UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 24, 1994

The Honorable Charlie Rose
United States House of Representatives
Washington, DC 20515

Dear Congressman Rose:

Enclosed, as requested by your Legislative Assistant, Mr. Bill Myers, is material regarding the number of Level IV Violations assessed by the Nuclear Regulatory Commission at the Brunswick Nuclear Power Plant since January 1, 1994.

We are providing a matrix showing violations cited by NRC inspectors at Brunswick during this time frame (Enclosure 1); copies of the reports (Enclosure 2); explanation of the NRC Enforcement Program (Enclosure 3); and a copy of the NRC's General Statement of Policy and Procedure for NRC Enforcement Actions (Enclosure 4).

If I can be of further assistance, please let me know.

Sincerely,

Dennis K. Rathbun

Dennis K. Rathbun, Director
Office of Congressional Affairs

Enclosures:
As Stated

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VIOLATIONS ISSUED IN 1994 ON THE BRUNSWICK PLANT

NRC Report #s	BNP Unit 1 Violations (50-325)	BNP Unit 2 Violations (50-234)	Total # Violations
50-325,324/93-55	93-55-04 93-55-05 93-55-06	93-55-04 93-55-05 93-55-06	6
50-325,324/93-58	93-58-01 93-58-02	none	2
50-325,324/94-01	94-01-01 94-01-02	94-01-01 94-01-02	4
50-325,324/94-02	94-02-01	94-02-01	2
50-325,324/94-04	none	94-04-01	1
50-325,324/94-07	94-07-01	94-07-01	2
Total Reports: 6	Total #s: 9	Total #s: 8	Total #s: 17

Enclosure 2

NRC ENFORCEMENT PROGRAM

The NRC's Enforcement Program seeks to protect the public health and safety by ensuring compliance with the Atomic Energy Act, the Energy Reorganization Act, NRC regulations, and license conditions, obtaining prompt correction of violations and conditions adverse to quality, deterring future violations, and encouraging improvement of licensee performance. Violations are identified through inspections and investigations. All violations are subject to civil enforcement action and may also be subject to criminal prosecution. After an apparent violation is identified, it is assessed in accordance with the Commission's Enforcement Policy. This Policy has been approved by the Commission and is published as Appendix C to 10 CFR Part 2 of the Commission's regulations.

There are three primary enforcement sanctions available: Notices of Violation, civil penalties, and orders. A Notice of Violation (NOV) summarizes the results of an inspection and formalizes a violation. It states the requirement and how that requirement was violated. A civil penalty is a monetary fine issued under authority of section 234 of the Atomic Energy Act. That section provides for penalties of up to $100,000 per violation per day. NOVs and civil penalties are issued based on violations. Orders may be issued for violations, or in the absence of a violation, because of a public health or safety issue.

The Commission's order issuing authority is broad and extends to any area of licensed activity that affects the public health and safety. Orders modify, suspend, or revoke licenses. As a result of a recent rulemaking, the Commission's regulations now provide for issuing orders to individuals who are not themselves licensed.

The first step in the enforcement process is assessing the severity of the violation. Severity Levels range from Severity Level I, for the most significant violations, to Severity Level V for those of minor concern. Severity levels may be increased for cases involving a group of violations with the same root cause, repetitive violations, or willful violations.

Enforcement conferences are held for violations assessed at Severity Levels I, II, or III, and may be held for violations assessed at Severity Level IV if increased management attention is warranted, e.g., repetitive violations. An enforcement conference is a meeting between the NRC and the licensee to (1) discuss the apparent violations, their significance, the reason for their occurrence, including the apparent root causes, and the licensee's corrective actions, (2) determine whether there were any aggravating or mitigating circumstances, and (3) obtain other information that will help the NRC determine the appropriate enforcement action. The decision to hold an enforcement conference does not mean that the agency has determined that a violation has occurred or that enforcement action will be taken. Enforcement conferences are normally closed to the public. However, the Commission has implemented a two-year trial program to allow certain enforcement conferences to be open for public observation.

Civil penalties are normally issued for Severity Level III or higher violations, absent mitigation, and may be issued for violations at Severity Level IV if the violations are repetitive or similar to previous Severity Level IV violations. Civil penalties are normally issued for any willful violation.

The NRC imposes different levels of civil penalties based on a combination of the type of licensed activity, the type of licensee, the severity level of the violation, and certain escalation and mitigation factors. These factors are: (1) who identified the violation, (2) was the corrective action prompt and extensive or untimely and only marginally acceptable, (3) was the violation a reflection of prior licensee performance, (4) did the licensee have prior opportunity to identify the violation, (5) were there multiple occurrences of the violation, and (6) how long did the violation or its impact endure.

If a civil penalty is to be proposed, a written Notice of Violation and Proposed Imposition of Civil Penalty is issued and the licensee has 30 days to respond in writing, by either paying the penalty or contesting it. The NRC considers the response, and if the penalty is contested, may either mitigate the penalty or impose it by order.

If the civil penalty is to be imposed by order, the order is published in the Federal Register. Thereafter, the licensee may pay the civil penalty or request a hearing.

In addition to civil penalties, orders may be used to modify, suspend, or revoke licenses. Orders that modify a license may require additional corrective actions, such as removing specified individuals from licensed activities or requiring additional controls or outside audits. The NRC issues a press release with a proposed civil penalty or order.

NOTE: Persons attending open enforcement conferences are reminded that 1) the apparent violations discussed at open enforcement conferences are subject to further review and may be subject to change prior to any resulting enforcement action and 2) the statements of views or opinion made by NRC employees at open enforcement conferences or the lack thereof, are not intended to represent final determinations or beliefs.

Enclosure 4

Appendix C — General Statement Policy and Procedure for NRC Enforcement Actions

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Preface

The following statement of general policy and procedure explains the enforcement policy and procedures of the U.S. Nuclear Regulatory Commission and its staff in initiating enforcement actions, and of the presiding officers and the Commission in reviewing these actions. This statement is applicable to enforcement in matters involving the public health and safety, the common defense and security, and the environment.[1] This statement of general policy and procedure is published in the Code of Federal Regulations to provide widespread dissemination of the Commission's Enforcement Policy. However, this is a policy statement and not a regulation. The Commission may deviate from this statement of policy and procedure as appropriate under the circumstances of a particular case.

I. Introduction and Purpose

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The purpose of the NRC enforcement program is to promote and protect the radiological health and safety of the public, including employees' health and safety, the common defense and security, and the environment by:

- Ensuring compliance with NRC regulations and license conditions;
- Obtaining prompt correction of violations and adverse quality conditions which may affect safety;
- Deterring future violations and occurrences of conditions adverse to quality; and
- Encouraging improvement of licensee and vendor[2] performance, and by example, that of industry, including the prompt identification and reporting of potential safety problems.

Consistent with the purpose of this program, prompt and vigorous enforcement action will be taken when dealing with licensees, vendors, contractors, and employees of any of them, who do not achieve the necessary meticulous attention to detail and the high standard of compliance which the NRC expects.[3] Each enforcement action is dependent on the circumstances of the case and requires the exercise of discretion after consideration of these policies and procedures. In no case, however, will licensees who cannot achieve and maintain adequate levels of protection be permitted to conduct licensed activities.

II. Statutory Authority and Procedural Framework

A. Statutory Authority

The NRC's enforcement jurisdiction is drawn from the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act (ERA) of 1974, as amended.

Section 161 of the Atomic Energy Act authorizes NRC to conduct inspections and investigations and to issue orders as may be necessary or desirable to promote the common defense and security or to protect health or to minimize danger to life or property. Section 186 authorizes NRC to revoke licenses under certain circumstances (e.g., for material false statements, in response to conditions that would have warranted refusal of a license on an original application, for a licensee's failure to build or operate a facility in accordance with the terms of the permit or license, and for violation of an NRC regulation). Section 234 authorizes NRC to impose civil penalties not to exceed $100,000 per violation per day for the violation of certain specified licensing provisions of the Act, rules, orders, and license terms implementing these provisions, and for violations for which licenses can be revoked. In addition to the enumerated provisions in section 234, sections 84 and 147 authorize the imposition of civil penalties for violations of regulations implementing those provisions. Section 232 authorizes NRC to seek injunctive or other equitable relief for violation of regulatory requirements.

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Section 206 of the Energy Reorganization Act authorizes NRC to impose civil penalties for knowing and conscious failures to provide certain safety information to the NRC.

Chapter 18 of the Atomic Energy Act provides for varying levels of criminal penalties (i.e., monetary fines and imprisonment) for willful violations of the Act and regulations or orders issued under sections 65, 161(b), 161(i), or 161(o) of the Act. Section 223 provides that criminal penalties may be imposed on certain individuals employed by firms constructing or supplying basic components of any utilization facility if the individual knowingly and willfully violates NRC requirements such that a basic component could be significantly impaired. Section 235 provides that criminal penalties may be imposed on persons who interfere with inspectors.

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Section 236 provides that criminal penalties may be imposed on persons who attempt to or cause sabotage at a nuclear facility or to nuclear fuel. Alleged or suspected criminal violations of the Atomic Energy Act are referred to the Department of Justice for appropriate action.

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[1] Antitrust enforcement matters will be dealt with on a case-by-case basis.

[2] The term "vendor" as used in this policy means a supplier of products or services to be used in an NRC-licensed facility or activity.

[3] This policy primarily addresses the activities of NRC licensees. Therefore, the term "licensee" is used throughout the policy. However, in those cases where the NRC determines that it is appropriate to take enforcement action against a non-licensee or individual, the guidance in this policy will be used, as applicable. Specific guidance regarding enforcement action against individuals and non-licensees is addressed in Sections VIII and X respectively.

B. Procedural Framework

Subpart B of 10 CFR part 2 of NRC's regulations sets forth the procedures the NRC uses in exercising its enforcement authority. 10 CFR 2.201 sets forth the procedures for issuing notices of violation.

The procedure to be used in assessing civil penalties is set forth in 10 CFR 2.205. This regulation provides that the civil penalty process is initiated by issuing a Notice of Violation and Proposed Imposition of a Civil Penalty. The licensee or other person is provided an opportunity to contest in writing the proposed imposition of a civil penalty. After evaluation of the response, the civil penalty may be mitigated, remitted, or imposed. An opportunity is provided for a hearing if a civil penalty is imposed. If a civil penalty is not paid following a hearing or if a hearing is not requested, the matter may be referred to the U.S. Department of Justice to institute a civil action in District Court.

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The procedure for issuing an order to institute a proceeding to modify, suspend, or revoke a license or to take other action against a licensee or other person subject to the jurisdiction of the Commission is set forth in 10 CFR 2.202. The licensee or any other person adversely affected by the order may request a hearing. The NRC is authorized to make orders immediately effective if required to protect the public health, safety, or interest, or if the violation is willful. Section 2.204 sets out the procedures for issuing a Demand for Information (Demand) to a licensee or other person subject to the Commissioner's jurisdiction for the purpose of determining whether an order or other enforcement action should be issued. The Demand does not provide hearing rights, as only information is being sought. A licensee must answer a Demand. An unlicensed person may answer a Demand by either providing the requested information or explaining why the Demand should not have been issued.

III. Responsibilities

The Executive Director for Operations (EDO) and the principal enforcement officers of the NRC, the Deputy Executive Director for Nuclear Material Safety Safeguards and Operations Support (DEDS) and the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations, and Research (DEDR), have been delegated the authority to approve or issue all escalated enforcement actions.[4] The DEDS is responsible to the EDO for the NRC enforcement programs. The Office of Enforcement (OE) exercises oversight of and implements the NRC enforcement programs. The Director, OE, acts for the Deputy Executive Directors in enforcement matters in their absence or as delegated. Subject to the oversight and direction of OE, and with the approval of the appropriate Deputy Executive Director, where necessary,

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the regional offices normally issue Notices of Violation and proposed civil penalties. However, subject to the same oversight as the regional offices, the Office of Nuclear Reactor Regulation (NRR) issues Notices of Violation and proposed civil penalties to vendors and suppliers and the Office of Nuclear Material Safety and Safeguards (NMSS) issues Notices of Violation and proposed civil penalties to certificate holders and to fuel cycle facilities for violations involving material control and accounting. Escalated enforcement actions are normally coordinated with the appropriate offices by the OE. Enforcement orders are normally issued by a Deputy Executive Director or the Director, OE. However, orders may also be issued by the EDO, especially those involving the more significant matters. The Directors of NRR and NMSS have also been delegated authority to issue orders, but it is expected that normal use of this authority by NRR and NMSS will be confined to actions not associated with compliance issues. The Director, Office of the Controller, has been delegated the authority to issue orders where licensees violate Commission regulations by nonpayment of license and inspection fees.

[4] The term "escalated enforcement action" as used in this policy means a Notice of Violation for any Severity Level I, II, or III violation; a civil penalty for any Severity Level I, II, III, or IV violation and any order based upon a violation.

In recognition that the regulation c nuclear activities in many cases doe not lend itself to a mechanistic treatment, judgment and discretion n be exercised in determining the seve levels of the violations and the appropriate enforcement sanctions, including the decision to issue a Noti of Violation, or to propose or impose civil penalty and the amount of this penalty, after considering the genera principles of this statement of policy the technical significance of the violations and the surrounding circumstances.

Unless Commission consultation o notification is required by this policy the staff may depart, where warrante in the public's interest, from this poli with the approval of the appropriate Deputy Executive Director and consultation with the EDO as warranted. (See also Section VII, "Exercise of Discretion.")

The Commission will be provided written notification of all enforcemer actions involving civil penalties or orders. The Commission will also be

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provided notice in those cases where discretion is exercised and discussed Section VII.B.6. In addition, the Commission will be consulted prior t taking action in the following situatic (unless the urgency of the situation dictates immediate action):

(1) An action affecting a licensee's operation that requires balancing the public health and safety or common defense and security implications of operating with the potential radiologi or other hazards associated with continued operation;

(2) Proposals to impose civil penalt in amounts greater than 3 times the Severity Level I values shown in Tab 1A;

(3) Any proposed enforcement acti that involves a Severity Level I violation;

(4) Any enforcement action that involves a finding of a material false statement;

(5) Exercising discretion for matter meeting the criteria of Section VII.A.1 for Commission consultation;

(6) Refraining from taking enforcement action for matters meeti the criteria of Section VII.B.3;

(7) Any proposed enforcement acti that involves the issuance of a civil penalty or order to an unlicensed individual or a civil penalty to a licensed reactor operator;

(8) Any action the EDO believes warrants Commission involvement;

(9) Any enforcement case involving an Office of Investigation (OI) report where NRC staff (other than OI staff) does not arrive at the same conclusions as those in the OI report concerning issues of intent.

(10) Any proposed enforcement action on which the Commission asks to be consulted.

IV. Severity of Violations

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Regulatory requirements [5] have varying degrees of safety, safeguards, or environmental significance. Therefore, the relative importance of each violation, including both the technical significance and the regulatory significance is evaluated as the first step in the enforcement process.

Consequently, violations are normally categorized in terms of five levels of severity to show their relative importance within each of the following eight activity areas:

I. Reactor Operations;
II. Facility Construction;
III. Safeguards;
IV. Health Physics;
V. Transportation;
VI. Fuel Cycle and Materials Operations;
VII. Miscellaneous Matters; and
VIII. Emergency Preparedness.

Licensed activities will be placed in the activity area most suitable in light of the particular violation involved including activities not directly covered by one of the above listed areas, e.g., export license activities. Within each activity area, Severity Level I has been assigned to violations that are the most significant and Severity Level V violations are the least significant. Severity Level I and II violations are of very significant regulatory concern. In general, violations that are included in these severity categories involve actual or high potential impact on the public. Severity Level III violations are cause for significant regulatory concern. Severity Level IV violations are less serious but are of more than minor concern; i.e., if left uncorrected, they could lead to a more serious concern. Severity Level V violations are of minor safety or environmental concern.

Comparisons of significance between activity areas are inappropriate. For example, the immediacy of any hazard to the public associated with Severity Level I violations in Reactor Operations is not directly comparable to that associated with Severity Level I violations in Facility Construction.

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Supplements I through VIII provide examples and serve as guidance in determining the appropriate severity level for violations in each of the eight activity areas. However, the examples are neither exhaustive nor controlling. In addition, these examples do not create new requirements. Each is designed to illustrate the significance that the NRC places on a particular type of violation of NRC requirements. Each of the examples in the supplements is predicated on a violation of a regulatory requirement.

The NRC reviews each case being considered for enforcement action on its own merits to ensure that the severity of a violation is characterized at the level best suited to the significance of the particular violation. In some cases, special circumstances may warrant an adjustment to the severity level categorization.

A. Aggregation of Violations

A group of violations may be evaluated in the aggregate and assigned a single, increased severity level, thereby resulting in a Severity Level III problem, if the violations have the same underlying cause or programmatic deficiencies, or the violations contributed to or were unavoidable consequences of the underlying problem. Normally, Severity Level I and II violations are not aggregated into a higher severity level.

The purpose of aggregating violations is to focus the licensee's attention on the fundamental underlying causes for which enforcement action appears warranted and to reflect the fact that several violations with a common cause may be more significant collectively than individually and may therefore, warrant a more substantial enforcement action. In addition, a civil penalty for multiple occurrences of a violation with the same root cause may be subject to escalation of the base civil penalty. (See Section VI.B.2.(e))

B. Repetitive Violations

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The severity level of a Severity Level V or IV violation may be increased to Severity Level IV or III respectively, if the violation can be considered a repetitive violation.[6] The purpose of escalating the severity level of a repetitive violation is to acknowledge the added significance of the situation based on the licensee's failure to implement effective corrective action for the previous violation. The decision to escalate the severity level of a repetitive violation will depend on the circumstances, such as, but not limited to, the number of times the violation has occurred, the similarity of the violations and their root causes, the adequacy of previous corrective actions, the period of time between the violations, and the significance of the violations. (Civil penalties may also be proposed for repetitive Severity Level IV violations as discussed in Section VI.B.)

C. Willful Violations

Willful violations are by definition of particular concern to the Commission because its regulatory program is based on licensees and their contractors, employees, and agents acting with integrity and communicating with candor. Willful violations cannot be tolerated by either the Commission or a licensee. Licensees are expected to take significant remedial action in responding to willful violations commensurate with the circumstances such that it demonstrates the seriousness of the violation thereby creating a deterrent effect within the licensee's organization. While removal of the person is not necessarily required, substantial disciplinary action is expected.

[5] The term "requirement" as used in this policy means a legally binding requirement such as a statute, regulation, license condition, technical specification, or order.

[6] The term "repetitive violation" or "similar violation" as used in this policy statement means a violation that reasonably could have been prevented by a licensee's corrective action for a previous violation normally occurring (1) within the past two years of the inspection at issue, or (2) the period within the last two inspections, whichever is longer.

Therefore, the severity level of a violation may be increased if the circumstances surrounding the matter involve careless disregard of requirements, deception, or other indications of willfulness. The term "willfulness" as used in this policy embraces a spectrum of violations ranging from deliberate intent to violate or falsify to and including careless disregard for requirements. Willfulness does not include acts which do not rise to the level of careless disregard, e.g., inadvertent clerical errors in a document submitted to the NRC. In determining the specific severity level of a violation involving willfulness, consideration will be given to such factors as the position and responsibilities of the person involved in the violation (e.g., licensee official [7] or non-supervisory employee), the significance of any underlying violation, the intent of the violator (i.e., careless disregard or deliberateness), and the economic or other advantage, if any, gained as a result of the violation. The relative weight given to each of these factors in arriving at the appropriate severity level will be dependent on the circumstances of the violation. However, the severity level of a willful severity level V violation will be increased to at least a severity level IV.

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D. Violations of Reporting Requirements

The NRC expects licensees to provide complete, accurate, and timely information and reports. Accordingly, unless otherwise categorized in the Supplements, the severity level of a violation involving the failure to make a required report to the NRC will be based upon the significance of and the circumstances surrounding the matter that should have been reported. However, the severity level of an untimely report, in contrast to no report, may be reduced depending on the circumstances surrounding the matter. A licensee will not normally be cited for a failure to report a condition or event unless the licensee was actually aware of the condition or event that it failed to report. A licensee will, on the other hand, normally be cited for a failure to report a condition or event if the licensee knew of the information to be reported, but did not recognize that it was required to make a report.

V. Enforcement Conferences

Whenever the NRC has learned of the existence of a potential violation for which escalated enforcement action may be warranted, or recurring nonconformance on the part of a vendor, the NRC will normally provide an opportunity for an enforcement conference with the licensee, vendor, or other person prior to taking enforcement action. Although enforcement conferences are not normally held for Severity Level IV violations, they may be scheduled if increased management attention is warranted e.g., if the violations are repetitive. The purpose of the enforcement conference is to (1) discuss the violations or nonconformances, their significance, the reason for their occurrence, including the apparent root causes, and the licensee's or vendor's corrective actions, (2) determine whether there were any aggravating or mitigating circumstances, and (3) obtain other information that will help the NRC determine the appropriate enforcement action.

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During the enforcement conference, the licensee, vendor, or other person will be given an opportunity to provide information consistent with the purpose of the conference, including an explanation to the NRC of the immediate corrective actions (if any) that were taken following identification of the potential violation or nonconformance and the long term comprehensive actions that were taken or will be taken to prevent recurrence. Licensees, vendors, or other persons will be told when a meeting is an enforcement conference. Enforcement conferences will not normally be open to the public.

When needed to protect the public health and safety or common defense and security, escalated enforcement action, such as the issuance of an immediately effective order modifying, suspending, or revoking a license, will be taken prior to the enforcement conference. In these cases, an enforcement conference may be held after the escalated enforcement action taken.

VI. Enforcement Actions

This section describes the enforcement sanctions available to the NRC and specifies the conditions unde which each may be used. The basic sanctions are Notices of Violation, civi penalties, and orders of various types. As discussed further in Section VI.D, related administrative mechanisms suc as Notices of Nonconformance, Notices of Deviation, Confirmatory Action Letters, letters of reprimand, and Demands for information are used to supplement the enforcement program. I selecting the enforcement sanctions to be applied, the NRC will consider enforcement actions taken by other Federal or State regulatory bodies having concurrent jurisdiction, such as in transportation matters. Usually, whenever a violation of NRC requirements is identified, enforcement action is taken. The nature and extent c the enforcement action is intended to reflect the seriousness of the violation involved. For the vast majority of violations, a Notice of Violation or a Notice of Nonconformance is the norm enforcement action.

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[7] The term "licensee official" as used in this policy statement means a first-time supervisor or above, a licensed individual, a radiation safety officer, or an authorized user of licensed material whether or not listed on a license. Notwithstanding an individual's job title, severity level categorization for willful acts involving individuals who can be considered licensee officials will consider several factors, including the position of the individual relative to the licensee's organizational structure and the individual's responsibilities relative to the oversight of licensed activities and to the use of licensed material.

A. Notice of Violation

A Notice of Violation is a written notice setting forth one or more violations of a legally binding requirement. The Notice of Violation normally requires the recipient to provide a written statement describing (1) the reasons for the violation or, if contested, the basis for disputing the violation; (2) corrective steps that have been taken and the results achieved; (3) corrective steps that will be taken to prevent recurrence; and (4) the date when full compliance will be achieved. The NRC may require responses to Notices of Violation to be under oath. Normally, responses under oath will be required only in connection with civil penalties and orders.

The NRC uses the Notice of Violation as the usual method for formalizing the existence of a violation. Issuance of a Notice of Violation is normally the only enforcement action taken, except in cases where the criteria for issuance of civil penalties and orders, as set forth in Sections VI.B and VI.C, respectively, are met. However, special circumstances regarding the violation findings may warrant discretion being exercised such that the NRC refrains from issuing a Notice of Violation. (See Section VII.B, "Mitigation of Enforcement Sanctions.") 57 FR 5791 In addition, licensees are not ordinarily cited for violations resulting from matters not within their control, such as equipment failures that were not avoidable by reasonable licensee quality assurance measures or management controls. Generally, however, licensees are held responsible for the acts of their employees. Accordingly, this policy should not be construed to excuse personnel errors.

B. Civil Penalty

A civil penalty is a monetary penalty that may be imposed for violation of (1) certain specified licensing provisions of the Atomic Energy Act or supplementary NRC rules or orders; (2) any requirement for which a license may be revoked; or (3) reporting requirements under section 206 of the Energy Reorganization Act. Civil penalties are designed to emphasize the need for lasting remedial action and to deter future violations both by the involved licensee as well as by other licensees conducting similar activities.

Civil penalties are proposed (absent mitigating circumstances) for Severity Level I, II, and III violations, and may be proposed for repetitive Severity Level IV violations or for any willful violation. In addition, civil penalties will normally be assessed for knowing and conscious violations of the reporting requirements of section 206 of the Energy Reorganization Act.

1. Base Civil Penalty

The NRC imposes different levels of penalties for different severity level violations and different classes of licensees, vendors, and other persons. Tables 1A and 1B show the base civil penalties for various reactor, fuel cycle, materials, and vendor programs. (Civil penalties issued to individuals are determined on a case-by-case basis.) The structure of these tables generally takes into account the gravity of the violation as a primary consideration and the ability to pay as a secondary consideration. Generally, operations involving greater nuclear material inventories and greater potential consequences to the public and licensee employees receive higher civil penalties. Regarding the secondary factor of ability of various classes of licensees to pay the civil penalties, 57 FR 5791 it is not the NRC's intention that the economic impact of a civil penalty be so severe that it puts a licensee out of business (orders, rather than civil penalties, are used when the intent is to suspend or terminate licensed activities) or adversely affects a licensee's ability to safely conduct licensed activities. The deterrent effect of civil penalties is best served when the amounts of the penalties take into account a licensee's "ability to pay." In determining the amount of civil penalties for licensees for whom the tables do not reflect the ability to pay, the NRC will consider as necessary an increase or decrease on a case-by-case basis. Normally, if a licensee can demonstrate financial hardship, the NRC will consider payments over time, including interest, rather than reducing the amount of the civil penalty. However, where a licensee claims financial hardship, the licensee will normally be required to address why it has sufficient resources to safely conduct licensed activities and pay license and inspection fees.

2. Civil Penalty Adjustment Factors

In an effort to recognize and encourage good performance, deter poor performance, and emphasize violations of particular regulatory concern, the NRC reviews each proposed civil penalty on its own merits and, after considering all relevant circumstances, may adjust the base civil penalties shown in Table 1A and 1B for Severity Level I, II, and III violations based on an assessment of the following civil penalty adjustment factors. Civil penalties for Severity Level IV violations are normally proposed at the base values identified in the tables without assessing the civil penalty adjustment factors.

While management involvement, direct or indirect, in a violation may lead to an increase in the civil penalty, the lack of management involvement 57 FR 5791 may not be used to mitigate a civil penalty. Allowing mitigation in the latter case could encourage lack of managment involvement in licensed activities and a decrease in protection of the public health and safety.

(a) *Identification.* The purposes of this factor is to encourage licensees to monitor, supervise, and audit activities in order to assure safety and compliance. Therefore, the base civil penalty shown in Tables 1A and 1B may be mitigated up to 50% when a licensee identifies a violation and escalated up to 50% if the NRC identifies a violation. The base civil penalty may also be mitigated up to 25% when a licensee identifies a violation resulting from a self-disclosing event [6] where the licensee demonstrates initiative in identifying the root cause of the violation. In addition, the base civil penalty may also be mitigated where warranted if a licensee identifies a violation as a result of its review of a generic notification. While mitigation under this factor is appropriate for a licensee identified violation that was not reported to the NRC, a separate enforcement action will normally be issued for the licensee's failure to make the required report.

[6] The term "self-disclosing event" as used in this policy statement means an event that is readily obvious by human observation or instrumentation such as a spill of liquid, an open door (required to be closed), an overexposure documented in a dosimetry report, an annunciator alarm, or a reactor trip.

(b) *Corrective action.* The purposes of this factor is to encourage licensees to (1) take the immediate actions necessary upon discovery of a violation that will restore safety and compliance with the license, regulation(s), or other requirement(s); and (2) develop and implement (in a timely manner) the lasting actions that will not only prevent recurrence of the violation at issue, but will be appropriately comprehensive, given the significance and complexity of the violation, to prevent occurrence of similar violations. Therefore, the base civil penalty shown in Tables 1A and 1B may be either mitigated or escalated by as much as 50% depending on the promptness and extensiveness of the licensee's corrective action. In assessing this factor, consideration will be given to, among other things, the timeliness of the corrective action (including the promptness in developing the schedule for long term corrective action), the degree of licensee initiative (i.e., whether NRC involvement was required before acceptable action was taken), the adequacy of the licensee's root cause

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analysis for the violation, and, given the significance and complexity of the issue, the comprehensiveness of the corrective action (i.e., whether the action is focused narrowly to the specific violation or broadly to the general area of concern). Notwithstanding good comprehensive corrective action, if immediate corrective action was not taken to restore safety and compliance once the violation was identified, mitigation of the civil penalty based on this factor will not normally be considered and escalation may be considered to address the licensee's failure.

(c) *Licensee performance.* The purpose of this factor is to recognize and encourage good or improving licensee performance and to recognize and deter poor or declining performance. Therefore, the base civil penalty shown in Tables 1A and 1B may be mitigated by as much as 100% if the current violation is an isolated failure that is inconsistent with a licensee's outstandingly good prior performance. The base civil penalty may also be escalated by as much as 100% if the current violation is reflective of the licensee's poor or declining prior performance. Neither mitigation nor escalation may be appropriate based on this factor where a licensee's poor prior performance appears to clearly be improving. Prior performance, as used in this policy statement, refers to the licensee's performance normally (1) within the last two years of the inspection at issue, or (2) the period within the last two inspections, whichever is longer. In assessing the licensee's prior performance, consideration will be given to, among other things, the effectiveness of previous corrective action for similar problems, overall performance such as Systematic Assessment of Licensee Performance (SALP) evaluations for power reactors, and the licensee's prior enforcement history overall and in the area of concern, including escalated and non-escalated enforcement actions and any enforcement actions that the NRC exercised discretion and refrained from issuing in accordance with Section VII.B. Notwithstanding good prior performance, mitigation of the civil

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penalty based on this factor is not normally warranted where the current violation reflects a substantial decline in performance that has occurred over the time since the last NRC inspection. In addition, this factor should not be applied for those cases where the licensee has not been in existence long enough to establish a prior performance or inspection history. Similarly, mitigation based on this factor is not normally appropriate where the area of concern has not been previously inspected, unless overall performance is good.

(d) *Prior opportunity to identify.* The purpose of this factor is to encourage licensees to take effective action in response to opportunities to identify or prevent problems or violations. Therefore, the base civil penalty shown in Tables 1A and 1B may be escalated by as much as 100% for cases where the licensee should have identified the violation sooner as a result of prior opportunities, such as (1) through normal surveillances, audits, or quality assurance (QA) activities; (2) through prior notice i.e., specific NRC or industry notification; or (3) through other reasonable indication of a potential problem or violation, such as observations of employees and contractors, and had failed to take effective corrective steps. Prior notification may include findings of the NRC, the licensee, or industry made at other facilities operated by the licensee where it is reasonable to expect the licensee to take action to identify or prevent similar problems at the facility subject to the enforcement action at issue. In assessing this factor, consideration will be given to, among other things, the opportunities available to discover the violation, the ease of discovery, the similarity between the violation and the notification, the period of time between when the violation occurred and when the notification was issued, the action taken (or planned) by the licensee in response to the notification, and the level of

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management review that the notification received (or should have received). Escalation of the civil penalty based solely on prior notification is normally not warranted where the licensee appropriately reviewed the notification for application to its activities and reasonable action was either taken or planned to be taken within a reasonable time.

(e) *Multiple occurrences.* The purpose of this factor is to reflect the added significance resulting from multiple occurrences of the violation. Therefore, the base civil penalty shown in Tables 1A and 1B may be escalated by as much as 100% where multiple examples of a particular violation are identified during the inspection period. Escalation of the civil penalty based on this factor will normally be considered only when there are multiple examples of Severity Level I, II, or III violations with the same root causes. Alternatively, separate civil penalties may be imposed for each violation.

(f) *Duration.* The purpose of this factor is to recognize the added significance associated with those violations (or the impact of those violations) that continue or remain uncorrected for more than one day. Therefore, whether or not a licensee is aware or clearly should have been aware of a violation, the base civil penalty shown in Tables 1A and 1B may be escalated by as much as 100% to reflect the added technical and/or regulatory significance resulting from the violation or the impact of it remaining uncorrected for more than one day. This factor should normally be applied in cases involving particularly safety significant violations or where a significant regulatory message is warranted. In lieu of escalating the civil penalty based on this factor, the NRC may impose daily civil penalties for violations that continue for more than one day. (See Section VII.A.3, "Daily Civil Penalties.")

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The civil penalty adjustment factors presented in paragraphs (a) through (f) are additive. However, in no instance will a civil penalty for any one violation exceed $100,000 per day.

Notwithstanding the application of the civil penalty adjustment factors, a civil penalty will normally be proposed in an amount of at least 50% of the base value in Tables 1A and 1B for Severity Level I and II violations involving overexposures, release of radioactive material, or loss of radioactive material to emphasize to the licensee the seriousness with which the NRC views these events and the importance of conducting licensed activities in a manner to avoid these violations. In considering mitigation for these cases, normally the only adjustment factors that will be considered to lower a base civil penalty will be identification and corrective action factors. In addition, as provided in Section VII, "Exercise of Discretion," discretion may be exercised by either escalating or mitigating the amount of the civil penalty arrived at after applying the civil penalty adjustment factors to ensure that the proposed civil penalty reflects the NRC's concern regarding the violation at issue and that it conveys the appropriate message to the licensee.

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TABLE 1A—BASE CIVIL PENALTIES

	Plant operations, construction, health physics and EP	Safeguards	Transportation: Greater than Type A quantity [1]	Transportation: Type A quantity or less [2]
a. Power reactors	$100,000	$100,000	$100,000	$5,000
b. Test reactors	10,000	10,000	10,000	2,000
c. Research reactors and critical facilities	5,000	5,000	5,000	1,000
d. Fuel fabricators and industrial processors [3]	25,000	100,000	25,000	5,000
e. Mills and Uranium conversion facilities	10,000	—	5,000	2,000
f. Industrial users of materials [5], and contractors and vendors	10,000	—	5,000	2,000
g. Waste disposal licensees	10,000	—	5,000	2,000
h. Academic or medical institutions [6]	5,000	—	2,500	1,000
i. Independent spent fuel and monitored retrievable storage installations	25,000	100,000	25,000	5,000
j. Other material licensees	1,000	—	2,500	1,000

[1] Includes irradiated fuel, high level waste, unirradiated fissile material, and any other quantities requiring Type B packaging.
[2] Includes low specific activity waste (LSA), low level waste, Type A packages, and excepted quantities and articles.
[3] Large firms engaged in manufacturing or distribution of byproduct, source, or special nuclear material.
[4] This amount refers to Category 1 licensees (as defined in 10 CFR 73.2). Licensee fuel fabricators not authorized to possess Category 1 material have a base penalty amount of $50,000.
[5] Includes industrial radiographers, nuclear pharmacies, and other industrial users.
[6] This applies to nonprofit institutions not otherwise categorized under sections "a" through "g" in this table and mobile nuclear services.

TABLE 1 B—BASE CIVIL PENALTIES

Severity Level	Base Civil Penalty Amount (Percent of amount listed in Table 1A)
I	100
II	80
III	50
IV	15

C. Orders

An order is a written NRC directive to modify, suspend, or revoke a license; to cease and desist from a given practice or activity; or to take such other action as may be proper (see 10 CFR 2.202). Orders may also be issued in lieu of, or in addition to, civil penalties, as appropriate for Severity Level I, II, or III violations. Orders may be issued as follows:

(1) License Modification orders are issued when some change in licensee equipment, procedures, personnel, or management controls is necessary.

(2) Suspension Orders may be used:

(a) To remove a threat to the public health and safety, common defense and security, or the environment;

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(b) To stop facility construction when,

(i) Further work could preclude or significantly hinder the identification or correction of an improperly constructed safety-related system or component; or

(ii) The licensee's quality assurance program implementation is not adequate to provide confidence that construction activities are being properly carried out;

(c) When the licensee has not responded adequately to other enforcement action;

(d) When the licensee interferes with the conduct of an inspection or investigation; or

(e) For any reason not mentioned above for which license revocation is legally authorized.

Suspensions may apply to all or part of the licensed activity. Ordinarily, a licensed activity is not suspended (nor is a suspension prolonged) for failure to comply with requirements where such failure is not willful and adequate corrective action has been taken.

(3) Revocation Orders may be used:

(a) When a licensee is unable or unwilling to comply with NRC requirements;

(b) When a licensee refuses to correct a violation;

(c) When licensee does not respond to a Notice of Violation where a response was required;

(d) When a licensee refuses to pay an applicable fee under the Commission's regulations; or

(e) For any other reason for which revocation is authorized under section 186 of the Atomic Energy Act (e.g., any condition which would warrant refusal of a license on an original application).

(4) Cease and Desist Orders may be used to stop an unauthorized activity that has continued after notification by NRC that the activity is unauthorized.

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(5) Orders to unlicensed persons, including vendors and contractors, and employees of any of them, are used when the NRC has identified deliberate misconduct that may cause a licensee to be in violation of an NRC requirement or where incomplete or inaccurate information is deliberately submitted or where the NRC loses its reasonable assurance that the licensee will meet NRC requirements with that person involved in licensed activities.

Unless a separate response is warranted pursuant to 10 CFR 2.201, a Notice of Violation need not be issued where an order is based on violations described in the order. The violations described in an order need not be categorized by severity level.

Orders are made effective immediately, without prior opportunity for hearing, whenever it is determined that the public health, interest, or safety so requires, or when the order is responding to a violation involving willfulness. Otherwise, a prior opportunity for a hearing on the order is afforded. For cases in which the NRC believes a basis could reasonably exist for not taking the action as proposed, the licensee will ordinarily be afforded an opportunity to show why the order should not be issued in the proposed manner by way of a Demand for Information. (See 10 CFR 2.204)

D. Related Administrative Actions

In addition to the formal enforcement mechanisms of Notices of Violation, civil penalties, and orders, the NRC also uses administrative mechanisms, such as Notices of Deviation, Notices of Nonconformance, Confirmatory Action Letters, letters of reprimand, and Demands for Information to supplement its enforcement program. The NRC expects licensees and vendors to adhere to any obligations and commitments resulting from these processes and will not hesitate to issue appropriate orders to ensure that these obligations and commitments are met.

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(1) Notices of Deviation are written notices describing a licensee's failure to satisfy a commitment where the commitment involved has not been made a legally binding requirement. A Notice of Deviation requests a licensee to provide a written explanation or statement describing corrective steps taken (or planned), the results achieved, and the date when corrective action will be completed.

(2) Notices of Nonconformance are written notices describing vendor's failures to meet commitments which have not been made legally binding requirements by NRC. An example is a commitment made in a procurement contract with a licensee as required by 10 CFR part 50, appendix B. Notices of Nonconformances request non-licensees to provide written explanations or statements describing corrective steps (taken or planned), the results achieved, the dates when corrective actions will be completed, and measures taken to preclude recurrence.

(3) Confirmatory Action Letters (CALs) are letters confirming a licensee's or vendor's agreement to take

certain actions to remove significant concerns about health and safety, safeguards, or the environment.

(4) Letters of reprimand are letters addressed to individuals subject to Commission jurisdiction identifying a significant deficiency in their performance of licensed activities.

(5) Demands for Information are demands for information from licensees or other persons for the purpose of enabling NRC to determine whether an order or other enforcement action should be issued.

VII. Exercise of Discretion

Notwithstanding the normal guidance contained in this policy, the NRC may choose to exercise discretion and either escalate or mitigate enforcement sanctions within the Commission's statutory authority to ensure that the resulting enforcement action appropriately reflects the level of NRC concern regarding the violation at issue and conveys the appropriate message to the licensee.

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A. Escalation of Enforcement Sanctions

The NRC considers violations categorized at Severity Level I, II, or III to be of significant regulatory concern. If the application of the normal guidance in this policy does not provide an appropriate sanction, or if particularly serious violations occur, such as in cases involving willfulness, repeated poor performance in an area of concern, or serious breakdowns in management controls, the NRC may apply its full enforcement authority where the action is warranted. NRC action may include (1) escalating civil penalties, (2) issuing appropriate orders, and (3) assessing civil penalties for continuing violations on a per day basis, up to the statutory limit of $100,000 per violation, per day.

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(1) *Civil penalties.* Notwithstanding the outcome of the normal civil penalty assessment process (i.e., base civil penalty adjusted based on application of the civil penalty adjustment factors addressed in Section VI.B), with the approval of the appropriate Deputy Executive Director and consultation with the EDO as warranted, the NRC may exercise discretion by either proposing a civil penalty where application of the factors would otherwise result in zero penalty or by further escalating the amount of the adjusted civil penalty to ensure that the proposed civil penalty reflects the NRC's concern regarding the violation at issue and that it conveys the appropriate message to the licensee. In addition to the approval of the appropriate Deputy Executive Director, consultation with the Commission is required if the deviation in the amount of the civil penalty proposed under this discretion from the amount of the civil penalty assessed under the normal process is more than two times the base civil penalty shown in Tables 1A and 1B.

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(2) *Orders.* The NRC will, where necessary issues orders in conjunction with civil penalties to achieve or formalize corrective actions and to deter further recurrence of serious violations. Examples of enforcement actions that could be taken for similar Severity Level I, II, or III violations are set forth in Table 2. The actual progression to be used in a particular case will depend on the circumstances. Enforcement sanctions will normally escalate for recurring similar violations.

TABLE 2.—EXAMPLES OF PROGRESSION OF ESCALATED ENFORCEMENT ACTIONS FOR SIMILAR VIOLATIONS IN THE SAME ACTIVITY AREA UNDER THE SAME LICENSE

Severity of Violation	Number of similar violations from the date of the last inspection or within the previous two years (whichever period is greater)		
	1st	2nd	3rd
I	a+b	a+b+c	d
II	a	a+b+c	a+b+c
III	a	a+c	a+b

Notes:

a. Civil penalty.

b. Suspension of affected operations until the Office Director is satisfied that there is reasonable assurance that the licensee can operate in compliance with the applicable requirements, or modification of the license, as appropriate.

c. Consider issuing an order for modification, suspension, or revocation of the license, as appropriate, through use of a Demand for Information.

d. Further action, as appropriate.

(3) *Daily civil penalties.* In order to recognize the added technical safety significance or regulatory significance for those cases where a very strong message is warranted for a significant violation that continues for more than one day, the NRC may exercise discretion and assess a separate violation and attendant civil penalty up to the statutory limit of $100,000 for each day the violation continues. The NRC may exercise this discretion if a licensee was aware or clearly should have been aware of a violation, or if the licensee had an opportunity to identify and correct the violation but failed to do so.

B. Mitigation of Enforcement Sanctions

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Because the NRC wants to encourage and support licensee initiative for self identification and correction of problems, the NRC may exercise discretion and refrain from issuing a civil penalty and/or issuing a Notice of Violation under certain circumstances. In addition, while the NRC may exercise this discretion for violations meeting the required criteria where the licensee failed to make a required report to the NRC, a separate enforcement action will normally be issued for the licensee's failure to make a required report. The circumstances under which this discretion may be exercised are as follows:

(1) Severity Level V Violations. The NRC may refrain from issuing a Notice of Violation for a Severity Level V violation that is documented in an inspection report (or official field notes for some material cases) provided that the inspection report includes a brief description of the corrective action and that the violation meets all of the following criteria:

(a) It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation or a previous licensee finding that occurred within the past two years of the inspection at issue, or the period within the last two inspections, whichever is longer;

(b) It was or will be corrected within a reasonable time, by specific corrective action committed to by the licensee by the end of the inspection, including immediate corrective action and comprehensive corrective action to prevent recurrence;

(c) It was not a willful violation.

(2) Licensee Identified Severity Level IV and V Violations. The NRC may refrain from issuing a Notice of Violation for a Severity Level IV or V violation that is documented in an inspection report (or official field notes for some material cases) provided that the inspection report includes a brief description of the corrective action and that the violation meets all of the following criteria:

(a) It was identified by the licensee, including as a result of a self-disclosing event;

(b) It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation or a previous licensee finding that occurred within the past two years of the inspection at issue, or the period within the last two inspections, whichever is longer;

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(c) It was or will be corrected within a reasonable time, by specific corrective action committed to by the licensee by the end of the inspection, including immediate corrective action and comprehensive corrective action to prevent recurrence;

(d) It was not a willful violation or if it was a willful violation:

(i) The information concerning the violation, if not required to be reported, was promptly provided to appropriate NRC personnel, such as a resident inspector or regional section or branch chief;

(ii) The violation involved the acts of a low level individual (and not a licensee official as defined in section IV.C);

(iii) The violation appears to be the isolated action of the employee without management involvement and the violation was not caused by lack of management oversight as evidenced by either a history of isolated willful violations or a lack of adequate audits or supervision of employees; and

(iv) Significant remedial action commensurate with the circumstances was taken by the licensee such that it demonstrated the seriousness of the violation to other employees and contractors, thereby creating a deterrent effect within the licensee's organization. While removal of the employee from licensed activities is not necessarily required, substantial disciplinary action is expected.

(3) Violations Identified During Extended Shutdowns or Work Stoppages. The NRC may refrain from issuing a Notice of Violation or a proposed civil penalty for a violation that is identified after (i) the NRC has taken significant enforcement action based upon a major safety event contributing to an extended shutdown of an operating reactor or a material licensee (or a work stoppage at a construction site), or (ii) the licensee enters an extended shutdown or work stoppage related to generally poor performance over a long period of time provided that the violation is documented in an inspection report (or official field notes for some material cases) and that it meets all of the following criteria:

(a) It was either licensee identified as a result of a comprehensive program fo[r] problem identification and correction that was developed in response to the shutdown or identified as a result of an employee allegation to the licensee; (If the NRC identifies the violation and all of the other criteria are met, the NRC should determine whether enforcement action is necessary to achieve remedial action, or if discretion may still be appropriate.)

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(b) It is based upon activities of the licensee prior to the events leading to the shutdown;

(c) It would not be categorized at a severity level higher than Severity Leve[l] II;

(d) It was not willful; and

(e) The licensee's decision to restart the plant requires NRC concurrence.

(4) Violations Involving Old Design Issues. The NRC may refrain from proposing a civil penalty for a Severity Level II or III violation involving a past problem, such as in engineering, design, or installation, provided that the violation is documented in an inspectio[n] report (or official field notes for some material cases) that includes a description of the corrective action and that it meets all of the following criteria:

(a) It was a licensee identified as a result of a licensee's voluntary formal initiative, such as a Safety System Functional Inspection, Design Reconstitution Program, or other program that has a defined scope and timetable and is being aggressively implemented;

(b) It was or will be corrected, including immediate corrective action and long term comprehensive corrective action to prevent recurrence, within a reasonable time following identification (this action should involve expanding the initiative, as necessary, to identify other failures caused by similar root causes); and

(c) It was not likely to be identified (after the violation occurred) by routine licensee efforts such as normal surveillance or quality assurance (QA) activities.

In addition, the NRC may refrain from issuing a Notice of Violation for cases that meet the above criteria provided the violation was caused by conduct that is not reasonably linked to present performance (normally, violations that are at least three years old or violations occurring during plant construction) and there had not been prior notice so that the licensee should have reasonably identified the violation earlier. This exercise of discretion is to place a premium on licensees initiating efforts to identify and correct subtle violations that are not likely to be identified by routine efforts before degraded safety systems are called upon to work.

(5) Violations Identified Due to Previous Escalated Enforcement Action. The NRC may refrain from issuing a Notice of Violation or a proposed civil penalty for a violation that is identified after the NRC has taken escalated enforcement action for a Severity Level II or III violation, provided that the violation is documented in an inspection report (or official field notes for some material cases) that includes a description of the corrective action and that it meets all of the following criteria:

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(a) It was a licensee identified as part of the corrective action for the previous escalated enforcement action;

(b) It has the same or similar root cause as the violation for which escalated enforcement action was issued;

(c) It does not substantially change the safety significance or the character of the regulatory concern arising out of the initial violation; and

(d) It was or will be corrected, including immediate corrective action and long term comprehensive corrective action to prevent recurrence, within a reasonable time following identification.

(6) Violations Involving Special Circumstances. Notwithstanding the outcome of the normal civil penalty assessment process (i.e., base civil penalty adjusted based on application of the civil penalty adjustment factors addressed in Section VI.B), as provided in Section III, "Responsibilities," the appropriate Deputy Executive Director may reduce or refrain from issuing a civil penalty or a Notice of Violation for a Severity Level II or III violation based on the merits of the case after considering the guidance in this statement of policy and such factors as the age of the violation, the safety significance of the violation, the overall performance of the licensee, and other relevant circumstances, including any that may have changed since the violation, provided prior notice has been given the Commission. This discretion is expected to be exercised only where application of the normal guidance in the policy is unwarranted.

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C. Exercise of Discretion for an Operating Facility

On occasion, circumstances may arise where a licensee's compliance with a Technical Specification (TS) Limiting Condition for Operation or with other license conditions would involve an unnecessary plant transient or performance of testing, inspection, or system realignment that is inappropriate with the specific plant conditions, or unnecessary delays in plant startup without a corresponding health and safety benefit. In these circumstances, the NRC staff may choose not to enforce the applicable TS or other license condition. This enforcement discretion will only be exercised if the NRC staff is clearly satisfied that the action is consistent with protecting the public health and safety. A licensee seeking the exercise of enforcement discretion must provide a written justification, or in circumstances where good cause is shown, oral justification followed as soon as possible by written justification, which documents the safety basis for the request and provides whatever other information the NRC staff deems necessary in making a decision on whether or not to exercise enforcement discretion.

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The appropriate Regional Administrator, or his designee, may exercise discretion where the noncompliance is temporary and nonrecurring when an amendment is not practical. The Director, Office of Nuclear Reactor Regulation, or his designee, may exercise discretion if the expected noncompliance will occur during the brief period of time it requires the NRC staff to process an emergency or exigent license amendment under the provisions of 10 CFR 50.91(a)(5) or (6). The person exercising enforcement discretion will document the decision.

For an operating plant, this exercise of enforcement discretion is intended to minimize the potential safety consequences of unnecessary plant transients with the accompanying operational risks and impacts or to eliminate testing, inspection, or system realignment which is inappropriate for the particular plant conditions. For plants in a shutdown condition, exercising enforcement discretion is intended to reduce shutdown risk by, again, avoiding testing, inspection or system realignment which is inappropriate for the particular plant conditions, in that, it does not provide a safety benefit or may, in fact, be detrimental to safety in the particular plant condition. Exercising enforcement discretion for plants attempting to startup is less likely than exercising it for an operating plant, as simply delaying startup does not usually leave the plant in a condition in which it could experience undesirable transients. In such cases, the Commission would expect that discretion would be exercised with respect to equipment or systems only when it has at least concluded that, notwithstanding the conditions of the license: (1) The equipment or system does not perform a safety function in the mode in which operation is to occur; (2) the safety function performed by the equipment or system is of only marginal safety benefit, provided remaining in the current mode increases the likelihood of an unnecessary plant transient; or (3) the TS or other license condition requires a test, inspection or system realignment that is inappropriate for the particular plant conditions, in that it does not provide a safety benefit, or may, in fact, be detrimental to safety in the particular plant condition.

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The decision to exercise enforcement discretion does not change the fact that a violation will occur nor does it imply that enforcement discretion is being exercised for any violation that may have led to the violation at issue. In each case where the NRC staff has chosen to exercise enforcement discretion, enforcement action will normally be taken for the root causes, to the extent violations were involved, that led to the noncompliance for which enforcement discretion was used. The enforcement action is intended to emphasize that licensees should not rely on the NRC's authority to exercise enforcement discretion as a routine substitute for compliance or for requesting a license amendment.

Finally, it is expected that the NRC staff will exercise enforcement discretion in this area infrequently. Although a plant must shut down, refueling activities may be suspended, or plant startup may be delayed, absent the exercise of enforcement discretion, the NRC staff is under no obligation to take such a step merely because it has been requested. The decision to forego enforcement is discretionary. Where enforcement discretion is to be exercised, it is to be exercised only if the NRC staff is clearly satisfied that such action is warranted from a health and safety perspective.

VIII. Enforcement Actions Involving Individuals

Enforcement actions involving individuals, including licensed operators, are significant personnel actions, which will be closely controlled and judiciously applied. An enforcement action involving an individual will normally be taken only when the NRC is satisfied that the individual fully understood, or should have understood, his or her responsibility; knew, or should have known, the required actions; and knowingly, or with careless disregard (i.e., with more than mere negligence) failed to take required actions which have actual or potential safety significance. Most transgressions of individuals at the level of Severity Level III, IV, or V violations will be handled by citing only the facility licensee.

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More serious violations, including those involving the integrity of an individual (e.g., lying to the NRC) concerning matters within the scope of the individual's responsibilities, will be considered for enforcement action against the individual as well as against the facility licensee. Action against the individual, however, will not be taken if the improper action by the individual was caused by management failures. The following examples of situations illustrate this concept:

• Inadvertent individual mistakes resulting from inadequate training or guidance provided by the facility licensee.

• Inadvertently missing an insignificant procedural requirement when the action is routine, fairly uncomplicated, and there is no unusual circumstance indicating that the procedures should be referred to and followed step-by-step.

• Compliance with an express direction of management, such as the Shift Supervisor or Plant Manager, resulted in a violation unless the individual did not express his or her concern or objection to the direction.

• Individual error directly resulting from following the technical advice of an expert unless the advise was clearly unreasonable and the licensed individual should have recognized it as such.

• Violations resulting from inadequate procedures unless the individual used a faulty procedure knowing it was faulty and had not attempted to get the procedure corrected.

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Listed below are examples of situations which could result in enforcement actions involving individuals, licensed or unlicensed. If the actions described in these examples are taken by a licensed operator or taken deliberately by an unlicensed individual, enforcement action may be taken directly against the individual. However, violations involving willful conduct not amounting to deliberate action by an unlicensed individual in these situations may result in enforcement action against a licensee that may impact an individual. The situations include, but are not limited to, violations that involve:

• Willfully causing a licensee to be in violation of NRC requirements.

• Willfully taking action that would have caused a licensee to be in violation of NRC requirements but the action did not do so because it was detected and corrective action was taken.

• Recognizing a violation of procedural requirements and willfully not taking corrective action.

• Willfully defeating alarms which have safety significance.

• Unauthorized abandoning of reactor controls.

• Dereliction of duty.

• Falsifying records required by NI regulations or by the facility license.

• Willfully providing, or causing a licensee to provide, an NRC inspecto investigator with inaccurate or incomplete information on a matter material to the NRC.

• Willfully withholding safety significant information rather than making such information known to appropriate supervisory or technical personnel in the licensee's organizati

• Submitting false information and a result gaining unescorted access to nuclear power plant.

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• Willfully providing false data to licensee by a contractor or other pers who provides test or other services, when the data affects the licensee's compliance with 10 CFR part 50, appendix B, or other regulatory requirement.

• Willfully providing false certification that components meet th requirements of their intended use, su as ASME Code.

• Willfully supplying, by vendors o equipment for transportation of radioactive material, casks that do no comply with their certificates of compliance.

• Willfully performing unauthorize bypassing of required reactor or other facility safety systems.

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• Willfully taking actions that violate Technical Specification Limiting Conditi for Operation or other license conditions (enforcement action for a willful violation will not be taken if that violation is the re of action taken following the NRC's decis to forego enforcement of the Technical Specification or other license condition o the operator meets the requirements of 10 CFR 50.54 (x), i.e., unless the operator ac unreasonably considering all the relevan circumstances surrounding the emergenc

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In deciding whether to issue an enforcement action to an unlicensed person rather than to the licensee, the NRC recognizes that judgments will have to be made on a case by case basis. In making these decisions, the NRC will consider factors such as the following:

1. The level of the individual within the organization.

2. The individual's training and experience as well as knowledge of the potential consequences of the wrongdoing.

3. The safety consequences of the misconduct.

4. The benefit to the wrongdoer, e.g., personal or corporate gain.

5. The degree of supervision of the individual, i.e., how closely is the individual monitored or audited, and the likelihood of detection (such as a radiographer working independently in the field as contrasted with a team activity at a power plant).

6. The employer's response, e.g., disciplinary action taken.

7. The attitude of the wrongdoer, e.g., admission of wrongdoing, acceptance of responsibility.

8. The degree of management responsibility or culpability.

9. Who identified the misconduct.

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Any proposed enforcement action involving individuals must be issued with the concurrence of the appropriate Deputy Executive Director. The Commission will be consulted prior to issuing a civil penalty or order to an unlicensed individual or a civil penalty to a licensed reactor operator. Prior notice will be given to the Commission on Notices of Violation without civil penalties that are issued to unlicensed individuals and enforcement actions taken against other unlicensed persons, such as corporations or partnerships. The particular sanction to be used should be determined on a case-by-case basis.[8]

Examples of sanctions that may be appropriate against individuals are:

* Issuance of a letter of reprimand,
* Issuance of a Notice of Violation, and
* Issuance of Orders.

Orders to NRC-licensed reactor operators may involve suspension for a specified period, modification, or revocation of their individual licenses. Orders to unlicensed individuals might include provisions that would:

* Prohibit involvement in NRC licensed activities for a specified period of time (normally the period of suspension would not exceed five years) or until certain conditions are satisfied, e.g., completing specified training or meeting certain qualifications.
* Require notification to the NRC before resuming work in licensed activities.
* Require the person to tell a prospective employer or customer engaged in licensed activities that the person has been subject to an NRC order.

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In the case of a licensed operator's failure to meet applicable fitness-for-duty requirements (10 CFR 55.53(j)), the NRC may issue a Notice of Violation or a civil penalty to the Part 55 licensee, or an order to suspend, modify, or revoke the Part 55 license. These actions may be taken the first time a licensed operator fails a drug or alcohol test, that is, receives a confirmed positive test that exceeds the cutoff levels of 10 CFR part 26 or the facility licensee's cutoff levels, if lower. However, normally only a Notice of Violation will be issued for the first confirmed positive test in the absence of aggravating circumstances such as errors in the performance of licensed duties or evidence of prolonged use. In addition, the NRC intends to issue an order to suspend the Part 55 license for up to three years the second time a licensed operator exceeds those cutoff levels. In the event there are less than three years remaining in the term of the individual's license, the NRC may consider not renewing the individual's license or not issuing a new license after the three year period is completed. The NRC intends to issue an order to revoke the Part 55 license the third time a licensed operator exceeds those cutoff levels. A licensed operator or applicant who refuses to participate in the drug and alcohol testing programs established by the facility licensee or

[8] Except for individuals subject to civil penalties under section 206 of the Energy Reorganization Act of 1974, as amended, NRC will not normally impose a civil penalty against an individual. However, section 234 of the Atomic Energy Act (AEA) gives the Commission authority to impose civil penalties on "any person." "Person" is broadly defined in Section 11s of the AEA to include individuals, a variety of organizations, and any representatives or agents. This gives the Commission authority to impose civil penalties on employees of licensees or on separate entities when a violation of a requirement directly imposed on them is committed.

who is involved in the sale, use, or possession of an illegal drug is also subject to license suspension, revocation, or denial.

In addition, the NRC may take enforcement action against a licensee that may impact an individual, where the conduct of the individual places in question the NRC's reasonable assurance that licensed activities will be properly conducted. The NRC may take enforcement action for reasons that would warrant refusal to issue a license on an original application. Accordingly, appropriate enforcement actions may be taken regarding matters that raise issues of integrity, competence, fitness for duty, or other matters that may not necessarily be a violation of specific Commission requirements.

In the case of an unlicensed person, whether a firm or an individual, an order modifying the facility license may be issued to require (1) the removal of the person from all licensed activities for a specified period of time or indefinitely, (2) prior notice to the NRC before utilizing the person in licensed activities, or (3) the licensee to provide notice of the issuance of such an order to other persons involved in licensed activities
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making reference inquiries. In addition, orders to employers might require retraining, additional oversight, or independent verification of activities performed by the person, if the person is to be involved in licensed activities.

IX. Inaccurate and Incomplete Information

A violation of the regulations involving submittal of incomplete and/or inaccurate information, whether or not considered a material false statement, can result in the full range of enforcement sanctions. The labeling of a communication failure as a material false statement will be made on a case-by-case basis and will be reserved for egregious violations. Violations involving inaccurate or incomplete information or the failure to provide significant information identified by a licensee normally will be categorized based on the guidance herein, in Section IV "Severity of Violations," and in Supplement VII.

The Commission recognizes that oral information may in some situations be inherently less reliable than written submittals because of the absence of an opportunity for reflection and management review. However, the Commission must be able to rely on oral communications from licensee officials concerning significant information. Therefore, in determining whether to take enforcement action for an oral statement, consideration may be given to such factors as (1) the degree of knowledge that the communicator should have had, regarding the matter, in view of his or her position, training, and experience, (2) the opportunity and time available prior to the communication to assure the accuracy or completeness of the information, (3) the degree of intent or negligence, if any, involved, (4) the formality of the communication, (5) the reasonableness of NRC reliance on the information, (6) the importance of the information which was wrong or not provided, and (7) the reasonableness of the explanation for not providing complete and accurate information.

Absent at least careless disregard, an incomplete or inaccurate unsworn oral statement normally will not be subject to enforcement action unless it involves significant information provided by a licensee official. However, enforcement action may be taken for an unintentionally incomplete or inaccurate oral statement provided to the NRC by a licensee official or others on behalf of a licensee, if a record was made of the oral information and provided to the licensee thereby permitting an
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opportunity to correct the oral information, such as if a transcript of the communication or meeting summary containing the error was made available to the licensee and was not subsequently corrected in a timely manner.

When a licensee has corrected inaccurate or incomplete information, the decision to issue a Notice of Violation for the initial inaccurate or incomplete information normally will be dependent on the circumstances, including the ease of detection of the error, the timeliness of the correction, whether the NRC or the licensee identified the problem with the communication, and whether the NRC relied on the information prior to the correction. Generally, if the matter was promptly identified and corrected by the licensee prior to reliance by the NRC, or before the NRC raised a question about the information, no enforcement action will be taken for the initial inaccurate or incomplete information. On the other hand, if the misinformation is identified after the NRC relies on it, or after some question is raised regarding the accuracy of the information, then some enforcement action normally will be taken even if it is in fact corrected. However, if the initial submittal was accurate when made but later turns out to be erroneous because of newly discovered information or advance in technology, a citation normally would not be appropriate if, when the new information became available or the advancement in technology was mad the initial submittal was corrected.

The failure to correct inaccurate or incomplete information which the licensee does not identify as significa normally will not constitute a separat violation. However, the circumstance surrounding the failure to correct may be considered relevant to the determination of enforcement action f the initial inaccurate or incomplete statement. For example, an unintentionally inaccurate or incompl submission may be treated as a more severe matter if the licensee later
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determines that the initial submittal w in error and does not correct it or if there were clear opportunities to identify the error. If information not corrected was recognized by a licensee as significant, a separate citation may be made for the failure to provide significant information. In any event, i serious cases where the licensee's actions in not correcting or providing information raise questions about its commitment to safety or its fundamen trustworthiness, the Commission may exercise its authority to issue orders modifying, suspending, or revoking the license. The Commission recognizes th enforcement determinations must be made on a case-by-case basis, taking into consideration the issues describe in this section

X. Enforcement Action Against Non-Licensees

The Commission's enforcement policy is also applicable to non-licensees, including employees of licensees, to contractors and subcontractors, and to employees of contractors and subcontractors, who knowingly provide components, equipment, or other goods or services that relate to a licensee's activities subject to NRC regulation. The prohibitions and sanctions for any of these persons who engage in deliberate misconduct or submission of incomplete or inaccurate information are provided in the rule on deliberate misconduct, e.g., 10 CFR 30.10 and 50.5.

Vendors of products or services provided for use in nuclear activities are subject to certain requirements designed to ensure that the products or services supplied that could affect safety are of high quality. Through procurement contracts with reactor licensees, vendors may be required to have quality assurance programs that meet applicable requirements including 10 CFR part 50, appendix B, and 10 CFR part 71, subpart H. Vendors supplying products or services to reactor, materials, and 10 CFR part 71 licensees are subject to the requirements of 10 CFR part 21 regarding reporting of defects in basic components.

When inspections determine that violations of NRC requirements have occurred, or that vendors have failed to fulfill contractual commitments (e.g., 10 CFR part 50, appendix B) that could adversely affect the quality of a safety significant product or service, enforcement action will be taken. Notices of Violation and civil penalties will be used, as appropriate, for licensee failures to ensure that their vendors have programs that meet applicable requirements. Notices of Violation will be issued for vendors that violate 10 CFR part 21. Civil penalties will be imposed against individual directors or responsible officers of a vendor organization who knowingly and consciously fail to provide the notice required by 10 CFR 21.21(b)(1). Notices of Nonconformance will be used for vendors which fail to meet commitments related to NRC activities.

XI. Referrals to the Department of Justice

Alleged or suspected criminal violations of the Atomic Energy Act (and of other relevant Federal laws) are referred to the Department of Justice (DOJ) for investigation. Referral to the DOJ does not preclude the NRC from taking other enforcement action under this policy. However, enforcement actions will be coordinated with the DOJ in accordance with the Memorandum of Understanding between the NRC and the DOJ, 53 FR 50317 (December 14, 1988).

XII. Public Disclosure of Enforcement Actions

Enforcement actions and licensees responses, in accordance with 10 CFR 2.790, are publicly available for inspection. In addition, press releases are generally issued for orders and civil penalties and are issued at the same time the order or proposed imposition of the civil penalty is issued. In addition, press releases are usually issued when a proposed civil penalty is withdrawn or substantially mitigated by some amount. Press releases are not normally issued for Notices of Violation that are not accompanied by orders or proposed civil penalties.

XIII. Reopening Closed Enforcement Actions

If significant new information is received or obtained by NRC which indicates that an enforcement sanction was incorrectly applied, consideration may be given, dependent on the circumstances, to reopening a closed enforcement action to increase or decrease the severity of a sanction or to correct the record. Reopening decisions will be made on a case-by-case basis, are expected to occur rarely, and require the specific approval of the appropriate Deputy Executive Director.

Supplement I—Reactor Operations

This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of reactor operations.

A. Severity Level I—Violations involving for example:

1. A Safety Limit, as defined in 10 CFR 50.36 and the Technical Specifications being exceeded;

2. A system [9] designed to prevent or mitigate a serious safety event not being able to perform its intended safety function [10] when actually called upon to work;

3. An accidental criticality; or

4. A licensed operator at the controls of a nuclear reactor, or a senior operator directing licensed activities, involved in procedural errors which result in, or exacerbate the consequences of, an alert or higher level emergency and who, as a result of subsequent testing, receives a confirmed positive test result for drugs or alcohol.

B. Severity Level II—Violations involving for example:

1. A system designed to prevent or mitigate serious safety events not being able to perform its intended safety function;

2. A licensed operator involved in the use, sale, or possession of illegal drugs or the consumption of alcoholic beverages, within the protected area; or

3. A licensed operator at the control of a nuclear reactor, or a senior operator directing licensed activities, involved in procedural errors and who, as a result of subsequent testing, receives a confirmed positive test result for drugs or alcohol.

C. Severity Level III—Violations involving for example:

1. A significant failure to comply with the Action Statement for a Technical Specification Limiting Condition for Operation where the appropriate action was not taken within the required time, such as:

(a) In a pressurized water reactor, in the applicable modes, having one high-

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[9] The term "system" as used in these supplements, includes administrative and managerial control systems, as well as physical systems.

[10] "Intended safety function" means the total safety function, and is not directed toward a loss of redundancy. A loss of one subsystem does not defeat the intended safety function as long as the other subsystem is operable.

pressure safety injection pump inoperable for a period in excess of that allowed by the action statement: or

(b) In a boiling water reactor. one primary containment isolation valve inoperable for a period in excess of that allowed by the action statement.

2. A system designed to prevent or mitigate a serious safety event:

(a) Not being able to perform its intended function under certain conditions (e.g., safety system not operable unless offsite power is available: materials or components not environmentally qualified): or

(b) Being degraded to the extent that a detailed evaluation would be required to determine its operability (e.g.. component parameters outside approved limits such as pump flow rates. heat exchanger transfer characteristics. safety valve lift setpoints. or valve stroke times):

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3. Inattentiveness to duty on the part of licensed personnel:

4. Changes in reactor parameters that cause unanticipated reductions in margins of safety:

5. A significant failure to meet the requirements of 10 CFR 50.59, including a failure such that a required license amendment was not sought:

6. A licensee failure to conduct adequate oversight of vendors resulting in the use of products or services that are of defective or indeterminate quality and that have safety significance:

7. A breakdown in the control of licensed activities involving a number of violations that are related (or, if isolated, that are recurring violations) that collectively represent a potentially significant lack of attention or carelessness toward licensed responsibilities: or

8. A licensed operator's confirmed positive test for drugs or alcohol that does not result in a Severity Level I or II violation.

9. Equipment failures caused by inadequate or improper maintenance that substantially complicates recovery from a plant transient.

D. Severity Level IV—Violations involving for example:

1. A less significant failure to comply with the Action Statement for a Technical Specification Limiting Condition for Operation where the appropriate action was not taken within the required time. such as:

(a) In a pressurized water reactor. a 5% deficiency in the required volume of the condensate storage tank: or

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(b) In a boiling water reactor. one subsystem of the two independent MSIV leakage control subsystems inoperable:

2. A failure to meet the requirements of 10 CFR 50.59 that does not result in a Severity Level I. II. or III violation:

3. A failure to meet regulatory requirements that have more than minor safety or environmental significance: or

4. A failure to make a required Licensee Event Report.

E. Severity Level V—Violations that have minor safety or environmental significance.

Supplement II—Part 50 Facility Construction

This supplement provides example violations in each of the five severity levels as guidance in determining the appropriate severity level for violatio in the area of part 50 facility construction.

A. Severity Level I—Violations involving structures or systems that a completed [11] in such a manner that th would not have satisfied their intende safety related purpose.

B. Severity Level II—Violations involving for example:

1. A breakdown in the Quality Assurance (QA) program as exemplifi by deficiencies in construction QA related to more than one work activity (e.g.. structural. piping. electrical. foundations). These deficiencies normally involve the licensee's failure conduct adequate audits or to take prompt corrective action on the basis c such audits and normally involve multiple examples of deficient construction or construction of unknow quality due to inadequate program implementation: or

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2. A structure or system that is completed in such a manner that it cou have an adverse effect on the safety of operations.

C. Severity Level III—Violations involving for example:

1. A deficiency in a licensee QA program for construction related to a single work activity (e.g.. structural. piping. electrical or foundations). This significant deficiency normally involves the licensee's failure to conduct adequate audits or to take prompt corrective action on the basis of such audits. and normally involves multiple examples of deficient construction or construction of unknown quality due to inadequate program implementation:

2. A failure to confirm the design safety requirements of a structure or system as a result of inadequate preoperational test program implementation: or

[11] The term "completed" as used in this supplement means completion of construction including review and acceptance by the construction QA organization.

3. A failure to make a required 10 CFR 50.55(e) report.

D. Severity Level IV—Violations involving failure to meet regulatory requirements including one or more Quality Assurance Criterion not amounting to Severity Level I, II, or III violations that have more than minor safety or environmental significance.

E. Severity Level V—Violations that have minor safety or environmental significance.

Supplement III—Safeguards

This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of safeguards.

A. Severity Level I—Violations involving for example:

1. An act of radiological sabotage in which the security system did not function as required and, as a result of the failure, there was a significant event, such as:

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(a) A Safety Limit, as defined in 10 CFR 50.36 and the Technical Specifications, was exceeded;

(b) A system designed to prevent or mitigate a serious safety event was not able to perform its intended safety function when actually called upon to work; or

(c) An accidental criticality occurred;

2. The theft, loss, or diversion of a formula quantity [12] of special nuclear material (SNM); or

3. Actual unauthorized production of a formula quantity of SNM.

B. Severity Level II—Violations involving for example:

1. The entry of an unauthorized individual [13] who represents a threat into a vital area [14] from outside the protected area; or

2. The theft, loss or diversion of SNM of moderate strategic significance [15] in which the security system did not function as required; or

3. Actual unauthorized production of SNM.

C. Severity Level III—Violations involving for example:

1. A failure or inability to control access through established systems or procedures, such that an unauthorized individual (i.e., not authorized unescorted access to protected area) could easily gain undetected access [16] into a vital area from outside the protected area;

2. A failure to conduct any search at the access control point or conducting an inadequate search that resulted in the introduction to the protected area of firearms, explosives, or incendiary devices and reasonable facsimiles thereof that could significantly assist radiological sabotage or theft of strategic SNM;

3. A failure, degradation, or other deficiency of the protected area intrusion detection or alarm assessment systems such that an unauthorized individual who represents a threat could predictably circumvent the system or defeat a specific zone with a high degree of confidence without insider

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knowledge, or other significant degradation of overall system capability;

4. A significant failure of the safeguards systems designed or used to prevent or detect the theft, loss, or diversion of strategic SNM;

5. A failure to protect or control classified or safeguards information considered to be significant while the information is outside the protected area and accessible to those not authorized access to the protected area;

6. A significant failure to respond to an event either in sufficient time to provide protection to vital equipment or strategic SNM, or with an adequate response force;

7. A failure to perform an appropriate evaluation or background investigation so that information relevant to the access determination was not obtained or considered and as a result a person, who would likely not have been granted access by the licensee, if the required investigation or evaluation had been performed, was granted access; or

8. A breakdown in the security program involving a number of violations that are related (or, if isolated, that are recurring violations) that collectively reflect a potentially significant lack of attention or carelessness toward licensed responsibilities.

D. Severity Level IV—Violations involving for example:

1. A failure or inability to control access such that an unauthorized individual (i.e., authorized to protected area but not to vital area) could easily gain undetected access into a vital area from inside the protected area or into a controlled access area;

2. A failure to respond to a suspected event in either a timely manner or with an adequate response force;

3. A failure to implement 10 CFR parts 25 and 95 with respect to the information addressed under section 142 of the Act, and the NRC approved security plan relevant to those parts;

4. A failure to make, maintain, or provide log entries in accordance with 10 CFR 73.71 (c) and (d), where the omitted information (i) is not otherwise available in easily retrievable records, and (ii) significantly contributes to the ability of either the NRC or the licensee to identify a programmatic breakdown;

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5. A failure to conduct a proper search at the access control point;

6. A failure to properly secure or protect classified or safeguards information inside the protected area which could assist an individual in an act of radiological sabotage or theft of strategic SNM where the information was not removed from the protected area;

7. A failure to control access such that an opportunity exists that could allow unauthorized and undetected access into the protected area but which was neither easily or likely to be exploitable;

8. A failure to conduct an adequate search at the exit from a material access area;

9. A theft or loss of SNM of low strategic significance that was not detected within the time period specified in the security plan, other relevant document, or regulation; or

10. Other violations that have more than minor safeguards significance.

E. Severity Level V—Violations that have minor safeguards significance.

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[12] See 10 CFR 73.2 for the definition of "formula quantity."

[13] The term "unauthorized individual" as used in this supplement means someone who was not authorized for entrance into the area in question, or not authorized to enter in the manner entered.

[14] The phrase "vital area" as used in this supplement includes vital areas and material access areas.

[15] See 10 CFR 73.2 for the definition of "special nuclear material of moderate strategic significance."

[16] In determining whether access can be easily gained, factors such as predictability, identifiability, and ease of passage should be considered.

Supplement IV—Health Physics (10 CFR Part 20)

58 FR 67657

≫ This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of health physics. 10 CFR part 20[17]

Paragraphs *A.–E.*

≫ [Reserved 58 FR 67657.]

Sections 20.1001—20.2401

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F. Severity Level I—Violations involving for example:

1. A radiation exposure during any year of a worker in excess of 25 rems total effective dose equivalent, 75 rems to the lens of the eye, or 250 rads to the skin of the whole body, or to the feet, ankles, hands or forearms, or to any other organ or tissue;

2. A radiation exposure over the gestation period of the embryo/fetus of a declared pregnant woman in excess of 2.5 rems total effective dose equivalent;

3. A radiation exposure during any year of a minor in excess of 2.5 rems total effective dose equivalent, 7.5 rems to the lens of the eye, or 25 rems to the skin of the whole body, or to the feet, ankles, hands or forearms, or to any other organ or tissue;

4. An annual exposure of a member of the public in excess of 1.0 rem total effective dose equivalent;

5. A release of radioactive material to an unrestricted area at concentrations in excess of 50 times the limits for members of the public as described in 10 CFR 20.1302(b)(2)(i); or

6. Disposal of licensed material in quantities or concentrations in excess of 10 times the limits of 10 CFR 20.2003.

G. Severity Level II—Violations involving for example:

1. A radiation exposure during any year of a worker in excess of 10 rems total effective dose equivalent, 30 rems to the lens of the eye, or 100 rems to the skin of the whole body, or to the feet, ankles, hands or forearms, or to any other organ or tissue;

2. A radiation exposure over the gestation period of the embryo/fetus of a declared pregnant woman in excess of 1.0 rem total effective dose equivalent;

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[17] Personnel overexposures and associated violations incurred during a life-saving or other emergency response effort will be treated on a case-by-case basis.

[18] [Reserved 58 FR 67657.]

3. A radiation exposure during any year of a minor in excess of 1 rem total effective dose equivalent; 3.0 rems to the lens of the eye, or 10 rems to the skin of the whole body, or to the feet, ankles, hands or forearms, or to any other organ or tissue;

4. An annual exposure of a member of the public in excess of 0.5 rem total effective dose equivalent;

5. A release of radioactive material to an unrestricted area at concentrations in excess of 10 times the limits for members of the public as described in 10 CFR 20.1302(b)(2)(i) (except when operation up to 0.5 rem a year has been approved by the Commission under § 20.1301(c));

6. Disposal of licensed material in quantities or concentrations in excess of five times the limits of 10 CFR 20.2003; or

7. A failure to make an immediate notification as required by 10 CFR 20.2202(a)(1) or (a)(2).

C. *Severity Level III*—Violations involving for example:

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1. A radiation exposure during any year of a worker in excess of 5 rems total effective dose equivalent, 15 rems to the lens of the eye, or 50 rems to the skin of the whole body or to the feet, ankles, hands or forearms, or to any other organ or tissue;

2. A radiation exposure over the gestation period of the embryo/fetus of a declared pregnant woman in excess of 0.5 rem total effective dose equivalent (except when doses are in accordance with the provisions of § 20.1208(d));

3. A radiation exposure during any year of a minor in excess of 0.5 rem total effective dose equivalent; 1.5 rems to the lens of the eye, or 5 rems to the skin of the whole body, or to the feet, ankles, hands or forearms, or to any other organ or tissue;

4. A worker exposure above regulatory limits when such exposure reflects a programmatic (rather than an isolated) weakness in the radiation control program;

5. An annual exposure of a member of the public in excess of 0.1 rem total effective dose equivalent (except when operation up to 0.5 rem a year has been approved by the Commission under § 20.1301(c));

6. A release of radioactive material to an unrestricted area at concentrations in excess of two times the effluent concentration limits referenced in 10 CFR 20.1302(b)(2)(i) (except when operation up to 0.5 rem a year has been approved by the Commission under § 20.1301(c));

7. A failure to make a 24-hour notification required by 10 CFR 20.2202(b) or an immediate notification required by 10 CFR 20.2201(a)(1)(i);

8. A substantial potential for exposures or releases in excess of the applicable limits in 10 CFR part 20 §§ 20.1001–20.2401 whether or not an exposure or release occurs;

9. Disposal of licensed material not covered in Severity Levels I or II;

10. A release for unrestricted use of contaminated or radioactive material or equipment that poses a realistic potential for exposure of the public to levels or doses exceeding the annual dose limits for members of the public, or that reflects a programmatic (rather than an isolated) weakness in the radiation control program;

11. Conduct of licensee activities by a technically unqualified person;

12. A significant failure to control licensed material; or

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13. A breakdown in the radiation safety program involving a number of violations that are related (or, if isolated, that are recurring) that collectively represent a potentially significant lack of attention or carelessness toward licensed responsibilities.

D. *Severity Level IV*—Violations involving for example:

1. Exposures in excess of the limits of 10 CFR 20.1201, 20.1207, or 20.1208 not constituting Severity Level I, II, or III violations;

2. A release of radioactive material to an unrestricted area at concentrations in excess of the limits for members of the public as referenced in 10 CFR 20.1302(b)(2)(i) (except when operation up to 0.5 rem a year has been approved by the Commission under § 20.1301(c));

3. A radiation dose rate in an unrestricted or controlled area in excess of 0.002 rem in any 1 hour (2 millirem/hour) or 50 millirems in a year;

4. Failure to maintain and implement radiation programs to keep radiation exposures as low as is reasonably achievable;

5. Doses to a member of the public in excess of any EPA generally applicable environmental radiation standards, such as 40 CFR part 190;

6. A failure to make the 30-day notification required by 10 CFR 20.2201(a)(1)(ii) or 20.2203(a);

7. A failure to make a timely written report as required by 10 CFR 20.2201(b), 20.2204, or 20.2206; or

8. Any other matter that has more than a minor safety, health, or environmental significance.

E. *Severity Level V*—Violations that are of a minor safety, health, or environmental significance.

Supplement V—Transportation

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This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of NRC transportation requirements.[19]

A. *Severity Level I*—Violations involving for example:

1. Failure to meet transportation requirements that resulted in loss of control of radioactive material with a breach in package integrity such that the material caused a radiation exposure to a member of the public and there was clear potential for the public to receive more than .1 rem to the whole body;

2. Surface contamination in excess of 50 times the NRC limit; or

3. External radiation levels in excess of 10 times the NRC limit.

B. *Severity Level II*—Violations involving for example:

1. Failure to meet transportation requirements that resulted in loss of control of radioactive material with a breach in package integrity such that there was a clear potential for the member of the public to receive more than .1 rem to the whole body;

2. Surface contamination in excess of 10, but not more than 50 times the NRC limit;

3. External radiation levels in excess of five, but not more than 10 times the NRC limit; or

[19] Some transportation requirements are applied to more than one licensee involved in the same activity such as a shipper and a carrier. When a violation of such a requirement occurs, enforcement action will be directed against the responsible licensee which, under the circumstances of the case, may be one or more of the licensees involved.

4. A failure to make required initial notifications associated with Severity Level I or II violations.

C. Severity Level III—Violations involving for example:

1. Surface contamination in excess of five but not more than 10 times the NRC limit:

2. External radiation in excess of one but not more than five times the NRC limit:

3. Any noncompliance with labeling, placarding, shipping paper, packaging, loading, or other requirements that could reasonably result in the following:

(a) A significant failure to identify the type, quantity, or form of material:

(b) A failure of the carrier or recipient to exercise adequate controls: or

(c) A substantial potential for either personnel exposure or contamination above regulatory limits or improper transfer of material:

4. A failure to make required initial notification associated with Severity Level III violations: or

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5. A breakdown in the licensee's program for the transportation of licensed material involving a number of violations that are related (or, if isolated, that are recurring violations) that collectively reflect a potentially significant lack of attention or carelessness toward licensed responsibilities.

D. Severity Level IV—Violations involving for example:

1. A breach of package integrity without external radiation levels exceeding the NRC limit or without contamination levels exceeding five times the NRC limits:

2. Surface contamination in excess of but not more than five times the NRC limit:

3. A failure to register as an authorized user of an NRC-Certified Transport package:

4. A noncompliance with shipping papers, marking, labeling, placarding packaging or loading not amounting to a Severity Level I, II, or III violation:

5. A failure to demonstrate that packages for special form radioactive material meets applicable regulatory requirements:

6. A failure to demonstrate that packages meet DOT Specifications for 7A Type A packages: or

7. Other violations that have more than minor safety or environmental significance.

E. Severity Level V—Violations that have minor safety or environmental significance.

Supplement VI—Fuel Cycle and Materials Operations

This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of fuel cycle and materials operations.

A. Severity Level I—Violations involving for example:

1. Radiation levels, contamination levels, or releases that exceed 10 times the limits specified in the license:

2. A system designed to prevent or mitigate a serious safety event not being operable when actually required to perform its design function:

3. A nuclear criticality accident: or

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4. A failure to follow the procedures of the quality management program, required by § 35.32, that results in a death or serious injury (e.g., substantial organ impairment) to a patient.

B. Severity Level II—Violations involving for example:

1. Radiation levels, contamination levels, or releases that exceed five times the limits specified in the license:

2. A system designed to prevent or mitigate a serious safety event being inoperable: or

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3. A substantial programmatic failure in the implementation of the quality management program required by 10 CFR 35.32 that results in a misadministration.

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C. Severity Level III—Violations involving for example:

1. A failure to control access to licensed materials for radiation purposes as specified by NRC requirements:

2. Possession or use of unauthorized equipment or materials in the conduct of licensee activities which degrades safety:

3. Use of radioactive material on humans where such use is not authorized:

4. Conduct of licensed activities by a technically unqualified person:

5. Radiation levels, contamination levels, or releases that exceed the limits specified in the license:

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6. Substantial failure to implement the quality management program as required by § 35.32 that does not result in a misadministration; failure to report a misadministration; or programmatic weakness in the implementation of the quality management program that results in a misadministration.

7. A breakdown in the control of licensed activities involving a number of violations that are related (or, if isolated, that are recurring violations) that collectively represent a potentially significant lack of attention or carelessness toward licensed responsibilities:

8. A failure, during radiographic operations, to have present or to use radiographic equipment, radiation survey instruments, and/or personnel monitoring devices as required by 10 CFR part 34:

9. A failure to submit an NRC Form 241 in accordance with the requirements in § 150.20 of 10 CFR part 150: or

57 FR 5791

10. A failure to receive required NRC approval prior to the implementation of a change in licensed activities that has radiological or programmatic significance, such as, a change in ownership; lack of an RSO or replacement of an RSO with an unqualified individual; a change in the location where licensed activities are being conducted, or where licensed material is being stored where the new facilities do not meet safety guidelines; or a change in the quantity or type of radioactive material being processed or used that has radiological significance.

D. Severity Level IV—Violations involving for example:

1. A failure to maintain patients hospitalized who have cobalt-60, cesium-137, or iridium-192 implants or to conduct required leakage or contamination tests, or to use properly calibrated equipment:

2. Other violations that have more than minor safety or environmental significance: or

58 FR 17321

3. Failure to follow the quality management program, including procedures, whether or not a misadministration occurs, provided the failures are isolated, do not demonstrate a programmatic weakness in the implementation of the QM program, and have limited consequences if a misadministration is involved; failure to conduct the required program review; or failure to take corrective actions as required by § 35.32; or

57 FR 5791

4. A failure to keep the records required by §§ 35.32 or 35.33.

E. Severity Level V—Violations that have minor safety or environmental significance.

Supplement VII—Miscellaneous Matters

This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations involving miscellaneous matters.

A. Severity Level I—Violations involving for example:

1. Inaccurate or incomplete information [30] that is provided to the NRC (a) deliberately with the knowledge of a licensee official that the information is incomplete or inaccurate, or (b) if the information, had it been complete and accurate at the time provided, likely would have resulted in regulatory action such as an immediate order required by the public health and safety.

57 FR 5791

2. Incomplete or inaccurate information that the NRC requires be kept by a licensee that is (a) incomplete or inaccurate because of falsification by or with the knowledge of a licensee official, or (b) if the information, had it been complete and accurate when reviewed by the NRC, likely would have resulted in regulatory action such as an immediate order required by public health and safety considerations;

3. Information that the licensee has identified as having significant implications for public health and safety or the common defense and security ("significant information identified by a licensee") and is deliberately withheld from the Commission;

4. Action by senior corporate management in violation of 10 CFR 50.7 or similar regulations against an employee;

5. A knowing and intentional failure to provide the notice required by 10 CFR part 21; or

6. A failure to substantially implement the required fitness-for-duty program.[31]

B. Severity Level II—Violations involving for example:

1. Inaccurate or incomplete information that is provided to the NRC (a) by a licensee official because of careless disregard for the completeness or accuracy of the information, or (b) if the information, had it been complete and accurate at the time provided, likely would have resulted in regulatory action such as a show cause order or a different regulatory position;

2. Incomplete or inaccurate information that the NRC requires be kept by a licensee which is (a) incomplete or inaccurate because of careless disregard for the accuracy of the information on the part of a licensee official, or (b) if the information, had it been complete and accurate when reviewed by the NRC, likely would have resulted in regulatory action such as a show cause order or a different regulatory position;

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3. "Significant information identified by a licensee" and not provided to the Commission because of careless disregard on the part of a licensee official;

4. An action by plant management above first-line supervision in violation of 10 CFR 50.7 or similar regulations against an employee;

5. A failure to provide the notice required by 10 CFR part 21;

6. A failure to remove an individual from unescorted access who has been involved in the sale, use, or possession of illegal drugs within the protected area or take action for on duty misuse of alcohol, prescription drugs, or over-the-counter drugs;

7. A failure to take reasonable action when observed behavior within the protected area or credible information concerning activities within the protected area indicates possible unfitness for duty based on drug or alcohol use; or

8. A deliberate failure of the licensee's Employee Assistance Program (EAP) to notify licensee's management when EAP's staff is aware that an individual's condition may adversely affect safety related activities.

C. Severity Level III—Violations involving for example:

1. Incomplete or inaccurate information that is provided to the NRC (a) because of inadequate actions on the part of licensee officials but not amounting to a Severity Level I or II violation, or (b) if the information, had it been complete and accurate at the time provided, likely would have resulted in a reconsideration of a regulatory position or substantial further inquiry such as an additional inspection or a formal request for information;

2. Incomplete or inaccurate information that the NRC requires be kept by a licensee that is (a) incomplete or inaccurate because of inadequate actions on the part of licensee officials but not amounting to a Severity Level I or II violation, or (b) if the information, had it been complete and accurate when reviewed by the NRC, likely would have resulted in a reconsideration of a regulatory position or substantial further inquiry such as an additional inspection or a formal request for information;

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3. A failure to provide "significant information identified by a licensee" to the Commission and not amounting to a Severity Level I or II violation;

4. An action by first-line supervision in violation of 10 CFR 50.7 or similar regulations against an employee;

5. An inadequate review or failure to review such that, if an appropriate review had been made as required, a 10 CFR part 21 report would have been made;

6. A failure to complete a suitable inquiry on the basis of 10 CFR part 26, keep records concerning the denial of access, or respond to inquiries concerning denials of access so that, as a result of the failure, a person previously denied access for fitness-for-duty reasons was improperly granted access;

7. A failure to take the required action for a person confirmed to have been tested positive for illegal drug use or take action for onsite alcohol use; not amounting to a Severity Level II violation;

8. A failure to assure, as required, that contractors or vendors have an effective fitness-for-duty program; or

9. A breakdown in the fitness-for-duty program involving a number of violations of the basic elements of the fitness-for-duty program that collectively reflect a significant lack of attention or carelessness towards meeting the objectives of 10 CFR 26.10.

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[30] In applying the examples in this supplement regarding inaccurate or incomplete information and records, reference should also be made to the guidance in Section IX, "Inaccurate and Incomplete Information," and to the definition of "licensee official" contained in Section IV.C.

[31] The example for violations for fitness-for-duty relate to violations of 10 CFR part 26.

D. Severity Level IV—Violations involving for example:

1. Incomplete or inaccurate information of more than minor significance that is provided to the NRC but not amounting to a Severity Level I, II, or III violation;

2. Information that the NRC requires be kept by a licensee and that is incomplete or inaccurate and of more than minor significance but not amounting to a Severity Level I, II, or III violation;

3. An inadequate review or failure to review under 10 CFR part 21 or other procedural violations associated with 10 CFR part 21 with more than minor safety significance;

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4. Isolated failures to meet basic elements of the fitness-for-duty program not involving a Severity Level I, II, or III violation; or

5. A failure to report acts of licensed operators or supervisors pursuant to 10 CFR 26.73.

E. Severity Level V—Violations involving for example:

1. Incomplete or inaccurate information that is provided to the Commission and the incompleteness or inaccuracy is of minor significance;

2. Information that the NRC requires be kept by a licensee that is incomplete or inaccurate and the incompleteness or inaccuracy is of minor significance;

3. Minor procedural requirements of 10 CFR part 21; or

4. Minor violations of fitness-for-duty requirements.

Supplement VIII—Emergency Preparedness

This supplement provides examples of violations in each of the five severity levels as guidance in determining the appropriate severity level for violations in the area of emergency preparedness. It should be noted that citations are not normally made for violations involving emergency preparedness occurring during emergency exercises. However, where exercises reveal (i) training, procedural, or repetitive failures for which corrective actions have not been taken, (ii) an overall concern regarding the licensee's ability to implement its plan in a manner that adequately protects public health and safety, or (iii) poor self critiques of the licensee's exercises, enforcement action may be appropriate.

A. Severity Level I—Violations involving for example:

In a general emergency, licensee failure to promptly (1) correctly classify the event, (2) make required notifications to responsible Federal, State, and local agencies, or (3) respond to the event (e.g., assess actual or potential offsite consequences, activate emergency response facilities, and augment shift staff.)

B. Severity Level II—Violations involving for example:

In a site emergency, licensee failure to promptly (1) correctly classify the event, (2) make required notifications to responsible Federal, State, and local agencies, or (3) respond to the event (e.g., assess actual or potential offsite consequences, activate emergency response facilities, and augment shift staff); or

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2. A licensee failure to meet or implement one emergency planning standard involving assessment or notification; or

C. Severity Level III—Violations involving for example:

In an alert, licensee failure to promptly (1) correctly classify the event, (2) make required notifications to responsible Federal, State, and local agencies, or (3) respond to the event (e.g., assess actual or potential offsite consequences, activate emergency response facilities, and augment shift staff);

2. A licensee failure to meet or implement more than one emergency planning standard involving assessment or notification.

3. A breakdown in the control of licensed activities involving a number of violations that are related (or, if isolated, that are recurring violations) that collectively represent a potentially significant lack of attention or carelessness toward licensed responsibilities.

D. Severity Level IV—Violations involving for example:

A licensee failure to meet or implement any emergency planning standard or requirement not directly related to assessment and notification.

E. Severity Level V—Violations that have minor safety or environmental significance.

Appendix D to Part 2—Schedule for the Proceeding on Application for a License To Receive and Process High-Level Radioactive Waste at a Geologic Repository Operations Area

Day	Regulation (10 CFR)	Action
0	2.101(f)(8), 2.105(a)(5)	Federal Register Notice of Hearing.
30	2.1014(a)(1)	Petition to intervene/request for hearing, w/contentions.
	2.715(c)	Petition for status as interested government participant & interested government participant petitions.
50	2.1014(b)	Answers to intervention & interested government participant petitions.
70	2.1021	1st Prehearing Conference.
100		1st Prehearing Conference Order; identifies participants in proceeding, admits contentions, and sets discovery and other schedules.
	2.1018(b)(1), 2.1019	Deposition discovery begins.
110	2.1015(b)	Appeals from 1st Prehearing Conference Order, w/briefs.
120	2.1015(b)	Briefs in opposition to appeals.
150		Commission order ruling on appeals from 1st Prehearing Conference Order.
548		NRC staff issues SER.
578	2.1022	2nd Prehearing Conference.
608		2nd Prehearing Conference Order; finalizes issues for hearing and sets schedule for pre-filed testimony and hearing.
618	2.1015(b)	Appeals from 2nd Prehearing Conference Order, w/briefs.
628	2.1015(b)	Briefs in opposition to appeals.
658		Commission order ruling on appeals from 2nd Prehearing Conference Order.
660		Last practicable date for motions for summary disposition.
680		Replies to last practicable motions for summary disposition.
690	Supp. info.	Discovery complete.
700		Presiding Officer order on last practicable motions for summary disposition.
710	2.1015(b)	Appeals from last practicable summary disposition order w/briefs.
720		Evidentiary hearing begins.
	2.1015(b)	Briefs in opposition to appeals from last practicable summary disposition orders.
810		Evidentiary hearing ends.
840	2.754(a)(1)	Applicant's proposed findings.
850	2.754(a)(2)	Other parties' (except NRC staff's) proposed findings.
860	2.754(a)(2)	NRC staff's proposed findings.
865	2.754(a)(3)	Applicant's reply to proposed findings.
955	2.760	Initial Decision.
965	2.788(a), 2.762(a), 2.1015(c)	Stay motions to Commission Notices of Appeals.
975	2.788(d)	Replies to stay motions.
995		Commission ruling on stay motion.
	2.762(b)	Appellant's briefs.
1005	2.788(a)	Stay motions to Commission.
1015	2.788(d)	Replies to stay motions.
1025	2.762(c)	Appellee's brief.
1035	2.762(c)	NRC staff brief.
1055	2.1023 Supp. info	Completion of NMSS and Commission supervisory review; Commission ruling on any stay motions; issuance of construction authorization; NWPA 3-year period tolled.
1085	2.763	Oral argument on appeals.
1125		Commission decision.

56 FR 14151

CONGRESSIONAL CORRESPONDENCE SYSTEM
DOCUMENT PREPARATION CHECKLIST

This checklist is be submitted with each document (or group of Qs/As) sent for ing into the CCS.

1. BRIEF DESCRIPTION OF DOCUMENT(S) Ltr to Rep Rose

2. TYPE OF DOCUMENT X Correspondence ____ Hearings (Qs/As)

3. DOCUMENT CONTROL ____ Sensitive (NRC Only) X Non-Sensitive

4. CONGRESSIONAL COMMITTEE and SUBCOMMITTEES (if applicable)

____ Congressional Committee

____ Subcommittee

5. SUBJECT CODES

(a) ____

(b) ____

(c) ____

6. SOURCE OF DOCUMENTS

(a) ____ 5520 (document name ____

(b) X Scan (c) ____ Attachments

(d) ____ Rekey (e) ____ Other ____

7. SYSTEM LOG DATES

(a) 6/7/94 Date OCA sent document to CCS

(b) ____ Date CCS receives document

(c) ____ Date returned to OCA for additional information

(d) ____ Date resubmitted by OCA to CCS

(e) ____ Date entered into CCS by ____

(f) ____ Date OCA notified that document is in CCS

8. COMMENTS 090015

____

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

JAN 13 1994

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

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/93-55 AND 50-324/93-55)

This refers to the Readiness Assessment Team Inspection conducted by H. O. Christensen of this office on December 6-15, 1993. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel and observation of activities in progress.

In the areas inspected operations, engineering, self-assessment capabilities and the work control process), you are capable of supporting Unit 1 restart and power operations. However, prior to restart the following issues need to be resolved: (1) approximately 100 local leak rate test surveillances will expire before the completion of an 18-month operating cycle; (2) complete additional training on procedures and information contained in NRC Information Notice 93-89 on the reactor vessel water level reference leg backfill modification; and (3) core shroud issues and associated refuel floor oversight.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). In addition, the enclosed Inspection Report identified activities that violated NRC requirements that will not be subject to enforcement action because the licensee's efforts in identifying and/or correcting the violation meet the criteria specified in Section VII.B. of the Enforcement Policy.

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You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, and its enclosures, and any reply will be placed in the NRC Public Document Room.

The response directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Jon R. Johnson
for Ellis W. Merschoff, Director
Division of Reactor Projects

Enclosures:
1. Notice of Violation
2. NRC Inspection Report
   w/Attachment

cc w/encls:
H. W. Habermeyer, Jr.
Vice President
Nuclear Services Department
Carolina Power & Light Company
P. O. Box 1551 - Mail OHS7
Raleigh, NC 27602

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Plant Manager Unit 1
Brunswick Steam Electric Plant
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Southport, NC 28461

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Brunswick Steam Electric Plant
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Southport, NC 28461

(cc w/encls cont'd - See page 3)

(cc w/encls cont'd)
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Associate General Counsel
Carolina Power and Light Company
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Public Service Commission
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Donald Warren, Chairman
Board of Commissioners
P. O. Box 2571
Shallotte, NC 28459

Mayor
City of Wilmington
2518 Park Avenue
Wilmington, NC 2840

Mayor
City of Southport
201 East Moore Street
Southport, NC 28461

Mayor
City of Boiling Spring Lakes
336 Cedar Road
Boiling Spring Lakes, NC 28461

ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power and Light Company
Brunswick Units 1 and 2

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

During an NRC inspection conducted on December 6-15, 1993, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C the violations are listed below:

A. Technical Specification 6.8.1.a requires that written procedures shall be established, implemented, and maintained covering the activities referenced in Regulatory Guide 1.33, November 1972. Included in the covered activities are maintenance procedures and instructions.

Contrary to the above,

1. Preventive maintenance procedure OPM-FLT508, Diesel Generator Starting Air and Control Air Filters, was not adequately maintained, in that torque specifications for the control air moisture-trap cap screws (obtained from the vendor on November 12, 1993, to preclude recurring gasket failures) were not included as of December 11, 1993. As a result, the control air moisture-trap associated with EDG 4 was reassembled on November 29, 1993, with technically deficient cap screw torque. This condition went undiscovered until NRC intervention on December 10, 1993.

2. As of December 11, 1993, Preventive Maintenance Routes 1MSLAAC and 1MSLAAB (Filter Inspection/Replacement On Starting/Control Air For EDGs 1 and 2, respectively) were not adequately maintained, in that both required inspection/replacement of a Hankison Dehydrafilter which no longer exits. This component was eliminated from the control air systems of EDG 1 and 2 on July 17, and October 5, 1993, respectively.

3. On December 14, 1993, maintenance instructions provided in Work Request/Job Order 93-BFLR2 (Troubleshoot Service Water Pump A Discharge Valve 2-SW-V14) were not adequately established, in that motor operator valve coupling replacement instructions did not reflect required torquing.

This is a Severity Level IV violation (Supplement I).

B. Technical Specification 6.8.1.a. requires that written procedures shall be established, implemented, and maintained as recommended in Appendix "A" of Regulatory Guide 1.33, November 1972. Paragraphs A.3 and A.4 of Regulatory Guide 1.33 recommend procedures for equipment control, temporary changes, jumper control and administrative procedures.

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Instruction OI-13, Valve and Electrical Lineup Administrative Controls, Operating Procedure Step 4.6, requires that all valves will be maintained in the position required for the Operating Procedure (OP) valve lineup. It further states that if a valve is being operated in the course of an approved procedure it will be returned to its OP lineup position when the procedure is completed.

Plant Procedure PLP-22, Temporary Modifications, Step 5.6, closeout, requires that temporary modifications (TPM) sketches be removed from the control room drawings when the TPM is closed.

Plant Notice PN-30, Integrated Recovery Methodology, Step 6.7.5, requires that for open items, the outage scope deletion form shall be used for the deletion of an item that is in the integrated startup schedule.

Administrative Instruction AI-59, Jumpering and Wire Removal, Step 5.3, requires that after the completion of the job, the wire is reconnected, the jumper and wire removal tags shall be attached to the work request (if contaminated, tags should be disposed of properly and explanation attached to the work request).

Contrary to the above:

1. On December 9, 1993, valve 1E41-F036 had not been returned to its OP valve lineup position upon completion of special procedure 1-SP-93-070, RCIC/HPCI Low Pressure Testing Using Auxiliary Steam. Based on this finding, the licensee identified three additional valves that had not been returned to their OP valve lineup positions.

2. On December 11, 1993, a TPM (1-92-0336) sketch was not removed from the Unit 1 Core Spray drawing D-25024 following closeout of the TPM on September 30, 1993. The licensee conducted an audit of temporary modifications on December 13, 1993, and identified additional problems with control of TPM sketches.

3. Open Item 93-ATDD1, Drywell Fan Isolators, was deleted from the startup schedule without completing the outage scope deletion form.

4. As of December 10, 1993, several jumper and wire removal tags in the Unit 1 drywell were not properly removed after work had been completed.

This is a Severity Level IV violation (Supplement I).

C. 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, states in part, Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformances are promptly identified and corrected.

Contrary to the above, the corrective actions for violations B.1, for NRC inspection Report 50-324/93-201, dated June 23, 1993, were inadequate, in that on December 14, 1993, an unauthorized operator aid (span gas data sheets) was identified on the drywell hydrogen and oxygen monitor, CAC 4409 and 4410. The data sheets were unauthorized due to the cancellation of Maintenance Procedure OMI-16-040A, Replacement of CAC-QT-4409/4410 Calibration Gas Cylinders, on November 2, 1993.

This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light Company is hereby required to submit a written statement or explanation to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or demand for information may be issued as to why the license should not be modified, suspended or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 13th day of January 1994

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/93-55 and 50-324/93-55

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: December 6 - 15, 1993

Team Leader: [signature] 1/13/94
Harold O. Christensen, Chief — Date Signed
Reactor Projects Section 1A
Division of Reactor Projects

Team Members: R. Carroll, Project Engineer
M. Thomas, Reactor Inspector
J. Lenahan, Reactor Inspector
C. Patterson, Senior Resident Inspector
R. Musser, Resident Inspector
C. Hughey, Resident Inspector
B. Parker, Radiation Specialist

Approved by: [signature] 1/13/94
David M. Verrelli, Chief — Date Signed
Reactor Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope:

This special team inspection was conducted to assess the readiness of Brunswick Unit 1 for restart and power operations. This inspection involved the areas of operations, engineering, self-assessment, and work control.

Results:

In the four areas inspected; operations, engineering, self assessment capability and work control process; the licensee is capable of supporting Unit 1 restart and power operations. Prior to Unit 1 restart the following issues must be resolved:

- Approximately 100 local leak rate test surveillances will expire (June 1995) before the completion of an 18-month operating cycle.

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- Complete additional training on procedures and NRC Information Notice on the reactor vessel water level ' ference leg backfill modification.

- Resolve the core shroud issues and refuel floor oversight.

During the inspection four violations were identified. The first violation was for failure to follow procedures with four examples: failure to lock open a HPCI drain valve, paragraph 2.b ; the failure to remove a temporary modification sketch from control drawings upon completion of the modification, paragraph 2.a; the failure to remove 10 jumper and wire removal tags when the work was completed, paragraph 2.b; and the failure to process an outage scope deletion on a work order, paragraph 4.c. The second violation was for inadequate maintenance instructions paragraph 5. The third violation was for the inadequate corrective action for the control of unauthorized operator aids, paragraph 4.c. The last violation, which will be an NRC identified non-cited violation, was for inadequate radiation work practices.

In the operations area the number of operator work-arounds and temporary modifications are relatively small, paragraph 2.a. The four systems walked down by the inspectors were appropriately maintained and were ready to support Unit 1 restart, paragraph 2.b.

The engineering backlog is large, but appears manageable. The licensee has plans to out-source the backlog and have it reduced by 1995. This process will be a challenge to the licensee to ensure that a quality product is produced, paragraph 3.a. The reactor vessel shroud repair lacked adequate quality control coverage and the test qualification procedures for bolt tensioning were inadequate, paragraph 3.c. These issues will be addressed further in NRC inspection report 93-58.

The licensee's self-assessment capability, both line organization and the Nuclear Assessment Department (NAD), was satisfactory. Issues were being identified and corrective actions were being addressed. The NAD Unit 1 Startup Readiness Assessment identified that management of contractors involved in refuel floor activities needed strengthening. The licensee took some actions to address this issue; however, additional oversight was still needed, paragraph 4.a. The PN-31 process, Line Management Self-Assessment of Readiness for Restart of Unit 1, appears adequate to ensure plant systems, processes, and people are ready to support Unit 1 restart, paragraph 4.c.

The work control process has improved; however, weaknesses still exist. The process is functioning and controlling the maintenance backlog. The maintenance backlog on both Units is manageable and no operability issues were identified, paragraph 5.

REPORT DETAILS

1. Persons Contacted

*W. Cavanaugh, President and COO, CP&L
*W. Orser, Executive Vice President, Nuclear Generation
*H. Habermeyer, Vice President, Nuclear Services
*R. Anderson, Vice President, Brunswick
*W. Campbell, Vice President, Nuclear Engineering Department
*C. Hinnant, Director, Site Operations
*J. Cowan, Plant General Manager, Unit 1
*C. Warren, Plant General Manager, Unit 2
*R. Grazio, Manager, Nuclear Engineering Department - Brunswick
*G. Miller, Manager, Technical Support
E. Quidley, Integrated Scheduling Manager, Work Control
C. Pardee, Manager of ECCS, Tech Support
G. Anthony, HPCI System Engineer, Tech Support
K. Horn, Unit Two Scheduling Manager, Work Control
*K. Ahern, Manager, Work Control
K. Huggins, Unit One Outage System Scheduler, Work Control
J. Lyash, Manager of Operations Support, Operations
D. Lichty, Unit One Operations On-Line Scheduler, Work Control
E. Hutt, Senior Reactor Operator, Operations

L [illegible] Employees

Other licensee employees contacted included maintenance supervisors, craftsmen, engineers, technicians, operators, and office personnel.

NRC Personnel

*S. Ebneter, Regional Administrator, Region II (RII)
*J. Johnson, Deputy Director, Division of Reactor Projects (DRP), RII
*G. Lainas, Assistant Director for Region II Reactors, Office of Nuclear Reactor Regulation (NRR)
*S. Bajwa, Acting Project Director, Project Directorate II-1, NRR
*P. Milano, Project Manager, NRR
*R. Prevatte, Senior Resident Inspector - Brunswick, DRP, RII

*Attended exit interview

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

2. Operations (71707, 71710)

a. Operator Work-arounds

The inspector reviewed the status of the Unit One operator work-arounds for potential adverse effect on plant operators. This consisted of reviewing control room annunciators/instruments and temporary modifications. During this review, the following procedures were used:

OI-55	Annunciator System
OI-05	Annunciator Status
PLP-22	Temporary Modifications
OI-70	Operator Work-Around Identification and Tracking
AI-109	Performance of Nuclear Safety Reviews

Operator Work-Arounds

This is defined in OI-70 as anything other than the initial response to an event or equipment failure that requires an operator to perform additional work or to take compensatory action because something does not work as it should. The goal established was for less than 20 and on December 7, 1993, there were 15. The inspector reviewed the list which was compiled of issues already tracked on clearances, LCOs, increased frequency PTs, or other. Each of the active items was reviewed and adequate disposition was planned or scheduled. This classification was more of a management tool for focusing attention on the number of items.

RTGB or Control Room Annunciator and Instruments

The goal for control room annunciators and instruments was less than five with a current count of 17. The inspector reviewed the list with operations management. Each of the items were being resolved. Although the goal was being exceeded, the goal was less than the operating Unit 2 goal of 40 which had a current count of 51. The applicable procedures were reviewed. The procedures give specific guidance for disabling annunciators and annunciators with multiple inputs. These requirements are tied to PLP-22, Temporary Modifications, that is also tied to AI-109, Performance of Nuclear Safety Reviews. Therefore, certain annunciators, if disabled, may require both processing a temporary modification and a corresponding safety evaluation.

During the review of the RTGB list in the control room, the inspector questioned why an RTGB item concerning a ground alarm on 480 volt substation 1E was still open. The description of the problem was that on October 15, 1993, a ground alarm was received, the alarm relay was picked up , and after five minutes the alarm cleared. The request was to investigate as soon as possible and WR/JO 93-BCFD1 was written. On November 2, 1993, maintenance determined that little could be done to locate the problem since the alarm had cleared. On November 8, 1993, the system engineer requested the work request be deleted. As a result of the inspector's questioning this item was closed on December 12, 1993.

Temporary Modifications

The inspector reviewed the temporary modification log sheets and there were 16 active modifications. The goal was less than 20. Two were designated as safety-related and the others were not safety-related. The safety evaluations were reviewed for the two temporary modification classified as safety related.

EER 92-0065, revision two, was written concerning operation of the RCIC system. This EER evaluated a problem with oxygen increase in the torus during RCIC operation and addressed operation of the vacuum pump and vent line. Operation of RCIC was not affected by this temporary modification.

EER 93-0585 evaluated a temporary hose connection from the demineralized water system to the CRDs. The temporary hose provides a means for maintaining water flow through the CRD system during periods when the CRD pumps are removed from service. This connection was for Operational Condition 5 and the vessel defueled.

The inspector questioned the classification of temporary modifications 1-92-0280, RHR A and 1-92-0280, RHR B. They were designated as nonsafety-related. This modification raised the RHR keepfill relief valves and pressure regulator setpoints to reduce the differential pressure across the regulating valve. The system was classified as a safety system on the RHR side of the isolation check valves and nonsafety on the keepfill side. Since the modification was on the keepfill side the temporary modification was classified as nonsafety. The safety assessment was detailed and complete addressing safety system operation.

The inspector reviewed the Unit 1 control room drawings to verify that temporary modifications were included. Several drawings contained a sketch of the temporary modification attached to the system drawing with the temporary modification number and EER number identified. However, one sketch without any identification number was attached to core spray drawing D-25024 sheet 2 concerning a temporary makeup connection to the fuel pool. The temporary modification had been closed on September 30, 1993, and the sketch should have been removed. The licensee initiated an ACR (93-398) to correct the problem. The temporary modification process (PLP-22) was started in March, 1993. In July 1993, the licensee performed a self assessment on the process and identified a number of weaknesses. Revision 1 to PLP-22 was issued on August 13, 1993, to correct the weaknesses. This revision tightened the controls for tracking numbers and controls for closure of temporary modifications.

As part of the corrective action for ACR 93-398, the licensee conducted an audit of temporary modifications on December 13, 1993, and found additional problems with control of TPM sketches.

During the transition from revision zero to revision one of PLP-22, the existing or old TPMs were not adequately controlled. Revision zero of the procedure required only sketches attached to control room drawings but revision one required that TPM sketches be attached to control room, work control, and clearance center drawings. For ten older TPMs the sketches were not added to work control and clearance centers.

This is a failure to follow procedures in accordance with PLP-22, and is the first example of, violation 93-55-04. TS 6.8.1.a requires procedures in regulatory guide 1.33 be implemented for temporary changes. PLP-22 implements this requirement and requires removal of sketches once TPMs are closed and establishes requirements for control of TPM sketches.

In summary, no restart issues were identified concerning the control of operator work-arounds, RTGBs, and temporary modifications. Items were being tracked and procedures were adequate to address safety issues. One violation example concerning failure to follow procedures for temporary modification sketches was identified.

b. System Readiness

High Pressure Coolant Injection System

The Unit 1 HPCI system was walked down to confirm system readiness by verifying proper system alignment (of valves, breakers, and remote indications), adequate material condition, and to ensure that piping and components were installed in accordance with plant drawings. During the walkdown, P&ID D-25023, sheets 1 and 2, "High Pressure Coolant Injection System" and procedure 1-OP-19, "High Pressure Coolant Injection System Operating Procedure" were utilized by the inspector.

A number of deficiencies were discovered by the inspector during the system walkdown. The first deficiency was identified while verifying valve positions. The inspector found that valve 1E41-F036, the Supply Drain Pot Normal Operating Orifice Upstream Isolation Valve, was in the open position while the system alignment specified in 1-OP-19 requires the valve to be in the locked open position. The valve lineup which was being maintained in the Unit 1 control room listed the valve's status as locked open. Upon being informed of this matter, the licensee initiated an investigation into the circumstances leading to the valve not being in the locked open position. The HPCI system engineer informed the inspector that this condition was the result of a recently performed special purpose test, 1-SP-93-070, "RCIC/HPCI Low Pressure Testing Using Auxiliary Steam," during which HPCI was operated using low pressure steam from the auxiliary boiler. The investigation revealed that the valve in question, 1E41-F036, was manipulated by the special procedure and returned to the open position in lieu of the locked open position. Additionally, the licensee identified three other valves (1-MS-V63, 1-MS-V64, and 1-E51-F038) which were manipulated during the performance of the special procedure and not returned to the locked open position. The licensee initiated an ACR (93-344) to document this matter. Paragraph 4.6 of OI-13, "Valve and Electrical Lineup Administrative Controls," requires that all valves and breakers will be maintained in the position required for the OP valve lineup. This is a violation of OI-13 and will be tracked as the second example of Violation 93-55-04, failure to follow procedures.

A second deficiency noted by the inspector was a missing conduit cover on a 2 inch conduit above the motor operator for valve 1-E41-F004. A second conduit cover on the north wall of the HPCI room was observed to be loose. Additionally, two pipe caps were observed to be missing downstream of valves 1E41-V23 and 1E41-V14. These deficiencies were documented on WR/JOs for disposition. Other minor discrepancies noted on the walkdown were that the HPCI system check valves and relief valves were not labeled and that an inconsistency existed on the HPCI P&ID in that the instrument valves were not always depicted.

The second portion of this inspection effort dealt with a review of problems known to have affected the HPCI system at Brunswick and other BWRs of similar vintage. The first item reviewed dealt with the licensee's efforts in assessing the Quad Cities rupture disc event. The licensee informed the inspector that based on their review of the Quad Cities event and the fact the discs installed at Brunswick differed from those installed at Quad Cities, that no preventive maintenance requirements including visual inspections during outage periods was required. The inspector informed the licensee that other utilities, are performing visual inspections of the discs at periodic intervals. Additionally, the inspector and the licensee independently contacted the vendor about any requirements for PMs/inspections on the discs. The vendor indicated that although no PMs were required, they recommended that the discs knife blades be inspected and that the discs be replaced on a maximum of a 5 year interval. Based on this recommendation, the licensee conducted visual inspections of the outer rupture disc knife blades, to verify that they are still sharp. Additionally, when the licensee enters their third 10-year IST interval, in 1996, they will implement the requirements of ASME/ANSI OM-1987 to replace the disc every 5 years.

Another item reviewed in this area dealt with the service life and shelf life of the HPCI EGM and EGR speed control components. Based on problems experienced at another BWR facility with the EGM, the inspector questioned the licensee to determine if any similar problems had been experienced at Brunswick. The licensee initially indicated that they knew of no problems of any kind related to failure of these components as they related to shelf life. However, after contacting GE, the licensee was informed that the EGM had a shelf life of 5 years (based on capacitors not being recharged) and that the EGR had a shelf life of 10 years. The licensee then contacted the manufacturer of the EGR and EGM, Woodward, who stated that the EGMs on the shelf should be removed from stock once every 18 months and connected to a power source for approximately 24 hours to prevent the deterioration of the electrolytic capacitors used in these components. This information is new to the licensee and had not been previously provided by the vendor. The licensea determined that the components (EGR and EGM) currently installed in the plant are functioning properly based on satisfactory performance during surveillance testing. The licensee is currently reviewing this matter in order to determine the proper storage and shelf-life requirements. This will be tracked as IFI 93-55-08.

The inspector also reviewed the status of other components known to be susceptible to problems/failure. Specifically reviwed, was the status of the HPCI full flow bypass to the CST valve, E41-F008, which is prone to erosion due to its use in throttling during surveillance testing. The licensee provided the inspector documentation demonstrating that the F008 valves in both units had been recently replaced (Unit 1 in March, 1991, and Unit 2 in November, 1991) with valves more suitably designed for this throttling application. The inspector also reviewed the licensee's actions as they related to past problems with the Topaz Inverters used to supply control power to the HPCI system. The inverters are currently operable, however, the licensee plans to replace the inverters due to age and the unavailability of replacement parts. The inspector inquired about the licensee's actions as they related to problems with the HPCI turbine mechanical overspeed trip design. In February, 1987, GE issued SIL No. 392, Supplement 1, which described a malfunction of the trip device due to swelling of the tappet. GE's recommendation was to replace the mechanical overspeed trip assembly with modified assemblies preventing this malfunction. This replacement has been accomplished on the Unit 2 HPCI turbine but not the Unit 1 turbine. The licensee plans to replace the Unit 1 assembly during its next refueling outage and will continue to follow GE's alternate recommendation. The recommendation was to verify that the unit trips and resets properly during each surveillance test. The inspector verified that this test was contained in the licensee's quarterly surveillance for the HPCI system.

The inspector also reviewed the backlog of work for the Unit 1 HPCI system. No major work items remained to be performed with the exception of the repair of a steam leak on the 1E41-F001 identified during the low pressure test. The licensee plans to repair the valve prior to startup.

Based on this review, the inspector determined that the HPCI system was ready to support Unit 1 operations.

Reactor Protection System

The inspector reviewed the status of the Unit 1 Reactor Protection System prior to startup. This included a review of the integrated backlog item report, a walkdown of the major components, indepth discussions with the system engineer, and a review of major work completed during the outage.

Although a final turnover and acceptance of the RPS had not been completed by the end of the inspection, almost all of the work had been completed. Final system turnover was not planned until all required MSTs had been completed.

As of December 3, 1993, only 3 open WR/JOs remained. None were assigned a priority of greater than 5. Only 1 open EWR remained which was for the development of a temporary modification to be used as a contingency based on problems experienced during Unit 2 startup with the turbine stop/control valve closure scram prior to reaching 30 percent power.

The inspector reviewed a listing of WR/JOs completed on RPS since April 1, 1993, and discussed selected items with the system engineer. Several actions had been taken to improve the reliability of the RPS. Examples included replacement of all six EPAs (Electrical Protection Assemblies) and several circuit boards, replacement of obsolete auto and manual scram contactors, replacement of RPS motor generator set motors with an improved version and improvements in the preventative maintenance program. These improvements were generally the same improvements completed in Unit 2 prior to the April 1993 startup. Unit 2 had completed a 210-day continuous run with no apparent significant RPS difficulties. The Topaz inverters associated with the RPS had experienced no recent spurious problems or failures; however, plans were to begin the commercial dedication process for a commercially available and more up-to-date unit because of anticipated end-of-life reliability problems and the unavailability of spare parts.

The inspector completed a walkdown of the Unit 1 RPS which included the RPS MG sets, EPAs, inside selected fuse panels and cabinets, and HCUs. No obvious or apparent deficiencies not previously identified were noted. The material condition of the equipment was good. No labeling deficiencies were noted. General cleanliness of the equipment was good. In addition, some selected system improvements discussed previously were verified to be installed.

In summary, there had been many improvements to the RPS completed since last April. These improvements were similar to those made previously to the Unit 2 RPS which had proven to be very reliable.

SRVs/ADS Walkdown

The inspector accompanied a system engineer and senior reactor operator on a preliminary walkdown in the drywell of the Unit 1 ADS/SRVs, accumulators, associated piping, valves, supports and snubbers. No significant discrepancies were observed. The SRV tailpipe vacuum relief check valves were verified free by the operator.

During the walkdown, the inspector observed several jumper and wire removal tags attached to air piping leading to several SRVs. These tags had been hung in August 1993 when the SRVs had been removed for offsite shipment. Although the SRVs had since been reinstalled and piping reconnected, the tags had not been removed.

In addition, the inspector found 3 tags hung on cables leading to the SRM Channel B, and IRM Channels D and B motor modules. These tags were dated 1988. The work orders associated with these tags showed that the work was completed in 1988.

Administrative Instruction 59, Jumpering and Wire Removal, Revision 21, paragraph 5.3 states that after the completion of the job, the wire is reconnected, the jumper and wire removal tag(s) shall be attached to the WR/JO if contaminated, tags should be disposed of properly and explanation attached to the WR/JO. The 10 jumper and wire removal tags were not properly removed after the completion of work. This is the third example of Violation 93-55-04, Failure to Follow Procedures.

EDG Starting/Control Air Systems

Overall, the assessment of EDG Starting/Control Air Systems found them capable of supporting dual unit operations. This readiness assessment was based on inspector walkdowns of the starting/control air system on all four EDGs, review of open items (i.e., WR/JOs, ACRs and EWRs), discussions with the system engineer, review of completed workpackages, and observations of system maintenance.

An indepth review of open items was performed on the following:

- ACR 93-353, Inadequate Torque On Control Air System Moisture-Trap Cap Screws Resulted In Gasket Failure And EDG 4 Inoperability

  As discussed in paragraph 5.c., the inspector verified that all EDG control air system moisture-trap cap screws had been torqued to the recently acquired vendor's specifications and assured procedural controls had been established to preclude similar gasket failures.

- EWR 12599, Seismic Qualification Of Air Start Piping/Control Air Tubing Between Each EDG And Its Associated Starting/Control Air Skid

  As addressed in paragraph 3, this issue was found to be acceptable.

- EWR 10855, Excessive Movement On EDG 4 Starting Air Piping

  Movement of the starting air piping was visibly noticeable with just the EDG pre-lube oil pump running. As addressed further in paragraph 3, this is not considered an operability issue.

- WR/JO 93-BAFS1, Repair Failed Low Pressure Cylinder Valves On EDG 3 Starting Air Compressor No. 2

  Identified as a degraded condition on September 16, 1993, this WR/JO had been rescheduled several times due to the onsite unavailability of a pilot-to-pilot valve low pressure gasket. At the end of the inspection, the WR/JO was scheduled to be worked during the week of December 20, 1993. As this condition has limited compressor operation to the high pressure cylinder only (i.e., operable, but very slow to raise pressure in starting air tank No. 2), followup will be accomplished under an Inspector Followup Item 93-55-09: Followup On Repair Of EDG 3 Starting Air Compressor No. 2

Another EDG starting/control air system integrity issue pursued by the inspector was the potential loss of control air due to a jet assist 2XLOCA logic relay failure. (Reference IR 93-39 and ACR 93-238.) The scenario specific failure (welded closed contacts) was attributed to the induced/dissipated current when the two 65 Watt jet assist solenoid valves are deenergized. To assure this potential failure does not take place (i.e., contact rating not exceeded) the inspector verified that at least one of the two jet assist solenoid valves on each EDG had been replaced with one having a 35 Watt rating.

The inspector also verified the installation and effectiveness of the associated Generic Letter 88-14 modification to improve the dew point of EDG control air. As committed in CP&L's response dated April 18, 1991, PM 92-107 (Diesel Generator Air System Moisture Removal) has been installed on EDGs 1 and 2 during the current outage and is scheduled for installation on EDGs 3 and 4 during the upcoming 1994 Unit 2 refueling outage. A review of sampling results for EDGs 1 and 2 (per 0-E&RC-0900) indicates considerable post-modification dew point improvement (i.e., from approximately +30 to approximately -30). With respect to EDGs 3 and 4, the inspector verified compensatory measures were being performed as committed (i.e., draining of low points and traps during AO rounds).

c. Clearance Process

The inspector reviewed the plant equipment clearance process using the applicable procedures, discussions with personnel, and observing a clearance in process. Records of completed clearances, prepared clearances, and active clearances were also reviewed.

The plant procedures reviewed were as follows:

AI-58, Equipment Clearance Procedure
AI-58.1, Radwaste-Fire Protection Equipment Clearance Procedure
PLP-21, Independent Verification

Clearances are initially prepared in the clearance center. This group has five SROs and several contractor personnel. Following preparation, the clearance is taken to the work control center for integration into operations. The control SRO authorizes the clearance and plant operators hang the clearance tags.

Completed Clearance

The inspector reviewed clearance 2-93-03705 on the CRD system to support scram time testing and 2-93-02902 that tagged two fan breakers for painting. It was noted that safety systems require a second review for preparation of the clearance and independent verification for hanging and removal of the clearance tags. Safety systems are designated in Attachment I of PLP-21.

Prepared Clearance

The inspector reviewed clearance package 2-93-01563 on the reactor feed pump seal water duplex strainer. The package contained the clearance sheets and tags plus drawing D-02023 with the valve to be tagged highlighted on the drawing. The isolation boundary was adequately specified for the work to be performed.

In-process Clearance

The inspector observed the hanging of clearance 2-93-03218 to remove a CRD hydraulic unit from service. This involved the isolation of nine valves and pulling two fuses. An auxiliary operator placed the clearances on the hydraulic unit for control rod 18-43. This clearance required independent verification and was first hung by one operator and later verified by another operator. The clearance package was well prepared containing the clearance sheets and tags, marked up drawing, and operating procedure for isolating the HCU. No problems with the process were noted.

Radwaste and Fire Protection Equipment

The inspector questioned why there were two procedures for equipment clearances. One general procedure, AI-58 was for most plant equipment and another one, AI-58.1 was for radwaste and fire protection equipment.

Additionally, the fire protection equipment (TS equipment) could be removed from service without knowledge and authorization of the control room SRO. The inspector toured the radwaste control room that is manned by non-licensed operators. The clearance sheets and LCO tracking sheets for fire protection were maintained in this area.

The inspector expressed a concern that TS requirements for fire protection were not under the control of the SRO. The licensee states that the fire protection control was placed under the radwaste operators to remove the administrative burden on the control room operators. Plans were to consolidate the two tagout instructions into one. This item was identified by the licensee under ACR 92-349, Chlorination Piping Contained Chlorine During Maintenance. This event occurred on May 12, 1992, and the a corrective action to combine the two clearance procedures into one was to be completed by December 31, 1992, but due to various reasons was changed to the current date of February 1, 1994.

In summary, the clearance procedures, preparation, and processing were adequate, however, the corrective actions of ACR 92-349 have not been timely. This corrective action will extend control over fire protection equipment required by TS and the corresponding LCO tracking to licensed operators.

3. Engineering (37700, 37701)

a. Engineering Organization

Engineering Support for Brunswick is provided by two departments,Technical Support, which includes the systems engineers, and the Nuclear Engineering Department (NED). The Technical Support organization's functions include system performance monitoring and improvement, providing engineering assistance and technical direction to Operations and Maintenance, inservice inspection, and initiating design changes. The Nuclear Engineering Department is responsible for design and configuration control for Brunswick. The interface between Technical Support and NED is through the Engineering Work Request (EWR) process, which is the method Technical Support uses to transfer/assign work to NED. The EWR process is controlled by Engineering procedure ENP-12, Revision 34, Engineering Work Requests, Evaluations, and Action Items.

The Technical Support personnel are located onsite. The training for systems engineers is good. More than 80 percent of the systems engineers have completed advanced training, referred to as certification, in their assigned system.

Prior to the current extended outage, the majority of the NED staff were located in the corporate office in Raleigh. A small NED staff was located onsite. The personnel in the onsite office were primarily contract engineers, with a few CP&L personnel occupying key management positions for the onsite staff.

In order to provide improved design engineering support to the Brunswick site, CP&L senior management has reorganized NED to decentralize and relocate the NED staff to the Brunswick, Harris, and Robinson sites. The relocation from Raleigh to the site is scheduled for the Summer 1994. All key positions have been filled, except for the head of the Electrical Engineering Design Unit. The majority of the sub unit manager positions have also been filled. Additional design support for the Brunswick site is provided by Architect-Engineer (A/E) firms who have been retained to complete specific design projects. The licensee plans to out-source additional design work in 1994 to A/E firms to reduce the current backlog of design work. The inspector concluded that the current NED organization and the future organization plans will support operation of both units.

b. Engineering Backlog

The inspector reviewed the backlog of engineering work items in Technical Support and NED. The backlog in both groups has been reduced during the current outage.

The backlog in Technical Support includes approximately 270 EWRs, 75 facility action commitment tracking system (FACTS) items, 48 procedure revisions, 38 engineering evaluation reports (EERs) action items, 47 internal action items, and 30 other items. The FACTS items involve response to NRC inspection findings, generic letters, information notices, and/or bulletins, responses to INPO items, corrective actions for adverse condition reports, and responses to findings identified by the Nuclear Assessment Department (NAD). The EWR is a formal document initiated to identify and track requests for technical assistance from Technical Support or NED. Engineering Evaluation Reports document the results of any evaluations performed by engineering, and are used to respond to EWRs. EER Action items, also called Engineering Action Items (EAI), are items resulting from engineering, typically EERs, include actions and methods to correct or compensate for plant conditions. EERs, and EAIs are controlled by procedures ENP-12. The inspector reviewed the items in the Technical Support backlog and concluded that there were no operability concerns which would not be resolved prior to Unit 1 restart.

Discussions with the Technical Support manager disclosed that the current plans are to reduce the backlog to less than 100 total items by April, 1994. The inspector concluded that the plan for reduction of the Technical Support backlog are adequate, and that the current backlog will not affect restart of Unit 1 or operation of either Units 1 or 2.

The backlog in NED is considerably larger, numbering approximately 8000 items. This large backlog is a result of the large number of items worked during the current extended outage, and the large backlog which existed at the start of the outage. The inspector reviewed the NED backlog and discussed the plans for reduction of the backlog with the NED site manager, and other NED personnel. The backlog items, and the schedule for reducing the backlog is summarized below:

- 1360 EWRs. The majority of these EWRs were identified during the current outage, and involve civil/structural deficiencies identified during either the hotside, coldside or material condition walkdowns. A large number are non-safety related. These items have been screened by either Technical Support or NED engineers who determined they did not affect operability of any system. Approximately 1000 of the EWRs will be out-sourced to an Architect Engineering firm. The contract is scheduled to be awarded in January or February, 1994. The contract will require completion of design work on the 500 highest priority EWRs by mid 1994, with the rest to be resolved by mid 1995. The remaining EWRs will be closed out in NED. The long term goal is to reduce the total backlog of open EWR to less than 400. The NED site manager stated that a large number of EWRs will be resolved and closed out in the next Unit 2 refueling outage. Approximately 50 new EWRs are opened each month.

  The inspector reviewed the listing of EWRs and concluded that none of the EWRs affected operability of any Unit 1 system. The inspector selected two EWRs related to the diesel generators for further review. These were EWRs 10855 and 12599. EWR 12599 concerned seismic qualification of the diesel generator control air piping. This item was classified as a short term structural integrity (STSI) item common to both units. The inspector discussed this item with licensee engineers to determine its effect on operability of the diesel generators. During the discussion one of the licensee's engineers recalled that he had completed calculations to resolve the issues. The engineer identified the calculations as calculation numbers PID 1534-38 and PID 1534-44. The inspector reviewed the calculation and noted that these calculations had been completed in early 1988. The calculation showed that the diesel generator starting air lines and the control air tubing were qualified in their existing configuration, except for a pipe support which required modifications to its baseplate. This work was completed in 1988. This is not an operability or startup concern. The inspector discussed the resolution of EWR 12599 with licensee engineers who indicated, that it would probably be closed out based on the previously completed calculations. The licensee engineer who issued the EWR had not been aware that the reference calculations had been completed in 1988 to address the original concern.

EWR 10855 was issued to request NED to investigate and evaluate excessive movement of the starting air header on diesel generator 4. Initial screening of this EWR resulted in the determination that it was not an operability concern. The inspector concurred with this assessment. The inspector reviewed a draft copy of EER-93-0398, Revision 0, which was issued to evaluate this problem. The cause of this problem was attributed to close proximity the air start piping to the lube oil piping which causes vibration of the air start piping. A modification has been proposed to install a rubber gasket material between the two systems to dampen and eliminate any movement.

- 3500 Engineering Drawing Changes. These drawing changes involved changes to 1400 drawings to correct errors identified by operations or maintenance personnel, and changes to 2100 drawings affected by completed modifications. The licensee has screened the drawings and verified they do not involve those required for use in the control room, or other critical drawings. A contract will be awarded to an A/E to complete the drawing changes. It is estimated that work will start in February, 1994, and will be completed in 1995, prior to the next scheduled Unit 1 outage.

- 800 Civil Calculations. These calculations require updating to incorporate the results of field changes when modifications were field completed. All the changes have been reviewed by NED engineers who determined that the changes would not invalidate the original calculations. A contract will be awarded to an A/E firm in February 1994 with a scheduled completion by the end of 1994. An additional 800 calculation updates will be generated during the next Unit 2 outage. These will also be out-sourced to an A/E, with a completion date of 1995. The calculations which require updating do not affect startup of Unit 1 or operation of either Unit.

- 590 Vendor Manual Updates. These updates are required to incorporate manual changes identified by equipment vendors. These changes also affect maintenance procedures. A contract will be awarded to an A/E in February, 1994, with a completion date of December 31, 1994, to resolve the vendor manual and maintenance procedure changes.

- 180 EER Action Items. A contract will be awarded to an A/E firm to resolve some of the EER action items. The remaining will be resolved in-house. This project will be completed by the end of 1994 or early 1995.

- 145 FACTS Items. These items will be resolved by April, 1994 .

- 35 Adverse Condition Reports (ACRs). These are internal ACRs identified by NED within the NED organization. The backlog will be reduced by April, 1994.

- 57 Changes to Design Basis Documents (DBD). Those affecting safety-related DBD will be resolved by December 31, 1993. The remaining, which affect balance-of-plant (nonsafety related) DBD, will be resolved in 1994. This work will be done by the in-house NED staff.

- EDBS Updates. EDBS is a computer data base containing equipment tag numbers, component identification numbers, part numbers, quality classifications, environmental qualification data, Appendix R data, maintenance data, etc. When the EDBS was originally implemented, it contained only safety related equipment and some major BOP components. The system is now being updated to include all BOP equipment. This will involve entering equipment data on 53000 line items, and an additional 35000 part numbers. The inspector discussed the impact of these changes on safety-related equipment with NED procurement engineers. These discussions disclosed that the plant "Q" list which lists safety related equipment is correct. The Q-list is controlled by procedure ENP-33.5, Structures, Systems, Components, and Parts Quality Classification Analysis and Dedication of Commercial Grade Items for Use in Safety-Related Applications. An independent assessment of the Q-list was recently completed by an independent contractor. The results of the assessment concluded that procedures ENP 33.5 was adequate to control the Q-list, that the procedure was being properly implemented, and that the "Q" list was accurate. The procurement engineers stated that changes to the Q-list are made in a timely fashion and that no backlog exists regarding changes to the Q-list . The portions of the EDBS pertaining to parts quality classification is also maintained current. Changes to the EDBS resulting from installation of a modification are made within 30 days following declaration of operability or partial operability of the modification. A backlog does not exist in this area. Therefore the inspector concluded that the deficiencies in the EDBS do not affect startup of Unit 1 or operation of Units 1 and 2.

- 770 PIDs. PIDs are Project identification numbers for projects authorized to be implemented for the plant. However, not all 770 projects are active. Licensee personnel are currently reviewing the PID list to determine which projects are completed and which ones should be canceled or re-scoped. The inspector reviewed a memo dated November 2, 1993, Subject: 1993 BNP NED Detailed Project List, which lists the current projects working in NED. Although the number of PIDs adds to the backlog of work in NED, they do not impact startup of Unit 1 or operation of Units 1 and 2.

The overall assessment of the backlog in NED is that although it is large, a plan is in place to reduce the backlog to a manageable level by 1995. The current backlog does not affect system operability. However, the large number of projects which will be out-sourced represent a challenge to NED in the area of contractor management, and achieving the proper level of owner review to assure they receive a quality product.

c. Plant Modifications (PM)

The inspector reviewed plant modifications to assess the licensee's programs for updating procedures and drawings affected by the modifications, performing training on the completed modifications, and to assess the licensee program for implementation of modification.

- PM 92-107, Diesel Generator Air System Moisture Removal. This modification involved installation of two new high-capacity desiccant dryers for the diesel generator starting air system. The new dryers were installed in parallel with moisture indicators, to permit isolating one of the dryers when the desiccant requires replacement. The original dryer involved a removable filter cartridge which required frequent replacement. Replacement of the cartridge required taking the diesel out-of-service. The modification has been completed on Diesel Generators one and two, and a partial operability has been declared for the PM on these two diesels. The modification will be implemented on Diesel three and four during the next Unit 2 refueling outage. The inspector reviewed calculation number OSDA-0004-92107, Seismic Qualification of Filter-Dryer for Diesel Generator

Starting and Control Air System. This calculation was completed to document the seismic operability of the new large capacity dryers. The inspector examined the complete modification on Diesel Generator number two, and verified that the new piping and the dryers had been installed in accordance with design requirements.

- PM 84-081, Diesel Generator Fuel Storage Tank Level Switches. This modification involves the installation of new level switches for the diesel generator fuel oil storage tanks. The modification relocated existing piping associated with the level switches and was completed for diesel tank rooms one and two. The modification was declared partially operable for Unit 1. The inspector reviewed the Unit annunciator procedures 1-APP-UA-19, 1-APP-UA-20, 1-APP-UA-21, and 1-APP-UA-22 and verified they had been updated to incorporate the changes required by the modification. The inspector also verified that critical drawings had been updated prior to declaring partial operability for Unit 1.

- PM 91-038, Steam Leak Detection System Upgrade. This modification involved installation of new instrumentation and electronic microprocessor units which monitor ambient temperature in the proximity of HPCI, RCIC, RWCU, RHR piping and in the main steam tunnel. This modification will improve plant performance by reducing plant trips and LERs resulting from instrumentation errors, extend surveillance intervals, and resolve ACR 91-0502. The inspector reviewed drawing number D-25027, Sheets 1A and 1B, drawing number 72078, and drawing number F70083, Sheets 1-3, and verified they had been revised to incorporate the changes to hardware resulting from the completed modification.

  The inspector reviewed the following procedures and verified they had been revised to reflect the modification: Emergency Operating Procedure EOP-3-SCCP; Annunciator Procedures 1-APP-A-01, 1-APP-A-02, 1-APP-A-03, and 1-APP-A-04; Operating Procedures 1-OP-01 and 1-OP-14, and Operating Instructions 0-OI-05, 0-OI-18, and 0-OI-50. Additionally, the inspector reviewed the special test procedure used to meet the system surveillance test requirements. The special test met the surveillance requirements for the steam leak detection system.

- PM 93-038, Unit 1 Core Shroud Repair. This modification involves installation of reinforcing clamps on the core shroud in the area of the top guide support ring to replace the function of two welds, H2 and H3.

The inspector witnessed qualification testing of the shroud clamp bolts performed on a mock-up of the core shroud. The testing on the mock-up was performed as a result of questions raised by NRC inspectors during the inspection documented in NRC Inspection Report Numbers 93-58 concerning the validity of the original qualification tests. On December 11, 1993, the licensee initiated testing of the shroud repair bolts on the mock-up. The testing was performed using GE procedure B1-SR/VT-001, Revision 0, Brunswick Unit 1 Shroud Repair Project Tensioner Load Test Verification Instruction. Prior to start of the test the inspector questioned the licensee regarding calibration of the load cell. The licensee provided a copy of the calibration data for the load cell, which was performed by United Calibration Corporation, through the full range of the load cell capacity of 300,000 pounds. The load cell was connected to an micro processor which the licensee stated indicated the pressure (load) acting on the load cell in pounds, divided by ten. The inspector questioned the licensee regarding the use of a multiplication factor of ten. They stated that this was used in previous testing. The inspector noted that the load cell reading indicated a load of negative 5000 pounds when the load was zero. The inspector was informed that at zero load, the load cell data is spurious.

The initial onsite test was started on the 2.5 inch diameter upper shroud bolts. The test was stopped after two data points were obtained because the new data did not agree with the original test date. After the test was terminated, the inspector questioned licensee regarding the use of the test equipment and the adequacy of the test procedure. The following problems were disclosed:

(1) The micro processor had not been calibrated with the load cell. The licensee assumed it had been.

(2) The licensee had no instructions for operating and/or reading the micro processor, nor a wiring diagram to verify the micro processor had been properly connected to the load cell. (After the test was terminated, additional information was discovered on the calibration data sheets regarding wiring the micro processor.)

(3) Licensee and GE engineers were not familiar with operation of the load cell, its operating characteristic, or the limitation of the equipment.

After the initial test was terminated, the test procedure was revised to Revision 1 to provide for reading the load cell output using a calibrated voltmeter. The load cell output, which is read in millivolts, was converted to pounds using the calibration data. The inspector witnessed several additional tests performed on bolts installed in the mock-up. The test data was erratic. However, the data did provide some confirmation of the original tests. Subsequent to this inspection, the licensee performed additional testing using ultrasonic test equipment. The results of this testing and the inadequacies of the testing on December 11, 1993, are discussed in Inspection Report 93-58. Resolving the shroud repair issues is identified as a restart issue, IFI 93-55-03.

- PM 91-001 and PM 92-073, Hardened Wetwell Vent. Training for these modifications were conducted as part of the LOR phase VII during 1992. The inspector reviewed the training package for this item. This included training on the modification and applicable procedures. This modification was discussed with the control room operators who were knowledgeable of the equipment, controls, and system operation.

- PM 93-031, Level Reference Leg Continuous Fill System. Training was conducted on this modification in phase VI of LOR during August - September 1993. The licensee in response to NRC Bulletin 93-03 made a modification connecting the CRD charging water header to the cold reference legs at a some point below the condensing pots. The training on the procedure changes was not clear since the form specifying the plant modification did not state which procedures were changed and another form indicated this would be completed in February 1994. From discussions with control room operators, they were not knowledgeable of how the system would be operated or maintained. Additionally, they were not aware of the problems discussed in NRC Information Notice 93-89, Potential Problems With BWR Level Instrumentation Backfill Modifications, dated November 26, 1993. Accordingly, additional training is needed for this modification covering operating procedures and problems as discussed in Information Notice 93-89. This item is considered a restart issue and will be tracked as IFI 93-55-02.

- PM 89-001, Digital Feedwater. Training on this modification was conducted using classroom lesson plan OPS-CLS-SM-032-C. The training was in phase V of the LOR. Also, training is scheduled again as part of the startup training scheduled for December 20, 1993, through January 20, 1994. The system was discussed with operators in the control room who were knowledgeable of the equipment operation. This modification had been placed on the simulator and training has been performed on it.

In summary, training has been conducted on the plant modifications reviewed as part of the LOR program. Unit 1 startup training is planned for December 20, 1993 - January 20, 1994. One exception was that additional training covering procedure and industry experience on the reference leg fill system should be completed prior to Unit 1 restart. The licensee committed to include this additional training on the operating procedures and Information Notice on the reference leg into their Unit 1 startup training. The inspectors concluded that the licensee's modification process (i.e., programs for implementing modifications, revising procedures and drawings, and providing operator training on the completed modifications) will support startup of Unit 1 and operation of both units.

d. Engineering Followup Items

- (Closed) Inspector Followup Item (IFI) 324/93-40-01, Recirculation System Piping Whip Restraint Clearances

  During walkdown inspections in the Unit 2 drywell performed in 1992, prior to restart of Unit 2, the inspector identified inconsistencies with several whip restraints on the recirculation system piping. The inspector reviewed the licensee's corrective action for this item for Unit 2, prior to Unit 2 restart, during an inspection documented in NRC Inspection Report Number 93-20. The licensee's corrective actions were found to be acceptable for Unit 2 restart. However the IFI remained open pending further review of its applicability to Unit 1. The licensee has also addressed this problem with the Unit 1 whip restraints. The inspector examined several whip restraints during a walkdown inspection conducted during the inspection documented in Inspection Report 93-50. No discrepancies were identified regarding the whip restraints. The licensee has issued EWR 93-0155 to document the settings of whip restraints for both Units 1 and 2. This work will be completed after restart of Unit 1. The inspector reviewed preliminary restraint data and concluded that this issue is resolved for restart of Unit 1.

- (Closed) IFI 325,324/93-45-02, Cumulative Effects of STSI Items in Common Areas

  During the current outage, the licensee identified some additional STSI items in common areas which required either corrective or evaluation for cumulative effects prior to restart of Unit 1. Three STSI items were identified which met the criteria in CP&L Report No. 1 MISCB-1005, Rev. 0, STSI Cumulative Evaluation - Unit 1. As of October 1993, the report documented three STSI items which required further review.

  - Completion of repairs to leaks in service water piping to diesel generator one, per WR/JO 93-AAEI. The inspector reviewed the WR/JO and verified the leaks had been repaired, hydrostatic tests were performed, and the work was accepted by QC.

  - NED Review of proper tie rod gaps in expansion joints on all eight diesel generator jacket water heat exchanger/service water piping. The inspector reviewed EER 93-0615 which documents review of the gaps. The review showed the gaps were acceptable on diesel generators one and two. For diesels three and four, the gaps will require some adjustment. However, the evaluation showed that the existing gaps are acceptable and the piping is operable. The gaps will be adjusted during implementation of PM 91-071 and 91-072, when replacing the service water inlet piping.

  - An operability review was required for panel 2-VA-MI-DG, taking into consideration the STSI item on the panel in combination with trouble tags with associated adjacent ¾ and 1 inch diameter conduits. This review was completed in calculation 2 DGB-0034-92083, Revision C. The existing conditions were found to be acceptable.

  The licensee issued Revision 1 to Report 1 MISCB-1005 to document closure of this issue identified in Revision 0. The inspector concluded that the cumulative effects evaluation were acceptable for restart of Unit 1.

4. Licensee Self-Assessment (35502, 40500)

a. Nuclear Assessment Department (NAD)

The inspectors reviewed selected NAD assessment reports in order to determine their adequacy and effectiveness. Findings identified during the NAD assessments were reviewed to determine the status of open items applicable to Unit 1 and to verify that the findings identified were adequately addressed prior to Unit 1 restart. Additionally, the inspector assessed the independence of NAD from the line organization. The inspectors reviewed the following assessment reports:

- B-MA-93-01, BNP Maintenance, Issued March 3, 1993
- B-CA-93-01, Corrective Action Management Program, Issued April 16, 1993
- B-SP-93-03, Engineering Products Special Assessment, Issued April 23, 1993
- B-SP-93-05, NED Design Process and Product Evaluation, Issued May 28, 1993
- B-OP-93-01, BNP Operations Assessment, Issued June 10, 1993
- B-OM-93-01, Brunswick Nuclear Plant Outage Management Assessment, Issued August 3, 1993
- C-NED-93-01, Nuclear Engineering Department, Issued September 7, 1993
- B-SP-93-06, Brunswick Startup Readiness Assessment, Issued September 8, 1993
- B-DC-93-01, Control of Documents Assessment, Issued September 22, 1993
- B-CA-93-02, BNP Corrective Action Management Assessment, Issued October 11, 1993
- B-SP-93-12, Brunswick Work Management Process Assessment, Issued November 27, 1993
- B-TQ-93-01, Brunswick Training and Qualification, Issued November 27, 1993

During the review of NAD assessment B-SP-93-06, the inspectors noted that NAD identified an issue concerning the licensee's need to strengthen their management of contractors involved in refuel floor activities. The licensee took action to improve oversight by assigning a project manager to monitor contractor activities on the refuel floor. However, NRC (NRC Inspection Report 93-58) inspectors identified findings during the core shroud repair activities which indicated that additional oversight was needed in selected areas. These areas include: 1) additional QA/QC coverage of contractor activities and 2) a more detailed review of contractor test and qualification procedures. Even though NAD and QC personnel were monitoring the core shroud repair activities on the refuel floor (in addition to the plant providing management oversight), these efforts were not effective in identifying the deficiencies identified by the NRC. The NRC findings are discussed in greater detail in NRC Inspection Report 93-58.

The inspectors determined that the NAD assessments were thorough and effective in identifying numerous issues and weaknesses during observations of plant activities. The scope of the assessments reflected current concerns and reviewed the status of previously identified NAD issues. The assessment scope process was enhanced by NAD's system for tracking Issues and commitments. The inspectors further noted that, in most instances, plant departments provided timely responses with adequate corrective actions specified for the NAD findings. The plant departments were still in the process of completing the specified corrective actions for some of the findings. Not all of the corrective actions were specified for completion prior to Unit 1 restart. The inspectors reviewed selected items designated for completion after restart and determined that the licensee had provided adequate justification for those items. Additionally, discussions with Brunswick management, NAD management and a review of the NAD assessments indicate that the assessments were independent and performance based.

b. Line Organization Self-Assessments

The inspectors reviewed selected self-assessments performed by various departments within the line organization. The licensee made a commitment in the Brunswick Nuclear Three-Year Plan dated December 15, 1992, (Initiative TY-303, Improve Ability to Identify and Correct Problems) to develop and implement a self-assessment program. The line self-assessments were reviewed for adequacy and effectiveness. Self-assessments performed by the following departments were reviewed: Operations, Maintenance, Technical Support, Work Control, Regulatory Compliance, Nuclear Engineering Department (NED), and Environmental and Radiological Controls.

The inspectors determined that the line self-assessments reviewed were adequate to meet the requirements of Plant Program 0-PLP-25, Self-Assessment. This program guideline was developed to address the Three-Year Plan Initiative TY-303. Most plant departments had not performed many self-assessments under 0-PLP-25 in that they developed their assessment procedures to meet 0-PLP-25 in July 1993. Corrective actions were developed to address the findings identified in the line self-assessments. The inspectors noted that the Technical Support Department had performed more self-assessments than most other plant departments. The self-assessments performed by Technical Support were considered to be thorough, in-depth, and aggressive in identifying areas for improvement within Technical Support and NED. The Technical Support self-assessments were considered a positive aspect of the line organization's self-assessment program.

c. Licensee Restart Assessment Processes

The inspector reviewed PN-30, Integrated Recovery Methodology; PN-31, System Turnover to Operations and Line Management Self-Assessment of Readiness for Restart of BNP-1; and the Unit 1 Startup and Power Ascension Plan; to determine if the licensee's processes are adequate for Unit 1 restart. PN-30 was the process used to identify and determine if an open items (deficiency) would be repaired prior to Unit 1 restart. The PN-31 process was used to determine if plant systems and line organizations are ready to support Unit 1 restart.

The inspector reviewed the Integrated Backlog Items Report (IBIR) for three systems. The IBIR list all open items on a plant system and identifies which items are required to be worked prior to restart. The review of the IBIRs for the reactor building HVAC, control building HVAC and standby gas treatment system indicated that open items were categorized appropriately for work prior to Unit 1 restart. However, the inspector identified several work items that were categorized as "need" (should be worked prior to startup), but were deleted from the need category without the proper outage scope deletion form being completed. A review of the items indicated that the majority were completed under different WR/JOs. However, WR/JO 93-ATDD1, Implement fixes to drywell HVAC short-term structural integrity issue, was deleted without completing the outage scope deletion form. This form documents that the item was recommended for deletion by the system engineer with technical basis for deletion; was reviewed and approved by PNSC; and the deletion was approved by the plant manager. The failure to document the WR/JO deletion from the IBIR is a violation of procedure PN-30, and this is another example of Violation 93-55-04, Failure to Follow Procedures. The item (drywell fan isolation) is scheduled for repair during the next Unit 1 outage.

By December 7, 1993, 50 of 70 systems were accepted by operations using the PN-31 process. The inspector reviewed the completed system walkdown reports, the system turnover checklists, and the readiness affirmations. The process appears adequate to determine the status of the systems and identify discrepancies that may affect system readiness. The items identified did not appear to affect system operability and WR/JOs were initiated.

The inspector reviewed the training material and records for the Unit 1 Startup and Power Ascension Plan. The training included the temporary startup organization, the testing plan, the assessment hold-points and other items. Unit 1 operators received the training on the power ascension plan. Additionally, all Unit 1 SCOs and COs received a minimum of 36 hours of watchstanding on Unit 2 while the unit was at power.

The licensee developed a Unit 1 Startup and Power Ascension Contingencies list for the identified problems noted during the Unit 2 startup and power ascension. This list identifies the problems, the corrective action (contingencies), the responsible department and the status of the actions. A review of the list indicates that good progress was being made to address these issues.

The inspector reviewed the licensee's actions on the restart issues from the Operational Readiness Assessment Team Inspection (Report 50-324/93-201) conducted in April 1993. The team identified four restart issues. These issues were 1) performance of an alternate safe shutdown drill; 2) backlog of maintenance procedure changes; 3) unauthorized operator aids; and 4) backlog of corrective maintenance. These items were adequately addressed by the licensee before Unit 2 restart. The inspector reverified the corrective actions for Unit 1. The licensee has completed alternate safe shutdown drills and performed the periodic test on the ASSD sound-powered phone system. Additionally, the number of backlogged procedures that were technically inadequate have been reduced from approximately 500 to 41 as of December 6, 1993. The inspector walked down the control room back panels with a control room operator and noted that one operator aid was in question. This aid was a Span gas data sheet that contained the calibration gas information for the Hydrogen/Oxygen Drywell monitors, CAC-4409/4410. The Span gas data sheets were controlled under Maintenance Procedure OMI-16-040A, Replacement of CAC-QT-4409/4410 Calibration Gas Cylinders. This procedure was deleted on November 2, 1993 because it was determined that gas cylinder change out was within the skill of the craft. However, the data sheets were not removed from the panels until identified by the inspector on December 14, 1993. Leaving the Span gas data sheet on the panel after the controlling procedure was cancelled represents an unauthorized operator aid. The failure to remove the span gas data sheet is a violation for failure to take adequate corrective action for the control of unauthorized operator aids (Violation 93-55-06).

The inspector determined that the licensees restart assessment processes were adequate to ensure plant systems, processes and people were ready to support Unit 1 restart. Additionally, the Startup and Power Ascension Plan was adequate to ensure a controlled startup process.

5. Work Control (62703, 61726, 62700, 83750)

In March 1993, Brunswick Unit 2 implemented a new work control process. This new process has only been implemented in Unit 1 over recent months. Unlike the work control process that was in place prior to the dual unit shutdown on April 21, 1992, the new process (see Attachment) has made plant maintenance a site responsibility instead of solely being that of the Maintenance Department. PLP-24, Work Management Process, in conjunction with process group desk top guides, address the processing path of a work item (e.g., corrective maintenance, preventive maintenance, minor maintenance, surveillances, modifications, etc...) and the specific tasks each responsible group performs as the work item is processed to completion. Although this new process is considered to be a vast improvement over the previous method of work control, it is not without some problems. Accordingly, the licensee has established various means (i.e., Work Control Process Focus Team for process assessment/adjustment, Daily Integrated Schedule Compliance Report to focus on schedule compliance problems, and various other feedback mechanisms) to promote continued work control improvement.

a. Scheduling

This portion of the work control inspection effort focused on the scheduling organization and how it affected the work control process. Prior to the establishment of the work control organization in March 1993, the scheduling of work was accomplished by SWFCG - Site Work Force Control Group which was not entirely dedicated to the scheduling function. By SWFCG not being solely dedicated to scheduling, the lack of a sophisticated scheduling mechanism, and the inclusion of prioritization of maintenance work as a function of the scheduling organization lead to an ineffective scheduling process.

In March 1993, the licensee established the Work Control Organization as delineated in Plant Program Procedure 0-PLP-24, "Work Management Process." One of the results of forming the work control organization was the establishment of a dedicated scheduling organization called Integrated Scheduling. Integrated Scheduling is headed by a manager with two supervisors reporting to him. These individuals head the scheduling organizations for each of the two units. The individual unit's scheduling organization is further broken down into on-line scheduling and outage scheduling.

All work conducted at the plant, including preventive and corrective maintenance, TS surveillance activities, and modifications is scheduled by integrated scheduling. An exception to this is that emergent work items, as determined by plant operations, may be worked without going through the planning and scheduling process.

For corrective and preventive maintenance activities that can be performed on-line, the scheduling organization has established a 12 week rolling schedule that contains every plant system. Each of the 12 weeks, labeled as A through L, has an assigned list of systems to be worked during that particular week. When the on-line schedulers receive a work item for a particular system, the scheduler then assigns the work item to be worked during the designated system work week. Approximately 5 weeks before each particular work week, a preliminary work list designated for that week is compiled. During the next 3 weeks, the preliminary work list, through a variety of on-line schedule development meetings, is trimmed down to a final weekly work schedule. This work schedule is combined into the weekly integrated schedule. Other items scheduled based on the system designated week are preventive maintenance items and TS surveillance tests.

Unit 2 has been under this scheduling process for approximately 5 months. Of the work being scheduled in Unit 2 on the final weekly work schedule, approximately 60 - 70 percent is being accomplished. This number has improved over the last few months and should continue to improve. Unit 1 initiated a form of the on-line scheduling process in November 1993. Because the unit is still in a outage condition, and the fact that the program is in its initial stages, the percentage of work being accomplished on Unit 1 is not as good as Unit 2.

Work items that are designated for work during an outage or forced outage are scheduled by the individual unit's outage system schedulers.

A problem which continues is the inability to predict the number of hours required to complete an individual task. The licensee hopes to improve in this area by getting input from the maintenance foreman.

The integrated scheduling portion of the work control process represents a vast improvement to the means previously used by the licensee. A continued decrease in the Unit 2 maintenance backlog since July, has demonstrated the licensee's ability to adequately schedule work. Licensee work control and scheduling management demonstrated an attitude that schedule compliance was a goal of the organization.

b. Planning

For the purpose of assessment, the planning function is considered to be the process of planning for the work and providing a work package to accomplish it. As seen on the attached process diagram, the planning function is accomplished by six major groups:

- Planning - plans by schedule, identifying necessary materials and support.

- Material Management - procures and provides identified materials.

- E&RC - provides ALARA and RWP requirements.

- Clearance Center - develops and provides necessary clearances.

- Work Management Center - prints the "hard copy" of the WR/JO (which has passed electronically through the process up to this point), defines PMTR, assembles work package, obtains Implementor review, and delivers package to Work Control Center when scheduled to work.

- Work Control Center - authorizes work package, implements setting of clearance by control room, and releases package for Implementor performance. (This function is performed by the radwaste control room if work concerns fire protection or radwaste systems.)

The lack of formal planner training was identified as one of many planner impediments prior to the dual unit shutdown. Subsequently, formalized planner-related training was conducted in November 1992. The development of an initial planner training program (Three-Year Plan Initiative TY202-15G) is currently on target for completion in December 1993.

Unlike the previous work control method, planners are no longer required to make ISI calls. Governed by a single PMTR process (0-PLP-20, Revision 1, Post-Maintenance Testing Program), ISI and TS PMTRs are now made up front by the Work Management Center. The Work Management Center also double checks planner assigned PMTRs; thereby, keeping Operations from being the only stop gap as before. By its involvement prior to (i.e., work package assembly and delivery) and after work performance (i.e., package review and archive preparation), the Work Management Center has not only provided planner relief but has alleviated some of the demands previously placed on the maintenance supervisor. Consequently, maintenance observations and discussions with maintenance workers and supervisors indicate that this has afforded the maintenance supervisors more availability at the job site than before.

c. Maintenance Observations

As part of the planning function assessment, the inspectors reviewed work packages associated with the WR/JOs listed below. Maintenance observations were made on asterisked(*) WR/JOs.

*WR/JO 94-PC7001	Semi-Annual Inspection/Replacement of EDG-2 Starting/Control Air Filters (PM Route No. 1MSLAAB)
WR/JO 94-PD1001	Semi-Annual Inspection/Replacement of EDG 1 Starting/Control Air Filters (PM Route No. 1MSLAAC)
*WR/JO 93-BCQA1	Change Lube Oil in EDG 2 Starting Air Compressor No. 1
WR/JO 93-BELR1	Replace EDG 1 Jet Assist Solenoid Valve SV-6552-1
*WR/JO 93-BBMI1	Check Calibration of EDG 2 Starting Air Compressor No. 2 Pressure Switch PS-6521-2 and Tank Pressure Indicator PI-1677... Resolve Disparity
*WR/JO 93-BFLR2	Service Water Pump A Discharge Valve 2-SW-V14 Troubleshooting
*WR/JO 93-BEPB1	Inlet/Outlet Scram Valve Cracking Pressure Adjustment (HCU 10-23)
*WR/JO 93-BEXP1	Inlet/Outlet Scram Valve Cracking Pressure Adjustment (HCU 22-03)

(1) On December 10, 1993, the inspector's preliminary work package review for WR/JO 94-PC7001 (EDG 2 Starting/Control Air Filter Replacements) revealed that supporting preventive maintenance procedure OPM-FLT508, Diesel Generator Starting Air and Control Air Filters, had not been revised to require the control air system moisture-trap cap screws to be torqued to 100 inch-lbs. Because of repetitive gasket failures/ blowouts, the moisture-trap cap screws in the control air system of all four EDGs had been torqued to 100 inch-lbs on November 12, 1993 (reference ACR 93-353). To preclude further gasket failures and possible EDG inoperability, a procedure change request was submitted to include the vendor recommended 100 inch-lb torque value in OPM-FLT508. However, due to a low priority assignment the change had not yet been made. Upon this discovery, the inspector inquired as to how many EDGs underwent similar filter replacement preventive maintenance (and hence utilized OPM-FLT508) since November 12, 1993. Two were identified -- EDG 4 (performed under WR/JO 93-QYL006 on November 29, 1993) and EDG 1 (performed under WR/JO 94-PD1001 on December 6, 1993). As work package review indicated that the EDG 4 control air system moisture-trap cap screws were only torqued to 75 inch-lbs, WR/JO 93-BFLS1

was initiated/completed on December 10, 1993, to increase the cap screw torque to 100 inch-lbs. Although a similar filter replacement was also performed on EDG 1, the procedural steps dealing with the moisture-trap were marked "NA" and indicated an earlier performance during the emergent 100 inch-lb torquing on November 12, 1993 (WR/JO 93-BDUY1). A temporary change to OPM-FLT508 was issued on December 12, 1993, which was in time to support the EDG 2 PM (WR/JO 94-PC7001) on December 13, 1993. The failure to maintain OPM-FLT508 as required by TS 6.8.1 resulted in inadequate torque being applied to the EDG 4 control air system moisture-trap cap screws during the November 29, 1993, performance of WR/JO 93-QYL006 (Preventive Maintenance Route NO. 2MSL083). As such, it is identified as the first example of Violation 93-55-05: Failure to Establish/ Maintain Maintenance Instructions/Procedures.

Further review of the aforementioned EDG 1 and 2 packages (WR/JOs 94-PD1001 and 94-PC7001) also revealed that each required inspection/ replacement of a Hankison Dehydrafilter which no longer exists on EDG 1 and 2. This component was eliminated months earlier (EDG 1-July 17, 1993; EDG 2-October 5, 1993) under Plant Modification PM 92-107, Diesel Generator Air System Moisture Removal. This failure to maintain current preventive maintenance work instructions as required by TS 6.8.1 is identified as a second example of Violation 93-55-05: Failure to Establish/Maintain Maintenance Instructions/Procedures.

During the December 13, 1993 pre-job briefing for WR/JO 94-PC7001 (EDG 2 Starting/Control Air Filter Replacements), it was indicated that parts reserved for similar work the following week on EDG 3 had to be used. A closer review of the EDG 2 work package revealed that the parts had not been reserved. The inspector also performed a closer review of the corresponding EDG 1 work package (WR/JO PD1001) which was performed on December 6, 1993 -- parts had not been reserved for it either. Apparently, the normal window for these two semi-annual preventive maintenance routes began in January 1994, but had been moved to accommodate the December 1993 scheduled EDG work weeks. Being routine preventive maintenance routes with pre-established work instructions and PMTRs on AMMS, printing "hard copies" of the associated WR/JOs was possible. However, since the planner was not informed of the intended earlier performance, parts were not reserved. This issue not only reflects a weakness in the planning function, but indicates a scheduling-related communication problem as well. To assure parts are reserved for routine preventive maintenance routes in the future, the licensee indicated that automatic parts reservation would be implemented in January 1994. In the interim, compensatory measures (i.e., direct schedular-to-planner communications and utilization of a data query system by planners) have been established.

(2) On December 14 and 15, 1993, the inspector observed maintenance/troubleshooting activities on Service Water Pump A Discharge Valve 2-SW-V14. Plant Operations had initiated a WR/JO due to the valve being stuck in the closed position. The inspector reviewed WR/JO 93-BFLR2 prior to maintenance initiating work. The WR/JO contained general work instructions for troubleshooting the valve that appeared adequate to the inspector. The mechanic demonstrated to the inspector that a clearance for the work had been placed. The inspector reviewed the clearance and determined it to be satisfactory for the intended work. The mechanic further demonstrated that he had "signed on" to the clearance through the licensee's computerized clearance system.

A pre-job briefing was held to discuss the details of the work to be performed. The initial plan was to uncouple the valve from the operator to determine if the problem existed with the valve or the operator. The inspector witnessed the removal of the coupling. Upon removal of the coupling, the mechanics demonstrated that the operator rotated freely, thus indicating that the problem existed within the valve. After removal of the coupling, it was noted that the coupling threads had been damaged and would require replacement. After consulting with maintenance supervision and the maintenance engineer, it was decided to temporarily recouple the valve to the operator in order to use the "hammer blow" feature of the operators hand wheel in an attempt to unseat the valve. This attempt to unseat the valve was successful.

The following day, after obtaining a replacement coupling for the valve, the licensee planned to install the coupling. The inspector discussed this evolution with the assigned personnel in the maintenance shop. When the inspector questioned the mechanic about any torquing requirement for the coupling, the mechanic stated that he had already asked that question of the maintenance engineer and was told to install the coupling "wrench tight." The mechanic then reviewed the procedure listed in the work package for maintenance on the valve, OCM-VBF501, Jamesbury Model 815L, 150 PSI, 4 Inch - 60 Inch, Lugged Body, Wafer-Sphere, Butterfly Valves, and found specific torquing requirements for the coupling. The coupling was then installed as specified. A review of the scope change added to the work package for installation of the coupling revealed that inadequate instructions had been provided to the maintenance personnel. Although procedure OCM-VBF501 was referenced in the work package, the scope change to replace the coupling did not specifically reference the procedure or list any torquing value. The inspector believes that if this matter had not been questioned, the coupling would have been installed without being properly torqued. This is another example of Violation 325,324/93-55-05: Failure to Establish/Maintain Maintenance Instructions/Procedures.

(3) In October 1993, the Unit 2 start of motion control rod scram time average exceeded Technical Specification requirements during scram time surveillance testings. Slower than normal times had been observed during previous surveillances but were within Technical Specification requirements. As a result, a diagnostic testing and maintenance was developed and implemented to reduce the average scram time. This program revealed that scram solenoid pilot valve (SSPV) time delays, scram inlet and outlet valve opening delays, and scram test switch delays all contributed to the slow times. Under this program individual SSPVs were replaced as needed, cracking pressure of the inlets and outlet scram valves were adjusted for optimum performance, and test switches were replaced. This program was expanded to included Unit 1.

Testing conducted on several removed SSPVs by the valve manufacturer (ASCO), General Electric and CP&L concluded that the use of a thread sealant (Loctite PST-580) on the valve fittings caused time-to-vent delays once the solenoids were de-energized. This sealant had been applied in a manner that allowed carryover of some excess sealant onto the exhaust diaphragms of the SSPVs during venting. This caused some adherence in the diaphragm-to-exhaust port seat interface which resulted in slight time-to-vent delays.

The SSPVs in the south banks of both Units were replaced during each Unit's most recent outage (August 1993 in Unit 1). PST-580 was used as a thread sealant when the air fittings were reconnected because the use of teflon tape (original installation) was banned site-wide in 1988. The remaining Unit 1 SSPVs on the north bank were rebuilt using kits in 1991. Since the valve bodies were never removed, teflon tape (the original installation) remained as the thread sealant and PST was never used.

Diagnostic testing and maintenance was in progress on both Units 1 and 2 during the inspection. As of December 10, 1993, testing of 69 out of 137 HCUs in Unit 1 had been completed. Cracking pressure adjustments to the inlet and outlet scram valves were required on 58 pairs of SSPVs. Repair or replacement of 8 rod scram test switches (in the control room) were required. Approximately 60 percent of the SSPVs on both units required either rebuild or replacement. The criteria for SSPV replacement was greater than a 60 millisecond response time between solenoid de-energization and diaphragm movement. This criteria was developed based on testing of new valves by the licensee which indicated an average response time of about 40 milliseconds and the average response time of "slow" valves seen after Unit 2 problems. Teflon tape was used for all reconnections.

The inspector observed the performance of diagnostic testing, cracking pressure adjustments, and valve replacement activities on Unit 1. Procedural compliance by technicians performing these activities was verified. The procedures listed below were reviewed:

OCMOSV018, ASCO Solenoid Operated Scram Pilot Valves Diaphragm, Core and Gasket Replacement, Revision 9, December 2, 1993. (This procedure specifically prohibits the use of PST-580 thread sealant).

OCM-A0005, Stroking Hammel-Dahl Scram Inlet and Outlet Pneumatic Valve Actuators, Revision 9, November 19, 1993.

During diagnostic testing on the Unit 1 HCUs, the SSPVs on HCU 26-33 did open and vent during diagnostic testing. The SSPVs were removed and replaced. The removed valves were sent to the CP&L E and E center at the Shearon Harris Plant for failure analysis. The results of that analysis indicated that the failure was <u>not</u> due PST-580. The sticking was thought to be due to the presence and degradation of a dark brown fluid at the core assembly/plug nut assembly interface (most likely residue from a metal cleaning fluid used during the manufacturing process). This failure was considered by the licensee to be an isolated case.

Corrective actions to identify and precluded future failures included the following:

- Diagnostic testing and repair of HCUs was underway on both Units. Testing of all Unit 1 HCUs was to be completed prior to startup. Testing in Unit 2 was approximately half complete. An average of 4 rods per week were being tested.

- Gross failure of any new or rebuilt SSPVs would be identified during testing after initial installation.

- Scram time testing will be required prior to the Unit 1 startup (during the vessel hydrostatic testing). Additionally, routine rod operability testing is required every 120 days.

- Analysis of several removed SSPVs by outside independent laboratories was still in progress at the end of the inspection.

After a review of Engineering Evaluation Report 93-0650, Rev. 0, and a 10 CFR 50.59 evaluation both associated with the issue, observation of testing and maintenance activities, and numerous discussions with licensee personnel, the inspectors considered the licensee's actions to be adequate.

The inspectors found no other work package discrepancies. Except as noted above, the reviewed work packages were adequate to perform the intended task. In all cases, PMTRs appeared to be commensurate with the work performed. For those work packages where the associated maintenance activity was observed, pre-job briefings were considered to be appropriate, the tasks were adequately performed, and supervisor oversight was apparent.

d. Surveillance

The inspector reviewed the various tracking systems to ensure that required tests are completed prior to Unit 1 restart. Also, three surveillance tests that had recently failed were reviewed to determine adequate disposition.

The inspector reviewed the surveillance tracking program. This system is computer based. Several surveillances for HPCI were randomly selected from TS and checked to ensure they were being performed on time. For example HPCI Surveillance 4.5.1.c.1 is to be performed every 18 months. This was performed on October 9, 1993, and was scheduled for April 8, 1995.

The inspector also reviewed the licensee's recent assessment of this area. Assessment report B-IAP-93-02 was conducted June 18, 1993, through August 20, 1993, to show that the TS surveillance testing program was effective in meeting requirements. Fifty-eight randomly selected test was sampled and all found to be acceptable.

Schedule of upcoming surveillances were checked and a potential problem was discussed concerning LLRT tests. These tests are performed once every 24 months and the customary 25% extension time is not permitted for these tests. The tests were last performed in April, May, and June of 1993 with an anticipated startup date of the fall 1993. However, with the outage length impacted by the shroud repair, the startup date is now in early 1994. This with an expected 18 month operating cycle will make the refueling outage start around July 1995. Therefore, the 24 months allowed for LLRT (over 100 items) could be exceeded. These tests would have to be performed during a mid-cycle outage or an extension on the 24 months requested from the NRC.

In addition, one other surveillance concerning SLC injection, OPT 06.2.3, would be overdue on June 16, 1995. Performance of this test requires that the SLC tank be isolated, firing of the Squib valve, and the unit to enter a shutdown LCO.

Resolution of these issues should be addressed prior to the unit restart. This issue will be tracked as IFI 93-55-01.

The inspector reviewed the following three surveillances that were recently completed and had to be reperformed to pass:

- OMST-BATT12Q, Diesel Driven Fire Pump. This surveillance was for the diesel driven fire pump. The test failed on December 6, 1993, because the specific gravity of the batteries was low. A surveillance test completion/exception form was completed indicating the requirements were not met. Applicable LCOs were entered and WR/JO 93-BFDWI was issued to correct the problem. The test was reperformed on December 7, 1993, and the applicable form completed indicating satisfactorily performance.

- PT-9.2, Stem Verification. This surveillance test did not pass on September 12, 1993, for two valves and LCO T-1-92-403 was entered for tracking. The test was completed on September 30, 1993 with the appropriate tracking forms completed. No problems were noted.

- 0-PT-08.2.2b, LPCI/RHR System Operability Test Loop B. This test is a full flow test of the system through a test line back to the torus. Leakage form the system to connecting systems is also checked. The test was performed initially on October 27, 1993, but failed due to three problems. The minimum flow valve did not open, and leakage from the system to the RHRSW flood-up connection and keepfill systems could not be verified. Three other performances of this test were conducted on November 21, 25, and 26, 1993, to complete a satisfactory test. The inspector reviewed the tests, tracking forms, and held discussions with personnel familiar with the problems and concluded the issues were resolved.

In summary, the surveillance tracking and test deficiency resolution were adequate.

e. Maintenance Backlog

Unit 2

On-line corrective maintenance backlog for Unit 2 as of December 14, 1993, was 979 items. This was below the licensee's 1993 goal of less than 1200 items. Prior to the startup of Unit 2 in April 1993 the on-line corrective maintenance backlog was approximately 1200 items. This number increased during power ascension testing and peaked at just under 1500 items. This increase was attributed to the restriction of maintenance activities to essential items to reduce the possibility of an inadvertent plant trip during startup activities. Since the completion of startup, the corrective maintenance backlog steadily decreased to its current level. Since the first part of November not much progress had been made in backlog reduction which the licensee attributed to the year end vacation schedule of maintenance personnel.

The on-line corrective maintenance running rate had also been decreasing since completion of Unit 2 startup. As of December 13, 1993, this rate was 76, well below the established 1993 target goal of less than 120.

Based on a review of Unit 2 backlog data and discussions with licensee personnel, it appeared that the licensee had been successful in significantly reducing the on-line corrective maintenance backlog as evidenced by a steadily decreasing trend since startup. At the end of this inspection, goals for 1994 had not yet been finalized by the licensee.

Unit 1

The inspector reviewed the on-line and off-line corrective maintenance lists for completeness and selectively verified that the work priorities assigned were consistent with the criteria specified in Nuclear Generation Group Manual 305-05, Prioritization Process. Discrepancies noted were resolved after further investigation. Items identified as being a possible restraint to startup appeared to be legitimate.

The total corrective maintenance backlog has steadily decreased since it peaked at just under 2100 items during May 1993. This peak could be attributed to a build up of items that occurred when maintenance resources were heavily focused on Unit 2. As of December 14, 1993, this total corrective maintenance (both on-line and off-line) backlog was just over 900 items.

As of December 14, 1993, the on-line corrective maintenance backlog was 607 items which was well below the licensee's 1993 goal of 1150. On-line corrective maintenance backlog on FOCUS systems was at 192 items, which was well below the startup goal of less than 650 items. Higher priority items (1-4) stood at 44 with a goal of less than 80. Twenty-one of these items were on FOCUS systems. The extension of the outage due to the core shroud work and the anticipated time required to replace the jet pump beams has provided additional opportunities to further reduce the backlog prior to Unit 1 startup.

Off-line (outage) maintenance backlog as of December 14, 1993, stood at 300 items. Approximately 50 of those items were scheduled to be worked prior to startup.

In summary, the Unit 1 backlog, both on-line and outage items, had been steadily decreasing since May 1993, and was well under established goals.

f. ALARA Planning

ALARA Work Controls

The inspector reviewed the following procedures and guidance concerning the work control function and its relation with ALARA planning:

- OPLP-24, Work Management Process, Rev. 5, dated November 1, 1993;
- 0-E&RC-0230, Issue and Use of Radiation Work Permit, Rev. 28, dated March 13, 1993;
- 0-E&RC-4105, E&RC ALARA Planning, Rev. 0, dated June 29, 1993;
- AI-53, ALARA Project Evaluation, Rev. 2, dated December 23, 1992; and
- OWM-004, E&RC Planning, Rev. 3, dated December 3, 1993.

The inspector discussed the documents with licensee representatives and noted no problems with the methods or procedures contained therein.

Environmental and Radiation Control (E&RC) Planners screened new WR/JOs on a regular basis and checked the "Y" block for those that required a Radiation Work Permit (RWP). WR/JOs proceeded through the remainder of the planning process and returned to E&RC if an RWP was required. If the RWP blocks were inadvertently left blank, WR/JOs would still return to E&RC as a backup measure to prevent work from proceeding without having proper controls in place. The E&RC Planners determined if the work could be accomplished under an existing general RWP and, if not, a special RWP was generated. The planners then developed an ALARA package for related groups of WR/JOs. A similar process was followed for ALARA reviews of Plant Modification packages.

The inspector noted that the licensee had developed approximately 68 ALARA packages since the Unit 1 Forced Outage began in April 1992. Eleven of the packages were for the Forced Outage, and 57 were for the Unit 1 Refuel Outage that began in March 1993. The packages typically included multiple WR/JOs and RWPs and incorporated other work needed to support the primary WR/JOs such as temporary shielding, hotspot flushing, or scaffolding. The inspector selectively reviewed the ALARA packages for content and adequacy of planning. Four of the packages reviewed (Packages No. 1958, 2021, 2025 and 2045) were associated with the Refuel Outage and two others (Packages No. 1953 and 1973) were part of the Forced Outage work. The inspector noted that the packages contained pre-job briefing material and attendees, area surveys, walkdown information, special instructions, and post-job evaluations that specified ALARA challenges, successes, lessons learned, and dose received. Job-in-Progress reviews were performed if (1) 80 percent of the projected dose was received without a comparable amount of work accomplished, (2) the scope of the job grew significantly, warranting additional budgeted dose, or (3) requested by management or ALARA personnel. The inspector noted no problems with the packages reviewed and found that pre- and post-job briefings were effective in identifying ALARA issues. Also, lessons learned were appropriately incorporated from previous work that was similar in nature. Data such as area surveys and dose per job/RWP was maintained and used for historical purposes. Job-in-Progress evaluations were performed prudently and with appropriate justification. Associated RWPs were well-written and contained effective controls and requirements to facilitate work while maintaining exposure ALARA.

The inspector noted two issues identified by the licensee that related to the E&RC input into the planning process. The first issue concerned the fact that by certain manipulations of the computerized work planning system, the Automated Maintenance Management System (AMMS), E&RC could be left out of the initial planning stages. Although E&RC would eventually have input, the lack of "early" input could result in significant work delays, both directly and indirectly, or more importantly, work performed at less than ALARA standards. The inspector noted that the licensee recognized this potential problem; however, the likelihood of this becoming a significant problem appeared remote as it would require deliberate action to deviate from the procedure in this manner.

The second issue concerned the scheduling of scaffolding. Scaffolding is needed by many different disciplines for a variety of jobs. Scheduling is a difficult task to do efficiently and effectively. The inspector noted that the licensee had recognized this and was working towards maximizing the use of scaffolding from an ALARA standpoint.

Overall, the licensee's work control and planning process was satisfactory from an ALARA standpoint.

During observation of work activities, the inspector noted a minor problem on the inlet side of the Unit 1 Condenser Bay while workers were painting the area. The bay area was controlled and posted as a contaminated area, except for the catwalks traversing the bay which were maintained as clean. All of the area beneath the grating of the catwalks was considered contaminated and a few sections of the catwalk grating were removed to facilitate painting.

A painter working on the catwalk needed a lanyard and could not easily reach the bayside to retrieve one due to the removed grating. Therefore, he requested a nearby worker dressed in protective clothing (PCs) working below the grating to inform someone on the side of the bay of the need for a lanyard. A worker at the bayside (in the clean area) retrieved a lanyard and brought it out on the catwalk to the edge of the removed grating. However, instead of handing or tossing the lanyard directly to the worker at the other edge of removed grating who requested it, the lanyard was handed to the worker in PCs who then passed the lanyard to the worker who requested it. The worker in PCs had his feet and legs below the grating level in the contaminated area but his upper body was above the grating level due to the removed grating. The inspector noted this to be a poor work practice.

The worker who received the lanyard realized upon receipt that there may have been a problem and took the initiative to check the lanyard for contamination. According to the worker, he left the work area and frisked the lanyard, noting no increased counts. He then took the lanyard to the small article monitor (SAM) at the main exit of the radiologically controlled area (RCA) and counted it there. He received an alarm indicating that the lanyard was slightly contaminated. The worker then turned in the lanyard and checked out another to return to work. Based on the minor safety significance and the initiative of the worker, a violation of CP&L's Radiation Control and Protection Manual was not cited as the criteria specified in Section VII.B of the Enforcement Policy were met (NCV: 93-55-07).

Postings

During tours of the plant, the inspector noted that housekeeping was excellent. The licensee had taken significant steps to reduce contaminated area, as well as improved the overall cleanliness of a majority of the plant. Many areas were decontaminated from floor to ceiling and a major repainting project continued during the inspection.

In addition, the inspector noted that postings and labeling were appropriate in all areas toured. The inspector conducted independent radiation surveys in many areas of the RCA, including the Reactor and Turbine Buildings and outside areas, verifying that a sufficient number of postings were posted and were clearly visible and informative. The inspector found that the licensee had recently removed or downgraded a number of postings in the plant due to (1) an overall reduction in radiation levels resulting from decontamination efforts and a relatively long-term shutdown period (Unit 1 - radioactive decay), and (2) a change in management philosophy that eliminated wasteful "overposting" and avoided desensitizing workers from an overabundance of signs. The inspector noted this to be a good initiative on the part of the licensee.

The inspector verified that areas posted and maintained as locked high radiation areas (LHRAs) were locked as required throughout the Reactor and Turbine Buildings. In addition, the inspector observed the controls used for the temporary storage of highly contaminated vacuum filters generated during the "swarfing" portion of the Unit 1 core shroud repair job. The filters were placed in high-integrity containers (HICs) in the spent fuel pool after use. The HICs were then removed from the pool, dewatered, and moved to a temporary outside storage area located on the north side of the Diesel Generator Building. There the HICs were loaded into large concrete culverts with covers inside an area shielded with water shields. A locked gate was placed at the entrance to the area and appropriate postings and barriers were noted. Independent radiation surveys of the area outside the water shields revealed no concerns.

During plant tours, the inspector noted an area within the Unit 1 Reactor Building in which an occupational safety hazard existed. The area involved was the High Pressure Core Injection (HPCI) roof on the north side of the Residual Heat Removal (RHR) system. The concern noted by the inspector was the lack of a handrail (or other means to prevent falling) near the point in which the catwalk leading from RHR North connected to the HPCI roof. At that point, a four to five foot expanse existed at the edge of the HPCI roof that was "open" and could provide a fall hazard to workers in the area, as well as a hazard to workers working on the RHR floor below. During the inspection, licensee personnel agreed that the area was hazardous and initiated a work request to provide some sort of fall prevention at that point on the HPCI roof.

6. Exit Interview

The inspection scope and findings were summarized on December 15, 1993, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below and in the summary. Proprietary information was not included in this report.

Item Number	Description and Reference
93-55-01	IFI: Restart issue, resolve actions on LLRT surveillances that will expire prior to an 18 month operating cycle, paragraph 5.d.
93-55-02	IFI: Restart issue, complete additional training on procedures and NRC information notice on the reactor vessel water level reference leg backfill modification, paragraph 3.b.
93-55-03	IFI: Restart issue, resolve the core shroud repair issues, including refuel floor oversight paragraph 3.b. and 4.a.
93-55-04	VIO: Failure to follow procedures, four examples, paragraphs 2 and 4.
93-55-05	VIO: Inadequate maintenance instructions, paragraph 5.c.
93-55-06	VIO: Inadequate corrective action for the control of unauthorized operator aids, paragraph 4.c.
93-55-07	NCV: Inadequate radiation work practice, paragraph 5.f.
93-55-08	IFI: Shelf life and proper storage of HPCI EGMs/EGRs, paragraph 2.b.
93-55-09	IFI: Review diesel generator #3 air compressor #2 repairs, paragraph 2.b.

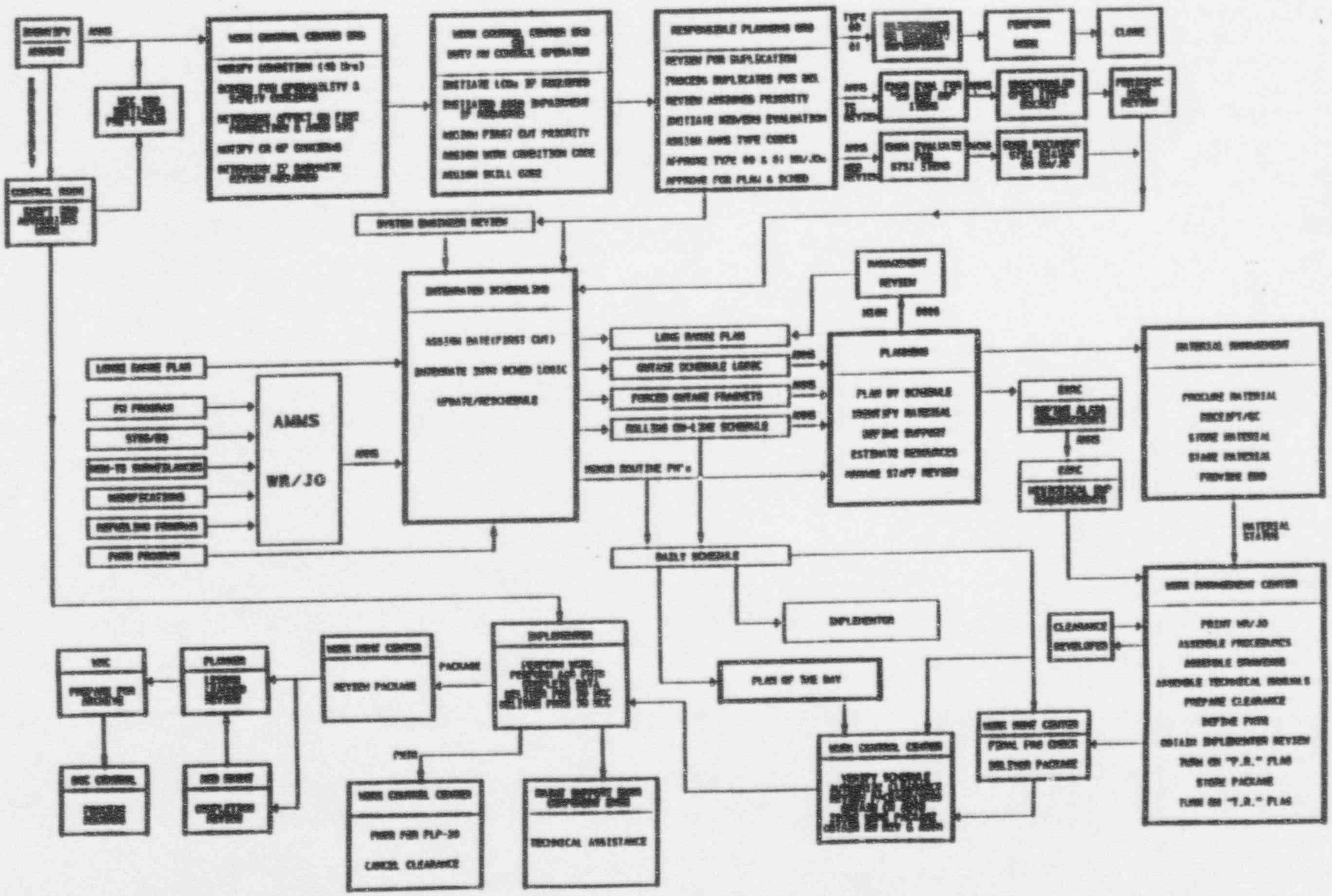
7. Acronyms and Initialisms

ACR	Adverse Condition Report
AI	Administrative Instruction
AMMS	Automated Maintenance Management System
AO	Auxiliary Operator
BOP	Balance of Plant
CRD	Control Rod Drive

EDBS	Engineering Data Base System
EDG	Engineering Diesel Generator
EER	Engineering Evaluation Report
E&RC	Environmental & Radiological Control
EWR	Engineering Work Request
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
IFI	Inspection Followup Item
IN	Information Notice
IR	Inspection Report
LOR	Licensed Operator Requalification
LPCI	Low Pressure Coolant Injection
NAD	Nuclear Assessment Department
NCV	Non-Cited Violation
NED	Nuclear Engineering Department
OI	Operating Instruction
P&ID	Piping & Instrumentation Diagrams
PLP	Plant Procedure
PMTR	Post-Maintenance Test Requirement
PT	Periodic Test
RCIC	Reactor Core Isolation Coolant
RHRSW	Residual Heat Removal Service Water
RTGB	Reactor & Turbine Building Gauge Board
RWP	Radiation Work Permit
SRO	Senior Reactor Operator
TPM	Temporary Modification
VIO	Violation
WR/JO	Work Request/Job order

ATTACHMENT

WORK MANAGEMENT PROCESS



JAN 14 1994

Docket Nos. 50-325, 50-324
License Nos. DPR-71, DPR-62

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/93-58 AND 50-324/93-58)

This refers to the inspection conducted by J. L. Coley of this office on December 6-10 and 15-18, 1993. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). The violations are of concern because they indicate a weakness in licensee oversight of vendor activities.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

9401250056

Should you have any questions concerning this letter, please contact us.

Sincerely,

/S/

Albert F. Gibson, Director
Division of Reactor Safety

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

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RII:DRS	RII:DRS	RII:DRS	RII:DRP
JColey	JBlake	CJulian	HChristensen
01/7/94	01/10/94	01/4/94	01/11/94

ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power & Light Co.
Brunswick

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

During an NRC inspection conducted on December 6-10 and 15-18, 1993, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C the violations are listed below:

A. 10 CFR Part 50, Appendix B, Criterion V requires, in part, that "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

Paragraph 2.0 of General Electric tensioner qualification procedure B1-SR/SCI-QUAL-002, Revision 0, states, "Tensioners are to be tested to determine the resultant preload on the joint bolt. Testing will be on a fixture against a calibrated load cell to determine preload as a function of hydraulic pressure on the tensioner." In addition, paragraph 3.0 states, "Equipment to be qualified will be of the same configuration to be used at the site and as described in this procedure." Paragraph 12.2.1 within Section 12.0 of the General Electric Quality Assurance Manual states, "Suitable measuring and test equipment with the proper range and accuracy shall be used to assure compliance with...project specifications." Paragraph 12.2.2 of the same section specifies, in part, "Records shall be maintained and equipment marked to reflect current calibration status."

Contrary to the above, while preparing for installation of core shroud clamps on November 13, 1993, tests were completed utilizing a bench test setup which was not representative of the configuration used at the site. Curvature of shroud surfaces and reduced area sections were not accounted for in the test setup. In addition, data was taken utilizing a load cell which was loaded beyond the calibration limits for the gage. On December 11, 1993, General Electric test procedure B1-SR/VT-001, Revision 0, was found to be inadequate in that the procedure did not specify instructions for connecting the load cell with the microprocessor, did not specify instructions for reading and interpreting the indicated load, and failed to require calibration of the microprocessor used to sense the load cell output and display the applied load. In addition, on December 18, 1993, a post installation bolt tension test was conducted on a mock-up of the shroud and the bracket at the Brunswick facility. The tension test used the hydraulic pressures established in the November 13, 1993, bolt tension qualification test which were subsequently used to tension the bolting for the twelve installed shroud brackets in Unit 1. The hydraulic pressure established for tensioning the lower shroud bolts resulted in a bolt preload greater than that delineated in the General Electric design criteria.

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This is a Severity Level IV Violation (Supplement 1).

B. 10 CFR Part 50, Appendix B, Criterion V requires that "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

Paragraph 8.4.5 within Section 8.0 of the General Electric Quality Assurance Manual states that "The status of material or items shall be maintained by a tagging system in accordance with Section 14.0 of the manual." Paragraph 14.4.1 requires the application of a "QC Accept" sticker or tag on accepted materials after satisfactory receipt inspection. Paragraph 10.5.1 within Section 10.0 of the General Electric Quality Assurance Manual requires in-process inspection to be "...performed and documented on the traveler, work package and/or subtier documents...as appropriate to the inspection being performed." Paragraph 10.5.2 states, in part, "No work shall progress beyond an established hold point until inspected by the person organizationally responsible or having the authority for establishing the hold point." Also, a Measurement Tool Check List which was part of bracket installation traveler stated in part, "Complete the following checks prior to installation [of the tool] in the reactor vessel."

Contrary to the above, on December 7 and 8, 1993, the inspector identified the following quality assurance and quality control violations:

(1) A lubricant used in the installation procedure for the shroud repair was not tagged with a "QC Accept" sticker.

(2) Measurement tool check lists within travelers for BRACK-15 and BRACK-135 were not signed as required although the work had been completed two days prior to this finding.

(3) Measurements for shim gap taken as required in Sequence 4A of the traveler for MSHIM-315 were recorded on the incorrect data sheet (MSHIM-225, SPCS-01, Steps 1 and 2) and were subsequently verified by quality control.

(4) The hold point associated with Sequence 2B of traveler MSHIM-15 was not signed although subsequent steps had been completed and signed off.

(5) A QC check of step 4A in the traveler BRACK-105 was not verified and signed prior to completion of subsequent procedural steps.

This is a Severity Level IV Violation (Supplement 1).

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light is hereby required to submit a written statement or explanation to the U.S. Nuclear

Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an Order or Demand for Information may be issued as to why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 14th day of January 1994

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/93-58 and 50-324/93-58

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: December 6-10 and 15-18, 1993

Inspector: J. L. Coley 1-7-94
J. L. Coley Date Signed

Accompanying Personnel: P. J. Rush, NRR Intern

Approved by: J. J. Blake 1/10/94
J. J. Blake, Chief Date Signed
Materials and Processes Section
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope:

This routine, announced inspection was conducted in the areas of inservice inspection - observation of Unit 1 core shroud repair activities.

Results:

In the areas inspected, two violations were identified. One violation dealt with the failure to provide adequate QA/QC oversight of the shroud repair work activities 2.A (1). The second violation addressed engineering discrepancies in determining the bolt preload for repair bracket fasteners on the Unit 1 core shroud, paragraph 2.A (2). An unresolved item was also identified which involved General Electric's (GE) use of an alternative method of providing approval signatures for engineering procedures, paragraph 2.A (1). Subsequent to the inspector's identification of the above violations the licensee was proactive in immediately addressing their cause. The shroud repair activities were stopped, all personnel on the refueling floor were given additional QA/QC training, QA/QC coverage was strengthen, additional engineers were brought in from Raleigh, NC to assist in the tensioner qualification test, qualification testing to determine upper limits of the bolt preload were conducted, and CP&Ls cognizant managers came to Atlanta on December 13, 1993, to report on the results of their additional qualification test and to discuss any open questions on the shroud modification installation.

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REPORT DETAILS

1. Persons Contacted

Licensee Employees

*R. Anderson, Vice President, Brunswick Nuclear Plant
○*M. Bradley, Manager, Nuclear Assessment Department
*J. Cowan, Plant Manager, Unit 1
*T. Eason, Quality Control
○*R. Godley, Manager, Regulatory Programs
□○*R. Grazio, Manager, Nuclear Engineering Department
□*C. Hinnant, Director, Site Operations
*G. Honma, Manager, Licensing
*W. Levis, Manager, Regulatory Affairs
□○*G. Miller, Manager, Technical Support
*J. Purkis, Manager, Projects
□*G. Thearling, Senior Specialist, Regulatory Affairs
□*J. Titrington, Manager, Unit 2 Operations
*S. Vann, Nuclear Engineering Department
□V. Wagoner, Nuclear Engineering Department
*C. Warren, Plant Manager, Unit 2
□D. Williams, Nuclear Engineering Department
□B. Wilton, Nuclear Engineering Department

Other licensee employees contacted during this inspection included engineers, technicians, and administrative personnel.

Other Organizations

General Electric Nuclear Energy (GENE)

□*L. Aiello, Manager, Site Services
□J. Charnley, Principal Engineer
□T. Hurst, Manager, Shroud Repair Program
*V. Kenney, Manager, Modifications and Services Quality
□P. Mayo, Manager, Shroud Repair Project
*J. Sherk, Manager, Plant Services

NRC Resident Inspector(s)

*P. Bryon, Resident Inspector
*C. Christensen, Reactor Projects Section Chief
*M. Janus, Resident Inspector

*Attended exit interview on December 10, 1993
○Attended exit interview on December 13, 1993
□Attended exit interview on December 18, 1993

2. Observation of Unit 1 Core Shroud Repair Activities (73753)

Background

In October, 1990, GE issued a Rapid Information Communication Service Information Letter (RICSIL No. 054) which reported cracking near a circumferential seam weld in the beltline area of the core shroud in a Boiling Water Reactor (BWR) located outside the United States. The core shroud is a reactor vessel internal component which surrounds the reactor core and directs coolant flow. Although the shroud is not a code component, the design stress intensities of the Brunswick Nuclear Plant (BNP) reactor vessel internals are in accordance with the applicable portions of Section III of the ASME Code Boiler and Pressure Vessel Code (1965 Edition through Winter, 1967 Addenda). The safety design basis of the shroud is to:

(1) Provide a floodable volume in which the core can be adequately cooled in the event of a breach in the nuclear system process barrier external to the reactor vessel.

(2) Limit deflection and deformation of the reactor vessel internals to assure that the control rods and the core standby cooling systems can perform their safety functions during abnormal operational transients.

Based on the recommendations contained in RICSIL No. 054, the BNP Unit 1 shroud was visually inspected in July, 1993, and an approximate 360° circumferential crack was confirmed in the inside diameter of the Top Guide Support Ring, at weld (H-3) to the shroud mid-section. The H-3 Weld is 2.25" thick and subsequent ultrasonic examinations of the crack revealed the depth of the indication to range from 0.95" to 1.71". Additional in-vessel visual inspections were conducted, and other circumferential and axial indications were confirmed elsewhere in the shroud on both the inside and outside diameter. None of the additional cracks detected were as severe or as safety significant as the crack at weld H-3. This weld was safety significant because if weld H-3 failed completely and a large main steam line break were to occur, the hydrodynamic loads across the shroud would be sufficient to result in the top guide core structure being lifted above the fuel assemblies. Should this happen the lateral support to the assemblies would no longer be provided and control rods may fail to fully insert.

Although GE's safety analysis would have allowed Unit 1 to continue operation for at least one additional cycle, the licensee elected to repair weld H-3. The repair consisted of installing twelve bolted brackets at 30° increments around the shroud. This arrangement was designed to carry the full load of the weld joint. The brackets were also designed to incorporate the H-2 weld since this weld had also experienced cracking and could not be used for support. The brackets were to be installed on the outside surface of the shroud with two bolts attaching the bracket to the upper shroud above weld H-2, and two bolts attaching the bracket to the shroud mid-section below weld H-3.

A. Shroud Repair Activities

On December 6, 1993, the inspector arrived at the Brunswick Nuclear Plant to observe the work processes used by the licensee and GE for installing the brackets on weld H-2 and weld H-3. Seven repair brackets had been installed on the shroud at the time of the inspector's arrival. All bolts on five of the seven installed brackets had been tensioned and all work was complete with the exception of installing and tack welding the keeper to the bolts. This work was performed underwater at a depth of approximately 60 feet.

In order to verify that the repair was proceeding satisfactorily the following areas were examined by the inspector: (1) bracket installation, cleanliness control, and associate engineering procedures, (2) the test procedure for determining installed bolt preload, (3) the welding specification for the bolt keeper and welder certification records for four welders, (4) the work travelers for each of the shroud brackets, (5) material certifications for the repair brackets and their associated hardware (bolts, fasteners, and washers), (6) QC/NAD surveillance checklists for monitoring the refueling floor activities, (7) inprocess repair activities were observed at various stages of bracket installation, and (8) a verification test of installed bolt preload on a representative mock-up of the shroud was observed.

(1) Review of procedures, and work instructions

On December 7, 1993, the inspector reviewed the procedures/work instructions listed below to determine whether they had been approved, properly delineated the work scope, and provided for verification of essential elements.

Document No.	Title or Subject
GENE B1-SR/SCI-001 Rev.3	Shroud Bracket Installation Procedure
GENE D50YP5 Rev.6	Nickel-Graphite Thread Lubricant
GENE D50YP12 Rev.2	Nonmetallic Impurity Limits
GENE 24A5116 Rev.2	Shroud Clamp Repair Procedure
GENE 25A5498 Rev.0	Weld Specification Procedure Shroud Repair Tack Welding
GENE FDI No.0146-75200	Final Disposition Instruction Rev.2

Document/Instruction Reviewed Cont'd

Document No.	Title or Subject
GENE 21A2040 Rev.1	Cleaning and Cleanliness Control
CP&L AI-112 Rev. 5C	Control of Materials in the Spent Fuel Pool
Traveler Nos. BRACK-XX	Installation of Bracket Clamps
Traveler Nos. MSHIM-XX	Machining of Bolt Shims for Upper Bolts in Shroud Repair Brackets
Traveler Nos. MKEEP-XX	Machining of Keepers for Upper Bolts in the Shroud Repair Brackets

The above travelers were reviewed for completeness, adequacy in controlling overall work progress, and quality control oversight. The travelers govern the progression of work on the bracket installation process. Various check lists, check points, hold points, and measurements must be signed and verified at certain stages prior to completion of subsequent work steps. The inspection of the above travelers found problems, as described below, indicative of a lack of effective quality control oversight on the repair process by GE.

- The "MEASUREMENT TOOL CHECK LIST" within the travelers for BRACK-15 and BRACK-135 were not completed although work on these brackets had been completed two days prior to the inspection. At the top of the check list sheets it is clearly stated that all checks on the list must be completed prior to installation of the measurement tool in the reactor vessel; however, none of the checks were signed and dated although shim gap measurements for these two brackets had been completed. The licensee and GE were informed of this finding during the inspection. GE personnel stated that the checks had been completed on December 5, 1993, during the installation procedure, but the check list was not properly completed as required.

- The inspector identified a procedure step with a quality control hold point not properly signed in the traveler MSHIM-15. Step 2B of the traveler requires that the shim be properly identified and the material heat numbers etched prior to machining to the proper dimensions. This hold point must be verified, signed, and dated by quality control prior to completion of subsequent steps of the traveler;

however, the inspector found subsequent steps completed without proper quality control signatures in Step 2B.

- The inspector reviewed the BRACK-105 traveler and found a quality control check not properly signed and dated in Step 4A. Step 4A required the upper bolts to be engaged in accordance with the installation procedure. The step included a hold point requiring verification by a designated projects member and a quality control check. Although the project's hold point was properly signed and dated November 28, 1993, the quality control check had not been completed at the time of the inspection.

- The inspector reviewed traveler MSHIM-225 and found shim gap measurement data within a subtier document. At the time, no work had begun on installing the bracket at the 225° azimuth of the shroud, but the subtier document (SPCS-01) to this traveler had shim gap data entered in Steps 1 and 2. The data was recorded on the sheet and the measurements were subsequently verified and signed by quality control. However, the data was for the measurements taken in accordance with Sequence 4A for traveler MSHIM-315. The contractor had inadvertently entered the information in the incorrect traveler. The problem was brought to the attention of the project manager responsible for work activity on the repair procedure. The shim gap dimensions were then transferred from SPCS-01 in traveler MSHIM-225 to SPCS-01 of MSHIM-315.

Paragraph 10.5.1 within Section 10.0 of The General Electric Quality Assurance Manual (QAM-001) requires in-process inspection to be "performed and documented on the traveler, work package and/or subtier documents...as appropriate to the inspection being performed." Paragraph 10.5.2 states, in part, that "No work shall progress beyond an established hold point until inspected by person organizationally responsible or having the authority for establishing the hold point." The above examples of inadequate QC oversight were reported to the licensee as violation 50-325/93-58-01, "Failure to Provide Adequate QA/QC Oversight of Shroud Repair Work Activities".

The inspector's review of the above documents also revealed that GE's engineering specifications and drawings did not have hand written approval signatures on the face of the document. Subsequent discussions with the licensee and review of data furnished by GE revealed that as of May 25, 1993, GE no longer hand signed these documents. The reason GE deviated from having the approval signatures on the documents was that many of these documents are now created using word processors or CAD systems. Hand written signatures on these documents would require that the document be printed in order to provide a signed copy. GE based their justification for deviation from standard practice, on ANSI Standard N45-2.9 which governs record authentication. Paragraph 3.2.1 of this document states:

"Documents shall be considered valid records only if stamped, or initialed, or signed and dated by authorized personnel or otherwise authenticated. This authentication may take the form of a statement by the responsible individual or organization. Hand written signatures are not required if the document is clearly identified as a statement by the reporting individual or organization. These records may be originals or reproduced copies."

GE had initially stated in discussions with the inspector that NRC's Office of Nuclear Reactor Regulations (NRR) had been notified of their decision to use an alternate method for the documentation of approval signatures which would be traceable to the document in the field; however, efforts to produce verification of this action were unsuccessful. The inspector's review of the alternate method used by GE revealed that it was a good alternative method and therefore the inspector had no technical bases to object to it's use.

Prior to the start of the exit meeting with management on December 10, 1993, the inspector was informed by the resident inspector that NRR had been notified of the inspector's finding and that they may not fully concur with GE's alternate method of procedure approval. When this item was discussed during the exit meeting CP&L's Vice President (BNP) committed to contact senior management at GE and request that they resolve this issue with NRR. This issue however was reported to the licensee as Unresolved Item 50-325/93-58-03, "Concurrence for Alternate Method of Signing Document Approvals".

(2) Observation of Work Activities

On December 6-7, 1993, the inspector observed repair activity on the Brunswick Unit 1 Refueling Floor. The observed bracket installation activities in progress during the inspection proceeded according to the steps of the procedure. Two video displays connected to cameras submerged within the vessel were frequently monitored by the project shift supervisor to ensure the activity progressed according to the installation procedure. Discussions held with various personnel involved in the repair activity revealed that workers were knowledgeable of both the overall repair process as well as the present stage of the work; tools and other components brought into the work area were checked and logged into the controlled area; and repair bracket components were identified by at least two individuals prior to entry into the work area.

During the inspection, the inspector observed that all threaded bolt surfaces were coated with a lubricating grease prior to entry into the vessel. The inspector questioned whether the grease, D50YP5B Lubricant ("Never Seez"), was qualified for use in the reactor vessel. GE personnel indicated that the lubricant is commonly used in nuclear applications, however the can of grease used for the installation process was not marked with a quality control acceptance sticker. GE personnel questioned on the absence of indication on the can stated that the lack of quality control acceptance sticker had been overlooked by those involved in the bracket installation process.

Paragraph 8.4.5 in Section 8.0 of the GE Quality Acceptance Manual states, "The status of material or items shall be maintained by a tagging system in accordance with Section 14.0 of this Manual." Paragraph 14.4.1 states, in part, "After satisfactory receipt inspection of material or items, acceptance is indicated by application of a 'QC Accept' sticker or tag..." The licensee's failure identify that materials in use during the installation procedure were improperly identified is an additional example of violation 50-325/93-58-01.

At the request of the inspector, GE personnel demonstrated the assembled configuration of the upper bolt joint using actual components (i.e. bolt, washer, bracket, nut, and shim). The physical configuration of the components was such that the curved shroud surface directly contacts the flat surfaces of the bracket in the lower joint and the washer in the upper joint. GE personnel indicated that this was true, noting that the curvature of the shroud surface was minimal. The inspector recognized that although the curvature was slight it could have an impact on the resultant preload in the shroud bracket bolts. The inspector requested the qualification procedures for the hydraulic tensioners so that an independent assessment could be made to ensure that required bolt preloads were obtained on the bracket bolts during the installation process.

In order to assure the adequacy of the installation procedure used at the Brunswick site, GE had performed two qualification tests. GE test procedure B1-SR/SCI-QUAL-002, Rev. 0, attempted to quantify the resultant preload on the joint bolt following pretensioning the bolt and torquing the nut. Test procedure B1-SR/SCI-QUAL-004, Rev. 0, assessed the viability of the installation procedures used to install the repair brackets on the Unit 1 core shroud. All testing was conducted at GE's facility in San Jose, California.

The inspector's review of test procedure B1-SR/SCI-QUAL-004, Rev. 0, revealed the environment for the test closely simulated the actual conditions which would exist during the installation of the shroud brackets at the Brunswick site. The testing verified the process of tightening the nuts on the bracket bolts to obtain consistent bolt preloads. The initial review of the test procedure indicated that the methodology employed in the bracket installation procedure (B1-SR/SCI-001, Rev. 3) would ensure that minimum design bolt preloads are obtained.

The inspector's review of test procedure B1-SR/SCI-QUAL-002, Rev. 0, which was used to qualify the hydraulic tensioning devices revealed that the test utilized an improperly calibrated instrument and was not conducted in a manner consistent with the prerequisites of the procedure.

The purpose of the test was to accurately quantify the resultant bolt preload for the upper and lower bolts installed on the shroud bracket. The bolts are pretensioned during the installation process using hydraulic tensioners. The data for the resultant bolt pre-loads following pretensioning the bolt and tightening the nut was recorded in the procedure. Bolts installed on a fixture were loaded in tension using the tensioners; the nut was tightened to a specified torque and the tension released; and the final residual compression as measured on a load cell within the fixture was recorded. Several iterations of tensioning the bolt and torquing the nut were necessary to obtain consistent compressive bolt pre-loads.

The load cell used in the test fixture was supplied by International Scientific Research. The rated capacity as specified by the vendor is 150,000 pounds in compression. United Calibration Corporation calibrated the load cell to 150,000 pounds on November 9, 1993, in accordance with procedures which conform to MIL-STD-45662A and ASTM E-74. The load cell was found to be accurate within one percent throughout the range of calibration.

The tensioner test procedure specified that the bolt in the test fixture was to be incrementally loaded using a hydraulic tensioner. Hydraulic pressure to the tensioners was measured on a calibrated pressure gage. The pressure gage was calibrated by Simco Electronics in accordance with NIST standards on November 12, 1993. The calibration range for the gage was 0 to 15,000 psig with an accuracy of ±2 percent over the entire range.

As required by the procedure, the 2.50 inch upper bolts were incrementally loaded to 175,000 pounds in tension; the 2.75 inch lower bolts were similarly tensioned in excess of 250,000 pounds. The upper load limits for both tests were in excess of the capacity and range of calibration for the load cell. Compressive load values, as measured on the load cell located in the bolted joint, were recorded on test data sheets for each bolt size. Numerous load data recorded on these sheets exceeded the range of calibration for the load cell.

Section 2.0, of procedure B1-SR/SCI-QUAL-002, Rev. 0, specifies that the tensioners are to be tested to determine the resultant joint bolt preload on a fixture using a calibrated load cell. Paragraphs 5.9 and 6.8 within the test procedure clearly state the load cell will go out of its calibrated range. The use of the load cell during testing beyond its range of calibration is identified as the first example of violation 50-325/93-58-02, "Engineering Discrepancies in Determining Bolt Preload on Unit 1 Shroud".

The inspector identified an additional problem associated with test procedure B1-SR/SCI-QUAL-002, Rev. 0. The purpose of the test as specified in Section 2.0 was to determine the resultant bolt preload on the joint bolt. The resultant preload on a bolt is a function of the physical characteristics of both the bolt and the components of the bolted connection. However, the test fixture used in the testing was not adequately representative of the actual bolted joint for an installed shroud bracket. The bolted joints of the bracket installed on the shroud have flat surfaces which contact the curved surfaces of the shroud. In addition, the force of the preloaded bolts carried by the joint in an installed bracket is transferred through sections of reduced area. The fixture utilized in the test procedure failed to simulate these conditions.

The 2.50 inch bolts installed on the upper shroud section mate the surfaces of the shroud, a 0.25 inch thick washer surface, a shim, and the bracket. The curved surface of the shroud directly contacts the relatively thin surface of the flat washer. The 2.75 inch bolts on the lower shroud section compress the curved shroud against the flat surfaces of the bracket. The test fixture to determine the resultant bolt preload consists of a flat plate and a load cell. The flat plate was intended to simulate only the thickness of the bolted joint in conjunction with the load cell in the fixture. Thus, the effects resulting from the mating of curved and flat surfaces was unaccounted for in the test procedure.

The washer and shim installed in the upper bolt joints of the bracket have a relatively small surface area over which the compressive load is carried. The inner washer surface is in contact with the curved shroud surface. A visual inspection of a preloaded bolt installed on the test mock-up of the core shroud revealed that the entire surface of the washer does not mate flush with the shroud surface. The curvature of the shroud permits contact between the outer shroud surface and the washer along a vertical axis perpendicular to the bolted joint. The outer washer surface away from the core shroud is in contact with a shim. The load bearing surface of the shim is also low due to its U-shaped configuration. The resultant preload in the bolt is dependent on the load carrying surface area of the joint. The fixture used in the test procedure did not attempt to model the complexities in load bearing surfaces evident in the actual bolted connection.

Section 3.0, of procedure B1-SR/SCI-QUAL-002, Rev. 0, states, "Equipment to be qualified will be of the same configuration to be used at the site and as described in this procedure." The inspector interpreted "the equipment" as the bolt, the components of the bolted joint, and the hydraulic tensioner as utilized during the actual installation process. The tests to determine the resultant bolt preload failed to model the dimensional characteristics of the bolted joint as specified by the procedure. This failure to adhere to procedure is identified as the second example of violation 50-325/93-58-02.

The inspector's review of qualification procedures for installing brackets and tensioning bolts to obtain the required preload found that the process did not ensure that the maximum design bolt preloads were not exceeded during the installation process. The licensee agreed at the initial exit interview held on December 10, 1993, to supply the inspector with additional information to clarify preloads on previously installed shroud bracket bolts.

In response to the inspector's concerns, GE conducted a series of tests on December 11-12, 1993, in an attempt to quantify the bolt preload. These test were also witness by an NRC inspector on site at the time. In these tests, a 300,000 pound capacity calibrated load cell was used to measure bolt preload. The load cell was connected to a microprocessor which the licensee stated indicated the pressure (load) acting on the load cell in pounds, divided by ten. The inspector question the licensee regarding how they knew to use a multiplication factor of ten. The licensee stated that this was the factor used in previous testing. The inspector also noted that the load cell was indicating a reading (load) of negative 5000 pounds when the load cell was in an unloaded condition. The inspector questioned this reading and was informed that at zero load, the load cell data was spurious.

The initial onsite test was started on the 2.5 inch diameter upper shroud bolts. However, the test was stopped after two data points were obtained because the new data did not agree with the San Jose data. After the test was terminated, the inspector question the licensee and GE engineers regarding the use of the test equipment and the adequacy of the test procedure. These questions disclosed the following problems:

(1) The electrical digital meter to display load cell output had not been calibrated in conjunction with the load cell. The licensee assumed it had been.

(2) The licensee had no instructions for operating and/or reading the microprocessor. The licensee also had no instructions, i.e. wiring diagram, to verify the microprocessor had been properly connected to the load cell at the test site.

(3) Licensee and GE engineers were not familiar with operation of the load cell, its operating characteristic, or the limitation of the equipment.

The licensee was notified that failure to calibrate the microprocessor was another example of violation 50-325/93-58-02.

After the initial test was terminated, the test procedure was revised to provide for reading the load cell output using a calibrated voltmeter. The load cell output which is read in millivolts, was converted to pounds using the calibration data. The inspector witnessed several additional tests performed on bolts installed in the mock-up. The test data was erratic. However, the data provided some confirmation of the San Jose test, but indicated that because of the curvature of the mock-up, the load cell readings were questionable.

At the licensee's request, a meeting was held in the NRC Region II office on December 13, 1993. Representatives from CP&L requested the meeting to present results from the shroud bolt testing conducted on December 11-12, 1993. Preliminary results from the testing indicated that the installed bolt preloads were higher than previously anticipated. Test results for the upper bolts were at or slightly higher than the design limit for bolt preload. Lower bolt data was not available at the time of the meeting. Since the early indications revealed bolt preloads were too high, the licensee had requested that General Electric provide the maximum allowable limit for the bolts should the design limits need revision. The licensee stated in the meeting that the limits could be extended to 124,000 pounds and 163,000 pounds for the upper and lower joint bolts, respectively. It was also stated in the meeting that anomalous load cell readings were recorded during the testing. The abnormalities were believed to be caused by asymmetric loading on the load cell.

The licensee and NRC restated all inspection findings discussed in the exit interview held on December 10, 1993, to ensure common agreement. The inspector committed to return to the site to verify the recently obtained test data and review the revised qualification procedures.

The inspector returned to the Brunswick site on December 15, 1993. CP&L personnel responsible for oversight of the testing presented the results from recent testing to the inspector. The licensee explained the complications involved with incorporating the load cell within the test fixture to measure the resultant preload.

Test results were presented which indicated that asymmetric loading of the load cell could lead to significant inaccuracies in computing resultant preload when directly using load cell output. In light of this discussion the inspector verified by independent calculation the accuracy of the original load cell data recorded in GE test procedure B1-SR/SCI-QUAL-002, Rev. 0. Using the readings of hydraulic pressure to the tensioner the applied load can be determined. Load cell data recorded on the test data sheets was compared with calculated tensioner load based on the hydraulic pressure. The comparison revealed that the load cell readings contained considerable error throughout the entire test range. These errors were caused not by the overloading of the load cell nor by inaccuracies in reading tensioner hydraulic pressure but by incorporating the load cell into a test setup which produced erroneous readings. Subsequent testing confirmed that the load cell could not be loaded in a manner as was done in the initial testing. In light of this discovery the inspector notified the licensee that the minimum bolt preload on the installed shroud bracket bolts may not be met as was stated previously in the initial exit interview held on December 10, 1993.

GE and the licensee then developed an alternative technique to measure bolt preload. General Electric procedure B1-SR/VT-002, Rev. 0, provided a method to quantify preloads based on calculating an elastic stiffness for a bolt and then subsequently measuring the elongation of the installed bolt. The resultant preload could then be computed by multiplying the bolt stiffness and elongation.

The inspector reviewed the procedure and witnessed testing on December 18, 1993. All instruments, tools, and gages used in the test were properly calibrated. The methodology used to derive the bolt preload was discussed with GE and the licensee and found to be acceptable.

Since past test results were influenced by asymmetric compression of the load cell, GE developed an alternative method to use the load cell output for load measurements. The inspector requested the licensee submit information to review this approach to compute the resultant bolt loading. A submittal dated December 28, 1993, was reviewed by the inspector justifying the use of load cell readings as was done in test procedure B1-SR/VT-002, Rev. 0. The methodology employed to calculate the resultant joint compressive load was found to be acceptable.

GE performed two tests to quantify the bolt preloads, one test for the upper bolts and another for the lower bolts. Due to the repeatability of results demonstrated in previous testing witnessed by the inspector this approach was acceptable. The results of the testing confirmed that the preloads on the installed lower bolts were not within the required design limits.

The lower bolt preloads were found to be in excess of the upper design compressive load limit by approximately 20,000 pounds. The measured preload for an upper bolt was within the required design range; however, the margin between the measured preload and the upper design limit was insufficient to ensure that the bolts had not been installed above the design limits. The licensee had previously indicated during the meeting held in Atlanta, Georgia, on December 13, 1993, that the upper design limits for bolt preload could be raised from their current values. In light of the test results, the inspector requested that the design preloads be modified to account for higher than anticipated preloads on the installed bolts.

As a result of the problems with the qualification test procedures encountered early in the inspection and the fact that the modification stress report (GE-NE-523-143-1093) stated that thermal stresses were neglected in the design analysis prompted the inspector to perform an independent calculation of bolt thermal stresses and their effects in conjunction with preload stresses. The calculations revealed that the thermal expansion mismatch between the bolts and the shroud/bracket assembly will elevate tensile stresses in the bolt by approximately fifteen percent. On December 16, 1993, the inspector asked the licensee to supply additional information regarding the impact of thermal stresses induced in the bracket bolts. The inspector reviewed the analysis dated December 17, 1993, which confirmed the calculations on thermal stresses.

The licensee submitted a response to the NRC dated December 28, 1993, which revised the upper design bolt preload limits. The inspector reviewed the licensee's calculations which, contrary to the statement within the stress report, did include the effects from thermal stresses. The inspector identified one inconsistency in the analysis which over estimated the amount of stress relaxation in the bolts after installation. NRR will further review the licensee's submittal to revise the design limits and determine the acceptability of their methodology.

(3) Review of Completed Documentation

The inspector reviewed completed records for the activities listed below to ascertain whether the documentation met regulatory requirements and licensee commitments.

a. Welder operator qualification tests were reviewed for welders that would perform the underwater tack welding of the keepers on the shroud bolts. The welding procedure specification (WPS) followed by the welders during the welding of the test coupons was UW-8.8.10-W. Six coupons were welded by each welder. The coupons were subsequently load tested until failure. The test results for all four welders met the drawing requirement of 2,000 pounds minimum and 12,000 pounds maximum load. The welders qualified were: G.S.M, L.R.R, R.J.S, and C.H.R .

b. The Certified Material Test Reports (CMTR) for materials used in the bracket repair of the Unit 1 reactor vessel shroud were reviewed by the inspector. These materials consist of the brackets (heat nos. 24319 and 24313), the bolts and nuts (heat no. 9E7474) and the shims and washers (heat no. 500910). GE reported a deviation to their design specification (E50YP20 Rev.4) in that the 304L stainless steel forging material used for the core shroud modification brackets failed the sensitization test criteria. The test method (ASTM A262, "Standard Practice for Detecting Susceptibility to Intergranular Attack in Austenitic Stainless Steels," Practice A) uses an oxalic acid etch to chemically attack and dissolve precipitates at the grain boundaries. This standard accepts material unless a 100 percent linear ditching of any one grain boundary is found in a sample. The GE design specification for sensitization testing rejects a heat of material if greater than 5 percent linear ditching is observed. The analysis of the bracket material resulted in ditching of 71, 70, and 29 percent.

The GE and CP&L technical position was to re-anneal the material with special controls on the heat treatment in an attempt to bring the material back into conformance with the specification requirements. These efforts however, failed to achieve the desired results in that, again each sample from the re-annealed block failed the acceptance criteria.

GE and CP&L then decided to test samples of the material in accordance with the more precise standard Practice E (ASTM A262). The standard Practice E involves immersing samples in sulfuric acid and copper sulfate for 24 hours followed by a 180 degrees bend test (the bend radius equal to the sample thickness), and a visual examination for intergranular cracking, fissures, or "orange peel" effects. All of the nine (9) samples passed the standard Practice E test, which was done on coupons from each heat of material from the original heat treatment.

The inspector reviewed CP&L evaluation of the material deviation NED-B-5263, "Resolution of Material Deviation to 304L Stainless Steel Forgings". This evaluation concluded that; since each heat of material passed the standard ASTM A262, Practice E test, the material was acceptable. In addition, no welding would be done on the bracket that could thermally sensitize the bracket material, and compressive stresses will exist when the bracket is loaded during normal operation, and a crack cannot propagate in a compressive stress field. Therefore, intergranular stress corrosion cracking of the bracket material is not a concern because the material has been demonstrated to be resistant to intergranular attack (<0.02 carbon, and passes the ASTM A262, Practice E test) and tensile stresses are not high enough in the brackets to initiate cracking.

Within the areas examined, no violations or deviations were identified except as noted in paragraphs 2.(1) and 2.(2) above.

B. Independent Review of Jet Pump Tensioning Activities

During the present refueling outage for Brunswick Nuclear Plant Unit 1, the licensee had also scheduled to replace the jet pump hold down beams in response to recently identified IGSCC problems encountered at other BWRs. These bolts which hold the beams in place are tensioned in a manner which is similar to the process for installing the bolts on the shroud bracket. As a result of the problems identified during the inspection regarding the qualification of the hydraulic tensioner and installed bolt preloads on the repair bracket bolts, the licensee was asked to submit information regarding the qualification procedure for the hydraulic tensioners used to tension jet pump hold down beams. The inspector reviewed the licensee submittal dated December 28, 1993. The qualification process for these tensioning devices used acceptable methods which assure that adequate design preloads are met during the installation process. The inspector found the qualification procedure for the jet pump hold down beam acceptable.

3. Exit Interview

The inspection scope and results were summarized on December 10, 1993, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection results listed below. At the licensee's request of December 10, a second meeting was held in the Region II NRC office in Atlanta, Georgia, on December 13, 1993. At the meeting, the licensee presented preliminary results of recent tests conducted in response to NRC concerns presented in the initial exit interview. In addition, the inspection issues were restated by both the licensee and the inspector to assure agreement between the two parties. The inspector agreed to return to the Brunswick site on December 15, 1993. Qualification testing to resolve test procedure concerns raised in the initial inspection was observed by the inspector on December 18. A final exit interview was held on December 18, 1993. The licensee committed to furnish the inspector with additional information regarding several inspection issues discussed in the body of this report. All documents have been received, reviewed, and found to be satisfactory by the inspector. Although reviewed during this inspection, proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

(Open) Violation No. 50-325/93-58-01, "Failure to Provide Adequate QA/QC Oversight of Shroud Repair Work Activities", paragraph 2.A.(1)

(Open) Violation No. 50-325/93-58-02, "Engineering Discrepancies in Determining Bolt Preload on Unit 1 Shroud", paragraph 2.A.(2)

(Open) Unresolved Item No. 50-325/93-58-03, "Concurrence for Alternate Method of Signing Document Approvals", paragraph 2.A.(1)

4. Acronyms and Initialisms

ANSI -	American National Standards Institute
ASME -	American Society of Mechanical Engineers
ASTM -	American Society for Testing and Materials
BNP -	Brunswick Nuclear Plant
BWR -	Boiling Water Reactor
CAD -	Computer Aided Design
CFR -	Code of Federal Regulations
CMTR -	Certified Material Test Report
CP&L -	Carolina Power and Light Company
FDI -	Final Disposition Instruction
IGSCC-	Intergranular Stress Corrosion Cracking
GE -	General Electric
GENE -	General Electric Nuclear Energy
MIL -	Military
NAD -	Nuclear Assessment Department
NED -	Nuclear Engineering Department
NIST -	National Institute of Standards and Technology
No. -	Number
Nos. -	Numbers
NRC -	Nuclear Regulatory Commission
NRR -	Nuclear Reactor Regulations
QA -	Quality Assurance
QAM -	Quality Assurance Manual
QC -	Quality Control
QUAL -	Qualification
Rev. -	Revision
RICSIL	Rapid Information Communication Service Information Letter
STD -	Standard
WPS -	Weld Procedure Specification

FEB 2 3 1994

Docket Nos. 50-325, 50-324
License Nos. DPR-71, DPR-62

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/94-01 AND 50-324/94-01)

This refers to the inspection conducted by E. D. Testa of this office on January 3-7, 1994 and the inspection conducted by D.B. Forbes of this office on January 21-25, 1994. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). These violations are of concern because failure to establish adequate procedures for personnel performing radiological work and failure to perform adequate radiological surveys may result in unneccessary exposure of personnel to radiological and other hazardous conditions.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790(a), a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

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The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980. Pub. L. No. 96-511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

/S/

William E. Cline, Chief
Radiological Protection and
Emergency Preparedness Branch
Division of Radiation Safety
and Safeguards

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

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Raleigh, NC 27602

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RII:DRSS	RII:DRSS	RII:DRSS	RII:DRSS	RII:DRP
DForbes	ETesta	EPharr	WRankin	HChristensen
2/18/94	2/16/94	2/22/94	2/17/94	2/23/94

ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power and Light Company
Brunswick Nuclear Plant

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

During an NRC inspection conducted on January 21-25, 1994, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," the violations are listed below:

A. Technical Specification 6.8.1 requires that written procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A, Paragraph G, "Procedures for Control of Radioactivity" of Regulatory Guide 1.33, dated November 1972.

Contrary to the above, on January 19, 1994, the licensee failed to establish and provide an adequate procedure(s) specifying engineering and work controls necessary to effectively control radioactivity commensurate with the hazards of the specific work evolution being performed in the Unit 1 Reactor Cavity area.

This is a Severity Level IV violation (Supplement IV).

B. 10 CFR 20.1501(a) requires each licensee shall make or cause to be made, surveys that (2) are reasonable under the circumstances to evaluate (ii) Concentrations or quantities of radioactive material and (iii) The potential radiological hazards that could be present.

Contrary to the above, on January 19, 1994, during performance of work in the Unit 1 Reactor Cavity area, the licensee failed to perform adequate surveys to evaluate the potential radiological hazards that could be present from unknown concentrations or quantities of airborne radioactivity that existed in areas of the Unit 1 Reactor Building not evaluated or established for the control of airborne radioactivity.

This is a Severity Level IV violation (Supplement IV).

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not

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received within the time specified in this Notice, an order or Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 23 day of FEB 1994

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

FEB 2 2 1994

Report Nos.: 50-325/94-01 and 50-324/94-01

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

Docket Nos.: 50-325 and 50-324

License Nos.: DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: January 3-7, and January 21-25, 1994

Inspectors: E. D. Testa, P.E.
E. D. Testa, P.E., Senior Radiation Specialist — 2/23/94 Date Signed

D. B. Forbes
D. B. Forbes, Radiation Specialist — 2/23/94 Date Signed

Elizabeth B. Shaw
E. B. Shaw, Radiation Specialist — 2/23/94 Date Signed

Approved by: William H. Rankin, P.E.
W. H. Rankin, P.E., Chief — 2/23/94 Date Signed
Facilities Radiation Protection Section
Radiological Protection and Emergency Preparedness Branch
Division of Radiation Safety and Safeguards

SUMMARY

Scope:

This routine, unannounced inspection of the licensee's radiation control (RC) program involved a review of health physics (HP) activities including organization and staffing; training and qualifications; internal and external exposure controls; control of radioactive material; ALARA; audits and appraisals and changes to the program since the last inspection.

In addition to the routine inspection performed, a reactive inspection related to an inadvertent spread of contamination was conducted and details of this reactive inspection are included in this report.

Results:

Based on observations, interviews with licensee management, supervision, personnel from station departments, and records review, the inspector found the licensee's program for occupational radiation safety was functioning

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adequately to protect the health and safety of the radiation workers. Improvements were noted in the plant physical appearance. Painting and floor resurfacing continued in Unit 1. The inspector noted a positive attitude of the health physics workers and considers this a program strength. The ALARA program was successfully working to reduce personnel exposure and reduce out of core radiation source terms. The successful clean-up of the Reactor Water Cleanup (RWCU) Phase Separator Room using robots was noted as a practical positive demonstration of the ALARA program. The inspector noted the health physics challenges associated with Unit 1 start-up, Unit 2 refueling and ALARA challenges associated with resumption of hydrogen water chemistry. In the areas inspected, two violations were identified. One violation was identified as a failure to establish adequate procedure(s) specifying engineering and work controls necessary to effectively control radiological work as required by Technical Specification 6.8.1. (Paragraph 8.). A second violation was identified as a violation of 10 CFR 20.1501(a)(2)(ii)(iii) for failure to perform adequate surveys to evaluate the concentrations or quantities of radioactive material; and the potential radiological hazards that could be present (Paragraph 8.).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

+K. Ahern, Manager, Work Control
+L. Aielle, General Electric
+*R. Anderson, Vice President, Brunswick Nuclear Plant
+*H. Beane, Manager, Quality Control
+M. Bradley, Manager, Nuclear Assessment Department
+*J. Cowan, Plant Manager, Unit 1
+*J. Ferguson, Manager, ALARA
+R. Grazio, Manager, Nuclear Engineering Department
*J. Harness, Manager, Nuclear Assessment Department
+J. Heffley, Maintenance Manager, Unit 2
+G. Hicks, Manager, Training
-*G. Honma, Manager, Licensing
-*T. Jones, Senior Specialist Investigator
+*W. Levis, Manager, Regulatory Affairs
+G. Miller, Manager, Technical Support
+*C. Robertson, Manager, Environmental and Radiation Control
+*R. Smith, Manager, Radiation Control
+S. Tabor, Senior Specialist Investigator
+J. Titrington, Operations Manager, Unit 2
+*P. Snead, Corporate Director, Radwaste and Environmental
+*C. Warren, Manager, Unit 2
+G. Warriner, Manager, Control and Administration
+K. Williamson, Manager, Nuclear Engineering Department

Other licensee employees contacted included engineers, technicians, and office personnel.

Nuclear Regulatory Commission

+*R. Prevatte, Senior Resident Inspector

*Attended January 7, 1994 Exit Meeting
+Attended January 25, 1994 Exit Meeting

2. Organization and Staffing (83750)

The inspector reviewed and discussed with licensee representatives changes made to the Radiation Control (RC) organization since the last inspection of this area conducted October 4-8, 1993, and documented in Inspection Report (IR) 50-325/93-46 and 50-324/93-46. As a result of realignment of corporate support, the site added several new positions. Two Senior Specialists have been added, one specialist to coordinate training for the Environmental and Radiation Control (E&RC) Staff and the other to provide professional support for the health physics (HP) program. These positions have been filled by former corporate support personnel. Seven additional RC technicians positions have been added and three have been filled. One additional RC Supervisor has been added to supervise the seven additional technicians. At the time of the inspection the selection process for this position was in progress. One Manager, Radiation Control was in the process of transferring to the corporate office and his successor had been appointed at the conclusion of this inspection. The E&RC Unit permanent approved staffing level was 120 personnel.

The licensee continued to maintain an experienced core technician staff of junior and senior technicians. The technician staff included senior technicians, junior technicians, and HP clerks. The inspector noted a positive worker attitude and considered this to be a program strength.

Based on discussions with licensee representatives and observations of activities in progress, no concerns were identified regarding the licensee's organization and staffing. The staffing level appeared adequate to support the activities associated with the operation of one unit and the ongoing and planned activities for start-up of the other unit.

No violations or deviations were identified in this area.

3. Self Assessment Programs (83750)

a. Quality Assurance (QA) Audits

The inspector reviewed the licensee's self assessment program for identification and correction of radiological deficiencies. Since the last NRC inspection of this area in May 1993, one QA audit related to the Environmental and Radiation Control function had been performed by the Nuclear Assessment Department (NAD): Report File Number B-ERC-9301, conducted November 29 through December 7, 1993. The inspector reviewed the audit report and discussed selected findings with licensee staff personnel. The audit appeared adequate in scope to address the major program areas and included procedure and documentation review and field evaluations. During the course of this audit the licensee QA auditors reviewed documents to include: Plant Operating Procedures, the Radiation Control and Protection Manual, Technical Specifications, and the Off-Site Dose Calculation Manual. The NAD Team interviewed management personnel, supervisors, and technicians. The QA auditors reportedly conducted a tour of all accessible areas of the RCA, offices, facilities, and laboratories observing housekeeping, chemical control, material condition, work on the Unit 1 Refueling Floor, preparation of radioactive shipments, performance of radioactive surveys and analyzing samples, ALARA practices, use of dosimetry, Radiation Work Permit (RWP) practices, posting of areas, and dose rate information.

The QA audit identified the weaknesses to be issues that require management attention and interdepartmental cooperation. The QA audit addressed the current actions currently being developed and implemented with the HP Supervisor. The audit also discussed corrective actions which had been implemented to close issues/findings identified during previous audits.

The inspector reviewed the findings of a Site Investigation Team (SIT) which was established to investigate the root causes of the contamination event discussed in Paragraph 8 which resulted in an inadvertant spread of contamination. The inspector reviewed the SIT findings for licensee self-assessment of root cause analysis which appeared to be a program strength.

b. Radiological Awareness Reports (RARs)

The inspector also reviewed selected RARs for 1993. These included procedural violations. Radiation Work Permit (RWP) violations, and poor work practices resulting in personnel and/or area contamination. During reviews of the selected RARs, the inspector noted thorough investigations, appropriate and comprehensive corrective actions, as well as visibility with the responsible department manager.

In general, the inspector found the licensee's Self Assessment Program to be adequate for self-identification of radiological findings. In addition, corrective action to findings noted were accomplished in a timely manner.

No violations or deviations were identified in this area.

4. Planning and Preparation (83750)

The inspector discussed with licensee representatives the planning and preparation for the expected restart of Unit 1 which included HP staffing, training, equipment, dose reduction methods to be employed, decontamination efforts, radwaste reduction and work scope sequencing. The inspector also discussed the planning and preparation for the upcoming Unit 2 refueling outage.

The licensee has a plan to transport several more rail cars of spent fuel prior to the end of the calendar year. The inspector reviewed the radiation surveys on two rail cars used for shipment in December and found no problems.

In general, the inspector did not determine problems with planning and preparation with exception to the planning for Unit 1, Cavity Seal Ring Work, as discussed in Paragraph 8.

No violations or deviations were identified in this area.

5. Radiation Protection Training (83750)

10 CFR 19.12 requires, in part, that the licensee instruct all individuals working in or frequenting any portion of a restricted area in the health protection aspects associated with exposure to radioactive material or radiation; in precautions or procedures to minimize exposure; in the purpose and function of protection devices employed; in the applicable provisions of the Commission regulations; in the individual's responsibilities; and in the availability of radiation exposure data.

The inspector discussed with training representatives the Health Physics Continuing Training Program and determined that continuing training is conducted quarterly. The inspector attended a Health Physics Continuing Training Session which was mandatory for all HP personnel. The training session was interactive and addressed issues of substance. The training instructor solicited feedback from the students and discussed feedback from previous sessions. The Radiation Protection Manager and his supervisory staff also attended the training sessions. The inspector reviewed the student handouts and licensee lesson plan TP-RR934AB-1, Revision 0 which was used by the instructor in the training session. The training was five hours in length and included the following objectives:

- Contrast the old RWP philosophy/ methodology to the new RWP philosophy/methodology.
- Discuss the HP technician, supervisor, and planner responsibilities in the planning package process.
- Identify the 10CFR20 requirements for access control of High Radiation Areas (HRAs).
- Describe acceptable methods for implementation of access control for HRAs and Very High Radiation Areas (VHRAs) described in Regulatory Guide 8.38.
- Describe the BSEP alternate method for controlling access to HRAs described in licensee Technical Specification (TS) 6.12 and 10 CFR 20.1008.
- Identify the requirements for control and support of site radiography activities in accordance with E&RC-0290, including:
    - Dosimetry
    - Personnel Monitoring
    - Postings
    - Communication

In follow-up to the training observed and the contamination event discussed in Paragraph 8, the inspector observed briefings conducted by HP personnel for workers prior to entering the radiologically controlled area (RCA) for work evolutions which required pre-job briefings and also observed a briefing conducted for workers continuing work evolutions following the contamination event. The briefings included reviews of current radiation surveys with emphasis on high dose areas and low dose waiting areas. Workers were also informed about the locations of hot spots in an overall work area and cautioned not to work six feet or in the overhead without notifying HP. The interaction between HP and the workers entering the RCA, in this regard, was considered adequate.

The licensee has recently installed computer access terminals at the RCA control point to be used by workers logging into the RCA on an RWP. The inspector observed the use of the terminals by workers logging into the RCA, to determine the effectiveness of training. The inspector discussed various RWP requirements with HP technicians and also discussed exposure tracking capabilities of the system. At the time of the inspection, the licensee was preparing training plans and software to implement a new Digital Alarming Dosimeter (DAD). The inspector also discussed features of the new system to preclude unauthorized access to the RCA by unqualified workers as well as the training to be provided to qualified workers.

Based on the above, the inspector concluded the licensee was effectively performing continuing training for HP technicians.

No violations or deviations were identified.

6. External and Internal Exposure Controls (83750)

10 CFR 20.1201(a),(b),(c),(d),(e), and (f) requires that the licensee shall control the occupational dose to individual adults to annual limits specified.

a. Personnel Dosimetry

10 CFR 20.1502(a) requires each licensee to supply appropriate monitoring equipment to specific individuals and requires the use of such equipment.

10 CFR 20.1501(c) requires that dosimeters used to comply with 10 CFR 20.1502(a) shall be processed and evaluated by a processor accredited by the National Voluntary Laboratory Accreditation Program (NVLAP) for the types of radiation for which the individual is monitored.

The inspector selectively reviewed the licensee's dosimetry program to ensure the licensee was meeting the monitoring requirements of revised 10 CFR Part 20. During tours of the plant, the inspector observed proper use of thermoluminescent dosimeters (TLDs) and self reading dosimeters (SRDs).

No violations or deviations were identified in this area.

b. Whole Body Exposure

The inspector discussed the cumulative whole body exposures for plant and contractor employees. The 1993 goal of 850 person/rem was exceeded. The licensee determined the person/rem cumulative total for the year to be about 872. Several work activities contributed to the overage. Unanticipated repair work for the Unit 1 shroud of approximately 26.7 person/rem and the extensive Unit 1 painting and coatings campaign for the reactor and turbine building added an additional 33.8 person/rem. Unit 1 remained in extended outage for the entire year and Unit 2 for a small portion of the year. There was however a carryover to the 1994 dose budget of an estimated 35 person/rem associated with the Unit 1 Rx Reassembly and an additional 96 person/rem for continued painting in the Reactor and Turbine Buildings and an additional 20 person/rem associated with Unit 2 torus restoration. The five year business plan had estimated a dose goal for 1994 of 550 person/rem. The additional unanticipated exposure of about 151 person/rem would total about 700 person/rem. The original goal of 550 person/rem was based on 11 outage weeks allowing for 34 person/rem/week. Additional work activities for the outage include ISI, maintenance, and modifications. The operational dose estimates for both units for the remainder of the year were estimated at 2.4 person/rem/week/unit (223 person/rem). The challenge level person/rem goal was requested to be 650 based on the carryover and added work scope.

Licensee representatives stated and the inspector independently confirmed that all whole body exposures assigned since the previous NRC inspection of this area were within 10 CFR Part 20 limits. The inspector independently verified the licensee dose assessments for the nine positive wholebody counts for the calendar year and determined that the internal doses were small percentages of applicable regulatory limits.

No violations or deviations were identified in this area.

c. Notices to Workers

10 CFR 19.11(a) and (b) require, in part, that the licensee post current copies of 10 CFR 19, 20, the license, license conditions, documents incorporated into the license, license amendments and operating procedures, or that a licensee post a notice describing these documents and where they may be examined.

10 CFR 19.11(d) requires that a licensee post NRC Form-3, Notice to Employees. Sufficient copies of the required forms are to be posted to permit licensee workers to observe them on their way to or from licensee activity locations.

During the inspection, the inspector verified that NRC Form-3 was posted properly at various plant locations permitting adequate worker access. In addition, notices were posted referencing the location where the license, procedures, and supporting documents could be reviewed.

No violations or deviations were identified in this area.

d. Breathing Air Quality

30 CFR 11.121 requires that compressed, gaseous breathing air meet the applicable minimum grade requirements for Type 1 gaseous air set forth in the Compressed Gas Association (CGA) Commodity Specification for Air, G-7.1 (Grade D or higher quality).

The inspector reviewed licensee procedure 0-E&RC-0135, Sampling Of Breathing Air To Meet Grade D Air Specifications, Revision 4 and discussed with the licensee representatives the program for testing and qualifying breathing air as Grade D. Review of breathing air testing records verified that the licensee was calibrating in-line carbon monoxide monitors and sampling in-use breathing air systems for certification in accordance with procedural requirements. For the tests reviewed, breathing air met Grade D requirements with the exception of one breathing line sampled in Unit 2 Reactor Building on the 50 foot level at location 2 SAV 148, which indicated levels of Carbon Dioxide to be 1000 to 1500 ppm. Records reviewed indicated the breathing line was secured from use and resampled on November 29, 1993. The later sample indicated carbon dioxide levels to be 800 ppm which was an acceptable carbon dioxide levels for meeting Grade D air specifications.

No violations or deviations were identified.

7. Control of Radioactive Material and Contamination, Surveys, and Monitoring (83750)

10 CFR 20.1501(a) requires each licensee to make or cause to be made such surveys as (1) may be necessary for the licensee to comply with the regulations and (2) are reasonable under the circumstances to evaluate the extent of radiological hazards that may be present.

a. Posting and Labeling

10 CFR 20.1904(a) requires, in part, each container of licensed material containing greater than Appendix C quantities to bear a durable, clearly visible label identifying the radioactive contents and providing sufficient information to permit individuals handling or using the containers, or working in the vicinity thereof, to take precautions to avoid or minimize exposures. During tours of the Unit 1 and Unit 2 Reactor Building, Unit 1 Turbine Building, Radioactive Waste Processing

Building and various radioactive material storage locations, the inspector independently verified that selected radioactive material areas were appropriately posted and that selected containers were labeled consistent with regulatory requirements.

No violations or deviations were identified in this area.

b. Personnel and Area Contamination

Unit 1 has undergone and continues to undergo a major painting and coating campaign. Surface preparation for the dados, pumps and pipes and subsequent painting provided a tough challenge to keep the number of PCEs controlled. The plant looks extremely clean and the new surfaces increased the brightness in the areas for worker safety and the coatings provide a surface more easily decontaminated.

During plant tours, the inspector observed adequate housekeeping and contamination control practices. The inspector observed handling, packaging, and surveying of contaminated equipment for movement and judged the work evaluations satisfactory.

No violations or deviations were identified in this area.

c. High Radiation Areas

TS 6.12.1 required, in part, that each HRA with radiation levels greater than or equal to 100 mRem/hr but less than or equal to 1000 mRem/hr be barricaded and conspicuously posted as a HRA. In addition, any individual or group of individuals permitted to enter such areas are to be provided with or accompanied by a radiation monitoring device which continuously indicates the radiation dose rate in the area or a radiation monitoring device which continuously integrates the dose rate in the area, or an individual qualified in radiation protection procedures with a radiation dose rate monitoring device.

During tours of the Unit 1 and Unit 2 Reactor Building, Turbine Building, and Radioactive Waste Processing Building, the inspector noted that all HRAs and locked HRAs were locked and/or posted, as required. Independent surveys performed by the inspector concluded the licensee had been successful in their efforts to reduce general area radiation levels in various areas by hydrolazing numerous clogged floor drains.

The inspector reviewed Procedure OE&RC-0040, Revision 11, dated November 17, 1993, titled High Radiation Area Key Control and performed an independent inventory check of selected Locked High Radiation Keys. The inventory check found no problems. All were properly signed out per the procedure and/or accounted for. The licensee performed a 100 percent verification check of the keys and the lock cores to insure operability. The check also included the emergency keys located in the Control Room. All keys were found compatible with the lock cores.

No violations or deviations were identified in this area.

d. Independent Surveys

During facility tours, the inspector independently verified radiation and/or contamination levels in Unit 1 and Unit 2 Reactor Building, Turbine Building, Radioactive Waste Processing Building areas, and other radioactive material storage areas including the Low Level Waste Handling Building. The inspector also performed radiation surveys of selected HRA boundaries including posted Hot Spots. The inspector reviewed the Hot Spot Engineering Data Report, the hot spots being tracked and the priorities assigned to work on the hot spots for dose reduction. The licensee has contact and 30 cm. survey readings for each of the identified spots and an action plan to reduce the dose associated with the spots. This plan includes but is not limited to the following: flush, cut out, shield or make the area inaccessible workers are made aware of hot spots during RWP briefings.

The inspector reviewed Procedure AI-112, Revision 5C dated February 23, 1993, titled Control of Materials in the Spent Fuel Pools. Activities associated with the refueling of Unit 1 were observed by the inspector. In response to several clarification questions posed by the inspector the Radiation Control Group certified that all work activities during the Unit 1 outage including the shroud project were performed in accordance with this procedure.

No violations or deviations were identified in this area.

8. Contamination Event of January 19, 1994

a. Initial Conditions

Unit 2 was operating at 100 percent power. Unit 1 was in cold shutdown. The reactor vessel head had been previously installed on Unit 1 and a reactor vessel hydro was in progress which was causing heat from piping below the reactor cavity to rise through penetration openings to the inside of the reactor cavity seal ring. The heat increase upward from the reactor cavity created a chimney effect moving hot air from the seal ring up to the refueling floor. A portable worksite ventilation duct was located in the reactor cavity at the time of the event to control airborne contamination during work evolutions in the cavity but appeared to be inadequate to control airborne radioactivity during the work scope performed.

b. Description of Event

On the evening of January 19, 1994, the licensee scheduled work activities in the Unit 1 Reactor Cavity area to include removing the old gasket from the seal ring flange area, cleaning the seal ring flange, installing a new gasket, and seating/installing the Dome on the reactor seal flange. Contract workers met with HP personnel on the Unit 1 refueling floor to obtain a briefing on radiological work controls prior to entering the reactor cavity to perform scheduled work. After being briefed by HP on radiation controls to be implemented and protective clothing (including full-face respirators)to be worn, the workers entered the Reactor Cavity area to perform work at approximately 2115 hours.

Subsequent to the work being performed, an HP technician in conversation with the contractors and the Refueling Floor Technical Manager decided shielding of the bellows area should be performed to reduce radiation exposure to the workers. The HP used a hose to fill the bellows area of the cavity outside the seal ring flange with water to cover the highly contaminated bellows area for the purpose of providing the shielding. Approximately six to eight inches of water was added to the bellows area by the HP.

The first two flange protectors removed by the workers were brought to the top of the cavity before HP and the decontamination personnel were ready to receive the protectors. Surveys determined contamination levels on the flange protectors were 100/200 mrad smearable. The decision was made by HP to place the protectors in the lay down area and temporarily cover them with herculite. The next set of smears indicated approximately 500 mrad smearable. During the work evolution, HP required that the remaining highly contaminated flange protectors be bagged in the cavity area prior to movement to the refueling floor lay down area. After removing the flange protectors, workers began removing and bagging the old gasket and proceeded to clean the dry, highly contaminated flange with abrasive material which included scotch-brite pads and wire brushes. Licensee procedure OSPP-RPV502, Revision 8C, dated October 6, 1993, was the procedure used by the contractors which provided instructions for the work evolutions being performed. The procedure addressed the use of cloths, scotch brite pads, water and/or alcohol to clean and prepare the flange for installing the new gasket and seating the Dome. The procedure did not specify the use of wire brushes for cleaning; however the procedure stated the tool list was recommended and not all inclusive.

At approximately 2135 hours HP determined personnel exiting the refuel floor had contamination on their shoes. Followup contamination surveys indicated contamination had been spread beyond the contaminated area to the uncontaminated area of the Unit 1 refueling floor (117 foot level). Immediate radiological casualty control efforts were initiated by HPs on the refueling floor which included taking gross wipes to determine the possible spread of contamination and high volume air samples to determine air quality. The HPs working the floor detected high levels of contamination on the previously uncontaminated side of the refueling floor in front of the contamination boundary step off pad. Survey results in front of step off pad indicated approximately 200,000 disintegrations per minute (DPM) on a gross wipe. During the clean area investigation of the 117 foot level, the first investigative high volume air sample indicated approximately 2.9E-9 uCi/cc or .217 Derived Air Concentration (DAC). The following backup high volume air samples indicated a rapid decrease in airborne radioactivity as a result of contamination settling out or being removed by building ventilation. The maximum DAC on the 117 foot level during the peak performance of work could not be determined because, no representative air sampling was performed as determined by the licensee during the licensee's investigation and verified by the inspector.

As a result of the initial surveys being performed, operations was notified that work on the refueling floor 117 foot level was shut down and personnel were removed from the floor.

In all, the personnel contamination events determined seven shoe contaminations, and two facial contaminations. Personnel with skin contamination were decontaminated and nasal smears on individuals with skin contamination were determined by the licensee to be negative.

c. Recovery

Efforts to contain the contamination once detected began immediately. Gross wipes were performed in previously uncontaminated areas of the Reactor Building to detect any possible spread of contamination to previously uncontaminated areas. Areas in which any activity above background was detected based on wipes over large areas, were roped off, posted as contaminated areas, and controlled until more detailed surveys could be performed. Surveys indicated contamination had passed through an open equipment hatch to lower elevations of the Unit 1 Reactor Building. Potential contamination was detected in areas of the Unit 1 Reactor Building to include the 117 foot clean area, the 98 foot elevation, the 80 foot east and 80 foot west elevations, and the 20 foot elevation near the elevator. These areas were decontaminated and detailed surveys performed to dis-establish contaminated area postings. The decontamination effort was completed during the onsite inspection.

The licensee reviewed security records to determine any individuals logged into the reactor building during the time of the event. The licensee recalled all of these individuals to be whole body counted. The inspector reviewed the whole body survey results which determined no positive uptakes of radioactivity for any individual in the Unit 1 Reactor Building during the event.

d. Inspector Followup

During the inspection, the inspector reviewed procedures, reviewed records, and interviewed selected personnel including personnel involved with work evolutions on the refuel floor that evening to assess potential root causes of the event. As a result of the inspector's followup to this event, the inspector identified several potential root causes of which any one or a combination thereof, may have contributed to the inadvertent spread of contamination beyond posted contamination barriers. The potential root causes identified included the following:

- The licensee's technical procedure being used by contractors performing the work had not formally been reviewed or concurred on by HP personnel. The procedure did not address any radiological engineering controls for this work evolution, nor were any other procedures available or prepared to address radiological engineering/work controls for the specific work being performed. A license procedure, Desk-Top Guide for Radiation Control Technicians, Revision 0, dated June 4, 1993, described the performance of surveys to be performed when the potential for changing conditions occurred which included the use of high volume air samples to provide early indication of airborne radioactivity; however, this instruction was not applied to this work evolution by HP personnel, nor did this desk instruction address engineering controls applicable to this work evolution.

- RP personnel responsible for work being performed in the Unit 1 Reactor Cavity did not attend the technical briefing, conducted by contract personnel, which was held on the evening of the 19th to discuss the procedural evolutions to be performed in the reactor cavity that evening as described above. Interviews with personnel involved in the briefing, determined that RP was not informed of the briefing.

- An inadequate turnover among HP refueling floor supervision failed to adequately inform the on-coming evening shift HPs of the work scope to be performed in the Reactor Cavity. The Desk-Top Guide included a section on Job Coverage Turnover which also addressed the possibility of areas likely to go airborne. This Desk-Top Guide was not applied in regards to questioning the potential for areas going airborne outside of the Reactor Cavity, such as the refueling floor and other levels of the Reactor Building.

- The HP briefing conducted on the refueling floor for contract workers entering the reactor cavity did not adequately discuss the scope of the work being performed. The briefing addressed the radiation controls and the personnel contamination clothing to be worn; however, work scope, contamination controls, and any special engineering controls were t discussed with the workers entering the reactor cavity. Statements provided by the HPs following the event determined that they were not aware of the total scope of work being performed. An ALARA plan had not been prepared by the licensee to aid in briefing workers on radiological controls for this specific work evolution; however ALARA plans have been used by HP on other evolutions involving high levels of contamination with airborne potential.

- The HPs providing work coverage in the Reactor Vessel Cavity area did not stop work, to question the adequacy of work controls, when the scope of the work extended beyond what the HPs initially understood it to be.

- The necessary in process surveys were not performed to determine potential changing radiological conditions commensurate with the engineering controls, environmental conditions that existed at the time, and work scope being observed by HPs.

The inspector discussed with licensee managers and reviewed actions by the licensee to continue work on the Unit 1 refueling floor and in the refueling cavity area to complete the seal ring flange area preparations and install the Dome. These actions were accomplished by the licensee without any radiological consequences. The licensee prepared specific ALARA plans to effectively provide guidance to HPs and contractors performing work, to ensure workers were adequately briefed on contamination control, and to ensure HPs performed the necessary surveys to respond to any changing conditions that might occur while performing highly contaminated work. Engineering controls were used, which included wetting down of the flange area, to control airborne radioactivity. The inspector had no concerns with licensee actions or practices during the continuance of work.

After reviewing the sequence of events and the actions taken by the licensee, the inspector informed the licensee that there were two apparent violations associated with the event.The first violation involved a violation of licensee TS 6.8.1 which requires that written procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33, November 1972. Contrary to this TS requirement, on January 19, 1994, the licensee failed to establish and provide an adequate procedure(s) specifying engineering and work controls necessary to effectively control radioactivity commensurate with the hazards of the specific work evolution being performed in the Unit 1 Reactor Cavity area. The failure of the licensee to provide an adequate procedure as required by TS 6.8.1 is a violation (VIO) of regulatory requirements (VIO 50-325, 324/94-01-01).

The second violation involved a violation of 10 CFR 20.1501(a) which requires: Each licensee shall make or cause to be made surveys that (2) Are reasonable under the circumstances to evaluate (ii) Concentrations or quantities of radioactive material; and (iii) The potential radiological hazards that could be present. Contrary to the above, on January 19, 1994, during performance of work in the Unit 1 Reactor Cavity area, the licensee failed to perform adequate surveys to evaluate the potential radiological hazards that could be present from unknown concentrations or quantities of airborne radioactivity that existed in areas of the Unit 1 Reactor Building not evaluated or established for the control of airborne radioactivity. The failure of the licensee to perform adequate surveys to evaluate the potential radiological hazards that could be present is a violation of regulatory requirements (VIO 50-325, 324/94-01-02).

Two NRC-identified violations (VIOs) were identified.

9. Program for Maintaining Exposures As Low As Reasonably Achievable (83750)

10 CFR 20.1101(b) states that the licensee shall to the extent practical, procedures and engineering controls based upon sound radiation protection procedures to achieve occupational doses to members of the public that are as low as reasonably achievable (ALARA).

Regulatory Guides 8.8 and 8.10 provide information relevant to attaining goals and objectives for planning and operating light water reactors and provide general philosophy acceptable to the NRC as a necessary basis for a program of maintaining occupational exposures ALARA.

During the inspection, the inspector reviewed and discussed with cognizant licensee representatives ALARA program initiatives and implementation for 1993. The inspector reviewed and discussed the status of the ALARA Suggestions Program implemented by the licensee and determined the program to be an effective measure used by the licensee to reduce exposure. The licensee tracks the suggestions. Outage doses have continued to trend downward and general area radiation levels have been reduced as a result of improved ALARA pre-planning packages, briefings, and area and system decontamination effectiveness.

The inspector determined that the licensee was aggressively implementing ALARA initiatives and was achieving a significant reduction of personnel doses.

The inspector reviewed the Reactor Water Clean Up (RWCU) phase separator room cleanup. This project reclaimed the area in the -3ft RWCU phase separator tank room. This job used a pair of robots to remove the previously spilled resins for disposal. The inspector reviewed selected snippets of the approximately 120 hours of video tape from the clean-up activities. The job activities appeared to be well coordinated and the final results exceeded expectations.

No violations or deviations were identified in this area.

10. Exit Meeting (83750)

The inspector met with licensee representatives indicated in Paragraph 1 at the conclusion of the inspection on January 7, 1994. The inspector summarized the scope and findings of the inspection. The inspector also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
50-325, 324/94-01-01	Open	VIO - Failure to establish and provide an adequate procedure(s) specifying engineering and work controls necessary to effectively control radioactivity commensurate with the hazards of the work being performed as required by TS 6.8.1 (Paragraph 8.).
50-325, 324/94-01-02	Open	VIO - Failure to perform adequate surveys to evaluate the extent of concentrations or quantities of radioactive material; and the potential radiological hazards that could be present as required by 10 CFR 1501(2)(ii)(iii) (Paragraph 8).

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

FEB 28 1994

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

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/94-02 AND 50-324/94-02)

This refers to the inspection conducted by Richard L. Prevatte of this office on January 5 - February 4, 1994. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). This violation is of concern because procedural inadequacies resulted in a loss of shutdown cooling. Under different circumstances this could have resulted in more serious consequences. Therefore, actions should be taken to ensure that future activities which could affect shutdown cooling are adequately reviewed and controlled.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and any reply will be placed in the NRC Public Document Room.

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The responses directed by this letter and the enclosed Notice(s)are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

for Ellis W. Merschoff, Director
Division of Reactor Projects

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

cc w/encls:
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(cc w/encls cont'd - See page 3)

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Mayor
City of Southport
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Southport, NC 28461

ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power and Light Co.
Brunswick Units 1 and 2

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

During an NRC inspection conducted on January 5 - February 4, 1994, a violation of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violation is listed below:

> 10 CFR 50, Appendix B, Criterion V requires that activities affecting quality shall be prescribed by documented procedures appropriate to the circumstances and shall be accomplished in accordance with these procedures.
>
> Contrary to the above, on January 11, 1994, Maintenance Surveillance Test 1-MST-RHR27M, Residual Heat Removal Shutdown Cooling Reactor Pressure Instrument Channel Calibration, Revision 9, was inadequate in that it did not require the isolation logic to be reset after the second trip signal. This resulted in a loss of residual heat removal and spent fuel pool cooling.
>
> This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light Company is hereby required to submit a written statement or explanation to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or demand for information may be issued as to why the license should not be modified, suspended or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 28th day of February 1994

9403150336

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/94-02 and 50-324/94-02

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: January 5 - February 4, 1994

Lead Inspector: R. E. Carroll Jr. for 2/17/94
R. L. Prevatte, Senior Resident Inspector Date Signed

Other Inspectors: P. M. Byron, Resident Inspector
M. T. Janus, Resident Inspector
R. E. Carroll, Project Engineer
C. Hughey, Resident Inspector - Grand Gulf
R. Bernhard, Senior Resident Inspector - Grand Gulf
R. Musser, Resident Inspector - Browns Ferry

Approved By: 2/18/94
H. O. Christensen, Chief Date Signed
Reactor Projects Section 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of operations, maintenance, surveillance, engineering support, plant support, and other areas. Inspections were conducted during normal working hours, on back shift, deep back shift, holidays, and weekends.

Results:

In the areas inspected, a violation was identified involving an inadequate procedure for residual heat removal shutdown cooling reactor pressure instrumentation channel calibration. This resulted in an eight minute loss of shutdown cooling on Unit 1, paragraph 3.b.

An unresolved item was identified involving the adequacy of testing of a containment atmosphere valve, paragraph 3.b.

The line management affirmation process (PN-31) has had a positive affect on plant personnel by establishing good communications and enforcing new and improved standards, paragraph 2.c.

A weakness was identified in the area of preventive maintenance on the control building air dryers, paragraph 4.

A weakness involving configuration control on balance of plant equipment was also identified, paragraph 2.a.

Unit 2 operated at essentially 100% power for the reporting period. Unit 1 was restarted on February 1, 1994.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Ahern, Manager, Operations Support and Work Control
R. Anderson, Vice President, Brunswick Nuclear Project
G. Barnes, Manager, Operations, Unit 1
*M. Bradley, Manager, Brunswick Project Assessment
*J. Cowan, Plant Manager, Unit 1
R. Grazio, Manager, Brunswick Engineering Support Section
*J. Heffley, Manager Maintenance, Unit 2
*G. Hicks, Manager, Training
C. Hinnant, Director of Site Operations
G. Honma, Manager, Regulatory Compliance
*P. Leslie, Manager, Security
W. Levis, Manager, Regulatory Affairs
*R. Lopriore, Manager, Maintenance, Unit 1
G. Miller, Manager, Technical Support
C. Robertson, Manager, Environmental & Radiological Control
*J. Titrington, Manager, Operations, Unit 2
*C. Warren, Plant Manager, Unit 2
G. Warriner, Manager, Control and Administration
*E. Willett, Manager, Project Management

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

*Attended the exit interview.

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

2. Operations

a. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, jumper/bypass, and daily/standing instruction logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification LCOs. Direct observations of control room panels, instrumentation and recorded traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position: each power supply and breaker was closed for components that must activate upon initiation signal: the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator: there was not leakage of major components: there was proper lubrication and cooling water available: and conditions did not exist which could prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

Configuration Control

There were four configuration control events during the inspection period:

- On January 2, instrument drain valve 2-FO-IV-127 on the DG fuel oil system was found open when it was required to be closed. An operator identified the discrepancy by observing fuel oil seeping around the pipe cap on this instrumentation drain line. This valve was placed in the correct position and ACR 94-016 was written to document the event.

- On January 5, two AOs observed condensation on the suction piping of the 1A reactor feedwater pump (RFP). Pursuing this observation, they found the 1A RFP suction valve (COD-V49) open. This valve was under clearance 1-93-2672 (boundary extension H) which required the valve to be shut. This event was documented by ACR 94-009.

- On January 31, an auxiliary operator discovered in RFP Room 2A that the outlet inboard drain valve (2-FW-V48) on Feedwater Flow Valve 2-FW-FV-V47 was open. System Operating Procedure 2-OP 32, Condensate and Feedwater System Operating Procedure, requires the valve to be shut. The operator placed the valve in the proper position. The licensee is still investigating this event.

- On February 2, an auxiliary operator discovered that valves 1-B32-F019 and F020, Recirculation Sample Line Isolation Valves, were shut. The normal lineup is in the open position. Clearance 1-94-430 was hung on 1B32-F020 and canceled on January 29, 1994. The restored position for this valve should have been open as required by Operating

Procedure 1OP-02, Reactor Recirculation System Operating Procedure.

These four events were all identified by auxiliary operators and the valves were placed in the proper position under the direction of a licensed operator. None of the events resulted in equipment malfunctions. The licensee continues their investigation of these events.

The licensee is concerned about the increased number of configuration events. On January 28, the Operations Managers for both units assembled a coaching paper containing a description of recent events. The shift supervisors then briefed their shifts on these configuration events to heighten crew awareness.

On January 28, clearance 2-94-00562 was written to remove the lube oil storage tank conditioner from service to allow for filter replacement. The clearance was developed for the breaker for the lube oil storage tank transfer pump, 2-2TE-CT5-52, rather than the lube oil storage tank condition breaker, 2-2TE-CV9-52. This discrepancy was identified before the clearance was accepted and the proper tag was then hung. This is an example of the operators identifying a potential clearance problem.

The inspector discussed his concerns with the licensee. In addition to the crew briefings, they are reviewing the clearance process in an attempt to simplify it. They have organized a task force to study the process and revise procedure AI-58, Equipment Clearance Procedure. The licensee has concluded that simplification of the process should reduce the configuration errors. The licensee's difficulty in correcting this configuration control issue is considered a weakness.

b. Unit 1 Core Reload Verification (60710)

On January 13, the licensee performed a core reload verification. This was performed by three individuals, a QC inspector, a nuclear engineer, and an SRO, who observed the video taping of the location of each fuel element on a TV monitor. They independently recorded the fuel element serial number for each physical location. At the end of each row, two of the observers read their recorded data for that row to the third. This data was reviewed against the core load sheets. Any discrepancies were immediately resolved. The inspector observed this evolution and did not identify any problems. He also reviewed the procedural steps of procedure OENP 24.13, Rev. 2, Core Verification and found them to be adequate.

The above video tapes were also independently reviewed by an SRO and a nuclear engineer who compared their observations with the core reload sheets for an additional verification. The inspector reviewed the above tapes, including the tapes which verified core height. The inspection for core height ensures that all fuel elements are fully inserted. The inspector independently verified that selected fuel elements were in their proper location. He also concluded that the licensee's process has sufficient depth to ensure that fuel is loaded into its proper location.

c. Unit 1 Restart Activities

In preparation for the Unit 1 startup following refueling, the licensee performed Periodic Test OPT-8.1, Reactor Pressure Vessel Hydrostatic Test, on January 21. The purpose of this periodic test is to provide for system pressure testing of the Class 1 Reactor Coolant Pressure Boundary piping and components in accordance with the ASME Boiler and Pressure Vessel Code. The inspector observed the start of the testing, the establishment of the test conditions, and performed portions of the drywell walkdown with the QC inspectors to identify any leaks following the four hour soak time at test pressure.

During his observation of the control room during this evolution, the inspector observed good control of the test evolution, proper use of procedures, and good communications and coordination of the different phases of this test. The inspector noted that a control operator had been dedicated to monitor and maintain test pressure conditions. This operator used the new plant process computer system to monitor the various test parameters in one location allowing him to identify and avert any adverse trends or degradations in condition. The licensee also assigned a second senior control operator on Unit 1 to assist and control the testing and startup evolutions, thereby eliminating some of the burden on the Unit 1 SCO. The inspector considered the use of the two additional dedicated operators to be a conservative approach to ensure the safe conduct of this test.

The inspector observed portions of the drywell walkdown following the four hour soak at test pressure to identify leaking piping and components. The walkdown was performed by QC personnel who had previously performed and were knowledgeable in this task. The QC inspector performed the walkdowns in accordance with OPT-80.1, and identified and quantified the existing leaks. The inspector discussed the inspection with the QC inspector. He did not identify any major deficiencies or adverse conditions during this inspection. The results of the inspection were reported to the control room and work tickets were processed for repairs. These repairs are scheduled to be re-inspected during a low power entry during the unit start up.

In accordance with CP&L's Plant Notice, PN-31, Systems Turnover to Operations and Line Management Self-Assessment of Readiness for Restart of Unit 1, each manager was required to assess and confirm his organization's readiness to support the safe and reliable restart and operation of Unit 1. These assessments, in conjunction with the completion of the pre-startup work scope, were established to assure CP&L management that Unit 1 was ready to restart. The final step in this process required each section and selected unit managers to formally meet with the site Vice President and affirm that their area was ready for Unit 1 restart.

An inspector attended the following meetings to observe and evaluate this process: Training, Outage Management, Regulatory Affairs, Project Management, Nuclear Engineering, Maintenance, Environmental and Radiation Control, Operations, and Technical Support. The meetings lasted about one and a half hours, and were conducted in a very positive atmosphere. Numerous questions were asked by the site Vice President. If clear positive answers were not provided, that manager was sent back to research and/or provide actions to address the issue. The inspector noted that the Vice President's standards and expectations were clearly defined and communicated to his managers. This process appears to be establishing good communications and enforcing new and improved standards for the plant. It also appears to be having a positive affect on plant personnel and improving the plant's readiness for restart and successful power operations. This process and its implementation is considered a strength.

General Plant Operating Procedures (GP) were reviewed with respect to changes made since the restart of Unit 2 and associated operator training. The GPs reviewed were:

- GP-01, Prestartup Checklist, Revision 126
- GP-02, Approach to Criticality and Pressurization of the Reactor, Revision 47
- GP-03, Unit Startup and Synchronization, Revision 32
- GP-04, Increasing Turbine Load to Rated Power, Revision 28
- GP-05, Unit Shutdown, Revision 63
- GP-10, Rod Sequence Checkoff Sheets, Revision 20

Commensurate with the scope and significance of the GP changes made, associated operator training was considered by the inspector to be appropriate. The inspector also reviewed GP-09, Initial Criticality After Core Alterations, and verified that it was also included in the Unit 1 Startup/Power Ascension Plan. Accordingly, the inspector confirmed that the Power Ascension Plan was included in the startup training provided to the operators.

As specified in the Unit 1 Startup and Power Ascension Performance Objectives and Management Plan, normal shift makeup has been augmented with a shift test coordinator and designated test teams. The purpose of this restart shift augmentation is to assure testing is adequately controlled and conducted in accordance with the detailed Startup/Power Ascension Test Plan/Schedule developed by the Power Ascension Test Manager. The inspector reviewed the current Test Plan/Schedule (Revision 3) and 1SP-93-058, Unit 1 Startup and Power Ascension Guidelines and Checklists, Revision 1.

Based on this review, and the similarity to controls employed during the restart of Unit 2, the inspector considers the established Unit 1 controls to be appropriate for the conduct of startup/power ascension testing.

In addition, the licensee's staffing plans and watch bills were reviewed for the restart of Unit 1, including the areas of: operations shift manning, the shift test coordinators, nuclear engineers, startup duty managers, system engineering support, maintenance support, and engineering support. The personnel assigned to these tasks were knowledgeable in their respective areas and the staffing levels appear adequate to support Unit 1 restart.

On January 27, the inspector accompanied licensee personnel on a final walkdown of the Unit 1 drywell prior to closure. The purpose of the inspection was to complete or verify completion of previously identified items, and to ensure all areas of the drywell were clear of trash, debris, cables, hoses, etc. Prior to entry, the inspector attended a pre-job brief for personnel entering the drywell and reviewed a list of discrepancies previously identified by the licensee for disposition prior to final drywell closure and reactor startup. In addition, the inspector reviewed Administrative Procedure AI-127, Drywell Inspection and Closeout, Revision 1, dated June 12, 1993, which gives general guidance for drywell inspections.

During the walkdown, the inspector noted several minor housekeeping items, radiological control signs, ropes and sampling equipment, and temporary power cables. These observations were passed on to licensee personnel in the drywell to insure that these items were removed or secured prior to drywell closure. Licensee QC inspectors noted several additional housekeeping discrepancies. No temporary filters on or around the drywell coolers were observed, and no trash or debris was observed in any of the downcomers. In conclusion, housekeeping in the drywell was satisfactory and no significant equipment discrepancies were observed by the inspector. The inspector also verified that the licensee corrected all identified deficiencies prior to final drywell closeout.

The inspector walked down accessible portions of the following areas for equipment condition, general area cleanliness, combustible material control, and proper radiological controls. The following was observed:

(1) Intake structure (including circulating water motors/pumps)

- housekeeping was good
- some temporary heaters were in place for cold weather protection

- a large number of mussel/clam shells were observed on the sides of the inlet water boxes under the traveling screens
- the circulating water pump motor bearing oil cooler radiators were extremely corroded and rubber hose connections on outlet of cyclone separators for lube water to the circulating water pumps were spraying water
- heavy corrosion was noted around the traveling screens

(2) Turbine building (including feedwater heater rooms, turbine/generator general area, main steam stop and control valves and main steam lines general area, steam jet air ejector rooms, feedwater pump rooms, condensate booster pump rooms, heater drain pumps area, lower condenser bay area, condensate pumps area, turbine building sample room)

- SJAE rooms - excellent condition
- FWP rooms - excellent condition, associated instrument racks in good condition
- condensate booster pump room - good condition although not painted
- heater drain pump area - excellent condition
- lower condensate bay area - good condition - some performance monitoring instrumentation cables were in disarray in some areas
- condensate pump area - contaminated area but housekeeping was good - minor oil leaks observed on a couple of valve actuators
- turbine building sample room in very good condition
- MS stop/control valve/main steam line areas in good condition
- observed several remote cameras located for use during operations to reduce personnel radiation exposure - good practice
- use of tags on temporary power cables is a good practice. Tag denotes use, person responsible, and supervisor's name.

(3) Radwaste building

- large double doors (trouble tag dated 10/24/91) not fully closed (partially open - not able to be closed) and door from outside into Unit 1 CFD were (elevation 23') wide open (trouble tag dated 7/1/92) with sign saying contact SRO prior to propping open - per TS 3.11.2.1 - concern was that these areas were unmonitored released paths. Subsequent conversations with E&RC management indicated that they were aware of these pathways and potential releases from these areas had been evaluated per ENP-54

- Unit 1 precoat tank mixer motor held on with a rope
- In general, housekeeping in radwaste was very good

(4) Service water building

- lots of components identified by trouble ticket as corroded
- bottom two floors painted and in very good shape
- top floor prepped for painting
- work ongoing in the area, pump replacement in process
- no significant discrepancies observed on any Unit 1 or Unit 2 nuclear service water pumps

(5) Containment Atmospheric Dilution and Containment Atmospheric Control Building, Augmented Off Gas Building, Transformer Yard, Switchyard and Battery Rooms - no discrepancies were identified

In summary, housekeeping in the areas toured was very good. Efforts to provide high quality painting of floors and walls was very noticeable. Discrepancies observed were provided to licensee management for resolution.

The inspector performed a walkdown of all of the elevations of the Unit 1 Reactor Building. This walkdown was performed to identify any potential problems which needed to be addressed prior to restart and to verify that all previously identified discrepancies were corrected.

The major systems, components and areas inspected during this tour included: core spray pump rooms, CRD pumps, RHR rooms, HPCI room, RCIC system, RHR heat exchangers, HCUs, RHR service water booster pumps, RBCCW, SBGT trains, SLC, reactor building ventilation room, the refueling floor, and the spent fuel pool.

During the walkdown, the inspector looked for indications of material degradations, component malfunctions, and valve and breaker mispositionings, removal of temporary power supplies and work equipment, and general housekeeping problems. The inspector identified a grease leak on a valve operator located on the D loop of the RHR system. This leak was reported to the system engineer who initiated a trouble ticket for its repair. The inspector also identified a minor leak on a flange on the discharge of the D RHR Service Water Booster Pump. This leakage was reported to the unit senior control operator.

The general appearance of the Unit 1 reactor building has greatly improved, with new paint on many systems, floors and walls, and a general clean up and decontamination effort to maintain contaminated areas at a minimum. The painting and cleaning effort will continue during and after the unit startup. The inspector also noted during the tour that there were a number of light bulbs in need of replacement. These were captured by the licensee's own identification program. Other than the two minor discrepancies noted above, no major problems or issues which would prevent the successful startup of the unit were identified.

The inspector also reviewed the control of components and equipment associated with safety systems. The inspector conducted tours of the control room and performed walkdowns of the Reactor Turbine Gage Boards and verified that all the safety systems were properly aligned. The inspector reviewed the established controls for valve manipulations, position changes, and the valve lineup process and found them acceptable. He also reviewed the control room logs and the daily work tickets to verify that identified discrepancies and deficiencies were tracked and captured by the system for evaluation and repair.

Additionally, the inspector followed the scheduled and emergent work activities in the areas of maintenance, plant modification, startup testing, and system turnovers. Each of these activities progressed well and all work needed to support Unit 1 restart was satisfactorily completed. All startup preparations were completed on January 31, and Unit 1 restarted on February 1, 1994. Startup and power ascension testing commenced on February 2. The following problems have occurred since startup.

- Air trapped in the reactor water level reference legs resulted in declaring several instruments inoperable until the instrument lines were purged.

- A temperature monitor on the drywell was not working and was replaced.

- An air leak in the valve actuator for a recirculation pump seal staging return line developed a leak in the actuator. This was rebuilt.

- A small steam leak on SRV J was identified by increasing tail pipe temperature. The valve will be cycled and monitored to see if leak stops as pressure and temperature increases.

- A phase to phase short in the bus bars for 480 MCC 1TA resulted in an electrical fire that extinguished itself when de-energized.

All of the above items were effectively responded to and repaired in a timely manner except the leaking SRV and MCC problem which were still being worked at the conclusion of the inspection period. The inspector noted that on-shift communications were excellent. Thorough and detailed pre-job briefings were being conducted prior to the start of important tasks or evolutions. Maintenance and other support organizations provided timely assistance when needed. Unit and site management have been very visible in the plant during Unit 1 restart. Other than the above minor problems, no significant deficiencies have been identified.

Violations and deviations were not identified.

3. Maintenance

a. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

On January 17, the licensee identified a body to bonnet leak of approximately 1 gpm on the Unit 1 No. 2 stop valve, 1-MS-SV-2. WR/JO 94-ABBT1 was written to replace the body to bonnet gasket. The inspector observed preparations to remove the bonnet. It appeared that efforts were performed sequentially rather than in parallel. Examples of this are as follows: the floor plugs were removed, then tools assembled at the job site, the Herculite was placed on the grating under the shop valve, and finally the craft commenced loosening the bonnet bolts. The inspector observed the work activity for approximately 2 1/2 hours and during that time, the Herculite was spread out under the stop valves and three nuts were loosened. The mechanics had difficulty in loosening the nuts with the "hi-torque" device. The inspector noted that three supervisors observed the work effort and a maintenance foreman made several appearances. This effort was later satisfactorily completed.

The inspector reviewed the work associated with WR/JO 94-ABBT1 and found it adequate. There was adequate engineering and HP support. The inspector found the work practices to be acceptable. The work effort took two days and was field completed on January 19.

b. Surveillance Observation (61726)

The inspectors witnessed/reviewed portions of the following test activities:

OPT 4.1.1, Reactor Building Vent Exhaust Monitoring System Functional Test

On January 31, during the performance of OPT 4.1.1, the STA found that the Hardened Wetwell Vent Valve, 1-CAC-V216, was not on the list of valves being tested. The STA reviewed RCI 2.6, Cross Reference to Technical Specifications, and Technical Specification 3.6.3, and concluded that CAC-V216 should have been tested during the performance of OPT 4.1.1. Subsequently, the licensee performed a partial OPT 4.1.1 which includes CAC-V216. ACR 94-052 was written to document this issue.

Plant Modifications PM 91-001 and 92-073 installed the Hardened Wet Well Vents for Units 1 and 2, respectively. The CAC V-216 valve is wired such that it can be operated manually from the RTGB with an override switch or closed automatically by a Group 6 isolation signal. The licensee's initial investigation determined that the post modification testing did not test the valve's operation from an isolation signal. The inspector reviewed procedure RCI 02.6, Cross Reference to Technical Specifications, Revision 12, Appendices A and B, dated November 4, 1993. Appendix A lists 1-CAC-V216, Hardened Wetwell Vent Outboard Isolation Valve and Appendix B lists 2-CAC-V216, Outboard Suppression Pool Vent Valve as primary containment isolation valves. However, OPT 04.1.1, Revision 41, dated December 14, 1993, does not test these valves. The licensee, as part of the resolution to the ACR, is conducting an investigation to determine if these valves are mis-classified. This issue is considered an Unresolved Item (URI 94-02-01), Inadequate Surveillance Procedure, pending the inspector's review of the licensee's resolution of ACR 94-52.

OPT 12.8.C, Diesel Generator Operability Test

The inspector observed the performance of an operability performance test on DG No. 3 in preparation for a maintenance outage on DG No. 1. The inspector observed that the operators used the procedure, and the test was well supported by maintenance, QC, and the shift supervisor. The inspector did not identify any deficiencies and considered the crew's performance to be acceptable.

Loss of RPS Bus A Power

During the restoration of 1MST-DG11R, DG-1 Loading Test, Unit 1 experienced a loss of power to the A Reactor Protection System. The loss of power resulted in the following ESF actuations: closure of the Main Steam Line Drain Inboard Isolation Valve 1-B21-F016; closure of the Reactor Water Cleanup Isolation Valve 1-G31-F001; and isolation of the Reactor Building HVAC system. Other systems which would have actuated were already running or isolated in support of the test. The licensee made a four hour report in accordance with 10 CFR 50.72 (b)(2)ii.

This event occurred while preparations were being made to parallel DG No. 1 with offsite power to restore the normal electrical alignment following the completion of the test. Emergency Bus 1 was powered from DG No. 1 during the test. During this process, the control operator improperly adjusted the DG frequency which resulted in the trip of EPA breaker 2 and the loss of power to RPS bus A. Following this event, the licensee aligned RPS bus A to the alternate power source and commenced restoration of the systems to their normal alignments. All systems functioned as designed. No further problems were experienced or noted.

Diesel Generator Load Tests

In preparation for restart of Unit 1, the licensee also performed the required refueling outage DG load test. These tests are conducted to determine the operability of the DG Emergency Power System. The tests provide a loss of power signal to the E Bus being tested, in conjunction with a start signal for the decisional ECCS loads. The following tests were performed: 1MST-DG11R, DG No. 1 Loading Test; 1MST-DG12R, DG No. 2 Loading Test; 2MST-DG11R, DG No. 1 Loading Test; and 2MST-DG12R, DG No. 2 Loading Test.

The inspector attended the pre-job brief prior to the performance of 1MST-DG11R on January 26, and noted that it was comprehensive with an emphasis on potential problems and safety. Following the brief, one inspector witnessed the performance of this test from the control room while a second inspector was present in the DG No. 1 control cell. This test provided a loss of power to Emergency Bus E1 in conjunction with a start signal for the Unit 1 Division 1 ECCS loads. All four diesels started and DG No. 1 picked up its required loads. During the performance of this test, the strip chart recorder used to record response time data indicated the 1X LOCA Jet Assist Solenoids remained open for approximately 27 seconds during this test. It was later determined that this was a problem with the recorder. As a result, special procedure 0-SPP-LOG005 was performed on January 29 and satisfactorily retested the Jet Assist logic portion of this test. The special procedure verified that the 1X LOCA Jet Assist solenoid only remained open for 4.3 seconds which is within the required range of 3.6 to 4.4 seconds.

While parallelling DG No. 1 with offsite power, an operator error resulted in the loss of power to the A RPS and several ESF actuations previously described in this report. The inspector verified that the licensee made the required four hour notification.

An additional problem with a chart recorder also resulted in having to reperform 2MST-DG11R on DG No. 1. The inspector verified that the test was satisfactorily reperformed on January 27. No other problems were identified during the performance of this test.

On January 27, the inspector witnessed the successful performance of 1MST-DG12R. This test provided a loss of power to Emergency Bus E2 in conjunction with a start signal for Unit 1, Division II, ECCS loads. The inspector was present in the DG control cell for the performance of this test and verified that all DGs started and ran as required, and that DG No. 2 loaded as required. During the performance of this test, a minor exhaust leak was identified on the number 2L cylinder which is scheduled to be repaired during the next maintenance window. Test results indicated that the 1X LOCA logic jet assist timing relay (JATR) timed out (i.e., jet assist solenoids remained open) approximately 6.37 seconds, which is longer than the required 3.6 to 4.4 second time period. The licensee identified and evaluated this issue in EWR 13167 and determined that it was not an operability concern, as the 6.37 second jet assist was bounded by an analyzed nominal 9 second combined 1X and 2X LOCA logic jet assist to the EDG's turbocharger. As the 1X LOCA JATR was energized for 2.37 seconds longer than its nominal 4 second value, the inspector felt that the EWR should have analyzed the 11.37 seconds of potential 1X and 2X combined LOCA logic jet assist (i.e., 9 seconds + 2.37 seconds). This concern was discussed with the system engineer. Subsequently, the licensee re-evaluated the operability concern (11.37 seconds of combined jet assist) in EWR 13169. This new EWR (based on the findings of EER 91-0151, which had previously determined that jet assist could be applied for 12.16 seconds without affecting the control air loads for the associated EDG) found the 11.37 seconds of combined jet assist not be an operability concern. The inspector reviewed EWR 13169 and found no discrepancies or problems with this new evaluation.

The final required diesel loading test, 2MST-DG12R, was performed satisfactorily on January 27, and observed by the inspector. This test provided a loss of power to Emergency Bus E2 in conjunction with a start signal for the Unit 2, Division II, ECCS loads. No problems or issues were identified during the performance of this test.

During observation of the performance of these tests, the inspector noted that all the tests were performed in a controlled manner in accordance with the procedures and requirements covered in the pre-job brief. The inspector noted a continued good use of the procedure and that verified copies were present and in use by the various test personnel at all testing locations. The inspector also noted that the requirement of the pre-job brief of strict adherence to proper communications between the control room and the test personnel in the field was followed. The above tests were well coordinated efforts with good performance by the test crews.

Loss of Shutdown Cooling

On January 11, following the performance of Maintenance Surveillance Test (MST) 1-MST-RHR27M, RHR Shutdown Cooling Reactor Pressure Instrument Channel Calibration, the licensee experienced a loss of shutdown cooling. The loss of shutdown cooling resulted from the closure of the inboard shutdown cooling isolation valve (1E11-F009) following the removal of the testing clearance and the restoration of power. The closure of the 1E11-F009 valve caused the 1A RHR pump to trip, resulting in the loss of shutdown cooling to the Unit 1 reactor. Shutdown cooling was lost for approximately eight minutes.

At the time of the event, Unit 1 was in the process of reloading fuel, with approximately 421 out of 560 fuel bundles reloaded into the vessel. During the eight minutes that shutdown cooling was lost, no changes in vessel clarity or fuel pool temperature were noted. Little or no decay heat was present, since the unit had been in shutdown conditions since April 1992.

The loss of shutdown cooling was the result of procedural inadequacies. The procedure allows the performance of the testing with shutdown cooling in service. As a prerequisite, 1MST-RHR27M directs the placement of clearances on both 1E11-F008 and 1E11-F009 (the outboard and inboard shutdown cooling isolation valves, respectively) to maintain shutdown cooling . These clearances de-energized the breakers for the valves, preventing their closure during the testing. These steps had been added to the procedure to allow testing with shutdown cooling in service during the last procedure revision on April 25, 1991. The procedure has been performed 20 times since then; however, shutdown cooling was not in service during the performance of these tests.

Problems of this nature have not been previously identified during the performance of this test. Prior to Revision 8, dated June 1, 1990, the test was performed using jumpers to prevent the isolation relays from de-energizing. Revision 8 deleted the steps to install the jumpers in accordance with the philosophy change to not use jumpers during testing. Revision 9, dated April 25, 1991, added the steps to de-energize the F008 and F009 valves if shutdown cooling was in service. Neither Revision 8 nor 9 added steps to reset the logic prior to re-energizing the valves.

The procedural inadequacy involved the failure to reset the group isolation logic following the completion of the trip testing of each logic channel. In accordance with procedure 1MST-RHR27M, a trip signal is inserted for the 1E11-F009 valve, verified, reset, and tripped again. Following the second verification of the trip signal, the procedure directs the tester to perform the same sequence of steps for the 1E11-F008 valve. Following completion of the testing activities, the procedure failed to provide direction to reset the remaining logic trip signal prior to re-energizing the breakers. This failure to reset the trip signal resulted in the 1E11-F009 valve stroking closed on the re-energization of its breaker. This procedural inadequacy is contrary to the requirements of 10 CFR 50, Appendix B and is a Violation, Inadequate Test Procedure (325,324/94-02-02).

The control operator and the senior control operator recognized the condition immediately when the core spray or RHR pump running annunciator alarmed and the 1E11-F009 valve was observed in mid position. An immediate attempt to reopen the valve failed. The operator then depressed the group isolation reset pushbuttons, the valve was successfully opened, and the A loop of RHR was returned to its shutdown cooling line-up. In accordance with the requirements of 10 CFR 50.72, the licensee made the appropriate NRC notifications.

The licensee's proposed corrective actions were to revise 1MST-RHR27M to include steps to reset the isolation logic and verify that the isolation relays are energized prior to re-energizing the breakers for the isolation valves. In conjunction with this effort, the licensee plans to review other related MSTs which test isolation circuitry and verify that the procedures are adequate to keep this from recurring.

Within the areas inspected, one violation was identified.

4. Engineering Support

Control Building Instrument Air Dryer

The control room air conditioners tripped on January 17, due to low instrument air pressure. The control building HVAC instrument air system provides air to the control building HVAC dampers. This closure rendered 2A and 2B Emergency Air Filtration (CBEAF) system inoperable and placed Units 1 and 2 in an LCO which required that a CBEAF system be restored or that both units be placed in hot shutdown within 12 hours [TS 3.7.2(a)(2)]. An investigation by the licensee revealed that the instrument air dryer was blocking instrument air flow. The dryer was bypassed and instrument air and both CBEAF systems were restored.

It was initially believed that due to extremely cold weather, possible freezing had occurred due to moisture entrained in the instrument air system. However; further investigation revealed that the dryer system had partially lost its refrigerant charge which resulted in it failing to remove the moisture in the instrument air system. This allowed condensate to build up in the air system and the extremely cold weather caused it to freeze. The dryer refrigerant was recharged and its operation observed to ensure it was functioning correctly.

The licensee initiated a root cause evaluation of this item to determine the cause and needed corrective actions. It was determined that this system did not have adequate preventive maintenance assigned. The past maintenance on this component and other refrigerant cooling systems had in the past been under a contract with a local HVAC contractor. The licensee has found this practice to be unsatisfactory and is presently developing a maintenance program for these components to be accomplished by plant personnel. This is identified as a weakness in the existing preventive maintenance program.

An additional issue identified that the failures of this single instrument dryer, which caused the loss of both CBEAF systems may not meet single failure criteria. The licensee performed a 10 CFR 50.59 evaluation of this issue and determined that the failure of the air dryer system was the result of a passive failure (loss of the pressure integrity of the refrigerant tubing) of mechanical components and was not required to met the single failure criteria.

The inspector reviewed the 10 CFR 50.59 evaluation, met and discussed this issue with the engineer who performed the evaluation, and attended a PNSC presentation on this issue. This conclusion was accepted by the PNSC. The inspector also found the evaluation to be reasonable and acceptable. The inspector will follow the licensee's actions in developing and implementing a PM program on this equipment.

Violations and deviations were not identified.

5. Plant Support (71707)

a. Radiological Controls

The inspectors verified that the licensee's HP policies and procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, posting and instrument calibration.

b. Security

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate.

c. Fire Protection

On January 28, at approximately 10:30 a.m., the inspector observed control room response to a suspected fire in the Unit 2 control room back panel area. The response was initiated when an operator smelled what seemed to be an electrical fire in the area. No open flames or smoke were ever observed by the operators or the inspector. The fire brigade was assembled and quickly responded to the back panel area. An announcement was made by control room personnel over the PA system to all plant personnel.

After a thorough search of the backpanel area revealed no fire, a continuous fire watch was established in the area. The actual source of the smell was never determined although a burned out cabinet cooling fan was suspected. The smell dissipated quickly after the incident. The inspector concluded that the initial response by control room personnel and the fire brigade was prompt and followup actions were adequate.

Violations and deviations were not identified.

6. Other Areas

a. Evaluation of Licensee Self-Assessment (40500)

The inspectors attended selected Plant Nuclear Safety Committee meetings conducted during the period. The inspectors verified that the meetings were conducted in accordance with Technical Specification requirements regarding quorum membership, review process, frequency, and personnel qualifications. Meeting minutes for those meetings not attended were reviewed to confirm that decisions and recommendations were reflected in the minutes and followup of corrective actions was completed.

At the January 13 meeting, a supplemental response to NOV 325,324/93-39-01 on the DG LOCA issue, an administrative procedural change to eliminate a HPCI door alarm, a procedural change for space control authority, and an update on planned testing for the testing of the reactor vessel reference leg water level modification were discussed. The supplemental response was sent back to have NED, Technical Support, and Regulatory Compliance provide additional clarification. The other three issues were items that did not require PNSC approval but were presented to provide information updates which had been previously requested by the PNSC. This meeting had active participation and good questions were asked by the PNSC members.

The January 28 meeting was conducted to complete the requirements of Administrative Instructions, Drywell Inspection and PNSC Outage Prestartup Checklist (AI-96). AI-96 is used to establish a PNSC/managers startup checklist which tracks and statuses each plant group's responsibilities and ensures that necessary issues are also closed and the unit is ready for restart. This meeting lasted for the majority of the day and each unit manager provided a detailed discussion of the activities that had been completed and provided a listing of all activities to be completed prior to startup. The inspector attended, reviewed, and evaluated the listing of startup exceptions that were provided by each manager. Although the meeting was lengthy, it provided adequate detail on each issue to ensure that the correct decision for readiness could be made by the PNSC and unit general plant manager. There were several issues presented at the meeting that required completion prior to Unit 1 restart. The inspector received a listing of the open items and independently tracked these items until their completion to ensure plant readiness for restart. Overall, the above process as prescribed by AI-96 was found to be an effective management tool to ensure restart readiness.

There were no significant concerns identified relative to the PNSC meetings attended. The resolution of safety issues presented during these meetings was considered to be acceptable.

b. Meetings with Local Officials (94600)

The Senior Resident Inspector (SRI) conducted several informational meetings with local officials at towns near the plant to provide an update on the NRC's organization, mission, and responsibilities. He also provided a summary of the plant status, business telephone numbers of appropriate NRC contacts, and a brief resume of the NRC resident inspectors. While making arrangements for these meetings, the inspector offered to make a presentation to the town and/or county governing board or meet with officials selected by the municipal governing body.

The SRI met with the Mayor and Council of Yaupon Beach in a regularly scheduled meeting on January 10, at 7:00 p.m. After the presentation, several questions involving past plant problems and current plant status were answered.

On January 11, the SRI and a resident inspector attended the City Council meeting at Carolina Beach at 7:30 p.m. After the presentation, the Mayor asked several questions involving the repairs on the reactor vessel shroud and plant readiness for restartup. These questions were answered and the SRI offered to respond to any future questions the Mayor or Council may have.

On January 18, the SRI and the Region II Branch Chief for Reactor Projects, Branch 1, met with the Wilmington Mayor and Council during a regularly scheduled council meeting at 6:30 p.m. No questions were asked following the presentation. The SRI offered to respond to any future questions the Council or Mayor may have.

On February 1, the SRI met with the Mayor and Council of Boiling Spring Lakes during their regularly scheduled meeting at 7:00 p.m. After the prepared NRC presentation, several questions were asked about a local issue involving a proposed quarry near the plant site. The SRI stated that this issue would be reviewed by NRR and any questions regarding this issue should be referred to the NRR

Project Manager. An offer to provide his telephone number was also made. No additional questions were asked.

The inspector is currently scheduled to meet with the town of Kure Beach on February 15 to complete this series of meetings. That meeting will be reported in Inspection Report 325,324/94-04.

c. Nuclear Safety Review Committee (40500)

The inspector attended the BNP Nuclear Safety Review Committee (NSRC) meeting held on January 12. The meeting was chaired by the Site Vice President and was attended by the CP&L Vice President - Engineering and two outside members, Messrs. Byron Lee and Ken Harris. The NSRC reviewed previous Action Item status and was given briefings by various site organizations. The outside members raised questions relative to the differences between the site and the other two CP&L sites. The Vice President-Engineering raised many issues from lessons learned at Robinson and questioned Brunswick's vulnerability to the same issues. The inspector viewed the discussions to be frank and open and questions were asked about potential problems which the site had not considered. The inspector believes that the NSRC provided added value to the licensee's review process.

Violations and deviations were not identified.

7. Licensee Action on Previous Findings (92701, 92702)

(Closed) IFI 93-55-01, Eighteen Month Surveillances. The Readiness Assessment Team identified that Unit 1 had some 18-month surveillances which would expire within 18 months of startup. On January 19, in a public meeting, the licensee informed the NRC that they planned to refuel Unit 1 in Spring 1995, and no required surveillances would expire prior to that time. They additionally stated that in the event a required 18-month surveillance was about to expire, they would shut the unit down to perform the surveillance. This response addressed the Readiness Assessment Team's concern.

(Closed) IFI 325/93-55-03, Refueling Floor Activities. The Readiness Assessment Team identified that several problems had occurred on the refueling floor involving the work associated with the reactor vessel shroud repair and other refueling floor activities. They noted that the licensee and other inspection groups had identified problems involving personnel performance and management oversite of contractor activities.

Inspection Report 325,324/93-54 covered the completion of the reactor vessel shroud repair activities, the start of core reload activities, and identified equipment and personnel problems involving core reload, operation of the refueling bridge, and the lack of exclusion of foreign material from the refueling floor area.

After identification of the above problems, the licensee took positive steps to strengthen their oversite and control of these activities by appointing a stronger manager for the refueling floor activities and increased NAD and QC oversite of this area. Subsequently, the reactor vessel head was set and tensioned on January 17, and the unit entered Mode 4. The preparations for Unit 1 restart appeared to be progressing without significant problems until activities involving installation of the drywell dome started. The cleaning activities associated with the efforts (i. e., removal of the flange protective covers, O ring removal, and flange cleanup) resulted in the creation of airborne activity which spread contamination on three elevations of the Unit 1 reactor building. This resulted in a work stoppage, cleaning of the contaminated areas, and reassessing how this task should be accomplished. Due to this occurrence, a Health Physics/Radiation Protection Specialist Inspector was dispatched from Region II to investigate this event and evaluate the licensee's corrective actions. (This will be documented in Inspection Report 325.324/94-01.) After cleanup of the above contamination, the drywell dome was installed on January 22, 1994.

(Closed) Unresolved Item 325/93-58-03, Concurrence for Alternate Method of Signing Document Approvals. A regional inspector identified that GE's engineering specifications and drawings did not have hand written approval signatures on the face of the document. This issue was discussed with NRR and they had a concern about the use of electronic signatures for E-mail. Subsequent discussions with GE revealed that they use a Computer Assisted Drawing (CAD) process for their drawings. They use an alternative method which is in accordance with ANSI 45-2.9 and NQA1.

On January 6, GE discussed this issue with NRR. Since GE does not use electronic signatures in E-mail and approval signatures for CAD generated drawings are maintained in a method which is in accordance with ANSI 45-2.9, NRR no longer had concerns. GE documented the resolution of this issue in a letter to the licensee (LLA-94-040) dated January 27, 1994. The inspector discussed GE's response with Region II and NRR and both are satisfied with GE's actions. This item is closed.

(Closed) TI 2515/112, Licensee Evaluations to the Environs Around Licensed Reactor Facilities. The inspector reviewed the licensee's program to evaluate the environs around the plant. This is not a formal program but is included under their program for annual FSAR updates. The inspector reviewed Regulatory Compliance Instruction (RCI) 04.1, FSAR Changes, Revision 2, and noted that the procedure does not specifically address this issue. The inspector's review determined that the licensee has an informal program to review changes in the environs which could affect the plant. The licensee indicated to the inspector that they plan to formalize the program by including it in the next revision of RCI 04.1.

The inspector reviewed the 1993 FSAR submittal and noted that it contained updated information relating to changes in the environs including a new natural gas pipe line which crosses CP&L property. The inspector noted a small discrepancy in the physical location of the pipe line. The inspector informed the licensee who stated that the correction would be included in their next annual FSAR update.

The North Carolina Division of Emergency Management has a Brunswick Task Force which meets monthly. This task force is composed of representatives from the state, Brunswick and New Hanover Counties, the Highway Patrol, Coast Guard, the licensee, and others. The task force reviews drills, improved communications, cooperation and changes, as well as other significant factors affecting emergency management. The licensee's representative disseminates task force information among the affected organizations for their review.

In addition, the inspector reviewed the licensee's submittal to the NRC for the updated organizational structure, GLS-93-216, dated December 31, 1993. He also reviewed the licensee's request asking that the state deny Martin Marietta's application for a mining permit for a quarry to be located near site boundaries. The inspector concluded from his review that the license's program is adequate and addresses the necessary elements.

Violations and deviations were not identified.

8. Exit Interview (30703)

The inspection scope and findings were summarized on February 4, 1994, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary and listed below. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
94-02-01	Unresolved Item, Inadequate Surveillance Procedure (paragraph 3.b.)
94-02-02	Violation, Inadequate Test Procedure (paragraph 3.b)

9. Acronyms and Initialisms

ACR	Adverse Condition Report
ALARA	As Low As Reasonably Achievable
ANSI	American National Standards Institute
AO	Auxiliary Operator
BNP	Brunswick Nuclear Project
CBEAF	Control Building Emergency Air Filters
CRD	Control Rod Drive
DG	Diesel Generator
ECCS	Emergency Core Cooling System
ENP	Engineering Procedure
ESF	Engineered Safety Feature

EWR	Engineering Work Request
FACTS	Facility Automated Commitment Tracking System
FSAR	Final Safety Analysis Report
GP	General Plant Operating Procedures
HCU	Hydraulic Control Unit
HP	Health Physics
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
INPO	Institute of Nuclear Power Operations
IPBS	Integrated Planning, Budgeting and Scheduling
JATR	Jet Assist Timing Relay
LCO	Limiting Conditions for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MST	Maintenance Surveillance Test
NAD	Nuclear Assessment Department
NED	Nuclear Engineering Department
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSRC	Nuclear Safety Review Committee
PA	Protected Area
PM	Plant Modification
PM	Preventive Maintenance
PNSC	Plant Nuclear Safety Committee
QC	Quality Control
RAT	Readiness Assessment Team
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feedwater Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
RTGB	Reactor Turbine Gauge Board
SBGT	Stand By Gas Treatment
SCO	Senior Control Operator
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SRI	Senior Resident Inspector
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
TS	Technical Specification
URI	Unresolved Item
WR/JO	Work Request/Job Order

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

MAR 24 1994

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

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/94-04 AND 50-324/94-04)

This refers to the inspection conducted by Richard L. Prevatte of this office on February 5 - March 4, 1994. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements. The violation is of concern because it indicates a lack of attention to detail in the review and implementation of plant modifications.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notices when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to these Notices, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and any reply will be placed in the NRC Public Document Room.

The responses directed by this letter and the enclosed Notices are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

9404110214

Should you have any questions concerning this letter, please contact us.

Sincerely,

for Jon R. Johnson, Acting Director
Division of Reactor Projects

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

cc w/encls:
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Nuclear Services Department
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(cc w/encls cont'd - See page 3)

(cc w/encls cont'd)
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Mayor
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Mayor
City of Southport
201 East Moore Street
Southport, NC 28461

ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power and Light Company
Brunswick Site

Docket No.: 50-324
License No.: DPR-62

During an NRC inspection conducted on February 5 - March 4, 1994, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violation is listed below:

> Technical Specification 4.6.3.1 requires that each primary containment isolation valve specified in Regulatory Compliance Instruction RCI-02.6, Technical Specification Cross Reference, be demonstrated operable prior to initially placing it in service.
>
> Technical Specification 4.6.3.2 requires that each primary containment isolation valve be demonstrated operable at least every 18 months by verifying that on a containment isolation test signal each valve actuates to its isolation position.
>
> Contrary to the above, between April 23, 1993, and January 31, 1994, the licensee failed to demonstrate that primary containment isolation valve 2-CAC-V216 would attain its isolation position upon the receipt of a containment isolation signal.
>
> This is a Severity Level IV violation (Supplement 1).

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light Company is hereby required to submit a written statement or explanation to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or demand for information may be issued as to why the license should not be modified, suspended or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 24th day of March 1994

9404110220

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/94-04 and 50-324/94-04

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: February 5 - March 4, 1994

Lead Inspector: [signature] 3/22/94
R. L. Prevatte, Senior Resident Inspector Date Signed

Other Inspectors: P. M. Byron, Resident Inspector
M. T. Janus, Resident Inspector
R. Bernhard, Senior Resident Inspector - Grand Gulf
R. Musser, Resident Inspector - Browns Ferry
L. Wert, Senior Resident Inspector - Hatch
C. W. Rapp, Reactor Engineer
R. W. Wright, Project Engineer

Approved By: [signature] 3/22/94
H. O. Christensen, Chief Date Signed
Reactor Projects Section 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspectors involved the areas of Unit 1 startup/power ascension, operations, maintenance and surveillance, engineering support, plant support, and other areas. Inspections were conducted during normal working hours, on back shift, deep back shift, holidays, and weekends.

Results:

In the areas inspected, one violation was identified involving the failure to perform adequate post modification and subsequent surveillance testing on the hardened wet well vent installation, paragraph 3.c.

The startup/power ascension plan and its implementation on Unit 1 was identified as a strength, paragraph 2.b.
Unit 1 was restarted on February 1, achieved full power on February 18, and was released for normal power operation on February 23, 1994.

Unit 2 was operated at essentially full power during the reporting period.

9404110225

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Ahern, Manager - Operations Support and Work Control
R. Anderson, Vice-President - Brunswick Nuclear Project
*G. Barnes, Manager - Operations, Unit 1
M. Bradley, Manager - Brunswick Project Assessment
*J. Cowan, Acting Director - Site Operations
G. Honma, Supervisor - Regulatory Compliance
*N. Gannon, Manager - Maintenance, Unit 1
*R. Grazio, Manager - Brunswick Engineering Support Section
*J. Heffley, Manager - Maintenance, Unit 2
*G. Hicks, Manager - Training
P. Leslie, Manager - Security
*W. Levis, Acting Plant Manager - Unit 1
*R. Lopriore, Manager - Regulatory Affairs
*C. Pardee, Manager - Technical Support
*C. Robertson, Manager - Environmental & Radiological Control
*J. Titrington, Manager - Operations, Unit 2
*C. Warren, Plant Manager - Unit 2
G. Warriner, Manager - Control and Administration
*E. Willett, Manager - Project Management

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

*Attended the exit interview.

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

2. Operations

a. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, daily/standing instructions and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification Limiting Conditions for Operations. Direct observations of control room panels, instrumentation and recorded traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was not leakage of major components; there was proper lubrication and cooling water available; and conditions did not exist which could prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

No violations or deviations were identified. The licensee's performance in this area was satisfactory.

b. Unit 1 Startup and Power Ascension (71710)
Sustained Control Room and Plant Observation (71715)

The licensee developed and implemented a comprehensive startup and power ascension plan for Unit 1 to ensure the unit was returned to service in a safe, controlled, and deliberate manner with all equipment tested and verified to be functioning correctly. The plan consisted of the following major elements:

- a startup organization and staffing
- defined command and control responsibilities
- guidance for resolution of emergent issues
- assessment performance objectives
- power ascension plan schedule
- startup test plan requirements
- system walkdown requirements

A manager was assigned to develop and implement this plan well in advance of its required date. Specific staff personnel were assigned on a full time basis to support the plan. A schedule was developed that provided for a 50 day startup, which included two contingency outages if needed to perform emergent repairs. The schedule included assessment hold points where an evaluation and a deliberate decision must be made by the Site Vice President to continue the startup sequence or shutdown and perform repairs. The decision to continue was based on an assessment of plant operations, plant material condition, personnel performance, organizational responsiveness, schedule adherence, and the functioning of administration and work control processes. Assessment holdpoints were pre-established prior to startup, prior to exceeding 40% power, and prior to returning the unit to normal operation at 100% power.

In addition to the above assessment hold points, four decision points were established (i.e., at cold shutdown, 165 psig, 15% and 60% power) which required an evaluation and determination by the Unit 1 Plant Manager to proceed with the startup. This decision was based on plant operation, material condition as determined by system walkdowns, the completion of all needed maintenance, and the satisfactory completion of scheduled tests.

The above plan was placed in operation in late January prior to Unit 1 restart on February 1. The inspector did a detailed review and evaluation of this plan prior to its implementation. He held discussions with management personnel involved in developing and implementing the plan. The inspector determined that the plan was well developed, had extensive management input, and provided highly effective controls and evaluation processes to ensure a successful startup. The inspector also attended each decision and assessment meeting and found that they were very thorough and detailed. The inspector determined that the licensee's startup and power ascension plan was well planned and effectively implemented.

As a part of NRC action plan for unit restart, the resident staff was augmented to support startup inspection activities. This provided for 24-hour shift coverage with an observer stationed in the control room to monitor the conduct of control room activities and other important startup and test activities. The 24-hour shift coverage started on January 30 and continued until the plant achieved 60% power on February 14. The resident staff, with selected assistance, provided general coverage of plant activities and direct observation of important tests until the unit achieved full power and was released for unrestricted operation on February 23. The following is a listing by power plateau of inspectors' observations including strengths, weaknesses, and equipment problems that were identified during the startup:

Cold Shutdown to Reactor Critical

The preparations for reactor startup were completed and rod pull commenced on January 31, 1994. Control rods were pulled to within two steps of the Estimated Critical Position (ECP) and it became evident that the reactor would not go critical at the calculated ECP. Rods were driven in and nuclear engineering began consultation with the fuels section in the corporate office to determine why the reactor did not go critical at or near the ECP. After extensive communications between the site nuclear engineers and the fuels section, it was determined that the ECP was overly conservative and a new ECP was developed. Rods were pulled again and the reactor achieved criticality at 11:35 p.m., on February 1.

Other than poor communications between the site and the fuels section, no deficiencies were observed.

Reactor Critical to 15% Power

During power ascension from startup to 15% power, testing was conducted on nuclear instrumentation, HPCI, RCIC, the recently installed digital feedwater control system, the reactor water level reference leg backfill modification, the reactor feedpumps, and the EHC system. In addition to the above testing, numerous PMTRs were conducted to verify equipment operability and an entry was made into the drywell to identify any leakage at full system operating pressure. The following problems were identified or occurred during this power plateau:

- air trapped in reactor water level reference leg required venting
- a drywell temperature detector required replacement
- minor weeping past SRV J - this stopped when pressure and temperature increased
- the air operator on a recirculation pump seal staging valve required repacking
- an electrical short in BOP MCC 1 TA required repairs
- several problems involving the overspeed and backup mechanical overspeed devices on the reactor feedwater pump delayed placing these units in operation. Some inadequacies were also identified involving the procedures used to startup and test the reactor feedwater pumps. Vendor assistance was obtained in this area, but the licensee was able to accomplish the required repairs without extensive assistance.

During this period of the startup and power ascension, the licensee's performance was very positive. Evolutions in the control room were performed in a very controlled manner with nuclear safety being the first priority. Prior to the performance of any activity, a pre-job briefing was conducted for all individuals involved in the execution of the task. In general, the briefings were thorough and described the task in detail. Infrequently performed evolutions, such as rod withdrawal and SRV testing were further briefed in accordance with the licensee's procedure, PLP-17, Identification, Development, Review, and Conduct of Infrequently Performed Tests or Evolutions. These briefings conducted by operations management emphasized strict adherence to procedures, the licensee's self-checking STAR technique, and a discussion of problems experienced by CP&L and other licensees performing similar evolutions.

During the startup, the inspector observed the operations shift turnover on a daily basis. During turnover, most critical activities were stopped so that a thorough turnover could be conducted between the on-coming and off-going shifts. The turnovers observed by the inspector were very thorough and detailed. This was particularly the case for turnover at the unit senior reactor operator position. Plant status, work activities, LCOs, past problems, startup schedule, and other matters affecting the unit were discussed in detail.

Equipment performance during the initial phases of the startup for a plant that had not operated for approximately 21 months was good. The digital controls for the Startup Level Control Valve, a newly installed modification, performed well during the startup. However, the licensee did experience some equipment problems. For instance, a control operator experienced difficulty in withdrawing numerous control rods. This was most likely due to venting problems with the control rod drives. Additionally, a water level instrument, N004C, did not reflect the correct water level when compared to other instrumentation. This problem resulted in a delay in the startup process so that the instrument's reference leg could be backfilled and vented. Overall, the plant's equipment operated properly and allowed for safe power ascension.

The operators performance during the startup was good. All observed evolutions were performed in a careful and deliberate manner. Senior reactor operators controlled all evolutions ensuring that the ROs and AOs understood their duties and responsibilities prior to commencing important activities. Problems that arose were quickly handled in a conservative and safe manner. For example, on February 2, when water level instrument N004C was discovered to be outside its acceptable operating band, all power ascension activities were stopped and the proper TS LCO entered. Working as a team, the operators took the correct actions within the required time frame as specified in the plant's technical specifications. Additionally, the control room maintained a professional work atmosphere throughout the startup. Control room access was controlled by the SROs and ROs as specified by plant procedures.

Good command and control was also exhibited during a minor fire which occurred on February 4, at approximately 5:00 a.m., due to a phase to phase short in MCC 1TA (see paragraph 3.a.). Following the initial report, the control room immediately notified and dispatched the fire brigade to the scene. During this time, the use of the plant page was restricted for emergency use only. Operators concentrated on their entry into the required procedures and the assessment of damages and recovery of lost systems. Effects of this fire were felt on both units, as Hydrogen Water Chemistry was lost on Unit 2 as a result of the fire. Unit 2 response and subsequent recovery/stabilization efforts were conducted in a smooth and efficient manner. The overall response to this event was well coordinated and controlled, demonstrating good use of command and control and a familiarity with emergency response actions.

Overall, this portion of the startup was performed in a cautious and deliberate manner. Although meeting their schedule was important, the safe operation of the unit was overwhelmingly the most significant objective during the startup.

15% To 35% Power

The licensee's efforts at this plateau consisted of inerting the drywell, testing the main turbine and its associated protective devices, synchronization to the grid, performing system walkdowns, feedwater testing, and other performance and operational tests.

The equipment problems experienced at this power level included the main turbine stop and control valves closing prior to achieving rated speed. It was determined that this had been caused by a faulty diode which was replaced. An incorrectly adjusted limit switch on the turbine control valve resulted in an automatic actuation of all four diesel generators while performing turbine overspeed trip testing. A steam leak was identified and repaired in a drain line in the MSIV pit area. All the above items were correctly diagnosed and repaired in a timely manner.

The inspectors continued to identify excellent pre-job briefings and exceptionally good internal and external communications in the control room and between plant operations and other supporting sections. Shift turnover continued to be detailed and professional. All observed testing was performed in a deliberate and controlled manner with good support provided by all units. Management continued to provide good oversite and direction.

One personnel error was identified when a vendor technician inadvertently pushed the wrong button on the digital feedwater control system in the back panel area. This resulted in a rapid change in reactor water level from 187 inches to 173 inches and the system transferred from three element to single element control as designed. The level was restored to normal and all testing was stopped to address this item. It was determined that operations was not aware that the individual was entering data into the system controls. The individual did not believe that his actions would have any effect on system operations. Overall performance at this plateau was good.

35% to 60% Power

This plateau consisted of placing the second feedwater pump in service, performing low power testing, LPRM calibration, performing system walkdown of the MSRs and heater drains, and the completion of performance, maintenance, and surveillance testing. No significant personnel or equipment problems were identified at this plateau. Operations and the support organizations continued to perform well in a controlled and deliberate manner. After the unit achieved 60% power, NRC control room staffing was reduced to the observation of special tests.

60% to Full Power

This plateau consisted of additional testing of the DFW system at 75% power, turbine valve testing at 80% power, followed by a period of fuel preconditioning at 80% power. This preconditioning was accomplished to reduce the potential for damage from any debris that may exist in the RCS and fuel area. After fuel preconditioning, power was reduced to 65% for a rod pattern change and power was then raised to 98% to attain Xenon equilibrium, perform core parameter checks, and complete DFW system final acceptance tests. These tests included a reactor feedwater pump trip and a recirculating pump runback from full power.

Prior to performing the final acceptance test, the operators were given specialized training on these transients in the simulator. This training included exercises with and without faults. The inspector observed this training and the plant acceptance testing. The tests were performed satisfactorily on February 22 and 23. After the above testing and an assessment by the unit manager and Site Vice President, the unit was released for unrestricted operations on February 23.

The above startup activities were conducted in accordance with a well organized, planned, and developed startup and power ascension plan. Inspections of equipment and spaces prior to and during the unit startup indicated that significant improvements had been made in the areas of plant cleanliness, preservation, and equipment maintenance and upgrading. Operator and support organizations morale and attitudes appeared to be positive and well focused on the unit restart. Management involvement and oversite had significantly increased and provided very positive results. Considering that the plant had been shutdown for 21 months with a large amount of work performed, the plant restarted and performed well with very few equipment and personnel problems. The startup and power ascension plan, including the performance of the plant staff during the unit 1 restart, is considered a strength.

c. Review of Operations LERs (92700)

(Closed) LER 1-91-27, Two Inoperable Control Rod Accumulators Result in Entry into Technical Specification 3.0.3. This event occurred when a CRD accumulator low nitrogen pressure alarm was received on HCU 46-27 while an operator was recharging the HCU 34-19 accumulator. With two inoperable HCU accumulators, TS 3.0.3 was entered when the Control Room declared the second HCU inoperable. The AO recharging HCU 34-19 was dispatched to verify low nitrogen pressure on the second HCU and to continue recharging 34-19.

HCU 34-19 was recharged and returned to service, thus exiting the TS LCO. The licensee recharged the accumulator for HCU 46-27 and on January 25, 1993, submitted a TS change that would eliminate the reportability of this event.

(Closed) LER 1-91-15, Two Inoperable Control Rod Accumulators Result in Entry Into Technical Specification 3.0.3. This event occurred when CRD accumulator low nitrogen pressure alarm was received on HCU 30-47. Maintenance was in progress on HCU 30-19 to repair a nitrogen leak at the same time. With two inoperable HCU accumulators, TS 3.0.3 was entered. An AO was dispatched to recharge the accumulator for HCU 30-47. The accumulator was recharged and returned to service, thus exiting the TS LCO. The licensee completed the maintenance on HCU 30-19 a day later. As previously indicated, a TS change was submitted on January 25 1993, that will eliminate the reportability of this event.

(Closed) LER 1-93-10, Hourly Fire Watch Technical Specification Surveillance Missed During Radiography. This event occurred when an assigned fire watch was unable to enter an area and perform the required hourly inspection due to radiographic activities. This occurred due to a breakdown in communications between the firewatch, health physics personnel, and radiography. Only one hourly round was missed. The individuals involved in this event were counselled and a faulty public address system phone that was a contributing factor was repaired under WR/JO 93-APLZ1. The inspector verified that the above actions had been completed.

d. Licensee Action on Previous Operations Inspection Findings (92701, 92702)

(Closed) Violation (325,324/93-19-01), Inadequate Corrective Action to Correct Deficiencies in Clearance Implementation, Tagout Audits, and Operator Shift Turnovers. On April 19,1993, clearance 2-93-1094 was hung which required the control switches for Containment Atmospheric Control Valves 2-CAC-V4, V55, V56, and V58 to be in the closed position. On April 21, the inspector found these switches to be in the neutral position. A tagout audit on April 20 and multiple control board walkdowns between April 19 and 21, 1993, failed to identify this discrepancy. This event was similar to that described in Notice of Violation (Violation B) dated August 25, 1992. The licensee responded to the violation in a letter dated June 25, 1993. The licensee's corrective actions were completed on April 1, 1993, and included:

- Counseling of involved individuals
- Senior Operations Management reviewing the event with each shift, re-emphasizing their expectations

- Each shift supervisor administering a control board awareness/walkdown checkout card to each operator assigned to his shift
- Operations management performing semi-weekly assessment/walkdowns of the control boards with the ROs for 10 weeks
- Implementing a new self-checking program called STAR (Stop, Think, Act, and Review)

The inspector reviewed the assessments that had been completed by operations management. He also reviewed the corrective actions for items identified during the assessments. The items identified by operations management were not significant and were similar to those observed by the inspector.

The licensee continually emphasizes the STAR process, and the inspector has observed a significant reduction in the number of personnel related issues. The licensee also continues to give control board walkdowns to the ROs. The inspector found the licensee's corrective actions for these issues to be effective.

(Closed) Violation 325,324/93-52-01, Inadequate Control Room Logs. This violation identified that an operator had failed to log when a control rod was found at position 46 instead of the required position 48. An investigation found that the rod had not been returned to position 48 after the performance of PT.14.1, Control Rod Operability Check, which exercised the rods weekly. This rod remained in the wrong position for 18 hours until identified by an oncoming nuclear engineer. This was identified during a shift turnover, and it appears that both operators thought the other one would make the log entry. The licensee responded to the violation in a letter dated January 28, 1994. The licensee corrective actions were to make a late log entry and counsel the applicable operators and discuss the item with all shift personnel. The inspector verified that these actions had been completed. The inspector also reviewed the licensee's existing guidance on log keeping (OI-71, Operations Shift Logs) and determined that it provides adequate detail and guidance on log keeping.

Violations and deviations were not identified.

3. Maintenance

a. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance. The inspectors observed/reviewed portions of the following maintenance activities:

94-ACTRI	Repair of Annunciator U4-23, Exhaust Hood A Vacuum Low
93-BCPN1	Adjust MGU/MSC overspeed stops, 1A RFPT
94-ACMS1	Repair DG No. 4 jacket water heating pump motor
93-BCPN1	Repair/adjust reactor feedwater pump 1A overspeed trip mechanism
94-ADAM1	Repair leak on B21 F038C steam line drain venturi
94-ACRV1	Repair damaged bus on MCC 1TA
93-IR9001	Lever adjustment for RFPT MGU
94-ADBI1	Troubleshoot spurious turbine trip and repair/ adjust limit switch on Unit 1 stop valve No. 1

MCC 1TA Repairs

Inspection Report 325,324/94-02 identified the occurrence of a short and resulting electrical fire in turbine building MCC-1TA that occurred on February 4. The main feeder breaker automatically tripped and extinguished the fire. The fire and damage to equipment was isolated to one cubicle in the MCC. The damaged area included arc damage to one phase of a 600 ampere vertical bus section adjacent to where the main power feeder cable connects to this bus. The bus loads are all balance of plant loads.

Plant maintenance removed the two cubicle buckets in the A section of the MCC and removed the damaged bus section. They did not have a 600 ampere replacement bus section in stock so they performed an engineering evaluation (EER 94-0038) that allowed them to install a modified 300 ampere bus assembly as a temporary replacement until parts could be obtained from the manufacturer. These actions allowed Unit 1 restart to continue.

The inspector reviewed the above EER and discussed it in detail with the engineers who performed the evaluation. The inspector found this repair to be acceptable until the correct replacement parts could be obtained and an outage of sufficient duration exists to permit replacement. The inspector observed the disassembly and inspection of the failed parts. No deficiencies were identified during the above repair activities.

RFP Overspeed Trip Repairs

The personnel working on this item experienced procedural problems that required a procedure revision. The lead mechanic who generally worked on this equipment was unavailable and it took a significant amount of time for the assigned people to familiarize themselves with the equipment and make the necessary repairs and adjustments. The individuals involved appeared to do an overall effective job and clearly gained confidence on this equipment.

DG No. 4 Jacket Water Pump and Steam Line Drain

The repairs to the DG jacket water heating pump motor and the leaking steam line drain were performed in a timely manner without impact on the unit restart.

No deficiencies were identified on the other observed WR/JOs.

b. Surveillance Observation (61726)

The inspectors witnessed/reviewed portions of the test activities during Unit 1 restart. Through observation, interviews and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors reviewed the test results and ensured that the equipment was correctly returned to service:

OPT-14.3.1	In sequence Critical Shutdown Margin
OPT-50.2	SRM/IRM Overlap Verification and IRM Range 6 and 7 Continuity Check
OPT-50.12	Measurement of In Sequence Critical Data
1MST-IRM25NA	IRM Range Correlation Adjustment
PM-89-001	Digital Feedwater Testing (SULCV)
OPT-10.1.1A	RCIC Component Test
OPT-10.11.L, 10.12.L, & 10.13.L	RCIC ASD Test
OPT-9.3A	HPCI Component Test
OPT-09.10L	HPCI Component Local and ASSD Test
OPT-9.3	HPCI Operability Test
OSP 93-049	Tune HPCI/RCIC Controllers
PM 89-001	RFPT High Level Trip Test
OCM-TRB521	1st RFPT Overspeed Test
PM 89-001	1st RFPT MGU/MSC Functional Test
OPT-37.2.1 & OPT-37.2.3	1st RFPT PTs
PM 92-152	1A RFPT Logic Redesign Acceptance
PM 89-001	Digital Feedwater Functional Test When 1st RFPT Placed In Service
OCM-TRB521	2nd RFPT Overspeed Test

PM 89-001	2nd RFPT MGU/MSC Functional Test
OPT-37.2.1 & PT-37.2.3	2nd RFPT PTs
PM 92-152	1B RFPT Logic Redesign Acceptance Test
OPT-50.2	IRM/APRM Overlap Verification
OPT-11.1.2	SRV/ADS Test
PM 89-001	Digital Feedwater Functional Test When Control System Placed in Master Automatic
OPT-10.1.1	RCIC 1000 psig Operability Test
OPT-09.2	HPCI 1000 psig Operability Test
OPM-TRB507	HPCI Operational Inspection
1MST-HPCI39R	HPCI Response Test
OPT-01.9E	TIP Axial Alignment
1SP-93-071	Feedwater Valve Inspection
OPT-80.2	Drywell Entry and Class 1 Conditional System Leak Test
OPT-20.3C	Drywell Air Lock Leak Test
ENP-24.15	Full Core TIP Scan Before Exceeding 25% Power
OPT-13.1	Jet Pump Operability
OP-26	Main Turbine Startup Tests
OPT-40.2.11	Generator Voltage Regulator
OPT-01.11	Core Performance Parameter Check
OPT-40.2.6	Main Turbine Overspeed Test
OPT-40.2.8	MSIV Closure Test
OPT-26.8.5, 8.6,8.7, & 8.10	Main Turbine Valve Testing (SV, BPV, CIV, NRV)
PM 89-001	Digital Feedwater Control System Functional Test - When Placed in Three Element Control
OPT-01.11	Core Performance Parameter Check
OPT-14.2.1	Single Rod Scram Insertion Time Test if Required
OPT-1.9D	TIP System Calibration @ <40% Power
OPT-1.9	LPRM Calibration @ <40% Power
OPT-1.8D	Core Thermal Power Calibration @ <40% Power
OPT-50.13	APRM/LPRM Flux Noise Baseline Data @ <40% Power
PM 93-031	RPV Reference Leg Backfill Sensitivity Test
OPT-37.2.2	RFPT 1A and 1B Stop Valve Test
PM 89-001	Recirculating Pump Runback Test @ 45%
PM 89-001	Digital Feedwater Functional Test When Second RFPT Placed in Service
OP-26.8.16	Main Turbine Power/Load Unbalance Test
1MST-RPS28R	MSL Rad Monitor Setpoint at 60% Power
OPM-NE001	LPRM Detector Performance Evaluation
OPT-50.3	TIP Reproductibility and Uncertainty Determination @ 60% Power
OPT-01.9E	Axial Alignment of TIP @ 60% Power

OPT-01.9	LPRM Calibration @ 60% Power
OPT-1.8D	Core Thermal Power Calculation @ 60% Power
OPT-50.14	TIP Tube and LPRM Configuration Verification @ 60% Power
PM 89-001	Digital Feedwater Functional Test at 75% Power
OPT-40.2.5 & 40.2.9	Main Turbine Valve Testing
PM 89-001	Digital Feedwater Functional Test @ 100% Power
1MST APRM11W	APRM CH A, C, and E Channel Functional Test RDS Inputs
2MST RPS 27R	RPS Scram Discharge Volume Hi Water Level Channel Functional Test and Channel Calibration
PM 93-031	RPV Reference Leg Backfill Sensitivity Test - Rated Reactor Pressure.

RPV Reference Leg Backfill

The inspector observed the testing performed in the above RPV reference leg backfill modification (PM 93-031) for Unit 1 during power ascension testing on February 12,1994. The first phase of this test was performed to gather data and determine the sensitivity on the unit's reactor water level instrumentation over variable flow rates. Flow sensitivity tests were performed for each of the seven reference leg condensing pots at 920 psig reactor pressure with flows that ranged from 0.002 to 0.016 gpm (note 0.016 gpm is 200% normal flow). Time history plots of the archived data were recorded by ERFIS. All plant parameters for the injected loops appeared to be relatively constant when observed with increased flows and compared favorably with the non-injected loops resulting in a successful test.

The second phase of the sensitivity testing involved increasing the back flow rate to all seven reference leg condensing pots to 0.016 gpm and observing their level indication sensitivity effects for each of the following reactor perturbations:

- Start the standby CRD pump and stop the operating CRD pump
- Transfer of CRD pump suction filters
- Transfer of CRD pump drive filters
- Transfer of CRD pump suction source to the CST
- Return the CRD suction source to the pretest condition
- Continual withdrawal of a selected control rod (30-03) to position 24
- Continual insertion of control rod (30-03) to position 00
- Notch withdrawal of control rod (30-03) to position 24
- Notch insertion of control rod (30-03) to position 00

The third phase of testing the unit's reactor water level instrumentation sensitivity involved performing the same above listed reactor perturbations for all seven leg condensing pots using a 0.008 gpm (100% normal flow rate) backfill flow rate.

The fourth and final sensitivity testing phase involved isolating level transmitter 1-B21-LT-N027A and monitoring the backfill flow indicator while slowly decreasing the backfill flow rate to 0.008 gpm using the flow metering valve.

Once all testing was complete, the backfill flow was left in the normal operational alignment and the vessel level instrumentation system was turned over to Operations. Observation and review of the sensitivity measurements recorded by this acceptance test determined the Reference Leg Backfill Modification should have no adverse affect on the reactor vessel instrumentation.

The inspector noted that excellent pre-job briefings were conducted for involved personnel prior to the performance of the above remaining tests. These briefings were detailed and covered the tests, anticipated results, and acceptance criteria. Applicable plant and industry experience associated with the test was also discussed. The assignments of test supervisors, coordinators, and specific test personnel enhanced this process and provided more effective control. The inspector noted that support organizations responded in a timely manner to provide assistance when needed. The questioning attitude of test personnel led to the identification and resolution of several problems, such as the need to test the CAC-V216 valve (See paragraph 3.c). The most significant problems encountered during the above test involved the reactor feedwater pumps. The majority of these problems related to poor procedures, workmanship, and inadequate knowledge on the equipment. The maintenance organization was challenged, but was able to resolve these problems with only minor assistance from a vendor. The pre-startup tests performed on HPCI and RCIC using auxiliary steam significantly reduced the problems normally experienced on this equipment during startup.

Digital Feedwater

The testing on the digital feedwater system went well and provided the operators with added assurance of this new system's capability. Overall, the above testing went exceptionally well with significantly less than anticipated problems.

TSC/EOF Diesel Generator

During a routine review of corrective actions identified and committed to during 1993, the licensee identified a failure to schedule and perform preventive maintenance on the TSC/EOF diesel generator as identified in NRC Violation 93-04-03. The violation identified the fact that the TSC/EOF diesel generator did not have a scheduled preventive maintenance program which was contrary to the requirements of plant emergency procedure PEP-04.2, Emergency Facilities and Equipment.

The above routine review identified that all the corrective actions committed to in the Reply to Notice of Violation dated April 16, 1993, were not met. In the Reply to Notice of Violation, the licensee committed to developing, scheduling, and completing semi-annual and eighteen month maintenance prior to August 25, 1993 and 1994, respectively. The licensee's review on February 3, 1994, found that these actions had not been completed. Adverse Condition Report 94-058 was initiated to track this issue to resolution, as well as a root cause investigation to determine why the maintenance and testing had not been performed after procedure development. The inspector will review the results of the root cause analysis when completed. On March 2, 1994, the scheduled preventive maintenance and testing was completed satisfactorily utilizing procedures OPM-ENG-505, Maintenance Instruction for Covington Diesel Generator Model 7123-7305, Rev. 1, and OPM-GEN-008, Covington Diesel Generator Electrical Inspection, Rev.1. This work was scheduled and performed under preventive maintenance routes: 94-JO1004, 94-JI3104, and 94-SA4001.

c. Licensee Action on Previous Maintenance Inspection Findings (92701, 92702)

(Closed) URI 325,324/94-02-01, Inadequate Surveillance Procedure. The Unit 2 Hardened Wet Well Vent Plant Modification PM 92-073 was completed in March, 1993. The modification included Hardened Wet Well Vent Outboard Isolation Valve 2-CAC-V216 which is listed in Appendix B of RCI-02.6, Cross Reference to Technical Specifications, as a Primary Containment Isolation System (PCIS) valve. This valve can be operated manually from the RTGB with an override switch or closed automatically by a LOCA signal provided by relay 3B (SK91001-Z-7007) in the Group 6 isolation logic.

The Nuclear Plant Modification Program (NPMP) Procedure, Section 4.3.6.1 requires that tests be included or identified to demonstrate that the changes made by a modification are satisfactorily implemented and to verify compliance with affected required surveillances. Technical Specification 4.6.3.1 requires that each PCIS valve specified in RCI-02.6 be demonstrated operable prior to returning the valve to service. Technical Specification 4.6.3.2 requires that each isolation valve be demonstrated operable at least once per 18 months by verifying that each PCIS valve actuates to its isolation position upon receipt of a containment isolation test signal. The licensee demonstrates this function for the CAC valves by performing 2-MST-CAC-41R, CAC PCIS Groups 2 and 6 Isolation Logic System Functional Test.

The licensee elected not to perform Group 6 isolation logic testing on CAC V216 after installation since it would have caused the other PCIS valves to isolate drywell ventilation. This action would have created a confined space and would have impacted the outage schedule. The licensee only tested CAC-V216 for valve stroke time and the operation of outboard isolation override logic and did not test the operation of the valve using a LOCA test signal. NPMP 4.3.6.2 states that those portions of acceptance tests which cannot be performed until after the unit is returned to service should be identified as startup tests. NPMP 4.3.7 also requires that documents requiring revision prior to operability be identified to support any surveillance and/or startup requirements. The engineer assigned to this project believed that the functional test described above was adequate to demonstrate operability. He therefore determined that 2-MST-CAC-41R, which demonstrates the operability of CAC-V216 was not required to be revised prior to operability. In addition, CAC-V216 was not incorporated into the monthly OPT-4.1.1, Reactor Building Vent Exhaust Monitoring System Functional Test, which would have demonstrated the valve's operability.

The licensee discovered this deficiency on January 31, 1994, when the Unit 1 STA noted that 1-CAC-V216 was not tested during the performance of OPT 4.1.1. Investigation revealed that the same valve for Unit 2 (2-CAC-V216) had not been adequately tested.

The inspector reviewed the modification package and determined that the licensee did not include a test to demonstrate that the CAC-V216 would close upon the actuation of a LOCA logic relay as required by Technical Specification 4.6.3.1. The licensee also failed to include this valve in their surveillance program. This is a Violation of Technical Specification 4.6.3.1 (50-324/94-04-01), Failure to Incorporate CAC-V216 into PCIS Test Procedures. This closes the URI. All corrective actions for this item will be tracked under this Violation.

The licensee documented the above event in ACR 94-052 and reported it to the NRC in LER 2-94-01. The immediate corrective action was to issue and perform a one-time only, temporary revision to OPT 4.1.1 which included valve CAC-V216. This test was performed on January 31, 1994. The valves for both units were tested satisfactorily. The licensee also plans to test these valves during the performance of MST-CAC41R, CAC PCIS Groups 2 and 6 Isolation Logic System Functional Test, which is performed each refueling outage. The licensee stated that OPT-4.1.1 will be revised to test the PCIS logic of these valves monthly.

4. Engineering Support

a. Installation/Testing of Modifications (37828)

The Plant Process Computer Replacement (PPCR) project (PM90-004) transferred the functions currently performed by the Plant Process Computer to a new advanced system with greater hardware and software capabilities, expandability, and reliability. The new system can be more easily maintained and supported. In conjunction with the installation of the new plant process computer system, the Nuclear Fuels services group updated and upgraded the core monitoring software. This modification expanded the capabilities and reliability of the existing system and provided a more efficient and user friendly system for the control room operators.

The PPCR project involved the removal of the existing system consisting of a Honeywell 4010 computer, analog and digital signal I/O cabinets, computer console, alarm typers and assorted printers. The system was replaced with new front end data acquisition equipment, data links, a high speed interface to existing VAX computers, additional VAX systems including CPUs, memory disks, controllers, special purpose interfaces to existing plant data systems, and new operator interface consoles. Associated with the hardware upgrade was an upgrade of the system software. This software upgrade includes new data acquisition and validation capabilities, a new core monitoring software package entitled POWERPLEX and system integration software to coordinate and monitor the entire system.

With the new system, POWERPLEX will be utilized to calculate core power distribution and margins to TS thermal limits. The program is a commercially available product of Siemens Nuclear Power Corporation which has been approved for use by the NRC and is currently in use at seven other BWRs around the country.

The installation of new equipment and new software required that training be conducted for the primary users of the system, control room operators and nuclear engineers. All primary users have been trained on the new system, and many have had actual experience using the system during the outage. Discussions with these individuals determined that the training was adequate to operate the system. Based on discussions with various system users, the upgrade was viewed as a useful improvement, providing increased monitoring capabilities over the existing system.

The inspector reviewed the scope of the project and discussed the various aspects of this modification with the responsible engineers and system users. These discussions included the various types of qualification and verification processes used in completing this modification, capabilities of the system, improvements over the previous system, and adequacy of training and support for use of the new system. The inspector did not identify any deficiencies in these areas. The inspector will review the final acceptance test package to verify no additional problems were identified. The modification completed on Unit 1 is identical to the modification which will be performed on Unit 2 during its upcoming refueling outage starting in March of this year.

Violations and deviations were not identified.

5. Plant Support

a. Radiological Controls (71707)

The inspectors verified that the licensee's HP policies and procedures were followed. This included routine observation of HP practices and a review of area surveys, radiation work permits, posting and instrument calibration. No deficiencies were identified.

b. Security (71707)

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate. No deficiencies were identified.

c. Review of Plant Support LERs (92700)

(Closed) LER 1-93-07, Sampling of Reactor Vessel Coolant Conductivity Not Performed. On April 22, 1993, while Unit 1 was in refueling with the reactor defueled and the fuel pool gates installed, the licensee terminated sampling of the reactor vessel water inventory and established chemical sampling of the fuel pool inventory. On April 24, 1993, Operations personnel recognized that sampling the fuel pool did not satisfy the intent of the Reactor Coolant System Chemistry Technical Specification. The intent of the requirement was to ensure the integrity of reactor materials which could be compromised by chloride induced stress corrosion cracking. Reactor coolant sampling was re-established on April 24, 1993, approximately 52.5 hours after it had been secured.

Investigations performed by the licensee indicated that the event was caused by a misinterpretation of the sampling requirement by both Operations and E&RC personnel. Further investigation revealed that this misinterpretation had existed since the mid-1980s. The personnel involved failed to recognize that the intent was to protect the reactor materials, not just the fuel.

The licensee reviewed the conductivity and chloride levels of the last sample taken from the reactor vessel, and when proper sampling was re-established, determined that all levels were within TS limits. It was determined that no activities which would have increased these levels occurred during this time period. The conductivity and chloride levels of available sources of water to the vessel were also within TS limits. Based on these reviews, the licensee determined that this event was not safety significant.

In response to the event, the licensee implemented the following corrective actions: re-established reactor vessel coolant sampling; issued a Standing Instruction to ensure consistency in interpretation of the TS sampling requirement; revised the E&RC procedures to ensure future sampling was performed in accordance with the TS; and evaluated the issue for future training for OPs and E&RC personnel. The inspector reviewed these corrective actions and found them adequate to prevent recurrence of this event.

(Closed) LER 1-93-013, Main Stack Wide Range Gas Monitor Failure Results in Group 6 Isolation. This failure occurred due to a blown fuse. This resulted in a Group 6 isolation and all components functioned as designed. The licensee established auxiliary stack sampling within one hour. The licensee replaced the fuse and placed the system back in service under a system monitoring mode for 2 days. They were unable to determine the cause of the blown fuse. After 2 days of monitoring, the system was declared operable. The inspector reviewed licensee logs and verified that backup sampling had been initiated as required. This item has not been a recurring problem on this system and the licensee's corrective action appears to be appropriate for the event.

Violations and deviations were not identified.

6. Other Areas (76000)

a. Meetings with Local Officials (94600)

The Senior Resident Inspector (SRI) met with the Mayor and Commissioners of Kure Beach at a regularly scheduled meeting at 7:30 p.m., on February 15. The SRI made a formal presentation to the Mayor and City Council which included an update on the NRC's organization, mission, and responsibility. A summary of the recent plant history and current status, a brief resume of the assigned Resident Inspectors, and the telephone numbers and addresses of appropriate NRC contacts were provided. The SRI responded to several questions involving the shipment of spent fuel and radioactive waste. He also offered to respond to and/or provide assistance and coordination in answering any future questions or concerns the Mayor or Council members may have involving the NRC or the Brunswick Plant. This meeting concluded the bi-annual meetings with officials of communities in the vicinity of the plant.

b. Nuclear Safety Review Committee (40500)

The February 10, PNSC meeting discussed LER 1-94-02 involving the CBEAF system inoperability. A revision to 0-AP-010, Procedure Use and Adherence; the 1993 calendar year security program review; and a review of 2-SP-93-0073/0074, A & B Loop RHR Chemical Decontamination, which is planned to be done just prior to the Unit 2 refueling outage. The RHR decontamination plan was discussed extensively with numerous questions being asked by the PNSC. The team presenting this item appeared to have done an excellent job in planning the project. Several questions could not be conclusively answered and the project managers were asked to research these issues and respond to the PNSC at a later meeting. The minutes of all other meetings for the month of February were also reviewed. No deficiencies were identified.

Violations and deviations were not identified.

7. Exit Interview (30703)

The inspection scope and findings were summarized on March 4, 1994, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
324/94-04-01	Violation: Inadequate post modification/ surveillance test involving valve CAC-V216 paragraph 3.c.

8. Acronyms and Initialisms

AO	Auxiliary Operator
BWR	Boiling Water Reactor
CAC	Containment Atmospheric Control
CPU	Central Processing Unit
CRD	Control Rod Drive
CBEAF	Control Building Emergency Air Filters

DFW	Digital Feedwater
DG	Diesel Generator
E&RC	Environmental & Radiation Control
ECP	Estimated Critical Position
EER	Engineering Evaluation Report
EHC	Electro Hydraulic Control System
ENP	Engineering Procedure
EOF	Emergency Operations Facility
ERFIS	Emergency Response Facility Information System
GE	General Electric Company
HCU	Hydraulic Control Unit
HP	Health Physics
HPCI	High Pressure Coolant Injection
LCO	Limiting Conditions for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPRM	Local Power Range Monitor
MCC	Motor Control Center
MSR	Moisture Separator Reheater
MST	Maintenance Surveillance Test
NPMP	Nuclear Plant Modification Program
NRC	Nuclear Regulatory Commission
OI	Operating Instruction
OP	Operating Procedure
PA	Protected Area
PCIS	Primary Containment Isolation System
PEP	Plant Emergency Procedure
PLP	Plant Procedure
PM	Preventive Maintenance
PM	Plant Modification
PMTR	Post Maintenance Testing Requirements
PNSC	Plant Nuclear Safety Committee
PPCR	Plant Process Computer Replacement
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RO	Reactor Operator
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SRI	Senior Resident Inspector
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
STA	Shift Technical Advisor
STAR	Stop, Think, Act, and Review
TS	Technical Specification
TSC	Technical Support Center
URI	Unresolved Item
WR/JO	Work Request/Job Order

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

APR 28 1994

Docket No.: 50-325 and 50-324
License No.: DPR-71 and DPR-62

Carolina Power and Light Company
ATTN: Mr. R. A. Anderson
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-325/94-07 AND 50-324/94-07)

This refers to the inspection conducted by Richard L. Prevatte of this office on March 5 - April 4, 1994. The inspection included a review of activities authorized for your Brunswick facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel and observation of activities in progress.

Based on the results of this inspection, certain of your activities appeared to be in violation of NRC requirements, as specified in the enclosed Notice of Violation (Notice). The violation is of concern because it represents a continuing trend of configuration events. We recognize that these examples were identified by your staff and that you have made gains in this area; but your corrective actions do not appear to be fully effective in preventing recurrence.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, and its enclosures, and any reply will be placed in the NRC Public Document Room.

9405230095

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Jon R. Johnson

Jon R. Johnson, Acting Director
Division of Reactor Projects

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

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(cc w/encls cont'd - See page 3)

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ENCLOSURE 1

NOTICE OF VIOLATION

Carolina Power and Light Company
Brunswick Site

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

During an NRC inspection conducted on March 5 - April 4, 1994, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violations are listed below:

Technical Specification 6.8.1 (a) requires that written procedures shall be established, implemented, and maintained covering the activities referenced in Regulatory Guide 1.33 Appendix A, November 1972.

Regulatory Guide 1.33, Appendix A, requires procedures for maintaining the Instrument Air System, the fuel storage pool systems and service water system.

Operating Procedure OP-46, Instrument and Service Air System Operating Procedure implements these requirements. Attachment to OP-46, Rev. 77, the Unit 1 Valve Line-up Prestartup Checklist requires valve 1-RNA-IV-2627 to be in the open position.

Special Procedure, 2-SP-91-047, Installation and Acceptance Testing of Supplemental Spent Fuel Pool Cooling System implements these requirements. Attachment A to 2-SP-91-047, revision 3, the Valve Alignment Checksheet - Primary Loop requires valve 2-G42-V011 to be in the closed position.

Plant procedure, 1-OP-43, Service Water System Operating Procedure implements these requirements. Attachment 1 to 1-OP-43, revision 46, the Valve Lineup-Prestartup Checklist requires valve 1-SW-V58 to be in the closed position.

Contrary to the above, the following valves were not in their proper position:

1) On February 27, 1994, Operating Procedure OP-46 was not adequately implemented in that, Instrument air Valve 1-RNA-IV-2627 was found in the closed position.

2) On March 13, 1994, Special Procedure, 2-SP-91-047 was not adequately implemented in that Spent fuel Pool Cooling Valve 2-G42-V011 was found in the open position.

3) On April 1, 1994, Plant Procedure 1-OP-43, was not adequately implemented in that Service Water Valve 1-SW-V58 was found in the open position.

This is a Severity Level IV violation (Supplement I).

~~9406230098~~

Pursuant to the provisions of 10 CFR 2.201, Carolina Power and Light Company is hereby required to submit a written statement or explanation to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order or demand for information may be issued as to why the license should not be modified, suspended or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

Dated at Atlanta, Georgia
this 28th day of April 1994

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/94-07 and 50-324/94-07

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: March 5 - April 4, 1994

Lead Inspector: R L Prevatte
R. L. Prevatte, Senior Resident Inspector — 4/22/94 Date Signed

Other Inspectors: P. M. Byron, Resident Inspector
M. T. Janus, Resident Inspector

Accompanying Personnel: E. Y. Wang, General Engineer (Intern)

Approved By: R L Prevatte for
H. O. Christensen, Chief — 4/22/94 Date Signed
Reactor Projects Section 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspectors involved the areas of operations, maintenance and surveillance, engineering support, plant support, and other areas. Inspections were conducted during normal working hours, on back shift, deep back shift, holidays, and weekends.

Results:

In the areas inspected, a Violation (325,324/94-07-01) was identified with three examples cited: Failure to Implement Procedures (paragraph 2.f). Additionally, an Unresolved Item (325,342/94-07-02) was identified: SPDS Does Not Meet Design Criteria, paragraph 4.b.

A strength was identified in the planning and decontamination of the Unit 2 RHR system (paragraph 5.b.)

Unit 1 operated at essentially 100% power for the reporting period. Unit 2 shutdown and started an anticipated 92 day refueling outage on March 26, 1994. The refueling outage appeared to be better planned than previous outages.

9405230103

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Ahern, Manager - Operations Support and Work Control
*R. Anderson, Vice President - Brunswick Nuclear Plant
*G. Barnes, Manager - Operations, Unit 1
*M. Bradley, Manager - Brunswick Project Assessment
*J. Cowan, Acting Director - Site Operations
G. Honma, Supervisor - Regulatory Compliance
*N. Gannon, Manager - Maintenance, Unit 1
*R. Grazio, Manager - Brunswick Engineering Support Section
J. Heffley, Manager - Maintenance, Unit 2
G. Hicks, Manager - Training
*P. Leslie, Manager - Security
*W. Levis, Acting Plant Manager - Unit 1
R. Lopriore, Manager - Regulatory Affairs
C. Pardee, Manager - Technical Support
*C. Robertson, Manager - Environmental & Radiological Control
*J. Titrington, Manager - Operations, Unit 2
*C. Warren, Plant Manager - Unit 2
*G. Warriner, Manager - Control and Administration
E. Willett, Manager - Project Management

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

*Attended the exit interview.

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

2. Operations

a. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, review of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, daily and standing instructions and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification Limiting Conditions for Operations. Direct observations of control room panels and instrumentation and recorded traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was not leakage of major components; there was proper lubrication and cooling water available; and conditions did not exist which could prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspector verified the valve lineup for the CS, HPCI and RHR systems for both units during this inspection period. Both CS systems and the Unit 1 HPCI and RHR systems were in their normal lineup. The inspector observed that the Unit 2 HPCI system was lined up to the torus because of a leaking check valve from the condensate storage tank. The Unit 2 RHR A Loop was also lined up to the torus for torus cooling to support HPCI and RCIC testing. The inspector verified that the above systems were returned to the normal lineup upon the completion of repairs and testing.

b. Control Rod Drive Pump 2 A (71707)

While conducting backshift tours on March 9, the inspector noted that the noise level of the running 2A CRD pump on Unit 2 was much higher than the running CRD pump on Unit 1. The 2A CRD pump area was contaminated and roped off so only visual observations of CRD pump 2A could be made from a distance of 3 to 8 feet. Closer observations required donning protective clothing. The inspector noted that the pump lube oil bubblers were adequately filled and did not observe any discoloration of this oil. Visual observation did not reveal any signs of overheating or excessive vibration of the pump assembly. The same day the inspector discussed this issue with the Unit 2 plant manager the 2A CRD pump motor experienced a bearing failure.

A lube oil sample had been taken and analyzed on this component in February, 1994. The inspector reviewed the analysis which did not reveal increased contaminant levels or any abnormalities that would have indicated potential bearing failure. A review of recent maintenance history found that the pump motor had been overhauled in 1992. Although no maintenance practice weaknesses were identified as a result of the above service, the inspector did note that the decision by the plant not to maintain this equipment or the surrounding area as radioactively clean (non contaminated) created circumstances that may have contributed to this failure.

It is a generally accepted practice for plant operators to monitor for satisfactory operation of equipment that does not have pressure and temperature gauges installed by "touch" and "feel". Since this equipment was contaminated, it required operators to dress out to perform this function on routine rounds. Discussions with operations personnel indicate that this may not have been accomplished on each round. The decontamination of this equipment may have allowed detection and prevention of this nonsafety-related equipment failure.

c. Preparation for Refueling (60705)

On March 11, 1994, during a tour of the unit 2 refueling floor (117'), the inspector observed an individual using a video camcorder inside the tool control area for the spent fuel pool (SFP). The camcorder was not tethered by a lanyard but held with the hand strap. The inspector immediately notified the licensee of this observation.

The licensee's investigation revealed that the individuals involved were contractors. They were in the SFP tool control area without the licensee's knowledge contrary to licensee requirements for refueling floor contractors. The licensee immediately restricted the access of the involved individuals. This was documented in ACR 94-092.

The inspector informed the licensee that he believed that the camcorder fell within the requirements of AI-106, Cleanliness Control of Reactor Refueling Floor, which requires that small hand tools used above the SFP be attached by a lanyard. The licensee does not consider the camcorder to be a small hand tool and they believe that the camera handstrap serves the same function as the lanyard. In addition, they believe that the requirement for lanyarding material only applies to small items which would be difficult to retrieve and offered several examples to illustrate their point.

The licensee took additional corrective action by issuing a new procedure, Conduct of Refueling Floor Activities for Outage B211R1, dated March 24, 1994. This procedure delineates duties and responsibilities of individuals working on the refueling floor. The inspector will follow the licensee's control of contractor activities to determine the effectiveness of their corrective actions.

On March 23, the inspector observed the uncrating, inspection, and storage of six new fuel elements. Four of the new fuel elements

(Serial numbers YJ8591, YJ8592, YJ8600, and YJ8602) were placed in a new fuel storage vault. Fuel elements (Serial numbers YJ8611 and YJ8607) were placed in the SFP at locations E6f1 and E6f2, respectively.

The inspector reviewed the following work package documents:

WR/JO 94-ABUS 2	New fuel inspection
OSPP-FUE 501, Rev. 4	Receiving and handling of new fuel bundles
OFPP 014, Rev. 7	Control of combustibles, transient fire load, and ignition sources
OSPP-RPV 501, Rev. 8	Reactor vessel (and associated components) disassembly for refueling
2MST-CR51R, Rev. 2	Operating and visual inspection of reactor building crane.

The inspector observed that the craft reviewed applicable procedures prior to commencing work. Procedures were followed and the work effort proceeded smoothly. The bridge SRO verified the serial numbers of the two fuel cells which were placed in the SFP. The SRO also changed the location of Serial Number YJ8611 when it was found that hoses were cluttering the planned location in the SFP. The inspector concluded that the work effort was safely performed with adequate controls.

On March 30, the inspector observed the removal of the reactor pressure vessel (RPV) head. He also observed some of the required preparations, including briefings and strong-back attachments. The licensee did an excellent job in the pre-job and health physics briefings. The work proceeded cautiously and smoothly. The procedure was at the job site. Discussions with the contractor's project manager indicated that he clearly understood the licensee's expectations and he had communicated those to his staff.

On March 31, the inspector observed preparations for the acceptance testing for the refueling bridge modifications, Plant Modification 92-002. These included the removal of the fuel pool gates. The outer gate required considerable effort to remove. It appeared to be binding and could only be moved in incremental stages. The inspector noted a buildup of an unidentified material on the gate that appeared to be the result of oxidation. The inner gate was readily removed.

The refueling bridge acceptance testing was performed by GE and accomplished by WR/JO 92-AKDQ4. The WR/JO directed that the test be performed over the core and would test the bridge travel limits. The testing was accomplished by GE documents RDE 62-1291, Startup Test, and GENE 771-14-0294, Unit 2 FANUC Logic Test. PM 92-002, Sections 7.11 - 7.13 delineated the acceptance tests which included the above two tests as well as OPT-18.1, Refueling Position Interlock Check. The inspector reviewed the above documents and noted that PM 92-002, Step 7.13 required the complete performance of OPT 18.1. Discussion with the GE Test Engineer revealed that the testing using procedure RDE 62-1291 duplicated the non-load testing portions of OPT 18.1. The licensee's engineering department evaluated the test and PT requirements and revised PM 92-002 to eliminate the test duplication. The GE acceptance testing was acceptable after the adjustment of several limit switches which the inspector observed.

On April 1, the licensee commenced the remaining sections of OPT 18.1 and found that they were unable to position the refueling bridge over the core. While troubleshooting, the licensee determined that a logic problem prevented the bridge from positioning over the core. A drawing error had caused the logic problem. The licensee determined that a cable was depicted with reversed leads at one end and was wired in accordance with the drawing. The discrepancy was repaired and OPT 18.1 was completed successfully at 12:20 AM on April 2. The inspector observed portions of OPT 18.1 and noted that the position interlocks were functioning properly. He noted that there was adequate support for the refueling bridge testing and the work was performed diligently and safely.

d. Outage Teamwork Meeting

The licensee conducted a series of meetings designed to develop teamwork and convey management expectations with the plant and contractor employees who will be involved with the current Unit 2 refueling outage. The outage organization and responsibilities, scope changes, risk assessment, material exclusions, and schedules were discussed. The inspector attended several meetings and the subjects were adequately addressed. He noted that the meetings were well received and appeared to be beneficial.

e. Engineered Safety Feature System Walkdown (71710)

On March 14, 1994, the inspector completed an electrical and valve lineup walkdown for the Unit 1 core spray system. The inspector verified that all components were positioned in accordance with Operating Procedure 1-OP-18, Core Spray System Operating Procedure, Revision 24. He walked down and verified proper component position for all accessible portions of the system including a control board walkdown to verify proper indication. He also reviewed the documented system lineup procedure to verify that those components located in inaccessible locked high radiation areas or in the drywell were properly positioned.

The inspector found that the system was properly aligned and in agreement with the current revision of the operating procedure. The material condition of the system was good, all components were clean, clearly labeled, exhibited no signs of leakage or material degradation, appeared to be in good working order, and had been recently painted. No significant discrepancies were identified during this system walkdown.

f. Configuration Control

In recent months, the licensee has continued to experience a number of events in the area of proper configuration control. The inspector reviewed Adverse Conditions Reports (ACRs) which were generated for configuration control problems identified during the period of January, 1993 through March, 1994. The number of events has remained relatively constant for the past 15 months with an average of 6 events per month, which demonstrates the ineffectiveness of the licensee's previous corrective actions.

Configuration control problems can be characterized into two areas. The first area involves clearances. This had been a problem, but the licensee's corrective action has resulted in some improvement in this area. The second area involves valves and components identified as not being in their required positions. The licensee has identified an increasing trend in valves/breakers being found in the incorrect position.

The following are examples of valve/component mispositioning events:

On February 27, an auxiliary operator (AO) found Unit 1 Instrument Air Isolation Valve, 1-RNA-IV-2627, in the closed position versus the open position, as required by Attachment 1 to Operating Procedure, 1-OP-46, Revision 77, Instrument and Service Air System Operating Procedure. The unit was operating at 100% power and the Instrument Air System was aligned for normal operation. This system supplies instrument air to operate valve 1-CAC-V216, Hardened Wetwell Vent Overboard Isolation Valve. Valve 1-CAC-V216 is an air operated valve which may be opened to relieve containment pressure in the event of an accident. Instrument air to CAC-V216 valve was isolated as a result of the closure of valve 1-RNA-IV-2627. However, because backup nitrogen was still available for the operation of 1-CAC-V216, the safety significance of this event was minimal.

Preliminary licensee investigation revealed that Procedure 1-OP-46, had been completed and signed off as satisfactory on September 19, 1993. However, the investigation was inconclusive as to the cause of the valve mispositioning. This event was documented by ACR 94-077. This is identified as the first example of a Violation of Technical Specification 6.8.1.a: Failure to Implement Procedures (325,324/94-07-01).

On March 13, the licensee discovered valve 2-G42-V011, a vent valve in the suction line from the Unit 2 spent fuel pool (SFP), in the open position when Special Procedure 2-SP-91-047, Installation And Acceptance Testing Of Supplemental Fuel Pool Cooling System, Attachment A, Revision 3, required it to be closed. The SFP Cooling System was in its normal alignment for SFP cooling. This valve is the first of two isolation valves for the vent line on the supplemental SFP cooling system suction line. The safety significance of this mispositioned valve is minimal as the second isolation valve (2-G42-V012) was closed.

Preliminary licensee investigation revealed that the valve in question was left open by an individual who failed to restore the valve to the closed position as required by 2-SP-91-047 on March 12. This event was documented in ACR 94-093. This is identified as the second example of a Violation of Technical Specification 6.8.1.a.

On April 1, an AO discovered valve 1-SW-V58, the 1A Conventional Service Water (CSW) pump discharge pressure gauge root isolation valve, open when 1-OP-43, Service Water System Operating Procedure, Attachment 1, Revision 46, required it to be closed. Closing of this valve was intended to prevent damage to the gauge caused by pressure spikes during pump starts. The safety significance is minimal because of the valve's purpose.

Preliminary licensee investigation revealed that the service water pumps are being replaced under an ongoing Plant Modification, 82-221L with 1A CSW pump scheduled to be replaced in June, 1994. When the modification is completed, the 1-OP-43 required valve position will be changed to open. However, preliminary investigation could not determine the exact cause of this valve mispositioning. This event was documented in ACR 94-420. This is identified as the third example of a Violation of Technical Specification 6.8.1.a.

Clearance issues also affect configuration control and continue to be a problem. The following are examples of recent clearance related configuration control problems:

On March 29, with Unit 2 in Mode 5, the control room operators received two alarms, HPCI Logic Bus "A" Power Failure and HPCI Condensate Storage Tank Water Level Low. Following the receipt of these alarms, HPCI Torus Suction Valves, 2-E41-F041 and 2-E41-F042 automatically opened. HPCI was aligned to the Condensate Storage Tank, at the time of this event, the torus was being drained for maintenance. These two alarms and the associated valve openings were a direct result of de-energizing the HPCI Relay Logic Feeder Circuit Breaker, 2-4A-13, while hanging clearance 2-94-791A.

The licensee's investigation indicated that the clearance preparer knew that de-energizing the HPCI Relay Logic Feeder Circuit Breaker would result in de-energizing HPCI logic bus A. The preparer failed to adequately address or identify the further consequences of de-energizing the HPCI logic bus A. This event was documented by FACTS 94-00410.

On March 16, the licensee found valve 2-SA-V943, the Pilot Air Service Valve, closed when it was required to be open. During cancellation of clearance 2-93-2641 on the Unit 2 Service Air Dryer, the 2A, 2B and 2C Joy air compressors auto started and assumed service air loads. However, the anticipated Service Air Header low pressure alarm did not annunciate. During the trouble shooting, an AO found the 2-SA-V943 valve in the closed position. This valve provides control air to the pneumatic controls of various valves on the air dryers. The licensee has not determined the exact cause of this valve misposition. This event was documented in ACR 94-095.

On March 30, the Unit 1 Hydrogen Water Chemistry (HWC) System tripped while at 100% power. Unit 2 personnel prepared a clearance for work on MCC-2TA which supplies power to both units' HWC systems. While hanging the clearance, MCC-2TA was de-energized which resulted in a trip of both HWC systems. Licensee investigation revealed that the clearance preparer failed to realize that MCC-2TA powered both units' HWC systems. This event was documented in ACRs 94-105/107.

The immediate corrective action in all the above events included re-alignment of the respective valves to their proper positions and performance of visual inspections to determine if there were other mispositioned valves in the surrounding area. The immediate corrective actions were generally adequate and effective. Additionally, the licensee's emphasis on being more observant of abnormal conditions has been successful, in that mispositioned components are being identified by AOs during their rounds.

Based on the number and continuing trend of equipment/valve misposition events, an Operations Management Team was established on March 9, 1994, to look into the problem. The team initiated a detailed study of mispositioned equipment/valves from October 1, 1993 to February 28, 1994. During that period, 23 configuration control failures were identified. In looking at these events, the team determined that there were five common causes which contributed to equipment mispositions:

- Lack of a required Operations review of field revisions to plant modification acceptance tests.
- Needed improvements to the locked valve program.
- Operations personnel only conducted a "courtesy review" of the other unit Special Procedures.
- Inadequate communications and turnovers.
- Configuration control problems related to clearances.

Based on the results of these findings, the team and Operations management implemented the following long term corrective actions to address these common causes:

- Technical Support was assigned the responsibility for all acceptance tests, as outlined in plant procedure MAP-006, Preparation, Review, Approval, and Performance of Post Modification Test Procedures.
- The Operations Projects team will develop a program to determine, identify, and control the positions of locked valves.
- Operations established a policy requiring a Technical Review versus "courtesy review" be performed on all Special Procedures.
- The Operations unit or sub-unit managers were required to brief all operators on expectations regarding communications and turnover. The following were stressed/reinforced:

    - The importance of thorough, adequate, and complete verbal communications and turnovers.
    - The importance of complete and detailed log entries.
    - The importance of self-checking.
    - Establishing the habit of "backing one another up".

- The requirement for performing valve lineups inside clearance boundaries when restoring systems to normal alignment following maintenance - included will be the revised philosophy that components requiring repositioning during this process not be considered as mispositioned.
- Operations ownership and accountability for the position verification of all plant equipment.
- Revision to clearance Procedure, AI-58, effective March 21, 1994, provided the following configuration control enhancements:

    - Eliminate the use of clearance tags for configuration control.
    - Generated an equipment control procedure, AI-58.2, providing a defined means for control of equipment using yellow configuration control tags.

The team also developed a performance indicator and established a goal of zero level 1 and 2 ACRs and 2 or less level 3 ACRs per month.

One violation with several examples was identified in the area of configuration control.

g. Unit 2 Refueling (60710)

Unit 2 commenced reducing power on the evening of March 25, in preparation for the 92 day scheduled refueling outage.

The Unit separated from the grid at 3:00 AM on March 26, entered mode 2 at 5:44 AM, mode 3 at 1:37 PM, and mode 4 at 11:36 PM, on the same day. It was noted that Unit#2 had operated continuously for 313 days at 100% power since being restarted in April of 1993, following an extended outage for repairs. This was the longest continuous run in the unit's history.

On March 27, the inspector toured several areas of Unit 2 that had been inaccessible during power operations. The inspector noted little evidence of system leakage or significant degradation during the extended power run. Discussions with Health Physics personnel indicated that radiation levels in the drywell and RHR rooms are higher than anticipated. It appears that the radiation levels in the drywell have increased by a factor of two to three over the previous outages. The levels on the 38 foot elevation are reading about 200 mR/hr general area versus past outage readings of approximately 75 mR/hr. The recirculation risers are reading approximately 2 R/hr. The licensee plans to decontaminate the recirculation system and risers in early April.

The inspector verified that RHR loop A was correctly aligned and in use for shutdown cooling and that RHR loop B was in use for suppression pool cooling. The inspector also followed the activities associated with drywell head removal. During the detensioning of the drywell head hold down bolts the licensee experienced several problems associated with the detensioning equipment and personnel expertise which resulted in a 30 hour delay in completing this task. This is documented in ACR 94-103. The reactor vessel head hold down bolts were detensioned on March 29, and the unit entered Mode 5. No significant deficiencies were identified during the above activities.

h. Refueling Activities (60710)

At 12:40 a.m., on April 2, the control room SRO authorized core alterations. The first fuel bundle (LYE362) was removed from the core 16 minutes later. The operator was unable to place it at location G01 in the SFP because the location was obstructed by the splash ring on the supplemental SFP cooling piping. The refueling SRO requested an alternate location. The Core Component Sequence (move) sheet was modified and the first fuel bundle was placed in the SFP at 1:33 AM.

On April 4, fuel movement was suspended at 7:30 AM due to a mispositioned fuel bundle in the SFP. The licensee determined that step 267 of the move sheet was prematurely signed off as being complete and the fuel bundle was placed in the SFP location for the next step. Six steps later, it was discovered that the fuel bundle in step 268 had not been removed from the core. The licensee immediately initiated an investigation and assembled all interested and involved individuals to review the event. A Site Investigation Team (SIT), headed by the Unit 1 Operations Manager, was assembled. The inspector attended the combined counselling and investigation meeting. It was determined that the refueling SRO had the only move sheet on the bridge and the spotter keyed from the SRO's initials. GE personnel stated that at other sites, both the spotter and the SRO had move sheets. It was concluded that there was not independent verification as both individuals worked from the same document. The SIT also determined that communications between the refueling bridge and the control room were not sufficiently detailed in that only the commencement and completion of steps were communicated.

The licensee's corrective actions were to counsel the involved individuals, brief all refueling personnel of the event, issue separate move sheets to the SRO and spotter, the spotter is to key off his move sheet, and communications with the control room will be more detailed in that the component and locations will be identified. The inspector reviewed the SIT report and considers that the two move sheets should provide more independence and more detailed communications which should provide an additional barrier with the control room. Fuel movement was recommenced at 3:50 PM on April 4, 1994.

The inspector concluded that the meetings and investigation were timely and thorough. They allowed the licensee to arrive at a root cause, implement corrective actions, and recommence fuel movement with minimal disruptions.

i. Review of Operations LERs (92700)

(Closed) LER 1-93-011, Inadequate Clearance Boundary Results in Unplanned Multiple Control Rod Insertions During Scram Discharge Volume Hydrostatic Test.

The licensee performed a root cause analysis and determined that the following factors contributed to this event:

- Operations developed a clearance that relied on compensatory actions to prevent rod movement.
- Technical Support was unaware of GE lineup recommendations.
- A lack of formal communications between the system engineer and Operations contributed to the HCUs being over pressurized by 380 psig.
- Although required by the Daily Instructions, operators failed to check the pressure of the HCU accumulators under clearance prior to inserting the scram.
- The late reporting of this event was attributed to an inadequate Operations review of OI-51, NRC 1-hour, 4-hour, and 24 hour Reporting Requirements.

- An inadequate management review of plant conditions and the appropriateness of performing the test.

Subsequent investigation by the licensee revealed that the performance of the test had been influenced by schedule pressures. The licensee's corrective actions were as follows:

- A Director of Site Operations memo to site management dated October 15, 1993, emphasizing that both risk and schedule must be evaluated.
- Operating Procedure OP-08, Control Rod Drive Hydraulic System Operating Procedure, for both units was revised on January 19, 1994, to include steps for HCU isolation with cooling water flow in service.
- All shift operators were briefed by Operations management on this issue.
- Special Process Procedure OSPP-HYDRO500, Pressure Testing of Pipe and/or Vessels, Revision 2, was issued January 27, 1994, to include required reviews of system configurations.
- The involved individuals were counselled.

The inspector reviewed the documentation and discussed the event and corrective actions with licensee personnel. In addition, the inspector attended several of the Operations' briefings. The licensee's root cause analysis was adequate and the corrective actions were effective.

j. Licensee Action on Previous Operations Findings (92701, 92702)

(Closed) Violation 325/93-16-02, Failure to Follow OP-8 CRD Venting Procedure. The event occurred when a reactor operator assigned to vent 30 control rods took further action, believing it was permitted under general operating guidelines, and moved the control rods additional steps after completing the prescribed venting movement. During this evolution, he apparently became distracted and failed to return one rod from the 02 to 00 position. The rod remained at that position for several hours before being discovered and repositioned.

The licensee, in a letter dated May 28, 1993, responded to the above Violation. Their short term corrective actions were to stop work and brief their crews on the event; require a second checker to verify rod pulls; increase checking of all rod positions to twice a shift; and counsel the involved reactor operator. The long term corrective action revised the Control Rod Drive Hydraulic System Operating Procedure, OP-8, to ensure that the shift supervisor, senior control operator, and nuclear engineer are aware of rod manipulations; require independent verification that control rods are left in their correct position after manipulation; and add steps to place the rod worth minimizer in test when HCUs are vented to enable the one-rod-out interlock. Revision 31 was issued on April 23, 1993, to incorporate this action. In addition to the above, this event was included in the 1993 LOR Phase 2 training for licensed operators. The inspector verified that the above actions had been completed. This appears to be adequate to prevent repetition of this event.

No other violations or deviations were identified.

3. Maintenance and Surveillance

a. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance. The inspectors observed/reviewed portions of the following maintenance activities:

- PM-82-220L 2B NSW Pump Replacement
- PM-91-041 Emergent Structural Repairs SW Bldg.
- PM-91-070 U1 DG SW Piping Replacement
- PM-91-071 U2 DG SW Piping Replacement

PM-91-070 and PM-91-071 are discussed in paragraph 4a. No deficiencies associated with the first two modifications were identified.

b. Equipment Temporary Storage (38702)

The inspector and licensee have identified recurring issues involving temporary storage. These include unprotected pipe openings and threads, unidentified material, unsegregated material, and improper storage. The licensee has responded to each individual instance but has not been fully effective in correcting this situation. Approximately 18 months ago, the licensee established a task force to develop a procedure for control of in-process materials. On March 3, 1994, Procedure 0AI-128, Control of In-Process Materials, Revision 0, was issued.

On March 11, 1994, the inspector observed a temporary storage area on the 50 foot level of Unit 2 by the RBCCW heat exchangers which was designated a "Q" storage area for Plant Modification, PM 93-032. The storage area contained a gang box, piping for the reactor vessel level modification, an air hose, an extension cord, and other unmarked material. The air hose and extension cord were stacked on the piping.

The licensee immediately corrected the identified deficiencies when informed by the inspector. Licensee management toured various spaces and identified other examples of not meeting temporary storage requirements. This issue has been discussed with craft supervisors and the licensee has implemented management/supervisory tours. The inspector has reviewed the tour summary reports and noticed that the licensee's efforts have resulted in some improvement in this area.

c. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, and record review the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspector witnessed/reviewed portions of the following activities:

OPT - 12.2C	No. 3 Diesel Generator Monthly Load Test
1 MST-APRM-11W	APRM (Ch. A, C, & E) Channel Functional Test (RPS Inputs)
1 MST-IRM-23R	IRM Channels B & D Calibration Test
OPT 18.1	Refueling Position Interlock Check

No deficiencies were identified during these tests.

d. Review of Maintenance LERs (92700)

(Closed) LER 1-93-08, Severe Winter Storm Results in Spurious ESF Actuation and a Loss of Off-Site Power.

On March 13, 1993, while Units 1 and 2 were in cold shutdown, spurious Emergency Safeguard Features (ESF) system actuations occurred on both units. The actuations were caused by on-site electrical distribution system voltage depressions. These depressions were due to the simultaneous loss of two of four Unit 1 and one of four Unit 2 incoming transmission lines. The licensee concluded that the loss of the two Unit 1 offsite 230 KV feeder lines was caused by a faulty weather proofing impregnation process (Cellon) of wooden transmission poles. The Cellon application did not thoroughly penetrate the poles, which allowed the centers to deteriorate. The weakened poles were unable to support the high wind loadings and two poles within one mile of the switchyard fractured. This allowed one feeder to come in contact with an adjacent feeder line causing the site feeder breakers to trip and lockout. The failure of the support structure also caused deflection of crossing transmission lines resulting in the loss of one of four Unit 2 off-site power sources.

A study and thorough inspection of the transmission line support structures were done by the licensee to ensure the reliability of the transmission lines. For Unit 1, the failed and weakened poles have been replaced. Besides the immediate replacement of fractured poles, the balance of weakened poles will be replaced during the current Unit 2 refueling outage.

On March 16, 1993, as a result of the March 13 winter storm, a Loss of Off-site Power (LOOP) occurred due to excessive salt build-up on switchyard insulators. The immediate corrective actions taken included cleaning of the switchyard and transformer yard equipment and insulators. As the result of an extensive study on salt build-up in the switchyard and transformer insulators, the licensee decided to use RTV (Room Temperature Vulcanizing) Silicon coating of the switchyard insulators to prevent future salt build-up. This was completed on Unit 1 in 1993 and is scheduled for completion on Unit 2 during the current outage.

During the March 13 winter storm, the TSC diesel generator shut down due to fuel supply problems. This resulted in a loss of AC power to the site (ROLM) phone system battery charger. Approximately one hour after AC power was lost, Node 2 of the ROLM phone system became inoperable. This resulted in the loss of the TSC phones, the Automatic Ringdown (ARD) phone circuits between the plant control room and TSC, and the ARD circuits between the plant control room and the dispatcher at Skaale Energy Control Center. An investigation into the cause of the ROLM phone failure and the associated battery backup system capacity during this storm was performed. This investigation included a TSC telecommunication system battery capacity test which revealed that back-up battery capacity would only provide power for approximately one hour. To improve the reliability of TSC communications, an eight-hour battery backup system was installed.

During the LOOP recovery effort, delays in de-energizing and restoring electrical equipment were encountered. A review and evaluation revealed that these delays resulted from the inflexibility of the clearance process to allow qualified personnel, other than plant operations, to switch and tag appropriate equipment. As a result of the evaluation, training of all on-shift operators on the execution of the clearance process during a LOOP event including the dispatcher and Wilmington Area Transmission Maintenance interface process was performed. In addition, the clearance required to recover from a similar event has been prepared and is ready to be implemented when needed. The above completed and scheduled actions are adequate to address this issue and this item is closed.

(Closed) LER 1-94-02, Control Building Emergency Air Filtration Trains Rendered Inoperable by Frozen/Plugged Instrument Air Dryer Line. This event occurred when the instrument air dryer lost its refrigerant charge due to a small leak which resulted in a moisture buildup in the instrument air lines. The moisture froze during extremely cold weather and rendered the CBEAF system inoperable. The dryer was bypassed and the system was returned to service upon discovery of this problem. A root cause investigation found that this was caused by poor dryer maintenance.

The licensee's corrective action for this item established a preventive maintenance route to ensure that refrigerant pressure is properly maintained. The inspector verified that PM route 12-M-SL-089 had been established to verify refrigerant pressure on a quarterly basis. This action appears adequate to keep refrigerant pressure within the vendor's recommended range of 33-37 psig suction pressure. This completed the corrective actions listed in the LER.

(Closed) LER 2-93-07, ADS Relays Energized Due to VOM Improperly Set During Performance of an MST. This event occurred when a test technician attempted to perform a monthly channel calibration on an RHR pump discharge pressure automatic depressurization system (ADS) permissive instrument with the volt/ohm meter (VOM) set on the OHM scale rather than VDC scale. With the VOM set on the OHM scale, it acted as a jumper and completed the ADS logic. The operator was aware that this test was being conducted and when he received the annunciator, he inhibited ADS from actuating. The licensee's corrective actions for this event included disciplinary action for the involved individual and discussing the event with Unit 1 and Unit 2 maintenance personnel to increase their awareness of the potential for this or a similar occurrence. The inspector reviewed the training attendance records and verified that this event had been included in routine maintenance training. The above actions appear appropriate to prevent a recurrence of this event.

e. Licensee Action on Previous Maintenance Findings (92701, 92702)

(Closed) Violation 325,324/92-21-01, Housekeeping Standards Not Adequately Implemented. This item occurred when mechanics were found using the 2C conventional service water pump discharge check valve (2-SW-V23) as a work surface with the valve internals exposed resulting in maintenance debris introduced to the internals. The licensee, in letters dated September 21 and October 12, 1992, responded to the above violation. The licensee, as a result of the above, evaluated their housekeeping and applicable maintenance procedures and determined that they were adequate. ACR No. 92-543 was written to document the issue and the ACR was reviewed with all maintenance crews. The inspector reviewed the attendance sheets and has not observed additional examples of working over open surfaces. The inspector concluded that the licensee's corrective action was effective.

Violations and deviations were not identified.

4. Engineering Support

a. Diesel Generator Service Water Piping Modification (37828)

The licensee's long range service water piping improvement program includes the replacement of the carbon steel concrete lined piping that cannot be visually inspected and/or easily repaired, with copper nickel piping to reduce the long term corrosive effects of salt water. The scope of this replacement encompasses the supply piping from the Units 1 and 2 nuclear service water header to each diesel generator (DG) jacket water cooler and the return piping from each jacket water cooler to a discharge line tie in outside of the DG building.

The above projects are being accomplished through four modification packages which include:

Plant Modification PM 91-070 - Unit 1 DG SW supply lines. An underground branch line has been installed from the nuclear header, approximately 50 feet north of the DG building to the basement of the DG building. This piping was installed in 1992 during the Unit 1 outage. A manual isolation valve was installed on this line in the DG basement. A supply header has recently been installed that runs north and south along the east basement wall about 2 feet off the floor. At each DG, a 6 inch branch line will rise through the 23 foot floor slab and terminate in the motor operated valve/check valve station prior to joining the Unit 2 supply piping. A common 6 inch line will then supply the jacket water cooler. This piping has been installed up to the MOV/check valve and was successfully hydrostatically tested on April 1, 1994.

Plant Modifications PM 92-047 and PM 91-071 - Unit 2 nuclear SW header tie in. A flanged tie in connector was installed into the Unit 2 nuclear service water header in No. 4 fuel oil tank storage room in 1992 during the repair of a leak in the existing nuclear service water line. A new line has been installed between this flange and the DG south end basement. This line will enter the DG basement and run to the north end of the basement with 6 inch branch lines going up to each DG MOV/check valve station described in modification, 91-070. This new piping was installed during power operation in 1994.

Plant Modification PM 91-072 - Unit 1 common DG return lines. This project will be accomplished after completion of supply piping installation.

The above projects were planned and are being accomplished in phases. The tie in to Unit 1 NSW was done while the system was out of service during the Unit 1 outage in 1992-93. The tie in to Unit 2 was accomplished during a system leak repair in 1992. The piping running up to each DG existing piping was done in January, February, and March of 1994, while the units were operating at power. The current plan will shift the MOV/check valve station on DGs 3 and 4 and tie in the new piping during the current Unit 2 refueling outage (B211R1). DG 1 and 2 piping will be tied in during refueling outage B110R1 in 1995. The old piping will be removed after the above outages while the units are at power. The return piping will be installed during the above time but will not be tied in until refueling outages B212R1 and B111R1.

The inspector observed the installation of the replacement piping from Unit 1 and Unit 2 Nuclear Service Water Headers as it was being installed in 1992 and 1993. He observed the at-power piping and pipe support installations on a frequent basis as they progressed in early 1994. He noted that special precautions were taken by plant operators to permit this work while the units were at power. A standing instruction required frequent inspections by the auxiliary operators and a notification to the shift supervisor of any change in work scope or schedule to ensure that these activities did not render a diesel inoperable. The inspector verified that the above inspections were being made and the precautions enforced. The inspector also verified that applicable compensatory measures were established when core drillings penetrated building walls and fire barriers. The inspector also noted that parts and material used for this work was properly stored and protected. The inspector verified that weld rods associated with the work were of the proper type and maintained in weld caddies and gas purges were used as needed for pipe welding activities. The inspector observed the hydrostatic test on the piping and found it to be satisfactory. Overall, the task was well planned, worked by competent and motivated people and was completed on time. No significant deficiencies were identified during the above work activities.

b. Safety Parameter Display System

On March 4, 1994, the licensee initiated Adverse Condition Report (ACR 94-085) to identify and document that the ERFIS computer (Safety Parameter Display System (SPDS)) does not meet the system design criteria of NUREG 696, Functional Criteria for Emergency Response Facilities or Supplement 1 to NUREG 737, Clarification of TMI Action Plan Requirements. NUREG 696 requires the system to have a short term accident data storage capability of 14 hours (2 hours pre-event and

12 hours post event). The system currently has a 7 hour data storage capability. The ACR also identified the fact that the system does not meet the required 99% (run mode) availability as required by NUREG 737, Supplement 1. Currently system run mode availability is between 80 and 85%.

Initial investigation into the issue indicated that this is not a recent problem, but has been previously identified at least two previous times by the licensee in ACR 93-059 and in Non Conformance Report A-89-03. The NRC also identified these and other initial system deficiencies in the post implementation audit of the system conducted in 1989. In a letter to the NRC dated December 11, 1991, the licensee reported the SPDS system operable as of October 2, 1991, and certified to fully meet the requirements of NUREG-737, Supplement 1. In light of the latest ACR, the licensee is currently researching the issue in an attempt to resolve these deficiencies. Based on this ongoing activity, the inspector will continue to follow the licensee's review and investigation of this issue. This item is identified as an Unresolved Item (325,324/94-07-02), SPDS Does Not Meet Design Criteria.

c. Review of Engineering Support LERs (92700)

(Open) LER 1-94-05, (Voluntary) Potential Use of Less Conservative Pressure Temperature Limit Curves.

On August 17, 1993, a surveillance capsule was removed from the Unit 1 reactor pressure vessel (RPV) for metallurgical analysis. This capsule was the first capsule removed from either RPV. The licensee contracted GE to perform the analysis. On February 17, 1994, GE informed the licensee that they believed the capsule they were examining should have been located in the Unit 2 RPV. The licensee immediately began an investigation and preliminary results indicated that the correct capsule was analyzed. Further review of the GE Nuclear Engineer Design Organization documents which form the basis of the pressure temperature limit (PTL) curves indicates that the Unit 1 PTL curves may be based on Unit 2 vessel material data and vice-versa. If the above indications are valid, Unit 1 may have operated with less conservative PTL curves. ACR 94-075 was initiated to document this event. The ACR's corrective actions are focussing on:

- Researching RPV fabrication and turnover records to determine if a documentation error occurred.
- Reviewing Unit 1 heatup and cooldown records to determine compliance with Technical Specifications. Unit 2 data is not being reviewed as its PTL curves are more conservative.
- Determine corrective actions as necessary.

Initial heatup and cooldown reviews indicated that one Unit 1 hydrostatic test conducted on January 24, 1991, exceeded the more conservative Unit 2 PTL curves by one to two degrees for a period of two and one-half hours. No safety limits were exceeded.

The historical review indicated that RPV No. 2471 was set for Unit 1 and RPV No. 2472 was set for Unit 2. The surveillance specimens were installed into surveillance baskets and designated as G1, G2, and G3 for RPV No. 2471 and marked with a binary code representing "38." The capsule removed from Unit 1 was G1 with a binary code "38." However, the NEDO documents list RPV No. 2471 as being installed in Unit 2. The licensee believes that the NEDO documents are incorrect and the construction documentation is correct. They plan to verify the unit 2 RPV serial number during the current refueling outage. Initial review by GE indicates that no significant safety issue resulted from the switched curves. The licensee has issued a Standing Instruction requiring both units to use the more conservative Unit 2 PTL curves until this issue can be resolved.

(Closed) LER 2-92-01, Unit 2 Scram During Main Turbine Control Valve Testing. On February 2, 1992, with reactor power at 80%, Unit 2 scrammed while testing the No. 2 Turbine Control Valve (TCV) during the performance of PT 40.2.5, Turbine Control Valve and Extraction Steam Stop Valve Testing. The scram occurred due to the actuation of an EHC Reactor Protection System pressure switch. A preliminary investigation revealed that the EHC accumulator piston seals had been subjected to excessive cyclic wear due to the hydraulic oscillations in the EHC system. The oscillations were caused by instability in the EHC system pressure regulator after the conversion from full arc to partial arc admission. The investigation revealed that the new valve curves used for partial arc admission were designed for a reactor output of 105%. The power uprate modification to 105% had not been performed which caused the new valve curves to be inaccurate for the actual operating power level. The resulting turbine instability caused TCV oscillations that led to EHC accumulator seal failure. The licensee's temporary remedial action was to reduce power to a lower level so that TCV No. 4 would not open. The final corrective action was to convert from partial arc-2 step to partial arc-3 step admission. The licensee's corrective action also included maintenance on the accumulators and modifications to eliminate "noise" in the EHC electronics.

The inspector reviewed the GE Service Report TB.S/N 170X470 for the Unit 2 EHC system checkout and startup, dated May 29, 1993. The vendor determined that the modified EHC system was performing as expected. The inspector attended many of the technical discussions between the licensee and the vendor to resolve technical issues.

The inspector also reviewed the following completed WR/JOs for TCV hydraulic operators:

92-AGAFI 93-AFSY1	TCV No. 1
92-AGAT1 93-AFSZ1	TCV No. 2
92-AGAK1 93-AFTA1	TCV No. 3
92-AGAL1 93-AFTB1	TCV No. 4

The inspector found that the WR/JOs were adequate and the licensee work performed during the outage was acceptable. The EHC system was tested and performed well during startup. The system operated satisfactorily after the final adjustments and system tuning during startup. This item is closed.

Violations and deviations were not identified.

5. Plant Support

a. Radiological Controls (71707)

The inspectors verified that the licensee's HP policies and procedures were followed. This included routine observation of HP practices and a review of area surveys, radiation work permits, posting and instrument calibration. No deficiencies were identified.

b. Unit 2 RHR System Decontamination (71707)

To reduce personnel exposure, the licensee has implemented an aggressive decontamination program. This program includes the removal of the active corrosion product layer on the interior surfaces of piping and components. This removal will reduce local and area radiation levels and improve personnel accessibility for routine and outage work activities. These activities have been underway for the past two years and have included the decontamination of the reactor recirculation system piping on both units and the Unit 1 RHR system piping.

The decontamination of Unit 1 RHR piping was performed after the unit had been in an extended shutdown and a very low heat removal demand existed. Due to constraints that exist during the upcoming Unit 2 refueling outage, B211R1, i.e. replacement of four RHR valves, core shroud repairs, jet pump hold down beam replacement, in vessel inspections, and refueling, the licensee determined that waiting until the fuel was removed from the vessel would add at least seven days to the outage and result in added exposure to personnel involved in work activities. Based on the added exposure and cost of extending the outage, the licensee performed an engineering evaluation and a probabilistic safety assessment to determine if they could decontaminate the RHR system prior to the Unit 2 shutdown.

EER 93-0640 documented the acceptability of installing temporary valves to isolate the RHR system from the chemical decontamination unit; evaluated the effects of the chemicals on seal materials of the RHR pump and shaft seals and determined the acceptability of performing this process with Unit 2 on line at 100% power. This EER also included the 10 CFR 50.59 evaluation and the risk assessment for accomplishing this task on line.

The inspector reviewed EER 93-0640 including the associated risk assessment and 10 CFR 50.59 evaluation. Additionally, the inspector held discussions with the engineer who performed these assessments and with the system engineers and team members assigned to accomplish this task. All questions and apparent concerns were answered satisfactorily. The inspector also attended the licensee's presentation to NRC Regional Management on this issue on January 24, 1994, in the Atlanta regional office. The inspector attended the PNSC meeting where this issue was presented on February 10, 1994. Several questions and concerns were voiced by the PNSC. Each of these concerns were satisfactorily addressed prior to final approval of this process. The inspector noted that the PNSC review of this issue appeared to be comprehensive.

After reaching a conclusion that this task could be safely performed while the unit was at power, the licensee developed special procedures and assigned a task force to perform this task. The special procedures included:

- 2SP-93-072 - Set Up of Chemical Decontamination Equipment
- 2SP-93-073 - A-loop Decontamination
- 2SP-93-074 - B-loop Decontamination

The task force assigned to accomplish this task included day and night shift teams composed of dedicated project managers and supervisors from the E&RC area, auxiliary operators, mechanical and electrical maintenance, technical support system engineers, health physics, craft labor, and vendor equipment representatives. These people had no other duties during the time they were assigned to this project.

System recovery and contingency plans were developed and implemented to allow for rapid response to a potential event and provide for timely recovery of the RHR system if required. All of the personnel assigned to this project were given training on the systems and associated project procedures. In addition to the above. measures were established to guard ESF systems while the above project was being accomplished.

The inspector reviewed the above procedures and verified that appropriate measures were in place and implemented during the project to guard ESF systems and allow timely restoration of the RHR system if required.

The decontamination of RHR Loop-B commenced on March 5 and was completed on March 8. RHR Loop-A commenced on March 12 and was completed on March 14. No significant problems were encountered during these tasks. The 30cm, dose reduction factors on Loop-B ranged from 1.2 up to 3.7 with an average of 2.6. The same readings on Loop-A ranged from 1.2 to 5.6 with an average of 2.9. The licensee's calculations determined that .6 curies of contamination was removed from Loop-B and .8 curies was removed from Loop-A.

The inspector observed the initial set up and connection of the vendor supplied equipment to the RHR system. He held discussions with the assigned project managers, the system engineers, and assigned technicians while the portable equipment was being installed, connected, operated, and disconnected. The assigned personnel appeared to be very knowledgeable on their respective portions and the overall project. The assigned support personnel provided timely and effective response to the only problem, a small leak on a skid mounted heater, when it occurred. Overall, this project was well planned, effectively managed, and accomplished well within the planned time limit without problems. This project resulted in a significant reduction in the radiation level in the RHR system areas and should contribute to a reduction in radiation exposure during the upcoming outage and during future plant operations. The licensee's planning and execution of this project is considered a strength.

c. Security (71707)

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate. No deficiencies were identified.

d. Housekeeping (71707)

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked clearances and verified the operability of onsite and offsite emergency power sources.

During recent plant tours, the inspector has noted that area painting and general upkeep has been slowly deteriorating in Unit 2. While Unit 1 has vigorously pursued general area decontamination, a vigorous painting and overall preservation program, it appears that Unit 2 has decided to defer these items for the upcoming outage. The inspector discussed these observations with several Unit 2 managers and supervisors. They indicated that they were aware of these conditions and plan to address them during the current refueling outage.

As a result of the above, the inspector reviewed security access records to determined the amount of time the managers and supervisors responsible for Unit 2 were actually spending in their assigned plant spaces. This review found that over the past two and a half months, several of these managers had not toured all spaces in their unit and several had spent less than 1 hour per month in their assigned unit spaces. The inspector provided this information to the Site Vice President for his review.

Violations and deviations were not identified.

6. Other Areas (76000)

a. Nuclear Safety Review Committee (40500)

The inspector attended a regular meeting of the NSRC on March 14. The agenda at the meeting included:

- Review of minutes of previous meetings
- Review of action item status
- Review of upcoming meeting schedule
- Presentation on Unit 1 and Unit 2 operations status by the unit managers
- A presentation on the following technical issues by the responsible managers:
    - Unit 2 shutdown outage safety assessment
    - EDBS/Configuration control
    - Storage of high activity radwaste
    - NAD assessments
    - Oversite of vendor QA program
- Review of LERs, violations, etc.
- NAD activities
- Nuclear safety review independent review
- Member comments and observations
- Summary of recommendations

This meeting lasted for approximately 8 hours. The inspector attended for approximately 3 hours and noted that the presentations produced frank and open discussions among the committee membership. The outside members offered several comments and recommendations on issues that were presented. The inspector noted that the outside members provided added value to this organization by bringing a different perspective to the committee.

b. Nuclear Safety Oversite Committee (40500)

The inspector attended a regular meeting of the NSOC on March 15. The agenda included the following:

- Review and approval of minutes
- Industry, CP&L, and NGG items of interest
- Corporate improvement initiatives
- NGG goals and standards on backlogs
- NGG employee survey results and action items
- Brunswick plant status, Unit 1 restart, Unit 2 outage
- Harris plant status, upcoming refueling outage
- H.B. Robinson plant status, plant improvement program, discussion of recent events, report on action items, and expectations of shift technical advisors
- Member comments
- Brunswick plant tours for NSOC members.

This meeting lasted for approximately 7 hours including a working lunch. Mr. K. R. McKee, an outside member, and W. Cavanaugh, President - CP&L, did not attend the meeting. Other topics that arose during the meeting included industry initiatives associated with the Regulatory Burden Initiative; Thermolag and positions being developed by the industry on this issue and how this issue will impact CP&L. Several of the presentations appeared to focus on reducing expenditures and the need to become more cost competitive with other utilities and independent power producers. Overall, presentations made to the committee were timely and well prepared. The inspector was very impressed with the level of participation, the depth of questions, and comments from the outside committee members. They are a definite asset to the committee and should provide assistance to the licensee in their pursuit of improved performance.

c. Plant Nuclear Safety Committee (40500)

The inspector attended the PNSC meetings conducted on March 17 and 24. The inspector verified that a quorum was present. The March 17 meeting agenda included:

- Special Report 1-94-02	Delayed restoration of diesel generator building fire seal
- LER 1-94-05 (voluntary)	Reversal of Unit 1 and Unit 2 heat-up/cooldown curves
- LER 2-94-03	Personnel contamination monitor panel cover falling against relay causing a PCIS Group 10 isolation

- Violation 94-02-02 Response to violation involving a loss of shutdown cooling
- Technical specification administrative change request
- Review of responses to Unit 2 outage shutdown risk assessment

The inspector noted active participation by all PNSC members. The only comments on the proposed special report and LERs were editorial in nature.

The issue involving the loss of shutdown cooling was discussed in detail. The Unit 2 plant manager assigned an action item to determine and evaluate the losses of shutdown cooling that have occurred in the past 2 years and the effectiveness of corrective actions taken to prevent recurrence.

The PNSC action items on the outage risk assessment were discussed in depth. Several of the issue resolutions were accepted and some were sent back for further evaluation and action.

The inspector noted that several excellent questions were asked and the members appeared to be actively challenging the issue presenters and requiring the right answers.

The March 24 meeting agenda included:

- Response to Violation 325,324/94-01-01
- Review of procedure OPT 40.2.9 turbine stop and control valve test
- Unit 2 core shroud modification
- Corrective action plan trend review
- Monthly temporary modification report
- PNSC open action items on Unit 1 shutdown risk assessment

There was very active participation and discussion by all members on the above issue. Several of these items did not require PNSC approval but were presented at the PNSC request to keep them informed on special planned tests or upcoming outage activities. The inspector was impressed with the amount and detail of the questions asked and issues raised by the PNSC.

The inspectors reviewed the minutes for those meetings not attended to confirm that decisions and recommendations were reflected in the minutes and followup of corrective actions was completed. There were no concerns identified relative to the PNSC meetings attended. The resolution of safety issues presented during these meetings was considered to be acceptable.

Violations and deviations were not identified.

d. Plant Management Review Meeting (30702)

The inspector attended the plant management review meeting on March 22. This meeting is a monthly presentation of the plant status, performance, and issues to senior corporate management. The agenda for this meeting included a plant financial review, the status of Units 1 and 2, the planned Unit 2 refueling outage, and the performance of Nuclear Engineering, Technical Support, Operations, Maintenance, and Nuclear Assessment. These meetings are held monthly at each nuclear site to keep senior management informed of each site's performance, plans, and permit corporate to communicate or address issues and expectations. The inspector noted that BNP appears to be meeting the majority of their goals, and it appears that adequate funding is being provided to complete planned plant projects and upgrades. It appeared that all presenters were well prepared and able to address issues that were brought up in the meeting. The inspector found this to be a meaningful update on plant projects and future corporate and site plans.

e. Harassment and Intimidation Training

The licensee provided training on how to maintain compliance with Section 211 of the Energy Reorganization Act and 10 CFR 50.7 and 50.70 to first line supervisors and above. The training was conducted by the Corporate Legal Department in six separate sessions. It focussed on Section 211 and 10 CFR 50.7 which protect individuals from discrimination for having identified an alleged violation of NRC requirements, for having participated in an NRC proceeding, for raising safety issues, and for other protected activities. The inspector attended one of the March 23rd sessions. The training consisted of describing various activities which could be included in the above Regulations, corporate expectations and policies, and supervisory responsibilities in dealing with these situations. The course instructors covered a broad range of examples and solicited class participation. The Site Vice President made opening remarks which reinforced management's support. The inspector found that this training was well developed and provided supervisors with a needed insight in this area.

7. Exit Interview (30703)

The inspection scope and findings were summarized on April 4, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
325,324/94-07-01	Violation - Failure to Implement Procedures (paragraph 2.d)
325,324/94-07-02	URI - SPDS Does Not Meet Design Criteria (paragraph 4.b)

8. Acronyms and Initialisms

ACR	Adverse Condition Report
ADS	Automatic Depressurization System
AO	Auxiliary Operator
BSEP	Brunswick Steam Electric Plant
CBEAF	Control Building Emergency Air Filters
CRD	Control Rod Drive
CT	Current Transformer
CQA	Corporate Quality Assurance
DG	Diesel Generator
EHC	Electro Hydraulic Control System
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
FTE	Full Time Equivalent
HCU	Hydraulic Control Unit
HP	Health Physics
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
IPBS	Integrated Planning, Budgeting and Scheduling
LCO	Limiting Conditions for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-Site Power
MCC	Motor Control Center
mR/hr	Millirem Per Hour
MST	Maintenance Surveillance Test
NAD	Nuclear Assessment Department
NED	Nuclear Engineering Department
NEDO	(GE) Nuclear Engineering Design Organization
NGG	Nuclear Generation Group
NRC	Nuclear Regulatory Commission
NSOC	Nuclear Safety Oversite Committee
NSRC	Nuclear Safety Review Committee
OM&M	Outage Management & Modification
ONS	Onsite Nuclear Safety
OPT	Both Units Performance Test
PA	Protected Area
PM	Plant Modification
PNSC	Plant Nuclear Safety Committee
PTL	Pressure Temperature Limit

QA	Quality Assurance
QC	Quality Control
RBCCW	Reactor Building Closed Cooling Water
RFP	Reactor Feed Pump
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SFP	Spent Fuel Pool
SIT	Site Investigation Team
STA	Shift Technical Advisor
SW	Service Water
TCV	Turbine Control Valve
TS	Technical Specification
URI	Unresolved Item
UT	Ultrasonic Testing
VOM	Volt/ohm Meter
WR/JO	Work Request/Job Order