# NEBRASKA PUBLIC POWER DISTRICT

## COOPER NUCLEAR STATION

# DIAGNOSTIC SELF ASSESSMENT

# SUPPORTING DOCUMENTATION

JULY - AUGUST 1994

A/29

## Diagnostic Self Assessment

## Supporting Documentation

The following documentation supports and amplifies the findings of the final Diagnostic Self Assessment Report.

### 1. Observations

The first section of this addendum contains a two part compilation of the DSA observations. Part I consists of Master Observations which are a composite of individual assessment observations and which focus on areas where significant improvement is needed in the operation of Cooper Nuclear Station. Each of the Master Observations is based on one or more of the individual assessment observations contained in Part II of this section. The information in these individual assessment observations was derived from review of NPPD policies and procedures, records, schedules, plans, tests, and interviews of management and staff personnel.

Where the cause of deficient condition is apparent, that cause has been included in the observation. Similarly, when the evaluator was able draw a conclusion concerning the programmatic and/or management causal factors, those causes have also been included. The absence of apparent cause or programmatic and management causal factors in the individual observation has not particular significance.

The observations are categorized within four functional areas:
Engineering and Technical Support (ENG);
Management and Organization (M&O);
Maintenance and Testing (MNT); and,
Operations and Training (OPS)

The assignment of an observation to a functional area is not intended to indicate an assignment of organizational cognizance within the NPPD Nuclear Power Group or Cooper Nuclear Station staff.

The observations are ordered alphabetically by the sequence number within the four functional areas. The sequence numbers are not nor were they intended to be all inclusive.

### 2. Root Cause - Compilation

This section contains the compiled results of the DSAT symptom classification causal analysis. The root causes were identified by evaluating and categorizing the problems and symptoms observed in CNS's functional performance. The symptoms were grouped under potential cause categories, the cause categories were evaluated for commonality and merged where appropriate. This process culminated in four major causes being identified. The enclosed compilation relates the DSA master and some individual issues (from Section 1) to the root causes.

### 3. Requests for Information

This section also contains two parts. Part I is a computer printout of the requests for review information (RFIs) made by the Diagnostic Self Assessment Team. The information requests typically did not include NPPD procedures, vendor technical information, drawings, and other general reference information available in either the Cooper Training Facility library or plant technical libraries. The assessment team regularly accessed this latter material directly without use of the RFI process.

Part II is a similar computer printout of the information requested by the NRC Special Evaluation Team (DET Request Log Sheets). The Diagnostic Self Assessment Team was provided a complete, indexed set of the NRC-requested material and used the material for general review and development of assessment issues.

### 3. Cooper Performance History

The last section of this addendum contains summary information about Cooper Nuclear Station's regulatory history, assessment results, and event history. This information was also used by the Diagnostic Self Assessment Team as both background information and as input to the DSA performance evaluation process. Three documents are included:

- "Cooper Nuclear Station Performance History" - a summary of NRC inspections, INPO evaluations and related NPPD activities prepared by NPPD.
- A "Summary of Inspection/Assessment Reports, June 1993-August 1994" prepared by NPPD.
- A summary of "Cooper Event History Insights" prepared by INPO

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MENG **SEQ:** MCB-01

**DESCRIPTION:** CORRECTIVE ACTION PROGRAM

There are too many occurrences of events or adverse conditions at Cooper station that result from failed or absent barriers that should have been provided by effetive evaluation of the lessons learned from in-house and industry operating experience.

**CAUSE:** In-house events:

Failure to conduct thorough root cause investigations or implement the necessary enduring corrective actions. (DK-01, CB-12, GW-19)

Industry operating experience events:

Technical evaluations were untimely, narrowly focused, based on incorrect assessment of station equipment performance history or inappropriately concluded that an industry problem was unlikely to occur at Cooper station. (CB-13, CB-10)

**EXAMPLES:** In-house events:

1. Preconditioning of equipment prior to demonstrating sequential loading of the emergency diesel generators. Note that industry operating experience also existed for this problem. (CB-16, CB-13)

2. Recurring unexpected half-scrams and containment isolations due to spurious tripping of RPS motor-generator protective relays. (CB-18)

3. Unexpected cycling of core spray minimum flow valves due to a long-standing problem with flow instrumentation (CB-20, GW-19).

Industry operating experience events:

1. Insufficient preventive maintenance on Westinghouse 480 volt undervoltage trip assemblies in the emergency diesel generator load shed logic resulted in multiple failures that were undetected due to incomplete logic system functional tests. (CB-12, CB-13)

2. Excessive reactor vessel thermal transients following loss of recirculation pump events that result in temperature stratification. (CB-10)

3. Control room habitability envelope failure and secondary containment integrity breach. (CB-13)

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**PROGRAMMATIC:** In-house events:

Recent changes have been made to the corrective action program; however, responsibility and accountability is not clearly defined for both the group administering the program and supporting groups. In addition, the program contains insufficient elements for performance monitoring and programmatic adjustments, and the long-term vision is ill-defined. (DK-01)

Industry operating experience:

The industry OE program relies primarily on a single manager to distribute industry OE documents to responsible line departments for evaluation and development of corrective actions. Other stations have established effective programs by creating a dedicated industry OE group, staffed with multi-disciplined technical and operational expertise to perform evaluations and/or conduct independent technical reviews of evaluations assigned to other groups. (CB-15)

**MANAGEMENT:** In-house events:

Senior management has not followed through on a commitment to upgrade the station corrective action program. Although actions specified in the CNS Integrated Enhancement Plan relevant to the corrective action program upgrades are considered complete, insufficient direction has been provided to the new corrective action program manager, and the responsibility and authority of this position have not been established. (CB-15, DK-01)

Industry operating experience events:

1. The group responsible for administering the industry OE program has insufficient staffing and resources, and supporting groups are not held accountable for carrying out assigned responsibilities. (CB-13, CB-15)

2. Management assessments and monitoring of the program have not been sufficient to discover the depth of the problems and their program adequacy implications when individual cases of failed or absent barriers were discovered or when adverse trends were reported.

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MENG **SEQ:** MGW-01

**DESCRIPTION:** Insufficient management direction and monitoring have caused engineering support to be ineffective in providing timely support. Documented management expectations address a number of engineering duties, such as system walkdowns, maintenance support, and system performance trending. However, assignment of additional duties to system engineers has resulted in an unreasonable workload for the current level of resources. For example, a lack of maintenance procedures and maintenance planning personnel has resulted in system engineers being called upon to prepare special instructions to perform maintenance activities on safety-related equipment. Additionally, local leak rate testing is performed by engineers that, due to the amount of work involved, are unable to focus attention on the adequacy program. As a result of these additional workloads, backlogs are increasing in a number of areas, including industry operating experience actions, corrective action program items, NPRDS reports, vendor manual reviews, and procedure reviews. These backlogs are increasing despite system engineers working 50% to 110% overtime over the last eighteen months. Additionally, the focus on addressing backlog items is resulting in system engineers not monitoring system performance effectively and not maintaining an awareness of system problems.

(EXAMPLES - REC patches and monitoring needs, SRM noise, changes in performance of the RHR pumps without evaluation).

Corporate engineering performance is also not providing the appropriate levels of support. Prior to the last refueling outage, the corporate engineering organization was unable to provide the design change packages to the station more than two months prior to the outage. Similarly, current levels of corporate engineering support to the station have impacted the completion of ongoing corporate engineering activities, such as the development of design basis documents, completion of setpoint calculations for safety-related instruments, and development of design change packages to support the next planned refueling outage.

Additionally, a lack of effective root cause analysis and thorough design have resulted in some design changes that do not correct the identified equipment performance problem or introduce new system problems.

Contributing to this problem is a lack of an effective management monitoring program to monitor and effectively determine the levels of site or corporate engineering performance.

Another contributing factor to these problems is the lack of clearly established roles and divisions of responsibility between the site and corporate engineering organizations. (EXAMPLES - operability evaluations, ownership for site issues, troubleshooting equipment problems, design control, walkdowns to determine drawing accuracy/adequacy).

**CAUSE:**

**EXAMPLES:**
-- lack of system walkdowns (DK-04, GW-04)
-- not recognizing problems with system performance (RHR turbulence and SRMs) (CB-15)
-- changes in RHR pump performance (GW-08)
-- overtime (JC-01)

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes



-- backlogs of OE items (CB-21)
-- backlogs of CAP items (RC-15)
-- backlogs of NPRDS reports (GW-04)
-- backlogs of vendor manuals for review (GW-04, GW-06)
-- backlogs of MWRs for review (CB-15)
-- backlogs of procedures (CB-08, CB-15)
-- lack of effective performance monitoring reports/activities (DK-01, GW-12)
-- delays in completing DBDs (GW-12, CB-15)
-- delays in completing instrument setpoint calculations (GW-12)
-- lack of progress on upcoming RFO modifications (DM-10, RC-12)
-- interviews and procedure reviews identifying interface/relationship problems (RA-05)

-- The 10CFR50, Appendix J program for local leak rate testing of containment isolation valves was not sufficient to verify containment integrity for more than 50 penetrations, including penetrations that had not been tested, as well as penetrations that were not tested in the accident direction. (GW-14)

-- The in-service testing program for pumps and motor-operated valves does not establish adequate bases for pump baseline data and the identified acceptance criteria for motor-operated valve stroke time testing. (GW-14)

-- The vendor manual program is not sufficiently developed or maintained to ensure vendor maunuals kept current in shop,s changes are reviewed in a timely manner, and appropriate requirements from ver. manuals are reflected in station programs, such as, corrective maintenance procedures and preventive maintenance requirements. (GW-04)

-- Problems identified with the potential degradation of the REC system were not monitored to enure the system would remain operational. (GW-10)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MENG **SEQ:** MGW-02

**DESCRIPTION:** ENGINEERING PROGRAMS INEFFECTIVELY DEVELOPED OR MAINTAINED

Development and maintenance of programs for monitoring equipment performance to ensure safety operations has been insufficient. A number of programs for monitoring equipment performance have been identified as deficient during the last eighteen months. Many of these programs were initially developed following plant startup and have not received a self-critical review since that time.

**CAUSE:**

**EXAMPLES:** -- The 10CFR50, Appendix J program for local leak rate testing of containment isolation valves was not sufficient to verify containment integrity for more than 50 penetrations, including penetrations that had not been tested, as well as penetrations that were not tested in the accident direction. (GW-14)

-- The in-service testing program for pumps and motor-operated valves does not establish adequate bases for pump baseline data and the identified acceptance criteria for motor-operated valve stroke time testing. (GW-14)

-- The vendor manual program is not sufficiently developed or maintained to ensure vendor manuals are kept current in shops, changes are reviewed in a timely manner, and appropriate requirements from vendor manuals are reflected in station programs, such as corrective maintenance procedures and preventive maintenance requirements. (GW-04)

-- Problems identified with the potential degradation of the REC system were not monitored to ensure the system would remain operational. (GW-10)

-- Monitoring of potential erosion of portions of the RHR system were not established as required by the modifications made to the flow trim on valves MO-27A/B and 34A/B.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MENG **SEQ:** MGW-06

**DESCRIPTION:** CONFIGURATION CONTROL IS NOT EFFECTIVELY MAINTAINED

Changes to station configuration are not adequately reviewed or controlled to ensure the station configuration reflects station design.

**CAUSE:**

**EXAMPLES:** -- Removal of the standby gas treatment check valves (GW-09)

-- Relay settings that are not in accordance with the current design calculations (RA-09)

-- Undocumented modifications identified in the plant (REC patch, drain plugs/caps missing, "A" RHR heat exchanger leak collection) (GW-09)

-- Drawings that do not identify expected valve positions and positions shown often differ from station valve lineup procedures/checklists (CB-12, DK-04)

-- Limited drawing walkdown program identified over 120,000 drawing discrepancies (RA-05)

-- Drawing change notices do not require adequate justification for changing drawings and often do not receive a design engineering review to ensure they are consistent with current station design (RA-10)

-- Station procedures allow the shift supervisor to change valve lineups from those shown on drawings (recent examples of REC lineup that was not adequate to support a design basis accident and recent recognition that station procedures do not prevent some unanalyzed electrical cross-ties). (GW-15)

-- Identification of essential equipment is not effectively maintained to ensure that controls and testing for equipment are appropriate. Additionally, controls over replacement parts sometimes do not reflect the correct equipment classification. (DM-08)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MENG **SEQ:** MGW-07

**DESCRIPTION:** DESIGN CONTROL IS INSUFFICIENT TO MAINTAIN DESIGN INTEGRITY.

Activities to control design are not sufficient to ensure analyses are based on correct and current design information. Contributing to this is a lack of readily available design basis information. Additionally, many system engineers were unaware of how to locate design basis information.

**CAUSE:**

**EXAMPLES:** -- During reviews of modifications, calculations were noted that did not reference design basis information, such as original system calculations, or identify whether the new calculation supersedes previous calculations. (CB-10, GW-17)

-- Testing is frequently used as a means of determining whether a modification will work correctly; however, the testing conditions and supporting analyses do not ensure that the test results can be extrapolated to ensure the system will meet design basis accident conditions. (RA-01)

-- A listing of design calculations exists, but it does not identify the relationships among calculations, or those calculations that have been totally or partially superseded by later calculations. For example, there is a series of three calculations that support the installation of the RHR flow orifices, one of the calculations precedes the testing, and the calculation that was prepared to size the orifice based on the testing results does not identify whether it supersedes a portion of the previous calculation. (RA-07)

-- SORC-approved MWRs are sometimes used to expedite the installation of a modification. The process involves a design engineer preparing sketches that depict the modification as he envisions it. In both cases of SORC-approved MWRs installed, the following design change package had to correct design errors included in the previously installed package. Additionally, some of the design calculations were not prepared until the modification had been installed in the plant for over a year. (GW-17)

-- The calculation process in place does not prevent the issuance of a calculation as an approved calculation before the modification it reflects is installed in the plant. This can contribute to incorrect understandings of "current" design. (GW-17)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MCB-02

**DESCRIPTION:** Several issues identified by the station and the DSAT team have generic implications regarding the ability of important plant systems to function as designed during plant transients or off-normal conditions. Although some of these issues have been, or are currently being addressed by the station on an individual basis, they currently represent a potential reduction in the margin of safety when viewed in the aggregate.

**CAUSE:**

**EXAMPLES:** 1. PRECONDITIONING (CB-16)

In June, 1993, the NRC identified a concern that prior to conducting secondary containment integrity tests, the station was performing preventive and corrective maintenance with the objective of passing the test, thereby precluding any opportunity to identify degradation that may have occurred prior to the test. Subsequently, in May, 1994, a similar situation associated with emergency diesel generator load shed testing was identified. In both cases, system functional degradations were revealed when followup tests were performed in the absence of preconditioning. Since this time, additional examples of procedurally established and unintentional preconditioning have been identified. Although actions have been taken to alert station personnel to identify and prevent preconditioning in the future and a review of station procedures is underway to identify additional cases, the DSAT team found insufficient guidance exists evaluating these cases to determine whether system functionality concerns potentially exist due to past practices.

2. PLANT STATUS CONTROL (MDM-11, CB-16)

The DSAT team identified that implementation and adequacy of the status control process does not ensure systems and components are controlled in the condition intended. Examples include the following:

a. Many examples of recently identified valve and switch mispositionings.
b. Valve lineup sheets have many known deficiencies.
c. Clearance order program implementation problems have resulted in components being out of their required position and violations of procedure requirements.

In addition, in May, 1994, a temporary blocking device was found installed in an undervoltage trip assembly (UVTA) of a non-essential 480 volt motor control center feeder breaker that rendered the load-shed function inoperable, potentially overloading the emergency diesel generator. The blocking device was installed by procedure during the Spring, 1993, refueling outage, but was inadvertently left in place due to lack of a procedure step to remove the device. The station conducted a special review of procedures that identified and corrected additional similar procedure deficiencies.

3. CORRECTIVE ACTION PROGRAM (MCB-01, DK-01)

There have been several recent events or adverse conditions at Cooper station that resulted from failed or absent barriers that should have been provided by effective evaluation of the lessons learned from in-house and industry operating experience. These situations have been caused by failure to conduct thorough ro...

cause investigations, thoroughly evaluate industry operating experience, or implement enduring corrective actions. The station modified its problem reporting system, established a corrective action program manager, conducted root cause training, obtained the services of root cause analyses coaches/mentors, and is conducting a review of actions taken in response to some industry operating experience documents that date back to 1982. Nonetheless, the DSAT team identified a lack of rigor in recent root cause analyses, corrective actions that insufficiently address the root cause, unclear responsibility and accountability for the corrective action program, a large backlog of incomplete root cause analyses and corrective actions, questions regarding the adequacy of the industry operating experience review scope, and lack of management follow-through on the commitment to upgrade the corrective action program.

4. ENGINEERING, CONFIGURATION CONTROL, AND DESIGN CONTROL ISSUES (MGW-01, MGW-06, MGW-07)

The DSAT team identified the station and corporate engineering organizations have not provided timely support to the station. Examples of issues that potentially impact system functionality include the following:

a. Ongoing monitoring of the reactor equipment cooling (REC) piping had not been performed to detect continuing IGSCC caused by previous system chemistry, resulting in the need for extensive system inspections when a leak recently developed.

b. Only nine design criteria documents have been completed since a reconstitution effort began in 1986. In addition, the DSAT team identified that activities to control station design are not sufficient to ensure analyses are based on correct and current design information; because, in part, many system engineers are unaware of how to locate design basis information.

c. SORC-approved MWRs are sometimes used to expedite modification to the plant. The DSAT team identified instances where the subsequent design change package corrected design errors in the MWR-implemented modification. Some design calculations were not prepared until the modification had been installed.

d. Instruments setpoint calculations have been accomplised for only approximately one-third of the technical specifications intruments.

e. The station identified deficiencies in the local leak rate test program that resulted in insufficient verification of the integrity of more than 50 containment penetrations. The DSAT team identified lack of an adequate basis for acceptance criteria and valve stroke times contained in the pump and valve in-service testing program.

f. The DSAT team indentifed deficiencies in the control vendor manuals. In addition, about 87 saftey related vendor manuals have not been reviewed to identify preventive maintenance requirements for associtated components. A second review is required for about 30 additional manuals due to inadequate first review.

g. The DSAT team identified changes in station configuration control that are not adequately reviewed or controlled to ensure the station configuration reflects station design. Examples include 120,000 station-identified drawing discrepancies, relay settings that are not in accordance with current design calculations,

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standby gas treatment check valves that have been removed, drawings that do not identify expected valve positions, drawings that show valve positions that differ from valve lineup checklists, and procedures that permit shift supervisors to change valve lineups from those shown on drawings.

5. WORK CONTROL (MRB-01, GW-02, GW-03)

The DSAT team identified that work activities on plant equipment are frequently started before a fully planned work package is available, and without first determining if other related work activities should be performed concurrently. This results in excessive system outage durations since systems are repeatedly removed from service because no work was able to be performed in accordance with vendor specifications due to insufficient procedural guidance and inadequate work plans. The DSAT team noted that these problems may be related to adverse trends over the last three years in HPCI system and diesel generator system unavailability.

6. QUALITY OF MAINTENANCE AND STATION MATERIAL CONDITION (MSV-01, MSV-03, MDM-10)

The DSAT team identified that maintenance is not consistently performed to assure equipment availability. Previous maintenance activities have resulted in nonconforming conditions, degraded plant equipment, increased out-of-service time, and rework. Examples include recent RHR pump overhauls using special instructions in place of approved procedures, replacement of emergency diesel generator components without a procedure, 4160 volt circuit breaker misalignment problems, and rework to adjust the service water pump impeller clearance.

The DSAT team identified long-standing equipment problems that have not been identified for corrective action. In addition, the team found a number of station-identified problems on important equipment that represent a potential challenge to plant operations. Examples include continuing problems with the main turbine bypass valves, excessive silt in the service water system that is compensated by operation of shutdown cooling with full service water flow and throttled reactor coolant flow (through a valve that isn't designed for throttling), silting that plugs instrument sensing lines, drywell sump level switch reset problem, excessive seat leakage on a reactor feed water pump that necessitates closure of a manual valve and extra demands on operators, spurious actuations of the standby gas treatment system fire detector resulting in manual isolation of the deluge valve and the need for local operator action in the event of a fire, and unexpected opening of HPCI, RCIC, and core spray system pump minimum flow valves during surveillance tests.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MJD-01

**DESCRIPTION:** RESOURCES

CNS appears to have had the financial resources necessary to conduct a quality operation. Staffing has been appropriately studied and is adequate in most areas. Where deficiencies were noted, appropriate actions are being taken with the possible exception of short-term responses to needs generated by an accelerated event investigation program.

**CAUSE:**

**EXAMPLES:** Funding appears to have been adequate. EUCG three year rolling average O & M less fuel, $/installed KW, places Cooper in the second quartile, slightly less than the industry median. Judgment by senior plant management is that funding is adequate. (interview) Corporate financial managers indicate that the budgeting process generally provided the nuclear operation with requested funding. (interviews) On this basis it is concluded that Cooper has been provided with sufficient funding, capital and O & M.

Staffing tends to be slightly low. (1994 Tim D. Martin staffing study). The engineering management indicated that engineering staffing increases are in progress. (interview) Maintenance staffing, another area indicating a deficiency, is more complex. In the judgment of the DSAT maintenance team, on the basis of historic backlog performance and current planning and scheduling issues, there is no apparent significant shortage of mechanics. On the other hand, planning and scheduling staffing may be light. (DSAT maintenance team input) Recent expansion of the experience assessment function has locally stressed organizational staffing in that area. (JD-08, WW-03)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** MJD-02

**AREA:** MM&O

**DESCRIPTION:** HUMAN RESOURCES

CNS does not use standard HR/OD tools and good practices to affect needed improvement in their performance. The corporate HR/OD resources appear inadequate to meet the need.

**CAUSE:**

**EXAMPLES:** Individual performance issues contribute to every aspect of the current performance problems at CNS whether its workers choosing against their managers' expectations and not using procedures; supervisors failing to plan, communicate, maintain accountability or follow administrative procedures; or managers choosing to perform in the reactive mode, ignore industry changes or not properly incentivize their organizations. The HR and Organizational Development (OD) tools that could help correct this category of problems are not generally made available to the personnel at the site or, if present (such as the performance review program) are not used with enough skill to affect improving performance.

The corporate HR organization is located over 120 miles from the site with only one contact clerical person at the plant, despite the fact that one-third of the company's employees are at Cooper. Further, the company does not appear to possess a significant OD capability. (corporate interview)

Management and supervisory training is available from the corporate HR organization, but is not utilized to a significant degree by the site organization. Interview data implied that HR assistance initiatives made toward the site were rebuffed, ignored, or given low priority. During an interview, an I & C foreman indicated that he has had three to four days of supervisory training since assuming his role five years ago. Most managers have not been trained. During the interview process, the person most knowledgeable in the field of supervisory skills was a technician (line worker with no supervisory responsibilities) who had just received a bachelors degree in industrial supervision from a nearby college.

The selection process for filling management positions has been biased toward technical competence with no apparent strong analysis of management potential. (interviews) In the case of supervisor selection, there remains a strong seniority component. (interviews) Currently available technology for targeting selections for filling vacancies is not used, reducing the likelihood of selecting the best talent for open positions.

Position incumbency appears unusually long. Rotation for career development is limited. During interviews, some managers stated that there were incumbents who were reluctant to assume their current positions in the first place and had made those concerns known in the selection process.

There is a performance review program in place, but interview feedback indicated that, while the forms are completed, real use of the program to improve personnel performance is scattered. Discipline does not appear to be used as a tool in shaping performance .

Cooper appears to have difficulty in managing change. Despite this, no efforts have been made to educate the management in Change Management techniques.

**PROGRAMMATIC:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**PROGRAMMATIC:**

**MANAGEMENT:** Management did not strongly sponsor the introduction and use HR/OD tools/practices in the past. There is evidence that this is being started now.

**AREA:** MM&O **SEQ:** MJD-03

**DESCRIPTION:** MANAGEMENT SYSTEMS

Management systems appear to be weak at CNS.

**CAUSE:**

**EXAMPLES:** A consistent system for the comprehensive monitoring of plant performance, comparing it against high standards, then holding responsible management accountable for substandard performance has not been observed. In fact, when a DSAT request was made for "collective or individual department level indicators or management tools available to routinely and systematically assess performance toward established goals" (request 5039), the response indicated that such a mechanism was not known to be in place. During many management interviews it was stated clearly that it did not exist. Similarly, initiatives for correction or improvement frequently languish for similar lack of control. Some examples include:

1. Monthly Rad Pro reports with important management control information is circulated serially, requiring time to complete the review and the distribution is followed by no clear accountability. (JD-12)

2. Important programs, such as cobalt reduction and initiatives stemming from the 1992 SRAB self assessment are not accomplished because the commitments are not systematically tracked and managers held accountable. (CB-21, GW-13, JD-09)

3. Important maintenance parameters are not tracked and controlled in a systematic way. (DM-10, GW-12)

4. Existing backlogs in the following areas: TPCNs, PCNs, PTMs, MWRs (RC-15), would benefit from a systematic management approach to assure that management expectations on backlogs are being consistently met. (RC-15)

Training in how to do this does not exist; neither do strong role models. Since these are universal business skills not unique to nuclear power, it could be expected that the corporate leadership would ensure that CNS is practicing them, but that leadership is not evident.

**PROGRAMMATIC:**

**MANAGEMENT:** Management did not sponsor the use of the management systems required to monitor and adequately control plant activities.

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MJD-05

**DESCRIPTION:** PLANNING

CNS is deficient in the organizational discipline of planning and execution of plans. This has been a significant contributor towards their difficulty in achieving improvement and solving long term problems.

**CAUSE:**

**EXAMPLES:** In general, activities are not well planned, contributing to an observation that programs and corrective actions are initiated but not carried through to completion. Current programs and management controls do not require or promote use of strategic or tactical planning; existing planning and scheduling systems are ineffective. Management has fostered an environment in which production and work accomplishment is usually given the first priority with pressure on the staff to achieve results with minimal delay. Non-routine activities are frequently planned orally and launched without benefit of a thorough plan. Activities were observed to "out run" plans to be initiated before planning was complete or even begun. Examples Include:

- Initially inadequate planning and work instructions for correction of improperly engaged spade lugs in safety related terminal blocks. (Reference SV-08)

- Poorly developed plan and unjustifiable bases for selection and review of Operating Experience Items in response to NRC Confirmatory Action Letter. (Reference CB-11, SE-04).

- The initial NPPD response to NRC concerns regarding preconditioning was not comprehensively planned. Resulted in ineffective field direction, communication of management expectations and management oversight. Examples of proceduralized pre-conditioning were observed that were not properly nor expeditiously dispositioned in accordance with management's expectations. (CB-16)

- The new Corrective Action Program (CAP) was implemented in 4/94 but ownership, oversight, and planning for correction of CAP problems has been erratic. The vision for full implementation is incomplete. Problems still exist in CAP activity ownership, trending, OE program ownership, reliance on QA, and HPES use. (Reference DK-01, DK-03).

- The CAP Program Manager and Team Leader organization has been created but not institutionalized via charter statement or program plan. (Reference CB-15)

- Development of a new work control program is proceeding without a comprehensive, management accepted project plan. (DM-02)

- Task assignments and parameters for investigation and response to plant problems with valve lineup discrepancies and CS-MOV-12 testing discrepancies were unclear. The VP-Nuclear or the Site Manager had to intervene in both cases to ensure that safety issues were addressed and adequate plans developed. Notwithstanding this intervention, planning remained ad hoc and informal. (Reference SE-04)

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

- The absence of a centralized maintenance work scheduling process has resulted in additional equipment out of service time, lost maintenance production hours, and an increase in maintenance backlog. Also places an unacceptable administrative burden on the Shift Supervisor to coordinate work. (Reference SV-02).

- NPPD had previously identified a number of needed maintenance program and performance improvements (e.g. procedures, work control elements, shop/personnel performance). However, management focus has been on short term, immediate needs and plans have not been developed or have been inadequate. (Reference SV-04)

- An orally implemented change in policy prohibiting repair work on "troubleshooting" MWRs resulted in a significant impediment to progress. A second policy change reduced its scope to only Technical Specification equipment. (Reference CB-15)

Strategic, or long-range planning, was also noted to be historically weak. Recently there appears to have been improvements in this area. In response to a growing awareness of deficient performance, management initiated a "Near Term Integrated Enhancement Program" (IEP) which represented a plan for near term improvement in specific areas identified as deficient. The program was published then updated in May, 1994. In parallel to this effort, CNS management, in recognition of the need for a more comprehensive, longer-term focus in "today's nuclear environment," developed a four-year business plan. The actions delineated in the IEP were subsumed into the Business Plan. In general, the new plan represents a good first step in long-range planning; however, its effectiveness will be dependent on several factors, as follows:

1. A systematic practice for holding responsible managers accountable for timely completion of their respective actions.

2. Branch Business plans, referenced in the Business Plan are developed.

3. The "EXPECTED RESULTS" and "PERFORMANCE MEASURES" are made more specific to enhance accountability.

4. The Plan gets resource tied, i.e., the budgeting and control process should be firmly linked to the long range planning process to ensure that resources are available for improvement.

5. A significant improvement is achieved in the areas of management candor and willingness to be self critical. The importance of this can not be overemphasized. The need is based on a reading of the CNS management response to the NRC's Diagnostic Assessment Team report on Fitzpatrick Nuclear Power Plant. The response covered 75 identified deficiencies in the Fitzpatrick report. It essentially concluded that Cooper did not need to take any action in response to this learning opportunity. Subsequently, many of the same areas have been identified as weak, and in the case of a few, if action had been taken, CNS could have minimized their present problems.

**PROGRAMMATIC:**

**MANAGEMENT:** Management did not sponsor planning at CNS.

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MJD-06

**DESCRIPTION:** BUDGET AND CONTROL

The systems in place for budget and control are conventional and adequate to support improving performance if coupled to the new Business Planning process.

**CAUSE:**

**EXAMPLES:** Budget and control activities are conducted in a manner not atypical to other facilities. Financial requirements are generated at appropriate levels within the organization and rolled up to the corporate level. Reasonable challenges are given throughout the process. Reports containing actual O&M expenditures, on a booked basis, versus budget are compiled monthly by a site accountant and forwarded to the responsible managers. Nuclear normally budgets and O&M annual contingency of approximately 4%.

Capital budgeting is also conventional. The budget is typically not fully spent due to limitations in the execution of spending plans. Carry over of unspent capital is practiced giving greater assurance that funding for necessary improvements and repairs is available. (interview)

As mentioned previously, funding for the nuclear program appears adequate for normal activities but the budget and control process is not well tied to the long range planning process. Instead, it appears that resource planning has traditionally been based on historical performance with programmatic escalators added in.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MJD-07

**DESCRIPTION:** INDEPENDENT OVERSIGHT

NPPD oversight was not well thought out or managed, and when they had the opportunity to improve, they either failed to take it or, if learning occurred, as in the case of the SRAB self assessment, follow through was deficient. The result was inability to assess station performance.

**CAUSE:**

**EXAMPLES:** NPPD independent oversight failed to detect the current performance deficiency existing at CNS. That failure was essentially total. Review of SRAB minutes and SORC minutes along with interviews using both the management, SRAB, and SORC questioning protocols indicate that these oversight functions believed that CNS performance was essentially strong. Unfortunately, this appears to have been reinforced by external oversight organizations despite the fact that the performance problems identified by the NRC and the DSAT are generally long standing and do not represent a rapid decrease in performance. In actuality, CNS may not have experienced a significant change in performance, but they have failed to keep up with improving industry standards and it's only the belated recognition of this that gives the appearance of a rapid decline in performance.

QA differs from SRAB and SORC in that it is a standing organization charged with oversight and possessing true organizational independence. SRAB and SORC, on the other hand, are committees convened periodically, composed largely of managers with line responsibilities. Because of these differences the causes of their respective failure to identify the performance issues also differ.

The following are judgments regarding casual factors for the SRAB/SORC failure, based on meeting observations (SORC only), review of minutes, and structured interviews:

1. The membership of both the committees was composed of a large component of plant line management. It is apparent that they have been unable to succeed at differentiating their line and oversight roles. In late 1993, the VP-Nuclear communicated to the SRAB chairman commenting on this concern.

2. The corporate management failed to apply basic understandings of oversight to the nuclear operation to ensure that common pitfalls were avoided.

3. Neither committee rigorously carried out their entire charter; SRAB's being the SRAB charter and SORC's being Tech Specs with emphasis on paragraph 6.2.1.A.4.e. In 1993, SRAB did a self assessment which identified important areas for improvement; however, there was little evidence that permanent change actually occurred.

4. Neither SRAB nor SORC appear to have taken advantage of the opportunity to understand their performance deficiencies in light of and at the time of the earliest indications of the current problems.

5. SRAB does not appear (from minutes review) to have challenged the QA function when performance problems "began."

6. SRAB was not effectively challenged on its performance by executive management when problems "began."

7. SRAB minutes due not indicate that they ever seriously challenged SORC oversight performance.

The QA failure is more complex, involving the following:

1. QA had a generally low performance malaise combining lack of vision of quality beyond compliance, an insensitivity to the need to evaluate performance vs. reviewing programs, and deficient management attention to the QA program. Until 1993, the program was being executed by only 23 people including the manager and two clerks. Interviews with QA management indicated that they considered that number too low. Further, QA management stated that their performance was also diminished by excessive use of their organization for performing staff duties. Additionally, the QA manager present on site for the bulk of the perfomance "decline" period stated that the QA organization was called upon to perform the functions that will now be carried out by the IRG (the ISEG) function. He acknowledged that this was an appropriate QA activity but he felt that this further stretched his recourse. The net result was an inability of QA to uncover most of the performance deficiencies now evident in the line organization.

The Quality Assurance audits, surveillances and evaluations were generally compliance oriented and performance-based issues were generally superficial and caused QA's credibility with the plant staff to suffer. Further, senior management did not rely on QA as a meaningful tool for evaluation of performance-based technical matters. As a result, QA's effectiveness was significantly impeded.

2.The DSAT had initially concluded that QA did not adequately follow up on open/overdue issues to ensure that they obtained senior line management sponsorship for appropriate response to their findings and concerns. (SE-03) The CNS QA organization disputed this observation. Since this is clearly a qualitative issue, CNS must determine what, in the way of QA follow up, works best for them. Bottom line is that response to QA issues must improve.

3. Similar to the above issue. The DSAT concluded that QA had a weakness in identifying repeat findings to management. (SE-03) In written feed back, QA management stated "this is not true". CNS performance has been characterized by repeat failures/events. If QA is, as they state, pointing out repeat performance deficiencies to the line organization, their efforts are without effect.

4. According to interviews with QA management, in the instances where QA identified poor performance in the line organization, response by the line organization was deficient, characterized by defensiveness, resistance to findings, and slow response. Ancillary comments received by the DSAT QA evaluator included statements to the effect that QA personnel were tired of being "beat up" when they took their concerns to line management. During an interview with a senior line manager, he characterized line management resistance as being real and valid based on the low quality of QA findings. A review of numerous findings indicate that there may be some truth in both positions, however, the real issue is the inability for the site organization to work through this serious performance deficiency in order to gain the performance advantage of having a strong QA function.

5. SRAB did not challenge QA to higher performance nor did it bring performance deficiencies to the attention of executive management.

6. A number of other QA performance deficiencies are discussed in the DSAT findings prefixed by SE.

**PROGRAMMATIC:**

**MANAGEMENT:** Management did not take control of the situation and improve QA performance and the QA/line interface to assure a strong QA function.

**AREA:** MM&O **SEQ:** MJD-08

**DESCRIPTION:** CORPORATE LEADERSHIP AND SUPPORT

Weak or uninvolved corporate leadership did not assist the site in areas where their expertise would have been beneficial.

**CAUSE:**

**EXAMPLES:** Corporate management should be assuring that management practices necessary to assure success in running a complex, high consequence operation are in place. These are the high-level skills and practices which are generic in nature and not related specifically to the nuclear process. Contrary to this, leadership was not supplied in certain areas:

1. Oversight was conducted in a way that has a low probability of success and when initial signs of failure occurred they were not used as a learning experience. Corporate executive management did not assure that these deficiencies were quickly fixed (JD-05). The corporate Board did not challenge SRAB. SRAB minutes did receive comment from corporate officers (interview)

2. Normal business management control practices were not practiced at the station (JD-12). This could have been detected by closer corporate leadership oversight of normal management practices.

3. Business planning which is normal and prudent for complex business processes was not done at CNS (JD-10). No challenge was apparent from corporate leadership to assure that quality planning was done.

4. State of the art HR practices are not employed to strengthen human performance (JD-08). This is another area that could have, but didn't benefit from corporate leadership.

**PROGRAMMATIC:**

**MANAGEMENT:**

## DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
### Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MJD-09

**DESCRIPTION:** SELF-ASSESSMENT

Cooper does not have a strong self assessment culture. In some cases when self assessment is done, it was ineffective due to a pronounced lack of a self-critical attitude.

**CAUSE:**

**EXAMPLES:** Cooper has a self assessment program described by a guideline. The program is under the adminstrative control of QA. The guideline describes methodology but is light on specific expectations about how frequently formal, systematic assessment should occur. A review of self assessment report files revealed only sporadic performance of self assessment. Also, during the DSAT review of maintenance performance, when a request was made for the self assessments of MWRs and field observations required by section 8.10 of the Conduct of Maintenance procedure, no reports existed. The quality of the assessments varied. Of the two reviewed in detail, the Rad Pro effort was excellent and the SRAB was marginal. The Rad Pro report resulted in a number of improvement initiatives, most of which were acted on. Notably, there was a conspicuous lack of action on instituting a cobalt reduction program. In fact, a plan does not even exist for program development.

SRAB did an assessment in the third quarter of 1991, and concluded that their activities were being "effectively implemented and the Board is making a meaningful contribution to the safe operation of CNS." Contrary to this conclusion, the Board was unable to detect or confront performance issues which were occurring at the station. A significant lack of ability to be self critical was evident. Poor conclusions not withstanding, the assessment report contained a number of comments and suggested improvements that would have improved the SRAB function had they all been acted on effectively. They were not. A less rigorous self assessment performed in late 1993, and correspondence between the VP-Nuclear and the SRAB chairman indicates that performance issues had not been resolved. (RB-01)

Self assessment should also be initiated whenever a significant opportunity for learning presents itself. Cooper took such an opportunity by evaluating themselves against the DET Report on Fitzpatrick station issued in late 1991. The CNS response was to systematically go through the report and identify 75 areas of deficient performance at Fitzpatrick and then compare these to CNS performance to determine if NPPD action was required. In form, the effort was excellent. Unfortunately, a surprising conclusion was reached that NO action was required on all but two items, and in those cases action was already in place. Many of the areas are the very same ones found to have significant weaknesses by the DSAT.

A self critical attitude is foundational to effective self assessment. It is apparent from the above discussions that the ability to be self critical at CNS is very weak. (SE-08)

**PROGRAMMATIC:**

**MANAGEMENT:** There did not appear to be strong enough sponsorship from senior management gain the full benefit of the program which was in place.

## DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MM&O **SEQ:** MSV-05

**DESCRIPTION:** Management and Culture

Overall improvements in maintenance has been limited due to involvement of management in day to day activities and problems. The culture of maintenance personnel resists change and involvement in new programs for overall improvement. Supervising personnel tend to emphasize work completion without full understanding of question's raised during field work. The management chain of command for outage activities is not clear to station personnel.

**CAUSE:**

**EXAMPLES:** Industrial safety practices in the station are considered a weakness. (RC-03)

During three tours of reactor building, noticed no maintenance work in progress in any of these tours. (RC-08)

Temporary Design Change (TDC) 91-116 (Cameras in Heater Bay) has been installed for greater than the established goal of six months (RC-09)

No clear management chain of command of the current forced outage. (RC-10)

Shutdown Safety Management is not effectively addressed. (RC-12)

Improvements in maintenance programs & performance is limited due to involvement of management in day to day activities & problems. Plan for near term and long term improvement is not developed. (SV-04)

Culture of maintenance personnel resists change and involvement in new programs for overall improvement. (SV-12)

Maintenance supervisor personnel do not adequately pursue questions raised in perform[illegible] f maintenance work. (SV-15)

Workers are unfamiliar with management expectations on what is required for work instruction prior to working on essential equipment. This results in some inappropriate actions by workers along with delays of critical work evolutions. (SV-27)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MMNT **SEQ:** MRB-01

**DESCRIPTION:** Ineffective planning, scheduling, and control of work.

The lack of a coordinated work control system has resulted in extended outage durations, an increase in the duration and number of equipment outages, repeated challenges to the outage risk assessment process, and a reliance on the operations shift supervisor to manage the control of work and the configuration of the plant's systems. Additionally, lack of an effective work planning effort is affecting the quality of work being performed. The lack of a LCO tracking system adds additional challenges to the ability of the site to manage daily work activities and to assess the impact of new work.

**CAUSE:** 1. OWNERSHIP: There is no single CNS owner of the work control process. Individual site organizations are continuously struggling with their piece of the process. If a single owner were assigned, the various elements, criteria, and schedules could be identified, responsibilities assigned, and performance monitored and improved. With no single owner, no one can be held accountable for the breakdown of the process.

2. ACCOUNTABILITY: No assignment of accountability fo the overall program or the individual elements has been assigned. Without identifying what is needed, when it is required, and who is accountable, the present situation will continue.

3. CULTURE: There is a general lack of appreciation for the negative impact that the present situation has on nuclear safety. The repeated removal from service of equipment, the lack of a reliable work plan or schedule, and the need to manage the outage "on the fly" results in having to continuously reassesS the status of the plant in a reactive manner.

4. TEAMWORK OF MANAGEMENT: The need for improving the work control process at CNS has been recognized for some time. The management team has been either unwilling or unable to resolve this problem from an overall plant standpoint.

**EXAMPLES:** 1. WORK PLANNING - Work activities on plant equipment is frequently started prior to h aving a fully planned work package and without first determining if other related work activities should be performed concurrently. (DM-07, RB-02, DB-01, RC-10, SE-04, SV-02, SV-08, SV-19). Maintenance work is not performed in accordance with vendor specifications due to insufficient procedural guidance and inadequate maintenance work plans. Work planning is typically performed by the show crews. This results in a tendency to start work prior to having a plan developed. Craft personnel are assigned the tasks of determining the problem to be repaired, the methods and techniques to be used, location of parts, review of available vendor information along with routing the paperwork through the approval process. Since the work and the planning process is performed by the same personnel after the work is assigned to the shop for implementation, short cuts are routinely taken to expedite work completion. (SV-03, SV-08, SV-09, SV-10). Systems are frequently removed from service with no work being performed due to inadequate job planning (DM-02, CB-14)

2. WORK SCHEDULING - Each individual department controls its own priorities without being provided centralized direction on what work should be given the highest priority (RC-07, RC-10, RC-08, SE-04, SV-02, SV-08). Systems are repeatedly removed from service for a single routine task, returned and then ta

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out of service a few days later for another routine task (DM-02, SV-02, SV-07, SV-18). The Shift Supervisor's (SS) time is consumed in reviewing all work requests as they show up at his office window, work is typically approved on a first-come, first-serve basis (DM-02, RB-02, RB-06, DB-01). Operations has limited involvement in the establishment of priorities for repairs to plant equipment (SV-02). A transver from Div. I to Div. II RHR is slipping, on a daily basis, as newly identified prerequisites are identified (RB-02, RB-03). No accountability to develop and schedule a swapover list of activities is assigned, nor does the need to develop such a list appear to be recognized by the CNS management team (RB-02, RB-03, RB-06, RC-10).

3. Longstanding equipment problems and discrepancies exist without their being tracked in the maintenance work request system for future scheduling and planning efforts (SV-16, SV-20, SV-21). This results in the station having to deal with some issues on an emergent basis, rather than on a well-coordinated schedule basis (SV-02). An inordinate increase in the backlog of MWRs indicates inefficiencies in that process and the inability to effectively schedule and complete required maintenance. (RC-15)

4. Lack of coordination of action items from the corrective action program, work planning and work scheduling have significantly reduced supervisor involvement in field activities. This has resulted in an increase in work delays and mistakes in field work (SV-06, SV-07, SV-09, SV-10, SV-13).

5. Outage risk assessment and management is continuously challenged as a result of a lack of an effective work control process (DM-05, RB-03, RC-10, SV-19). System Operability determinations following maintenance require multiple meetings between representatives from various departments in order to be reached (DM-05).

6. A station Limiting Conditions for Operation (LCO) tracking system does not exist (DM-05, RB-04) resulting in frequent challenges to the SS's ability to make decisions regarding work activity authorization. Mode dependent LCO's are not tracked rigorously, making plant mode change decisions difficult (RB-04).

7. The lack of an effective comprehensive review of evolutions performed that could affect the margin of shutdown safety has resulted in the inability to adequately assure Defense-in-Depth of key safety functions (SV-08, SV-19)

**PROGRAMMATIC:** It is noted that while the DSAT team was onsite, an effort at overall improvement of the work control process was undertaken. The deficiencies in the program have been known for some time, but the station has just now undertaken to implement improvements. It is still too early to assess the effectiveness of these efforts. Long term commitment and follow-through on this improvement program will be required to realize the benefits. (see RB-06)

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MMNT **SEQ:** MSV-01

**DESCRIPTION:** QUALITY OF MAINTENANCE ACTIVITIES

Maintenance work is not consistently performed to assure equipment availability. Inadequate controls on previous maintenance activities have resulted in non-conforming and degraded plant equipment. Improper maintenance work has resulted in an increase in out of service time and rework. Quality Control verifications are not made consistently before and during maintenance work to ensure quality of repairs to equipment important to nuclear safety.

**CAUSE:**

**EXAMPLES:** Various examples of rework required after maintenance on 4160V breakers, service water pumps, turbine equipment cooling pump, diesel generator engine repairs, drywell inlet inboard isolation valve, RHR service water booster pumps, motor-operated valves overhauled during the refuel outage. (SV-07, SV-18)

SCRAM discharge level transmitter and RHR pump motor repairs resulted in degraded conditions of the equipment. (SV-23)

Various weaknesses in the Quality Control Program results in inconsistent quality verification of field w on safety-related equipment.

1. Quality Control requirements are routinely not specified for work on safety-related equipment. (RC-02)

2. Verification of system cleanliness, proper torque of fasteners and proper materials used for maintenance are not performed consistently to assure quality of plant is material. (WW-04, SV-23, SV-08)

3. Requirements for independence of Quality Control are not clearly understood by personnel responsible, resulting in the lack of problems identified by QC inspectors. (SV-01, SE-14)

4. Field verification of quality in replacement parts is not consistent. Examples include: Diesel generator air compressor, HPCI control relays, various safety-related valves, RHR lockwashers. (SV-22, RB-10, SE-11, SE-14, SE-16, SV-10)

The combination of craft preparation of their own maintenance packages (including definition of QC requirements); over-reliance on skill-of-the-craft over approved procedures and instructions; and a Peer QC program leads to a concern of the adequacy of the maintenance performed. Little management or independent oversight of the activities of the maintenance craft personnel is noted and, when viewed with the above concern, leads to the perception of "the fox running the hen house."

**PROGRAMMATIC:**

**MANAGEMENT:**

## DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
### Field Notes

*31-Aug-94*

**AREA:** MMNT **SEQ:** MSV-02

**DESCRIPTION:** PROCEDURES AND INSTRUCTIONS

Management has not ensured tha procedures sufficient to adequately operate, maintain and test the facility are developed, controlled and used as required by Technical Specifications. Some work on equipment that is important to nuclear safety is conducted without approved procedures. Procedures and maintenance work plans do not always provide sufficient technical information to assure work is in accordance with vendor specifications. Administrative controls in procedures frequently have ambiguous or inadequate instructions and tend to weaken the management expectations for procedure adherance. Procedures used for surviellances and field work frequently result in inappropriate actions or work interruption due to incorrect information. There is a lack of confidence by station personnel in the ability to revise and improve processes and programs in a timely manner due to an inadequate procedure improvement program.

**CAUSE:**

**EXAMPLES:** Work is routinely performed on safety-related equipment without SORC-approved procedures such as: 4160V breakers, Core Spray MOV-5A breaker, RHR Pump motor, diesel generator. (CB-12, RC-05, SV-01, WW-14)

Procedures and work instructions do not always include required vendor specifications: such as procedures for diesel generators, service water pumps, etc. (SV-14)

Some procedures contain ambiguous administrative guidelines and instructions (RB-05, RC-02, WW-20)

Some procedures are not adequate, resulting in interuption and delay of surviellances and field work. (CB-08, CB-12, WW-01, 07, 17, JC-02 )

The procedure change process is cumbersome and backlogged resulting delay in the improvement of many procedures. (DK-06)

There has been a poor adherance to clearance orders. (DM-06, WW-07, WW-19)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** MSV-03

**AREA:** MMNT

**DESCRIPTION:** LONG TERM EQUIPMENT PROBLEMS

Longstanding equipment problems and discrepancies noted during operation and maintenance exist in the plant without being tracked for future resolution

**CAUSE:**

**EXAMPLES:** Longstanding equipment problems and discrepancies noted during maintenance exist in the plant without being tracked in the maintenance work request system for future resolution. Examples include, process water leakage from the" A" RHR heat exchanger, temporary patch on the REC piping, degraded condition of the RHR-MO-39B valve, and service water system spargers. (SV-21)

Long standing problems in the service water system due to silt accumulation has resulted in operational work arounds and a relatively high amount of maintenance required on critical service water components. Problems include non-functional service water spargers, high maintenance of various service water valves and pumps, non- functional RHR heat exchanger differential pressure indicator, pressure switches that are backflushed prior to calibration (DM-09, SV-16, MDM-10)

Inadequate controls on previous maintenance activities have resulted in non-conforming and degraded p... equipment. In addition, when problems are identified root cause is not adequately addressed to prevent reoccurrences. Examples include SCRAM discharge level transmitters installed with improper bolting and loose bolts on the RHR motor. (SV-23)

During the operation of the 'B' shutdown cooling loop, flow turbulence caused a noticeable 'chugging' sounds in the vicinity of the heat exchanger bypass valve, RHR-MO-66B.(GW-08)

The potential for leakage in the REC (reactor equipment cooling) piping has not been adequately monitored to minimize the potential for leakage and impact on plant operations. Leakage problems were identified in 1979, with analysis by GE and subsequent changes to system chemistry. However, the utility has not taken action to monitor the condition of the piping system to ensure leakage does not occur. (GW-10)

Possible work-around associated with SGTS filter train fire detection system. Glass inspection ports on filter housing have been covered over with duct tape because inspections with flashlights have caused spurious actuations. What inspections are no longer being conducted (if any) because ports are covered? What was causing the spurious actuations (flashlight?) and does this have implications regarding operability of the fire detectors? (CB-02)

Temporary Design Change (TDC) 91-116 (Cameras in Heater Bay) has been installed for greater than the established goal of six months. (RC-09)

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

The tolerance level for accepting oil leaks on plant equipment needs to be adjusted. More emphasis needs to be placed on minimizing the number of oil leaks in the plant. (WW-05)

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** MMNT **SEQ:** MSV-04

**DESCRIPTION:** INDUSTRIAL SAFETY

Standards for industrial safety are not consistently enforced by station management. Personnel frequently ignore station and corporate safety guidelines in the performance of work. Independent verification of clearances is not performed to provide for worker safety. Observance of accepted safety practice is often by-passed in place of expediency of work completion. Performance indicators for Industrial Safety Accident Rate at the station is well above the industry median.

**CAUSE:**

**EXAMPLES:** Industrial safety practices of personnel performing work in the station are not in accordance with station guidelines. Examples include the inadequate use of personal protective equipment, lack of fall protection, and improper construction and use on scaffolding. (RC-03)

The station's industrial safety accident rate performance indicators have been well above the industry average for the past four years. Currently the station ranks 60th out of 71 plants in over all industrial accident rate performance. (DM-01)

Observations were sufficiently numerous to indicate that management is either not out in the plant observing activities or, if they are, are not regularly enforcing expectations. (JD-07)

An established practice in the station was to have an operator rotate the service water pump shaft without the protection of a clearance order, (WW-07)

CNS has an established procedural practice to only require independent verification for those clearances that are in the main flow path of safety-related systems. (RB-10) This suggests that the independent verification process is not intended to provide for personnel safety.(DM-03)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MOPS

**SEQ:** MRB-02

**DESCRIPTION:** COMPLIANCE-Compliance standards not always conservative.

There is not a well-established management expectation with regard to a conservative compliance with established procedures and programs. Interpretations of Technical Specification requirements are sometimes misunderstood or inconsistent. Procedural adherence expectations are inconsistant between departments. The requirements established in some programs are bypassed through the misuse of other processes.

**CAUSE:** Program/process development is not always accomplished in a manner that takes into consideration all possible requirements or other department needs. This result from:

1. OWNERSHIP: Individual programs do not have owners that enforce the expectations/standards with all involved having responsibility for their part of the program.

2. STANDARDS: There appears to be a lack of upper level expectations/standards that fosters development of processes and programs through a deliberate, thought-out manner that considers all the interfaces and possible requirements. Accomplishing this correctly creates the expectations/standards needed by the owners in item 1 above.

3. MANAGEMENT: Management style does not promote managers taking time to develop or change processes such that the end product has the bugs worked out with other involved groups before implementation.

4. MONITORING/ASSESSMENT: By prohibiting QA from initiating findings, simply by generating a NCR/DR, management can selectively impede the QA oversight function.

5. ACCOUNTABILITY: A clearly established accountability for all employees to adhere to the spirit and intent of procedures, programs, and regulations needs to be both established and enforced.

5. CULTURE: The fundamentally conservative culture essential to the nuclear industry is being undermined by the various institutionalized work arounds at the station.

**EXAMPLES:** 1. Activities at the station are conducted in a manner that does not always communicate a conservative approach toward the interpretation of the CNS Technical Specifications(JD-01,SV-1), regulatory requirements, and approved plant procedures (SV-5,SV-27,WW-14). The lack of followup of QA and self assessment findings, coupled with procedural ambiguities, has hampered the station's ability to identify and address this as a potentially significant cultural issue.

2. Some containment isolation valves are procedurally disabled, in the open position, without entry into the LCO (RB-11). Should the component remain disabled for an extended duration it is unclear how the requirements of the 24-hour shutdown LCO will be satisfied. Maintenance on nuclear safety related components is sometimes performed without detailed written procedures (JD-01, SV-18, SV-13, SV-10, SV-08). This is not in accordance with the requirements of T.S. 6.3.1. Proceduralized pre-conditionir

has resulted in the inability to determine the as-found condition (CB-16) of some equipment.

3. Emergency plan erroneously stated that the STA function was staffed at all times (SE-07, WW-18). A Condition Report was generated when this discrepancy was recognized during a 8/5/94 SORC meeting. (SE-07). Failure to ensure that different programs establish consistant requirements resulted in securing the STA function without first recognizing the discrepancy.

4. The QA program was changed to reduce the frequency of certain audits (SE-15). The QA program is working to a lesser version of ANSI N18.7 (SE-16). Neither of these issues has yet been submitted to the NRC for review and approval (SE-16).

5. Procedures are sometimes ambiguous (RC-02). For example, the Conduct of Maintenance procedure allows the Maintenance Manager to make exceptions to that procedure but fails to establish controls or documentation requirements. The Temporary Design Change (TDC) procedure explains that TDC's are not considered permanent while another step in the same procedure describes what to do when a TDC is considered permanent (RC-02). Ambiguities in procedures results in worker confusion regarding management's expectations.

6. Procedural statements imply that procedures provide guidance only and are not intended to constrain work (WW-20). This non-conservative message appears to have reached the average maintenance worker as documented in DSAT team interview results (JD-01, RC-05, SV-12, SV-15). It needs to be noted, however, that the CNS Operations Department appears to have a strong commitment toward procedural use and adherence (JD-01).

7. Opportunities to benefit from QA audits (SE-13) and SRAB self assessments have been missed. There is no requirement to followup to QA recommendations (SE-02), and QA has been instructed not to write a finding if a NCR on the same item exists (SE-02). Self assessments of the SRAB (JD-09) have identified findings that, if addressed, would have enabled CNS to advert some of the present plant performance problems. The performance of the SRAB appears to be that of a second SORC (JD-05, RB-01) rather than that of a board chartered with providing broad oversight of CNS operations.

8. Decisions to postpone the Emergency Plan's 50 mile IPZ dose assessment model to EPA 400 requirements were made without modifying the Emergency Plan or the Emergency Plan Implementing Procedures (WW-03).. The Special Instructions process allows instructions to include the individual component manipulation steps to isolate work for personnel protection without using a Clearance Order. This is in conflict with the Clearance Order (CO) procedure. (DM-06)

9. The Special Instructions process allows instructions to include the individual component manipulation steps to isolate work for personnel protection without using a Clearance Order. This is in conflict with the Clearance Order (CO) procedure. (DM-06)

10. Tech Spec requires that SORC approved maintenance procedures exist that describe the conduct of maintenance. These maintenance procedures would contain such things as assembly/disassembly directions, torque requirements and repair instructions. Special Instructions have been used in place of maintenance procedures when maintenance procedure did not exist. However, Special Instructions do not receive the same level of approval as maintenance procedures when they contain procedural type details for

the conduct of maintenance. (WW-14, SV-01)

11. The need for an improved Work Control process has been known for some time. However, until recently their has not been an integrated approach to establishing this process and even these efforts have not considered the full scope of what work control involves.

12. Some existing program/process procedure guidance is written in a manner that makes it subject to interpretation. (DM-06, WW-19, WW-20)

13. A well established procedure validation and walkdown process has been circumvented through the misuse of special instructions. While not intended to be used as procedures, special instructions have sometimes been used in place of procedures. Since special instructions are neither validated or walked down, errors go undetected until they are actually being performed in the field.(RB-13, MRB-01)

**PROGRAMMATIC:**

**MANAGEMENT:** Management style does not promote managers taking time to develop or change processes such that the end product satisfies all regulatory and procedural requirements with the bugs worked out with other involved groups before implementation.

# DIAGNOSTIC SELF ASSESSMENT MASTER OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MOPS **SEQ:** MWW-03

**DESCRIPTION:** Portions of CNS management have viewed training as an obligation instead of an opportunity, subsequently, several Training programs are lacking quality due to a lack of management oversight.

**CAUSE:**

1. LACK OF OWNERSHIP - There is a general lack of ownership in terms of Maintenance supervision (Maintenance Manager and Maintenance Supervisor) providing feedback to training . The general thought has been that journeyman are "master craftsmen" and need only basic skill of the craft training. Once this training is complete the journeymen can handle most task in the plant using procedures or special instructions. Subsequently maintenance supervision (with the exception of the Ops Manager who owns the I&C training program) does not promote his personnel coming to training in that it is viewed as an obligation instead of an opportunity.

System engineer training was given low priority during its initial development in the 80's. Problems noted in the engineering training staff concerning their lack of system knowledge was never fed back into the training program.

2. LACK OF MANAGEMENT FOLLOW-UP - Due to the attitude for a lack of ownership, sections of management did not participate in periodic training observations which had been mandated by management beginning in 1992. This program was intended to provide for management follow-up however it was ingnored by some even though remainders were sent to them by Training.

3. LACK OF TEAMWORK - Concerning HP continuing training, HP supervision has held the continuing training program close to their vest maintaining too much ownership. Due to this, the benefit of obtaining and coordinating a more detailed and challenging continuing training program does not exist.

4. MONITORING/ASSESSMENT - As previously discussed the monitoring and assessment for the maintenance, engineering, and HP continuing training programs was weak. The Operations Manager has provided feedback to the Operations and I&C training programs however, there was one noted disconnect concerning the expectations of the SS to industry standards during emergency events.

5. LACK OF NUCLEAR CULTURE - The utility has not recognized the need for the accurate determination of core needs for competency. Subsequently they have personnel performing activities that do not fully understand system operation and interaction. Also, engineers do not fully understand the importance of ensuring the CNS design basis is maintained.

**EXAMPLES:** 1. The Operations Managers expectations for the Shift Supervisor maintaining a "stand back" overview during emergency events has not been implemented into simulator training. (WW-06)

2. Since CNS Directive 54, Management Overview of Training and Evaluation Activities, was issued in 1992, the Maintenance Manager and Maintenance Supervisor have not conducted observations required by CNS Directive 54. Additionally, the Engineering Manager has not conducted any observations since 1992. The purpose of these observations was to ensure management feedback into training activities(WW-25)

*31-Aug-94*

3. Position-specific guidelines for selected engineering support positions were not incorporated into training effective 1/1/93, as specified by the issuance of INPO ACAD 91-017, Guidelines for Training and Qualifications of Engineering Support Personnel. These guidelines were not incorporated due to a training management oversight. (WW-25)

4. The initial engineering support personnel training program provides limited insight regarding system interactions and overall system knowledge. System engineers are expected to complete self study training on their systems using the operators/STA training materials, pass a written test, and demonstrate over time their knowledge of the system to their lead before being "certified" as system engineers. Additionally, some system responsibilities are separated between electrical and mechanical system engineers, with limited cross-training of the engineers to improve the knowledge of the other(mechanical or electrical) aspects of system operations. Furthermore, system engineers are often unaware of where the design basis for their system is located or how to identify the applicable design basis information for their system. System engineers currently prepare special instructions for maintenance work activities on safety-related components, and corporate engineers often prepare the special instructions for design change package implementation. Neither group has received training in work planning or procedure preparation. Additionally, Corporate engineering personnel do not receive systems training(MGW-04)

5. Skill of the craft training needs are not understood and are inadequately defined . Many JPM's are evaluated in the Training shop environment to a generic skill and few follow-up motor skill evaluations are conducted on specific in-plant equipment. Training relies on procedures and skill of the craft training in order for maintenance activities to be properly performed. However, DSAT observations indicate this process appears inadequate.(WW-26)

6. The HP continuing training program is limited in that it does not build an in-depth technical program following the fundamental training program. Although HP supervision conducts continuing training during periodic meetings, the continuing training process needs to be defined from a Training department perspective and expanded to provide more technical detail and challenge for HP personnel. (WW-27)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-02

**DESCRIPTION:** The station is living with a long-term equipment problem in the standby gas treatment system by blocking the filter housing viewing ports with tape.

**CAUSE:**

**EXAMPLES:** Glass inspection ports on the standby gas treatment system (SGTS) filter housing have been covered with duct tape because flashlight inspections have caused spurious actuations of a flame detector in the past. This has resulted in system inoperability due to wet charcoal when the fire protection deluge valve opens. A manual valve has been closed isolating the deluge valve, and the fire procedure includes a provision for local valve manipulation to suppress fires.

The SGTS flame detector is a Pyrotronics model DFS-3 detector that responds to flickering infrared light between the frequency of 5-30 cps and is not affected by constant light sources, such as incandescent light (according the vendor manual). The vendor manual also indicates that operational checks can be made with a special flashlight having a built-in transistorized flasher. This conflicts with the spurious actuation history at Cooper,as well as the routine surveillance procedure. The surveillance procedure includes steps to remove the duct tape over the inspection port, shine a flashlight (ordinary flashlight?) into the port, confirm that the alarm actuates, and replace the tape. At the conclusion of the DSAT evaluation, the station was unable to explain this inconsistency.

In addition, the DSAT team questioned whether a flame detector is appropriate for the SGTS filter housing application. According to the vendor manual, the DFS-3 is intended to protect hazards where the anticipated fire will develop quickly with little or no incipient smoldering stages, where ignition is almost instantaneous (such as gasoline, alcohol, etc.). This seems inconsistent with a location where charcoal is the primary combustible. At the conclusion of the DSAT evaluation, the station was unable to explain this inconsistency.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-07

**DESCRIPTION:** The operability determ ination for a deficient plant condition was untimely.

**CAUSE:** Although the station has recently changed to a single problem reporting system, a different system was used to document the deficient condition.

**EXAMPLES:** During a management walk-through, a broken flex conduct was identified on an instrument on Standby Gas Treatment System (SGTS) filter housings. The walk-through report was reviewed by Tech Staff Manager who assigned I&C to repair the conduit. I&C documented the deficiency on Condition Report proposed as category 5. The Condition Report review group raised priority to category 3 and assigned to Engineering to conduct operability determination prior to startup. Process was delayed by failure of manager to document on Condition Report promptly.

**PROGRAMMATIC:** The management walkthrough program is structured so that identified deficiencies are forwarded to a walkthrough coordinator for subsequent processing, rather than requiring that the inspecting manager use existing systems for documenting problems. A procedure revision is reportedly in progress that would address this issue.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-08

**DESCRIPTION:** A surveillance test procedure was aborted on several occasions, and the immediate problems were fixed by procedure revision; however, none of these individual cases prompted a thorough review of the procedure in its entirety. When a reactor recirculation pump unexpectedly tripped during the test, a condition report was finally initiated, because it was a potentially reportable occurrence.

**CAUSE:** Failure to conduct verification and validation of a procedure that has undergone extensive changes.

**EXAMPLES:** Control room logs document the following:
-- 7/24/94 0122 - Terminated S.P.6.2.2.5.14 due to procedural deficiencies. Appropriate steps taken place A & B loops of RHR into normal LPCI line up
-- 7/24/94 2150 - Same words as 0122 entry repeated again
-- 7/25/94 2133 - Issued SP 6.2.2.5.14 RHR initiation and containment spray logic functional test
-- 7/26/94 0005 - RRMGA tripped during SP 6.2.2.5.14
-- 7/26/94 Condition reports for CRG review documents CR No.05861 Reactor recirc pump 1A tripped following unexpected closure of RR-MO53A during performance of SP 6.2.2.5.14.

During the first attempt to perform this procedure on 7/24/94, four relay contacts that were to be confirmed as open were found to be closed. The procedure was terminated and it was determined that the procedure was in error. The relay contacts should have been closed (as they were found to be). A procedure change was initiated to correct these errors. During the second attempt to conduct the procedure later that evening, an annunciator unexpectedly cleared during one step, and three relay contacts on another relay were found closed rather than open as specified in the procedure. The procedure was terminated and again found to be in error. Another procedure change was initiated to address these problems. During the third attempt at the procedure on 7/26/94, a recirculation pump discharge valve closed as designed; however, since the recirculation pump was running, it unexpectedly tripped according to design. A temporary procedure change was initiated and the procedure was continued. The procedure precautions/prerequisites did not ensure that the recirculation pump in the loop being tested was not in service before performing the test.

Station personnel reported that the surveillance procedure had undergone an extensive revision since its last performance to incorporate more thorough logic system functional testing. Although some similar procedures have recently undergone validation and verification, this procedure had not.

**PROGRAMMATIC:**

**MANAGEMENT:** Management failed to establish high standards for procedure adequacy expectations when a thorough evaluation was not initiated after the second attempt to complete the procedure failed.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-09

**DESCRIPTION:** NPPD is a member of the BWROG scram reduction subcommittee and has paid a fee to participate, but station ownership was recently transferred from Technical Staff to Engineering. Since this transfer of ownership, CNS has been unrepresented at the last two meetings. This is an important source of industry operating experience that is not being taken advantage of.

**CAUSE:** Station work was deemed to be higher priority than attending meetings.

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:** Although management routinely approves requests for attending industry meetings, they do not take an active role in encouraging CNS personnel to attend industry meetings.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-10

**DESCRIPTION:** Station management has not provided an aggressive plan to minimize the likelihood of repeated thermal overstress on reactor vessel structures during plant transients that involve thermal stratification of reactor coolant. Repeated occurrences may exceed the design basis and may eventually result in fatigue failure.

**CAUSE:** Insufficient evaluation of industry operating experience. Failure to document a significant condition adverse to quality to ensure proper evaluation, prioritization, and tracking to closure. (Once apparent violation was recognized, no new deficiency report, nonconforming condition report, or condition report was written.) Failure of management to provide appropriate direction and expectations for an identified deficiency.

**EXAMPLES:** GE SIL No. 251, Control of RPV Bottom Head Temperatures dated October 13, 1977, originally described the concern with thermal stratification of reactor coolant and established a core exit coolant and bottom head drain coolant temperature differential limit for starting reactor recirculation pumps (145 degrees F). The limit was considered necessary in order to avoid thermal overstress on control rod drive stub tubes and in-core housing welds caused by sweeping hot water across these relatively cooler vessel structures. The SIL indicated that repeated occurrences may exceed the design basis and may eventually cause fatigue failure. Information Notice (IN) 93-62, Thermal Stratification of Water in BWR Reactor Vessels, dated August 10, 1993, describes recent industry experience and indicates that once thermal stratification occurs, any rapid circulation of water could result in a large step change in the temperature of the water adjacent to the reactor bottom head penetrations. The IN cautioned that a step change in temperature may violate technical specification limits, and that the correct and timely operator response to these conditions depends upon proper actions being specified in plant procedures and appropriate operator training. CNS review of this on September 24, 1993, concluded that the issue had been adequately addressed by a previous evaluation of INPO SER 5-93. The station evaluation of SER 5-93 included a review of all scram recovery procedures and startup procedures (these were considered adequate in addressing the concerns), and development of a new PMIS display of reactor pressure-temperature curves for operator use during transients. No further training was recommended because it was determined that adequate procedure guidance existed for this type of event. The SER evaluation was also based, to some extent, upon a faulty analysis which concluded that the possibility of both recirculation pumps tripping was low because a modification previously implemented provided separate off-site power supplies to the recirculation pumps. On December 14, 1993, a feedwater controller malfunction resulted in a reactor recirculation pump trip on low-low water level. Cooldown rate concerns existed because little decay heat was present early in the core operating cycle, so operators closed the MSIVs. With recirculation pumps off and MSIVs closed, reactor coolant temperature stratified. About 9.5 hours later, with reactor pressure about 230 psig, MSIVs were opened to continue the cooldown. Reactor pressure quickly dropped, and better mixing of the reactor coolant resulted in reactor vessel bottom head temperature increasing by 116 degrees F (from 134 to 250) in one hour. Concerns with whether this increase violated technical specification limits were not expressed by the shift crew, nor was the excessive thermal transient evaluated during the post-trip review process.

Following the scram, a deficiency report (DR) was written to comply with the practice of documenting unanticipated conditions that require use of abnormal operating procedures. Subsequently, on January 18, 1994, disposition of this DR was combined with a review of INPO SER 5-93, Supplement 1, that described additional industry occurrences of stratification-induced violations of reactor vessel pressure-temperature limits and heatup rate limits. CNS personnel then reviewed plant records and recognized that an apparent violation of the vessel heatup rate limit had occurred during the December 1993 scram. On February 9, 1994, a technical specification clarification request was submitted to clarify the apparent violation.

On February 24, 1994, the Nuclear Licensing and Safety Manager documented in a Technical Specification Clarification memorandum to the plant manager that although the technical specification gives heatup/cooldown rate limits measured by reactor coolant temperature changes, the transient limit applies equally to vessel metal temperatures. The document stated that since the basis for the restriction is limiting cyclic fatigue on the metal, if vessel metal temperature exceeds the 100 degrees F limit averaged over a one- hour period (regardless of coolant temperature), then a technical specification violation has occurred. Discussion with GE had indicated that water temperature was used as the criteria because in most cases, measured changes in water temperature would be greater than the vessel metal transient, therefore bounding the actual cyclic duty on the metal. This memorandum was forwarded by the plant manager to the operations manager with instructions written indicating that because he did not agree, a response should be prepared to have the interpretation retracted. No further action had been taken on this interpretation at the time of this review.

As a result of the continuing review, SER 5-93, Supplement 1 and the loss of feed scram at CNS were reviewed during licensed operator requalifications cycle 94-12. The review was conducted in a classroom discussion concentrating on the importance of monitoring reactor vessel pressure-temperature limits and heatup/cooldown limits. Following the discussion, a simulator demonstration was conducted applying concepts and actions discussed in the classroom. A February 28, 1994 letter from the SRO instructor documents several ideas and indicates that management guidance is needed. These ideas include methods to control reactor pressure and promote mixing to allow time to restore recirculation pumps, minimize the amount of cold feed water injected, means to more rapidly restore reactor water cleanup, and reduction control of rod drive flow.

Although some of these techniques were applied during a subsequent reactor scram on March 2, 1994, resulting in successful restart of recirculation pumps and minimization of thermal stratification, the 100 degrees per hour heatup rate was again violated. No changes have yet been formally adopted in procedures and training since the original event in December 1993.

**PROGRAMMATIC:** The post-trip review procedure (Conduct of Operations Procedure 2.0.6) contains no guidance for conducting a critical review of vessel metal temperatures following coolant stratification transients.

**MANAGEMENT:** The site operations review committee did not thoroughly evaluate the post-trip review. Station Management perceives the significance of this condition to be low.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-11

**DESCRIPTION:** Special reviews are sometimes completed without the forethought and planning that provides for the development of a problem statement, establishing the scope of activities and its basis, and deciding how the results will be used to come to a conclusion of the issue.

**CAUSE:** Crisis management practices driven by a perceived need to conclude the work by a preestablished target date.

**EXAMPLES:** The Confirmatory Action Letter (CAL) response plan dated July 30, 1994, indicates that prior to startup, the operating experience data base will be reviewed by

1) developing a screening criteria,
2) developing a basis for a two year review,
3) reviewing operating experience for safety significance and,
4) reviewing operating experience for adequacy of implementation of safety significant issues.

At about 11:00 on August 1, 1994, according to the contractors tasked with the effort, the review was essentially complete. A screening criteria had been developed and was in use; however, the scope of operating experience documents reviewed and its basis did not yet formally exist. According to the contractors, the scope included all operating experience documents recieved after January 1, 1992, with the following exceptions: those documents received after January 1, 1992 that are not closed, excluding INPO SOER recommendations that have been closed by INPO. This resulted in about 800 to 1,000 documents being included in the review. When asked about the basis for the scope, the contractors stated that CNS licensing was responsible for defining and justifying the scope. CNS licensing indicated that the contractor had been tasked with selecting the basis for the scope. None of the individuals interviewed could provide a satisfactory answer when asked to justify excluding pre-1992 operating experience, or operating experience that is not currently closed. Note: there have been several recent station events that have been rooted in the inadequate disposition of older operating experience documents. Statements offered in response to this issue ranged from a perception that the time requested to perform a broader review would be excessive, to a general feeling of acceptable evaluation of prior station operating experience, to reliance on the complete review of all operating experience back to 1982 that is to be completed within about two months after restart. No one indicated that the scope seemed to have been predetermined by the CAL-supplemental plan which stated 'develop a basis for a two-year review.' The scope was subsequently expanded based upon further review.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-12

**DESCRIPTION:** Corrective actions for a recent significant condition adverse to quality did not adequately address the root cause, or an inappropriate root cause was assigned, resulting in an increased likelihood of similar problems recurring.

**CAUSE:** The root cause techniques described in the station root cause guidelines were not formally and rigorously applied. The condition review team (CRT) report states that a barrier approach was used to determine the root cause and contributing factors. However, contrary to the root cause guidelines document which states that failure path and barrier analysis is a systematic method used to identify possible root causes, the CRT team leader indicated that the analysis was performed informally by conducting a group discussion with a maintenance manager and a consultant who is providing root cause coaching and mentoring. The barrier analysis is not documented other than the results contained in the CRT report. Industry experience has shown that event and causal factor charting is a more appropriate method for investigating an event such as this. Schedule pressure for completion of the root cause analysis resulted in short cuts. The CRT team leader stated that there was no time for charting the barrier analysis or performing an event and causal factors analysis due to the expected completion date. The expert consultant mentoring and coaching root cause analyses inappropriately provided implied consent for the informal root cause process used.

**EXAMPLES:** The root cause for condition report 94-0295, Failures of Undervoltage Trip Assemblies (UVTA), was determined to be lack of management commitment to operating experience review program implementation. The contributing factors described in the (Condition Review Team) CRT report do not support this root cause. (Contributing factors included inadequate maintenance procedures, inadequate surveillance procedures, failure to investigate prior UVTA failures, and absence of an equipment reliability program to detect adverse failure trends.) Discussions with the CRT leader indicate that the root cause of management commitment was intended to apply to an individual maintenance manager (no longer at the station) who was responsible for revising a maintenance procedure in 1984 to incorporate detailed vendor instructions for periodic lubrication of UVTAs. Rather than incorporating three pages of detailed instructions and drawings into the procedure, a non-specific statement was added to lubricate all pivot points on the device if necessary. Lubrication was considered by the manager to be within the skill of the craft. Lack of management commitment exemplified by inappropriate performance by an individual manager in 1984 who is no longer at the station does not fit the station definition of root cause (the most basic reason for a problem within the control of management which, if corrected, will prevent recurrence). Additionally, corrective actions approved by the station corrective action review board do not address the assigned root cause. Instead, the corrective actions address equipment performance aspects including elimination of inappropriate pre-conditioning, correcting deficient surveillance test procedures, developing methods to detect and evaluate abnormal equipment performance, and evaluating non-safety related circuit breakers for similar problems. One action, credited for already being in progress as a result of prior problems, was accepted for addressing the assigned root cause of lack of management commitment. The action involves assessing station evaluations of past operating experience documents and implementing programmatic changes that may be indicated. Although this would be appropriate for a programmatic deficiency root cause, it does not address management commitment issues such as management oversight and program monitoring, adequacy of staffing and resources (including training and experience), and authority, responsibility, and accountability provided to groups tasked with program implementation.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**PROGRAMMATIC:** Corrective action review board procedures do not contain explicit guidance that the corrective actions should be evaluated against the root cause.

**MANAGEMENT:** Management oversight and monitoring of improvements ongoing in the root cause analysis program has been delegated to expert consultants.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-13

**DESCRIPTION:** Evaluations and actions taken in response to industry operating experience information have been ineffective in preventing the occurrence of similar events at Cooper Station.

**CAUSE:** Shallow technical evaluations often based on non-factual assessment of prior station equipment failure history or underestimation of the likelihood of problems from other facilities manifesting themselves at Cooper Station. Generic issues are sometimes not addressed on a scope broad enough to discover weaknesses in station programs that should be enhanced to prevent recurrence.

**EXAMPLES:** 1. Inadequate sequential load testing of emergency diesel generators led to undetected failures in the load shed logic on 5/25/94. (IN 91-13, IN 88-83)

2. Failure of Westinghouse 480 volt circuit breaker undervoltage trip assemblies led to unrecognized emergency diesel generator overload on 6/14/94. (IEB 83-08, Westinghouse Technical Bulletin).

3. Calibration inaccuracies in feedwater flow instrumentation led to non-conservative indication of reactor power and subsequent power derating by 0.8 percent on 4/11/94. (GE SIL 452 and 452 Supplement I)

4. Deficient abnormal operating procedure for loss of feedwater events resulted in unrecognized potential for placing the plant in the power instability region during a reactor water level transient by tripping a recirculation pump on 12/14/93. (SER 23-93)

5. Multiple failures of GE type SBM control switches. (GE SIL 155 and Supplements 1 and 2)

6. Multiple interruptions of shutdown cooling and 12-hour delay in entering shutdown cooling due to isolation system actuations caused by pressure surges when voids collapse (5/26/94, 6/21/93, 3/6/93). (GE SIL 175)

7. Control room habitability envelops test failure on 4/11/94 due to excessive leakage and design deficiency. (IN 86-76)

8. Failure to control interfacing ventilation systems during secondary containment integrity tests led to undetected ten-inch penetration with no water loop seal since original construction on 3/8/93. (IN 90-02)

9. Shifting emergency diesel generator loads as part of the test setup before load shed testing - preconditioning issue. (SER 27-93)

10. High pressure coolant injection pump discharge valve failed on 9/30/93 due to a dislodged motor pinion gear key. (Limitorque maintenance update, SER 9-88)

11. Primary containment declared inoperable and shutdown action statement entered on 10/11/93 due to core spray dual-function valve (mini-flow valve) not meeting licensing basis. (Duane Arnold OE 5033, 1/10/92, and Fitzpatrick OE 5493, 8/3/92)

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**PROGRAMMATIC:** CNS procedure 0.10.3, Industry Operating Experience Program Effectiveness Review, specifies that the annual effectiveness review is to be based upon a review of documents that are:
1) dispositioned and closed for a minimum of one year to make sure time has transpired for the changes to become effective
2) closed greater than two years so that the review is reflective of the current program. This narrow sampling does not assess the continuing effectiveness of important industry experience, or the timeliness of recent high-priority operating experience.

**MANAGEMENT:** Weak monitoring and oversight of program effectiveness and failure to relate individual cases of performance problems to broader implications.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-14

**DESCRIPTION:** Work practice observations.

**CAUSE:** Failure to incorporate well known industry scram-reduction practices into station work practices. Excerpting procedure steps from a surveillance instruction into a corrective action or troubleshooting activity without a thorough regard for applicability to the situation.

**EXAMPLES:** Work on a scram discharge volume level transmitter was observed on August 2, 1994. The task was performed by two instrument technicians under maintenance work request (MWR) 94-4197 and its attached special instruction. The system engineer who wrote the special instruction was present during most of the work, and the instrument maintenance supervisor observed some of the work. The activity involved isolating, venting, and draining the transmitter sensing line and removing the transmitter cover (which is a reactor coolant system pressure boundary during a scram) for inspection and cleaning if necessary. This activity was part of an investigation of erratic calibration shifts experienced on a redundant flow transmitter. The erratic transmitter had been inspected the previous day and corrosion products (apparently originating from the carbon steel instrument volume and sensing lines) had been found in the transmitter housing and in the folds of the bellows. The following observations were made:

1. The work instructions were not written in a sequence that minimized the length of time the reactor protection system (RPS) was in a half-scram condition. After tripping the "B" RPS channel, the instrun. technicians returned to the shop to obtain the necessary tools, progressed to the work site, and obtained the services of a radiation protection technician. About 1/2 hour transpired before manipulation of the transmitter valves began. A similar delay occurred after local work at the transmitter was complete. Better work instructions could have reduced the length of time the RPS system was in the non-coincidence mode (and vulnerable to full RPS actuation from spurious trips on the other channel), from about two hours to about one hour. Recent industry experience has shown that a significant contributor to unplanned automatic scrams is spurious RPS actuations while one channel is tripped for surveillance or troubleshooting.

2. The special instruction contained a pen-and-ink change over the typewritten instruction that changed the designated RPS channel to be tripped from channel A to channel B. The shift supervisor who authorized commencement of the work did not question this change as a potential for a wrong train event and performed only a superficial drawing review when prompted by the system engineer to confirm that the transmitter to be worked was in the "B" RPS logic. When questioned about whether there were other activities ongoing that might result in tripping of the other RPS channel, the shift supervisor's response indicated that he had only considered whether other surveillance procedures were in progress.

3. The valving sequence involved first opening the transmitter drain valve and draining fluid from the sensing line and scram discharge instrument volume until no more water was present (this took about 10 seconds), then closing the transmitter isolation valve. Had an inadvertent scram occurred during this interval, the scram discharge volume would have been open to the reactor building atmosphere, creating a personnel safety hazard. The system engineer who wrote the special instructions indicated that the valve sequence in the special instruction was extracted from a portion of the calibration surveillance procedure that is performed at full power.

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4. The instrument technician worked in the overhead by sitting on a ventilation duct. The instrument maintenance manager was asked about the practice of climbing on overhead components, such as ductwork and cable trays, and stated that although it is less than desirable, sometimes it is the only method available. The only expectation for this practice is that the components should be substantial (for example, not a conduit).

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-15

**DESCRIPTION:** Miscellaneous insights from various personnel interviews.

**CAUSE:**

**EXAMPLES:** During our counterpart tour, the Technical Staff Manager (who has overall responsibility for the industry operating experience review program) demonstrated weaknesses in his knowledge of recent industry operating experience. He indicated that he does not routinely review NUCLEAR NETWORK Operating Experience (OE) topic entries. A member of his staff routinely downloads NETWORK entries and routes OE entries and questions from other topics to departments determined to be applicable by her. For example, he was not aware that a BWR recently experienced an unexpected reactor power increase above 100% while shifting recirculation pump lube oil pumps; nor was he aware of the BWRs who have had difficulties in implementing the reactor water level backfill modification (which was recently implemented at CNS). The Technical Staff manager used to be the station representative on the BWROG scram reduction committee. This responsibility has recently been moved to the engineering department, and CNS has been unrepresented at the last several meetings. The Technical Staff Manager indicated that he had recently asked for additional people to address expanded management expectations for root cause analysis and independent safety review. He proposed the need for ten additional people, but this request was rejected. He noted subsequently that the new CRT group was established (outside his department) with s people and the new independent review group was to be staffed with four people which totals ten new people performing the functions he had proposed. LER writing is also being moved to licensing from Technical Staff. The Technical Staff Manager stated that the delay in getting the root cause trend data base implemented results from cancelling this task originally assigned to FPI due to CNS dissatisfaction with the work. The Technical Staff Manager stated that in response to the corrective action program oversight group (CAPOG) findings on inadequate responses to selected industry operating experience documents, he requested an additional person for his department to be dedicated to independent close-out review of industry operating experience documents. This request has not materialized. By default, this leaves the Technical Staff Manager as the only person assigned this task. During a discussion with the Technical Staff Manager related to recent management decisions, he related a policy change on work control. In response to a concern that short cuts were being made by keeping some MWRs open for an inordinate length of time and conducting multiple work episodes, a verbal change in policy was made to the effect that no longer could work be accomplished on a troubleshooting MWR. The problem is to be found on the troubleshooting MWR, and then another MWR is to be written for repairing the problem. The work process slowed considerably after this, since after troubleshooting found the problem, work would stop, the equipment would be restored, the MWR would be closed, and a new MWR with work instructions would have to be processed and worked. Once this process became burdensome, the policy was changed to apply only to technical specification equipment.

The Corrective Action Program Manager indicated that although his position is not yet shown on the organization chart, he reports directly to the Senior Nuclear Division Manager of Safety Assessment. He has five condition report team leaders currently on loan for six months from training, operations, mechanical maintenance, corporate nuclear engineering, and CNS mechanical engineering. The group does not yet have a charter statement (he is drafting one). The Vice President, Nuclear established the position of CAP program manager on June 10, 1994, after a contractor performed an assessment of the program and recommended one be created, and following criticism by the NRC of condition review team performance on a RHR system problem evaluation. Regarding a program plan or similar document that outlines milestones to achieve management expectations, he indicated that these expectations haven't yet been finalized. From his perspective, he intends to begin administrating the morning condition review group meeting and processing of CRs, possibly taking over maintenance of the CR database, and performing routine trend reviews, and maybe incorporating the industry OE program. (These functions are currently performed by the Technical Staff).

A review of the recent QA audit of the corrective action program with the lead auditor revealed the two main messages intended for management were the backlog of open corrective actions, and the quality of problem investigation (condition review team guidance, training, and performance). Although these major issues were addressed in the executive summary of the audit, they are not listed as findings or in condition reports, and no formal response from station management was required (the only issues from the audit requiring response are those condition reports generated by the audit team). The lead auditor was asked if they were able to performance-base the backlog issue with examples of recurring events or reduced margin of safety and whether he was able to help the station by probing the causes for the backlog. The backlog problem was essentially arrived at by a count of the numbers, although one example of a repeat occurrence was offered as potentially avoidable by prompt correction of an adverse condition report (an isolation valve failed a LLRT); however, this was a weak example because the valves were different, and it is not unusual to have isolated LLRT failures each outage. The only insight into the cause of the backlog was that engineering is responsible for the majority. (Note: in a later interview, a system engineer indicated that the backlog was mostly due to the slow pace of getting any new work done because they have been constantly looking back at prior work in response to the corrective action program oversight group {CAPOG}, and an extreme burden of dealing with special regulatory inspections such as the OSTI, leak rate and penetration issue inspections, and electrical distribution review prompted by the plastic tie-wrap.)

The contractor root cause mentors/coaches were interviewed about the root cause process. From their perspective, the key areas in need of attention are timeliness of investigations and quality of the evaluations. Currently, their job is to work one-on-one with the condition report team leaders. We asked about the results of the culture index worksheets described in Corrective Action Program Audit No. 94-15 which concluded that the overall safety culture index average at Cooper station was 10.4, which was stated to be above the U.S. average of 9.5. The contractor indicated that the methodology used to collect the data (an opinion survey) probably skewed the results so that it is not appropriate to compare these results to other stations. The value of the exercise was to provide a basis for future trends and to look at the distribution of the results across various station departments. We discussed their role in the root cause investigation of Westinghouse DB-50 undervoltage trip assemblies. They functioned as a mentor in the analysis. The team leader used barrier analysis techniques. They showed us a back-of-the-envelope sketch of an events and casual factors chart started at one point but never followed through (the contractor had suggested that an events and casual factors chart be made, but the team leader chose not to pursue this.)

The neutron monitor system engineer was interviewed regarding his judgment on postponing implementation of SIL 564 until next refueling outage. The SIL is recent and provides several tests recommended to detect sources of instrument noise and other failures that have plagued some facilities, particularly during startups. When I asked about the system performance at Cooper, he replied that it was good and has not been troublesome. I asked whether the temporary modification accomplished to defeat the nuisance SRM period alarm during this outage was related to instrument noise that could be detected by

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tests such as those described in the SIL. He was not aware of any noise problems with SRMs and was not aware that the period alarm was defeated.

In our discussions with the Safety Review Group Supervisor, he volunteered that his title was probably a misnomer, and he should more appropriately be called the Procedure Review Group Supervisor. He stated that when the job was created about five years ago, his boss thought that he may have time to branch out into other areas, but it hasn't evolved that way. (Note: his job description indicates that 10% of his time should be dedicated to independent investigation of CNS activities.) We discussed the new draft procedure on procedure use and adherence. The procedure was started in response to an informal perceived need by the safety review group, and it subsequently found itself in the strategic plan for performance improvement (SPPI) His group (composed of three senior staff specialists, one technician and three procedure clerks) is responsible for tracking, coordinating procedure changes, and performing design basis impact (10CFR 50.59) reviews for procedure changes. The large delay in getting procedure changes implemented is sometimes due to the fact that routine priority items suffer from higher priority changes, particularly during outage and startup preparations. In addition, some departments who are responsible for drafting the procedure change have large backlogs, particularly engineering. Due dates are not routinely assigned to procedure change notices. There are plans to have a consultant (NUS) perform an independent assessment of the procedure change process at Cooper, and this may expand to a review of the complete procedure process and hierarchy.

**PROGRAMMATIC:**

**MANAGEMENT:**

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-16

**DESCRIPTION:** Lack of management response to regulatory concerns regarding preconditioning resulted in recurrence of a similar significant event, and undetected degradation of the emergency electrical system.

**CAUSE:** Actions taken to address generic issues were narrowly-focused and compliance-based.

**EXAMPLES:** Background: In June 1993, the NRC identified a concern regarding the way secondary containment testing was performed (NRC Inspection Report 50-298/193-17). It was found that the methods used for the test (preconditioning) precluded any opportunity to identify degradation that may have occurred prior to the test. During the week of May 23, 1994, the NRC conducted a special inspection of problems at CNS related to failure of 480 volt motor control center undervoltage trip assemblies (UVTA) needed to support emergency diesel generator post-accident load shedding and load sequencing. In summary, a plastic tie-wrap had been found defeating the function of a UVTA. The tie-wrap had been placed there according to a procedural step in CNS procedure 7.3.2.1, which was last performed during the spring of 1993 refueling outage. Follow-up investigation determined that the presence of the tie-wrap was not revealed by subsequent tests (Surveillance Procedure SP 6.3.4.3, "Sequential Loading of Emergency Diesel Generators") because these tests did not properly verify load shed function of these devices. CNS informed the NRC that Maintenance Procedure MP 6.3.4.3 was used to demonstrate operability. Since this maintenance procedure contained instructions for cleaning and lubricating prior to performance of the breaker functional testing, the NRC judged this and other procedures to be inadequate in that they allow "preconditioning" of the breakers before they are performance tested. (Note: no generic action had been initiated by CNS management during the intervening period between June, 1993, and May, 1994, address the preconditioning concern.)

A special (Nuclear Power Group) NPG assessment of the incident completed on June 4, 1994, recommended that CNS ensure that equipment is not preconditioned before it is tested where such preconditioning would invalidate important as-found data. Reviews by maintenance, operations/I&C, and engineering were quickly begun to identify and correct similar problems. (Note: After a special test procedure was written and performed on June 14, 1994, to verify load shedding of components not checked or tested by SP 6.3.4.3, four UVTA failures were detected.)

In NPPD's July 28, 1994, response to the NRC Confirmatory Action letter on this subject, management expectations with respect to preconditioning were stated as follows: "With regard to preconditioning, CNS will neither test nor repair components, systems, or structures for the purpose of satisfying as-found acceptance criteria in surveillance tests. As-found testing will be performed prior to maintenance requiring adjustments of setpoints or recalibration per the surveillance program. For example, prior to performance of Technical Specification instruments surveillance calibrations and setpoint adjustments, as-found data will be recorded. Similarly, prior to performance of maintenance on essential electrical breakers, as-found data will be recorded."

Additional guidance is contained in a memorandum from the plant manager to all CNS managers dated July 27, 1994. This memorandum states that prohibition on preconditioning applies to essential and/or Technical Specification components, systems, or structures. The memorandum further states "Frequently performed surveillance tests (less than or equal to three months) need not be performed for as-found data prior to maintenance, given that set point changes and recalibration are not involved. Surveillance tests performed at intervals greater than three months will normally be performed for as-found data before maintenance. However, as-found testing is required before corrective maintenance is performed.

Station procedure reviews have uncovered additional instances of preconditioning and these examples have been documented on Condition Reports. Additionally, CNS Procedure 0.26, "Surveillance Program," was revised on July 15, 1994, to provide additional guidance on actions required and the need for operability determinations if as-found data are outside any limits, and to delete previous guidance in the procedure that states, "For instrumentation, if the specific procedure provides a means for readjustment and the instrument is promptly readjusted to within limits, the system/component need not be declared inoperable."

The DSAT team found that little guidance had been developed for operability determinations in cases where potential preconditioning concerns were uncovered during procedure reviews. For example, on August 1, 1994, a Condition Report was written for procedure 6.2.2.4.1, "Calibration and Functional Test of the Core Spray Flow Instrumentation Loop," because the procedure as written exercises both the time delay and the alarm contacts for the core spray minimum flow valves, prior to as-found data being taken. The shift supervisor who performed the initial operability assessment on the Condition Report considered it to be NA (not applicable), because preconditioning was a progammatic issue. When the condition report was reviewed by the Condition Review Group (CRG) on August 8, 1994, the judgment of the group was that operability was not a concern because of the as-found performance history (such as undetected adverse instrumentation drift), they did find a need to address the issue of continuing discoveries of proceduralized preconditioning by creation of an overall condition report on preconditioning. This CR was subsequently written later that day. The root cause analysis was completed on August 8, 1994, concluding that the cause was narrowly-focused and compliance-based values exhibited by management resulted in effective corrective action.

**PROGRAMMATIC:**

**MANAGEMENT:**

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**AREA:** ENG **SEQ:** CB-17

**DESCRIPTION:** Equipment performance anomalies noted during periodic surveillance tests were not reported and evaluated for root cause and corrective actions.

**CAUSE:** The problem reporting threshold was too high to capture seemingly insignificant and apparently understood anomalies.

**EXAMPLES:** While operating at full power on January 19, 1994, the high pressure coolant injection (HPCI) pump minimum flow valve unexpectedly opened during a surveillance test when the pump discharge valve opened. This valve automatically opens to provide adequate pump flow when system flow instrumentation senses less than 485 gpm while the pump is running (as sensed by pump discharge pressure above 125 psig). Discussions with control room operators revealed that occasionally, the valve had automatically opened during past surveillance testing as well. Those previous actuations had not been reported as an LER due to misunderstanding of the reportability requirements for unexpected ESF component level actuations. The January, 1994, event was reported in LER 298-94001, and the root cause was attributed to design deficiency. Subsequent tests had determined that during pump discharge valve stroking, pressure fluctuations created by the pressure maintenance (or keep-fill) system could approach 140 psig, actuating the pump discharge pressure switch.

Corrective action for this event involved changing the surveillance test procedure to indicate that although actuation of the minimum flow valve may not occur every time, it should not be considered an unexpected event because system pressure fluctuations occur near the pump discharge pressure switch setpoint. A similar change was also made to the RCIC surveillance test procedure because operators indicated that the same situation had been noted on that system in the past. The LER also committed to evaluate the pump discharge switch configuration and setpoint, and to implement changes if practical, to eliminate the unnecessary cycling of minimum flow valves.

**PROGRAMMATIC:** Criteria for the reporting problems to the corrective action program was inadequate.

The high-reporting threshold was known by management, and program changes were made to address this. Recognition and reporting of the spurious valve actuation in this case was attributed to the success of this change.

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** CB-18

**DESCRIPTION:** Events involving spurious containment isolation signals, half scrams, and shutdown cooling interruptions recur due to inadequate root cause determination and failure to follow through with identified corrective actions.

**CAUSE:** The corrective action was ineffective in reducing recurring events or because it was not entered into the corrective action tracking system.

The root cause for the first 1993 event was not determined due to inadequate review of past operational history of the underfrequency relays and failure to determine that an EWR existed to correct the equipment performance problems.

The root cause for the second 1993 event was incorrect because the prior operational history was unknown to the LER author (LER written on 7/21/93 and new EWR written on 7/22/93).

**EXAMPLES:** On March 31, 1993, during a plant outage, the "B"RPS bus expectedly lost power resulting in several group containment isolations and a half scram. Investigation of this event was unable to determine the cause and it was attributed to spurious actuation of an electrical protection assembly (EPA) on the output of the RPS motor-generator. On June 21, 1993, the "B" RPS bus again lost power; however, since fuel had been re loaded and the RHR system was operating in the shutdown cooling mode, the containment isolation sig resulted in a seven minute interruption of shutdown cooling. Following this second event, a defective underfrequency monitoring unit in the RPS motor-generator control circuit was discovered and was attributed as the cause of both events.

Further investigation of this problem revealed that an Engineering Work Request (EWR) had been written and approved in July, 1990, recommending that the non-essential motor-generator output breaker trips be removed due to repetitive spurious actuations during the previous two refueling outages. (The originally installed underfrequency, undervoltage, and overvoltage trips were provided for protection of RPS components; however, the system was subsequently upgraded with Class 1E EPAs that provide the same protective functions with more conservative trip settings). The EWR recommended that the circuit modification be performed in 1991; however, the EWR was subsequently closed by mistake before a design change was initiated. A new EWR was approved in August, 1993, recommending that the modification be accomplished in 1994.

The LER for the 1993 events (298-93010) attributed the root cause of the spurious actuations to a defective underfrequency relay. It did not discuss the previous similar events, the inadvertent canceling of the EWR, or the breakdown in control and tracking of corrective actions. Although not associated with this event, a procedure change is currently being considered to the EWR process (procedure 3.4.1) to minimize the potential for inadvertent cancellations by clearly identifying activities that involve commitments or corrective actions for station events.

**PROGRAMMATIC:** The EWR process does not require the proposed work to be linked to corrective actions from the problem reporting system. (The original EWR identified the item only as an "operational desire," and the subsequent EWR identified the item only as an "operational necessity.")

Poor root cause analyses and inadequate corrective actions are known to station management and program upgrades and training are in progress. However, more recent events indicate that similar problems are continuing.

**MANAGEMENT:**

**AREA:** ENG **SEQ:** CB-19

**DESCRIPTION:** Erratic performance of the main turbine digital electrohydraulic control system recurred due to insufficient troubleshooting and root cause analysis.

**CAUSE:** The power supply failures were not detected following the initial event because they were not tested under a fully loaded condition.

**EXAMPLES:** On March 2, 1994, during operation at 97% power, the main turbine governor valves partially closed resulting in a reactor scram. Subsequent investigation found no component failures; however, the failure analysis determined the most likely cause to be spurious actuation of a transistor relay in a digital electrohydraulic control (DEH) system valve transfer control card. The card was replaced as a conservative action; however, during the subsequent startup on March 12, 1994, erratic DEH system operation recurred, causing bypass valve control problems and a small reactor pressure spike and associated reactor power increase. Special monitoring instrumentation installed after the scram identified that the primary 24 volt DC power supply degraded while the investigation was in progress and the secondary power supply was also degraded and unable to support the system. The root cause was attributed to momentary degradation of both power supplies and both were replaced. The LER (298-94004) states that an evaluation is continuing to identify long-term corrective action to prevent recurrence.

**PROGRAMMATIC:** No DEH troubleshooting procedures are available. Troubleshooting procedures are currently being developed by a turbine control specialist contractor.

**MANAGEMENT:**

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*31-Aug-94*

**AREA:** ENG **SEQ:** CB-20

**DESCRIPTION:** Numerous errors made during the process of evaluating the root cause and potential operability impact of unexpected cycling of a core spray pump minimum flow valve.

**CAUSE:**

**EXAMPLES:** On February 1, 1994, while operating at full power, a core spray pump minimum flow valve unexpectedly closed and then automatically opened when the system test return valve was stroked open during valve operability surveillance testing. An investigation was unable to recreate the anomalous equipment behavior. Because the core spray flow instrument had a history of problems associated with air in the sensing line and the flow transmitter had been removed from service and calibrated earlier that day, the most likely cause was attributed to instrument spiking caused by air in the sensing lines. Continuing evaluation of the event had subsequently dismissed the air entrapment cause when the event recurred on April 27, 1994. In both instances, the effected core spray subsystem was declared inoperable pending further evaluation of the spurious flow spike. After the first event, the instrument lines were backfilled, the core spray loop was vented, and the subsystem was declared operable after demonstrating operability by performing a surveillance test.

The work history for core spray flow transmitters was reviewed and numerous problems associated wit' erratic and erroneous flow indication dating back to 1985 were documented. Some of the problems hao been attributed to air in the sensing lines and some were rectified by adjusting the sensing line snubber settings. As recently as April, 1993, erratic flow indication was noted while the core spray pump was running, and the pump minimum flow valve was found to be cycling. No definitive cause was determined for the April 1993, event.

Continuing evaluation of this problem identified another potential cause to be intermittent crud buildup at the sensing line snubbers, possibly created by the instrument calibrations prior to the event. The station conducted followup tests to evaluate this possibility. (Note: Although not directly related to this event, it was also discovered that the station response to NRC IN 92-33 - dealing with the potential for inadequate instrument response times caused by sensing line snubbers - identified 31 instruments that require evaluation but inappropriately excluded the snubbers on these core spray flow instruments.)

An operability determination completed on April 28, 1994 concluded that the system was operable because unexpected cycling of the core spray minimum flow valves occurs only during testing (note the inconsistency of this statement with the March 1993, event described above) and there is no evidence to suggest that the valve may spuriously operate during system initiation because surveillance tests were performed to demonstrate proper operation with the core spray pump running.

In June, 1994, the NRC regional project manager expressed three concerns to the station with respect to the LER on this event as follows:

1. After the first event, the system was returned to an operable status without performing an operability evaluation.

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2. The LER states that an engineering evaluation was performed and no documented evaluation was found. This may be inaccurate information.

3. The LER states that no similar events have occurred; however, it is known that there were previous occurrences. This may be inaccurate information.

The Quality Assurance Department was tasked with evaluating these concerns and documented the evaluation in a memorandum to the Vice President on July 12, 1994. The Vice President responded to this report on July 13, 1994, by noting that it failed to determine the barriers that broke down to allow the deficiencies to occur and directed that QA determine those barriers that broke down or those that need to be put in place to prevent future concerns of this nature.

On July 23, 1994, a condition report was written documenting that during performance of a revised core spray surveillance procedure, it was determined that the minimum flow valve could cycle continuously, and that because the valve operator is not designed for this duty, it could fail in a non-conservative position during an actual demand.

**PROGRAMMATIC:**

**MANAGEMENT:**

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**AREA:** ENG **SEQ:** CB-21

**DESCRIPTION:** The length of time to process industry operating experience and establish barriers to prevent similar occurrences at Cooper station is excessive.

**CAUSE:** Cognizant managers have not been held accountable for meeting the initial evaluation timeliness goals contained in procedure 0.10.1 (30 days).

Management expectation have not been established for timeliness of actions resulting from evaluations of industry operating experience.

**EXAMPLES:** The following data was provided in a June 13, 1994, industry operating experience program status memorandum:

1. There were 110 industry OE documents open for initial disposition with 113 open action items. This was a 31 percent increase in open action items as compared to January 1993. The engineering department was responsible for a majority of open action items (42 percent).

2. The average age of industry OE documents in initial disposition was 7.8 months as compared to 4.3 months for February, 1992 (the last prior date for which this information was available).

3. To assess the timeliness of actions initiated following the initial disposition, a chart showing distribution by age indicated that most actions were in the 0-6 month bracket; however, 37 percent were older than 6 months, and 18 percent were older than 1 year. 43 percent of the open actions were overdue with 75 percent of the engineering actions being overdue.

Although the DSAT team did not perform a detailed analysis of OE program statistics, a general picture of the timeliness of processing industry OE documents can be formed as follows:

The industry OE document is received at CNS and promptly screened for applicability and assigned for evaluation. This evaluation (CNS initial disposition) generally takes about 7.8 months. Following this, it may take 6 months to a year to implement actions which establish barriers to the event at CNS. Thus, there is a time lag of 1 to 1.5 years after notification before the industry issue is fully addressed.

**PROGRAMMATIC:** The annual industry OE program effectiveness review procedure requires that timeliness be addressed only on an individual industry OE document basis and not the entire program (procedure 0.10.3).

**MANAGEMENT:** There is a lack of clear organizational authority for program implementation (fragmented responsibility and accountability).

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*31-Aug-94*

**AREA:** ENG **SEQ:** DK-04

**DESCRIPTION:** Vacuum Breaker coating failure evaluation indicates a weakness in system engineering's system monitoring program and their ability to recognize all potential operability impacts of an identified deficiency.

**CAUSE:**

**EXAMPLES:** Control Room log entry on 7/24/94, 0739, terminated Procedure 6.3.10.4 (Torus Vacuum Breaker Examination) due to finding paint chipping and flaking on the inside of the vacuum breaker. Condition Report CR-94-0448 had been written on 7/19/94 to address this concern. An investigation and evaluation by engineering concluded that the coating was failing because it was at the end of its service life. The main concern of the evaluation was the potential for coating flakes to enter the suppression pool and migrate during accident conditions to a ECCS suction line strainer and degrade ECCS System performance. The concerns identified from reviewing this condition are:

1. The investigation revealed that the coating failure had existed prior to 1991 and can be seen on the surrogate tour system pictures. This is an indication of the failure of system walkdowns and inspections to identify conditions that have a potential to degrade the system.

2. The initial evaluation by engineering did not address the potential for these large coating chips to become lodged in the vacuum breaker seat and prevent full closure, thus creating drywell to suppression pool bypass flow. This concern was addressed and the evaluation revised after questioning by the DSAT. The evaluation concludes that in the unlikely event that a paint flake landed on the seat when a valve was open, it would not prevent the valve from reseating.

3. The initial evaluation also did not address the potential for the paint chips to enter the torus vent header and migrate to the header low point drain line and clog it. When asked by the DSAT team if this drain line existed at CNS and if they had evaluated the clogging potential, they indicated it had not been evaluated and they would need to verify it existed. Engineering did find the drain line on the drawings and believe that the potential for clogging has no significance.

**PROGRAMMATIC:**

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**SEQ:** GW-02

**AREA:** ENG

**DESCRIPTION:** HPCI system unavailability (based on one year averages in PPIP data) has been increasing over the last three years.

**CAUSE:** Lack of clear management direction regarding system engineering responsibilities (GW-04)

**EXAMPLES:** PPIP data indicates a declining trend in HPCI availability.

The mechanical system engineer indicated the increase in unavailability was due to a new philosophy of declaring the equipment inoperable during testing and preventive maintenance. He indicated he was not aware of any specific equipment problems or other factors that contributed to increased unavailability of the HPCI system.

**PROGRAMMATIC:**

**MANAGEMENT:**

**SEQ:** GW-03

**AREA:** ENG

**DESCRIPTION:** Diesel generator system unavailability has been trending upward over the last three years. Additionally, the current outage was initiated due to diesel generator inoperability.

**CAUSE:**

**EXAMPLES:** The mechanical system engineer indicated the diesels have experienced a number of equipment failures and problems during the past year. Most notably, one diesel was started before the fuel racks were balanced, resulting in high vibration and a need for further engine inspections. The system engineer also described problems with a switch that prompted breaker and relay inspections that contributed over 70 hours of unavailability.

Furthermore, the system engineer noted that a number of work items identified prior to the diesel generator being declared inoperable due to electrical system problems were not worked during the approximately eight weeks that the diesels have been considered inoperable. Working these items at a later time could result in additional unavailability time for the diesel generators.

**PROGRAMMATIC:**

**MANAGEMENT:**

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*31-Aug-94*

**AREA:** ENG **SEQ:** GW-04

**DESCRIPTION:** Station management expectations for system engineering responsibilities and duties are unrealistic and the assignment of additional tasks beyond those identified in the procedure and engineering directive have resulted in a workload that is almost impossible for the system engineers to accomplish.

**CAUSE:** Management has not clearly identified the desired role for the system engineers, with system engineers assigned responsibilities for activities in a number of areas. The system engineering program is described by plant procedures and engineering directives, but the activities assigned to system engineers are often not included in the procedure or directives.

**EXAMPLES:** 1. System trending and system engineer walkdowns are not being consistently performed.

2. Although corrective action program items currently make up the majority of the system engineers workload, they are not being completed in a timely manner.

3. Backlogs in vendor manual Maintenance and NPRDS reports are increasing because system engineers are spending the majority of their time on corrective action documents and are therefore unavailable to perform required reviews.

4. System engineers are required to review all work items prior to work commencing in the field, but it is not clear what their reviews are intended to accomplish.

5. The REC system engineer (assigned to the system for approximately one-and-a-half years) was not aware of an undocumented weld patch on the system.

6. The system engineer for the electrical distribution system did not appear to be knowledgeable about CR 6451 written on an overvoltage situation on the emergency 4160 bus that required an operability call. There appeared to be a total lack of involvement by the system engineer on this operability issue that must be resolved for plant startup.

7. The system engineers are tasked with developing special instructions for MWRs, as necessary. In this role, the system engineer is preparing work plans that, elsewhere in the industry, would be prepared by maintenance work planners.

8. Various procedures are routed to engineering for review. The need for engineering review of these procedures has not been clearly identified, and a backlog of procedures awaiting review is developing.

9. The system report card program, which was scheduled to be implemented by June, 1994, has not been fully implemented. Some activities in support of the system report cards have been developed, but the overall program has been delayed by the need for engineering response to the emerging issues.

**PROGRAMMATIC:** The station procedure and associated directive establish unrealistic expectations for system engineers, with additional duties assigned that are not addressed in either the procedure or ne directive. Management does not appear to be effectively addressing the growing backlogs of work and the need for additional resources nor do they define more realistic priorities to ensure work is completed in a timely manner.

**MANAGEMENT:** Ineffective management activities do not allow identification of the growing backlogs in various areas, as well as a lack of monitoring of system engineering activities, including system walkdowns, system trending, development of special instructions, and system engineer role in corrective action activities.

**SEQ:** GW-05

**AREA:** ENG

**DESCRIPTION:** System Engineers review all work items prior to implementation. This had been done for essential systems in the past, but was recently changed to include non-essential systems to ensure engineers were aware of all work on their systems. Additionally, system engineers are instrumental in determining post-maintenance testing requirements for the maintenance performed.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:** Inefficient work management program.

**MANAGEMENT:** Lack of management's ability to effectively establish a maintenance work planning process.

**SEQ:** GW-06

**AREA:** ENG

**DESCRIPTION:** Eighty-seven safety-related vendor manuals have not been reviewed to identify preventive maintenance requirements for the associated equipment. In response to NCR 93-235, the station has planned to re-review an additional 30 safety-related vendor manuals to establish a basis to ensure the adequacy of initial review.

**CAUSE:** Low priority activity for engineering and maintenance personnel.

**EXAMPLES:** Based on interviews.

**PROGRAMMATIC:**

**MANAGEMENT:** Lack of management to establish a trend program as well as a lack of dedicated resources to address a potentially safety significant backlog.

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*31-Aug-94*

**AREA:** ENG **SEQ:** GW-08

**DESCRIPTION:** During the operation of the 'B' shutdown cooling loop, a noticeable "chugging" was occurring in the vicinity of the heat exchanger bypass valve, RHR-MO-66B. This was noted during a physical inspection of the 'B' RHR heat exchanger room. (SEE GW-15 FOR ADDITIONAL DISCUSSION)

**CAUSE:** Severely throttled flow through the heat exchanger.

**EXAMPLES:**

**PROGRAMMATIC:** System engineer indicated this flow noise was typical for the system (and generally cannot be heard over the flow noise that originates in the RHR service water system.)

**MANAGEMENT:** This known deficiency has not been previously documented or evaluated.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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**AREA:** ENG **SEQ:** GW-09

**DESCRIPTION:** Control of station configuration is insufficient to ensure that configuration is accurately reflected in station drawings.

**CAUSE:** Lack of sensitivity to the accuracy of as-built station drawings.

**EXAMPLES:** 1. During actions to correct possible single failure in the Standby Gas Treatment (SGT) system, it was found that check valves shown on system drawings were not physically installed (additionally, IST testing of check valves was being performed to verify the valves opened - closure was not verified). Instead, the check valves had been removed and spool pieces installed in their place. The NCR written to investigate the removal of these check valves, NCR 93-095, identified a number of problems that could have contributed to the failure to properly document the removal of the check valves and ensure the USAR accurately reflected the plant. However, the NCR was completed 1/10/94 and the root cause section states, "...Although the rigor of the applicable programs in existence at the time of this occurrence may have been a contributing factor, the current EDF program as noted in the 'Extent' section, would clearly disallow addition of components to the EDF without prior documented determination of safety classification. As such, there is no added value in determining if programmatic weaknesses contributed to the root cause.

2. When leaks in the REC system were being investigated, undocumented modifications to the system w identified, including patches, weldments, and the relocation of a vent valve.

3. During investigation of the NCR related to the SGT check valves (NCR 93-095), it was noted that there had not been any NCR's found since 1978 that documented finding a station configuration that had differed from approved drawings. A further review of the NCR, DR, and CR databases only identified approximately 60 documented instances of plant configuration differing from approved drawings. However, during the mid-1992 through mid-1994 time frame, well over 100 Drawing Change Notices were submitted to correct "errors" on drawings to make them reflect field conditions.

4. Walkdowns of approximately 1600 drawings, conducted between 1986 and 1993, identified over 120,000 discrepancies. Although many of the problems that could be corrected by updating drawings or databases have been addressed, station actions to correct physical problems (tagging, labeling, physical repairs, and procedure revisions) have sometimes not been timely. As of April 30, 1994, 111 Type 2 and 827 Type 4 items were still awaiting resolution. Also, as of April 30, there was a total of approximately 2,400 of the discrepancies awaiting resolution.

During the course of the project, over 250 spade terminals were identified that had less than 50% of the terminal inserted in the connection, with some of the problems identified in 1986. During two interviews with corporate engineering personnel, it was indicated that work items had been submitted to correct these problems during the course of the walkdown project. However, these work items had been returned to NED with no action planned (there were no MWR numbers assigned to the work items). These improperly connected spade terminals were recently added to the outage work list for correction prior to plant restart.

Additionally, over 700 items (including over 200 valves) were identified through walkdowns that were not included in valve lineup checklists. Some of these valves were identified as needing to be included in checklists as early as 1992, but station operations personnel were unable to establish a priority for getting the valve lineup checklists corrected.

**PROGRAMMATIC:** Drawing change notice program does not appear to include actions to investigate as-found conditions to ensure that station configuration has been properly analyzed and meets safety requirements.

**MANAGEMENT:** Management has not encouraged the identification of possible station configuration problems to ensure they are properly evaluated.

**AREA:** ENG **SEQ:** GW-10

**DESCRIPTION:** The potential for leakage in the REC (reactor equipment cooling) piping has not been adequately monitored to minimize the potential for leakage and impact on plant operations. Leakage problems were identified in 1979, with analysis by GE and subsequent changes to system chemistry. However, the utility has not taken action to monitor the condition of the piping system to ensure leakage does not occur.

**CAUSE:** One member of management indicated that the philosophy of operation with regard to the system was that it would leak before any piping break, so the leaks could be detected and would not affect system operability.

**EXAMPLES:** 1. Leakage identified on 7/28/94, with an additional leak identified on 7/30/94.

2. The system engineer indicated he was unaware of any previous problems with the system and, based on his knowledge of system performance to date, had not seen a need to develop a process or program to monitor the piping for potential crack growth.

3. The root cause of the 1979 leakage was identified as intergranular stress corrosion cracking, most probably brought on by exposure of the piping to nitrates coming from the decomposition of sodium nitrites used to provide a corrosion inhibitor for the system. The GE letter indicated that cracking problems would not be alleviated by removal of the nitrites from the system, but it should prolong the life of the piping. However, at that time, the station did not recognize the need to establish a monitoring program to address the cracking problem.

**PROGRAMMATIC:** The station did not establish a monitoring program for this piping. Additionally, this piping may have been inappropriately excluded from the station ISI program. Follow-up actions were not put in place to monitor piping defects and take action prior to leakage. The problem had been identified in 1979, but the GE recommendations had not addressed the need for ongoing monitoring activities to assure proper performance.

**MANAGEMENT:** Willingness to allow continuing equipment degradation without effective action to monitor the degradation and take action to minimize impacts on plant safety and reliability.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** GW-11

**AREA:** ENG

**DESCRIPTION:** Engineering training is not sufficient to ensure engineers (both at site and in corporate) have the technical expertise necessary to perform assigned duties, including understanding system operations, performing safety evaluations and preparing operability evaluations.

**CAUSE:** Lack of emphasis on training for system engineers and urgency to get immediate work done. Additionally, the need for specific task training has not been effectively identified.

**EXAMPLES:** 1. The station engineer involved in the initial review of the REC welds using ultrasonic testing (UT) was not knowledgeable of UT requirements or the methods or times necessary to perform UTs on the REC piping. During later discussions, the engineer indicated he was not the normal ISI engineer and was serving as a 'back-up' because the station ISI engineer had recently left the organization. He indicated he has not had any formal training on UT methods or requirements.

2. Some system engineers have limited knowledge of their systems. The assignment of system responsibilities for many standby systems (such as RHR, RCIC, HPCI, Core Spray) are split between a mechanical engineer and an electrical engineer. Some engineers, during interviews, were unable to discuss or explain many of the features of the system that were not in their 'discipline'. Additionally, one engineer that had had his system for approximately two years had very limited knowledge of other systems durin walkdown.

3. The system engineering overall training program consists of 50-hours of formal classroom instruction that provides limited overall exposure to station systems and little systems interaction training. Many of the system engineers have not attended this training.

4. Qualification as a system engineer requires completion of a self-study activity using the STA lesson plan, with a test to verify knowledge. One engineer interviewed indicated he had taken over a year to complete this self-study activity due to the number of activities that have required his engineering attention during the last year. The engineering performance enhancement plan indicates that, as of 1993, many of the system engineers had not completed 'certification' training on their assigned systems. However, the system engineers for all essential (safety-related) systems were qualified at the end of 1993.

5. During interviews with systems engineers, it was noted that there is frequently not a specific individual assigned to serve as the system engineers' "backup." As a result, the lead engineer for the group (who usually has received STA training and has a better overview of all the plant systems and system interaction considerations) acts as a backup when the system engineer is not available. This limits the ability of the lead engineer to monitor and direct the activities of his assigned system engineers.

6. Corporate engineering training does not include formal training to enable the engineers to understand systems operation or interactions. One engineering manager indicated the design engineers "learn as they go" regarding system operations when they are preparing modifications. Additionally, one corporate engineering manager indicated the design engineers prepare the entire modification package, including work instructions and installation and test procedures. However, one engineer interviewed indicated training on preparation of work instructions and procedures was not provided to the engineers.

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7. Two members of the corporate engineering staff indicated that the station and corporate engineering staffs have not been provided training to improve their understanding of the station Probabilistic Safety Assessment. One engineering manager indicated that corporate personnel have been trying to conduct this training for approximately eighteen months, but the station management has not supported this concept.

8. A self-assessment of the On-the-Spot Change (OSC) process, conducted in March 1994, found that corporate design engineers had received no formal training on the OSC process. This process has been used frequently to allow minor field changes to design change packages. However, the self-assessment identified some instances where the process was used incorrectly.

**PROGRAMMATIC:** Lack of emphasis on training for system engineers and urgency to get immediate work done. Ineffective prioritization of engineering tasks and resources and poor corrective actions since this weakness had been identified as a weakness during INPO accreditation reviews.

**MANAGEMENT:** Management emphasis on engineering training and qualification has not been sufficient to ensure the appropriate training has been identified and the system engineers receive appropriate training to ensure their work is of highest quality.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-12

**DESCRIPTION:** Engineering work management efforts and performance monitoring are not sufficient to identify the resources necessary to accomplish assigned tasks and to ensure adequate performance by engineering staff.

**CAUSE:** Management has not effectively monitored engineering activities and workloads to determine whether resources are available to complete work assigned to engineering.
Management has not effectively promoted teamwork or a sense of ownership in the corporate engineering organization for site problems.

**EXAMPLES:** 1. A program for development of design criteria documents (DCDs) began in 1986; since then only nine DCDs have been completed. Engineering managers indicated the first set of DCDs produced did not meet the needs of the organization, so they were abandoned. Subsequently, a new format was developed by a task group and nine new DCDs are in place. However, the April 1994 Nuclear Engineering and Construction Division activities status indicates the currently planned DCDs are not on schedule due to shifting resources needed to address emergent issues. Additionally, engineering management personnel indicated the planned schedule for the DCD development has been changed (although a revision to the schedule is not available) and they are considering bringing in contractors to improve the rate of completion and the resolution of open items resulting from the development of DCDs.

2. Backlogs of work associated with plant engineering organization continue to grow, including modification closeouts, NPRDS reports, and corrective action program activities.

3. Instrument setpoint calculations for Tech Spec setpoints have only been done for approximately one-third of the Tech Spec instruments during the past two years.

4. Performance indicators for site engineering have recently been developed, but have not been maintained due to emerging issues. As a result, the site engineering performance indicators provide limited capability to monitor what is currently a major portion of the site engineering organization's work.

5. There are no formally issued performance indicators or feedback mechanisms for corporate design engineering activities. As a result, station personnel are unable to monitor progress on important corporate engineering activities, such as addressing walkdown discrepancies, design basis document open items, development of design basis documents, development and validation of the PRA and the associated external events analyses, or the schedule and quality of design change packages. The Nuclear Engineering and Construction Division Manager provides the Nuclear VP with a monthly activities summary with explanations of problems, but does not distribute this information outside the Nuclear Engineering and Construction Division. Additionally, it is not clear from this summary what the goals of the Nuclear Engineering and Construction Division are and whether they are being met.

6. There appears to be an excessive number of "on-the-spot changes" related to design or constructability problems. Although corporate engineering management recently had a self-assessment performed to determine whether actions were necessary to decrease the number of "on-the-spot changes", the trends and corrective actions are not communicated to station personnel.

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7. There have been two (OSC and Service Water) self assessments or SSFIs in the last several years. The Service Water self assessment was conducted in order to prepare for an NRC inspection of the Service Water system. Corrective actions for these two activities are not specifically tracked and communicated to station personnel.

**PROGRAMMATIC:**

**MANAGEMENT:** Management has not been effective in monitoring the workload of engineering through either formal or informal means and has not encouraged being self-critical of engineering programs.

**AREA:** ENG **SEQ:** GW-13

**DESCRIPTION:** The technical competency of the corporate design staff is not sufficient to provide management assurance of their capability without third party reviews of many engineering analyses.

**CAUSE:** Engineering management does not recognize their ownership of plant design.

**EXAMPLES:** 1. For the problems identified on the REC system, GE is performing analyses of the weld indications to ensure the piping will not fail (fracture mechanics analyses). Management has begun looking for a third party qualified to verify that the analyses are correct.

2. The design change process includes a checklist item that allows the use of a third party reviewer (contracted) to review design changes designed by either NPPD personnel or contractors.

3. Development of some new programs is performed using contractor personnel, such as the PRA external events analyses and the development of design basis documents.

**PROGRAMMATIC:**

**MANAGEMENT:** Management has not clearly established responsibility for design control and held appropriate groups accountable for properly assuming this responsibility.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-14

**DESCRIPTION:** Engineering personnel are not effective in identifying programmatic problems because the engineers are often new to the systems area and take over existing programs that they assume to be adequate. In addition, the engineering workload has been so heavy that the engineers have not had the opportunity to effectively scrutinize their programs, and truly understand the programmatic requirements.

**CAUSE:**

**EXAMPLES:** 1. The engineer responsible the station Appendix J program indicated that he was hired upon graduation from college and took over a program that he assumed was adequate. He indicated that it has taken approximately five years for him to fully understand the programmatic requirements and, due to other problems, his program has been heavily scrutinized and changed.

Additionally, the engineer indicated his perception that the program was adequate was reinforced in 1991 when the NRC conducted a VOICE inspection of the Appendix J program. The plant personnel interpreted the inspection results to indicate the Appendix J program was quite thorough and compared well with others in their region. Also, the plant Tech Specs identified some of the testing boundaries, although these boundaries were later found to be unacceptable, such as the RHR-MO-25A and RHR-MO-27A boundary. In 1993, station engineers recognized that this penetration was not being tested correctly when RHR-M 27A would not pass its local leak rate test, so they changed the testing boundary to the check valve (26 inside containment and the outside containment isolation valve (25A). However, this recognition that this penetration was being tested improperly did not prompt a review of other penetrations.

During 1994, a penetration was discovered that had a cable going through a valve. As a result of this finding, the Appendix J program was reviewed to determine its overall adequacy. As a result of this review, the scope of the program increased from approximately 65 penetrations to approximately 120 penetrations.

2. The station ISI program has recently been assigned to a new engineer with little experience and no training in this area. Training for the individual is planned, although the current workload in engineering may prohibit this in the near term. Additionally, the station is approaching the time when the next ten-year update must be submitted to the NRC.

Additionally, during the NRC Service Water inspection, it was noted that portions of the REC and Service Water piping had incorrectly been excluded from the scope of the ISI program.

3. The station IST program engineer has been responsible for this program for some time. During interviews he indicated the basis for valve stroke times established under the IST program were either the USAR tables or the Tech Specs. CR 94-0297, dated 6/14/94, identified some discrepancies between the USAR narrative on the LPCI system and the times included in the motor-operated valve stroke timing procedures. When questioned about references to design specifications for determining stroke times, the engineer indicated that this was not typically done. Additionally, some stroke times were changed as a result of NRC Generic Letter 89-04, that required utilities to establish meaningful valve stroke time limits. As a result of the station response to this Generic Letter, the allowable stroke times for valves RHR-MO-

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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27A/B were established as 35 seconds {(average of four good stroke time tests)*1.35}. The GE design specification for the RHR system indicates these valves should stroke in 24 seconds or less. Additionally, the following stroke time discrepancies in the RHR system were noted:

| VALVE | IST LIMIT | GE DESIGN SPEC. (max.) |
|---|---|---|
| 25A/B | 27 | 24 |
| 26A/B | 14 | 10 |
| 31A/B | 15 | 10 |
| 38A/B | 15 | 10 |
| 17 | 40 | 38 |
| 18 | 40 | 38 |

As a result of CR 94-0297, corporate configuration management personnel reviewed original design information and subsequent changes to determine whether the acceptance limits changed. One corporate engineer indicated the 27 second stroke time was acceptable for valves 25A/B because that value had been used in the latest GE core reload analysis with no adverse effects noted. However, he did not address past acceptability of the valve stroke time limits. As a result of this review and additional reviews, corporate configuration management personnel transmitted a letter to the station indicating the LPCI system was operational on 6/16/94. As of 8/17/94, the condition reports has not been closed, and the results of a review of the injection valves on RHR, core spray, HPCI, and RCIC have not been finalized, although the preliminary results were that six valves required further review, with all being found acceptable.

Additionally, the RHR pumps have shown some inconsistencies in performance, such as the A pump showing an 8 psi increase in pump differential pressure from one quarterly test to the next. Based on discussions with the system engineer and the IST engineer, there have been no evaluations performed to identify the cause for this discrepancy (expected actions would include verifying accuracy of the pressure gauges, analysis of system temperatures during testing to determine if that might be impacting pump efficiency, or a review of maintenance records to determine whether any maintenance activity could have resulted in changes to the internal clearances of the pump). In addition, the B RHR pump was re-baselined because the pump was unable to achieve its reference value. The basis for re-baselining was past test results rather than an evaluation of whether there were any explanations for not achieving the reference value shortly after it was established.

**PROGRAMMATIC:**

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-15

**DESCRIPTION:** Various items were identified during a detailed review of the RHR system.

**CAUSE:**

**EXAMPLES:** 1. During a plant tour, flow turbulence was noted in the "B" RHR heat exchanger room when the "B" loop of RHR was operating in the shutdown cooling mode. The noise was intermittent "chugging" that frequently recurred. When asked, the system engineer indicated that the noise had "always been there" (although there had not been any questions from operators or other station personnel regarding the noise), and indicated that the noise was usually masked during normal shutdown cooling operations by the cavitation noises that come from the service water valve at the heat exchanger inlet.

As a follow-up to the question regarding the flow turbulence, the system engineer contacted a contractor to perform a fluid system analysis to try to determine the cause of the flow turbulence. Additionally, the system engineer contacted the maintenance engineer that handles the vibration monitoring program. Using vibration monitoring equipment, the engineers determined that the origin of the flow turbulence was the restricting orifice in the pump discharge line. The system engineer contacted the design engineering organization to obtain their insight into the possible causes of the flow turbulence. The system engineer indicated that one design engineer had reviewed the system flows and pressures, and determined that th was a high probability that the restricting orifice was inducing cavitation in the line, resulting in the flo turbulence noises. The design engineer also informed the system engineer that these restricting orifices had been replaced as part of a set of modifications installed during the time frame from 1990 through 1993 (DC 89-252 A through E), and that the calculations for the orifices had not addressed the possibility of cavitation. A follow-up ultrasonic test of the discharge piping in the vicinity of the restricting orifice showed that the piping thickness had not been diminished by the cavitation.

Based on the information regarding the modifications, the modifications were reviewed to identify the specific calculations included in the modification analyses. The following calculations were reviewed: NEDC 92-202, NEDC 90-236, and NEDC 89-1944. The calculation description for each calculation is as follows:

NEDC 89-144, rev. 1 - "This calculation estimates the losses in the RHR system with the new anti-cavitation trim installed in valve 34A,B and 27A,B. These losses (i.e. flow losses) determine whether the flows required by CNS Technical Specifications are met after the new trim is installed. Minimum flow requirements for suppression pool cooling are also verified. The calculated pressure drops should be verified by test after the trim is installed."

NEDC 90-236, rev. 1 - "This calculation sizes the maximum flow orifices for RHR Pumps B & D. The results and conclusions of this calculation are given on page 21. It was determined that the restriction orifices for Pumps B & D should be machined to 6.470 inches diameter."

NEDC 92-202, rev. 0 - "This calculation calculates the single pump and two-pump flows under accident conditions for RHR Loop A using the test data under DC 89-252 E taken on 5/28/93."

Of the three calculations, only calculation 92-202 references one of the other three calculations (90-236, rev. 1). Additionally, two of the three calculations reference a fourth calculation (91-290, rev. 0). Also.

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only calculation 90-236 references information that could be considered design basis information (Burns & Roe Work Order 2978-14, page 6 of 13, 9/13/76). For all three of the calculations, the blank that identifies the superseded calculations is marked "N/A." As a result, it is not clear which of the calculations takes precedence, and what portions of which calculation constitute the latest design information.

Additionally, calculation 89-1944 indicates its purpose is to ensure the pump flows meet Technical Specifications. As such, it does not consider the original design and the margins included in these during plant design. Similarly, calculation 92-202 uses test information to verify that the results of testing performed meet Technical Specifications. The lack of reference to design basis and original design considerations to ensure the testing alignment properly reflects the necessary design considerations.

2. During walkdowns and control room observations, it was noted that the heat exchanger outlet valve for the "B" loop was open (not its normal condition) and not tagged. When questioned, operations personnel indicated the valve is used to throttle flow through the heat exchanger, although it is a gate valve and the motor operator is not intended to be used for throttling, since the motor receives a seal-in signal to stroke to its full open or full closed position. The operations personnel also indicated the method for throttling the valve is to station an operator near the motor breaker and, after positioning the control switch to give the valve an open signal, having the operator trip the breaker to stop the valve in the mid-position. The system engineer indicated the reason that operations throttles the valve in this manner is because throttling the service water flow through the heat exchanger results in severe cavitation through the service water valves and significant erosion.

3. When shutdown cooling was transferred to the "A" loop, a system walkdown by the system engineer identified a leak at the pump bowl on the "A" pump. The "C" pump was started and the "A" pump shut down for retorquing of the casing bowl bolts. However, an operator observing the "C" pump noted that a similar leak was occurring at the pump bowl. The system engineer reviewed maintenance records and indicated that the pumps had not been disassembled since 1986. As a precautionary measure, the "B" and "D" RHR pumps, as well as the core spray pumps, were retorqued to ensure the leakage was minimized.

4. During additional RHR system walkdowns, the system engineer noted a tygon tube that exited from under the insulation on the "A" heat exchanger and was tie-wrapped to a nearby service water drain line, leading to a floor drain. When the system engineer inquired about the tube, he was told that the tube was put there to capture condensation from the heat exchanger. When the insulation was removed, the system engineer found a "gutter" type catch containment that was attached to the circumference of the heat exchanger. When questioning other personnel about the purpose of the "gutter" the system engineer learned that there was a leak around a flanged connection on the heat exchanger that had existed since approximately 1986. The system engineer researched maintenance history records and found that a maintenance work request had been submitted on the flange leak, but the MWR had been cancelled during 1990 with a note to delay the activity until an outage of sufficient duration. However, a new MWR had not been initiated to ensure the problem was effectively tracked and corrected.

The leakage was identified as primary coolant from the shell side of the heat exchanger. The station manager indicated he felt that a safety evaluation was necessary to justify operating with a known leak from a reactor coolant pressure boundary, and the possibility that the leakage could lead to the release of fission products in the event of an accident. It is not clear how the ISI program did not identify this leakage as part of system pressure testing requirements.

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5. During a walkdown with the mechanical system engineer, the evaluator noted that differential pressure switch 125B was reading off-scale high. The engineer indicated that the instrumentation was the responsibility of the electrical system engineer, and he would try to determine whether this reading was expected or whether there was an MWR to correct the problem. He further indicated that he does not look for electrical or instrumentation problems when he is walking down the system, because these areas are the purview of the RHR System Electrical Engineer.

6. The system engineer indicated that he has not had detailed training on systems, other than self-study training on his assigned systems (RHR and RWCU). He indicated that other system engineers also had a limited knowledge of other systems outside their assigned systems because they received only minimal formal training on other systems. Interviews with other system engineers confirmed this to be the case.

7. During a system walkdown with the mechanical system engineer, he pointed out the MO-27 valve as the previous outside containment isolation valve, and MO-25 (which is also outside containment) as the previous inside containment isolation valve. He indicated that the containment isolation boundary was modified in 1993 when the MO-27 valve could not pass local leak rate testing, so the testing method was reconsidered, using the check valve inside containment as an isolation valve, and the MO-25 valve as the outside containment isolation valve. Although this was recognized as a problem in 1993, actions were not taken to determine if other Appendix J valves were not tested in the accident direction.

When questioned about how valves RHR MO-27A/B could be considered containment isolation valves when neither receives a close signal on containment isolation, engineering personnel responded that the valve principally has a core cooling function as part of LPCI. However, the response does not recognize the overall system design that provides an injection isolation valve (that receives an isolation signal under certain conditions) and a check valve inside containment (to prevent backflow). Additionally, this response does not address the original design of the system, nor the analyses/bases used to include this valve as an Appendix J boundary valve in the Technical Specifications.

8. There is currently a temporary modification installed on the RHR system that provides a pressure gauge downstream of a normally closed valve on a pressure switch manifold. The gauge was installed to provide a means to monitor pressure on the portion of the line downstream from the shutdown cooling isolation valves (MO-17 and MO-18) because there had been a problem prior to the last refueling outage wherein the pressure switch had been actuating, providing an alarm in the control room indicating leakage past the isolation valves. Additionally, the discharge from the relief valve cannot be monitored, so the engineer could not tell how significant the leakage had been. During the refueling outage, the valves were disassembled, and cracks were identified in the seat of the inboard valve, with one crack noted in the seat of the outboard valve. As a means of monitoring for possible leakage, the engineer initiated the temporary modification to install the gauge, and monitors the pressure on a regular basis to determine whether leakage is occurring. When asked why a recorder wasn't installed under the temporary modification to make tracking and trending of the pressures easier, the engineer and his lead indicated the cost of a recorder would be too high to justify the expenditure.

9. The shutdown cooling isolation valves have actuated during initiation of shutdown cooling in March and May of this year. A review of the corrective action documents for the events noted that the March event was attributed to flashing in a stagnant section of recirculation system piping, temporarily increasing

pressure in the recirculation piping and causing isolation of the shutdown cooling isolation valves. Additionally, the event description indicated that the reactor was at 175 degrees F and atmospheric pressure. However, further review of event documents indicated that there was a mechanical vacuum pump in service at the time of the event. The corrective actions do not address the possible impact of having the vacuum pump in service, and whether this practice should be discontinued to prevent recurrence of the event in the future.

Additionally, in May there were three isolations of shutdown cooling during one day. It was later determined that the cause of these isolations was leakage past the pump minimum flow valve, since the valve indicated closed, but was not fully seated. When the shutdown cooling valves were opened to admit reactor coolant to the pump suction, the leakage past the minimum flow valve depressurized this portion of the line and caused flashing in the shutdown cooling piping and actuation of the shutdown cooling isolation valves.

10. During comparisons of design requirements established through GE specifications with the valve stroke times used as limits in the IST program, a number of inconsistencies were noted. Further review identified a condition report (94-297) that had been written on June 14, 1994 to document finding differences between the times used in the IST procedure and the times specified in the narrative portion of the USAR. To date, some of the valves have been evaluated and, based on more recent analyses, the IST limits have been deemed acceptable. However, the review to date has not evaluated the performance of the valves prior to the reanalysis, and it is not clear whether the reanalysis has fully addressed the original design requirements.

11. During a review of pump performance test results as part of the IST program, it was noted that RHR pump 1A had shown an increase in differential pressure of approximately 8 psi from one quarterly test to the next. When questioned, the IST engineer indicated that any analysis of the data would be the responsibility of the system engineer and the IST engineer typically does not require such an analysis unless the pump results fall into an "alert" or "action" range.

Additionally, a review of RHR pump 1B test data noted that the pump had not achieved the reference value for a number of tests, with the differential pressure typically falling about 10 psi short of the reference value. A further review of the data showed that the pump was re-baselined in early 1994 to establish a baseline that matched with the typical data. The basis for this re-baselining was the long-term inability of the pump to achieve the initially established reference value. This basis did not address why the pump had not been able to consistently achieve the reference value, nor did it address whether there had been a degradation of the pump performance. Finally, the justification for re-baselining the pump did not address whether the new baseline values would ensure the pump could meet design bases.

12. During a period of time when the heat sink for the fuel pool cooling system was taken out of service, the RHR system was not considered as an alternative method for providing fuel pool cooling. A review of the USAR identified that the fuel pool cooling description indicates the RHR system can be used to provide fuel pool cooling if the fuel pool temperature approaches 150 degrees. When questioned about the basis to support the USAR statement, engineering personnel indicated the fuel pool cooling capabilities of RHR had been evaluated in response to a 1993 NRC IE Notice, and that RHR had been operated with shutdown cooling and fuel pool cooling concurrently. This response does not address the bases for the original USAR statement.

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13. During a comparison of system operating procedures (including valve lineup checklists) with current design drawings, a number of inconsistencies were noted. For example, the following valves are shown on the P&ID (drawing 2040) as normally open, but are required to be closed for normal valve lineups by procedure 2.2.69 and valve lineup checklist 2.2.69A: MO-15A/B/C/D, MO-20, MO-16A/B, MO-274A/B, MO-36A/B, and vent or drain valves V-145, V-357, V-138, V-377, V-302, V-125, V-29, V-30, V-196, and V-396.

Additionally, the following valves are identified in the valve lineup checklist as being sealed open, but are not shown as locked open on the drawing: RHR-10-88, RHR-105, and RHR-106.

14. During procedure reviews and review of station events, it was noted that the pump minimum flow valves (MO-16A/B/C/D) are closed with their breakers opened when preparing to start a pump in the shutdown cooling mode. NCR 94-035 was also generated to request a safety evaluation to justify this method of operation, which can be interpreted to be contradictory to the description of the pump minimum flow capability in the USAR. The NCR indicates this practice has been in place since approximately 1982, due to concerns regarding vessel draindown during initiation of shutdown cooling. Although the procedure does address the need to quickly establish a flow path after pump start, the procedure does not address actions to be taken if the heat exchanger bypass valve (MO-66A/B) does open when the control switch is operated.

15. A walkdown of a portion of the electrical support system for the RHR system was also conducted. 4160 volt buses 1F and 1G (containing the breakers for the RHR pumps) were inspected, including labeling, configuration, and component conditions. Also inspected were the 480 volt motor control centers Q, R, and CA which contain starter cubicles for a number of "A" train RHR motor operated valves. In addition, starter panels for 250 volt DC and 125 volt DC RHR motor operated valves were inspected.

The appearance of all inspected switchgear and starter cubicles was clean and in good repair. The 480 volt MCC Q cubicle door latching screw for RHR-MO-15A did, however, appear to be loose, possibly due to thread problems in the mechanism. The breaker cubicles had the correct labeling and were in the proper configuration per electrical drawings.

Several of the 250 volt DC motor starter enclosure clamps were also noted to be missing. However, all enclosures had more than 50% of the clamps installed and secured. Additionally, the areas in the vicinity of the switchgear and starter panels were well kept and uncluttered.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-16

**DESCRIPTION:** Management has ineffectively managed changes to station programs and processes, lacking effective planning and anticipation of impacts of changes on station activities and the workloads of station groups, such as system engineering.

**CAUSE:**

**EXAMPLES:** 1. Management made significant changes to the CR/MWR process without considering the impacts of this change on the workload of the maintenance, engineering, and management groups tasked with reviewing, investigating, and correcting the problems identified through the process.

2. Changes to the MWR process to prevent performance of work on troubleshooting MWRs were not effectively planned and implemented. The changes were intended to minimize the potential for work to be ineffectively planned and documented. However, management did not provide adequate oversight and coaching of the activities, resulting in a number of instances where work was still accomplished under troubleshooting MWRs.

3. The system for controlling the new digital dosimeter and computerized station work permit process has been installed since May 1994 with management monitoring the status of the process weekly and the process be "backed up" with forms that require manually logging in and out of the RCA, as well as using the computerized system. Due to some continuing concerns with overall system reliability, the manual logging process continues to be used. Actions necessary to resolve the problems with overall system reliability have not been identified.

4. The changes to the emergency plan that were prompted by the revised 10CFR20 and EPA 400 were not completely addressed in the Emergency Plan implementing mechanisms, specifically the computer program planned to provide dose assessment calculations could not be easily updated to coincide with the changes. As a result, the program CNS-DOSE has needed to be maintained current to provide dose assessment capability.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-17

**DESCRIPTION:** Design basis information is not readily available and is sometimes not used when developing design change calculations.

**CAUSE:**

**EXAMPLES:** 1. Design basis information for the RHR system was requested, with listings of calculations, specifications, safety evaluations, and correspondence provided, but site engineering personnel indicated they were not aware of this information, and didn't think the information was available on site.

2. A modification to correct single failure and potential flow problems on the standby gas treatment system (DC 93-064) included a calculation (NEDC 93-089, approved 6/3/93) to determine air flows through portions of the standby gas ductwork during various modes of system operation, such as drywell/torus purging and venting, as well as calculating pressure drops in portions of the ductwork. This calculation does not reference any original design calculations, and identifies the following information as part of the "design bases/references" section:

USAR Table V-2-1
Tech. Specs. 3.7.B.2.a, 3.7.c.21
EOPs and SOPs
Drawings
Calculation NEDC 90-027, rev. 2

The calculation does not address whether it supersedes original design calculations, and does not address similarities or differences from original design assumptions.

3. System engineering personnel indicated the currently issued design criteria documents (DCDs) are of limited value because they don't provide additional insight beyond what is described in the USAR and the Tech Spec bases. Additionally, system engineering personnel indicated the lists of design basis information in records that are included as a part of the DCDs do not provide a "user-friendly" means of obtaining design information. They further indicated that the System Training Manuals are a much more useful source of information.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** GW-18

**DESCRIPTION:** Design control activities are ineffective in ensuring that station configuration is maintained consistent with design bases.

**CAUSE:**

**EXAMPLES:** 1. SORC-approved MWRs (refer to RA-01) have been used to expedite design changes in the plant. In the cases of the standby gas treatment system and the reactor vessel level reference leg continuous fill modification, the design changes that made these modifications permanent required additional changes to correct items not properly evaluated in the preparation of the SORC-approved MWRs. As a result, the changes installed under the SORC-approved MWRs did not fully meet design requirements, and should have been identified as nonconformances.

2. Design basis information is not readily available or used by engineers when preparing modifications. As a result, it is not clear whether modifications are consistent with design bases, or may be deviating from the station design basis.

3. Engineering personnel interviewed indicated that there is no index of historical design basis calculations. One individual indicated that an effort had been undertaken to review design calculations in records and identify those that had been superseded by later calculations. However, when the initial review identified 24,000 calculations, it was determined that the effort was too massive and would take too long to complete.

4. Interviews with engineering personnel indicated they were not sure whether the station configuration and current design information submitted to GE to support the core reload transient analyses is controlled. Inaccuracies in the information submitted could have an impact on the accuracy of the fuel and safety analyses used to support operations with a new reactor core.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG

**SEQ:** GW-19

**DESCRIPTION:** Engineering investigation into root causes of some equipment problems have not been successful in identifying the root causes and identifying the needed corrective actions. In some cases, the investigation has focused on one aspect of system performance and bypassed the opportunity to identify other system problems.

**CAUSE:**

**EXAMPLES:** 1. On February 1, 1994, during stroke time testing of a core spray test line isolation valve, the minimum flow valve unexpectedly stroked from the full-open position to full-closed, then returned to the full-open position. Since it was assumed that there might be air trapped in the instrument sensing lines for the core spray flow transmitter (the minimum flow valve gets a close signal on adequate system flow from this flow transmitter), the instrument sensing lines were backflushed and operators stroked the test line isolation valve to see if the problem recurred. When the problem would not repeat, the engineer and operators assumed that the instrument sensing lines had gotten air trapped in them during calibrations prior to the valve stroke time testing, and the backflushing had addressed the problem. The core spray system was declared operable after venting and performance of the pump operability test. The event recurred on April 27, 1994 during core spray test line isolation valve stroke time testing. At this time, additional root cause investigations were undertaken, including bringing in contractors to assist in determining the causes. Additionally, a review of maintenance history following the February event had identified instances wh the flow transmitter had given erratic indication during pump operation with discharge through the test line or the minimum flow line. The maintenance history also showed that the problem of erratic flow indication had also occurred on the other loop. Root cause analysis was focused on the occurrences where the minimum flow valve had stroked during stroke time testing of the test line isolation valve. To conduct the root cause analysis, high speed recorders and pressure transmitters were attached to the instrument sensing lines while the test line isolation valve was stroked. Based on the information gathered during the test line isolation valve stroking, the consultants and the site engineering personnel believed that there was air trapped in the sensing lines to the flow transmitte.. A further examination of the flow element drawings, and further discussions with the manufacturer of the flow element, revealed that the instrument tap points on the flow element would allow air to be trapped in the flow element near the sensing lines. The manufacturer also indicated that this did not present a problem in systems where there was continuous flow through the flow element, because the continuous flow drew the air out of the stagnant spaces. Additionally, the results of the recorder traces were sent to individuals that the station considers experts in analysis of water hammers and instrumentation. These individuals indicated the frequencies represented by the instrument recorder traces showed that a small volume of air was trapped in the system, consistent with the volume of air that appeared to be trapped in the flow element. As a result of the root cause analysis of the event, corrective actions were identified to provide a six to eight second time delay in the minimum flow valve circuitry to prevent operation unless the valve received a sustained signal from the flow transmitter indicating the system flows were adequate to allow closure of the minimum flow valve.However, the investigation into the root causes of the event did not include the occurrences where the flow transmitter indicated erratically during pump operations, and did not ensure that there were not additional system problems that might be masked by the installation of the six to eight second time delay in the minimum flow valve actuation circuitry. For example, the testing of the flow transmitter did not include testing during pump operation, although the maintenance history review identified instances where

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the flow element had demonstrated erratic indication during pump operation. Additionally, the investigation did not include a verification that the system was adequately vented to ensure the erratic flow indication was not a result of system dynamic effects associated with air trapped downstream of the point in the system where the test return line is attached. A walkdown of the system showed that the vent piping for one loop of the core spray system was connected to the reference leg backfill modification, resulting in the vent valve remaining open with a downstream valve used to vent the pump prior to operation, and the downstream valve being located well below the elevation of the piping.On August 17, 1994, the system operability test was observed. The following aspects of core spray system operation were noted: a. The operator venting the system was concerned about the possibility of splashing from the drain hub when opening the valve used to vent the system. He indicated that some times when the valve is opened there is a fast rush of air and water that splashes out from the drain hub. After he cautiously cracked the vent valve off its seat, he opened the valve to allow slight flow into the drain hub. The vent piping did not flow full. Instead, he allowed enough flow to provide a film around the circumference of the pipe. When asked, the operator indicated this was a typical method of venting the pipe, and that the B loop was much more difficult to drain because the vent line went further into the drain hub, making it more difficult to gauge flow through the vent line. It should be noted that whenever the test return line isolation valve is opened, the main core spray system piping is drained through this valve and must be refilled by the pressure maintenance system. Lack of an adequate vent could cause this process to allow air to remain in the system and, potentially, cause a failure in the downstream piping on an automatic pump start during an accident scenario. b. When the core spray pump started, the one-inch diameter vent line "hammered" approximately three-fourths of an inch on the horizontal piping run. c. As part of the surveillance procedure, flow through the reactor vessel level instrument reference leg backfill line (fed from the core spray system at the high point vent) was to be verified. As part of the procedure, a tygon tube was to be attached to a drain line on the backfill portion of the system, and the flow rate was to be verified by collecting flow from the drain during a specified period of time. The procedure indicated this portion of the test was to be done after the system was aligned to route pump discharge through the test line, and system flow was stable. After the test line isolation valve was opened, the operators prepared to open the solenoid operated valve in the system to admit flow through the backfill portion of the system. After the drain valve was opened, the operators monitored flow through the tygon tube to ensure stable flow through the backfill system. Initially, the drain line passed air, followed by a stream of water, followed by a rapid release of air, water, and water with air entrained. Additionally, after the rapid air release and a short release of water, a greenish water was released through the drain piping. The operators monitored flow through the drain for approximately four minutes, with air evident in the effluent throughout this time. After discussing the need for stable system flow (as described in the procedure), the operators determined the flow was adequately stable with the periodic air bubbles in the line. Therefore, they collected the effluent for one minute in the calibrated vessel, and determined the flow rate met the procedure acceptance criteria. The procedure did not address any special actions to be taken by operators if air was found in the reference leg line. d. Based on discussions with personnel observing the test in the control room, and information obtained from plant operations personnel, when the solenoid operated valve for the reference leg backfill system was opened, the reactor vessel level indication showed a momentary eight to twelve inch level spike. Shortly thereafter, the level returned to normal. A reactor scram signal, and shutdown cooling isolation signal, had been received in June when the core spray reference leg backfill system had been found to be leaking past the solenoid valve and air had been introduced into the reference leg. e. Personnel in the vicinity of the pump at the time of pump start indicated the pump seemed to surge for approximately five minutes after the start. This type of surging could be indicative of pressure waves resulting from air trapped in the system. Additionally, the reference leg backfill subsystem was opened approximately five minutes after the

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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pump start, with air being removed from the system during the subsequent four minutes. The personnel at the pump indicated the surging decreased after five minutes and slowly subsided. It is not known whether the pump was approaching a shutoff head condition during the "surging," and it is also not known what what pressure spikes occurred in the downstream piping. f. During observation of the piping in the vicinity of the pump, it was noted that the minimum flow piping was vibrating excessively (movements of one-half to one inch), most notably in the area above the pump after the piping went through a floor penetration. Also, the test line piping was vibrating while the test line isolation valve was open, with noticeable cavitation heard downstream of the isolation valve and the restricting orifice.2. Similar to the core spray system minimum flow valve actuations, the HPCI minimum flow valve was found to cycle open during stroke time testing of the pump discharge valve. The LER indicates the cause of this valve stroking is a pressure wave induced in the pump discharge piping when the pump discharge valve is opened. Subsequently, the minimum flow valve is provided an open signal on an indicated pump discharge pressure greater than 125 psig.A review of the non-conformance report (NCR) for this event noted some additional aspects of the system configuration and testing that may have contributed to this event. For example, the NCR indicates, during pressure monitoring to determine the cause of the event, the pressure downstream of the pump discharge valve increased from a normal pressure of approximately 70 psig to approximately 100 psig when the pump discharge valve is closed. Additionally, the NCR indicates the pressure downstream of the pump discharge valve increased to approximately 140 psig when the injection valve was opened, then increased further to approximately 150 psig when the injection valve was closed. Upon opening the pump discharge valve, the pressure downstream of the pump discharge valve was indicated to approach zero, possibly due to the opening of the minimum flow valve.The root cause discussed in the NCR, similar to the LER, indicates the problem is a pressure wave that sets off the pump discharge pressure switch. Howe the NCR investigation does not address the possibility that there is backleakage through the pump, and the isolation of the pump discharge valve allows the pressure maintenance system to achieve the e pected pressure in the piping system. As a result, the minimum flow valve may be actuating on either a pressure spike caused by the downstream system volume suddenly filling the pipe, or some indication of flow based on reverse flow through the flow element. Additionally, the instrumentation of the system did not include a pressure gauge upstream of the pump discharge valve that could have indicated whether isolating the pump discharge valve could have resulted in draining of a portion of the pump discharge piping.Possible corrective actions being considered for this event include changes to the pressure switch calibration. The corrective actions do not address identifying any potential leak paths that might result in the draining of the system when the pump discharge valve is closed and the pressure maintenance system is not available ot provide makeup.

**PROGRAMMATIC:** System engineers focus on the quickest and simplest fix available for plant problems

**MANAGEMENT:** System engineering workload is so ecxessive that the system engineers cannot afford the time necessary to think about the entire problem when dealing with equiment issues or problems.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** JC-01

**DESCRIPTION:** (Identified during Interview)
System Engineering: Low Productivity and Effectiveness

**CAUSE:**
1. Crisis Management
2. Start-Up-Now Philosophy
3. Do only startup issues as soon as possible

**EXAMPLES:** (From interviews)

1. Excessive number of CRs and Corrective Action Reports prevent System Engineers from performing field work, walkdowns, etc.

2. CR process does not identify "hot" items that may require immediate action.

3. Interdepartmental rapport with System Engineering has declined to minimum.

4. Excessive overtime by System Engineers over the last seven months.

**PROGRAMMATIC:**

1. New Corrective Action Program is a "Catastrophe" ie., is "Cumbersome" and "does not appear to provide results that are intended."

2. CR process can take several days to get through the system.

3. Perception that mistakes, bad news and problems brought forward will be met with termination of employment, or other disciplinary action.

4. This borders on being outside station procedure 0.12, overtime.

**MANAGEMENT:**

1. Unrealistic expectations of System Engineers and required activities.

2. No feedback on CR/CAP programs from people who have to use them was looked at by management.

3. Rumors that preceded the new Site Manager's arrival cultivated employee perception of job loss from any past or present mistakes. Management should have defused this now minimal work effort is being done to stay out of the way of this site manager.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** JC-02

**AREA:** ENG

**DESCRIPTION:** Deviation from Procedure 14.30.1; "RHR System Instrument Calibration"

**CAUSE:** Instruments are non-essential and non-EQ, however, latest procedure should be used.

**EXAMPLES:** Randomly reviewed, 14 of 47 (30%) RHR Calibrations covered under Proc. 14.30.1. All 14 of the last completed calibrations were done with data recorded on superseded instrument calibration data sheets, and several were neither reviewed nor approved by foreman, supervisor or IST engineer as required by 14.30.10.

**PROGRAMMATIC:** Procedure Compliance

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** RA-01

**DESCRIPTION:** Design changes accomplished by SORC-approved MWRs are sometimes completed and installed without a complete engineering resolution and analysis of design.

**CAUSE:** Crisis Management Practices.

**EXAMPLES:** 1. Design change 93-076 Cold Reference leg Continuous Backfill modification documented work performed under SORC approved MWR 93-2259 and MWR 93-3023. This design change had to modify the work performed under MWR 93-3023 to include changing the filter size from 60 microns to 5 microns and added filter vents and drain valves. The metering valves were replaced with double pattern valves. The design change package states that the two check valves in series will provide a leak-tight seal preventing back flow from one reference leg to the other. A preventative maintenance procedure will be written to inspect and leak test the check valves every scheduled outage. This procedure has not been written.

2. Design change 93-064 was developed to document the work that was previously performed under MWR 93-1172 "SOV Overpressure Protection" and MWR 93-1814 "SGT Damper". While developing the design change, it was determined that the work performed under MWR 93-1814 could possibly introduce flow into the reactor building plenum during the de-inerting process. The design change required additional work to AD-R-1B to preclude this from happening. Additionally, a review of the calculations associated with the design change identified that some calculations to demonstrate the acceptability of configurations authorized under the SORC-approved MWRs were not completed until almost one year after the SORC-approved design change had been installed in the plant and declared operable.

3. Design change 89-252C documented SORC approved work item 90-3941 which replaced the MS-MP trim elements with a spacer ring designed and approved by Anchor Darling for RHR-MOV-MO27B.

4. A total of six additional design changes that have been installed under SORC-approved MWRs were identified from the list of open modifications. These include the following:

DC 93-034, HV and RW AOV Supply Air Upgrade
DC 93-047, Reactor Feed Pump Minimum Flow Alteration
DC 93-076-1, Recalibration of Instrumentation Affected by the Continuous Backfill Modification
DC 93-128, Diesel Generator Day Tank Water Sampling
DC 93-135, Service Water Pipe Supports
DC 93-138, Service Water Pipe Supports - REC Radiation Monitor Supply Lines

**PROGRAMMATIC:** Design change program allows this to occur.

**MANAGEMENT:** Management expectations to do work first and follow up with the detailed analysis and documentation later.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

SEQ: RA-05

**AREA:** ENG

**DESCRIPTION:** Responsibilities and interfaces of the plant and corporate engineering organizations are not clearly defined.

**CAUSE:**

**EXAMPLES:** 1. Engineering Procedure 3.1 - Engineering Interfaces does not define the responsibilities of the Site Engineering Manager's department whose primary responsibility is to provide direct interface between station engineering personnel and corporate engineering personnel.

2. Responsibilities for addressing problems identified in the plant are not clearly established. For example, when questions arose regarding the shutdown cooling flow turbulence, system engineering personnel contacted a consultant to perform thermal/hydraulic analyses. When additional information indicated the turbulence emanated from a restricting orifice installed as part of DC 89-252, the system engineer contacted corporate personnel regarding the analysis that supported the design change and whether it addressed possible causes of the turbulence.

3. When leakage of REC piping was identified, station engineering personnel requested support from the corporate engineering organization. During the scoping of the required inspection effort, site and corporate personnel were performing somewhat redundant efforts to review drawings and identify suspect weld locations. The corporate engineering organization was charged with responsibility for identifying the sc... of inspections and criteria for scope expansion, as well as determining whether indications identified were acceptable (using GE). However, the site engineering manager was considered the responsible manager for managing the overall inspection and repair project.

4. Corporate engineering personnel have been managing the drawing walkdown project with minimal station involvement since 1986. The process has identified a number of drawing discrepancies, but the walkdown discrepancies have been totally separated from the station problem reporting process, resulting in difficulties in informing the station operating staff of potentially affected equipment.

**PROGRAMMATIC:**

**MANAGEMENT:** Management not providing clear expectations to the work groups.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RA-07

**AREA:** ENG

**DESCRIPTION:** There does not appear to be a process for controlling "future building" of design calculations for plant design changes.

**CAUSE:**

**EXAMPLES:** During the development of design changes, new calculations or calculation revisions may be necessary. Once the new/revised calculation is approved, it is then sent to the records department for the "calculation of record". This may be done prior to initiation of work in the field. Also the electrical calculations are updated periodically to incorporate minor changes to the calculations. This method is acceptable; however, it is not proceduralized.

**PROGRAMMATIC:** The calculation program needs more refinement.

**MANAGEMENT:**

**SEQ:** RA-08

**AREA:** ENG

**DESCRIPTION:** Procedure for evaluation of open items identified during DCD production needs to be updated.

**CAUSE:**

**EXAMPLES:** NECDP-09 steps 5.3.3 and 5.3.4 refer user to write a NCR in accordance with O.P. 0.5.1 when a category 1 and 2 discrepancy is identified. The NCR has been replaced by the CR. This step should refer user to the O.P. 0.5 which is the CR procedure.

**PROGRAMMATIC:** Not all documents/procedures that refer to the old Corrective Action Program have been updated.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RA-09

**AREA:** ENG

**DESCRIPTION:** Lack of configuration control.

**CAUSE:** Valve lineups or breaker lineups may be changed in a modification without engineering review and approval. This could invalidate the design basic calculations and/or special test results.

**EXAMPLES:** 1. EP 3.4.10 Station Modification Changes, Step 2.1.2 allows the Shift Supervisor to change the design engineer's proposed system lineups without engineering approval. Also see E.P. 3.5 Special Test Procedure, Step 2.8.3.

2. CR2 94-0459 described the REC valve lineup configured system such that the REC HXs are incapable of providing required cooling under post LOCA conditions with a concurrent loss of Division II emergency power.

3. There currently exists a difference between relay settings and design bases calculations. Edan Engineering draft report No. EE-007-94-0 of May 25, 1994, identifies several instances where relay settings (tap, time dial and instantaneous) differ between the protective relay design basis calculations and Drawing E-150 which is the master document for relay setpoints, test requirements and acceptance criteria. Edan could not identify a basis for these differences the setting values and the original design basis. The discrepancies are:

NO: 1
BREAKER: SSIF
E-150 SETTINGS: Tap - 6, Time Dial - 6, Inst. - 107A
B&R CALCULATION 2.09.06: Tap - 5, Time Dial - 5, Inst. - 105A

NO: 2
BREAKER: RSWP 1A
E-150 SETTINGS: Inst. -30A
B&R CALCULATION 2.09.06: Inst. - 40A

NO: 3
BREAKER: RSWP 1B, C, D
E-150 SETTINGS: Inst. - 38A
B&R CALCULATION 2.09.06: Inst. - 40A

NO: 4
BREAKER: SWPs
E-150 SETTINGS: Time Dial - 3
B&R CALCULATION 2.09.06: Time Dial - 5

NO: 5
BREAKER: 1FE & 1GE
E-150 SETTINGS: Time Dial - 5, Inst. - 40A

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B&R CALCULATION 2.09.06: Time Dial - 4, Inst. 50A

In addition, essential relays are not being tested or maintained on a regular basis. Per the EDAN report, these include 18 ground detection relays (50G) on 4160V buses 1F and 1G and Emergency Transformer overvoltage relays.

4. Recently NED engineering provided operating restrictions on transferring DC buses and MCCs during plant operations to station personnel. This was done to ensure the plant would be operated within design basis.

**PROGRAMMATIC:** Program allows configuration changes without appropriate engineering review.

**MANAGEMENT:** Lack of emphasis on operating the plant within its design bases.

**AREA:** ENG **SEQ:** RA-10

**DESCRIPTION:** Change to plant drawings to "correct error" without adequate justification/review to ensure conformance with design basis.

**CAUSE:**

**EXAMPLES:** C94-0439 Modified the critical control panel load and fuse schedule.
C94-0096
C94-0097
C94-0098
C94-0099

C94-0439 Removed controls on main turbine emergency oil pump starter.

C94-0450 Modified the wiring diagram for the 120V AC @ starter in MCCB.

C94-0975 Modified service water system to diesels.

C93-1240 Removed TS-202C and TS-203C contacts.

C93-1241 Removed PS-201C contacts.

C94-0162 Changed logic in ADS.

**PROGRAMMATIC:** The drawing change process is not clear on the appropriate use of the "correct error" field and only requires a review of the applicable design criteria document to identify changes to those documents.

**MANAGEMENT:** There is no overall directive on configuration management.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG **SEQ:** WW-12

**DESCRIPTION:** A trend of Agastat relay problems has been observed by engineering. CR 94-0523 and OD 94-82 have been written to address program enhancements.

**CAUSE:**

**EXAMPLES:** Approximately 19 Agastat relays have failed in 20 year time period. After further discussions with an electrical engineer and my review of Agastat relay failures it appears that CNS does not have an operability issue at this time and it appears the normal OD process will determine an in-depth review concerning E-7000 Series relays. This item is considered closed.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** ENG **SEQ:** WW-14

**DESCRIPTION.** The MWR Special Instructions associated with REC shutdown (MWR 94-4081) were not approved in accordance with station procedure.

**CAUSE:** The test engineer who presented the Special Instructions to the SORC stated that the Special Instruction had been approved by the SORC on the basis of the philosophy and general context. The specifics were not approved by the SORC in that the SORC had discussions whether this guidance should be a Special Instruction or Special Procedure. The SORC decided to make the guidance a Special Instruction in order to allow changes to be made if needed. This was out of the ordinary to the test engineer and he did not include the approval sheet needed for Special Instructions.

**EXAMPLES:** See description.

**PROGRAMMATIC:** The test engineer failed to recognize the need for approval signatures at the supervisory level since he had the approval for the Special Instruction context from the SORC.

**MANAGEMENT:** Failure of management to communicate expectations for approval requirements.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** ENG

**SEQ:** WW-17

**DESCRIPTION:** The testing associated with SW-PS-364A and SW-PS-364B is inadequate for determining the autoclosure capabilities of SW-MOV-36MV and SW-MOV-37MV, Service Water pumps crosstie to non-essential header isolation. Since there is no other method of testing the auto-closure of these valves on low pressure, the operability of this auto function is questionable due to the standard condition of the sensing lines due to silting.

**CAUSE:**

**EXAMPLES:** 1. The instrument calibration data sheets associated with the above instruments do not give specifics concerning:

a. Instrument and root valve manipulations

b. The mechanism for backflushing - two technicians stated they use a high-pressure pump and demin. water to clean the sensing lines.

2. The instrument lines are backflushed prior to performing the instrument calibration (24-month frequency).

3. There are no other mechanisms for testing the autoclosure feature of SW-MOV-36MV and SW-MOV-37MV.

4. Discussions with I & C supervisors, I & C technicians, and I & C trainers gave three different techniques for backflushing these pressure-sensing lines.

**PROGRAMMATIC:** The surveillance program may need further review concerning testing techniques for meeting internal functions.

**MANAGEMENT:**

*31-Aug-94*

**AREA:** M&O **SEQ:** DB-01

**DESCRIPTION:** PLANNING/MANAGEMENT OF EMERGENT ISSUES

Activities are not being planned or well directed. Work activities are performed before coherent plans are made or the activities out-run the plans. Examples include the NRC CAL OER review, maintenance program and performance improvements, corrective action program management, investigation of plant problems.

**CAUSE:**

**EXAMPLES:** - Initially inadequate planning and work instructions for correction of improperly engaged spade lugs in safety related terminal blocks. (Reference SV-08)

- Poorly developed plan and unjustifiable bases for selection and review of Operating Experience Items in response to NRC Confirmatory Action Letter. (Reference CB-11, SE-04).

- The initial NPPD response to NRC concerns regarding preconditioning was not comprehensively planned. Resulted in ineffective field direction, communication of management expectations and management oversight. Examples of proceduralized pre-conditioning were observed that were not prop nor expeditiously dispositioned in accordance with management's expectations. (Reference CB-16)

- The new Corrective Action Program (CAP) was implemented in 4/94 but ownership, oversight, and planning for correction of CAP problems has been erratic. The vision for full implementation is incomplete. Problems still exist in CAP activity ownership, trending, OE program ownership, reliance on QA, and HPES use. (Reference DK-01, DK-03).

- The CAP Program Manager and Team Leader organization has been created but not institutionalized via charter statement or program plan. (Reference CB-15)

- Development of a new work control program is proceeding without a comprehensive, management accepted project plan. (DM-02)

- Task assignments and parameters for investigation and response to plant problems with valve lineup discrepancies and CS-MOV-12 testing discrepancies were unclear. The VP-Nuclear or the Site Manager had to intervene in both cases to ensure that safety issues were addressed and adequate plans developed. Notwithstanding this intervention, planning remained ad hoc and informal. (Reference SE-04)

- The absence of a centralized maintenance work scheduling process has resulted in additional equipment out of service time, lost maintenance production hours, and an increase in maintenance backlog. Also places an unacceptable administrative burden on the Shift Supervisor to coordinate work. (Reference SV-02).

- NPPD had previously identified a number of needed maintenance program and performance improvements (e.g. procedures, work control elements, shop/personnel performance). However, management focus has been on short term, immediate needs and plans have not been developed or have been inadequate. (Reference SV-04)

- An orally implemented change in policy prohibiting repair work on "troubleshooting" MWRs resulted in a significant impediment to progress. A second policy change reduced its scope to only Technical Specification equipment. (Reference CB-15)

**PROGRAMMATIC:** Current programs and management controls do not require or promote use of strategic or tactical planning; existing planning and scheduling systems are ineffective. Non-routine activities are frequently planned orally and launched without benefit of a thorough plan.

**MANAGEMENT:** Management has fostered an environment in which production and work accomplishment is usually given the first priority with pressure on the staff to achieve results with minimal delay.

**AREA:** M&O **SEQ:** DK-01

**DESCRIPTION:** The Corrective Action Program is being ineffectively administered resulting in recurring events. According to the CNS Integrated Enhancement Plan (IEP), CNS has not consistently demonstrated the ability to identify, aggressively pursue and permanently resolve their own problems. When problems were identified, the implemented corrective action did not consistently prevent recurrence. The inability to resolve recurring problems has been attributed to a failure to conduct thorough root cause investigations or implement the necessary, enduring corrective actions. Several IEP actions have been accomplished; most notably changing to a single overall problem reporting system and lowering the problem reporting threshold. Although this has resulted in drastic improvement in identifying station problems, the ability to determine the root causes and establish corrective actions has not yet been demonstrated. The following deficiencies of the CNS CAP will be explained in detail on the supporting Issue Development Sheets:

1. Inadequate program vision. (DK-01.1)

2. Program Manager responsibilities not developed. (DK01.2)

3. Inadequate program performance monitoring and programmatic adjustments. (DK01.3)

**CAUSE:**

**EXAMPLES:** Examples of recurring events are described in CB-16, CB-17, CB-18, and CB-19.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** DK-01.1

**DESCRIPTION:** The vision for full implementation of new Corrective Action Program is incomplete. Although several elements of the Integrated Enhancement Program (IEP) have been implemented, it is recognized that additional activities will be required to completely implement the program. The vision for where the program is headed has not been clearly described or communicated.

**CAUSE:**

**EXAMPLES:** 1. Ownership of CAP - As the new CAP procedures were implemented in April of 1994, administration of the process has been disjointed. The initial screening and preparation of Condition Reports (CRs) for the Condition Review Group (CRG) meeting resides with the Tech Staff Group. After the CRG, assigned responsible managers are charged with determining the cause and corrective actions to prevent recurrence. Once the corrective actions are approved by the Corrective Action Review Board (CARB), the responsibility for closure of the item resides with the department managers without verification of closure by the CAP program manager.

2. Ownership of the industry OE review process - It is not clear whether evaluation of the OE documents performed by various departments will continue to be a tech staff responsibility or be incorporated into the CAP Manager's area.

3. Reliance on QA to identify trends - Station line management relies on QA to perform trending of station problems. This method has been ineffective in addressing adverse trends. The QA Trend Report for the last quarter of 1993 and the first two quarters of 1994 indicated an adverse trend in the area of procedure use and adherence. A systematic approach to address this issue was not taken by the station, resulting in continuing procedural problems. The CAP procedures do not give direction on how trending data should be used and the tech staff does not appear to be staffed to do this type of trending. QA procedures contain the trending responsibilities.

4. Back loading of NCR and DR information into the trend database has been completed, but the cause and event codes used cannot be directly related to the current set of codes that are part of the new CAP. This makes it difficult, at best, to identify and compare adverse trends between the old and the new system. When the new CAP procedures were being developed, the manager requested additional personnel to establish the trending database, but his request was not filled resulting in a delay in entering the backlog of information and possibly preventing the recoding of the old information.

5. CRT/Root cause ownership - A new group of Condition Resolution Team (CRT) Leaders has been formed under the CAP program manager. The group is being mentored by FPI consultants. A trial period of six months has been initiated. The criteria for success of this trial has not been developed. The majority of root cause evaluations and investigations are still done outside of this groups direction.

6. Human Performance Enhancement Program - There is no clear owner of the Human Performance Enhancement Program. This was intended to be part of a new group called the Independent Review Group (IRG) as stated in the Integrated Enhancement Program (IEP). The IRG Manager and staff positions have not been filled and the IRG has not been formed. NPG Directive 1.2.1, Independent Review Group

Charter, states that the IRG is responsible for the "Human Performance Education" portion of the Corrective Action Program, but it is unclear if this includes the total HPES program.

7. Self Assessment of the CAP. There is currently no provision in the CAP program implementation procedures to perform a periodic self assessment. The lack of this provision was pointed out in a FPI report as well as a recent QA audit, AQD940139. The IEP calls for an assessment of the effectiveness of the CAP in October of 1994.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** M&O **SEQ:** DK-01.2

**DESCRIPTION:** The CAP program manager responsibilities are not developed.

**CAUSE:** The CAP Manager position was established in response to a consultant's recommendation without clear definition of a problem statement or a program weakness to be addressed by the position.

**EXAMPLES:** 1. There is no Charter and/or position description of the CAP Manager. There is no project planning type document or milestone schedule for full implementation of this organization.

2. The CAP Manager does not appear in the current organization chart and is not mentioned in NPG Directive 3.30, Corrective Action Program.

3. The Condition Resolution Team (CRT) leader group that now reports to the CAP program manager has no charter and the manner in which they will be used has not been fully developed.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** DK-01.3

**DESCRIPTION:** CAP - Inadequate program performance monitoring and follow up.

**CAUSE:**

**EXAMPLES:** 1. The problem reporting threshold has been lowered two discreet times since late 1992, resulting in a substantial increase in documented problems that require managing (prioritizing, tracking, resolution, and trending). In 1990 through 1992, the primary reporting process for significant conditions was the nonconformance report (NCR), with an average of 138 NCRs per year. A discrepancy reporting (DR) process was initiated during the fourth quarter 1992 to capture lower threshold events. As a result, in 1993, 679 DRs were generated and the number of NCRs doubled to 273 as a consequence of the increased sensitivity to problem reporting (a total of 952 problem reports for 1993). This trend in problem reports continued until a new single problem reporting system (condition reports or CRs) was implemented in April, 1994, that again lowered the reporting threshold. Through the first half of 1994, problem reports have been generated at a rate which would result in 1420 reports for the year.

2. At the close of the first quarter 1994, the following number of NCRs remained open: 1989 - 3, 1990 - 6, 1991 - 11, 1992 - 15, 1993 - 224. The DSAT team reviewed the open 1989 - 1992 NCRs to determine the reasons for the apparent lack of timeliness and found that most remained open for appropriate reaso and interim actions that were in place appeared to be reasonable.

3. At the end of the second quarter 1994, the following problem report statistics were available:
a. Significant problem reports (NCRs, CR category 1/2): A total of 104 problem reports were in initial disposition (root caused investigation assigned or in progress). 55 percent of these were overdue and 25 percent were greater than 6 months old.
b. Other problem reports (DRs, CR category 3): A total of 380 problem reports were in initial disposition. 38 percent of these were overdue, and 15 percent were greater than 6 months old. (NOTE***: This seems to indicate that lower priority work is being accomplished at the expense of higher priority work.)
c. With respect to implementation of corrective actions for problem reports, there were 280 actions being tracked with 33 percent being overdue (note that a single condition report typically has multiple corrective actions).

4. Considering just the condition reports generated since the new program began in April 1994, as of July 11, 1994; 62 category 1/2 CRs have been generated (requiring full root cause analysis) and 43 remained in initial disposition. Out of 314 category 3 CRs generated (requiring apparent cause determination), 220 remained in initial disposition.

5. Statistics for CR closure rates are not routinely provided to station management for performance monitoring and trending.

6. Accountability for overdue Condition Reports (CRs) is missing. Station reports listing overdue corrective actions are provided to department managers on a weekly basis; however, these reports are not discussed in manager's meetings. A calendar listing of overdue CRs is attached to the Friday CRG list

but it is not discussed. The 7/29/94 list contains over 100 items that are overdue and about 50 items due within the next week. The 7/22/94 list contained about the same number.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** M&O **SEQ:** DK-05

**DESCRIPTION:** The significance of items and events are not recognized in a timely manner. Although a heightened awareness of this issue was developed following the plastic tie wrap incident, additional examples continue to occur.

**CAUSE:**

**EXAMPLES:** 1. Mispositioned Valves. In the CRG meeting on 7/30/94, three valve mispositioning events were described, CR SN-06574,-07133 and -07134. They were assigned a category 2 and rolled und - a previous event, CR 94-0490. There was very little discussion about their significance and the overall ap roach to the problem. On 8/02/94, three more valve mispositioning events were listed on the CRG report. At the meeting, the QA manager present said this should be a startup issue, and there was little response by the group. On 8/02/94 at the 10:00 Manager's meeting, the plant manager indicated that the OPS manager should satisfy the QA manager that was questioning the station's response to the issue. A little later in the same meeting, the Site Manager said it was a very important issue and a plan needed to be developed. From this point on, the plan was developed and adjusted continually as more mispositionings were discovered. Overall, the CRG did not recognize the significance of the events and the issue did not receive the appropriate attention until the site manager became involved. The QA manager recognized the adverse trend but was unable to get an appropriate response from the group.

2. SBGT flex cable. (See CB-07)

3. Inerting of the Torus. On 7/30/94, CR-94-0150 was discussed at the morning CRG meeting. The CR described the potential loss of nitrogen while inerting the torus (See JD-01, example 3). The CRG was not sure which group should have responsibility for this CR and what, if any, immediate actions needed to be or had been taken. An investigation into what had happened to the nitrogen had not taken place. This discussion took place three days after the event had occurred. HP had taken the precaution to monitor each drywell entry since the location of the excess nitrogen was not known.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** DK-06

**DESCRIPTION:** Procedure change backlog has grown by about 65% since 1992. This has resulted in a significant increase in the number of procedures that go beyond their biennial review date. Procedure changes to improve processes and programs are not made in a timely manner. Monthly Procedure Status reports are provided to station management. They provide the statistics on the volume of procedures in the change process along with lists of overdue and near term due dates for specific procedures at various stages in the change process.

**CAUSE:** Inadequate monitoring and control of the procedure change process.

**EXAMPLES:** 1. The number of Procedure Change Notifications (PCNs) in process throughout most of 1992 averaged just above 200. In November 1992, this number started to increase and has stabilized over the last several months at about 325. There was no mention of this increase or recommendations on how to address it in the letter that provides these statistics.

2. During the same time periods above, the number of PCNs staying in any one department for longer than two months also increased from an average of about 30 to an average of about 90. This also occurred without any specific mention.

3. The list of procedures that have not been approved prior to their biennial review due date + 25% also grew from less than five to about 30 a month. Although the process allows these procedures to become overdue with proper management approval, the growing number of overdues illustrates ineffective oversight and control of the process. Most notable of those procedures that have not been approved prior to their due date is 3.4.1, Engineering Work Request, which became overdue on 2/24/92 and remains overdue two and one half years later. The SRG Supervisor indicated that all efforts to complete the review and revision of this procedure have failed.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** JD-01

**DESCRIPTION:** Management has not ensured that procedures sufficient to adequately operate, maintain, and test the facility are in place, properly reviewed, and/or being used as required by Technical Specifications 6.3.1, 6.3.2, and 6.2.1.4.a.

**CAUSE:** 1. It appears that the NPG management team is not committed to an over all, aggressive program of procedural control of station activities.

2. The principal focus in parts of the CNS organization is to assure that procedures are not a constraint to work rather than on providing high quality procedures that give the guidance required to help assure quality work.

3. Methods for streamlining the SORC approval process in common use in the industry have not been implemented at CNS.

4. Management indicators of the procedure revision process have not been used to bring about improvement to the timeliness of the process.

**EXAMPLES:** 1. Procedures exist for only six LLRTs.

2. A number of incidents were observed including work on environmentally qualified equipment where maintenance was conducted without procedures, utilizing instead, job unique instructions which did not receive SORC review.

3. CR 94-00150 described an event which occurred during inerting of the Torus in which inadequate procedural guidance was given to describe the approximate time required to perform the evolution resulting in the process being continued for twelve hours when the normal time requirement is approximately four hours. The event was only terminated by the emptying of the nitrogen supply tank.

4. REC had been removed from service for weld inspections. During this period RHR, which receives room cooling from REC, remained in service using non-SORC approved operating instructions.

5. RHR pumps have received major maintenance without the use of SORC approved procedures.

6. During an interview, a maintenance staff person stated that CNS maintenance personnel do not like to be constrained by procedures.

7. Interviews with operators indicate a strong commitment to procedure use and adherence.

8. Data gathered by interviews indicates that finalization of procedure revisions can take a year to accomplish.

9. A senior member of NED stated that placing a modification in service with procedures in draft form would be considered acceptable.

10. A recent "interpretation" of tech specs declared, in effect, that SORC approve higher level generic guidance governing the preparation of the subtier procedures.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** JD-05

**DESCRIPTION:** Declining performance at Cooper Nuclear Station appears to have been identified and reinforced by the NRC earlier and more effectively than by the SRAB despite the SRAB's charter which charges them with the responsibility to "provide oversight of activities throughout the Nuclear Power Group (NPG) relating to CNS operation to determine if the plant has been, is being, and will continue to be operated and maintained in a safe manner." Failure to self identify and report to the VP-Nuclear declining performance and/or follow up on corrective action effectiveness indicates fundamental performance flaws in the oversight function.

**CAUSE:** SRAB does not appear to adhere to its Charter as noted in the problem statement. There does not appear to be a high level of accountability which demands that the board keep management informed of declining performance as indicated in the board minutes or as a result of interviews of board members. SRAB composition, as stated in example number three may be a significant contributor when coupled with the observed tendency for members not to be self-critical as noted in the letter to the board from the VP Nuclear and as observed as a general tendency in the site organization by the DSAT.

**EXAMPLES:** 1. Since September 1993 SRAB has been engaged in a process of reviewing their own performance. It was concluded at meeting 1-93 held in September that "...SRAB needs to be more aggressive in areas where problems are identified." To date, minutes of meetings held in the intervening period, do not indicate that aggressive action has been required of the line organization and where notice has been taken of the need for improved performance, follow up is not evident from the minutes.

2. The inspection team identified that QA consistently fails to identify as findings important performance deficiencies and is not required to follow up on observations and recommendations. This and other deficiencies were not detected or challenged by SRAB.

3. The SRAB composition consists of four site managers including the Division Manager of QA. This represents a significant percentage of the NPG Senior Managers and, even though permitted by Tech Specs, may be contributing to the SRAB's inability to confront plant performance problems prior to their discovery by external oversight organizations. In a letter to the SRAB chairman attached to the minutes of meeting 178, the Vice President-Nuclear noted that in the past the SRAB was not aggressive enough in pursuing real root causes of potential deficiencies due to being too sensitive to SRAB member's responsibilities. The minutes of subsequent meetings did not indicate a significant change in this area.

4. SRAB tours of the plant by the CNS members were noted as deficient by the chairman in a February, 1994, letter to the board. Subsequent minutes did not indicate improvement and during the DSAT evaluation numerous deficiencies were noted that should have been obvious during SRAB tours and would, if identified, have been of concern to the Board as regarding adherence of plant personnel to management expectations. Additionally, this had been identified by a 1992 self assessment but not corrected.

5. SRAB is never attended by the President, corporate Board members, or, historically, the VP-Production (interview data). While these individuals may not have "nuclear" experience, their assessment of the quality of an oversight function from a generic perspective would have been valuable and prudent.

## DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
### Field Notes

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6. SRAB receives input from SORC and QA and monitors their performance by attending SORC meetings and participating with QA in the audit program. Despite this, there appears to be little challenge to both these organizations about their performance vs NRC observations (minutes).

7. SRAB does not appear to have been overly self-critical relative to their own performance vs NRC observations (minutes).

**PROGRAMMATIC:** The SRAB's self assessment activities (as noted in the minutes) do not highlight the significance of deteriorating conditions being identified more effectively to the line management by external oversight organizations. There does not appear to be documented evidence that line management took issue with this failure to receive timely notification of their decreasing performance.

**MANAGEMENT:** Executive management and Board of Directors are not monitoring the performance of their highest level nuclear performance as soon as it became evident that external agencies were seeing deteriorating performance prior to SRAB.

**AREA:** M&O **SEQ:** JD-07

**DESCRIPTION:** Management expectations regarding industrial safety are frequently ignored or otherwise not carried ou the employees. Observations were sufficiently numerous to indicate that management is either not out in the plant observing activities or, if they are, are not regularly enforcing expectations.

**CAUSE:**

**EXAMPLES:** 1. Significant safety errors were noted with scaffolding erected for weld inspections despite the presence of a signed scaffold control tag.

2. A worker grinding a weld in preparation for inspection was observed wearing a full face shield while another worker with his face just as close to the job was wearing no eye protection at all and appeared to be squinting to protect his eyes from the grindings.

3. An HP was observed walking along elevated cable tray with no climbing protection.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** JD-08

**DESCRIPTION:** The Nuclear Power Group does not effectively utilize Human Resource and Organizational Development resources to assure strong management and supervisory performance. It should be noted that these issues have been discussed in recent months among senior nuclear management and some preliminary steps have been taken.

**CAUSE:** 1. It appears as though the site management has historically had little understanding of or appreciation for the importance of combining quality HR skills and techniques with a good technical program to achieve excellence in operations.

2. The corporate HR organization, in some instances, appears to play a more passive service role with respect to the NPG rather than an aggressive leadership role.

**EXAMPLES:** 1. Interviews with human resource personnel indicate that NPPD has instituted a supervisory skills training program which has been effective in the rest of the company but that participation by the NPG has been on a low priority basis. At least one case of zero NPG attendance at scheduled training was attested to. At least one first line supervisor attested to having only 3 to 4 days of supervisory training in his 5 years incumbency.

2. Selections of new/replacement management and supervisory personnel are made by an unstructured interview process. Processes similar to "targeted selection" would represent the state of the art for identifying 'best' candidates, but this technology is not made available by the corporate Human Resources organization.

3. The only HR staffing at the plant site is one clerk. The balance of the HR organization resides at the company Headquarters 120 miles away. The lack of this resource reduces the probability that effective human resource techniques will be utilized in staffing, performance management and management training.

4. The corporation has instituted a management development program under the sponsorship of the Vice President of Finance and Administration. Rather than utilize this corporate program, NPG developed their own program.

5. There is little evidence that the performance review program is being used to performance manage or replace managers with performance weaknesses. During an interview with one site manager it was acknowledged that he did not use the program as a principal tool for performance management, rather he preferred "counselling".

6. Virtually all management interviewed, when asked how site supervision and management were historically selected, responded that it had been principally based on technical proficiency in the previous job.

**PROGRAMMATIC:** It appears as though a centralized HR organization physically located a long distance from the plant has resulted in a dysfunctional relationship preventing the application of state of the art HR practices that would

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have strengthened plant management.

**MANAGEMENT:** Corporate leadership did not recognize that, for an operation with the high organizational performance requirements of a nuclear power plant, the historic approach of NPPD Corporate HR may be insufficient to provide the requisite service.

**AREA:** M&O **SEQ:** JD-09

**DESCRIPTION:** Self Assesment at CNS is not conducted in a way that has resulted in the improvements required to maintain overall satisfactory station performance.

**CAUSE:** An adequate program for self assessment which requires the use of current industry standards of excellence, has been defined with the exception of communicating clear expectations on actually carrying it out and clear expectations on follow through on recommendations.

**EXAMPLES:** 1. Despite adequate self assessment guidance and expectations being in existence since 1991, neither maintenance, engineering nor operations has conducted a comprehensive functional self assessment.

2. SRAB conducted a self assessment in 1991, the findings of which, had there been follow through, would have enabled SRAB to prevent the current performance problems. For instance, the following observation and actions were extracted from the 1992 SRAB self assessment;

a. ...VP should occasionally attend meetings

b. SRAB should increase its participation in audits

c. Review of CNS performance indicators appears to be only cursory at SRAB meetings

d. Recognition is not being given by SRAB to the potential function performance indicators (PIs) can provide in predicting future problems and setting worth while operating goals. SRAB is not making use of a potentially useful oversight tool.

e. SRAB should review the goals (of the performance indicator program) in light of the need to ensure that rising standards are being established to promote excellence...

f. Members do not conduct a comprehensive plant tour (this observation was repeated in 1994 so obviously was not effectively corrected in 1991).

**PROGRAMMATIC:** No systematic follow through on self assessment has occurred. Where assessments have been done, they have resulted in generally excellent corrective actions. However, management's failure to ensure that assessments are done and results tracked has resulted in failure to produce improvement in performance.

**MANAGEMENT:** Management proactively put a program in place then failed to hold their organization accountable for carrying it out.

## DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
### Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** JD-10

**DESCRIPTION:** Although plans are now in place for an integrated business planning process, historically, comprehensive long-term planning has been insufficient to achieve substantial improvement in organizational performance.

**CAUSE:** Lack of early recognition for the need for comprehensive long-range planning.

**EXAMPLES:** 1. A four-year Business Plan has only recently been developed despite a long-standing need for improving organizational performance.

2. Although planned for the future, the BusinessPlan is not yet linked to the budgeting process to ensure that resources will be available to support the improvement process.

3. Branch Business Plans, specified in the planning guidance, have not been developed. As a result, important projects necessary for future success, are either not integrated into the Plan or will need the added detail of the Branch Plans. The necessary coordination, resource allocation, and accountability forum may not be accomplished. Examples of important projects not observed in the Business Plan or requiring a more detailed plan from the Branch Business Plan include:

a. Response to IE Bulletin 89-10.
b. AOV and check valve initiatives.
c. Maintenance Rule (mentioned in the Business Plan but needs Branch level detail).
d. Work planning and control upgrades (also needs Branch level details).
e. HPES implementation.

4. Many due dates have already been missed in the current Business Plan.

5. Interviews with plant management indicate that, at this time, the Busines Plan and business planning is dormant.

6. Methods for monitoring and holding management accountable for plan execution are not in place. These are necessary to help assure follow-through.

7. Cobalt reduction plans, stemming from a 1991 self assessment have not been executed .

A few preliminary steps have been taken but an identifiable plan does not exist.

**PROGRAMMATIC:**

**MANAGEMENT:** There does not appear to have been a challenge from executive management for the nuclear portion of the NPPD organization to utilize business planning despite the complex nature of the operation and the potential impact on the Company.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** JD-11

**AREA:** M&O

**DESCRIPTION:** SORC was unable to anticipate and/or influence correction of the many problems identified by the NRC despite their Tech Spec requirement to "Review station operation to detect potential nuclear safety hazards."

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** JD-12

**DESCRIPTION:** Management does not appear to comprehensively monitor plant activities, compare performance to acceptable standards, nor exercise consistent accountability when performance falls below those standards.

**CAUSE:** Well thought out systems for basic management of plant activities are not in evidence. The station appears to manage by a combination of large doses of micro-management for data input and providing of direction, communication by extensive meeting attendance, and accountability triggered mainly by unanticipated events or prompting by external oversight observations.

**EXAMPLES:** 1. Radiation protection data is distributed monthly. Distribution is via a single report which travels a serial route through the organization. No accountability forum appears to be used to assure that managers are aware when performance in their respective organization falls short of standards.

2. When corrective action is recognized to be necessary, e.g., the need for a cobalt reduction program stemming from 1992 Rad Pro self assessment, clear planning with accountability is deficient.

3. Maintenance performance parameters, typically monitored and compared against accepted standards at other plants, are not systematically tracked at CNS (management interview). Without this sort of input, it is difficult to understand how the process could be managed in any other way than a reactive mode.

**PROGRAMMATIC:** 1. No strong role models for systematic management appear to exist.

2. Corporate executive management does not appear to have provided the leadership necessary to assure that CNS was provided with, and held accountable for, the management skills necessary to assure that performance has kept up to industry standards, or in some cases, even met the minimum levels required by regulation, e.g.:

a. use of procedural controls
b. management of the facility configuration
c. conduct testing in a way that assures system integrity.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RC-01

**AREA:** M&O

**DESCRIPTION:** Management does not clearly communicate management goals and expectations to lower levels.

**CAUSE:** Lack of management follow-through. Maintenance Manager has been instituting regular and ad-hoc meetings to improve the effectiveness of intra-departmental communications. Continual communications and feedback will be essential for the success of this effort.

**EXAMPLES:** 1. Lack of clearly defined problem statement and development of resolution observed at Maintenance Department Supervisors' meeting with respect to the issue of Pre-Conditioning.

2. At the 10:00 am Managers' Meeting on Thursday, 8/4, the importance of the special test to be performed on the 4160V breakers was discussed. It was stated that this was considered a startup issue. Despite this, the System Engineer and the Test Engineers performing the test, when asked, were unaware of the reason for the urgency of the test.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** RC-06

**DESCRIPTION:** Management chain of command is sometimes bypassed, making it difficult for line managers to effectively manage staff and resources.

**CAUSE:** 1. Perceived sense of urgency to restart the station.

2. Lack of confidence on the part of the management team to handle problems effectively.

**EXAMPLES:** 1. An individual was assigned to the DSAT counterpart team without discussing with or informing the department manager of the assignment. The individual later notified his department manager of this assignment and the department manager had to hire a contractor to fill the critical vacancy created by this temporary assignment.

2. Following identification of the REC piping issues, the plant manager selected an REC team leader. The team leader wasn't fully capable of performing the task (and his manager was aware that the individual wasn't the best choice for the job), so the individual's supervisor had to assume the lead on the project to ensure the plan for resolution of the problem was properly handled.

3. During observations of control room activities and interviews with shift supervisors, it was noted that the shift supervisor frequently contacts the plant manager with operating issues. When asked, the shift supervisors indicated they generally contact their manager following the contact with the plant manager.

**PROGRAMMATIC:**

**MANAGEMENT:** Less than adequate management communication and utilization of chain of command

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** RC-10

**DESCRIPTION:** No clear management chain of command for the current forced outage.

**CAUSE:** Ineffective management practices regarding accountability, oversight and chain of command.

**EXAMPLES:** Despite a clear process described in the Outage & Modifications Department procedures manual, no CNS Senior Managers have been assigned the position of Outage Director for the current forced outage. Due to the magnitude and number of issues the plant staff is currently addressing, no Senior Manager was deemed "available" to direct this outage. Consequently, two lower level Outage Coordinators were assigned the position of Shift Outage Director. It is not clear to whom these Outage Directors report for single point direction of the outage. This has resulted in no single individual having clear accountability or responsibility for directing and coordinating the efforts of this shutdown. Issues such as scope identification, growth and control; schedule adherence and accountability; information dissemination and communication go largely unaddressed.

Responsibility and authority for these issues are spread throughout the organization and are thus diluted. Lack of a single point of accountability for the shutdown and subsequent startup is evident. Numerous personnel in the station were posed the question,"Who's in charge of the outage?" and no consistent answers were received. O&M Department procedure 1.2, section 4.2 identifies the Senior Manager of S Support as the individual responsible for overall outage planning, scheduling and performance, howeve limited involvement has been noted in this area. It appears as if the Site Manager has personally taken control of the outage, diluting the effectiveness of the chain of command.

Contributing to the apparant lack of management focus for the current outage is the fact that th outage organization chart has been revised 22 times since May 25 and there have been over 9 different outage directors.

**PROGRAMMATIC:**

**MANAGEMENT:** Inability to flexibly respond to numerous, significant technical and managerial challenges simultaneously.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** RC-15

**DESCRIPTION:** An apparent large amount of backlog work exists in numerous areas.

**CAUSE:**

**EXAMPLES:** 1. Temporary Procedure Change Notices (TPCNs):
As of 8/15/94, 128 TPCNs were outstanding. The oldest dated to 4/10/93. At least 33 of these were past their expiration date. The majority of the TPCNs that were identified as expiring "when PCN approved" did not have a corresponding outstanding PCN identified in the PCN backlog. Per procedure 0.4.2 on procedure changes, the TPCN originator is required to initiate a PCN when a TPCN is determined to be permanent.

2. Procedure Change Notices (PCNs):
As of 8/15/94, 385 PCNs were outstanding in some portion of the procedure change process. The oldest of these dated to 4/23/93. 331 of these outstanding PCNs have been initiated since the start of the current forced outage (5/25/94.)

3. Plant Temp Modifications (PTMs):
As of 8/14/94, 30 PTMs were identified as being in place. The oldest of these dated to 5/31/93. 12 of these PTMs were initiated since the start of the current forced outage (5/25/94.)

4. Preventive Maintenance (PMs):
As of 8/15/94, 430 PMs were scheduled. Very few of these appear to be overdue. It appears that the station is keeping up with the PMs that are identified.

5. Maintenance Work Requests (MWRs):
As of 8/15/94 there was a backlog of 1629 MWRs. When the DSAT arrived on site, the backlog (as of 7/11/94) was 1311 MWRs. (An increase of 318 over a 5 week period.) Historical information indicates a large continuing increase in the backlog of MWRs:

| | | |
|---|---|---|
| 1st 1/4, 92: 389 | 1st 1/4, 93: 1390 | 1st 1/4, 94: 1096 |
| 2nd 1/4, 92: 394 | 2nd 1/4, 93: 1148 | 2nd 1/4, 94: 1392 |
| 3rd 1/4, 92: 438 | 3rd 1/4, 93: 695 | |
| 4th 1/4, 92: 1123 | 4th 1/4, 93: 874 | |

6. Corrective Action Program (CAP) Open Items -- (Includes CRs, NCRs and DRs)
As of 8/15/94, the backlog for initial disposition of CAP Open Items was 572, some dating back to NCRs as old as 10/5/89.
As of 8/15/94, the backlog for followup actions for CAP Open Items was 401, some dating back to NCRs as old as 1/24/89.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** SE-01

**AREA:** M&O

**DESCRIPTION:** Previous QA audits did not identify fundamental weaknesses in the corrective action program at Cooper Nuclear Station until prompted by numerous outside agencies.

**CAUSE:** The audit report 92-98 lacks rigor. Also, the threshold for considering problems as findings was too high.

**EXAMPLES:** QA Audit 92-98 dated January 18, 1993 of the Corrective Action Program at CNS identified no findings or observations. A consultant for the SRAB stated that the audit was too broad. The audit states that reporting of deficiencies was done appropriately, root causes associated with deficiencies were adequate and corrective actions have been sufficient to preclude recurrence. Subsequent self assessments and NRC reports have shown significant weaknesses in these areas. Additional areas of operating experiences (industry and in-house) were also reviewed to determine if the program was in compliance with the station procedures rather than ascertaining the effectiveness of the program. A review of repeat occurrences was not included in this review. No findings or observations were provided in these areas.

**PROGRAMMATIC:** The audit report tends to focus on program compliance as defined in procedures rather than the effectiveness of the program.

**MANAGEMENT:** No action was taken following a consultant's comment (that the audit was too broad) to refocus with gre[illegible] intensity on the audited area. Follow-up actions were not taken until after numerous additional reports fundamental weaknesses in the corrective action program were received. Management's reaction to the lack of depth of this audit was not timely.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-02

**DESCRIPTION:** QA does not aggressively follow-up on identified deficiencies. Also, some identified problems are not highlighted as findings or observations.

**CAUSE:** Management policy was established in this manner.

**EXAMPLES:** Based on the definition of 'finding' QA did not write a QA finding if a Non-Conformance Report (NCR) is written to address the issue. This reduced QA group accountability to ensure identified problems were tracked to completion.

Based on the definition of 'recommendation' QA can make recommendations from audits or surveillances but performs no follow-up to ensure the recommendation has been considered and dispositioned. This reduces QA accountability for the process.

A recommendation was made in QA audit 92-28 dated January 18, 1993, to revise the Deficiency Report Closure cover sheet to allow closure when corrective actions for identified discrepancies have been initiated rather than when corrective actions are completed. This would allow tracking mechanisms to be closed indicating that actions are complete when, in fact, actions may not be completed.

A change has been made to the QA audit problem in Spring, 1994, that requires that the QA issues be documented and tracked to completion using a Station Condition Report. Although there are some advantages to using a collective tracking system for issues raised at the station, combining QA issues with other station issues weakens QA department accountability and weakens the QA escalation process for open issues. Audit Report 92-28 noted that 'procedural or human miscue problems did not include much analysis relating to programmatic deficiencies'. This deficiency was not highlighted as a QA finding or observation. Subsequent self-assessments and NRC documents have identified this as a fundamental weakness in the corrective action program at CNS.

**PROGRAMMATIC:** The QA organization has been programmatically relieved of the responsibility to follow-up on some issues to ensure corrective actions are implemented in a timely manner and in a way that prevents recurrence of the issue.

**MANAGEMENT:** The management tool provided by the QA group has been weakened by the failure to aggressively hold people accountable for completing corrective actions.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-03

**DESCRIPTION:** Repeat findings or observations from audit reports are not highlighted for increased management attention.

**CAUSE:** Repeat audit findings or observations are not given a higher level of management attention.

**EXAMPLES:**

**PROGRAMMATIC:** Backlogs in outstanding audit findings or observations drove the attitude that it would be easier to close the issue to a previous finding rather than open a new one or emphasize the repetitive nature of the finding. Subsequent self assessments and NRC reports have heightened sensitivity to this issue.

Issue is known to station management.

**MANAGEMENT:** QA management was attempting to prevent further increases in backlogs. Station Senior Management was shielded from seeing the repetitive nature of this type of discrepancy.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-04

**DESCRIPTION:** Task assignments and parameters for conducting investigation and recovery actions are sometimes not clear.

**CAUSE:** Lack of coordination between station departments and a failure to thoroughly plan actions.

**EXAMPLES:** Morning management meeting - REC piping examination program required additional meetings and coordination to ensure objectives will be met. (G. Horn interview).

Some senior program managers were not aware of the status of some programs or selection criteria for examination parameters:

1. Selection criteria for reviewing valve line-up problems could not be clearly described during morning meeting of 8/5/94.

2. CS-12 (MOV) is not tested in the accident mode during monthly surveillance tests because the plant is normally at operating pressure. Engineering indicated that the valve operator would not be powerful enough to move the valve at operating pressure due to the significantly higher differential pressure. (The reactor pressure is essentially at 0 psig in the accident mode.) Past practice has been to manually crack the valve off the seat to equalize the pressure and then reseat the valve with the motor operator without completely cycling the valve. Some management personnel did not view this as a problem until prompted by the Site Manager.

3. The selection criteria for limiting the scope of the OER program issues was based on some program changes in 1987. This criteria was assumed to represent an improvement in OE reviews. However, weaknesses in the OE program from 1987 to 1992 have been identified and cast doubt on the quality of the OE reviews performed in this period. In addition, the scope of the OE review was limited by excluding SOERs that were previously closed by INPO and excluding NRC Bulletins and Generic Letters because a written response was submitted to the NRC. The basis for excluding these items needs to be evaluated to establish confidence that significant nuclear safety issues have been adequately addressed and enduring corrective actions to prevent recurrence are in place.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-05

**DESCRIPTION:** The escalation process for QA findings and other issues has been ineffective, contributing to the backlog of open QA issues.

**CAUSE:** Management support of the QA program has not been consistent.

**EXAMPLES:** Interviews with QA management personnel indicated that, in the past, several issues were escalated to senior management but the issues remain unsolved.

**PROGRAMMATIC:** Failure to conduct a QA self assessment. Issue is known to management.

**MANAGEMENT:** Support of the CNS QA program has been inconsistent.

**AREA:** M&O **SEQ:** SE-07

**DESCRIPTION:** Coordination between station departments is sometimes lacking.

**CAUSE:** Personnel error in ensuring requirements are met.

**EXAMPLES:** A condition report was written 8/3 stating that the CNS Emergency Plan requires the STA position to be manned at all times, however, the STA coverage had been terminated several days previously, as permitted by the Technical Specifications and Station Procedures. The Engineering Manager had not been aware that a conflict existed between the E-Plan and the CNS Technical Specifications until being informed the previous day by the Emergency Plan Coordinator. His understanding was that the EP plan would be promptly changed to agree with the Technical Specifications. The next day however, the Engineering Manager was informed that the change could not be made without NRC concurrence. The STA position was reactivated soon thereafter. This required reassignment of individuals who had been participating in some of the high-visibility work tasks in support of plant start-up. Realization of the problem did not occur until the SORC meeting on 8/5/94. It was also not clear if the event was reportable to the NRC as an unauthorized change to the emergency plan.

**PROGRAMMATIC:** Lack of coordination led to this problem.

Issue is known to management.

**MANAGEMENT:** Lack of management coordination between work groups.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-08

**DESCRIPTION:** Weaknesses in the QA audit program have been identified in NRC Inspection Reports, self assessment reports and reports by consultants. These weaknesses include the difficulty in focusing QA resources on emerging issues, identifying programmatic and generic issues and the closure of long-term open items. In spite of these difficulties, the CNS QA department has initiated a reduction in audit frequency and audit scope. The CNS Technical Specification 6.2.1.B charters the QA department to provide the audit function for the SRAB "of selected aspects of plant operation with a frequency commensurate with safety significance." In order to meet the intent of this T.S. requirement and to fulfill the oversight function envisioned by the NRC regulations, the QA department and CNS management should implement an improvement program to strengthen the QA department audit function sufficient to provide management with the tools necessary to reach a higher level of performance.

**CAUSE:** Based on various interviews, weaknesses are related to inconsistent management support exacerbated by a lack of focus on meaningful emerging issues.

**EXAMPLES:** 1. An analysis of NRC issues at CNS was performed on June 21, 1994 by a consultant. This report stated that in 1993 and 1994, nearly 30% of the NRC violations involved a failure to follow procedures and procedure inadequacies. A similar analysis of internal audits shows a similar problem (about 30%). There is no specific QA activity scheduled in 1994 to focus on this emerging issue.

2. The same consultant's report indicates that 64% of all QA issues are found during QA audits. The remainder of the issues are split between surveillances, assessments and evaluations. The audit process tends to be the best method for identifying issues, but tends to require more resources than other QA Methods. In order to reduce the resource requirement, the audit program was reduced, but this also reduced the program that identified the most issues.

**PROGRAMMATIC:** Failure to conduct rigorous QA departmental self assessments.
Tendency for QA audits to focus on compliance rather than on both compliance and performance.

Issue is known to station management.

**MANAGEMENT:** Same.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-09

**DESCRIPTION:** Audit Report 94-05 on Setpoint Trending identified significant weaknesses that were not highlighted for corrective action. In addition, the audit report tends to focus on documentation rather than on the overall effectiveness of the setpoint trending program at CNS.

**CAUSE:** QA program weakness.

**EXAMPLES:** 1. From the one finding and five observations made, five deal entirely with the failure to document reviews or to have documentation available. The only issue that was performance driven deals with the identification of an adverse trend in a setpoint that was not detected by the engineering staff. This item was presented as an observation that requires no formal QA follow-up.

2. The audit report identifies three recommendations that do not require additional QA follow-up. As an overall conclusion, the audit report narrative section states that the Setpoint Trending Program has not had the appropriate level of management attention. Also, the objectives of the program do not appear to have been clearly established and incorporated into program procedures. Neither of these conclusions are reflected in the findings, observations or recommendations sections of the audit. Therefore, no corrective actions are intended or will be pursued by QA.

3. None of the objectives for the audit questioned the testing configuration of the systems nor checked preconditioning of as-found test data.

4. There was no recommendation directed toward resolving the interpretation differences between engineering and QA. It appears that QA accepted the engineering interpretation without pursuing the issue further. The specific example given relates to the definition of an adverse trend in data.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-11

**DESCRIPTION:** Weakness exist in the QC Peer Inspection Program.

**CAUSE:**

**EXAMPLES:** QC Inspection strategy is established by the line organization's output of hold, verification or witness points in the governing procedures. Some managers responsible for establishing the QC inspection strategy have not been trained to perform this function. Maintenance and testing can be performed using special instructions provided within Maintenance Work Request (MWR.) There is no program requirement that includes reviewing MWR instructions for QC inspection nor is this occurring.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** SE-12

**AREA:** M&O

**DESCRIPTION:** A significant backlog of "open" QA issues exits at CNS.

**CAUSE:** The escalation process for outstanding QA issues has been ineffectively implemented.

**EXAMPLES:** 1. The June 8, 1994 status report of QA Issues indicates that 37 issues remain open. Of these items, 13 issues have gone beyond the target completion date and 4 issues are past due with no acceptable response nor extension to the due date. The open issues date from 2/3/92; the oldest issues have had at least six extensions approved to the due date. The oldest open QA issue (2/3/92) deals with inadequate control of software and computer processes. Other older issues (1 to 2 years old) deal with:

a. "Notice of Failure" letter not issued from Fitness for Duty (positive test)

b. Fire Protection - Records of fire watch, fire watch training, fire protection system surveillances.

In addition, on 2/18/94, a deficiency report was found to be closed without correcting the identified problem during the 93-32-05 Corrective Action Audit. This item has no acceptable response, and the extension due date has been exceeded by two months.

2. In an independent assessment by a consultant, the report dated 25 May 1994 (R. W. Bass to V. L. Wolstenholm) concluded that "not only are organizations not responding to QA items, they are not asking for extension." This report also indicates that the current average length of open issues is 200 days.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-13

**DESCRIPTION:** QA audits identify significant issues that are not always captured as condition reports so followup of corrective actions can be performed.

**CAUSE:** Past difficulties have been experienced by the QA Department in getting issues resolved.

**EXAMPLES:** 1. QA Audit 93-03 dated March 30, 1993, on the configuration Management area:

a. Nine audit findings were presented, of which eight dealt with documentation problems and one dealt with training certification. There were no issues.

b. Six recommendations were issued; three dealt with program improvements and three with improvements in the gathering of historical information. Since recommendations do not require a formal response as specified by the QA Audit Program, there is no assurance that the recommendations were accepted or implemented.

2. QA Audit 94-15 dated July 18, 1994, on the Corrective Action Program:

a. Significant issues were discussed in the narrative section of the report including:

i. Backlog - "Significant backlog of corrective action items exist and appears to be growing." Examples include actions to resolve NCR 93-036 excessive leakage from RHR-MOV-MO13B was written 3/14/93 and remains open with nine extensions. This is an issue determined to have "high impact on safety."

ii. Timeliness of Root Cause Determination - NCR 93-021 (MS-MOV-M077) has also had nine extensions and the root cause has not been determined to date.

b. Problem Investigation

i. Depth of investigation

ii. CRT training and guidance

iii. No specific condition reports were written to address these issues.

Recommendations were made, but since there is no requirement for formal action or followup of recommendations, these actions need not be addressed.

c. If the checklist response to objective 1.01 paragraph F, it states that "Shift Supervisors stated that the amount of paperwork reviewed reduces the amount of time spent monitoring plant activities." This problem was not highlighted for actions nor raised as an issue for formal followup to completion.

d. The response to objective 1.05 paragraph states that only operations has included "self-checking" training into requalification training. This was also not highlighted for additional action.

e. Many other examples of problems hidden in the responses to the audit questions exist in this audit report.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-14

**DESCRIPTION:** Improvements in the QA program were initiated in September, 1993, in response to the 1993 SALP report. QA department reorganization and program changes have not been fully effective in raising the performance of the QA group to the desired level of performance.

**CAUSE:** Lack of management support for the fundamentals of Qa practices has limited the effectiveness of the changes.

**EXAMPLES:** 1. The QA surveillance program was to be strengthened to compensate, in part, for the reduction in internal audit frequency. However, the effectiveness of the surveillance program has been limited by the improper focus of the group and internal programmatic program.

2. The Quality Control Inspection program was not targeted for improvement in the reorganization and program enhancement plans. Recent assessments of the QC peer inspection program by QA management have shown a need for further training and program enhancements.

3. Initiatives were not taken to reduce the backlog of open QA findings. As of the first quarter of 1994, the rate of growth of the QA backlog had increased more than in the previous four quarters. The average length of time for open items was 200 days during the first quarter of 1994.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-15

**DESCRIPTION:** A change was made to the QA program that reduced the level of commitment to the NRC without processing the change in accordance with 10CFR50.54(a).

**CAUSE:** Discussed with QA management. It was believed that the change in audit frequency was not a reduction in the level of QA commitment to the NRC even though the previous auditing program was believed to be based on the annual auditing schedule.

**EXAMPLES:** 1. By action dated September 8, 1993, the QA audit frequency was changed for certain audits from annually to biannually. The change was made using a 10CFR50.59 change that addressed a USAR commitment stated in amendment 39; specifically, paragraph 8.12 of Letter NPPD to NRR dated 5/25/79 that states, "All of the QA Program elements will be audited at least once every year in accordance with the guidance provided in Regulatory Guide 1.33." The audit program was amended to reduce the frequency of QA Program elements from every one to every two years.

2. In a memo from QA to SRAB dated 10/13/93, the following audits were identified as those that will not be performed as scheduled based on the change in audit frequency requirements:

Station Operation
Repair Maintenance
Environmental
Procurem Control
Contract nsultant Control
Reporting and Responding
SRAB and SORC Activities
Software and Computer Processes

3. 10CFR 50.54a(3) states that "Changes to the quality assurance program description that do reduce the commitments must be submitted to NRC and receive NRC approval prior to implementation." The change to audit frequency described above was made without prior NRC notification.

**PROGRAMMATIC:** Misinterpretation of the meaning of QA commitments to the NRC and to the regulatory requirements necessary to change the commitments.

Issue is known to station management.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** SE-16

**DESCRIPTION:** Cooper QA program commits to Regulatory Guide 1.33 Rev. 2 which, in turn, endorses ANSI NI8.7 - 1976 as an acceptable method to meet the requirements of 10CFR50AppxB
The QA program commits to ANSI N18.7 but to an earlier revision of the standard (1972) than the revision endorsed by R.G.1.33 R2. The differences between the 1976 version and the 1972 version raise fundamental issues in the QA program. The 1976 revision to the standard (N18.7) should be used as the basis for the QA program since it is specifically provided for the operational phase of nuclear plant operation. Since this is the revision referenced in R.G.1.33, any lesser or other commitment should be an exception that would require review and approval by the NRC in accordance with 10CFR50.54(a).

**CAUSE:**

**EXAMPLES:** An example of the complications raised is in the area of QC inspections. N18.7 - 1976 requires that the operational phase QC inspection practices be shown to be equivalent or better than the inspection practices used during the design and construction phase (paragraph 5.2.7). Also, for modifications and major maintenance items, the inspection program shall be similar to the inspection practices used during design and construction. The N18.7 - 1972 revision does not include these requirements.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** M&O **SEQ:** WW-01

**DESCRIPTION:** While observing U/V testing on 7/27/94 SP 6.2.2.1.10 was stopped at step 8.1.97 when apparently an unexpected response was obtained. It appeared another relay actuated. Provide all corrective action information concerning root cause determination of inadvertent relay actuation. This item is closed based on an interview with Roger Moberly. Per Roger the test results were expected however not part of the expected test criteria. This was the only item of this type during the conduct of the test.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O

**SEQ:** WW-03

**DESCRIPTION:** On-site CNS management does not proactively support implementation of the Emergency Plan.

**CAUSE:** Until 7/18/94, the EP coordinator reported to an off-site supervisor and off-site manager; subsequently, there was no on-site overview. Currently, the EP coordinator reports to a vacant on-site EP manager position. This has caused the EP coordinator to present his problems to the SMSS, who assumed responsibility for Emergency Planning (EP) 7/18/94, and apparently has not been able to devote attention to the EP coordinator concerns.

Inadequate management oversight.

**EXAMPLES:** 1. E Plan and EPIPs reference the use of a 50 mile IPZ dose assessment model that has not been updated to EPA 400 requirements.

2. In 1993 EP staffing was reduced even though the plans were to update two dose assessment programs to EPA 400 requirements.

3. Verbal approval has been obtained from the NRC and four states concerning the current status of 'ADAM' program, but written permission does not exist.

4. The EP staff on-site assumes the 1993 staff reduction was due to the prior year budget (over budget by $12 million).

5. The on-site and off-site EP have different goals for 'ADAM' update completion (Dec. 94 vs. Oct. 94, respectively). The off-site EP supervisor wants 'ADAM' updated prior to the annual Emergency Exercise.

6. Current changes to update the ADAM program are being done in a clandestine manner.

7. The EP coordinator is attempting to implement a policy change for crew call out, but does not have management approval for this change.

**PROGRAMMATIC:** The EP coordinator did not assess this problem as a potential licensing issue. The EP supervisor and coordinator considered verbal approval adequate, even though the E Plan and EPIPs were specific (a culture of informality appears to exists).

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** M&O **SEQ:** WW-18

**DESCRIPTION:** CNS failed to provide STA staffing as described by EPlan.

**CAUSE:** Management unaware of EPlan requirement.

**EXAMPLES:** On 8/4/94, CNS personnel noted that the EPlan providing for an STA position during the current plant conditions. CNS was making preparations for staffing the STA position which had been terminated several weeks earlier in order to support other engineering activities. This item is similar in nature to item WW-03

**PROGRAMMATIC:** See WW-03

**MANAGEMENT:** See WW-03.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RB-12

**DESCRIPTION:** Health Physics Posting
Housekeeping
Material Condition

**CAUSE:**

**EXAMPLES:** Plant tour on 8/12/94 to compare plant HP posting against CNS Procedure 9.1.2.2 "Area Posting-Radiological"

OVERALL
-------------

All plant HP postings satisfy procedure requirements.

Every hose that crosses a contamination boundary is properly secured and is tagged by HP to prevent inadvertent removal. These tags are a good initiative.

Radiation Areas, inside the RCA are posted with a circular sign on the floor. While some plants don't p individual radiation areas (assume entire RCA area is a radiation area) CNS posting is a good initiative these floor signs are unique and support ALARA.

CONTAMINATED AREAS
--------------------------------

All are properly posted.
The following barriers are particularly well installed:
Outside RWCU pump room
Around Main Turbine bypass valves
Condensate pump coupling housings
1R-25-56B
Jet pump instrument rack
1R-25-60

RADIATION AREAS
---------------------------

Low threshold for posting inside RCA.

Good human factor floor signs. To avoid potential for confusion these floor signs should be explained in GOT.

The low radiation levels around the SDIV's and RHR HX's is noteworthy.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

HOT SPOTS

Well posted above TIP shield room.

Should be factored into a hydrolaze program to reduce source term.

AREAS FOR IMPROVEMENT - RADIOLOGICAL

The contaminated area around the front standard is not marked on the floor with tape. This is the only exception noted.

A hose runs in the clean area parallel to the front standard contaminated area. It is not secured, the walk way is tight and no floor level barriers exist. This could result in this clean hose moving into the contaminated area.

HOUSEKEEPING AREAS FOR IMPROVEMENT - NON RADIOLOGICAL

North water box floor is badly water stained.

Two overhead troughs outside MVP room have drain hoses that end outside the sump barriers. If draining occurs this will result in unnecessary pooling in the corridor

MATERIAL ITEMS FOR IMPROVEMENT - NON RADIOLOGICAL

Numerous oil leaks noted at Reactor Feed Pumps, Hydrogen Seal Oil Pump skid, and condensate booster pumps.

Condensate booster pump suction valves (chain operated) cannot be operated without standing on the pumps - poorly designed chain operator.

Loud, possibly cavitation, noise at water box south downstream of RF-28MV

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RC-02

**DESCRIPTION:** Procedures frequently provide inadequate or ambiguous instructions.

**CAUSE:**

**EXAMPLES:** 1. Guidance provided in procedure 0.4, section 8.5.1 regarding appropriate use of Interim Procedure Change (IPC.)

2. Guidance on use of Temporary Procedure Change Notices (TPCNs) per procedure 0.4.2, section 6.2.6.2.

3. Methods to assure most up-to-date TPCNs exist (ref. 0.4.2, section 8.1.3.)

4. Determination of need for Pre-Test, Post-Test or Quality Control requirements are not clearly delineated in procedure 7.0.1.2.

5. Step 1.2 of procedure 7.0.4 states that Maintenance Manager can make exceptions to this procedure (conduct of Maintenance) for non-S/R items, but doesn't explain what exceptions are allowed or how they are documented.

6. Step 2.4.1 of procedure 3.4.4 states that Temporary Design Changes (TDCs) are not considered permanent while step 2.4.4 describes the steps to be taken when a TDC is considered permanent.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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**AREA:** MNT **SEQ:** RC-03

**DESCRIPTION:** Industrial safety practices in the station are considered a weakness.

**CAUSE:**

**EXAMPLES:** 1. Individuals performing cutting on pipe in preparation for weld repairs on REC system piping were observed to not be wearing safety glasses or hardhats during the cutting operation.

2. An electrical extension cord was observed to be passing through a doorway to the RWCU Heat Exchanger with no protection provided from the door.

3. Scaffolding erected for work on the REC piping was not in accordance with CNS expectations or accepted industry practices. Contrary to standards, a scaffolding was erected and allowed to be used without guardrails, the scaffold inspection tag was signed by the maintenance supervisor to allow it to be used. Work was completed on the system without correcting the condition. Inspection of other scaffolding indicated many examples of problems with compliance with accepted standards such as:

A. Lack of use of toe boards
B. Lack of use of mid-rails
C. Inadequate support of tall scaffolding towers to prevent tipping.

In all cases, the scaffolding was inspected by maintenance supervisors and approved for use.

4. An HP technician was observed walking in cable trays approximately 25 feet above the floor without fall protection. There were no obstructions below the area where the technician was working.

5. Designated smoking area located outside the mechanical maintenance shop with numerous ashcans and 'butt-buckets' within 15 feet of Oxygen and Argon gas bottle storage.

6. In two interviews with CNS Managers they indicated pride in an "excellent" personnel safety record. In the 8/1/94 issue of "Current Events" the following injuries were noted to have occurred during the current outage (through 66 days):

| | First Aid only | Restricted Work Activity | Other Recordable | Totals |
|---|---|---|---|---|
| CNS permanent employees | 7 | 1 | -- | 8 |
| NED permanent employees | 1 | -- | -- | 1 |
| Temporary Construction Management employees | 2 | -- | 1 | 3 |

| | | | | |
|---|---|---|---|---|
| Totals | 10 | 1 | 1 | 12 |

7. According to INPO performance indicators, CNS ranks 60th of 71 nuclear stations in this category and for the past 4 years has been above the industry median as well above their own goals.

8. During work to replace a level transmitter on the Scram Discharge Volume level transmitter (LT-231C) on 8/11/94, an I & C Technician was observed working on top of ventilation ductwork. The technician accessed the ductwork from the staircase and climbed on top of the ductwork. The technician did not use any sort of fall protection and had no obstructions to prevent a fall from the ductwork.

9. During weld repair work on the REC piping on 8/11/94 a welder was observed welding on a pipe line while standing on top of a pipe support. There was scaffolding constructed in the area but was not sufficient to provide access to this work area. The welder used the scaffolding which had not been built to industry standards as observed earlier to access the work area. The welder then climbed off the scaffold onto the pipe support to perform the work. The pipe support was constructed of steel rods off a wall bracket and did not provide sufficient footing. The welder used a safety harness, but tied the harness lanyard off to the pipe he was working on. In this configuration the safety harness would not have prevented a fall from the pipe support. To compound the saftey hazard, the welder was working with a weld helmet which completely obstructed his vision. In this condition the welder's concentration was fixed on the welding process and he could have easily slipped from the pipe support.

11. During an observation of the work in progress on the Service Water sparger line, it was observed that there was no fall protection around the access hole. In the process of rotating Service water pumps, an equipment operator working very near to the hole lost footing on the wet floor and almost slipped.

10. Inconsistent use of hardhats and foot protection noted throughout the plant site.

**PROGRAMMATIC:** It does not appear that management is aware of this weakness or that they perceive their performance as a weakness.

**MANAGEMENT:** Failure to monitor performance against goals.

Failure to implement effective corrective actions when exceeding established goals.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RC-04

**DESCRIPTION:** Lack of adherence to configuration control procedures.

**CAUSE:**

**EXAMPLES:** MWR 94-006 modified the main control room air conditioning unit by adding a sheet metal and steel plate structure to the drip pan assembly and by adding pipe supports to the drip pan drain line. This constitutes a configuration change without appropriate modification or engineering specification change documentation.

In addition, numerous examples have been identified by station personnel during efforts to prepare the plant for restart from the current outage. During the 8/9/94 Condition Report Group (CRG) meeting, the following CR's were presented:

- CR S/N 04538 7 valves not added to valve lineup procedures following DC closeout
- CR S/N 04539 4 potential unauthorized temporary modifications identified
- CR S/N 07274 6 valves not added to valve lineup procedures, although installed in the plant per a DC
- CR S/N 07365 actual electrical loads on critical instrument and control power panel not properly reflected on drawing
- CR S/N 07368 2 valves removed from system without proper DC
- CR S/N 07379 1-125VDC breaker mispositioned per power supply checklist and identified 3 other breakers found closed that apparantly feed circuits reserved for future loads
- CR S/N 07402 1 breaker found out of position
- CR S/N 04245 valve position on drawing doesn't match position in lineup procedure
- CR S/N 04504 unapproved temporary gauge installed without appropriate PTM

WI 91-4119 installed "temporary" cameras and cabling in the heater bays in December, 1991. Procedure 3.4.4 on Temporary Design Changes limits temporary changes to six months. This change (TDC 91-116) is still in place awaiting a permanent DC package from GO to make it permanent. (See RC-09)

**PROGRAMMATIC:** 1. Lack of clarity in procedures for threshold for what constitutes a design change.

**MANAGEMENT:** Although station staff and management are aware of these issues individually (i.e., valve mispositioning in general, breaker mispositioning in general, unauthorized plant modifications, etc.) they do not appear to recognize a generic configuration control concern when all these items are taken together.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RC-05

**DESCRIPTION:** Inconsistent use of SORC approved procedures when performing maintenance on essential equipment

**CAUSE:** Procedures are viewed more as a burden than a craft aid. When used, procedure changes are frequently required. Procedure changes are difficult to obtain.

**EXAMPLES:**

**PROGRAMMATIC:** Lack of knowledge on the part of maintenance personnel of Tech Spec requirements. Over-reliance on the 'Skill of the Craft.'

**MANAGEMENT:** CNS personnel are aware of this deficiency and have submitted a Tech Spec clarification request to the General Office for guidance on this. Additionally a Tech Spec change request has been submitted to allow flexibility in the use of procedures (ref. memo CNSS940177, dated 4/14). This request has not been acted upon as yet and station personnel maintain the status quo despite the feeling that, in some cases, they may not be in compliance with Technical Specifications.

**AREA:** MNT **SEQ:** RC-07

**DESCRIPTION:** Maintenance work control practices and planning and scheduling do not effectively support the accomplishment of maintenance work. (see also DM-02, SV-02 & SV-08)

**CAUSE:** Work planning efforts, while assigned to a planning & scheduling group, are typically performed by the craft shops. Priority, plant mode required, QC and PMT requirements, program(s) applications and existing procedures (if known) are addressed by the planner. The MWR is then sent to the shop where the craftsperson is responsible to obtain any Special Instructions (SIs), additional procedures, drawings, vendor manuals etc. prior to starting work. The craftsperson is also responsible for obtaining all work authorization signatures prior to beginning work. He/she is also responsible for obtaining necessary tools/equipment and parts. Note: efforts are underway by the maintenance department to change many of the items discussed above; however at this time, few results have been achieved.)

**EXAMPLES:** Interview with Maintenance Manager indicates that maintenance craft personnel are spending only approximately 30% of their time in the field.

**PROGRAMMATIC:**

**MANAGEMENT:** Station Management is aware of this deficiency and is attempting to correct the problem. Numerous recommendations were made in the INPO Work Management Assist Visit report from earlier this Spring. A team has been formed to implement improvements in the work control process; however it has not been able to focus on this issue due to the extended forced outage the station is currently in.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RC-08

**AREA:** MNT

**DESCRIPTION:** During three tours of reactor building, no maintenance work was observed.

**CAUSE:** Administrative workloads placed on the crafts to plan and schedule work activities and to obtain all required approval signatures significantly limits time available to perform maintenance. During one interview, Maintenance Manager indicated that he estimates that craftspeople are only able to be in the field for a maximum of 30% of their time due to these limitations.

**EXAMPLES:** Tours of reactor building, all accessible areas and levels, on 8/4, 8/8 and 8/10 no work activities noted in the plant. These tours were taken during normal working hours (one potentially during lunch break period). Despite the fact that the plant is in a shutdown condition with a large amount of work to be accomplished, no work was observed.

**PROGRAMMATIC:** Lack of an effective work control and planning and scheduling process.

**MANAGEMENT:**

**SEQ:** RC-09

**AREA:** MNT

**DESCRIPTION:** Temporary Design Change (TDC) 91-116 (Cameras in Heater Bay) has been installed for greater than the established goal of six months

**CAUSE:** Apparant lack of priority placed on this effort by the Design Engineering group.

**EXAMPLES:** TDC-91-116 was installed in 12/91 under WI-91-4119. The removal date of this TDC has been deferred twice. A Design Change to make this installation permanent is needed and the WI is on "Planning Hold" awaiting the DC from GO in Columbus. The goal for TDCs is to be installed for no longer than 6 months. This TDC has been installed for over 31 months at the present time.

EWR -92-100 has been generated, however the design change DC-92-100 installation has been delayed to the 1995 refueling outage, apparently due to cost-benefit considerations.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RC-12

**DESCRIPTION:** Shutdown Safety and Outage Risk Management could be strengthened.

**CAUSE:** Lack of clear Shutdown Safety Guidelines provided. Although the Outage & Modifications (O&M) Department procedure manual provides policies and procedures for safely scheduling and conducting outages, they are inconsistent in their application (directed for use in refueling outages but applicability to forced outages not adequately addressed.)

Lack of direction and guidance for the use of these procedures.

**EXAMPLES:** Reviewed procedures in the Outage & Modifications (O&M) department procedures manual. The Shutdown Safety requirements are included in procedures 2-1, "Refueling Outage Schedule Development and Review" and 3-2, "Outage Reports and Meetings.

(note: Despite the fact that these procedures reference refueling outages only in the Purpose section, it has been observed that some elements of these processes are being practiced during the current forced outage. These procedures could be strengthened by clearly stating the differences in requirements and implementation between planned and forced outages.)

1. The guidelines for safety system requirements are contained in Attachment 2 to procedure 2-2. 17 guidelines are presented for system availability during outages, however these guidelines are not specifically tied to the Key Safety Functions. For example, guideline 2 requires both REC subsystems to be available at all times but does not provide the basis for this requirement (i.e., is REC required for fuel pool cooling, RHR system support or both?) This lack of specificity has led to potential non-conservative decisions when REC has been secured. Four Deviations from Outage Guidelines (DOGs) (no's. 69, 70, 71 and 72) were prepared for REC outages and the contingency actions included in the DOGs addressed FPC only and not the support functions REC provides to other shutdown safety functions such as RHR and CS.

2. Procedure 3-2 describes reports and meetings that pertain to refueling outages. This procedure primarily focuses on scheduling and administrative issues, however section 8.1.9 provides minimal information on the Outage System Status Report (OSSR.) No guidance is provided on the use and development of this form.

Attachment 3 is the OSSR, a 13 page checklist to be used as a reference for determining availability of systems.

Attachment 4 to 3-2 is the Outage System Availability Description, a 52 page matrix that apparantly provides the details of what components or support systems are required to declare a system on the OSSR available. No description of or reference to this table is provided, and its usability as a tool for determining system availability is questionable.

3. When DOGs 69, 70, 71 and 72 (described above) were instituted to document the contingency actions required for REC system being drained, the only consideration was to fuel pool cooling. Impact on the support REC provides to RHR was not addressed. The OSSRs for the dates these DOGs were in effect did

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not show the impact on RHR from the REC unavailability although the Outage System Availability Description matrix shows REC as a required support system for A RHR LPCI NW FCU and B RHR LPCI SW FCU.

Other considerations not addressed by the removal of the REC: (1) REC is identified as a required support system for RWCU system (which is a backup to RHR) as cooling to the Non Reg heat exchangers and RWCU pumps; (2) REC is identified as a required support system for Reactor Recirc Pumps (to be used as a backup method for reactor temperature monitoring.); (3) REC is identified as a required support system for the FCUs for the core spray pumps and for the CRD pumps (for inventory control.)

These DOGs did not address any of these key safety functions.

The above discussion indicates an incomplete review of the impact of the REC outages on all Key Safety Functions.

**PROGRAMMATIC:** Inadequate implementation of shutdown safety requirements.

Less than adequate attention to shutdown safety.

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** RC-13

**DESCRIPTION:** Lack of adequate Self-Assessment in the maintenance department.

**CAUSE:** Lack of Management follow-through on established procedural requirements.

Lack of appreciation of need for and value of self-assessment.

**EXAMPLES:** Procedure 7.0.4, "Conduct of Maintenance", section 8.10 "Performance Based Self Assessment Program" requires:
a) the establishment of a formal MWR Overview Review Group to periodically assess the quality and adequacy of completed MWRs (8.10.1.1); and
b) the establishment of a formal MWR Field Observation Group to periodically field observe the implementation of MWRs (8.10.1.3)

These requirements include a summary report of the activities of each of the groups be prepared and forwarded to the Maintenance Manager at the end of each review period.
Despite these requirements, no such groups or reports are in existence.

**PROGRAMMATIC:** Less than adequate assessment by QA for ensuring adequate self-assessments are made in individual departments.

**MANAGEMENT:** Lack of culture that promotes self-criticality and continuous improvement through self assessment.

**AREA:** MNT **SEQ:** RC-14

**DESCRIPTION:** Excessive failures of LLRTs on one valve with no apparent root cause or detailed evaluation.

**CAUSE:**

**EXAMPLES:** Reviewed the maintenance history on CS-MOV-MO-5B. 34 MWRs dating back to May, 1981 were reviewed. Noted six successive failures of this valve to pass LLRT testing [1981 (MWR 81-0949), 1983 (MWR 83-1043), 1984 (MWR 84-2336), 1986 (MWR 86-4559), 1988 (MWR 88-1213), and 1990 (MWR 90-1380)]. There has been no apparant detailed evaluation of the trend this represents or of the root cause of these failures.

**PROGRAMMATIC:**

**MANAGEMENT:**

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## Field Notes

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**AREA:** MNT **SEQ:** SV-01

**DESCRIPTION:** Some work on equipment that is important to nuclear safety is conducted without approved procedures as required by the stations technical specifications. There is an insufficient number of generic maintenance repair procedures to control overall work on safety related equipment. As a result there is inconsistent control and verification used for work on important plant equipment. Some work on safety related equipment is performed by "skill of the craft" where the maintenance work request identifies the problem and specifies "repair as required." Special work instructions are used with some safety related work that are written by a variety of station personnel. Special Work instructions have been written by engineers, managers, supervisors, crew leaders, craft personnel and planners with the required approvals of the individuals supervisor and maintenance planner. The inconsistent guidance to work on nuclear safety related equipment results in some inappropriate actions by craft personnel, lack of quality control verification during work and lack of documentation of work performed on important equipment.

**CAUSE:**

**EXAMPLES:** 1. Problems with alignment of safety related 4160 volt breakers were repaired without use of approved procedures. (See SV-07 for details). The maintenance work requests used for the work varied in instructions and control. Some of the breakers were repaired with special instructions and some were repaired with "skill of the craft". No quality control verification was used in any of the work activities.

2. Replacement of a contactor in the breaker for the core spray 5A motor operated valve was performed on MWR 94-4084 on 7-29-94. Work was performed with special work instructions written by the work crew leader. No SORC approved procedure was used for the work.

3. Complete overhaul of an RHR motor was performed on MWR 93-1720 on 5/9/93 without an approved procedure. Special instructions were used to control the work. Recent problems discovered with loose bolting on the RHR motors were repaired without use of approved procedures. The B RHR motor bolting was retorqued on MWR 94-4260 on 8/5/94 and the A RHR motor bolting was retorqued on MWR 94-4136 on 7/30/94. Both repairs were made using special instructions approved by system engineering and maintenance planning.

4. Various repairs to the emergency diesel generator engines were conducted without approved procedures such as:

(a) Replacement of the 5L fuel injection pump on the #2 diesel generator on MWR 93- 1741 on 4/30/93 using special instructions.

(b) Rebuilding of the fuel injector nozzles on the #2 diesel generator on MWR 93-0820 on 3/13/93 using special instructions.

(c) Replacement of lube oil piping on the #2 diesel generator on MWR 93-0775 on 3/13/94 using "skill of the craft".

(d) Removal, repair and reassembly of the #2 diesel generator exhaust manifold on MWR 93-1009 on

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3/20/93 using "skill of the craft".

Review of various MWR's performed to current evaluation period indicates the excepted practice to perform work on Saftey Related equipment using "skill of the craft" without instructions or process control that would normally be in procedures or work instructions.

**PROGRAMMATIC:** Maintenance program and policies are not in accordance with Tech. Spec 6.3.3 & 6.2.1.A.4a that requires SORC approved procedures to be used for maintenance performed on equipment and systems that could effect nuclear safety

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-02

**DESCRIPTION:** Lack of advance scheduling of maintenance work results in additional equipment out of service time, lost maintenance production hours, and an increase maintenance backlog.

**CAUSE:** No centralized work scheduling process. Limited involvement of operations in the scheduling of work. Work crews scheduling their own work based on work groups priorities.

**EXAMPLES:** 1. Backlog has increased significantly in past six months. Total open backlog was 1023 in January, 1994, and has increased to 1392 in June, 1994.

2. Work is not routinely scheduled to maximize completion of backlogged corrective and preventive maintenance work while equipment is out of service. Equipment is regularly taken out of service to perform a single routine maintenance task, returned to service for post-maintenance testing, and within a few days removed from service to perform another single routine maintenance task. The following are examples where multiple equipment clearance orders were issued within a relatively short time frame for routine work:

a. A Clearance was issued 1/11/94 to repair an indicating lamp on the A air dryer, a second clearance was issued to perform a PM on 1/15/94.

b. A clearance was issued 2/23/94 to perform a PM on the B air dryer, no parts were available for the PM.

c. A clearance was issued 4/28/94 to perform a PM to inspect a control cabinet on the B air dryer, a second clearance was issued on 5/9/94 to perform a PM to inspect desiccant and repair an air valve.

d. A clearance was issued on 5/11/94 to perform a PM on the B air compressor to change oil and inspect air filters, a second clearance order was issued on 6/28/94 to clean motor screens.

e. A clearance was issued on 1/17/94 to perform repairs to an unloader on the C air compressor, a second clearance was issued on 1/24/94 to perform a PM to replace a bearing, a third clearance was issued on 2/2/94 to repair a broken sight glass, a fourth clearance order was issued on 2/26/94 to perform a PM to inspect air filters.

f. A clearance was issued on 3/1/94 to repair a gland water line on the D service water booster pump, a second clearance was issued 3/8/94 to perform a PM to change oil, a third clearance was issued on 3/11/94 to perform an alignment check.

g. A clearance was issued on 3/8/94 to perform a PM to change oil on the B service water booster pump, a second clearance was issued 3/10/94 to perform an alignment check.

h. A clearance was issued on 3/8/94 to a PM to change the oil on the A service water booster pump, a second clearance was issued on 3/11/94 to perform an alignment check.

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i. A clearance was issued on 6/2/94 to replace brushes on the A reactor recirc. motor generator set, a second clearance was issued on 6/6/94 to replace a voltmeter, a third clearance was issued on 6/9/94 to calibrate relays.

j. A clearance was issued 6/2/94 to replace brushes on the B reactor recirc. motor generator set, a second clearance was issued on 6/9/94 to calibrate relays.

3. Numerous examples of work scheduled by work groups not being released by the control room on the day the work was intended to be performed.

4. Operations is not consistently involved in assigning priorities on maintenance work for plant equipment.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** MNT **SEQ:** SV-04

**DESCRIPTION:** Improvements in maintenance programs and performance is limited due to involvement of management day to day activities and problems. Plan for near term and long term improvement is not developed.

**CAUSE:** Overall culture of production and limited priority placed on overall improvement

**EXAMPLES:** 1. At a Maintenance department meeting the Manager stated that electrical shop performance was a major concern with Senior Management. No plan to improve was proposed. Supervisors were apparently expected to identify their own problems and develop solutions based on this "concern."

2. Work control improvement manager and personnel assigned, but limited involvement of management due to involvement in restart issues.

3. Maintenance management involvement has been limited in areas such as the Motor-Operated Valve Program.

**PROGRAMMATIC:** Management focus has been on restart. Key managers have been assigned to supervise activities related to start-up of the plant

**MANAGEMENT:** Personnel believe they are not getting clear direction from senior management.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-06

**DESCRIPTION:** There has been an increased occurrence of maintenance work delays and mistakes in field work.

**CAUSE:** Time demands from the corrective action program, work planning and work scheduling have significantly reduced supervisor involvement in field activities.

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-07

**DESCRIPTION:** Inadequate maintenance on plant equipment has resulted in an increase in out of service time and rework. Maintenance reliance on "skill of the craft" results in inconsistent implementation of maintenance work. Mistakes in performance of field work and system work-arounds are a result of workers responsible for planning, work instruction, and MWR approval process.

**CAUSE:**

**EXAMPLES:** 1. 4160 Breaker alignment problems that resulted in failure of the IGS breaker (feeder to 480v bus) was the result of improper maintenance performed. Electric shop changed the shims on the wheels for the breaker when the breaker was swapped out with a spare. During this shim installation, the wheels were misaligned resulting in the breaker not rolling on internal tracks properly, causing the position contacts to not operate properly due to misposition.

Investigation by the plant (discussions with G.E.) revealed that the wheels and shims for these breakers are not required to be changed when a breaker is swapped from one cubicle to another. The plant has been performing this work, swapping shims from one breaker to another for many years during prior breaker change-outs. No procedure covers this work.

The plant's correction to this problem was to remove all 4160 essential breakers and check alignment of wheels. The plant does not have a design drawing for the correct measurement to assure proper alignment. In place of the drawing, an engineer has developed a tool from dimensions of a breaker believed to be correctly aligned. This tool was used to align the wheels on all breakers that could be removed without major plant impact. This included six breakers. Improper position of one breaker caused failure of the breaker to operate correctly. When questioned, the engineer said that testing would verify operability. Two other essential breakers could not be removed because they were feeder breakers to the 480V MCC cubicles. On the breakers that could not be removed a boroscope was used through a bottom opening in the breaker to inspect that the wheels were in their tracks. In addition, the boroscope was used after the six other breakers were realigned to check that the wheels where in their tracks. The inspection revealed that all the wheels were in their tracks but not all were centered with some wheels up against the track sides. One of the breakers that could not be removed had the wheels that were not centered in the tracks. When questioned, the engineer said that testing would verify operability.

On 6/25/93 the 1GS breaker for the feeder to 4160 BUS G was swapped with the breaker for RHR pump "C" on MWR 93-2572. On 6/16/94 condition report 94-0443 was written that identified improper operation of the 1GS breaker. On 6/16/94 Condition Report 94-0443 was written to identify that MWRs 84-2859, 91-1088, 91-2847, and 90-3911 had similar problems identified in breaker operation but root causes were not well defined. The station documented failure of the breaker to operate properly on CR S/N 0-04414 and evaluated the issue with a CR Team for Condition Reports 94-0295, 0296, 0299 and 0300. The electrical maintenance shop attempted to repair the 1GS Breaker for Feeder to 4160 BUS 1G on the follwing MWRs:

-- MWR 94-2976 Realigned Breaker on 6/16/94
-- MWR 94-3884 Inspected Breaker with G.E. on 7/23/94
-- MWR 94-3899 Realigned Breaker on 7/23/94

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-- MWR 94-3943 Replaced the 52H/in-out switch on 7/24/94
-- MWR 94-3989 Removed Breaker to measure and adjust wheels 7/27/94

The 1FS breaker for feeder to 4160V BUS F from the Emergency transformer was found to be out of adjustment MWR 94-4083 on 7/28/94.

The 1GB breaker for TIE to 4160V BUS B was swapped with the Service Water Pump "D" Breaker on MWR 93-2573 on 6/25/93. The 1GB breaker was readjusted for misalignment on MWR 94-3997 on 7/26/94.

The SWP1A breaker for the "A" service water pump was swapped with 1FA Feeder breaker for the 1F BUS MWR 93-2574 on 6/29/93. The SWPIA breaker was inspected for misalignment on MWR 94-3994 on 7/26/94 and found aligned properly. When the breaker was returned to service the charging motor failed to charge the springs after the breaker was racked in. The SWPIA breaker was removed again and found that improper height adjustment and alignment resulted in failure. The breaker was adjusted for height and alignment on MWR 94-4048 on 7/27/94.

2. Service Water Pump A impellor clearance was adjusted on MWR- 94-2923 on 8/1/94 and adjusted again on MWR 94-4203 on 8/2/94 on MWR 94-0433. The second time the pump was worked the "as-found" clearance was approximately .025 inches out of adjustment.

The pump was removed from service on 8/1/94 after one hour run time per the maintenance procedure. The purpose of the one hour operation is to assure no sand is in the pump casing prior to setting the impellor clearance. The work crew adjusted the impellor clearance to .023 inches as documented on MWR 94-2923 and released the pump to operations for test. The test resulted in high motor current reading for approximately 9 minutes. Operations secured and isolated the pump for maintenance to recheck the clearances. The work crew on the following shift rechecked the "as-found" clearances on MWR 94-4203. The "as-found" impellor clearance was .047 inches. The work crew readjusted the clearance to .021 inches and released the pump to operations for a retest. The cause for the difference between the first adjustment and the "as-found" clearance on the second adjustment has not been determined by the plant.

3. The Turbine Equipment Cooling Pump (TEC-P-8) was rebuilt on 2/14/94 on MWR 94-0433. The work replaced the mechanical seals, bearings and wear rings. When the pump was returned to service for post maintenance test the mechanical seal leaked. The pump was disassembled again on the same MWR. An "O" Ring was found to be missing on the mechanical seal. In addition the shaft was found scored during coupling assembly. The shaft, shaft sleeves and bearings were replaced on the second rebuild.

4. New MWR's were written 9/93 on #2 diesel generator for various oil leaks and water leaks in the area of cylinder gaskets, valve cover gaskets, and cylinder leaks. Major work was conducted 6/93, disassembling the engine cylinders. Work 6/93 affected all gaskets that were found leaking 9/93.

5. The drywell inlet inboard isolation valve PC-MO-232 MV was improperly assembled on 3/16/93 during a PM (036337) on MWR 92-2816 resulting in a failed LLRT. The valve was removed again on 5/24/93 to reset the ring and set on the same MWR.

6. The RHR service water booster pump "B" discharge valve (SW-V-85) was found to be leaking by on

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
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5/5/93. The valve was replaced on MWR 93-1867 on 6/5/93. The failure was attributed to a prior maintenance activity on the valve in which the proper seating of the valve disc was not checked after repairs.

7. The RHR service water booster pump "D" discharge valve (SW-V-99) was found to be leaking by on 4/22/93. The valve was replaced on MWR 93-1562 on 4/24/94. The failure was attributed to a prior maintenance activity on the valve in which the proper seating of the valve disc. was not checked after repairs.

8. A number of valves disassembled for repairs during the last refueling outage required rework in order to pass the LLRT.

**PROGRAMMATIC:**

**MANAGEMENT:**

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## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-08

**DESCRIPTION:** Work control process needs improvement in various areas in order to handle large increase in work due to zero threshold corrective action system. Weak areas include:

1. Planning-- Very little input into work instruction

2. Scheduling--On-line schedule created a week at a time

3. Limited work is being performed during outage due to lack of looking beyond individual day-to-day problems. Special instructions written by system engineers are, at times, inadequate resulting in many revisions and work-arounds by craft.

**CAUSE:**

**EXAMPLES:** 1. A significant amount of work scope increase was added to the station's pre-startup requirements without the knowledge of the responsible management staff. A series of walkdowns had been performed in the station with use of a contractor (APA). The walkdowns were conducted under the direction of engineering/construction management and had been ongoing for the past five to six years. A number of problems had been identified by the walkdowns and the station had been routinely correcting or evaluating the issues as they were found.

A problem was discovered by the APA inspection team with electrical forked lug connections. A larger number of the connections were found to be not fully inserted around the termination screws.

On August 3rd, the Work Item Tracking (WIT) supervisor received a list of 15 terminations from engineering and was told to develop MWR packages to perform the work as required prior to start-up.

At this time the WIT supervisor discussed the issue with the maintenance manager. Concerns for the time involved to prepare work packages along with the impact to the plant were raised at that time. The WIT supervisor was told by the Maintenance Manager to prepare the packages as requested by NED.

On the following day (8/4) the WIT supervisor was given a list of approximately 250 terminations that required repair. He was told by engineering that all would have to be completed before start-up. The WIT supervisor assigned a planner to develop priority 1 MWR packages to perform the 250 termination repairs.

Interviews with other management personnel indicated a lack of knowledge of this work and its impact on the plant and the outage schedule.

Review of the MWR planning for the repairs indicated that the work was to be performed by the contractor group and special instructions were provided to the WIT planner by the work group. Planning was in progress at the time of the review so the planner was interviewed to determine the approach that was to be taken. The following problems were identified in the planning of the MWR packages to perform work on essential terminations:

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A. No SORC-approved procedure was to be used to perform the terminations on safety-related components.

B. Torque values for the termination screws were not considered in the plan. The station does not routinely require tightening termination screws to specified torque values.

2. Work item backlog contained 363 Priority One work requests - all work items generated for the outage are specified as Priority One.

3. Inadequate planning on MWR 94-4117 for I & C to replace a Scram Discharge Volume Level Transmitter resulted in delays in performance of work and unnecessary out-of-service time for the equipment. The special instructions written by the system engineer identified the wrong junction box for the transmitter terminations. Additionally, the instructions identified the wrong torque valve for the transmitter mounting bolts. The work was stopped until the discrepancy could be researched and corrected in the special work instructions. The engineer indicated that a walkdown of the work was not performed to develop the special instructions.

The instructions specified 35 ft.lbs for the mounting screws based on the assumption that the mounting screws where 3/8". At the start of the work it was realized that the mounting bolts were only 1/4". The instructions were changed to specify 5 ft-lbs for the mounting screws.

After the transmitter was replaced in the system the technicians noticed that the vendor tagging did not match the transmitter next to the one they had worked on. The technicians were working on LT-231C and installed the transmitter input bellows per the special instructions. The instructions specified to install the bellows labelled " low pressure input" to the bottom of level column and the bellows labelled "high pressure input" to the top of the level column. When the technicians compared the tagging on the LT-231D installed on the same level column, the tagging was reversed. The work was stopped to wait for the system engineer to communicate with the vendor.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-12

**DESCRIPTION:** Culture of maintenance personnel resists change and involvement in new programs for overall improvement.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:** Maintenance workers reflect attitude that work completion is primary concern and procedures, documentation, etc. are not important.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
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*31-Aug-94*

**AREA:** MNT **SEQ:** SV-14

**DESCRIPTION:** Maintenance work is not performed in accordance with vendor specifications due to insufficient work instructions in procedures and maintenance work plans.

**CAUSE:**

**EXAMPLES:** 1. Workers performing on the A service water pump on MWR 94-4203 did not assemble the pump coupling in accordance with the vendor manual. The vendor manual specifies that the coupling bolts should be thoroughly cleaned, lubricated and torqued to the specification in a table. The vendor manual also gives a recommended torque pattern to use for tightening sequence. Contrary to the vendor specifications, the work crew did not tighten the bolts using a torque wrench. The bolting was not cleaned and lubricated prior to assembly and a tightening pattern was not used.

2. Installation of the 5L fuel injection pump on the #2 diesel generator on MWR 93-1741 on 3/20/93 was not in accordance with vendor requirements. The Cooper-Bressmer Vendor Manual VM 245 requires that the fuel injection pump mounting bolts be torqued to 55 ft-lbs. The fuel pump was replaced using special instructions and did not include torquing of the bolts.

3. Work performed on MWR 94-4203 and MWR 94-2923 on 8/2/94 to set the impellor clearance on th service pump was not in accordance with vendor specifications. The vendor manual for the pump VM 1 specifies to set the impellor clearance to .056 inches. The procedure for the pump specifies to set the impellor clearance between .021 and .035 inches. When questioned, the crew leader could not explain the difference between the two specifications. The workers set the impellor clearance to .023 inches.

4. Work conducted to replace the exhaust manifold on the #2 diesel generator was not in accordance with the vendor specifications. The exhaust manifold was replaced on MWR 93-1009 on 3/23/93. The manifold bolting was not torqued in accordance with the vendor manual VM 245. No measured torquing was conducted during the replacement.

**PROGRAMMATIC:**

**MANAGEMENT:**

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*31-Aug-94*

**AREA:** MNT **SEQ:** SV-15

**DESCRIPTION:** Maintenance supervisory personnel do not adequately pursue questions raised in performance of maintenance work.

**CAUSE:** Maintenance culture is to deal with all problems and issues within the group - with requests for input from other groups only if specifically required in the process.

**EXAMPLES:** 1. Work performed to reset the A service water pump impellor clearance after a failed post maintenance test required work outside procedure guidance without further review and approval beyond the work crew leader. The crew leader submitted a procedure discrepancy form after discussion with procedure writers on how the work could progress without running the pump as specified in the procedure. The procedure requires running the pump for one hour prior to setting the impellor clearances in order to clear sand from the pump casing. The pump was run for 9 minutes before securing due to high amps. When questioned the crew leader stated that he did not discuss the issue with system engineering for technical justification prior to the work.

2. The crew leader on the A service water pump repairs did not respond when questioned by the workers about verification of the position of the pump impellor before performing work. The workers questioned how they could be sure the impellor was not sitting on sand without running the pump per procedure guidance. The crew leader did not respond to this question and did not pursue an answer prior to completing the work on the pump. After work was completed and after the pump was released to operations, the workers and crew leader discussed their questions with NED engineers to satisfy their concerns.

**PROGRAMMATIC:** Maintenance culture is to deal with all problems and issues within the group with requests for input from other groups only if specifically required in the process.

**MANAGEMENT:**

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*31-Aug-94*

**AREA:** MNT **SEQ:** SV-16

**DESCRIPTION:** Long standing problems in the service water system due to silt accumulation has resulted in operational work arounds and a relatively high amount of maintenance required on critical service water components.

**CAUSE:**

**EXAMPLES:** 1. Service water pumps that are not in operation are rotated by hand at least once per shift by operations and each time the pump is started in non-automatic mode.

2. High current readings on the service water pumps are normally experienced when pumps are initially started after maintenance.

3. Maintenance procedures for setting the impellor clearances on the pump require a one-hour operation to ensure that the casing is clear of sand prior to work on the pump.

4. RHR heat exchanger service water outlet valves SW-MOV-MO89B and SW-MOV-MO89A are not used to regulate temperature of the RHR system. High maintenance of these valves has been experienced in the past and throttling of the valves is avoided by using the RHR primary system valves to throttle and regulate temperature. The service water valves are operated in manual mode.

5. Service water booster pump maintenance has been high considering the relatively low amount of use on the pumps. It has been the practice to overhaul the Service Water booster pumps every 18 months. Experience has shown that the wear on the pumps seen during the overhauls justifies the schedule. This wear is present even though the pump runs only when heat demand on the RUR system is high, such as plant shutdowns and surveillances. The booster pumps are not needed during normal operation and later in an outage after decay heat has been reduced.

6. Spargers used in the service water bay for keeping silt in suspension have been in need of maintenance for many years. The plant design has five sets of spargers (two of which are redundant) in the suction bays of the service water pumps. The system is designed to work with automatic valves feeding three sparger headers. Due to excessive wear of the spargers, the plant operates with only two spargers in operation at one time. Operating more than two results in pump run-out. This condition has existed for many years but is not identified in the current maintenance back log.

7. Travelling screens are operated continuously to prevent binding from silt accumulation. Previous problems with screens require quick response of maintenance to avoid accumulation of silt, preventing operation. Divers have been used regularly to free up screens due to silt accumulation.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MNT **SEQ:** SV-18

**DESCRIPTION:** Diesel generator lube oil strainers required inspection and cleaning due to insufficient documentation of work performed during last overhaul. Maintenance crew cleaned strainers during overhaul but could not verify through documentation so both diesels were sequentially removed from service and strainers inspected, adding to out-of-service time.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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**AREA:** MNT **SEQ:** SV-21

**DESCRIPTION:** Longstanding equipment problems and discrepancies noted during maintenance exist in the plant without being tracked in the maintenance work request system for future resolution.

**CAUSE:**

**EXAMPLES:** 1. RHR heat exchanger leaks were identified in 1986 and a catch containment system was set up in 1988. An MWR was not in the backlog to track the problem. The problem still exists.

2. A degraded condition of the MO39B RHR motor operated valve, known to some station personnel, is not identified in the MWR system. The MO 39B Valve had extensive repairs performed on the valve intervals on 7/94 under MWR 94-3319. The repairs were conducted to correct seat leakage resulting in a failed LLRT. After the repairs were completed and during testing of the valve it was determined that excessive running load was experienced during VOTES testing. During interviews, personnel stated that the valve made loud screeching noises when stroked open and closed. The VOTES testing also indicated an unusual condition that the excessive running thrust was experienced in only one direction of valve travel.

A new MWR was written (94-3488) to replace the packing. The valve was previously packed with "ARGO" packing that utilized recent packing technology. The carbon spaces of the packing set were found to be broken. The station removed the packing set and installed an older style packing set that utilized softer material. The valve was again tested and found to have reduced the excessive running thrust to an acceptable level. It was noted that the unusual condition of higher thrust in one direction of valve travel still existed. An engineering evaluation from the MOV engineer also indicates that the disc was misaligned in the valve body causing the disc to make contact with the seat before the actual full seating of the valve.

The completed MWR 94-3488 documents input from the maintenance crew indicate that the cause of the failure was misaligned valve stem and/or bonnet was not true. Discussion with the MOV project supervisor indicated that running thrust should be approximately the same in both directions and a notable difference would indicate internal valve problems.

The degraded condition of the valve was not identified as of 8/12/94 in the MWR or CR systems.

3. A temporary patch installed in the REC system to correct a weld leak remained in place for approximately 17 years before being permanently repaired. A temporary patch was installed on the REC outlet pipe line from the Reactor Recirc. Motor Generator set lube oil coolers on MWR 77-2-64 on 7/77. The patch was identified during a system walkdown on 8/1/94 and removed and repaired with a permanent repair. The patch utilized filet welding on a piping system constructed with butt-welded joints. This modification to this system was not controlled with the use of a design change.

4. Long standing deficiencies in the Service Water spargers were not identified in the system.

**PROGRAMMATIC:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
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*31-Aug-94*

**MANAGEMENT:**

**AREA:** MNT **SEQ:** SV-22

**DESCRIPTION:** Recent problems identified with parts used on safety related systems indicates a weakness in the control of quality in the installation of replacement parts.

**CAUSE:**

**EXAMPLES:** 1. Unavailability of a quality part resulted in incomplete performance of a Preventive Maintenance (PM) on the diesel generator starting air compressor and additional out of service time on the diesel generator air compressor. On 3/13/93 maintenance was performing a PM on the #2 diesel generator starting air compressor (DG SA-CPSR-2B) on MWR 93-0612. The oil filter was not replaced as specified on the PM (05016) due to the fact that the only available filter was non-safety related. An additional work item was not generated to identify that the filter was not replaced. On 4/19/94 maintenance performed the PM again on the #2 diesel generator starting air compressor (DGSA-CPSR-2B) on MWR 94-0729. The oil filter was replaced on this PM. The non-safety related filter was used and the equipment was returned to operations for testing. The system engineer determined that a non-essential filter was installed on the essential compressor. The compressor (DGSA-CPSR-2B) was declared inoperable on 5/3/94. The filter was qualified per WI 94-2207 and CGI 94-018 and the compressor was returned to service on 6/5/94.

2. Operability Determination No. 94-050 identifies that a 250 volt control relay was installed in place of a 125 volt control relay for the Auxiliary oil pump on the HPCI pump.

3. Operability Determination No. 94-058 identifies that the relief valves installed on the Emergency Diesel Generator starting air system is undersized. Valve number DGSA-RV- 15RV.

4. Operability Determination No. 94-063 identifies various check valves installed in the NBI, RCIC, RR, MS and HPCI were not supplied safety related.

5. Operability Determination No. 94-77 identifies Lockwashers used on RHR pump motors A, B, C, and D were supplied as commercial grade on an essential purchase order and may not be qualified for use.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
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*31-Aug-94*

**AREA:** MNT **SEQ:** SV-23

**DESCRIPTION:** Inadequate controls on previous maintenance activities have resulted in non-conforming and degraded plant equipment. In addition, when problems are identified root cause is not adequately addressed to prevent recurrences.

**CAUSE:**

**EXAMPLES:** 1. The level transmitters used on the scram discharge volume were not mounted in accordance with the vendor specifications. The CRD level transmitters (LT 231 C and 231 D) were installed in 1981 under a design change work package 81-10-1. The transmitters were installed with 1/4" mounting screws. During a correction maintenance evaluation to replace the LT 231 C transmitter on 8/11/94 it was determined that the mounting bolts should have been 5/16".

During the planning of the work, system engineers identified through the vendor manual for the transmitter that 3/8" mounting bolts were used for this transmitter. The special instructions were written to torque the mounting bolts to 35 ft-lbs. When the I & C technicians went to the work site to perform the work it was determined that 1/4" screws were used to mount the transmitter. The system engineer contacted the vendor for the instrument and determined that the vendor used 5/16" mounting bolts to qualify the transmitter. The vendor also stated that they would not recommend using bolting that was smaller than 5/16" to mount the transmitter.

The system engineer changed the work instructions to torque the 1/4" screws to 5 ft-lbs on the LT 231C so that the transmitter installation could be completed, instrument tested and returned to operation. The system engineer then wrote a Condition Report to address the improper bolting condition which initiated an operability evaluation and a MWR to correct the condition.

2. In July, 1994, the A RHR pump was found to have loose bolting on the lower motor frame. An oil leak was noted but was not attributed to the loose bolting. The plant corrected the problem by torquing the motor bolting to vendor specifications. Additionally, MWRs were written to check the torque of the bolting on the remaining RHR pumps.

Review of maintenance history indicates that the same problems with loose bolting and oil leaks were discovered on the 'C' RHR pump in March of 1993. The QA department wrote DR 93-044 on the issue, and the maintenance department replaced the motor with a spare under MWR 93-2046. The motor removed was disassembled, inspected and reassembled. The cause of the loose bolting and oil leaks was determined to be failure of G.E. Repair Shop to properly torque the reservoir bolting during the motor overhaul in 1988. It was determined that there was no QA check on the torquing of the bolting in question at the G.E. Shop. The plant's corrective action as a result of this investigation did not include checking of other motor bolting on the remaining three RHR pump motors.

The B and C RHR motors were removed in 1988 and sent to G.E. for rebuild. All four RHR motors were removed and disassembled in 1986 under MWRs 86-4461 and 86-4610. No torquing requirements were specified in the 1986 work packages. The plant's response to the DR in 1993 did not address the common problem of bolt torquing in the other RHR motors. The result was more loose bolting found in 1994.

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Questions should be raised as to how can the station be assured that other bolting is properly torqued to required specifications.

3. On 7/1/94, working under MWR 93-3275 which stated: "RF-AOV-FCV11B leaks by. Closed and left closed RF-V-33 to stop the valve from wiggling. The valve probably doesn't leak by too bad but would get worse and as such reduce plant thermal efficiency. Request repairs as required. Mechanics found the valve body "eroded beyond repair." MWR 94-3411 was then issued on 7/7/94 to repair this valve. Parts were reportedly available to perform this work, but WIT was directed to schedule this MWR for the next outage so that startup from this outage was not impacted. Although not a safety-related issue, this indicates station willingness to live with known problems that present an operations work around and potential loss of plant efficiency.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

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**AREA:** MNT **SEQ:** SV-27

**DESCRIPTION:** Workers are unfamiliar with management expectations on what is required for work instructions prior to working on essential equipment. This results in some inappropriate actions by workers along with delays of critical work evolutions.

**CAUSE:**

**EXAMPLES:** 1. Work on the core spray Motor-operated valve 5A breaker repair on MWR 94-4084 was delayed approximately 24 hours due to a lack of understanding of who was to write the special work instructions. The MWR was considered high priority (priority 1) work needed for startup. A recent change was dictated by station management that all work on safety-related equipment would be in accordance with special instructions. The MWR 94-4084 was given to electrical maintenance by the work item tracking group to implement repairs without the special work instruction. The electrical maintenance group handed off the MWR to the system engineer to write the special work instructions. The system engineer stated that special instructions were not needed and skill of the craft would be adequate for the work. The electrical maintenance crew leader did not proceed with the breaker work on that shift. On the following morning, the Maintenance Manager expressed his dissatisfaction with the electrical supervisor for not completing the work as planned. Through discussion of the issue, it was decided that maintenance shops could write their own special instructions and engineering would assist if required. The electrical supervisor was instructed by the maintenance manager to request engineering, write the instructions or write the instructions in the shop and get the system engineer to approve the instructions. The electrical supervisor did request the system engineer involvement and decided to write the work instructions himself. The special instructions were then circulated through the maintenance group for approvals. The system engineer was not requested to review the instructions. When asked, the electrical supervisor stated that enough bad feelings were created over the issue, and there was no need to have the system engineer involved. Earlier statements of the electrical supervisor were that system engineering input was needed. The work was completed at the end of the following shift.

2. Work on the Service Water Pump breaker 1A was performed without special instructions or procedures contrary to a recent directive of station management. Problems were discovered with the operation of the SWPIA breaker after a previous check of the alignment on MWR 94-3994 on 7/26/94. A new MWR 94-4048 was issued to electrical maintenance to repair the problems without special instructions. The electrical crew performed adjustments on the height and alignment of the breaker without special instructions. A condition report was written to identify that the work was conducted contrary to the requirement that all safety-related work be performed in accordance with special instructions. When questioned, the electrician stated that work was performed as they have always in the past and they had not realized that this work would have required special instructions. The electrical supervisor stated that there was a lot of confusion on the need for special instructions.

3. An I&C technician performed repairs on 3/25/94 on a square root board in the "A" channel neutron monitor flow units on an MWR that was written to troubleshoot, contrary to station procedures. Procedure 7.0.1.2 states " . . . the responsible shop will perform the troubleshooting, document the results and recommend corrective action on page two of the MWR. A second MWR will be issued for repair." The I&C technician found the problem on the card to be a wire that was too long causing shorting on a metal

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tag. The technician repaired the problem by cutting the wire shorter on the original MWR. This problem was identified by the NRC on a documentation review.

When questioned, the I&C supervisor stated that some technicians did not completely understand the recent change to the work control procedures.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** MNT **SEQ:** WW-05

**DESCRIPTION:** The tolerance level for accepting oil leaks on plant equipment is high. More emphasis needs to be placed on minimizing the number of oil leaks in the plant.

**CAUSE:** Management feels that performance is better than it was and improvements can be made.

**EXAMPLES:**

1. 'A' and 'B' Reactor Feed Pumps currently have at least seven oil leaks per skid.
2. 'A' Reactor Feed Pump inboard pump bearing seal is leaking approximately one drop every two secc
3. The HPCI skid area has at least six oil leaks.
4. Oil bags are located in several area sumps.
5. Core spray surveillance test pump in stairwell, oil on skid between pump and wall.

**PROGRAMMATIC:** Substandard expectations.

**MANAGEMENT:**

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**AREA:** MNT **SEQ:** WW-26

**DESCRIPTION:** Skill of the craft is not defined nor understood

**CAUSE:** CNS chose to place the responsibility for conducting OJE on Training Instructors vice reinforcing expectations of MM personnel.

**EXAMPLES:** 1. As a response to deficiencies noted in mechanical maintenance OJE when conducted by mechanical maintenance personnel, many JPMs were combined into Training labs evaluated in the Training shop area by Training personnel. The byproduct of conducting most OJE in the Training shop environment was that the overall number of in-plant specific JPMs were significantly reduced, or combined and replaced by generic labs. For example, setting clearances is not evaluated on in-plant equipment but is evaluated as a generic skill of the craft activity. Subsequent followup evaluations on specific in-plant equipment are not conducted.

2. JPMs do not exist for many plant-specific components. Training relies on the procedure and skill of the craft training in order for maintenance activities to be properly performed. However, observations SV-01 and SV-07 indicate this process appears inadequate.

**PROGRAMMATIC:** Failure to properly assign responsibility of ownership.

**MANAGEMENT:** Lack of desire for ownership.

Readiness of management to take path of least resistance.

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## Field Notes

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**AREA:** MOPS **SEQ:** DM-10

**DESCRIPTION:** MATERIAL CONDITION

The overall number and individual importance of equipment problems represents a potential challenge to the operation of the plant. Compounding this issue is a willingness to accept certain degraded conditions without an aggressive effort to limit their existance.

**CAUSE:** 1. STANDARDS: Standards for accepting material conditions. Too accepting of certain conditions, especially where other actions or measures are considered adequate to compensate for the condition. Need to be especially sensitive to conditions that add any additional burden on operators, or have the potential to create operational problems. (see examples: 1, 4, 6, 7, 9, 10, 17, 20)

2. LACK OF PROCESS: Need for an integrated work control process. An integrated work control process includes procurement, engineering, planning, MWR planning, scheduling, working to a schedule, work coordination, LCO tracking, goals and work assessment. With work control in place, long term material condition challenges become easier to handle and work is completed more efficiently. (see examples: 3, 5, 20, 21, 24, 25, 26)

3. MONITORING: Some material conditions were not being tracked in the MWR data base, which indicates that they were not considered a problem. (see examples: 4, 5, 7, 8, 16, 23)

**EXAMPLES:** 1. Instruments that indicate SW D/P on RHR Heat Exchanger divider plates are pegged low due to problems with sensing line plugging. Loss of this indication prevents operators from being able to perform the precaution in an IST surveillance procedure that requires verification that D/P is less than 10 psid in order to prevent damage to the RHR Heat Exchanger divider plate. (see RB-08)

2. HPCI aux. oil pump switch sticks between auto & start (see MWR 93-3273, also EWR 93-193 was sent to Columbus, December, 1993).

3. Spargers used in the Service Water (SW) bay for keeping silt in suspension have been in need of maintenance foe many years. The plant design has five sets of spargers. The system is design to work with automatic valves feeding the sparger header. Due to excessive wear of the spargers, the plant operates with only two spargers in operation at one time. This condition has existed for several years but was not identified in the current maintenance back log. (see SV-16)

4. Caution tag guidance not to bias RFC-MA-84A/B positive due to causing RFPs to not go into track and hold following a scram This occurred during scram 93-02 (see long-term list 12/14/93).

5. Drywell F sump low level cutout switch doesn't reset until level is high so can cause high fill rate alarm (MWR-94-2589 long term list 6/4/93). Living with this condition could result in operators becoming less sensitive to drywell leakage annunciators and as a result take less than prompt action should actual leakage occur.

6. SRM period alarm is bypassed in the MCR and listed as a nuisance alarm. Discussions with operators

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revealed that the alarm will occasionally come in associated with other operations in the plant such as resetting RPS.

7. RHR HX outlet conductivity ANN bypassed. Conductivity cells are abandoned in place with no apparent design change. These cells are associated with the steam condensing mode.

8. Because the demin water LCV leaks by the seat, it has been isolated requiring operators to manually open DW-34 prior to starting the Mechanical Vacuum Pump from the MCR (3/9/93).

9. The B RFP minimum flow valve leaks by its seat at 200 gpm and as a result is kept isolated by shutting a manual valve RF-V-33. This is identified with a caution tag that was hung on 8/26/93. Isolating the leakage improves plant efficiency by avoiding heat losses to the condenser but requires operators to manually open RF-V-33 if the minimum flow path is needed.

10. The control switch for main turbine bearing lift pump operations is in manual to prevent operation while the speed input to its control circuit is erratic (8/29/93). This may be fixed and awaiting PMT?

11. A Caution tag informs operators that operation of DGSA-V-37 or 38 with their PCV failing, could overpressurize the DG H&V air piping (6/18/94).

12. Because Vessel level injection valve NBI-SOV-739 leaks past its seat, NBI-V-577B is isolated. This fill (injection) line is from the CS system and would be used during EOP conditions when level reference legs are needed to be filled. With it isolated, an operator would be sent to the reactor building, second level to open NBI-V-577B (7/12/94). A decision has been made to keep this valve isolated. Preventing the fill line from causing problems with vessel level indication takes priority over the convenience of having remote control of reference leg fill.

13. Same as above for NBI-SOV-738 (7/16/94).

14. Pressure gages PI-2754 and 2755 on DG 1 and 2 are classified as non-essential and are therefore kept isolated (see caution tag 94-050 dated 7/21/94). Investigation reveal that these gages have been dedicated recently,however, the NED needs to be contacted so the caution tags can be removed.

15. Possible work-around associated with SGTS filter train fire detection. Glass inspection ports on filter housing have been covered over with duct tape because inspections with flash lights have caused spurious actuations. (see CB-02)

16. While operating at full power on January 19,1994, the high pressure coolant injection (HPCI) pump minimum flow valve unexpectedly opened during a surveillance test when the pump discharge valve opened. Discussions with operators revealed that this had happened in the past during surveillance testing. Corrective action to this involved changing the surveillance test to indicate that although actuation of the minimum flow valve may not occur every time, it should not be considered an unexpected ECCS actuation. A similar change was also made the RCIC surveillance test procedure because operators indicated that the same situation had been noted on that system in the past. (see CB-17)

17. On March 2, 1994, during operations at 97% power the main turbine governor valve partially closed

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causing a reactor scram. A card in the DEH system was replaced, however, during the subsequent startup Bypass valve oscillations where identified as being caused by power supply problems. PTM 94-09 was used to jumper the normal primary and secondary power supplies with alternate 26 volt DC power supplies. The LER (298-94004) states that an evaluation is continuing to identify long-term corrective action to prevent recurrence. PTM 94-09 is scheduled to be restored during the 1995 refueling outage. (see CB-19)

18. On February 1, 1994 a core spray (CS) pump minimum flow valve unexpectedly closed and then automatically opened when the system test return valve was stroked open during valve surveillance testing. The work history for core spray transmitters was reviewed and numerous problems with erratic flow indication date back to 1985. A 8 second time delay has been installed in the control for this valve to prevent spurious operation. (see CB-20)

19. Problems with silting in systems that use water from the Missiouri River has resulted in problems with instrument sensing lines plugging and loss of the associated indication or control function. Silting concerns have cause the station to change the manner in which they operate the RHR system during Shutdown Cooling (SDC) operations. The RHR system heat exchanger outlet valve, which is not design to be throttled, is throttled to control cooling to avoid throttling of Service Water (SW) valves designed for this purpose. The concern the station has with throttling SW valves is the additional erosion caused by the presence of silt. (see DM-09)

20. Traveling screens are operated continuously to prevent binding from silt accumulation. Previous problems with screens required quick response of maintenance to avoid accumulation of silt from preventing operations of the screens. (see SV-16)

21. Service water booster pump maintenance has been high considering the relatively low amount of use on the pumps. (see SV-16)

22. RHR heat exchanger shell side leaks were identified in 1986 and a catch containment set up in 1988. An MWR was not in the backlog to track this problem. (see SV-21)

23. More emphasis should be placed on minimizing the number of oil leaks in the plant. (see WW-05)

24. HPCI system unavailability has been increasing over the last 3 years. (GW-02)

25. Diesel Generator system unavailability has been increasing over the last 3 years. Observation of work on the Division 2 DG indicates it was out of service more than necessary due to delays that a better work control process could have prevented. (GW-02, DM-02, DM-05)

26. Vacuum Breaker coating failures. Paint peeling off the vacuum breaker disc has been a problem since at least 1991, and was only recently corrected. (DK-04)

**PROGRAMMATIC:**

**MANAGEMENT:**

*31-Aug-94*

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** MOPS **SEQ:** DM-11

**DESCRIPTION:** STATUS CONTROL

The implementation and adequacy of the status control processes does not ensure that systems and components are controlled in the condition intended. This has resulted in Clearance Order violations, valves out-of-position and insufficient control of work boundaries. Additionally, the administrative programs for control of seal wired valves and independent verification need strengthening.

**CAUSE:** Not driven by an attitude that keeps the fundamentals requirements of status control first and foremost. A tendency to go with less control of things due to more focus on accomplishing work, with less focus on preventing components from being mispositioned or other mistakes. This has resulted from the following causes:

1. OWNERSHIP: No clear owner of status control to enforce status control expectations across department lines. When everybody is responsible for it but no one owns it expectations can become unclear.

2. STANDARDS: Clear-cut expectations for controls do not exist. Controls are different depending on which process is being used. For example, the controls in the Clearance Order process are stricter than those sometime used when work is controlled by a Special Instruction. (see example 9) The Clearance Order procedure itself distinguishes between safety related systems and even certain portions of these systems in its required level of component position control. Components not in the main flow paths of safety related system do not require independent verification. (see RB-10)

3. OVER RELIANCE ON PEOPLE OVER PROCESSES: A tendency to rely on people over a strict procedure requirement. While the performance of people is an extremely important aspect of every activity it is a injustice to lay too much burden on individuals. Without well defined processes that have consistent requirements, the actions of many can add together and create situations where mistakes are made or components are not maintained in the desired position.

4. CULTURE: To allow the operation of Danger Tagged valves during LLRTs does not reflect the level of importance the industry places on maintaining a "HANDS OFF" attitude when it comes to danger tagged components. In the industry this is a "Zero Tolerance" for error area. It is also widely accepted in the industry that only operators should hang and remove danger tags, however, other personnel such as I&C are still utilized to remove instruments from and place instruments in service.

**EXAMPLES:** 1. The Clearance Order (CO) program and in a broader sense "status control" is not implemented correctly in that there are examples of components out of their required position, and of violations of procedure requirements. (DM-03, WW-19)

2. The CO program is weak in that the procedure does not specify that only operators should implement COs and does not always require the person implementing the CO to use the clearance sheet to direct their actions. (DM-03, DM-06)

3. Seal wire valve problems found in the field are not programmatically addressed. (WW-13)

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4. No procedure guidance exists on how to implement the valve line-up program. (DM-04, RB-09, WW-15)

5. Valve line-up sheets have many known deficiencies. (GW-09)

6. Only the MCR drawings are kept up-to-date with changes in the plant.

7. P&ID drawings have known deficiencies. (GW-09)

8. The use of independent verification could be extended to more areas where it is appropriate, and the use of double verification should be implemented. (RB-10)

9. The use of Special Instructions (SI) weakens control because SI, when appropriate, are not approved with the same rigor as procedure changes.

10. SI steps to position components should not be used in place of a Clearance Orders because of the additional control using clearance tags provides. (DM-04)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DK-02

**DESCRIPTION:** Plant tour 7/26/94 - Material Condition Observations. General areas of the plant look neat and clean. Less trafficked areas are not as well maintained.

**CAUSE:**

**EXAMPLES:** 1. SBGT A&B room - some trash on the floor, two equipment ID tags laying on a support with a small screw driver - cannot tell where they came from.

2. RCIC area - two solenoid valves with yellow tape labels, painted plywood over hole in concrete mezzanine.

3. Steam Tunnel entrance - Writing all over the hallway walls - needs painting.

4. Stairwell - Radio cable strung through penetration and tie-wrapped to piping and going down several floors.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** OPS **SEQ:** DM-01

**DESCRIPTION:** There are several plant performance indicators (Chemistry Index, Radiation Exposure, Solid Rad Waste, Industrial Safety) that are either below the Industry Median or in the case of Radiation Exposure is better than the Industry Median but not improving to the 1995 goal. These areas have the potential, given other weaknesses in plant performance, to be problem areas in the next two years.

**CAUSE:**

**EXAMPLES:** 1. Chemistry is well below Industry median (N25 of 35) 3 yr. avg. as of 1/94. Improved significantly the first five months of 1994.

2. Solid Rad Waste is above Industry Median and above the 1994 Unit Goal

3. Industrial Safety Accident Rate is well above Industry median (N60 of 71)(see JD-07 & RC-03)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-02

**DESCRIPTION:** The work control process does not reflect a pre-planned approach to the identification, planning, coordination and scheduling of daily work items.

**CAUSE:** 1. There is no overall Work Control Process that handles preplanning of the work that should be completed over the next few to several weeks.

2. The plant does not use a scheduling approach to accomplish activities.

**EXAMPLES:** 1. Work approved at the SS window is on a first come - first serve basis.

2. The "Night Shift Notes", "Shift Coordinator Meeting Minutes", and "Sequence of Events" sheets give the big picture activities for the present day only. No schedule exists beyond the present day that clearly identifies what needs to be completed to end a window or achieve a milestone such as startup. Lists exist but they are inaccurate or do not clearly show the integration of how and what to do. (see RB-06).

3. The SS approval of work is the point at which what can work and when is decided. However, he only gets to choose from what shows up at his window.

4. Clearance requests may get to the shift the night before but will often accompany the MWR the day it is asked to work.

5. A Clearance hung the night before as requested was not needed as planned when the shop discovered they needed a scaffold to work the job.

6. Several SS's commented that it was not unusual to take systems down for work more than once, had the work been coordinated, once would have been enough. (SV-02)

7. Each time SDV work was performed during the week of 8-8-94 the time spent with a half scram in to support this work was twice as long as necessary had the job been better planned and coordinated.

8. An LCO tracking program does exist. This contributes to not knowing what MWR, CR. PTM, Caution Tag, or other issue is open that affects an LCO. (see DM-05 & RB-04)

8. See CB-14,DB-1, GW-05, RB-02, RB-03, RC-07, SV-02, SV-06, SV-08

**PROGRAMMATIC:** The utility is aware of this deficiency; however, they have yet to implement a different work control process. There is talk of doing it and it may be in development.

Known to station management.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-03

**DESCRIPTION:** Some Clearance Order practices deviate from good industry practice for clearance tagging of components and in some respects the Clearance Order procedure.

**CAUSE:** Not holding to the fundamental requirements of a safety tagging program that are necessary to ensure safety to personnel as well as equipment under all possible situations.

**EXAMPLES:** 1. In the past, during LLRTs the test valves were danger-tagged and the valves are manipulated during the performance of the LLRT with the danger tags still attached.

2. Work that breeches a system (Scram Discharge Vol. Level Sw.) was isolated using a special instruction and not with a clearance. The Clearance Order procedure requires the use of a clearance order for all work and all equipment at CNS. (see 0.9 step 2.4 ) CNS 0.9 step 4.1.1 further states that clearances are needed when it is required that portions of a system not be operated or that it be placed in a specific configuration for safe conduct of work. By using a SI instead of clearance tags to control the position of valves, there is insufficient control of the position of that component under all reasonable situations that could likely occur.

3. Operators do no always use the clearance order sheet during the hanging and removal of danger tags.

4. Operators related two different examples where a clearance was either hung or removed by other tha operator. This is not specifically prohibited by procedure and management expectations in the past allowed this.

5. Using a SI instead of a clearance order removes an important tool the Shift Supervisor (SS) has to control the condition of systems in the plant following work. With the restoration of a system isolated to do work relegated to a step in the SI, the shift is removed from the decision that everything is back to normal prior to restoration of the system lineup. A fundamental prerequisite to clearance release (see CNS 0.9 step 8.1.8) is that repairs have been completed and the system is ready for service.

6. Clearance procedure adherence. (see WW-19 ex. # 1,2,3)

**PROGRAMMATIC:** An attitude that allows personnel to deviate from procedural intent through their own justification. If what you want to do seems justified and is not specifically prohibited, it could be allowed. The example of operating Danger Tagged LLRT valves is known and the utility is changing their procedures to address this.

**MANAGEMENT:** Management does not pick up on these deviations as problems and has not created an environment that prevents personnel from taking too much latitude in their interpretation of program procedure requirements. Surveillance Procedure are adhered to very well.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-04

**DESCRIPTION:** Control and awareness of system and component status.

**CAUSE:**

**EXAMPLES:** 1. Several valves have been found out of the expected position.

2. SDV work that required the level switch to be isolated and removed was performed using SI steps to isolate the work vice using a Clearance Order.

3. Many examples are typically found during the periodic checks of seal wired valves of improper seal wires. (see WW-13)

4. System line-ups following maintenance are not always performed (see RB-09 & WW-15). Additionally, a procedure does not exist to describe the expectations and requirements for how to administer the valve line-up program. For example, valve line-up guidance should include requirements that detail how to handle valves found out of the position specified on the valve line-up sheet, and how to conduct system line-up verifications as opposed to an actual system line-up.

5. Configuration control weaknesses (see RC-04 & RW-09) contribute to status control effectiveness.

6. Clearance Order practices (see DM-03)

7. Clearance Order recent incidents (see WW-19 ex. # 3)

8. Field problems noted with SDV work on 8/11/94 was a question on whether the other (North SDV) Level Switches not being worked were connected correctly with respect to high and low pressure connection locations. The system engineer resolved this issue on his own through discussions with the vendor and maintenance without reporting it to the Shift Supervisor.

9. Clearance Order adherence (see WW-19 ex. # 1&2)

10. Independent verification (see RB-10)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-05

**DESCRIPTION:** The status of work affecting Limiting Conditions of Operations (LCO) such as outstanding CRs, MWRs, mods, etc., is not tracked in a manner that lends itself to be a ready reference for the SS use in determining readiness for operability.

**CAUSE:**

**EXAMPLES:** 1. The LCO white board in the SS office is the main tool used by the shift. It does not identify all outstanding items or issues open against each LCO.

2. The process to determine if a system is ready to be declared operable following an outage involves several meetings to gather and status the open items that affect a system's operability. This information is not maintained on an ongoing basis.

3. During one 11:00 meeting that was focused on getting Division 2 work completed, the printout of work did not include the AMOT valve which was open against DG-2 operability.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-06

**DESCRIPTION:** Adherance to the intent of program requirements specified in procedures

**CAUSE:**

**EXAMPLES:** 1. CNS Procedure 0.9 'Clearance Orders and Caution Tag Orders' states that it applies to all equipment and work conducted at CNS; however, work is isolated and performed on safety related systems using Special Instructions that do not use a Clearance Order. (see DM-03)

2. While CNS Procedure 0.9 allows the CRO to designate persons to implement a Clearance Order, the practice of allowing other than operators to implement a Clearance Order as a minimum violates normal industry practice.

3. Examples where the basic requirements for changing procedures are not adhered to when dealing with changes to such things as Special Instructions.(see WW-14)

4. The procedure adherence guidance in 2.0.1 (Rev. 21) addresses all the appropriate aspects of procedure adherence. However, the wording used to convey some of the expectations could be subject to misinterpretation unless extra effort is made to ensure personnel understand the meaning. For example: 8.5.1.3 states that more complex or less frequently performed tasks will require "more procedural discipline" and 8.5.1.1 says "procedures are not to be a substitute for common sense." Why not say what is meant by "more procedural discipline," and can "common sense" be used in place of what a procedure says? 8.5.3 uses the words "adversely effect the performance of the procedure" in describing when a TPC shall be initiated. Commonly accepted wording for this expectation in the industry is "cannot be performed as written." (see WW-20)

**PROGRAMMATIC:** An attitude that allows a deviation from procedural intent through justification. In some cases a new process is developed and it is apparently not recognized that requirements, like those addressed in the examples above, are still applicable even in the new process.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** DM-07

**AREA:** OPS

**DESCRIPTION:** Based on a review of the Outage Development Plan O&M 2-1, Key activities required to be completed prior to the start of a refueling outage are not scheduled with sufficient lead time to allow adequate review and planning to be accomplished. This practice leads to crisis management and less thorough completion of activities.

**CAUSE:** The plant's method for handling activities in based on a crisis management approach. Management has not forced a change to this culture by insisting on better planning.

**EXAMPLES:**

1. Outage DCs are not sent for initial site review until within 2 months of the outage start.

2. Procedural changes needed to support the outage are submitted within 2 months of the outage start.

3. Outage DC are submitted for SORC review within 1 month of outage start.

4. Outage scope is not validated until within 2 months of outage start. This is the same time frame that the schedule is sent out for review.

5. PM scope is not scheduled to be identified until several months after the scope freeze date. How ca' there be a scope freeze when even the pre-outage schedule itself doesn't recognize a scope freeze?

6. Personnel interviewed remembered the project being late meeting pre-outage schedule activities including those above and the scope freeze date during preparations for the last refueling outage.

**PROGRAMMATIC:** A lack of appreciation for planning ahead with sufficient time to prepare.
It is unknown whether management is aware of this issue.

**MANAGEMENT:** Not realizing what sufficient planning and preparations means.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** DM-08

**AREA:** OPS

**DESCRIPTION:** Weaknesses in maintaining the Plant Essential Equipment

**CAUSE:**

**EXAMPLES:** 1. The control room HVAC system was not classified as essential (PTM 94-14)

2. Pressure gauges on DG air start are not essential and are being kept isolated (Caution Tag 94-050).

3. Marotta Scientific Controls supplied valves to essential application not treated as safety-related were installed (see OD 94-063).

4. Lockwasher used on RHR Motors supplied as commercial grade were used in an essential (Caution Tag 94-063) application (Caution Tag 94-77)

5. NRC exit on 8/12/94 reported that several containment penetrations were not classified as essential

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** DM-09

**DESCRIPTION:** Adequacy of measures in place to address the numerous areas where silting could be causing problems across the plant.

**CAUSE:**

**EXAMPLES:** 1. Intake structure sparger equipment problems have existed for some time and were only recently addressed.

2. CW flow transmitters indicate 0 GPM and Alert lights are lit due to flow transmitter sensing line plugging (94-2206, 0064, 1907).

3. Condenser 1A2 water box D/P line partially clogged due to silt (94-2787).

4. RHR HX divider plate D/P indicators are pegged low due to plugging from silt.

5. SW pumps are rotated periodically due to silt buildup in them while not running. (see WW-07)

6. Service Water pressure switches plugging (see WW-17)

7. During Shutdown Cooling operations, RHR is being throttled in place of throttling SW because of valve erosion concerns in SW that are aggravated by the presence of silting. In SDC vessel cooldown must be control so the effects of having SW flow not throttled as it was design to be has required the RHR flow through the heat exchanger to be throttle to compensate. However, the controls for the RHR discharge valve that is used to throttle flow is not design to permit throttling. Therefore, the valve is positioned to a partially open position by taking its C/S to open then opening its breaker to stop the valve in a throttled position. This may be contributing to the chugging observed in the RHR system during SDC operations. (see GW-08 & SV-16)

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RB-01

**AREA:** OPS

**DESCRIPTION:** Attended 8/9/94 SRAB meeting to review Rev #23 to emergency plan. Although this item does not appear to meet the threshold listed in section 6.2.B.4 of the T.S., the SRAB review contributed toward improvement in the quality and accuracy of the revision. The comments made in the SRAB meeting should have been captured in the SORC meeting (numerous editorial and organization chart errors). The SRAB review did not appear to address the revision from a management overview or safety impact (however, I believe each member individually assessed these items). The review appeared to be similar to a SORC review.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:** 1. Management expectations of the quality of documents presented to SRAB should be communicated when not satisfied.

2. Not all items need to be presented to SRAB - better use of senior management time.

3. The purpose of a SRAB review of documents should be clearly established (shouldn't be a second SORC) and conclusions documented in SRAB minutes (didn't have opportunity to review minutes of this meeting yet).

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-02

**DESCRIPTION:** The station does not have an effective work control process.

**CAUSE:**

**EXAMPLES:** Attended the 11:15 Daily Outage Schedule Meeting on 8/9/94 and made the following observations concerning the work list:

1. All the maintenance items on the list were on hold due to the need for SORC approval of the work instructions.
2. The only items for 8/10/94 on the list were I & C items, no other department had work items on the list.
3. Some work items were sent to the shop to be worked, but the paperwork was misplaced. Therefore, the jobs did not start and no one was responsible to track these items.
4. The I & C work items for 8/10/94 have special instructions that have not yet received SORC approval.
5. The plan is to swap over to Div II RHR tomorrow, but this may too ambitious because:
   -- Four Div II maintenance jobs are on hold for SORC review of special instructions
   -- During the meeting it was identified that the insulation for the B & D RHR Pump Discharge Lines needs to be installed and non-seismic scaffolding removed prior to the swap. These tasks were not on the list and the insulators are still in training and may need to be escorted.
   -- An engineering decision regarding a Div II battery test is still pending, is not listed as a prerequisite and if required will delay the swap over.
6. Actions required to support the schedule are identified during the meeting but are not captured on an action list for follow-up review.

**PROGRAMMATIC:** 1. A milestone certification for the RHR swap over does not exist. Last minute identification of prerequisites results in outage delays.

2. Management permits jobs to be scheduled by the shops rather than by centralized outage management. Therefore, prerequisites for placing items on the schedule are not always established.

3. A lack of a centralized scheduling process will result in removing components from service numerous times due to a lack of job coordination. This presents unnecessary challenges to operators (numerous unnecessary tagouts) and inefficient use of limited resources.

4. Attendees at meetings are assigned actions that are not captured for followup. This results in a lack of accountability and reduced efficiency due to a need for subsequent reviews to identify previously identified actions.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RB-03

**AREA:** OPS

**DESCRIPTION:** The risk associated with outage work may not receive advance review prior to being placed on the schedule.

**CAUSE:**

**EXAMPLES:** 1. There is not a comprehensive list of authorized work activities at the station. As a result, the SS is required to process and evaluate each work request as it shows up at his office window.

2. The scope of each work request is not fully defined before it reaches the shop (see I & C scope question at 11:15 meeting on 8/9/94 on observation RB-02).

3. Div II work is on hold for special instruction approval and a battery test requirement remains undefined on the day before the scheduled RHR swap over.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-04

**DESCRIPTION:** LCO Tracking

**CAUSE:** A LCO tracking program does not exist (other than white board in SS office).

**EXAMPLES:** 1. Steps 8.3.1.3 and 8.2.1.4 of procedure 0.5, 'Condition Reporting' do not provide SS instructions on where to record an inoperable determination, where to document compensatory actions resulting from a decision that a SSC is inoperable, or where to track LCOs.

2. There is a white board in the SS office used to track LCOs. This is a good initiative by OPS but lacks the rigor of a programmatic approach to tracking LCOs and associated compensatory measures.

3. The white board in the SS office was observed to be completely filled on 8/8/94 and 8/9/94. There was no more space to add additional LCOs. The board was re-written on 8/10/94 which allowed additional space for use.

4. In the SS turnover sheet there is a space provided to list existing LCOs. This must be filled in each shift leaving the once-a-day chance for human error.

5. Existing LCOs do not appear to be communicated station wide. Such communication could aid othe. departments in determining which jobs cannot be worked due to existing LCOs thereby reducing the number of challenges faced by the SS when requests to commence work are made at the SS window.

6. Procedure 2.0.2, step 8.1.2.1, excludes the need for the SS to log inoperable equipment in the SS turnover sheet if the equipment is not required to be operable. Most of the current LCOs on the white board fit this requirement. This could cause a challenge if all LCOs aren't tracked and the plant changes modes.

**PROGRAMMATIC:** An informal LCO tracking system that requires repeated manual listing on a daily basis (for the SS turnover sheet) and on a less frequent basis (white board) can result in a loss of information due to human error. The current system does not provide for the documentation and tracking of compensatory actions. This could result in a T.S. violation if compensatory actions are overlooked. The current system doesn't track mode change LCO's. This will challenge the operator's ability to identify all pre-requisites necessary to support changing plant conditions.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RB-05

**AREA:** OPS

**DESCRIPTION:** Procedure accuracy.

**CAUSE:**

**EXAMPLES:** In Proc. 0.27, "Operability of SSCs," steps 3.1.2 and Page 9 - Note 2 refers to Proc. 0.5.1 'Nonconformance and Corrective Action.' Proc. 0.5.1 was revised on 3/24/94 and 7/27/94 and is now titled 'Disposition and Closure of CAT I Condition Reports.' Proc. 0.27 should be revised to describe the CR system and to resolve any confusion caused by the note on Page 9 of 0.27 (should refer to Proc. 0.5, 'Condition Reporting')

**PROGRAMMATIC:**

**MANAGEMENT:**

**SEQ:** RB-06

**AREA:** OPS

**DESCRIPTION:** Work Control

**CAUSE:** Reliable work schedule does not exist.

**EXAMPLES:** On 8/9/94 H. Hess implemented a 2-day look ahead process on the attached flow chart (see RFI #7054). This is a good first step in the development of a reliable daily schedule at CNS.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-07

**DESCRIPTION:** Operator self-checking, procedure adherence and communications.

**CAUSE:** Excellent operator performance.

**EXAMPLES:** Observed the 8/10/94 performance of procedure 6.3.20.1 - RHR Service Water Booster Pump Test for the B & D pumps and observed strong operator performance by the Control Room Supervisor (Randy Carlson) and BOP Operator (Steve Norris) as follows:

1. Before starting each SW Booster Pump, the BOP Operator demonstrated excellent self-checking by first touching the pump control switch prior to switch actuation.

2. BOP Operator thoroughly reviewed procedure prior to beginning test.

3. BOP Operator clearly communicated with Control Room Operator prior to his leaving Control Room to obtain readings in the Critical Switchgear Room.

4. BOP Operator initiated two Condition Reports as a result of performing this test:
   - -- SW-DPI-359B DP gauge pegged downscale
   - -- Step 8.2.37 gross leakage observed downstream of SW-863.

5. Control Room Supervisor closely monitored the conduct of the test and ensured that condition reports were generated in a timely manner.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**SEQ:** RB-08

**AREA:** OPS

**DESCRIPTION:** Operator unable to observe procedure precautions.

**CAUSE:** Repeated silt blockage of impulse lines affects needed intrumentation.

**EXAMPLES:** Step 5.2 to procedure 6.3.20.1 cautions operator regarding a high differential pressure (dp) concern across RHR HX SW divider plate. At step 8.2.8.3 (and 8.2.28.3) the operator was unable to obtain a reading due to instrument being pegged downscale. Per the operator, this deficiency has existed since the last time this test was performed three months ago.

A computer search shows a history of a frequent need to flush the impulse lines for SW-PPI-359A and SW-DPI-359B. This same computer search shows that engineering intends to replace the 359B sensing lines and closed the outstanding WR (WR 94-1727). The replacement has not yet been made and additional failures have occurred.

**PROGRAMMATIC:** Management's slowness in correcting prolonged instrumentation problems deprives operators of important data necessary to protect a safety system component. A review of the recent history of problems with this dp instrument shows that silt blockage of the impulse lines of this instrument is occurring on a regular basis.

**MANAGEMENT:**

**SEQ:** RB-09

**AREA:** OPS

**DESCRIPTION:** No documented program to require periodic valve lineups.

**CAUSE:**

**EXAMPLES:** Per RFI 6049, there is no procedural requirement to perform periodic valve lineups. Current practice is for the Operations Supervisor to identify need based on recent work. He also has all ECCS, Feed, Condensate, fuel pool cooling and turbine generator valve lineups performed after major outages.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-10

**DESCRIPTION:** Independent verification program.

**CAUSE:**

**EXAMPLES:**

PROCEDURE #: 6.2.1.2.1
PROCEDURE PURPOSE: RWCU Flow Isol.
STEP(S): 8.1.3, 8.1.4, 8.2.3, 8.2.4
COMMENTS: Breakers opened with no independent verification required

PROCEDURE #: 6.2.1.2.1
PROCEDURE PURPOSE: RWCU Flow Isol.
STEP(S): 8.1.17
COMMENTS: Breakers closed with no independent verification before proceeding.

PROCEDURE #: 6.2.1.2.4
PROCEDURE PURPOSE: RWCU Area Hi Temp.
STEP(S): 8.2, 8.23, 8.54
COMMENTS: Breakers opened with no independent verification required.

PROCEDURE #: 6.2.1.2.4
PROCEDURE PURPOSE: RWCU Area Hi Temp.
STEP(S): 8.22, 8.53
COMMENTS: Breakers closed with no independent verification required before proceeding.

PROCEDURE #: 6.2.2.3.2
PROCEDURE PURPOSE: HPCI Area Hi Temp.
STEP(S): 7.4, 7.5
COMMENTS: Breakers opened with no independent verification required.

PROCEDURE #: 6.2.2.6.9
PROCEDURE PURPOSE: RCIC Area Hi Temp.
STEP(S): 8.2.1, 8.2.2
COMMENTS: Leads lifted with no concurrent verification required.

PROCEDURE #: 6.2.2.6.9
PROCEDURE PURPOSE: RCIC Area Hi Temp.
STEP(S): 8.3, 8.18

*31-Aug-94*

COMMENTS: Breakers opened with no independent verification required.

PROCEDURE #: 6.2.2.6.9
PROCEDURE PURPOSE: RCIC Area Hi Temp.
STEP(S): 8.16
COMMENTS: Breakers closed with no independent verification required.

**PROGRAMMATIC:**

Section 8.14 of Procedure 2.0.1, "Operations Department Policy," establishes CNS's Independent Verification requirements. The established requirements have numerous exceptions regarding when independent verification is needed. The effect of these exceptions is that the proper selection and operation of breakers, valves and leads need not be verified for each operation. Step 8.14.1 of this procedure waives the need for independent verification for clearances affecting non-safety related system components and safety-related components that are not in the main flow path.

Whenever breakers are operated for testing, no procedural requirement is established to verify that the correct breaker has been (or is being) operated each time before proceeding. This could result in the incorrect breaker being operated.

Although breakers and leads are independently verified as one of the final steps in the procedure, they are not verified each time they are operated or installed. The incorrect installation or operation during earlier steps in the procedure could significantly affect the ability to perform the procedure, could affect the operation of other plant equipment and could affect personnel safety.

Technicians lift leads with no procedural requirement to have another person concurrently verify that the lead about to be lifted is the correct lead each time the lead is lifted. This practice could result in an incorrect lead being lifted with no opportunity for a second person to catch the error ahead of time.

Technicians land leads on terminals without concurrent verification that the lead and locations are correct each time the lead is landed. This could result in a lead being landed on the wrong terminal before a second person has the opportunity to detect the error.

The issue was discussed with station personnel who indicated an interest in the "dual concurrent verification" process for application at CNS. Such a process can greatly reduce, and possibly eliminate, instances where incorrect breakers are operated and where incorrect installation and removal of electrical jumpers and leads occur.

The established practice of not verifying the opening of breakers (or lifting of leads) overlooks the real potential for removing an incorrect piece of equipment from service or cause an inadvertent actuation of an electrical circuit due to an incorrect lead or terminal selection. This practice can also result in a hazard to personnel if work is performed on components that were incorrectly isolated for maintenance - regardless of the nuclear safety aspects of the system involved.

**MANAGEMENT:**

*31-Aug-94*

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-11

**DESCRIPTION:** Technical Specification Compliance

**CAUSE:** In discussions with operations department personnel it was explained that the CNS philosophy is to station an operator adjacent to the opened breaker with instructions for the operator to close the breaker when so instructed. Procedure 0.26, "Surveillance Program," Step 8.1.9 states that "Generally, tech spec related equipment is not considered to be inoperable during surveillance testing."

**EXAMPLES:** CNS renders containment isolation valves inoperable by opening breakers with the valve in the open position without entering the action statements specified in the Technical Specifications. Examples of this practice include:

PROCEDURE #: 6.2.1.2.1
PROCEDURE PURPOSE: RWCU Flow
STEP(S): 8.1.3, 8.1.4
COMMENTS: RWCU-MO-15 breaker open, with the valve open.

PROCEDURE #: 6.2.1.2.1
PROCEDURE PURPOSE: RWCU Flow
STEP(S): 8.2.3, 8.2.4
COMMENTS: RWCU-MO-18 breaker opened with the valve open.

PROCEDURE #: 6.2.1.2.4
PROCEDURE PURPOSE: RWCU Area Temp.
STEP(S): 8.2, 8.54
COMMENTS: RWCU-MO-15 breaker opened with the valve open.

PROCEDURE #: 6.2.1.2.4
PROCEDURE PURPOSE: RWCU Area Temp.
STEP(S): 8.23
COMMENTS: RWCU-MO-18 breaker opened with the valve open.

PROCEDURE #: 6.2.2.3.2
PROCEDURE PURPOSE: HPCI Area Temp.
STEP(S): 7.4
COMMENTS: HPCI-MO-15 breaker opened with the valve open.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

PROCEDURE #: 6.2.2.3.2
PROCEDURE PURPOSE: HPCI Area Temp.
STEP(S): 7.5
COMMENTS: HPCI-MO-16 breaker opened with the valve open.

PROCEDURE #: 6.2.2.6.9
PROCEDURE PURPOSE: RCIC Area Temp.
STEP(S): 8.3
COMMENTS: RCIC-MO-16 breaker opened with the valve open.

PROCEDURE #: 6.2.2.6.9
PROCEDURE PURPOSE: RCIC Area Temp.
STEP(S): 8.18
COMMENTS: RCIC-MO-15 breaker opened with the valve open.

**PROGRAMMATIC:** Although steps 8.6.2.1 of the "Operations Department Policy" procedure (procedure 2.0.1) states that "personnel should not override automatic actions of engineered safety systems unless continued operation in automatic will result in unsafe plant operation", operators performing certain routine procedures override the automatic isolation feature of certain containment isolation valves without entering the appropriate LCO.

This practice resulted from the application of step 8.1.9 of procedure 0.26, "surveillance program" which states "Generally Tech Spec related equipment is not considered to be inoperable during surveillance testing."

There are no procedural instructions requiring the operator to enter the applicable limiting conditions for operation whenever the automatic isolation function for isolation valves are defeated for surveillance purposes.

The CNS Technical Specifications do not provide for allowable out of service times (AOT) for the performance of required testing. AOT Technical Specifications are a part of standard Technical Specifications and could be incorporated into the CNS Technical Specifications.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** RB-13

**DESCRIPTION:** Procedure validation oversight.

**CAUSE:** Special Instructions do not receive a validation prior to performance.

**EXAMPLES:** In response to a DSAT request for copies of CNS procedures that describe the procedure validation program, I received copies of procedure 0.4, "Procedure Change Process," procedure 0.22, "Emergency Operating Procedure Maintenance Program," and copies of CNS EOP Validation and EOP Verification programs.

Based on the review of these documents, it is clear that there are established procedural requirements to "validate" EOP and EOP support procedures and to "walkdown" all other CNS procedures that meet the criteria established in section 8.2.2.5 of procedure 0.4.

A major deficiency in the validation process appears to be that Special Instructions are not subject to the "validation" or "walkdown" requirements.

**PROGRAMMATIC:** Special Instructions are outside the CNS "validation" or "walkdown" process. Special Instructions have been issued and difficulties with their performance resulted due to a lack of a validation process prior to [illegible]

**MANAGEMENT:**

**AREA:** OPS **SEQ:** WW-02

**DESCRIPTION:** Either management expectations concerning communication of responsibilities have not been adequately communicated to training supervisors, or management expectations concerning communication responsibilities were limited.

**CAUSE:**

**EXAMPLES:** A training supervisor expressed to staff personnel a displeasure in that he had been told that the Site Manager had decided that the lack of proper communication issue was a training problem. The training supervisor felt the finger had been pointed only at training. After discussions with the Training Manager this item is closed.

**PROGRAMMATIC:** Policy confusing or incomplete.

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-04

**DESCRIPTION:** Plant cleanliness in infrequently traveled areas is lacking attention.

**CAUSE:** Substandard expectations.

**EXAMPLES:**
1. 'A' and 'B' Reactor Feed Pumps have numerous oil leaks that are not contained.
2. 'A' Reactor Feed Pump oil conditioner has a thick layer of dust and grime.
3. A rope is hanging from the overhead in the angle valve room (in front of dry well personnel air lock).
4. Air sampler and HP meter left on floor by dry well personnel air lock.
5. Back corner of CRD pump area moderately clean.
6. A container of refrigeration oil is located in the compressor housing of the CO 2 unit.
7. Welding cables are hung on a support in the HPCI room.

**PROGRAMMATIC:** Clear expectations not proceduralized leading to substandard performance.

**MANAGEMENT:** Inadequate management oversight.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-06

**DESCRIPTION:** Specific expectations for the shift supervisor maintaining a 'stand back' overview have not been implemented into training or to operations supervision..

**CAUSE:** Specific expectations have not been communicated to the training department nor to all operations supervision. The operations manager indicated this had been operations expectations for approximately two years.

**EXAMPLES:** 1. The following observations were noted during a simulator dynamic exam:

A. The shift supervisor was used by the control room supervisor to check the status of plant systems.
B. The shift supervisor positioned switches on at least four occasions.

2. During the instructors/evaluators critique session, there was a lot of discussion on what was the expectation. This session included:

A. Training Supervisor and 2 Operations Supervisory personnel. During these discussions there were different opinions of philosophy.
B. Additional Operations Supervisors interviewed were unaware that Shift Supervisors were not to become involved with control board manipulations.

**PROGRAMMATIC:** There is no set policy that has been communicated to all levels of Operations and Training.

**MANAGEMENT:** Inability to set a policy and communicate that policy.

**AREA:** OPS **SEQ:** WW-07

**DESCRIPTION:** Observed station operator using bar to rotate SW pump shaft. Operators placed switch in "pull to lock." Subsequently, on 8/7/94 a night order entry informed Operations personnel to discontinue this practice. Apparently, several years ago a seal water modification and the practice of swapping service water pumps daily should have resulted in the discontinuance of rotating the SW pump shaft by hand. Rotating the SW pump shaft by hand resulted in the essential equipment losing its auto-start feature every six hours.

**CAUSE:**

**EXAMPLES:** See description.

**PROGRAMMATIC:** Failure to recognize the importance of maintaining essential equipment operable.

**MANAGEMENT:** Inadequate management oversight.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-08

**DESCRIPTION:** The Control Room Envelope Test has been terminated due to winds < 4 mph. Further indicates the engineering basis for this criteria is justified in a response to the NRC dated 8/5/94. This item is closed.

**CAUSE:**

**EXAMPLES:** The test was terminated on 7/28/94 and 7/30/94 due to test conditions not being met.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** OPS **SEQ:** WW-09

**DESCRIPTION:** The USAR 10.3.5.1 states that the Rad Waste Building is kept at a minimum negative pressure of 0.25" wg. Does SP 6.3.17.18 meet this criteria?

After a review of provided design drawings and procedures this item is considered closed. See RFI 6073 which contains a copy of 2.2.46 and dwg 2021

**CAUSE:**

**EXAMPLES:** SP 6.3.17.18 lists acceptance criteria for Radwaste 2 as < or = to -0.25 and Radwaste 1 as < or = to -0.10. Apparently Radwaste 1 maintains the Radwaste Building clean area at a higher pressure than the Radwaste Building's contaminated area (Radwaste 2 which maintains -0.25). Does this operation meet the intent of the USAR?

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-10

**DESCRIPTION:** Specific expectations concerning the shift supervisor ensuring that ED functions are performed at the onset of an accident are not clearly defined and reinforced consistently in training. Deleted after interviews with Training Supervisor, Station Operators and review of procedure 2.0.5 which provides responsibility of Shift Communicator.

**CAUSE:**

**EXAMPLES:**

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** OPS **SEQ:** WW-11

**DESCRIPTION:** A service water pump was secured approximately one minute following a start following completion o second lift adjustment on 8/2/94. This item was documented for information only. No further action is required.

**CAUSE:**

**EXAMPLES:** The pump was secured due to MCB amps indicating 45 amps and switch gear indicating 41 amps.

**PROGRAMMATIC:**

**MANAGEMENT:**

## DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-13

**DESCRIPTION:** A lead wire seal is used for normally sealed open/closed valves associated with reactor safety and are installed in such a manner as to prevent valve operation without destroying the seal. The policy for noted discrepancies is to repair the deficient condition only. The root cause for broken, missing or improperly installed seals is not determined to preclude repetition.

**CAUSE:** Expectations are to repair the seal not to prevent further deficiencies.

**EXAMPLES:** Since 4/16/94 seven deficiencies have been noted. Three of these were observed on 7/29/94 during plant walkdown by the DSAT. The last quarterly valve seal audit was performed 6/21/94.

**PROGRAMMATIC:** The seal wire program does not seek to prevent recurrence.

**MANAGEMENT:** High management tolerance to repeating noted deficiencies.

**AREA:** OPS **SEQ:** WW-15

**DESCRIPTION:** Following the discovery of 2 mispositioned valves on the Reactor-Recirc system, six systems were selected for performance of valve line-ups. Subsequently additional valves were found mispositioned. The Operations Manager informed the Site Manager that all line-ups would be performed since the additional valves were discovered. The Site Manager questioned if that was needed and wanted a specific scope determined. There is no procedural guidance for conducting system line-ups when returning from an extended shutdown or outage.

Follow-up information as of 8/16/94. To date there have been a total of 65 components (valves, dampers, or breakers) designated as mispositioned. System line-up are continuing.

**CAUSE:** The process for performing valve lineups is at the discretion of the Operations Supervisor, not a standard plant philosophy that is proceduralized.

**EXAMPLES:** See description.

**PROGRAMMATIC:** See Cause description.

**MANAGEMENT:** Management has not set the expectations to proceduralize this problem.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-16

**DESCRIPTION:** Operations supervision considered #2 diesel generator inoperable based on NED's input documented (on a CR) that an emergency light was not installed in an area requiring breaker manipulation to achieve alternate shutdown capability. The Shift Supervisor and Operations Supervisor decided to declare the D/G inoperabie based on Operations not being able to take credit for station operators carrying flashlights. After more detailed observations, interviews and a review of the OD process Operations Shift Supervisors determines the operability of equipment based on operational knowledge with input from support groups(e.g. Engineering, NED, etc.). This item is considered closed.

**CAUSE:**

**EXAMPLES:** See description.

**PROGRAMMATIC** Operations personnel appear hesitant to justify operability based on sound operational philosophy when an engineer's strict interpretation of the code may not be justified.

**MANAGEMENT:** Establish an operational philosophy that is consistent.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-19

**DESCRIPTION:** Adherence to clearance order system.

**CAUSE:**

**EXAMPLES:** 1. On 8/4/94 clearance order 94001011, Step 2 for removal had not been initialed, yet the verification had been performed.

2. Clearance order 94001011 had been completed (danger tags removed); however, two placement steps had not been initialed and one placement step had not been verified. Note: this clearance order had been issued in order to flush 'A' RHR which was not performed due to a service water system air leak.

3. Recent incidents have occurred concerning Clearance Orders:
a. A pole top disconnect was closed while an active Clearance Order was still hanging requiring the disconnect to be in the open position (DR 93-469, discovery date 10/18/93).
b. Clearance Order 93-376 required SW-V-36 to be positioned 'Open'. When the tagout was issued, the valve was positioned 'closed' (DR 93-035, discovery date 3/14/93).
c. Found valves SA-V-58A and IA-V-166B closed in violation of Clearance Order 94-099 (Instrument Air Dryer 'A'), which required these valves to be open (DR 94-101, discovery date 2/7/94).

**PROGRAMMATIC:** Management expectations/procedures/policies are not strict enough.

**MANAGEMENT:** Management does not fully recognize the significant importance of the Clearance Order system.

**AREA:** OPS **SEQ:** WW-20

**DESCRIPTION:** Procedural guidance concerning the conduct of procedural adherence contains statements which appear to weaken the management expectations for procedure adherence.

**CAUSE:**

**EXAMPLES:** Conduct of operations procedure 2.0.1 paragraph 8.5.1.2 states, "procedures provide a consistent method of performing a task and are meant to aid, rather than burden, personnel performing the given task." Conduct of maintenance procedure 7.0.4 paragraph 2.10.19 defines skill of the craft as, "job tasks which are within the normal capabilities and training of the craftsman, which typically do not require procedures or special instructions to perform."

**PROGRAMMATIC:** Policies are not strict enough.

**MANAGEMENT:** Substandard expectations.

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS **SEQ:** WW-21

**DESCRIPTION:** Observations during the performance of SP 6.3.20.1, RHR SWBP Surveillance:

1. Steps 8.2.1 and 8.2.2 vent the "B" and "D" pump casings respectively. This venting is conducted prior to starting the pumps for testing. Is this a good practice or is there a history which indicates air is commonly present in the pump casing? The station operator knew of the need for venting to prevent water hammer, but was not aware of any history of problems with these pumps.

2. No air was present when venting the casing of "B" pump.

3. Step 8.2.2 states "Open SW-96, RHR SWBP IC Vent (C-882), until air-free water flows and then close valve." However, a hose is attached to the vent line inside the floor drain preventing the observance of air or water flow. In discussions with the station operator, he felt confident that he could determine the presence of air by holding the vent line as he opened the valve. Also, he would ensure any air was removed by leaving the valve open for an extended period of time.
It appears this was established as a good practice. While this is a good practice it should be stressed to station personnel that they should be observant of any air that may have accumulated and report any accumulations to their supervisor for resolution.

**CAUSE:**

**EXAMPLES:** See description.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS/T **SEQ:** WW-25

**DESCRIPTION:** Inadequate management oversight of training activities.

**CAUSE:**

**EXAMPLES:** 1. Operations Manager expectations for the Shift Supervisor maintaining a "stand back" overview during an emergency event has not been implemented into training as indicated by the following simulator observations:

a. The Shift Supervisor (SS) was used by the Control Room Supervisor to check the status of plant systems.

b. The SS repositioned switches on at least four occasions.

c. During the critique, which included a Training Supervisor, two Operations supervisory personnel, and two instructors, there were different opinions of philosophy concerning SS expectations. This critique ended with Training investigating whether a change in expectations had occurred.

2. CNS Directive 54, Management Overview of Training and Evaluation Activities, was issued in 1992 to improve feedback methods and monitoring of accredited training activities by plant management and supervisory personnel. This directive was developed in response to an INPO-Identified problem (Problem : CPR-IMCHT 2-1) noted in the 1992 INPO Accreditation Renewal evaluation conducted on the Technical Training programs. The INPO evaluation noted weaknesses in the content and implementation of several Technical Training programs. INPO concluded that deficiencies in identifying training problems and managing corrective actions contributed to the weaknesses which indicated a need for more effective feedback methods and monitoring of training activities.

CNS Directive 54 requires the direct involvement of managers and supervisors (Attachment A provides a specific list of supervisory positions requiring direct involvement in training activities) is to be utilized to ensure consistency and provide documentation for followup as required. The Department Manager and Supervisors are responsible for personally observing a training session (at least one hour in length) in one of the accredited training programs within their department at least each calendar quarter. This observation will include completion of the observation form (Attachment B). Since Directive 54 was issued, the Maintenance Manager and Maintenance Supervisor positions have not performed any training observations. Additionally, the Engineering Manager has not performed any observations since 1992. Observations of engineering and maintenance work activities during the DSA indicated that some work quality deficiencies may be attributed to training inadequacies.

3. The issuance of ACAD 91-017, Guidelines for Training and Qualifications of Engineering Support Personnel, included industry expectations for engineering training programs to develop position-specific guidelines effective 1/1/93 for selective engineering positions. Until an INPO inquiry of ACAD 91-017 status in the fourth quarter of 1993, the engineering program supervisor was not aware of the training requirement. Subsequently, guidelines generic to the INPO document were created and distributed as needed. Currently, 40 position-specific guidelines have been drafted, yet not incorporated into the training

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes



program.

**PROGRAMMATIC:**

**MANAGEMENT:**

**AREA:** OPS/T **SEQ:** WW-27

**DESCRIPTION:** The HP continuing training program is limited in that it does not build upon the fundamentals training program.

**CAUSE:**

**EXAMPLES:** There is no clear definitive continuing training program that expands upon the fundamental training program. The current program needs to be expanded to include industry issues, technology changes, in-depth theory, and HP management input. Currently, continuing training is conducted in a less formal environment by HP supervision. The process that HP supervision currently employs uses weekly meetings to cover industry events. This is an excellent process to improve communications and expectations, additionally, HP supervision uses this format as an opportunity for discussing procedure changes and new equipment. However, the process of expanding on that information in more detail using the training program processes needs to be improved. Currently, the HP continuing training program is limited in that it does not build upon the fundamental training program.

**PROGRAMMATIC:**

**MANAGEMENT:**

# DIAGNOSTIC SELF ASSESSMENT OBSERVATIONS
## Field Notes

*31-Aug-94*

**AREA:** OPS/T

**SEQ:** WW-28

**DESCRIPTION:** Positive attributes noted during DSAT observations.

**CAUSE:**

**EXAMPLES:**

1. CNS has taken a proactive approach in reducing the percentage of contaminated areas. This was evident during plant tours and in discussions with the Operations Manager.

2. The fidelity of the simulator based on 5 simulator observations and discussions with the simulator group concerning programs in place to ensure the simulator represents actual plant response and a simulated control room environment. No simulator fidility problems were noted during the 5 observations.

3. The effort and current emphasis placed on improving operational communications in the Control Room is a positive attribute. This is evident by observations of simulator critiques , interviews with Operation shift personnel, and self assessments performed by off-shift Shift Supervisors. Although observed operational communications were good there is still room for improvement. Operation management, supervision, and Training management and supervision recognize their goal has not been achieved and has programs in place to continue improving and reinforcing their operational communication.

**PROGRAMMATIC:**

**MANAGEMENT:**