11, DW-17, DW-32) listed as closed were not checked by the inspectors to verify adequacy of corrective action. The licensee stated that other HPCI SSFI items listed as closed will be reviewed for adequacy of corrective action.

2. The three items (DW-21, DW-34, DO-21) with due dates extended were all assigned to the technical support department. In a recent NRC inspection, Report No. 50-324,325/87-31, this department was identified as having an excessive backlog of EWRs to process. The inspectors noted on that inspection many of the old WR/JOs were being held up awaiting resolution of EWRs by the technical support department. It appeared that this department

may not be able to process its backlog of work in a timely manner. The EWR process was previously identified as being weak. This item will be addressed during a followup of items identified in NRC Inspection Report 50-324,325/87-31.

3. Changes to the due dates were made by the head of the department that was assigned the items. No other management review was required or was done. The licensee stated that additional upper management attention would be placed on timely resolution of the HPCI SSFI items.

The inspectors also observed that the licensees HPCI unavailability problem did not seem to have a simple remedy. The HPCI SSFI performed by the licensee in 1987 took three months and identified approximately 179 action items. Yet the HPCI problems that occurred during the two weeks of this inspection were not identified by that SSFI. These new problems included: thermal binding of F001, starting resistors in F001 and F006, and undersized motor on F006. SOER 84-7 described thermal and hydraulic binding problems in valves. In 1985, the licensee reviewed applicability of this SOER information to ECCS valves in normal/emergency plant operating conditions, but did not consider abnormal/maintenance conditions. Thus, the potential thermal binding problems of F001 were not identified. The licensee stated that SOER 84-7 will be reviewed again, for applicability to all plant conditions.

In the area of HPCI availability, the following weaknesses were observed:

1. HPCI unavailability continued to be high, with continued valve failures. Although the licensee had undertaken several initiatives toward improving HPCI reliability, no resultant improvement in the HPCI system unavailability had occurred through the first half of 1988.

2. Insufficient upper management attention and resources have been used to identify, evaluate, and correct the multitude of potential HPCI and other ECCS system problems in a timely manner.

f. Scram Reduction and Personnel Error Reduction

Through the use of PRA, the licensee had determined that unnecessary challenges to the plant automatic safety systems represented a significant contribution to overall plant safety. As part of a scram reduction program, the maintenance department had this performance goal: "Maintain the number of unplanned automatic scrams traceable to maintenance at or below the industry standard of 3 per unit per year." Recent performance had exceeded that goal:

| Unit 1 | | Unit 2 | |
|---|---|---|---|
| June 1987 | 1 | Jan. 1987 | 1 |
| July 1987 | 1 | Mar. 1987 | 1 |
| Total 1987 | 2 | Total 1987 | 2 |
| First half 88 | 0 | First half 88 | 0 |

In addition to the scram reduction program, an overall low personnel error rate has been achieved in the maintenance department. During 18 months of the previous SALP period, 11 maintenance department personnel errors resulted in LERs. During the first 12 months of the current SALP period, only 5 maintenance department personnel errors resulted in LERs.

Efforts toward scram reduction and personnel error reduction have included: an Incident Investigation Team, scheduling of most surveillance testing and maintenance activities during the weekday (when more supervision and support are available), procedure upgrades, the Operational Experience Report and Maintenance Experience Report programs for review of incidents, and training. The licensee expressed plans to implement a HPES for further improvement in followup of personnel error incidents for root cause determination and corrective actions.

The maintenance procedure upgrade program was started in 1986 and is ongoing. Using a corporate Procedure Administration Manual format, all surveillance procedures were upgraded first. This upgrade included a technical review plus use of a writers' guide. Maintenance procedures are being upgraded. At the time of this inspection, approximately 600 out of 2000 maintenance procedures had been upgraded. The maintenance procedure upgrade program is considered to be a licensee strength. During the procedure upgrades, outstanding procedure revision requests are incorporated. At the time of this inspection, a backlog of about 2380 maintenance procedure revision requests existed. At the rate of 1487 procedure revisions per year accomplished in 1987, and an average of 2 revision requests in each revision, this backlog represents about 1 year of work. This large 1 year backlog of procedure revision requests is considered to be an area of weakness.

The overall positive results of scram reduction and fewer maintenance personnel error incidents are considered to be a licensee area of strength.

g. Repetitive Failures

An analysis was performed of the licensee's program for repetitive failure analysis. The responsibilities of this program were described in SOP-02.40 dated 5/27/88, Rev. 1.1. The instructions on the determination and identification of repetitive failures were delineated in MP-14A, Corrective Maintenance, section V.8.d., Rev. 7. Interviews were conducted with maintenance planners, who had the responsibility for identifying Q-list repetitive failures; and personnel from the maintenance engineering department, who had the responsibility for analyzing the information and disseminating it to the PNSC for review.

The repetitive equipment failure identification program had only been implemented since November 1987 and as a result had insufficient time to establish a record of corrective actions taken as a result of identified repetitive failures. Because of this, the program was primarily reviewed for scope, format, an understanding of responsibilities of the parties involved, and their abilities to perform their functions, particularly those of the maintenance planner.

Maintenance planners use the AMMS to perform a review of historical data for the WR/JO that they are planning. The planner inputs the tag number and calls up all WR/JOs connected with the tag number for both Units. Any failures that are similar in nature that have occurred in the past 18 months will be flagged as "repetitive" and be noted as such in the planning field. The "keyword" repetitive will also be used to identify the WR/JO for future reference. If the planner or foreman recognizes the failure as repetitive, although it was not identified as such via the tag search, they are instructed to flag the WR/JO as repetitive in that it would be useful in identifying repetitive failures that may not appear in AMMS historical data. The most recent (up to three) and appropriate WR/JOs with similar failures shall be listed in the repair instruction. If a repetitive condition is discovered after the WR/JO is printed out for work, the planner will write in that it is a repetitive failure, and this will be entered into the AMMS upon completion and review of the WR/JO.

In order to assess the effectiveness of the process by which the planners were flagging repetitive failures, the inspector did a review using the AMMS to perform historical searches on equipment that was of interest because of past performance (HPCI valves, RCIC valves) or exhibited failure modes during the inspection period (RHR valves). The brief period of time that the repetitive failure program had been implemented limited the scope of the audit. However, the problems with the HPCI valves had been flagged with the keyword repetitive, although only for failures that had occurred since November 1987. In addition to the AMMS review, the inspector interviewed several planners and observed their actions as they planned WR/JOs. All of them performed the requisite history searches to determine if the failure for which the WR/JO was written was repetitive. During the review, the inspector found no evidence that repetitive failures had not been noted as such.

The Maintenance Engineering department performed the collection and analysis of the AMMS data for repetitive failures for presentation to the PNSC on a monthly basis. The inspector reviewed one of these reports dated 7/14/88. The report contained a listing of component failures as well as part failures. The parts failures were determined through the use of the EDBS and were flagged if they were used more than three times in the past 18 months. While all of this made for a comprehensive package listing potential repetitive failures, the list was rather large (189 component failures and 89 part failures) and may have contained more information in too general of a format for the PNSC to effectively review and act upon.

Overall, the licensee's program for performing equipment failure trending and analysis had been implemented, but it lacked a track record of performance and results that would provide an adequate basis for determining its success or failure.

h. Post Maintenance Testing

The licensee's methods for accomplishing post maintenance testing were contained within MP-14A, Corrective Maintenance, Rev. 7. The identification of the components that were contained in the scope of the In Service Testing program and their post maintenance requirements were described in ENP-17, Pump and Valve Inservice Testing, Rev. 4. Also reviewed was ENP-16, Procedure for Administrative Control of Inservice Activity, Rev. 24.

The inspector reviewed the above procedures as to their effectiveness in accomplishing the acceptance testing for equipment that had undergone corrective or preventive maintenance. The inspector also audited both planned and completed WR/JOs to assess the quality of the work packages. Planners were interviewed and observed to assess their understanding of and abilities to determine the requisite post maintenance testing for any given WR/JO.

The following WR/JOs were reviewed for the adequacy of the post maintenance testing and its applicability to the maintenance performed as well as the function of the component:

| WR/JO # | COMPONENT |
|---|---|
| 88-AQLF1 | Service Air Compressor 1D |
| 88-ANYP1 | Condensate Booster Pump Motor 1A |
| 88-ALWK2 | Instrument Air Dryer Tower A |
| 88-ALSB1 | TBCCW Hx A Service Water Inlet Valve |
| 88-AMHN1 | Oil Cooler 2B Inlet Isolation Valve |

| | |
|---|---|
| 88-AQRZ1 | Service Air Compressor 1D |
| 88-AKSK1 | Air Compressor 1D Discharge Valve |
| 87-AELA1 | RHR Service Water Pump 1A Motor |
| 87-BBIB1 | RHR Pump 2B Motor |
| 87-BFDY1 | RHR Hx 1A Outlet Valve Motor Operator |

The inspector questioned and observed planners as they processed WR/JOs, completing the sections on PMTR. All documents that a planner needed to aid them in their planning of PMTR were readily accessible. In many cases the procedures called for in the WR/JO also contained the PMTR under the section titled "Acceptance Criteria". All reformatted procedures after Revision 1 of MP-52 will contain this section which conveys "what should be done when the procedure is performed under routine circumstances." No problems were noted in this area of review of PMTR implementation.

i. Maintenance on Motor Operated Valves

As detailed in other sections of this report, the licensee has experienced numerous problems with MOVs. The inspector performed a review of the licensees maintenance programs that have been implemented or proposed to address these problems from a maintenance standpoint. Procedures and plans that were reviewed in this area were: MP-57, Limitorque Valve Failure Analysis and Troubleshooting Procedure, Rev. 2; MP-60, Valve Failure Analysis Guide, Rev. 0; [illegible]005, Motor Operated Valve Actuator Diagnostic Test, Rev. 2; Project Plan for Improved Maintenance of Valves and Valve Actuators, dated [illegible]8/87; and Supplement to Project Plan for Improved Maintenance of Valves and Valve Actuators, dated 6/24/88.

The Project Plan was initiated in response to industry wide concerns about valve reliability, problems encountered at the Brunswick plant, and NRC IE Bulletin 85-03 on MOV common mode failures. The Project Plan thoroughly outlined goals and the means to achieve them. It included both MOV actuators and pneumatic actuators as well as the valves themselves. Among the improvements described were the development of highly skilled maintenance personnel, procurement of diagnostic equipment, expansion of predictive and preventive maintenance, increased spare parts inventory, and improve quality of air supply. Also detailed were upgrades and expansions on maintenance procedures, enhancement of the availability and quality of technical data, a proposed predictive maintenance schedule, and a HPCI/RCIC valve parts inventory list. The Project Plan appeared to be very well thought out and the inspector noted that nearly all of the proposed actions had been implemented (procedure upgrades, technical information, expansion of predictive and preventive maintenance, and the implementation of valve diagnostic testing).

The licensee recently completed a supplement to this project plan. This supplement discussed the generation of a list of all valves that were essential to plant operation that are active during an accident condition. A task force will review all failures to ensure root cause determination and that proper actions have been taken. This supplement was essentially an enhancement of the previous plan, most importantly though was its emphasis on root cause determination and proper corrective action followup. This Project Plan and its supplement was considered a strength in the area of MOV problems, although the time that was required for the licensee to react to apparent problems, evidenced by the licensees HPCI SSFI, was considered a weakness.

The licensee had two procedures that deal with valve failure troubleshooting, MP-57 and MP-60. The only difference between these two procedures was that MP-57 was directed specifically at Limitorque operators while MP-60 was a more general valve failure procedure. Both procedures were relatively new, MP-57 having been originally approved on 7/29/87. Again it is difficult to judge these programs since they were only implemented recently, especially when the licensee continued to have problems with their valves. This emphasis on troubleshooting would have been considered a strength if there had been evidence of improvement in the areas of root cause failure identification and the reliability of the valves.

The final area of review for MOV maintenance was in the efforts put forth to procure and employ MAC testing equipment. This equipment was similar to the more commonly used MOVATS. The MAC system that the licensee employs does not use a thrust measuring device. Instead, it measures the maximum current of the motor which provides an indirect indication of the thrust. The licensee plans to use a thrust measuring device as soon as the manufacturer of the MAC system, Limitorque, completes development of it.

The licensee has developed teams to perform this testing. During the inspection period, the licensee had some difficulty with some of the equipment and was also in the process of upgrading the computer component of the system Nevertheless, the licensee successfully demonstrated the MAC system upon testing of the Unit 2 E41-F006 valve that had recently undergone motor replacement. Overall, the MAC testing was determined to be a strength.

The assessment of the licensees MOV maintenance program concentrated specifically on the programs that were designed to improve the degree of scrutiny on MOV performance. These programs did a good job of addressing the problems that had occurred in the past and will continue to occur in the future. It is difficult to assess the success of the programs due to their recent implementation, but in final analysis, the licensee had taken the adequate first steps to address this problem area, and with continued vigilance, should succeed in gaining control of it.

j. Preventive and Predictive Maintenance Programs

The preventive maintenance program was established under procedure MP-10, Preventive Maintenance Program, Rev. 29. Section 3 of the Maintenance Management Manual, Preventive Maintenance Route and Work Order Procedure, Rev. 1, detailed the maintenance manager's responsibilities in implementing their respective PM programs. The inspector reviewed these procedures and interviewed maintenance planners to assess the extent and thoroughness of the licensees PM program.

The maintenance program staff along with the maintenance supervisors determined what PMs were to be performed as well as their frequency based on the following criteria:

- Criticality of the equipment;
- Equipment maintenance history;
- Equipment operational history;
- Historical maintenance cost;
- Industry recommendations;
- Manufacturers recommendations.

The maintenance foremen are responsible for implementing the weekly PM schedules and initialing schedule revisions. Any PMs that cannot be performed, for whatever the reason, must have a completed PM exception form detailing the specific reasons why, and these reasons must also be noted in the comments section of the WR/JO. If the completed PM does not meet the acceptance criteria, and a corrective maintenance WR/JO has been initiated, then a PM exception form need not be issued. A completed PM exception form is forwarded to the maintenance supervisor for review and approval. The PM package is then returned to the foreman who then forwards it back to the maintenance planner for rescheduling. At the time of the inspection only 7% of the PMs were overdue. Overdue PMs are used as a factor in employee performance evaluations, so there is incentive for pursuing overdue PMs.

The PM program encompassed all equipment designated as Q-List, any regulatory related instrumentation as well as other equipment designated by maintenance supervisors. The program had adequate provisions for adding new equipment, revising PM instructions, or changing the frequency of PMs. The program appeared to adequately implement and address PM concerns.

Predictive maintenance was still in the formative stages at the plant. During the inspection, the licensee was performing a comprehensive schedule that included pumps, traveling screens, motor generators, air compressors, and diesel generators. There were plans to perform thermography for breakers and acoustical monitoring for valves, but these had not advanced beyond the project plan stage. In response to INPO SOER 86-3 on check valve failures or degradation, the licensee had formulated a project plan to assess check valve reliability.

The licensee had a program for sampling and analyzing lubricating oils. The inspector reviewed MI-10-500I, Maintenance Instruction for Oil Analysis Report, Rev. 2; and Volume 8 of E&RC-1145, Sampling and Analysis for Lubricating Oils, Rev. 6. These procedures detailed the methods and schedules for sampling lubricating oils. The inspector found this program, as well as the rest of the predictive maintenance program, to be comprehensive, aggressive.

Within this area, no violations or deviations were found.

5. Management Controls (40700)

The subject of plant management controls was reviewed in order to assess the adequacy of the following areas:

- Management assertiveness and control.
- Coordination of activities between plant groups.
- Accuracy of plant status information conveyed in plant status meetings versus actual plant status.
- Participation by attendees in plant status meetings.
- Adequacy of LERs and threshold for writing.
- Interface between plant groups.
- Resolution of previous problem areas.
- Time spent by plant manager reviewing the status of various plant areas such as operations, maintenance, training, engineering, and plant housekeeping.

a. Plant Status Meetings

Selected daily plant status meetings were attended to determine the adequacy of:

- Interface between plant groups.
- Accuracy of status information.
- Participation by attendees.
- Management assertiveness and control.

It was observed in most of the meetings attended that there was a lack of substantive participation by most meeting attendees. The meetings were terse restatements of plant status with little, if any associated discussion. This was despite the fact that on some occasions, safety significant issues with associated operability concerns were mentioned but were not resolved nor was definitive direction given to bring about expeditious resolution.

As an example, in the meeting of June 28, 1988 it was announced that Unit 2 HPCI steam supply valve F002 had apparently tripped on thermal overload on the evening of June 26 when the operators were attempting to place the system in standby readiness. It was also stated in the meeting that the thermal trip device was thought to have been found set at 125%. The acting plant manager stated that he thought the thermal trip should be set at 300% of full load. Since none of the licensee personnel present at the meeting knew the correct set point, nor in retrospect actual plant status, the acting plant manager elected to have technical services personnel obtain further information relative to the event and report same at the morning meeting the following day. There was no mention of the possible inoperability of Unit 1 HPCI Valve E41-F002 or for that matter any other valve with thermal trip devices installed.

Later that day, the inspector found out that on the day before, Monday, June 27, licensee technical staff had performed testing on valve E41-F002 which verified that the thermal device was set properly. Furthermore, the trip set point was actually set at a value of about 166% full load. The trip setpoint was the result of what had been described as a programmatic, facility wide engineering effort to come up with realistic setpoints which protect the cable and associated circuitry. It was of interest to note that management present at the morning meeting were obviously not aware that this analysis had been performed nor that the relative actions were implemented.

The inspectors observed that 1) when faced with a possible operability question, no assertive action was taken; and 2) management was not totally aware of current plant status.

Later in the day on June 28, during the licensee's investigation into why the valve had apparently tripped it was concluded that the probable cause was a rapid "jogging" open of the valve by the operator. Testing to confirm this hypothesis was not performed yet based on that assumption, the valve was returned to service and an operations standing order was implemented describing an acceptable method of "jogging" the valve.

In the morning meeting of June 29, 1988, the operations manager reported that valve E41-F002 had been returned to service based on the aforementioned testing and the issuance of the standing order. Neither the extent of the testing, validity of the testing, test results nor the standing order were challenged.

Also discussed in the morning meeting of June 29, 1988, were certain nuclear service water pressure switches which control cooling water for the diesel generators. It had been determined that these switches were seismically inoperable which in turn was to result in a realignment of nuclear service water as compensatory measure.

The information relayed in the meeting was quite terse and virtually devoid of technical detail. Comments in the room indicated that this was the first time some of the meeting participants had heard of the issue, yet there were no questions nor discussion relative to the technical validity of the basis for the compensatory measures. It should be noted that the technical validity was indeed flawed in that the nuclear service water realignment scheme had not adequately addressed single failures. Details of this concern are documented in inspection report 50-324,325/88-21.

In terms of management assertiveness and control, the inspector detected a marked difference between meetings chaired by an acting plant manager and those chaired by the plant manager. The plant manager appeared to be much more interested in and attuned to the technical details and safety complications to events than was the acting plant manager mentioned previously.

With respect to management awareness, more details relative to management's processing of the F002 problem can be found in inspection report 50-324,325/88-21.

In conclusion,the following items were identified as weaknesses:

- The accuracy and adequacy of status information versus actual plant status.
- Participation by attendees in the plant status meetings was minimal.
- Management assertiveness and control varied widely dependent on the subject.

b. Management Involvement

The inspector reviewed Plant Notice PN-15, Backshift and Weekend Management Review, Rev. 20. This notice provides guidelines for the conduct of backshift and weekend visits by plant management to assess safe plant operations. This PN indicates that a list of personnel (Managers, Directors, and Supervisors) will be promulgated by the GM to conduct tours on a weekly basis. Upon completion of the tours, the assigned individual will record and submit their observations to the GM for review.

The inspector reviewed completed tour documentation for the period of 1/4/88 through 7/10/88, a period of 26 weeks. The results of this review indicated that five tours were assigned to managers. Of these tours, one was not accomplished (no documentation), one was performed by a subordinate level supervisor, and the other three were accomplished by the managers. Two other tours were assigned to director level personnel and one of these was performed by a subordinate level supervisor. Three tours by managers and one tour by a director during 26 consecutive weeks reflects adversely on the licensees commitment and initiative towards obtaining excellence in plant operations. Station Managers do not appear to be touring the plant on a frequent basis, nor getting involved. This is also substantiated by a review of security access records.

Additionally the inspector noted that five of the twenty-five documented tours were not signed by the GM as being reviewed. PN-15 indicated that tour sheets will be submitted for his review, but it does not require that the GM will/shall sign the sheets, but the implied intent is that the GM will somehow acknowledge his review and satisfaction with the tours.

In order to evaluate management's direct involvement in and oversight of control room and plant activities, the inspector requested a printout of security computer transactions to determine how often and for how long key members of management accessed the protected and vital areas.

Analysis of the printout revealed that upper level management's involvement in the plant is less than optimum. In fact, it was noted that one key member of the management team had not been in the protected area since April. A brief analysis of the period spanning May 27 through July 11, 1988 revealed that upper level management, superintendent and above, which in this case was 6 individuals, spent collectively 411 hours and 25 minutes in the protected area out of a possible 1536. If the Operations Manager and Maintenance Managers, whose offices are inside the protected area are extracted from the analysis, the remaining managers collectively spent 31 hours and 20 minutes inside the protected area, or an average of approximately 8 hours each. This equates to about 3% of the available time using 32 eight hour days as a base.

The lack of Managements direct involvement in plant activities was considered a weakness.

c. Management Involvement In HPCI SSFI:

Brunswick Plant Management called for a self-initiated SSFI on the HPCI System in early 1987. A multi-disciplined team performed the SSFI between March 15, and May 15, 1987. The stated purposes of the SSFI was to; (1) evaluate the HPCI system design bases, (2) identify design and programmatic problems, (3) report strengths and weaknesses impartially, and (4) gain insight into the SSFI process. The SSFI was conducted using the NRC guidelines for SSFIs and focused on areas where NRC SSFIs had found weaknesses.

The licensee's inspection found weaknesses in:

(1) Motor (MOV) sizing.

(2) Breaker PMs not performed.

(3) De facto modifications without adequate evaluation.

(4) Conflict between documents regarding Design Bases or Limits.

(5) Potential design deficiencies.

(6) Procedure errors.

(7) Vendor recommendations not addressed.

(8) Throttle valve logic.

(9) Internal wiring drawings not updated.

(10) Lack of defined designing bases for some components.

(11) System reliability.

Of concern to the NRC was the fact that the SSFI was completed over a year ago, yet HPCI was still unreliable not to mention the serious safety implications that each of the above weaknesses entailed and which were yet to be fully resolved.

More detail relative to recent HPCI reliability and equipment problems can be found in NRC Inspection Reports 50-324,325/88-21 and 88-27.

The lack of Management involvement in the resolution of identified deficiencies was considered to be a weakness.

e. Residual Heat Removal Heat Exchanger Capacity

During the team inspection, it was noted that attempts to run HPCI PT 9.2 had to be aborted due to torus temperature becoming elevated. This was despite the fact that at the time, both loops of RHR were running on torus cooling. Since each of the RHR heat exchangers were designed to remove 176 million BTUs per hour, the inspector became interested as to why the heat exchangers could not remove the heat that the HPCI turbine exhaust was injecting.

The inspector asked first if routine heat exchanger capacity tests (heat balance) were performed on the units; they were not. The only capacity tests performed on the heat exchangers were the pre-op tests the results of which contained some unit untraceable, unexplainable factors.

Discussions with engineering, operations, and technical services personnel revealed that the problem discussed above was an old issue which occurred every summer and was associated with elevated service water temperature.

Apparently, management had either never become aware of the problem, or had not taken action to resolve it.

Subsequent testing performed on July 17 and 18, 1988 indicated that RHR heat exchangers met their design capacity.

The lack of Management aggressiveness with respect to the identification and/or the resolution of identified technical deficiencies was considered a weakness.

f. Vital Battery Inoperability Concern

During a tour of the vital battery rooms, the inspector detected that certain of the unit 1 battery cells were misaligned relative to what was designed as a compact, intact, secured seismic configuration. A subsequent operability justification was performed which indicated that the battery was operable although it was indeed not the configuration qualified.

It should be noted that the concern relative to seismic operability was legitimate, and could have possibly been detected previously through aggressive management direct involvement.

Within this area, no violations or deviations were found.

6. Action on Previous Inspection Findings (92700, 92701, .!702)

(Open) Unresolved Item 324,325/87-12-01, Evaluation of Licensees Action to Resolve Equipment Failures Associated with Licensee Event Reports 1-86-024, 1-87-u01, 2-87-001, 2-87-004.

This item involved the licensees difficulties with their HPCI system. The licensee is still pursuing the HPCI component problems. This item will remain open pending NRC review of the licensees actions.

(Closed) IFI 324,325/87-12-02, Commitment to Revise Administrative Procedure.

This item was generated to follow up on a licensee commitment to revise their administrative procedures to preclude the practice of backing out of procedures except in valid emergencies with prior approval of plant management. A previous event (LER 2-87-04) was caused by an operator attempting to backup out of a procedure. The licensee has since revised their OI-01, Operating Principles and Philosophy Operating Instructions in Rev. 20, dated 6/11/87 to specifically note that the performance of procedural steps in reverse order is not an appropriate method of exiting a procedure unless this method is specifically authorized by the procedure. The inspector also interviewed operators to ensure that they were cognizant of the new OI-01 requirement. No discrepancies were found. This item is closed.

(Open) IFI 324,325/87-12-03, Review of LER Preparation Process

The inspector reviewed selected 1988 LERs to determine the adequacy of corrective actions, root cause determination, and trending and tracking of similar events. The LERs reviewed comply with 10 CFR 50.73 and NUREG-1022. In a related matter, as documented in inspection report 324/87-12, the licensee committed to review and revise procedure RCI-06.1. Review of the licensee's actions to revise RCI-06.1 to fully describe the LER preparation process and actions to improve the quality of LERs was identified as IFI 324, 325/87-12-03. Procedure RCI-06.1 was reviewed by the inspector, but has not been revised. The item remains open.

(Closed) IFI 325/87-12-04, Evaluate Results of Licensees Inspection of Contact Block Assemblies on the AC operators for Major Flow Path ECCS Valves.

The licensee has replaced the contact block assemblies on all AC operated major flow path ECCS valves. The Unit 2 valves had their model 205 contact block assemblies replaced with model 305 contact block assemblies by 4/6/87. The Unit 1 valves had the same replacement which was accomplished by 9/3/87. The licensee reported the deficiency in LER 1-87-001 Rev. 1 Supplemental response and also submitted a 10 CFR Part 21 report on the condition. These actions taken to address this issue are satisfactory and this item is closed.

7. Exit Interview

A pre-exit interview was conducted on July 15, 1988 and the final inspection scope and results were summarized on August 18, 1988, at the CP&L corporate office in Raleigh, N.C. with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

| Item number | Status | Description/Reference Paragraph |
|---|---|---|
| 324, 325/88-19-01 | OPEN | IFI - Method by which temporary procedure revisions are attached to control room and working copies of existing procedure, paragraph 2.b. |
| 324, 325/88-19-02 | OPEN | IFI - Control and posting of operator aids is observed as a weakness, paragraph 2.h |
| 324, 325/88-19-03 | OPEN | IFI - No site documentation available that provides justification for not concurrently perform actions for power, level, and pressure control according to the BWROG, paragraph 3.d. |
| 324, 325/88-19-04 | OPEN | IFI - Steps that were accepted in the PSTG verbatim from the BWROG did not appear in the EOP flowcharts and steps existed in the flowcharts that are not documented as to the overall safety impact, paragraph 3.d. |
| 324, 325/88-19-05 | OPEN | IFI - Planning and processing of WR/JOs appeared to be weak, paragraph 4.a. |

8. Acronyms and Initialisms

ALARA - As Low As Reasonably Achievable
AMMS - Automated Maintenance Management System
AO - Auxiliary Operator
ASSD - Alternate Safe Shut Down
ATWS - Anticipated Transient Without Scram
BNP - Brunswick Nuclear Plant
BWROG - Boiling Water Reactor Owners Group
CO - Control Operator
CRD - Control Rod Drive
CST - Condensate Storage Tank
CTS - Commitment Tracking System
CWIP - Circulating Water Inlet Pumps
ECCS - Emergency Core Cooling System
EDBS - Equipment Data Base System
EHC - Electro Hydraulis Control
EOP - Emergency Operating Procedure
EQ - Environmental Qualification
E&RC - Environmental and Radiological Controls
ERG - Emergency Response Guideline
EWR - Engineering Work Request
GM - General Manager
HPCI - High Pressure Coolant Injection
HPES - Human Performance Evaluation System
I&C - Instrumentation and Control
IFI - Inspector Followup Item
INPO - Institute of Nuclear Power Operations
ISI - In Servce Inspection
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MAC - Motor Actuator Characterizer
MI - Maintenance Instruction
MOV - Motor Operated Valve
MOVATS - Motor Operated Valve Actuator Test System
MP - Maintenance Procedure
OPA - Operational Performance Assessment
PM - Preventive Maintenance
PMTR - Post Maintenance Test Requirements
PNSC - Plant Nuclear Safety Committee
PRA - Probablistic Risk Assessment
PSTG - Plant Specisic Technical Guidelines
PT - Performance Test
QA - Quality Assurance
QC - Quality Control
Q List - Safety Related Component List
RCIC - Reactor Core Isolation Cooling
RHR - Residual Heat Removal
RPS - Reactor Protection System
RSCS - Rod Sequence Control System

Acronyms and Initialisms (cont'd)

RWCU - Reactor Water Clean Up
RWM - Rod Worth Minimizer
SALP - Systematis Assessment of Licensee Performance
SF - Shift Foreman
SJAE - Steam Jet Air Ejector
SLC - Standby Liquid Control
SOER - Significant Operating Experience Report
SOS - Shift Operating Supervisor
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
SSFI - Safety System Functional Inspection
STA - Shift Technical Advisor
SWFCG - Site Work Force Control Group
WR/JO - Work Request/Job Order

## APPENDIX A

## LABELING DISCREPANCIES

LEP-02, Alternate Control Rod Insertion (Unit 1)

1. In Panel 609 bus CC-71A, fuse F18G had a removable label on it designated as F18A.

2. In Panel 611 bus CC-71A, fuse F18H had a removable label on it designated as F13B. This was marked as a 5 amp fuse when in fact F18H is a 15 amp fuse.

3. In both Panels 609 and 611, the use of the removable labels was inconsistent. Some fuses had them, others did not. A permanent label was located next to each fuse.

LEP-03, Alternate Boron Injection (Unit 2)

1. Section 1, Step 5 - This step directs the operator to "PLACE the filter flow controllers for both F/Ds to "MAN" and REDUCE flow to a minimum". There is no label "filter flow controller" on the RWCU F/D panel; however, there are two controllers labeled 2-G31-FC-74A and 2-G31-FC-74B.

NOTE: All the "AO" valve name labels below have a "1" prefix instead of the expected "2" prefix (for Unit 2) on the RWCU panel in the plant

2. Section 1, Step 8 - This step directs the operator to "CLOSE the following valves:

   a. F/D A Effluent Valve, G31-Z002-AO-41A

   b. F/D B Effluent Valve, G31-Z002-AO-41B"

   The actual panel labels are "A F/D Effluent Strainer, AO-41A" and "B F/D Effluent Strainer, AO-41B".

3. Section 1, Step 10 - This step directs the operator to "OPEN or VERIFY OPEN the following valves for the selected F/D:

   a. F/D A(B) Drain Valve, G31-Z002-AO-33A(B). The actual panel label is "A(B) F/D Drain, AO-33A(B)".

   b. F/D A(B) Air Inlet/Vent Valve, G31-Z002-AO-30A(B). The actual panel label is "A(B) F/D Dome Vent/Air Inlet, AO-30A(B)".

c. F/D A(B) Dome Drain Valve, G31-Z002-AO-29A(B). The actual panel label is "A(B) F/D Dome Drain Valve, AO-29A(B)".

d. F/D A(B) Precoat Return Valve, G31-Z002-AO-34A(B). The actual panel label is "A(B) F/D Precoat Return, AO-34A(B)". Also, this valve label on "A" Panel has a "B" designation.

e. Precoat Pump Discharge Isolation Valve, G31-Z002-15. No deficiencies noted.

f. Air Inlet Valve, SA-V395. The actual valve label is "SA Supply to RWCU Sys, SA-V395".

g. Demineralized Water Supply to RWCU Isolation Valve, DW-V377. This valve is located approx. 10 feet above the floor (operated by a chain) and the valve label is impossible to read without a ladder. Actual valve label is correct.

h. F/D A(B) Precoat Supply Valve, G31-Z002-AO-38A(B). The actual panel label is "A(B) F/D Precoat Supply, AO-38A(B)".

i. Precoat Pump Seal Water Isolation Valve, DW-376. No deficiencies noted.

j. Precoat Pump Suction Isolation Valve, G31-Z002-55. No deficiencies noted.

4. Section 1, Step 12.a - This step refers to the automatic opening of F/D A(B) Dome Drain Valve, G31-Z002-12A(B). The actual panel valve label is "A(B) F/D Dome Drain Valve, AO-12A(B)".

5. Section 1, Step 12.c - This step refers to the automatic opening of F/D AO Air Inlet Valve, G31-Z002-13A(B). The actual panel valve label is "A(B) Air Inlet, AO-13A(B)". This step also refers to AO-12A(B) in the same manner as step 12.a (see item 4 above).

6. Section 1, Step 12.d - This step verifies that "The dome drain closed and F/D vessel is charged to 90 psig minimum air pressure". The only panel gage that appears to measure air pressure is labeled 2-G31-PI-71.

7. Section 1, Step 12.e - This step verifies that "Holding pump A(B) stops and F/D A(B) Holding Pump Discharge Valve, G31-Z002-14A(B), closes". The actual panel label is "A(B) F/D Hold, AO-14A(B)".

8. Section 1, Step 12.f - This step refers expected actions when "F/D A(B) AO Drain Valve, G31-Z002-8A(B)", opens. The actual panel valve label is "A(B) F/D Drain, AO-8A(B)".

9. Section 1, Step 14.a & b - See comment 3 above.

10. Section 1, Step 15 - This step directs the operator to "OPEN Precoat Tank Drain Valve To CRW, G31-Z002-46". The actual valve label is "Precoat Drain Valve to CRW, G31-Z002-V46".

11. Section 1, Step 23.a - This step directs the operator to "Manually OPERATE switches to OPEN the following valves:"

    a. F/D A(B) AO Dome Vent Valve, G31-Z002-7A(B). The actual panel label is "A(B) F/D Vent, AO-7A(B)".

    b. F/D A(B) AO Precoat Supply Valve, G31-Z002-11A(B). The actual panel label is "A(B) F/D Precoat Pump Disch, AO-11A(B)".

12. Section 1, Step 26 - This step says to fill the RWCU precoat tank until full as indicated by RWCU-FS-4869 (RWCU-FS-4871). This indication could not be found as labeled but the operator thought it was a white light on the RWCU Panel.

13. Section 1, Steps 27-38 - These steps repeat previously noted labelling problems (see items 2 - 11 above).

14. Section 3, Step 4 - This step directs the opening of SJAE Condensate Recirculation Valves, CO-FV-49-1 and CO-FV-49-2. In fact, the intent of this operation is performed by use of controller CO-FIC-49.

15. Section 3, Step 5.b - In order to BYPASS one condensate booster pump, this step directs the operator to "REMOVE control power fuses from the selected pump's 4KV breaker". The control power fuses in the breaker cabinet are not labeled.

16. Section 4, Step 1.b - This step instructs the operator on how to rig up a heavy duty rubber hose from the HPCI/RCIC CST suction line to the SLC Tank drain line. It refers to the "HPCI and RCIC CST Suction Vent Valve, CO-V301". The actual label name at valve CO-V301 is "High pt vent to HPCI/RCIC suct". Also, the SLC tank drain line on the Reactor Building 50 foot elevation is not labeled.

EOP-01-SRP-ISA, Instrument/Service Air System Recovery (Unit 2)

1. Step C.1 - This step directs the COntrol Operator to "ISOLATE the service air header from the RTGB". No RTGB valve designations are specified.

2. Steps C.2 & C.3 - These steps direct the operator in the positioning of the "Unit 1 and Unit 2 Cross-tie Valve, SA-V7". The actual valve label is "Service Air Cross Connect, SA-V7".

3. Step C.4.a - This step directs the operator to "ISOLATE the interruptible instrument air header". No valve label designation is specified.

4. Step C.5.b(1) - See comment 2 above.

5. Step C.5.b(2) - This step directs the operator to close the "Noninterruptible Instrument Air Isolation Valves, IAN-V50 and IAN-V51". The valve labels for each is actually "Non. Instr. Air Header to RB A Loop Isolation".

6. Section 1, Step 1 - This step directs the operator to "Locally CHECK CLOSED service and interruptible instrument air header isolation valves". No valve label designations are specified.

7. Section 1, Step 2 - This step directs the operator "IF iny isolation valve is NOT closed or is leaking by, THEN ISOLATE the manual valve in series with the affected valve". No valve label designation is specified.

8. Section 1, Step 3 - This step requires the operator to locate the instrument air dryer and filter dP gages. No gages were labeled as such and the operator was unable to state how he would determine the dP. Also, the valve label for SA-V79 is actually "SA Heater & Dryer Bypass" versus "Air Dryer No. 2 Bypass Valve" as per the procedure.

9. Section 3, Step 2.c(3) - This step directs the operator to "RESET the instrument air isolation by depressing the isolation reset. (CS-722)" The actual pressure switch label is IA-PS-722-1 and is not easily visible. The reset pushbutton is not labeled.

10. Section 3, Step 2.d(3) - This step directs the operator to "RESET the service air isolation by depressing the service air isolation reset. (CS-706)" The actual pressure switch label is SA-PS-706-1 and is not easily visible (etched on casing). The reset pushbutton is not labeled.

EOP-01-FP-4, Flowpath 4 (Rev. 4)

1. Step 27 - In Unit 2, local indication of RBCCW header pressure is not labeled.

APPENDIX B

| Month | Percentage of non-outage WR Over 3 months old | Month | Percentage of non-outage WR Over 3 months old |
|---|---|---|---|
| Jan. 87 | 66.7% | Oct. 87 | 68.0% |
| Feb. | 67.3 | Nov. | 76.0 |
| Mar. | 67.4 | Dec. | 74.8 |
| Apr. | 66.9 | Jan. 88 | 76.3 |
| May | 66.7 | Feb. | 74.6 |
| June | 66.1 | Mar. | 64.8 |
| July | 66.3 | Apr. | 66.3 |
| Aug. | 65.2 | May | 70.9 |
| Sept. | 64.3 | June | 67.8 |

| | Total | Year Submitted | | | | | Priority | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| U1 I&C Planner | | | | | | | | | | |
| WR/JO Status | 270 | 84 | 85 | 86 | 87 | 88 | 2 | 3 | 4 | 5 |
| Awaiting parts | 47 | | | 1 | 9 | 37 | 1 | 39 | | 7 |
| On hold | 31 | | | 3 | 12 | 16 | 6 | 19 | 6 | |
| Not scheduled | 103 | 1 | 1 | 6 | 13 | 1 | 8 | 89 | 1 | 4 |
| Interrupted | 50 | 1 | 1 | 15 | 19 | 14 | 15 | 24 | 9 | |
| In progress | 39 | 1 | 1 | 5 | 12 | 20 | 7 | 28 | 3 | 1 |
| Ages of the priority 2 WR/JO above | 37 | | | | | | | | | |
| Awaiting parts | 1 | | | | | 1 | | | | |
| On hold | 6 | | | | | 6 | | | | |
| Not scheduled | 8 | 1 | | 3 | | 4 | | | | |
| Interrupted | 15 | 1 | | 3 | 6 | 5 | | | | |
| In progress | 7 | | | | 2 | 5 | | | | |
| U2 Mech. Planner | | | | | | | | | | |
| WR/JO Status | 68 | 84 | 85 | 86 | 87 | 88 | 2 | 3 | 4 | 5 |
| Unplanned | 45 | 1 | 2 | 16 | 26 | | 1 | 42 | 2 | |
| Awaiting parts | 10 | 2 | 1 | 3 | 4 | | 0 | 10 | 0 | |
| On hold | 13 | 2 | 7 | 1 | 3 | | 1 | 11 | 1 | |
| U2 Elec. Planner | | | | | | | | | | |
| WR/JO Status | 191 | 83 | 85 | 36 | 87 | 88 | 2 | 3 | 4 | 5 |
| Unplanned | 21 | | | | | 20 | 1 | 17 | 3 | |
| Awaiting parts | 72 | | | 10 | 21 | 41 | 18 | 41 | 13 | |
| On hold | 98 | 1 | 13 | 29 | 23 | 32 | 18 | 64 | 16 | |

| Ages of the Priority 2 WR/JO Above | 37 | 83 | 85 | 86 | 87 | 88 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|---|---|---|---|
| Unplanned | 1 | | | | | 1 | | | | |
| Awaiting parts | 18 | | | 3 | 5 | 10 | | | | |
| On hold | 19 | | 2 | 9 | 7 | 1 | | | | |