U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/90005(DRP)

Docket No. 50-440 License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant, Unit 1

Inspection At: Perry Site, Perry, Ohio

Inspection Conducted: February 28 through April 16, 1990

Inspectors: P. L. Hiland

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Approved By: P. R. Pelke, Acting Chief
Reactor Projects Section 3B

5/3/90
Date

Inspection Summary

Inspection on February 28 through April 16, 1990 (Report No. 50-440/90005(DRP))
Areas Inspected: Routine, unannounced safety inspection by resident inspectors of licensee action on previous inspection items; evaluation of QA program implementation; evaluation of self-assessment capability; information notice followup; licensee event report followup; engineered safety feature walkdown; monthly surveillance observation; monthly maintenance observations; operational safety verification; and onsite followup of events.
Results: Of the ten areas inspected, one violation for which a Notice of Violation was not issued, was identified in the area of licensee event report followup (paragraph 6.); two violations, for which Notices of Violation were not issued were identified in the area of onsite followup of events (paragraph 11.b.5.). As discussed in those paragraphs, the licensee met the criteria stated in 10 CFR 2, Appendix C, Section V.G.1 for not issuing a Notice of Violation. One Unresolved Item was identified in the area of maintenance observations (paragraph 9.b.) concerning the adequacy of maintenance controls/prioritization. The continued inoperability (6 months) of an emergency service water screen wash pump resulted in the licensee declaring an ALERT on April 3 when the redundant system failed.

For this inspection period, the area of plant operations was considered a strength based on routine observations of plant evolutions and the inspectors review of operator response to events. The area of maintenance and surveillance activities was considered adequate; however, the inspectors identified concerns with the adequacy of maintenance oversight that may have failed to recognize the potential impact of degraded support equipment (paragraph 9.b.). The inspectors considered the licensee's investigation and followup corrective action to events to be adequate with the appropriate level of management involvement. In general, the inspectors considered the licensee's implementation of security and radiological control programs to be a strength based on routine observations throughout the inspection period. The inspectors considered the licensee's emergency planning to be adequate based on observations made during the April 3 ALERT declaration.

At the conclusion of the report period, licensee management was aware of the identified open items and were taking appropriate actions.

DETAILS

1. Persons Contacted

a. Cleveland Electric Illuminating Company (CEI)

A. Kaplan, Vice President, Nuclear Group
*M. Lyster, General Manager, Perry Plant Operations Department (PPOD)
*D. Cobb, Senior Operations Coordinator, PPOD
V. Concel, Manager, Technical Section, Perry Plant Technical Department (PPTD)
*W. Coleman, Manager, Operations Quality Section, Nuclear Quality Assurance Department (NQAD)
M. Gmyrek, Manager, Operations Section, PPOD
H. Hegrat, Compliance Engineer, Nuclear Support Department (NSD)
S. Kensicki, Director, PPTD
*R. Newkirk, Manager, Licensing and Compliance Section (NSD)
R. Stratman, Director, Nuclear Engineering Department (NED)
F. Stead, Director, NSD
*D. Takacs, Acting Director, NQAD
*M. Cohen, Manager Maintenance Section, PPOD

b. U. S. Nuclear Regulatory Commission

*P. Hiland, Senior Resident Inspector, RIII
G. O'Dwyer, Resident Inspector, RIII
T. Colburn, Perry Project Manager, NRR
B. Drouin, Reactor Engineer, RIII
S. Stasek, Resident Inspector, Fermi, RIII

*Denotes those attending the exit meeting held on April 18, 1990.

2. Licensee Action on Previous Inspection Findings (92701)(92702)

a. (Closed) Violation (440/89022-03(DRP)): Inadequate Corrective Actions to Control Overtime. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.2.2, the licensee was not adhering to their administrative controls for approving overtime. A previous violation had been issued in Inspection Report 50-440/88012 for similar problems with the licensee controlling plant personnel overtime. Since the corrective action for the 1988 violation was not effective, the NRC staff issued the subject violation.

The licensee responded to the subject violation in letter PY-CEI/NRR-1071L, dated October 11, 1989, in a timely manner. As stated in that response, the licensee revised Plant Administrative Procedure (PAP)-110, "Shift Staffing and Overtime," to clarify the use of overtime deviations. In addition, the licensee provided training on the subject violation to all managers and first line

supervisors. Training of personnel affected by the revision to PAP-110 was conducted through the licensee's procedure revision training process.

The root cause identified by the licensee for failure to implement established administrative controls over staff overtime was attributed to incomplete procedural compliance and inadequate procedural guidance (ref.: Audit 89-12, AR0002 rev. 1). The inspectors concurred with the licensee's root cause assessment; however, existing procedural guidance appeared to have been adequate had strict compliance been required.

In order to determine the effectiveness of the licensee's corrective action, the inspectors reviewed "time-cards" for all Operations Department personnel. The review covered the time frames of January 1 through March 15, 1990. In general, the inspectors noted licensee compliance with established overtime guidelines. A few (4) "Overtime Deviation Requests" were required during an unexpected forced outage. The inspectors noted that proper approval had been obtained for those deviations.

Based on the inspectors' review of the licensee's corrective actions taken in response to the subject violation and the inspectors' verification that those corrective actions were effective, this item is closed.

b. (Closed) Open Item (440/89022-04(DRP)): Operator Aids. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.2.2, the licensee control of operator aids was not effective in ensuring their adequacy or accuracy. The licensee responded to this item in letter PY-CEI/NRR-1043L dated July 29, 1989, Section 2.1.2.4, stating that: in addition to correcting specific operator aid deficiencies, a walkdown of all in-plant control panels was to be conducted to identify other uncontrolled or inadequate operator aids.

Licensee memorandum G. Chasko to M. Gmyrek dated December 21, 1989, stated that a walkdown of all plant areas was completed. In addition to in-plant control panels, the licensee expanded the scope of the walkdown to include any hand-written component numbers or any "graffiti" in the plant. The licensee stated that all handwritten discrepancies had been removed and that permanent labels, where required, were being prepared for permanent plant installation.

During the report period, the inspectors performed a walkdown of control panels in the main control room and other safety-related buildings to verify completion of the licensee's response to this item. The results of that walkdown indicated that the licensee was effectively controlling operator aids. Based on the actions taken by the licensee to improve control of operator aids and verification that actions were completed as stated by the licensee, this item is closed.

c. (Closed) Open Item (440/89022-08(DRP)): Implementation of Corrective Actions. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.2.8, the licensee's corrective actions following a 1988 "special evaluation" of root cause for personnel errors that had resulted in a number of reactor trips had not all been effectively implemented. The licensee responded to the subject item in letter PY-CEI/NRR-1043L, dated July 29, 1989. In that response, the licensee stated that a re-evaluation of the status of recommendations from their 1988 "special evaluation" would be performed.

The inspectors reviewed licensee memorandum M. Gmyrek to Operations Section dated December 27, 1989, which discussed licensee management actions that had been taken to specifically address all of the "special evaluation" report recommendations. In addition, the memorandum detailed actions taken to improve communications between management and the operating crews. The inspectors noted that each of the "special evaluation" recommendations was responded to by Operations Management. Recommendations were incorporated if appropriate; however, some recommendations were not incorporated after licensee evaluation. The basis for not incorporating recommendations was clearly stated or was an obvious management prerogative. In addition, the inspectors reviewed licensee actions to improve communication within the Operations Section. Based on review of Operations Management responses to operator problems and/or concerns that had been expressed at "Management-Operator" meetings, the inspectors concluded that, as stated in the licensee's response to the subject item, improvements in communications had been made. The inspectors also noted through routine review of "Daily Instructions" that the Superintendent of Plant Operations was effectively communicating and responding to issues and concerns generated within the plant Operations Department.

Based on the actions taken by the licensee to re-evaluate recommendations from their 1988 "special evaluation," this item is closed.

d. (Open) Open Item (440/89022-10(DRP)): Equipment Trend Analysis. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.3.6, the inspectors considered the licensee's effectiveness in equipment trending based on maintenance history to be diminished due to incomplete maintenance history records. The licensee responded to this item in letter PY-CEI/NRR-1043L dated July 29, 1989. In that response, the licensee stated that their Reliability Information Tracking System (RITS) would be implemented during the fourth quarter of 1989. That system implementation was intended to improve the quality and quantity of root cause/failure analysis.

Licensee memorandum J. Register to E. Root, dated January 3, 1990, stated that the RITS program was incorporated into the licensee's

mainframe computer. In addition, training was provided to potential RITS users and a "users'" manual was published and issued as a controlled document.

However, the inspectors noted that audit Action Request PA90006-001 dated April 3, 1990, was initiated by the licensee to establish required administrative controls over the RITS program. This item will remain open pending the inspectors review of the licensee's response to that audit action request.

e. (Closed) Unresolved Item (440/89022-16(DRP)): Vacuum Breaker Surveillance Testing. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.4.2, the inspectors concluded that Surveillance Instruction (SVI)-M16-T0414 was technically deficient. That conclusion was based on the fact that the subject surveillance instruction directed that drywell vacuum breakers be opened with their power operators before relief settings were measured and verified. The licensee responded to this item in letter PY-CEI/NRR-1043L, dated July 29, 1989, stating that "as-found" setpoints were not adversely affected by first cycling the drywell vacuum breakers with their power operators.

Although the licensee provided a reasonable technical basis for their "no-impact" on as-found data conclusion, further review with the inspectors and cognitive licensee personnel noted that approved changes to the licensee's Inservice Test Program required full stroke of the drywell vacuum breakers at least once per 18 months with the plant in COLD SHUTDOWN. Therefore, the need to equalize pressure across the vacuum breakers could be accomplished by other means than pre-exercising. The licensee revised SVI-M16-T0414, revision 2, via temporary change number 4, dated December 28, 1989. That change incorporated instructions to lock-open the drywell airlocks (normal cold shutdown condition) and to open the vacuum breaker isolation valves. Those procedural instructions would allow vacuum breaker pressure equalization without the need to pre-exercise.

Based on the licensee's actions to revise the surveillance instruction such that as-found data would be accurately obtained, this unresolved item is closed.

f. (Closed) Open Item (440/89022-17(DRP)): Work Package Rejection Rate. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Section 3.5.4, the inspectors concluded that a continued large work order rejection rate was due to a lack of management attention.

The inspectors reviewed licensee memoranda E. Parker to D. Graneto, dated May 16, June 14, July 24, 1989, and licensee memorandum L. Minter to M. Cohen dated December 5, 1989. The subject of those memoranda was the evaluation and analysis for work order rejection rates between April 1 and October 31, 1989. The work order

rejection rates were reduced from the DET reported high of 32 percent to 3 to 9 percent, except for the month of July 1989, which had a 16 percent work order rejection rate.

The inspectors considered the continued lower work order rejection rate sufficient indication that adequate licensee management attention was devoted to improving the work order process. This item is closed.

g. (Closed) Open Item (440/89022-18(DRP)): Root Cause Analysis Program. As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, Sections 3.5.7 and 3.6.8, the inspectors concluded that several weaknesses in the licensee's root cause analysis program existed. The licensee responded to this item in letter PY-CEI/NRR-1043L dated July 29, 1989. The response detailed the licensee's initiatives for improving root cause analysis, timeliness of corrective actions, and equipment failure analysis.

As detailed in licensee memorandum D. Conran to H. Hegrat dated February 9, 1990, the licensee's enhancements to improve corrective action effectiveness since January 1988 included the following:

(1) Enhanced documentation in work orders.

(2) Establishment of an Incident Response Team.

(3) Engineers, Maintenance Planners, Supervisor and Event Investigators trained in HPES, MORT and K-T Techniques.

(4) Condition Report Program enhancements which included:

(a) Lowering the threshold for condition report initiation.
(b) Emphasizing corrective action effectiveness.
(c) Improving CR/LER trending.

(5) Maintenance Self Assessment which also identified, established, and/or enhanced:

(a) Quality of documentation.
(b) Trending and problem identification.
(c) Thirteen week Rolling Schedule.
(d) Functional equipment grouping codes.
(e) Plant System Status Report.
(f) Work order categories/priorities.
(g) Forced outage ready to work list.
(h) Automatic Tag-Out System (partially implemented, but still under development).
(i) Outage critiques.

(6) Implementation of Reliability Information and Tracking System (RITS) used to trend data from corrective maintenance.

(7) Improved status feedback mechanisms.

(8) Training on initiation criteria.

Since the DET report was issued in May 1989, the inspectors have observed/reviewed several of the above corrective action enhancements (Ref: Inspection Reports (IR) 50-440/89017, /89023, /89026, and /90002). Work orders reviewed during numerous maintenance inspections were found to contain adequate documentation. Effectiveness of the licensee's "Incident Response Team" was considered adequate during the inspectors followup review of a January 7, 1990, reactor trip (Ref: IR50-440/90002). The inspectors review of licensee event reports, condition reports, action requests, and licensee responses to NRC Notice of Violations or Deviations indicated adequate training of investigators and a reasonable threshold for initiating corrective action.

The inspectors reviewed the licensee's third and fourth (draft) quarter 1989 report for condition report and licensee event report trends. Those reports appeared comprehensive and critical of negative trends. The inspectors noted that those quarterly trend reports received appropriate level of licensee management review with assignment of recommendations to the responsible section. Status of previous recommendations was included in the trend report.

The inspectors observed on-going maintenance self assessment by reviewing daily maintenance activities, planned maintenance activities in the licensee's thirteen week rolling schedule, and through review of the first refuel outage critique and the January 1990 forced outage critique. In general, the inspectors considered the maintenance self assessments to be adequate with a clear goal of improving maintenance activities to better support overall plant operations. In addition, the inspectors noted that the Reliability Information System was implemented. However, the inspectors noted that adequate attention to prompt corrective maintenance on an emergency service water screen wash pump may have led to an ALERT declaration on April 3, 1990, as discussed below in paragraphs 9.b and 11.b.(2).

Based on the inspectors observations and review of the licensee's corrective action and root cause analysis programs as discussed above, this item is closed.

h. (Open) Open Item (440/89022-19(DRP)): Independent Safety Engineering Group (ISEG). As detailed in the Diagnostic Evaluation Team (DET) report for the Perry Nuclear Power Plant dated May 1989, the inspectors concluded that the ISEG had limited effectiveness due to a lack of management attention and support. The licensee responded to this item in letter PY-CEI/NRR-1043L dated July 29, 1989. That response stated that a new ISEG "charter" was to be in place in 1989.

Appendix B, Revision 2, of the Perry Nuclear Power Plant Quality Assurance Plan, "Independent Safety Engineering Group Charter," was issued on November 6, 1989. The inspectors noted that the revised charter defined the function, composition, and responsibilities of ISEG and met the requirements of Technical Specification 6.2.3. The inspectors reviewed several ISEG reports (89-005, 89-007, 89-009, and 90-002) since the licensee revised the ISEG charter; however, the inspectors had not completed a review of the ISEG effectiveness in accordance with Inspection Manual procedure 40500, "Evaluation of Licensee Self Assessment Capability." This item will remain open pending the inspectors further review of ISEG effectiveness.

i. (Closed) Open Item (440/88020-03(DRP)): Loss of All Rod Position Indication. This item was previously reviewed by the inspectors in Inspection Report 50-440/89017(DRP), dated August 18, 1989, paragraph 2.h. At the time of that review, the inspectors noted actions taken by the licensee to proceduralize methods of obtaining control rod position indication following loss of a power supply. However, the inspectors did not document or discuss with licensee management staff expectations that Technical Specification action statements be adhered to regardless of the existence of an alternate method of determining control rod position.

NRR memorandum M. Virgilio to E. Greenman dated March 20, 1989, clarified the staff's expectations on actions to be taken by the licensee in response to the inspectors questions following a December 12, 1988, event at Perry. During that event, a 5-volt DC power supply was lost resulting in a loss of the rod display module (RDM) and the operator control module (OCM) (Ref: Inspection Report 50-440/88020, paragraph 7.b.(2)).

For the December 12, 1988 event, the loss of both the RDM and OCM resulted in the inoperability of the rod position indication system (RPIS) and the rod control and information system (RCIS), respectively. Under these conditions, normal insertion/withdrawal of control rods was not possible. Control rods could be inserted by a manual or automatic scram.

First, since Technical Specifications indicated that control rod insertion was required in lieu of "no-action" when accompanied by a loss of all rod position indication, the inspectors requested a clarification from the NRC staff. The following was provided:

> "Before responding to Region III's concerns, a brief discussion of the intent of the two applicable Specifications is pertinent. The intent of Specification 3.1.3.1 is that all (or nearly all) control rods should be operable. The intent of Specification 3.1.3.5 is that at least one RPIS should be operable or that a control rod with an inoperable position indicator should be moved to a position with an operable position indicator. The Basis for these two Specifications states that the occurrence of eight (or more) inoperable control rods could be indicative of a generic problem and the

reactor must be shut down (emphasis added) for investigation and resolution of the problem. The Perry event was an unusual event that, among other things, clearly resulted in more than eight inoperable control rods. In fact, all of the control rods were inoperable. Therefore, entering Action Statement c of Specification 3.1.3.1 would have led to the reactor being placed in at least Hot Shutdown within the next 12 hours. This result would meet, therefore, both the scope and intent of the two applicable Specifications.

For the Perry event, it is not obvious that control rods could not or did not receive erroneous insert or withdrawal signals from the failed systems (the RDM, the OCM, the RPIS and the RCIS). Thus, the exact state of the reactor was not absolutely known during the event. On this basis, NRR cannot recommend a no-action position, that is, leaving the reactor in its assumed pre-event position. In fact, if control rods had moved because of erroneous signals, the no-action position could cause fuel thermal limits to be exceeded so that fuel failures could possibly result. The Technical Specification position is clearly the preferred position because it places the reactor in a known, safe condition. Here we have no evidence that the failed systems would affect the trip function of the Reactor Protection System or the scrammability of the control rods. If they did, this event would be an ATWS precursor. The disadvantage of tripping the reactor is, of course, the challenge to safety systems. All things considered, we advise against the no-action position and prefer the Technical Specification position. In addition, we conclude that a reactor trip is not unconservative and that the subsequent potential for stuck rods and out-of-sequence rod movement that could result in hot spots and potential core damage should not be of concern. However, for a Perry type of event, we suggest a possible modification to the Technical Specification position if the action statement has been entered to bring the reactor to the Hot Shutdown condition within 12 hours. This possible modification is to reduce power by reducing recirculation flow, consistent with the applicable flow control line and stability restrictions, if a portion of the 12 hours is used to perform trouble-shooting before bringing the reactor to a Hot Shutdown condition. This reduction in power without resorting to control rod movement has the advantage of ensuring ample margin to the thermal limits."

Second, during the December 12, 1988 event, the licensee was able to obtain control rod positions off of control room back panels on a rod-by-rod basis. The inspectors requested clarification if the rod position obtained from the back panel readings was sufficient for not entering Action Statement of Technical Specification 3.1.3.5 or exiting the Action Statement once operators were setup to monitor back panel rod indication. The following was provided:

"Our response to the second of Region III's two concerns is straightforward. It is not permissible, as the Specification is now written, to obtain rod position indication by back panel readings on a rod-by-rod basis to prevent entering the Action Statement of Specification 3.1.3.5 or to allow exiting the Action Statement once operators are setup to monitor back panel rod indication. In this instance, restoration of the normal rod position indication is required. However, credit could be taken for using the back panel as an alternative method for obtaining rod position indication if a licensee followed the usual procedures for modifying Technical Specifications. This means that the licensee would have to (1) evaluate the back panel as an alternate means of rod position indication including establishing a time interval for performing the rod position readings and the development of procedures, and (2) submit the evaluation and a proposed Technical Specification modification to the NRC. If an evaluation led to a favorable Safety Evaluation, the NRC would issue a license amendment authorizing the use of the back panel as an alternative means for determining rod position for Specification 3.1.3.5. It should be noted that for the loss of the 5 volt DC power supply, this would only permit exiting TS 3.1.3.5, the LCO and associated ACTION STATEMENTS of TS 3.1.3.1 would still apply."

The inspectors discussed the above clarifications and recommendations with the Manager Plant Operations during the report period. This item is closed.

No Violations or deviations were identified.

3. Evaluation of Licensee Quality Assurance Program Implementation (35502)

To evaluate licensee Quality Assurance (QA) program implementation, the inspectors conducted an in-office analysis of previous NRC inspection reports, SALP reports, licensee corrective actions for NRC inspection findings, and licensee event reports (LERs).

Based on the inspector's review, Region III management determined that no significant weaknesses existed in licensee QA program implementation which warranted special regional followup during the remainder of the SALP 10 period. However, several weaknesses were identified during the in-office review which will receive continued NRC scrutiny during the SALP 10 period. The weaknesses are described below:

a. Poor communications among plant staff had been a contributing factor to several plant events during the period that was reviewed. Recent examples included a November 25, 1989, lack of communications between the operating staff, the reactor engineers, and the shift technical advisors which delayed the correct analysis of failed scram time test results for control rod 34-47 for approximately 8 hours. Poor communications between plant and reactor operators on

January 31, 1990, resulted in the failure to un-isolate loop seal level instrumentation, the subsequent overpressurization of the loop seal, and an Offgas System transient.

b. Maintenance and Surveillance activities were involved in 16 of 32 LERs in 1989 and 3 of 4 LERs in 1990. Personnel error inattention to detail was the cause of several maintenance/surveillance errors. Examples of personnel errors were: (1) maintenance personnel removed the wrong fuses which caused the loss of control power to the turbine driven feedwater pumps and resulted in a reactor scram on low level (LER 90001); and (2) control power transformer to the "A" emergency service water (ESW) discharge valve was burned out during the performance of a surveillance when technicians jumpered the wrong terminals resulting in the inoperability of "A" ESW system (LER 89027). Inattention to detail was evidenced by several inadequate surveillance instructions (SVI) or inadequate SVI revisions. Examples include: (1) poor SVI revision led to the isolation of the RCIC steam supply valve during the performance of a surveillance on the leak detection system logic (LER 89003); (2) a procedural deficiency resulted in incorrect calibration of the scram discharge volume water level high channel (LER 89022) and the inappropriate Division 2 under-voltage time delay relay settings (LER 89021); (3) motor operated valves were not stroked open/closed as required (LER 90003) resulting in an entry into Technical Specification (TS) 3.0.3; and (4) Unit 2 snubbers were not included in required snubber surveillances (LER 90004).

There were also several examples of plant staff performing activities without being fully aware of impacting plant conditions which resulted in plant events. The isolation of drywell (DW) instrument air to perform maintenance on the DW personnel air lock resulted in the closure of three of four main steam isolation valves on June 27, 1989 (Inspection Report No. 440/89017(DRP)). Maintenance personnel isolated an alternate radiological process sampler to perform troubleshooting on the permanently installed process sampler. The alternate sampler was required to be available by Technical Specification when the permanent sampler was inoperable (LER 89029). Maintenance personnel transferred an Automatic Bus Transfer (ABT) device from its emergency to normal supply, which was providing power to "A" RPS alternate bus. RPS bus "A" was utilizing its alternate power source, and "B" RPS bus was deenergized for maintenance. The transfer of the ABT caused a momentary loss of power to the Balance of Plant (BOP) isolation relays supplied by the "A" RPS bus, which resulted in an outboard BOP isolation (LER 89012).

c. A concern about the thoroughness and timeliness of licensee technical submittals to the NRC was noted in the SALP 8 and 9 reports. Recently, the NRC experienced some problems with the licensee's initial Technical Specification change request (RCIC Delta-T) in February 1990.

The licensee's communications and maintenance/surveillance weaknesses described above will be monitored by the NRC during routine inspections for the purpose of early trend identification.

Any violation of NRC requirements resulting from the events described above were noted in appropriate NRC inspection reports. No violations were identified as a result of the in-office review.

4. Evaluation of Licensee Self-Assessment Capability (40500)

During the report period, the inspectors observed several on-site review committee meetings to evaluate that organization's effectiveness. For the meetings attended, the inspectors considered one of more of the following attributes: degree of plant management involvement and/or domination of conversations; if constructive discussion occurred; if the majority of the committee consistently voted the same as the chairman; if the committee was biased toward operation or safety; and, if the committee used design basis, FSAR, or vendor technical manuals for their determinations in addition to the technical specifications.

The inspectors attended on-site review committee meetings 90-024 (March 8), 90-027 (March 27), 90-028 (March 22), and 90-029 (March 29). In preparation for the attended meetings, the inspectors reviewed draft submittals of items that were submitted for the on-site committee approval. Items presented to the on-site review committee included safety evaluations, licensee event reports, proposed revisions to technical specifications, licensee condition reports, temporary changes to procedures, scram report 1-90-1, procedural revisions, and design change packages.

The inspectors noted that the required quorum of committee members were present for each meeting observed. The meetings were conducted in a professional manner following an approved agenda. Each item presented to the committee was done so by a cognizant individual (sponsor) who remained available to answer committee members questions. The inspectors noted that committee members conducted constructive discussions free from any influence by a single individual or line organization.

For the meetings attended, the inspectors noted that items approved were done so by a unanimous vote of committee members. Items that were not acceptable to all committee members were "tabled" until outstanding questions and/or concerns were resolved. The inspectors noted that the committee used various technical information and did not rely solely on technical specifications and the judgement of management in their deliberations.

Based on the inspectors observations of items rejected or "tabled" at the attended meetings, the inspectors concluded that the on-site committee viewed plant safety as a primary concern. The inspectors concluded the on-site review committee was effectively implementing the requirements of technical specifications.

No violations or deviations were identified.

5. NRC Information Notice Followup (92701)

During the report period, the inspectors performed a review of licensee actions related to selected Information Notices issued by the Office of Nuclear Reactor Regulation. The review included verification that each information notice was reviewed for applicability; the information notices received proper distribution to appropriate personnel; and if applicable, the scheduling of appropriate corrective action was completed.

a. (Open) Information Notice No. 88-24 (440/88024-IN): Failure of Air Operated Valves Affecting Safety Related Systems.

The subject information Notice (IN) dated May 13, 1988, was received by the licensee on May 23, 1988. In accordance with the licensee's administrative controls, the subject IN was distributed to the I&C Mechanical department for review. That review concluded that the referenced ASCO model solenoids were not in use at Perry. Since some application problems with other model ASCO valves were identified at a similar RIII facility, the inspectors requested the licensee to review their safety-related solenoid valve application again.

That additional evaluation focused on the maximum operating pressure differential (MOPD) that ASCO solenoids were designed for compared to the normal operating instrument air pressure of 120 psig. Two valves (1B33-F419 and -F420) were identified where their MOPD of 110 psig was below the normal instrument air pressure. The licensee concluded that those two "sample valves" could fail with no impact on safe shutdown capabilities of the system or plant. The inspectors requested the licensee to continue and broaden their review process to assure that other safety-related solenoid valves (not limited to ASCO) were not subject to the concerns identified in the subject IN. At the conclusion of the report period, that additional review was still in progress. This item will remain open pending the inspectors review of the licensee's completed actions.

b. (Closed) Information Notice No. 90-18 (440/90018-IN): Potential Problems With Crosby Safety Relief Valves Used On Diesel Generator Air Start Receiver Tanks.

The subject information notice (IN) was issued on March 9, 1990, and was initiated in part from an event that occurred at the Perry Nuclear Power Plant. As documented in licensee Condition Report (CR) 89-060, dated February 19, 1989, the Division 1 emergency diesel generator (EDG) air receiver tank relief valves inadvertently actuated after mechanical agitation. During the licensee's investigation it was identified that the installed Crosby relief valves had not been seismically qualified since the system designer, Transamerica Delaval, considered that component to be mechanically

passive. Based on the event occurrence, the licensee reclassified the relief valves as active components and performed seismic qualification tests.

The licensee did not consider the identified relief valve deficiency to be reportable under the provisions of 10 CFR 21; however, licensee letter PY "T" SO-5445, dated March 13, 1989, advised the current responsible organization, Cooper Industries, of the event and identified corrective actions taken or planned. As stated in the subject IN, Cooper Industries submitted a 10 CFR 21 report on January 17, 1990.

Licensee letter PY-CEI/NRR-1043L, Section 2.1.6.8, dated July 29, 1989, detailed corrective actions taken and planned for the EDG relief valves in response to an NRC Diagnostic Evaluation Team (DET) report dated May 1989. During this report period, the inspectors reviewed the current status of corrective actions with cognizant licensee personnel.

The subject IN indicated that a single relief valve actuation caused both of the redundant Division 1 air receiver tanks to depressurize As documented in CR 89-060, the sequence of events were: While a plant operator was attempting to reseat the first actuated relief valve, the second relief valve was mechanically agitated by the operator's movements causing it to actuate also. At Perry, the air cross connect valve between the redundant receiver tanks is maintained closed and was closed during the February 19, 1989, event.

Corrective actions completed included:

- Air receiver tank relief valves were reoriented in the vertical plane to satisfy seismic test results.
- Hanger rods that were located in close proximity to the relief valves were removed to prevent mechanical agitation.
- Air receiver relief valves were reclassified as active components in the licensee's "Q-List."
- Air receiver relief valves were seismically qualified by the licensee (Ref: Farwell & Hendricks, Inc. Report No. 10470, dated April 24, 1989).
- Reviewed safety related plant systems to confirm classification of relief valves as active or passive.

In addition to the above, the licensee identified that the installed Crosby relief valves had a 60 percent blowdown upon lifting at the 275 psig setpoint. The 120 psig "reset" value was 30 psig below the EDG 150 psig lockout. The licensee issued a purchase order to procure new relief valves that will reset above the EDG lockout

value. The licensee informed the inspectors that the new relief valves were still being manufactured and that upon receipt, replacement of the currently installed valves would be implemented.

Based on the inspectors review of current licensee actions with regard to the EDG air receiver relief valves and the planned modification to replace with upgraded components, this item is closed.

No violations or deviations were identified. One item remained open pending completion of licensee activities.

6. Licensee Event Report Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event report was reviewed to determine if reportability requirements were fulfilled, immediate corrective actions were accomplished in accordance with Technical Specifications and corrective action to prevent recurrence had been accomplished.

(Closed) LER 87061-00: Failure to Maintain The Inner Drywell Airlock Door Closed While The Outer Drywell Door Was Inoperable. In August 1987, a mechanical failure of the drywell outer personnel airlock door occurred at the time Health Physics personnel were taking surveys inside of the drywell. With the inoperable outer door, Health Physics personnel exited the drywell by opening the inner drywell airlock door. Failure to maintain at least one drywell personnel airlock door closed was a Violation (440/90005-01) of Technical Specification 3.6.2.3. However, a Notice of Violation was not issued in accordance with 10 CFR 2, Appendix C, Section V.G.1 because: the violation was identified by the licensee; this specific violation would normally be classified at a Severity Level IV or V; the violation was reported by the licensee in accordance with 10 CFR 50.73; the licensee completed corrective actions as discussed below; and it was not a willful violation.

The root cause for the failure of the outer door was identified by the licensee to have been the design of the airlock door closing mechanism causing overstress and eventual failure of bushings. Initially the licensee proposed to modify the closing mechanism to obtain better alignment. However, in licensee memorandum W. Farrell to H. Hegrat dated March 3, 1990, the corrective action was revised based on actual operating practices and maintenance experience since the August 1987 failure. As stated in that memorandum, minimum usage of the drywell airlock doors occur during plant operation; the drywell airlock doors are blocked open during plant outages to allow access into the drywell; and the mechanical failure had not recurred. The licensee revised preventative maintenance instruction 89-115 and -116 to include inspection of the mechanical linkage bushings. That inspection was performed during the Spring 1989 (RFO-1) outage and was scheduled for the Fall 1990 (RFO-2) outage.

Although the licensee revised the corrective action stated in the subject report, the inspectors concluded that appropriate corrective actions had been completed. Based on the inspectors review of NUREG-1022, Supplement No. 1, Question 13.2, the licensee's decision not to submit a supplemental report appeared reasonable. This item is closed.

One violation was identified for which a Notice of Violation was not issued in accordance with 10 CFR 2, Appendix C, Section V.G.1.

7. Engineered Safety Feature (ESF) Walkdown (71710)

During this inspection period, the inspectors performed a detailed walkdown of the accessible portions of train "B" of the residual heat removal (RHR) system. The system walkdown was conducted using Valve Lineup Instruction (VLI)-E12, Revision 4, System Operating Instruction (SOI)-E12, Revision 6, "Residual Heat Removal System (Unit 1)," and piping and instrumentation diagrams (P&IDs) for the RHR System.

During the walkdown, the licensee identified the "B" train as operable. The inspectors took into account that during the walkdown the "B" train was in various modes of operation and therefore in various valve lineups.

During the system walkdown, the inspectors directly observed equipment conditions to verify that hangers and supports were made up properly; appropriate levels of cleanliness were being maintained; piping insulation, heaters, and air circulation systems were installed and operational; valves in the system were installed in accordance with applicable P&IDs and did not exhibit gross packing leakage, bent stems, missing handwheels, or improper labeling; and, that major system components were properly labeled and exhibited no leakage. The inspectors verified that instrumentation associated with the system was properly installed, functioning, and that significant process parameter values were consistent with normal expected values. By direct visual observation or observation of remote position indication, the inspectors verified that valves in the system flow path were in the correct positions as required by the various modes of operation that were required; power was available to the valves; valves required to be locked in position were locked; and, that pipe caps and blank flanges were installed as required.

Based on the walkdown performed as described above, the inspectors concluded that the "B" train of RHR was properly aligned to perform its intended engineered safety function.

No violations or deviations were identified.

8. Monthly Surveillance Observation (61726)

For the below listed surveillance activities the inspectors verified one or more of the following: testing was performed in accordance with procedures; test instrumentation was calibrated; limiting conditions for operation were met; removal and restoration of the affected components

were properly accomplished; test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test; and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Surveillance Test No.	Activity
SVI-1B21-T0032D, Revision 3	"Reactor Vessel Steam Dome Pressure and Reactor Vessel Pressure (RHR Cut-in Permissive) Channel D Functional For 1B21-N678D"
SVI-D17-T0040-D, Revision 2	"Main Steam Line Radiation Monitor 1D17-K610D"
SVI-E12-T5368, Revision 1, TCN 4	"ECCS/LPCI Pump B Start Time Delay Channel Functional"
SVI-P53-T6305, Revision 1	"Lower Containment Airlock In-Between The Seals Test"
SVI-P53-T6312, Revision 1	"Upper Primary Containment Airlock In-Between The Seals Test"

Details

a. During The Performance of Step 5.1.11 of Surveillance Instruction (SVI) -D17-T0040-D, Revision 2, "Main Steam Line Radiation Monitor 1D17-K610D," on March 24, 1990, an unexpected half scram was received. The unit supervisor and instrumentation and calibration (I&C) personnel made a preliminary determination that the procedure probably needed a caution before Step 5.1.11 warning that a half scram may be received when performing this step. The unit supervisor directed that the SVI be terminated; however, the equipment was still considered operable since the problem appeared to be procedural. The unit supervisor also directed the lead technician to initiate a condition report to investigate the problem and confirm that it was a procedural problem and to change the procedure if necessary. Revision 3 to SVI D17-T0040-D was issued on March 23, 1990. That revision included a precaution in Section 2.12 identifying the potential to receive reactor protection system half scrams during performance of the SVI. In addition, Section 5.1.11 clearly stated that a half scram signal would be generated.

b. During the inspectors observation of SVI-E12-T5368, the test was terminated when the expected relay timing did not occur. The technicians performing the test suspected test equipment problems

and informed the on-shift senior reactor operator. A procedural problem was subsequently identified concerning the use of recently modified test equipment. SVI-E12-T5368 was revised on April 9, 1990, via Temporary Change 5 to correct the test equipment procedural deficiency.

No violations or deviations were identified.

9. Monthly Maintenance Observation (62703)

Station maintenance activities of safety related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety related equipment maintenance which may affect system performance.

The following specific maintenance activities were observed/reviewed:

Details

a. Work Order 90-1266, was written because the fuel handling building ventilation exhaust fan "C" motor was running warmer and noisier than normal and the trend of vibration data indicated potential degraded motor bearings. On March 27, 1990, the fan motor was meggered and it passed Generic Electrical Instruction, Revision 1, "Performing Insulation Resistance Checks." Maintenance personnel disassembled the fan motor and on March 28, replaced the inboard and outboard sets of motor shaft bearings.

b. Work Order 88-5560, Revision 2, which directed the replacement of the O-rings, a pitted shaft and the shaft sleeve on screen wash pump, OP49C002B.

The inspectors reviewed licensee actions regarding the maintenance activity being conducted on emergency service water screen wash pump OP49C002B. That safety-related component had been removed from service on November 15, 1989, to perform maintenance.

The purpose of screen wash pump OP49C002B was to remove debris, by water spray, from associated traveling screen OP49D001B. At Perry, there are two traveling screens located in the emergency service water pumphouse. As detailed in Perry Updated Safety Analysis Report (USAR), Section 9.2.1, the traveling screens were designed to meet the requirements for Safety Class 3 and Seismic Category I equipment. In accordance with the licensee's administrative controls, a "potential" limiting condition for operation (LCO) tracking sheet was initiated on November 15, 1989, to indicate that the LCO may be "active" if a loss of redundant screen wash pump OP49C002A occurred. As discussed below in paragraph 11.b.(2), the "A" screen wash system failed on April 3, 1990, requiring the licensee to declare an ALERT until repairs were made to restore that component to service.

Since screen wash pump OP49C002B was a safety related component and it performed an indirect support function on safety related traveling screen OP49D001B, the inspectors reviewed the licensee's basis for concluding that no affect on system operability occurred when screen wash pump OP49C002B was removed from service. Perry USAR Table 9.2-13, "Traveling Screens," provided design information that indicated sufficient screen area was available with only one traveling screen in service (i.e. the two traveling screens provided 100 percent redundancy). The inspectors noted that Perry USAR Appendix 9A, "Fire Protection Evaluation Report," Tab 9A.7 Section G8, indicated that the emergency service water system had operated for two months prior to initial plant operation without availability of traveling screens. Emergency service water pump operation during that time span was not degraded. In addition, the licensee indicated that traveling screen OP49D001B could be manually cleaned if required.

As defined in Perry Technical Specification 1.29, a "system" shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function and when all <u>necessary</u> auxiliary equipment <u>required</u> for the "system" to perform its function are capable of performing their related support function. The "system" supported by the screen wash pumps was emergency service water (ESW). The ESW operability requirements are stated in Perry Technical Specification 3.7.1.1. Based on the fact that traveling screen OP49D001A was capable of performing the required screening function; the USAR information that indicated no increase in differential pressure across the traveling screens after a two month period of pump operation without traveling screens; the ability to compensate for the inoperable screen wash pump on traveling screen OP49D001B by manual cleaning; and the inspectors direct field observation that no affect on screening capabilities had occurred with screen wash pump OP49C002B removed from service, the inspectors noted that the licensee's basis for concluding no immediate "system" impact was reasonable. However, the inspectors also noted that the licensee had not defined a maximum out-of-service time for one of the two traveling screens. The inspectors requested the NRR staff in Region III memorandum E. Greenman to J. Zwolinski dated March 19, 1990, to review actions taken

by the licensee and the acceptability of those actions to comply with Perry Technical Specifications. The inspectors will document the results of that staff review in a future inspection report.

The inspectors noted that the extended length of time screen wash pump OP49C002B was out of service was apparently due to delays in procurement of repair parts. The inspectors were concerned that adequate management attention may not have been focused on this safety related component due to a lack of awareness of its safety significance. The inspectors based their concern on the fact that the licensee's monthly performance report for December 1989 did not list the screen wash pump as an out of service component even though its out of service time had exceeded the 30 day criterion. In addition, the inspectors noted that the licensee's January 1990 monthly performance report identified the screen wash pump as an out of service component; however, the potential impact on plant operations was not accurate. The inspectors noted that these "management tools" depend on accurate input from several line organizations. At the conclusion of the report period, the inspectors were still evaluating whether the licensee's maintenance program was effectively implemented commensurate with the safety significance of the out of service screen wash pump. Pending completion of the inspectors review, the adequacy of corrective actions taken following removal of screen wash pump OP49C002B from service on November 15, 1989, is considered an Unresolved Item (440/90005-02(DRP)).

One Unresolved Item was identified concerning adequacy of corrective maintenance.

10. Operational Safety Verification (71707)

a. General

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during this inspection period. The inspectors verified the operability of selected emergency systems, reviewed tag-out records and verified tracking of Limiting Conditions for Operation associated with affected components. Tours of the intermediate, auxiliary, reactor, and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for certain pieces of equipment in need of maintenance. The inspectors by observation and direct interview verified that the physical security program was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, 10 CFR, and administrative procedures.

b. Details

(1) During the inspection period, the inspectors walked down the accessible portions of the following systems to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning, and calibrated.

- High Pressure Core Spray (HPCS) System
- Emergency Diesel Generator (EDG) - Division 3
- Emergency Service Water (ESW) - Division 3
- 120 VDC Batteries - Division 3

The following were noted during the walkdowns:

(a) Excessive leakage was evident from ESW pump 1P45-C002. Water was observed coming from the shaft seal area and running down to a nearby floor drain. Subsequently, the licensee determined that the gland seal leakoff line had become blocked. The blockage was removed and leakage subsequently decreased.

(b) Inlet pressure gauge 1P45-R0237 to ESW strainer 1P45-D003 was observed to be indicating approximately 18 psi. With the system in operation and the strainer outlet pressure gauge reading 74 psi, the inspector concluded that the inlet gauge was inoperable and possibly valved out. The licensee subsequently confirmed the inspector's determination that the gauge was inoperable.

(c) The strainer outlet pressure gauge 1P45-R0236, although apparently indicating properly, was missing its front faceplate glass cover.

(d) Switch 1E22-N724 on the Division 3 EDG had a deficiency tag hung on it dated December 21, 1988 describing that it was "undersized for operating pressure." When approached on this matter, the licensee determined the tag was associated with nonconformance report NEDO 3565-2 which had, prior to the inspectors review, been dispositioned as "use as is."

(e) A Xertex Sensall Control sonic type level transmitter which provided local indication of Division 3 fuel oil tank level was observed to be reading 99 percent full. However, a local low level alarm light was also illuminated on the unit. When brought to the attention of the operating authority, review determined that the local low level alarm light was not routinely used to check tank level; control room annunciation logic was separate from

the local alarm circuit. A work request was subsequently initiated to adjust the alarm setpoint such to clear the local alarm light.

(f) A substantive amount of combustible material (wood) was noted in the ESW pumphouse. Examples included approximately a dozen 4x4s, apparently once used as dunnage, stored in a location near the entrance to the diesel fire pump room, a storage area for scaffolding parts that included flats of plywood, and a plywood enclosure approximately 3x3x5 feet placed to enclose a strainer control panel adjacent to the ESW Division 3 line. The inspector contacted the licensee's fire protection group and questioned the effect of these additional combustibles on the analyzed fire loading for that area.

In response, the fire protection inspection group performed an inspection of the ESW pumphouse. The plywood enclosure was found to be an acceptable installation. However, the excess dunnage was nonapproved and involved enough material to potentially impact the limitations specified in plant administrative procedure PAP-1913, "Control of Transient Combustibles." The licensee's fire protection group removed the subject dunnage. They also determined the scaffold storage area had not been established in accordance with plant administrative procedures in that a review per PAP-1913 had not been performed. Condition Report 90-049 was initiated by the licensee to document corrective actions taken. Subsequent tours of the affected area by the inspectors noted that the licensee had taken effective corrective actions.

(2) During a walkdown of control room panels on March 5, 1990, the inspectors noted that the control switch for the shutdown cooling outboard isolation valve (E12-F008), had an information tag hung indicating it had been manually torqued closed to 580 ft-lbs. Followup discussions with control room operators revealed that the valve had been torqued to that value in accordance with engineering recommendations to eliminate leakage past the seat with the unit at power. Control room operators stated that to reopen the valve required use of a specific procedure. However, during a subsequent walkdown of the remote shutdown panel (RSP) on March 8, the inspector observed that although control of E12-F008 was also available at the RSP, no information tag was hung on its respective RSP control switch. The inspectors noted that the requirement to hang an information tag at the RSP was contained in Administrative Procedure PAP-1404, "Information Tags." The licensee took corrective action to place an information tag at the RSP.

No violations or deviations were identified.

11. Onsite Followup of Events at Operating Power Reactors (93702)

a. General

The inspectors performed onsite followup activities for events which occurred during the inspection period. Followup inspection included one or more of the following: reviews of operating logs, procedures, condition reports; direct observation of licensee actions; and interviews of licensee personnel. For each event, the inspectors reviewed one or more of the following: the sequence of actions; the functioning of safety systems required by plant conditions; licensee actions to verify consistency with plant procedures and license conditions; and verification of the nature of the event. Additionally, in some cases, the inspectors verified that licensee investigation had identified root causes of equipment malfunctions and/or personnel errors and were taking or had taken appropriate corrective actions. Details of the events and licensee corrective actions noted during the inspectors' followup are provided in Paragraph b. below.

b. Details

(1) Loss of Containment Integrity

On March 16, 1990, at about 8:00 p.m. (EST), while operating at 100 percent power, the licensee declared a loss of containment integrity due to exceeding allowable secondary containment bypass leakage. At Perry, the Technical Specification limit for allowable bypass leakage (0.0504 La) is 5051 standard cubic centimeters per minute (SCCM). The known bypass leakage prior to the event was 2506 SCCM.

Upon identification that a post accident sample system containment penetration was leaking water past the closed isolation valves at a rate of 0.132 gpm, the licensee performed initial calculations to determine equivalent bypass leakage and concluded the Technical Specification limit was not met. The licensee entered the action statement of Technical Specification 3.6.1.1.1 which required restoration within 1 hour or be in HOT SHUTDOWN within the next 12 hours. At about 3:20 a.m. on March 17, the licensee commenced an orderly shutdown.

While performing the plant shutdown, additional measurements were made to determine leakage of water at normal system pressure of 1024 psig. The initial calculations were performed assuming 125 psig. With the containment isolation valves closed and sensing normal system pressure, the measured leakage was quantified at 0.176 gpm. That leakrate was then calculated to an equivalent "bypass" leakage and added to the known bypass

leakage of 2506 SCCM. The total bypass leakage was calculated to be 4454 SCCM which was below the allowed value of 5051; therefore, the licensee exited the SHUTDOWN action statement at about 5:00 a.m. At the time the action statement was exited, plant power had been reduced to about 50 percent. The licensee returned to 100 percent power at about 7:00 a.m. The licensee notified the NRC operations center of the event via the ENS at about 4:00 a.m. on March 17 within one hour of commencing the power reduction.

The inspectors observed the licensee's actions during the event from the main control room. In addition, the inspectors reviewed the calculations performed as documented in Field Change Report (FCR) No. 13704 dated March 17, 1990. Based on the observations and reviews performed, the inspectors concluded that the licensee had complied with Technical Specifications for this event.

(2) ALERT Due To Loss Of Emergency Service Water

On April 3, 1990, at about 2:30 a.m., while operating at 100 percent power, the licensee declared emergency service water (ESW) systems "A" and "B" inoperable due to component failures. At the time of event occurrence, testing of Division 1 emergency diesel was in progress due to the failure of the Division 3 emergency diesel (High Pressure Core Spray). As discussed below in paragraph 11.b.(4), the Division 3 emergency diesel had been declared INOPERABLE on April 2, 1990, due to degraded fuel oil; therefore, Technical Specifications required surveillance testing be performed on the Division 1 and 2 emergency diesels. During that test performance, a gasket failed on an inspection cover for the ESW-"A" pump discharge strainer. With the gasket failure, a water spray developed that wetted several Division 1 electrical components in the immediate vicinity of the ESW-"A" pump strainer including a 480 volt motor control center.

The immediate action of plant operators was to declare ESW-"A" and associated systems inoperable. With the Division 1 emergency diesel generator inoperable (cooled by ESW-"A"), Technical Specification Action statement 3.8.1.1.e required that within 2 hours all systems, subsystems, trains, components, and devices dependent on the remaining OPERABLE emergency diesel be verified OPERABLE. The ESW-"B" screen wash pump had been inoperable since November 15, 1989, as discussed above in paragraph 9.b. The water spray from the failed gasket had caused the failure of ESW-"A" screen wash system. With both "A" and "B" screen wash systems inoperable, the licensee considered the traveling screen support function to be inoperable and declared ESW-"A" and "B" inoperable.

Since the licensee had determined that ESW-"A" and "B" were INOPERABLE, the associated supported emergency core cooling system (ECCS) were declared INOPERABLE. Those systems included Residual Heat Removal (RHR) trains A, B, and C, and Low Pressure Core Spray (LPCS). In addition, all three emergency diesel generators were INOPERABLE; Division 1 and 2 because of the loss of ESW-"A" and "B" and Division 3 which was already INOPERABLE due to degraded fuel oil.

In accordance with Emergency Plan Instruction (EPI)-A1, "Loss of Shutdown Functions, Decay Heat Removal or Reactivity," Revision 3, the licensee declared an ALERT at about 2:30 a.m. The ALERT declaration was made due to the loss of ESW-"A" and "B". The inspectors monitored the licensee's actions in the Control Room Operations Support Center, and Technical Support Center from the time of arrival on site (about 3:00 a.m.) until event termination at about 6:00 a.m. The inspectors noted that ESW-"B" was running throughout the event and did not exhibit any degradation due to the loss of the support function provided by screen wash pumps "A" and "B". Repairs were made by maintenance teams working out of the Operations Support Center. Repairs performed included: ESW-"A" pump discharge strainer inspection cover gasket was replaced; a shorted control power transformer in the wetted Division 1 480 volt motor control center was replaced; inspections for grounded equipment were performed with a "megger" at the 480 volt motor control center; and the repaired equipment was functionally tested prior to declaring it OPERABLE.

At about 5:30 a.m., following successful post maintenance testing of affected equipment, ESW-"A" and "B" were declared OPERABLE. In addition, the supported emergency core cooling systems were also declared OPERABLE. At about 6:00 a.m. the licensee terminated the ALERT after consultation with State and local officials.

The licensee initially informed the NRC operations center of this event via the ENS at about 3:15 a.m. A continuous communication link via the ENS was maintained with the licensee until event termination at 6:00 a.m. The inspectors will review the licensee's root cause determination for this event in a subsequent report following the licensee's submittal of the licensee event report required by 10 CFR 50.73.

(3) <u>High Pressure Core Spray System Inoperable</u>

On April 5, 1990, at about 4:00 a.m. (EDT), while operating at 100 percent power, a loss of a safety function occurred when the high pressure core spray (HPCS) system was declared inoperable. While performing a routine surveillance activity, the measured vertical pump displacement (2.5 mil) exceeded the surveillance acceptance criteria and HPCS was declared

inoperable. However, upon further review of the actual method used to measure the HPCS pump vertical displacement, the licensee noted that during the "failed" surveillance the proper location was not used by plant technicians when measuring vertical displacement. The surveillance was repeated the morning of April 5 with acceptable results. The HPCS system was then declared operable; however, as discussed below, the HPCS system was declared inoperable again at about 1:00 p.m. on April 5 due to its associated emergency diesel generator exceeding the technical specification allowed out of service time of 72 hours.

The licensee informed the NRC operations center of the event via the ENS at about 5:15 a.m. on April 5, 1990.

(4) High Pressure Core Spray System Inoperable

On April 5, 1990, at about 1:00 p.m. (EDT), while operating at 100 percent power, the licensee declared the high pressure core spray system inoperable due to its associated emergency diesel generator being inoperable greater than 72 hours. The Division 3 emergency diesel had been declared inoperable on April 2 when routine sampling identified the Division 3 fuel oil storage tank contained greater than .05 percent sediment. At that time, in accordance with technical specifications, the Division 3 emergency diesel was declared inoperable and the licensee began actions to replace the fuel oil. The licensee completed replacement of the Division 3 fuel oil and the high pressure core spray system was declared operable on April 6, 1990.

The licensee informed the NRC operations center of this event via the ENS at about 1:30 p.m. on April 5.

(5) Loss of Control Room Ventilation Safety Function

On April 11, 1990, at about 8:35 a.m. (EDT), with the plant operating at 100 percent power, a loss of control room ventilation safety function occurred. At the time of event occurrence, the "A" train of control room ventilation system had been declared inoperable (but functional) for planned maintenance activities on an associated support system. The "B" train of control room ventilation was operable and in standby. As part of a routine preventive maintenance activity, surveillance technicians requested control room operators to align the control room ventilation system to prevent spurious starts while changing out cassette tapes on air intake monitors. The plant operators placed the "A" train (inoperable but functional) in its emergency recirculation mode and placed the "B" train in a secured status by placing its control switch in the pull-to-lock position. Plant surveillance technicians then proceeded with the cassette tape changeout.

About 10 minutes after establishing this ventilation lineup, control room operators recognized that an error had been made and that the control room ventilation trains were both inoperable. The "A" train had been declared inoperable due to the planned maintenance on its support system (cooling water) and the "B" train was made inoperable by moving its control switch to the pull-to-lock position (i.e. the "B" train was not capable of responding to automatic signals). Control room operators restored the "B" train to service in the emergency recirculation mode at 9:12 a.m.

The inspectors noted that the on-shift senior licensed operator (SRO) directing the ventilation lineup was aware of the train "A" inoperability; however, when that SRO directed the ventilation lineup change, he was not specific to control room operators as to which train should be secured. Since the "A" train was functional and running, it was placed in emergency recirculation and the "B" standby train was secured by placing it in pull-to-lock. When the control room operators reported to the SRO the specific lineup performed about 10 minutes after completion, the SRO recognized the error made and took actions to restore the control ventilation systems to an operable condition.

Failure of the licensee to maintain at least one train of control room emergency recirculation system operable due to the above described personnel error is a Violation (440/90005-03(DRP)) of Technical Specification 3.7.2. However, a Notice of Violation was not issued in accordance with 10 CFR 2, Appendix C, Section V.G.1 because: the violation was identified by the licensee; this specific violation would normally be classified at a Severity Level IV or V; the violation was reported by the licensee via the ENS as discussed below and an LER will be provided; the violation was promptly corrected by the same individual who made the error; and it was not a willful violation.

The licensee informed the NRC operations center of this event via the ENS at about 2:00 p.m. on April 11. In accordance with 10 CFR 50.72(b)(2), "four-hour reports," the licensee should have reported this event no later than 12:45 p.m. which was 4 hours past the "discovery" time noted on licensee Condition Report 90-085. The failure to report this event within 4 hours of event recognition is a Violation of 10 CFR 50.72(b)(2) (440/90005-04(DRP)). However, a Notice of Violation was not issued in accordance with 10 CFR 2, Appendix C, Section V.G.1 because: the failure to report was identified by the licensee; this specific violation would normally be classified at a Severity Level IV or V; the failure to report on time was reported during the event notification discussed above; the violation was corrected by self-reporting; and it was not a willful violation. The inspectors noted that while a notice of

violation was not issued for the licensee's failure to meet the 4 hour reporting requirement, the licensee had been issued a notice of violation (50-440/88015-03) in November 1988 for failure to report the identical event. The licensee's self identification and prompt reporting (about 1 hour late) was the primary basis for the NRC not issuing a notice of violation for this event.

(6) Loss of Control Room Ventilation Safety Function

On April 11, 1990, at about 11:10 p.m. (EDT), with the plant operating at 100 percent power, the licensee experienced a second (see paragraph 11.b.(5)) loss of control room ventilation safety function. While performing pre-shift panel walkdowns, the oncoming control room operators noted that the OPERABLE control room ventilation train "B" was not running. At the time of discovery, the "A" control room ventilation train was inoperable following planned maintenance activities. The shift supervisor took action within 1 hour to commence an orderly plant shutdown in accordance with Technical Specification 3.0.3. In addition, the shift supervisor directed that a priority work request be initiated to troubleshoot failure of the "B" control room ventilation train and that necessary inspection personnel be called in to review the completed work packages on the "A" control room ventilation train.

At about 3:00 a.m. on April 12 the licensee restored train "B" of the control room ventilation system to service and exited Technical Specification 3.0.3. The cause for the train failure was identified to be a failed relay (K-103) in the "B" train's supply fan circuit. That relay was replaced with a spare under Work Order 90-1927. At about 3:15 a.m. on April 12 required inspection activities were completed on the "A" train of the control room ventilation system and it was returned to an operable condition.

The licensee informed the NRC operations center of this event at about 2:57 a.m. on April 12 within the 4 hour requirement of 10 CFR 50.72(b)(2). The inspectors will review the final root cause determination and the licensee's corrective actions to prevent recurrence after issuance of the required licensee event report.

Two violations were identified for which Notices of Violation were not issued in accordance with 10 CFR 2, Appendix C, V.G.1.

12. Violations For Which A "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not

generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section V.G. These tests are: (1) the violation was identified by the licensee; (2) the violation would be categorized as Severity Level IV or V; (3) the violation was reported to the NRC, if required; (4) the violation will be corrected, including measures to prevent recurrence, within a reasonable time period; and (5) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation. Violations of regulatory requirements identified during the inspection period for which a Notice of Violation will not be issued were discussed in Paragraphs 6 and 11.b.(5).

13. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether it is an acceptable item, a violation or a deviation. An unresolved item is identified in Paragraph 9.b.

14. Exit Interviews (30703)

The inspectors met with the licensee representatives denoted in Paragraph 1 throughout the inspection period and on April 18, 1990. The inspector summarized the scope and results of the inspection and discussed the likely content of the inspection report. The licensee did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.

During the report period, the inspectors attended the following exit interview:

Inspector	Exit Date
W. Liu	3/8/90