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June 15, 1984

Office of Inspection and Enforcement
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Mr. R. C. DeYoung, Director

Dear Sir:

Subject: Docket No. 50-362
Response to Notice of Violation and Proposed Imposition
of Civil Penalties
San Onofre Nuclear Generating Station, Unit 3

References: (1) Letter, Mr. J. B. Martin (NRC) to Mr. D. J. Fogarty (SCE), "Notice of Violation and Proposed Imposition of Civil Penalties," dated May 16, 1984

(2) Letter, Mr. H. B. Ray (SCE) to Mr. J. B. Martin (NRC), "Confirmation of Immediate Notification," dated March 17, 1984

(3) Letter, Mr. H. B. Ray (SCE) to Mr. J. B. Martin (NRC), "Follow-Up, Immediate Notification," dated March 26, 1984

(4) Letter, Mr. J. G. Haynes (SCE) to NRC Document Control Desk, "Licensee Event Report No. 84-009," dated March 30, 1984

The referenced letter forwarded a Notice of Violation and proposed imposition of civil penalty based on inspections conducted by Messrs. J. L. Crews, A. E. Chaffee, J. P. Stewart and A. J. D'Angelo during the period March 17 through March 29, 1984. This letter forwards Southern California Edison Company's (SCE) request for remission of the proposed civil penalty pursuant to 10 CFR 2.205 (Enclosure I) and the response required by 10 CFR 2.201 (Enclosure II).

IE:14

Notwithstanding the fact that the violation identified by Reference (1) did not create a significant hazard to the public health and safety, and in the words of the referenced letter, "No serious threat to public health and safety existed during this event...", SCE recognizes the violation as a serious error for which aggressive and effective corrective action is warranted. Our commitment to such corrective action is evidenced by the extensive actions immediately undertaken upon recognition of the error and other corrective actions identified following more thorough review of the error and its cause. These corrective actions have been described in References (2) through (4) and discussed with Mr. J. B. Martin and members of his staff at a meeting on May 3, 1984. SCE remains firmly committed to corrective action to prevent such errors.

However, SCE is gravely disappointed with the characterization of the effectiveness of management controls at San Onofre contained in Reference (1) and objects to a conclusion that the identified violation or other identified incidents suggest such controls are inadequate. Each of these incidents, which were identified and reported by SCE, are instances where an opportunity existed for an individual personnel error to lead to undesirable consequences. Each was an isolated opportunity for an unchecked error. These isolated opportunities occurred in an administrative program which has prevented unchecked error in hundreds of evolutions and activities during the startup of Units 2 and 3. Corrective action was promptly and effectively implemented in each case to require a second check to prevent or immediately detect individual personnel error. These corrective actions and other improvements and refinements we have made to our administrative controls during the successful startup and preparation for commercial operation of the large, sophisticated new units at San Onofre do not represent a legitimate basis to conclude the controls were, or are, inadequate.

We are also disappointed that the basis for your conclusion that a $250,000 fine is warranted, is not addressed in Reference (1) nor provided to SCE through any other means. Circumstances identified in your General Statement of Policy and Procedure for NRC Enforcement Actions as warranting imposition of such a civil penalty, are not present in this case. Moreover, no civil penalty is necessary to emphasize the importance NRC places on conducting licensed activities in accordance with established procedures or our various responsibilities, which is identified in Reference (1) as the purpose of the proposed fine. We could not be more fully committed to the principles that activities must be performed in accordance with approved procedures and that SCE is responsible to continually assess their adequacy and take prompt and effective corrective action. The identified violation involved neither a failure to follow a procedure nor failure to take prompt and effective corrective action.

We do not understand why, out of the interest to objectively assess the circumstances in this case to determine appropriate enforcement action, the NRC has not reflected consideration of our identification and prompt reporting of the violation nor our extensive and aggressive corrective action. Reference (1) and the associated NRC Inspection Report provide no acknowledgement of these facts which bear directly on whether and, if so, what amount of civil penalty is to be assessed. Similarly, we do not understand why the associated Inspection Report, while discussing at length the safety significance of the violation based on accident analysis presented in the Final Safety Analysis Report, fails to consider, or even acknowledge, additional analysis and evaluation of the safety significance of the violation presented in Attachment II to Reference (3).

Finally, we note that a self-evident purpose of the NRC implementation of their General Statement of Policy and Procedures for NRC Enforcement Actions is to ensure enforcement actions are applied in a fair, even-handed and consistent fashion. It is recognized that the NRC's policy is to consider the associated circumstances in each violation and to tailor the proposed enforcement action to the facts in each case. However, we can find no justification for the dramatic inconsistency between the enforcement action proposed against SCE compared to enforcement actions taken at other facilities for equivalent or more egregious violations. In particular, inoperability of the Containment Spray System at both Indian Point 2 and Farley Unit 2, for which civil penalties of $40,000 each were imposed, for periods of violation considerably longer than at San Onofre, demonstrates that the proposed civil penalty in this case is excessive. Similarly, we can find no justification for the inconsistent approach in crediting licensees for identifying and reporting violations. In particular, a recent violation at McGuire Unit 2 involving the mispositioning of a valve in the Containment Spray System led the NRC to consider escalation of a $40,000 civil penalty because the licensee had not adequately improved its ability to independently verify the operability of key safety systems following earlier enforcement action. However, the civil penalty was not escalated because the violation was identified and reported by the licensee. Although the violation at San Onofre Unit 3 was also identified and reported by the licensee (and prompt, extensive and aggressive corrective action was taken), there is no evidence that these facts were considered in establishing the proposed enforcement action.

Notwithstanding our objection to any conclusion that our administrative controls are inadequate or that the proposed civil penalty is warranted, and in recognition of the fact that every reasonable effort must be undertaken to achieve operating performance void of any error, however minor, we have devoted considerable attention to remarks made by Mr. DeYoung and Mr. Martin and other members of the NRC Regulatory Staff at the May 9, 1984 Enforcement Conference. In response to the expressed concern that more thorough and consistent contact between supervision and working personnel is required, and supervision needs to effectively reflect and communicate management's policies, we have developed a multipart action plan to aggressively pursue and correct conditions which have led to these concerns to the extent they may exist. This plan has been provided to your Senior Resident Inspector for his information.

In conclusion, be assured that SCE considers that the identified violation represents a serious mistake for which aggressive and effective corrective action is warranted (and has been implemented). However, for the reasons stated above and discussed more fully in Enclosure I, SCE respectfully objects to the proposed civil penalty and requests that it be remitted.

Subscribed on the 15th day of June 1984 by

David J. Fogarty

David J. Fogarty
Executive Vice President
Southern California Edison Company

Subscribed and sworn to before me this 15th day of June 1984. Agnes Crabtree

OFFICIAL SEAL
AGNES CRABTREE
NOTARY PUBLIC – CALIFORNIA
PRINCIPAL OFFICE IN
LOS ANGELES COUNTY
My Commission Expires Aug. 27, 1986

Enclosures

cc: J. B. Martin (USNRC Regional Administrator, Region V)
A. E. Chaffee (USNRC Resident Inspector, Units 1, 2 and 3)
J. P. Stewart (USNRC Resident Inspector, Units 2 and 3)
A. J. D'Angelo (USNRC Resident Inspector, Unit 1)

ENCLOSURE I

REQUEST FOR REMISSION OF CIVIL PENALTY
PROPOSED IN NRC LETTER J. B. MARTIN TO D. J. FOGARTY
DATED MAY 16, 1984

In accordance with the provisions of 10 CFR 2.205(b), this enclosure requests remission of the civil penalty proposed in the NRC letter identified above. The basis for this request is as follows:

A. Errors exist in the Notice of Violation

Errors, identified below, exist in the Notice of Violation which formed the basis for the determination that a civil penalty in the amount of $250,000 should be proposed.

1. Most significantly, the above-referenced letter does not accurately or fairly characterize the adequacy of our management and administrative controls. It concludes that inadequate controls contributed substantially as an underlying cause of the inoperability of the San Onofre Unit 3 Containment Spray System (CSS) when Unit 3 entered Mode 3 on March 4, 1984.

   Inoperability of the Unit 3 CSS was not caused by inadequate administrative controls. Administrative controls in place at the time provided for the development of an appropriate valve checklist by a trained and qualified individual (a licensed Senior Reactor Operator) to ensure the proper positioning of valves in the CSS prior to entering Mode 3 on March 4, 1984. The administrative controls further provided for the independent verification of proper valve positioning by two qualified individuals. These administrative controls have provided for the proper alignment of systems literally hundreds of times in the startup and operation of Units 2 and 3.

   Inoperability of the Unit 3 CSS was caused by an individual personnel error in the development of the checklist to be utilized to verify proper system alignment of the CSS prior to entering Mode 3 on March 4, 1984. No administrative control program can completely eliminate individual personnel errors; it can only serve to:

   1. minimize the possibility of an error by providing for activities to be performed in documented, reviewed methods by properly trained and qualified individuals, and

   2. promptly detect any error by independent verification, check or review of activities.

Our administrative control program is based on these two fundamental objectives and inoperability of the Unit 3 CSS when Mode 3 was entered on March 4, 1984, revealed an activity (development of partial checklists) where individual personnel error can lead to undesirable consequences. Therefore, additional review of this activity has been shown to be warranted and our administrative control program has been correspondingly modified.

The above-referenced letter indicated that two additional events, recently occurring (the unplanned operation of the Unit 2 CSS and the failure to reconnect electrical leads on the Unit 3 Plant Protection System following surveillance testing), were the result of failure of our management control system. These two events are also each the result of individual personnel errors. The March 4, 1984 CSS inoperability and the two earlier events identified as having recently occurred each identified the need for procedural improvement to minimize the possibility of individual personnel error and/or accelerate detection and correction of such an error. Review of these events and their causes does not reveal any fundamental weakness or inadequacy in our administrative control program. Two of the three events (CSS inoperability and failure to reconnect electrical leads) were associated with activities being performed for the first or second time. Procedural improvements shown to be necessary or desirable by the initial performances of the procedure or any evolution are not evidence of inadequate administrative controls. The fact that the events were recognized, corrected and reported as soon as they were, in the absence of these procedural improvements, rather than remaining undetected for considerably longer periods of time as has occurred at other facilities, reflects positively on our personnel's diligence in the performance of their duties.

2. Similarly, improvement in management and administrative controls is not accurately or fairly characterized in the above-referenced letter which indicated that such controls have not improved as expected over the past year based on evaluation of NRC enforcement actions since January, 1983.

During the period identified, one or both of San Onofre Units 2 and 3 were in the midst of startup testing and preparations for placement of the units into commercial operation. This period, as well as the preceding approximately one year, was a period which unavoidably included more challenges to proper performance by systems, equipment, programs and personnel than during comparable periods of commercial operation. This fact was discussed by SCE representatives with Mr. J. B. Martin and members of his staff at a meeting on May 3, 1984. At that meeting it was pointed out that the rate of startups and shutdowns at San Onofre during this period was more than double the rate at a contemporary two unit station in commercial operation and more than ten times the rate at older single unit stations.

Startup periods necessarily represent periods in which new programs and controls (as well as systems and equipment) are exercised and improvements and refinements are sought and implemented. Our March 26, 1984 letter to Mr. J. B. Martin concerning inoperability of the Unit 3 CSS on March 4, 1984, discussed areas shown by events since January, 1983 as warranting revision or enhancement of our administrative control program and implementing procedures. As discussed in our March 26, 1984 letter and in the May 3, 1984 meeting with Mr. Martin and members of his staff, past corrective actions in these areas have been effective in preventing recurrence of specific past events as well as related events. As also discussed previously, inoperability of the Unit 3 CSS on March 4, 1984, could not have reasonably been prevented by corrective actions indicated by past events. The fact that events during this startup period revealed areas where improvements in administrative control is warranted should not be viewed as evidence that such control has not improved. The fact that corrective actions from these events have prevented recurrence and that the March 4, 1984 Unit 3 CSS inoperability could not have reasonably been prevented by corrective actions indicated by past events, demonstrates that administrative controls have, in fact, been improved.

Review of NRC enforcement actions against Units 2 and 3 since January, 1983, as is identified as the basis for the NRC conclusion that our controls have not improved as expected, reveals the fact that enforcement actions have, in fact, been reduced. During each of the two most recent six-month periods (January 1984 - June 1984 and July 1983 - December 1983) items of non-compliance have numbered two or three per six-month period as compared with nine in the prior six-month period (January 1983 - June 1983) and ten in the next prior six-month period (July 1982 - December 1982). Therefore on the basis of NRC enforcement actions alone, administrative controls have dramatically improved.

A final point with respect to the NRC conclusion that controls have not improved as expected, the above-referenced letter identifies inadequate procedures, failure to follow procedures, and inadequate operator knowledge of regulatory requirements and systems status as being the apparent causes of most violations during the past year. Such causes, so broadly stated are fundamental to nearly all activities at a nuclear generating station. Therefore, nearly any error could be characterized as resulting from one or more of these causes, regardless of the adequacy of administrative controls. The conclusion that administrative controls are inadequate or unimproved on the basis that these broadly stated causes still result in error is not appropriate.

3. The above-referenced letter indicates that on at least two occasions on March 2, 1984, there were opportunities for operating personnel to detect isolation of the Unit CSS prior to entering Mode 3 on March 4, 1984. Review of circumstances surrounding each of the evolutions characterized as opportunities reveals that opportunity existed only as hypothetical possibility and not as a consequence of activities performed in response to procedural or regulatory requirements.

   a. The first occasion identified by the above-referenced letter was the operation of a pump within the Unit 3 CSS as part of an operation to flush the CSS header on March 2, 1984, without verifying the flowrate with a meter in the Control Room. This flush was being performed pursuant to an operating instruction that calls for a flush of the CSS header prior to entry into Mode 3 from Mode 4. The operating instruction calls for this flush since portions of the Shutdown Cooling System (SDCS) are aligned and utilized as a portion of the CSS when the unit is in Mode 3 or higher modes of operation; the flush replaces fluid of boron concentration of the SDCS with fluid of boron concentration of the CSS within that portion of the SDCS that is aligned and utilized as a portion of the CSS in Modes 1, 2, and 3.

      During a CSS flush operation at Unit 2, it is required that the appropriate flowrate be verified during the flush. Such a verification is procedurally required at Unit 2 since its SDCS has not yet been modified to meet Branch Technical Position (BTP) 5-1 which requires that the operator be able to bring the plant from normal operating conditions to SDCS entry by remote action from the Control Room. The Unit 2 SDCS Heat Exchanger Bypass valves are not throttle valves and only have open/closed indication and therefore during flushing of the spray header at Unit 2, the appropriate flowrate is verified by examination of the flowrate meter in the Control Room.

      In contrast, at Unit 3 the SDCS Heat Exchanger Bypass valves are throttle valves with full (0-100%) Control Room position indication and, therefore, the appropriate flowrate is established by throttling the valves and no verification of flowrate from a meter is required. No procedural step calling for such verification exists.

      Flush of the CSS prior to entering Mode 3 has been established as a procedural requirement to establish the appropriate boron concentration of all CSS fluid following utilization of a portion of the system in SDCS service. The flush is not performed pursuant to any regulatory requirement nor is it necessary to ensure conformance with the assumptions of accident analyses presented in the Final Safety Analysis Report.

      The absence of a flowrate verification step in the Unit 3 operating instructions is not indicative of any shortcoming in our administrative control program. Flowrate verification during flush of the Unit 3 spray header is neither required nor routinely accomplished and did not represent an opportunity to detect isolation of the Unit 3 CSS.

b. The second occasion identified by the above-referenced letter was the performance of a routine monthly test of the CSS on March 2, 1984. This test includes verification of specified valves in the containment spray flow path to ensure they are in the correct positions. Performance of the monthly test on March 2, 1984, did not represent an opportunity to detect isolation of the Unit 3 CSS. This conclusion is based on the fact that Technical Specification Surveillance Requirement 4.6.2.1 specifically excludes locked valves (such as MU012 and MU014, the two valves left closed, isolating the CSS) from such monthly verification. Our surveillance procedure implementing the Technical Specification, correspondingly does not require position verification for locked valves.

   Accordingly, the monthly test of the CSS did not represent an opportunity to detect isolation of the Unit 3 CSS.

Based on the above, it is concluded that neither of the above-described circumstances represents an evolution that was performed or should have been performed which would have revealed the mispositioned valves which rendered the Unit 3 CSS inoperable. They did not represent opportunities to detect the Unit 3 CSS isolation nor do they represent shortcomings in our administrative controls.

4. Administrative Procedure SO23-0-35, which allowed operations personnel to specify the performance of a portion of a valve alignment checklist prescribed by procedure, was not in violation of Technical Specification 6.8.3 as indicated in the above-referenced letter and the associated Inspection Report. In accordance with Administrative Procedure SO23-0-35, an SRO was permitted to designate a portion of a checklist to be performed when changes in system status did not require an entire checklist to be performed. Designation of a portion of a checklist (partial checklist) was provided for in our administrative controls in order to avoid errors resulting from development of special purpose checklists. Such special purpose checklists would otherwise be required when conducting retests following correction of component failures within lengthy surveillance procedures, for example. Partial checklists also satisfied ALARA objectives where complete system alignment, including vents and drains in high radiation area, is not warranted. This aspect of our administrative controls also permits personnel to specify an additional (i.e., beyond the initial and second verifications) system alignment check for a portion of a system which may have been affected by a maintenance or surveillance activity or plant evolution.

   A comprehensive review of all applicable regulatory guidance including Regulatory Guide 1.33, "Quality Assurance Program Requirements," ANSI Standard N18.7, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," and NUREG-0737, Section I.C.6, "Guidance on Procedures for Verifying Correct Performance of Operating Activities," fails to yield any guidance that indicates that partial checklists should be considered procedure changes (or temporary procedure changes), rather than the authorized omission of procedural steps that are not applicable to a particular proceduralized evolution.

Neither regulatory guidance nor our Techrical Specifications require the treatment of omission of procedural steps, considered not applicable by an individual authorized and qualified to perform the procedure, as a procedure change. Consequently our administrative controls:

1. permit the identification of procedural steps which are not applicable to a desired procedural evolution,

2. do not require their treatment as procedural changes, and

3. do permit the designation of partial checklists which are not treated as procedural changes.

Our review of administrative controls at several other nuclear power stations revealed that they, too, do not treat authorized procedural step omission or designation of partial checklists as procedure changes.

Based on the above, it is concluded that although the partial checklist developed and implemented on March 2, 1984 was not properly developed or adequately reviewed, its development and execution did not violate Technical Specification 6.8.3. However, because of the potential for recurrence of the sort of error which occurred in this instance, administrative controls have been revised so that all partial checklists will be treated as procedure changes at San Onofre and approval requirements will be as established in Technical Specifications 6.8.3.

B. Other reasons why the penalty should not be imposed

Factors influencing the magnitude of proposed civil penalties, as established in 10 CFR 2, Appendix C, as revised March 8, 1984, have not been properly assessed, as discussed below.

1. The Notice of Violation indicates that for purposes of computing a civil penalty, each day of operation in or above Mode 3 with the Unit 3 CSS isolated (March 4-17, 1984) is considered a separate violation. 10 CFR 2, Appendix C, Section B provides for the assessment of civil penalties on a per day basis where ". . .NRC intends to apply its full enforcement authority. . ." Such full enforcement authority is indicated as being warranted in cases involving:

   a. willfulness

   b. flagrant NRC-identified violations

   c. repeated poor performance in an area of concern, or

   d. serious breakdown in management controls.

   Clearly, the identified violation was neither willful nor a flagrant NRC-identified violation. (A discussion of Southern California Edison Company's identification and immediate NRC notification is provided in Section B.2, below.) As was summarized in Sections A.1 and A.2 above from previous letters and meetings, CSS inoperability at Unit 3 on March 4, 1984, is not repeated poor performance in an area of concern.

The CSS inoperability is attributable to a single personnel error and the event is not comparable with nor could it have been reasonably prevented by corrective action indicated by past events, including those resulting in enforcement action. It is related to the two events referred to as having occurred recently (unplanned operation of the Unit 2 CSS and the failure to reconnect electrical leads on the Unit 3 Plant Protection System following surveillance testing), since each identified an activity where an individual personnel error could lead to undesirable consequences and appropriate and effective corrective action was taken in each case. Also as summarized in Sections A.1 and A.2 above, the March 4, 1984 Unit 3 CSS inoperability does not represent a serious breakdown in management controls. The event represents an individual personnel error which does not warrant a conclusion that management controls are inadequate.

It is therefore concluded that the conditions which give cause for the NRC to apply its full enforcement authority are not present in these circumstances and, therefore, calculation of a civil penalty on a per day basis is inappropriate.

A review of past enforcement actions taken by the NRC for similar violations confirms the conclusion that a civil penalty should not be assessed on a per day basis at San Onofre. At Alabama Power Company's Farley Unit 2 Station, the CSS remained valved out for as long as 17 months during which time the reactor was in Modes 1 through 4, based on misinterpretation of valve position. At Consolidated Edison's Indian Point 2 Station, the CSS remained valved out for 36 days while the reactor was made critical five times, based on erroneous initial and independent verification of valve position by two different operators. Enforcement actions at neither Farley nor Indian Point 2 were assessed on a per day basis.

2. 10 CFR 2, Appendix C, Section V.B.1, provides for a reduction of up to 50% of the base civil penalty when a licensee identifies the violation and promptly reports the violation to the NRC. In addition, 10 CFR 2, Appendix C, Section V.B.2 states, "unusually prompt and extensive corrective action may also result in reducing the proposed civil penalty as much as 50% of the base value". No reference is made in the Notice of Violation to our prompt reporting, immediate corrective actions or subsequently developed extensive and effective corrective action.

On March 17, 1984, the day of discovery of the condition, telephone reports were made both to the NRC Operations Center and to the NRC Resident Inspector. That same day, a written confirmation letter of the telephone notification was sent to the NRC Regional Office. The March 17, 1984 letter identified the cause and identified immediate corrective actions being taken including: modifications of administrative procedures reflecting additional control and documentation requirements for the use of checklists; and personnel training.

Prior to the 30-day follow-up report required by 10 CFR 50.73, on March 26, 1984, a follow-up report was submitted which discussed, in detail, the cause of the event and discussed corrective actions to:

1. revise administrative controls on the preparation and use of partial checklists to increase approval requirements and clarify documentation requirements

2. revise the CSS operating procedure to require flow verification when the CSS is returned to service

3. verify proper valve alignment for other systems

4. revise the SDCS operating procedure to include a specific step devoted to proper positioning of valves when CSS is returned to service

5. revise the monthly surveillance checklist to include locked valves even though such locked valves are not required by the Technical Specifications to be included in the monthly surveillance checklist

6. develop additional Piping and Instrumentation Diagrams as operator aids

7. develop additional valve alignment checklist for valves in main process flow streams for designated systems, and

8. re-examine and revise operator training in ways to emphasize the need for operator recognition of proper system alignments during various plant evolutions.

On March 30, 1984, the Licensee Event Report was submitted 17 days early. Licensee Event Report No. 84-009 summarized the event and delineated corrective actions described in the previous letters.

On May 3, 1984, SCE management requested a meeting to further present to NRC Region V management specifics of the results of our investigation and corrective actions. At this meeting, additional corrective actions were identified including actions to:

1. provide additional operator aids

2. request a Special Assistance visit by INPO specifically focused on Units 2 and 3 operations

3. supplement operations shift supervision, and

4. redirect Shift Technical Advisor responsibilities to provide additional overview of operational activities.

Based on information presented in this section, reduction of the base civil penalty by 50% is warranted. Review of a recent enforcement action proposed for a violation involving the mispositioning of a valve in the CSS at McGuire Unit 2 for a period of twenty-one (21) days reveals the fact that licensee identification and reporting of a violation serves to reduce the proposed civil penalty. At McGuire, the NRC considered escalating a $40,000 civil penalty because the corrective action for previous similar violations had not been effective. However, the civil penalty was not escalated because the violation was identified and reported by the licensee. There is no evidence that SCE identification, reporting and prompt and extensive corrective action for the violation at San Onofre Unit 3 was considered in establishing the proposed enforcement action.

ENCLOSURE II

RESPONSE TO NOTICE OF VIOLATION (10 CFR 2.201)

In accordance with 10 CFR 2.201, this enclosure provides the Southern California Edison Company (SCE) response to the Notice of Violation contained in the enclosure to Mr. J. B Martin's letter of May 16, 1984.

In addition to the five specific factors requested by the Notice of Violation, we have set forth a separate section (identified as Section 2) that provides the facts and circumstances surrounding the event.

The enclosure to the May 16, 1984, letter states:

A. "Technical Specification 3.6.2.1 states, in part,

"Two independent containment spray systems shall be OPERABLE with each spray system capable of taking suction from the RWST on a Containment Spray Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal. Each spray system flow path from the containment sump shall be via an OPERABLE shutdown cooling heat exchanger.

"APPLICABILITY: MODES 1, 2 and 3...."

"Technical Specification 3.0.4 states, in part,

"Entry into an OPERATIONAL MODE or other specified conditions shall not be made unless the conditions of the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION requirements...."

"Technical Specification 3.0.3 states, in part,

"When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within one hour, action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in:

1. at least HOT STANDBY within the next 6 hours,

2. at least HOT SHUTDOWN within the following 6 hours, and

3. at LEAST COLD SHUTDOWN (sic) within the subsequent 24 hours...."

"Contrary to the above requirement, on March 4, 1984, Unit 3 entered OPERATIONAL MODE 3 at approximately 0955 hours with both containment spray pump discharge stop check valves locked shut, thus rendering both independent containment spray systems inoperable. This condition continued until 0200 on March 17, 1984, at which time the licensee identified and corrected the above condition. During this entire period Unit 3 was in OPERATIONAL MODES 1, 2 and 3.

"The violation concerning the inoperability of the containment spray system is an example of an event in which the licensee was unaware of a condition resulting in a continuing violation. The licensee should have been aware of the condition and had an opportunity to correct the condition. A separate violation and attendant civil penalty may be considered for each day that the licensee clearly should have been aware of the condition or had an opportunity to correct the condition but failed to do so. Consequently, each day the licensee operated from March 4 through March 17, 1984, is considered a separate Severity Level III violation for purposes of computing a civil penalty. In view of the circumstances of this case, a cumulative penalty of Two Hundred Fifty Thousand Dollars is being proposed for these violations.

"This is a severity Level III violation. (Supplement I)

"(Civil Penalty - $250,000)."

1. ADMISSION OR DENIAL OF THE ALLEGED VIOLATION:

   SCE admits that on March 4, 1984, Unit 3 entered OPERATIONAL MODE 3 at approximately 0955 hours with both containment spray pump discharge stop check valves locked shut. SCE admits that this condition continued until 0200 on March 17, 1984, when the condition was discovered and corrected as identified below.

2. STATEMENT OF FACTS AND CIRCUMSTANCES:

   The following is a sequence of events associated with the identified violation:

   02/27/84 0520 Unit 3 entered Mode 4 from Mode 5 as part of the return-to-service from an extended surveillance and maintenance outage. Procedure SO23-3-2.9, "Containment Spray/Iodine Removal System Operation," Checklist 5.1, was performed to align the Containment Spray System (CSS) in preparation for Mode 3 entry. MU012 and MU014 were verified locked open, and this condition was documented on Checklist 5.1.

   A need to return to Mode 5 was identified to allow repair of High Pressure Safety Injection (HPSI) valve 3HV9327.

   02/28/84 2135 Valve alignment for going back on shutdown cooling was verified. MU012 and MU014 were closed in accordance with Procedure SO23-3-2.6, "Shutdown Cooling System Operation - Unit 3," and Shutdown Cooling System (SCS) was placed in service.

   02/29/84 0029 The unit entered Mode 5 to facilitate disassembly and repair of valve 3HV9327.

03/02/84 Following repair of 3HV9327, a partial valve alignment checklist was developed from Checklist 5.1 of Procedure SO23-3-2.9 which had been performed on February 27, 1984, to realign CSS in preparation for Mode 3 entry. Such a partial checklist was developed since a complete alignment had been done four days earlier and no work had been done on the CSS. CSS valves MU012 and MU014 were erroneously omitted from the list.

03/07/84 2120 Unit entered Mode 1.

03/10/84 2240 Unit tripped on low condenser vacuum.

03/12/84 2030 Unit entered Mode 1.

03/17/84 0145 A Nuclear Plant Equipment Operator (NPEO) on routine equipment rounds, discovered CSS valves MU012 and MU014 closed.

0200 The NPEO notified the Unit 3 Control Operator and was directed to lock open the valves. The valves were immediately locked open.

3. REASONS FOR THE VIOLATION:

Inoperability of the CSS was caused by an individual personnel error in the development of a checklist to be utilized to verify proper system alignment of the CSS prior to entering Mode 3 on March 4, 1984. This checklist was developed pursuant to Administrative Procedure SO23-0-35 which authorizes an SRO to designate a portion of a checklist to be performed when changes in system status do not require an entire checklist to be performed. Although the Control Room Supervisor (an SRO) who developed the checklist, did so after checking appropriate Piping & Instrumentation Diagrams (P&IDs), he did not recognize that the containment spray pump manual discharge isolation valves are closed when entering the shutdown cooling alignment. Therefore, in designating the subset of CSS valves to be repositioned and verified upon leaving the shutdown cooling alignment, valves MU012 and MU014 were omitted and remained closed until identified on March 17.

The Control Room Supervisor did not consider a complete system alignment was required since the entire checklist had been performed only 4 days earlier.

4. CORRECTIVE STEPS WHICH HAVE BEEN TAKEN AND THE RESULTS ACHIEVED:

The following corrective actions were immediately taken upon discovery of the closed valves:

a. The valve alignment of other parts of Engineered Safety Features systems at Unit 2 and Unit 3 was examined. No other discrepancies were identified.

b. Temporary revisions were issued to administrative procedures to require that two SRO's approve any use of only a portion of a valve alignment checklist. This was done to provide added assurance that all valves affected by a particular system evolution are included in the alignment and verification is performed. (Further investigation has resulted in modification of this action by imposing controls required for procedure changes as described in Section 5 below.)

c. Administrative procedures were revised to require that, for each instance that a valve alignment checklist is utilized, an unused checklist form is obtained and filled in. Previously completed checklists will not be modified to create a new checklist. This provides added assurance that the valves included on a partial checklist are completely and clearly defined.

d. Operating Procedure SO23-3-2.7, "Safety Injection System Operation," was revised to require verification of flow through valves MU012 and MU014 following return from the shutdown cooling alignment. This provides added assurance that the valve realignment was properly performed.

5. CORRECTIVE STEPS WHICH WILL BE TAKEN TO AVOID FURTHER VIOLATIONS:

a. As described above, administrative procedures were immediately revised to require that two SRO's approve any use of only a portion of a valve alignment checklist. Further review resulted in the decision to require instead that any use of a portion of a valve alignment checklist in connection with a procedure, or the establishment of an abnormal valve alignment, will be subject to the same approvals as a temporary change to a procedure as described in Section 6.8.3 of the Technical Specifications. This will be accomplished through revision of Procedures SO23-0-36, "Control of System Alignments," and SO23-5-1.3, "Plant Startup from Cold Shutdown to Hot Standby," and will be completed by July 2, 1984.

b. The monthly surveillance checklist will be revised to include valves MU012 and MU014 and other similarly locked main process valves in safety systems which are not in normal operation. This will provide added assurance of a proper alignment of these valves. Appropriate operating procedures will be revised by July 2, 1984.

c. Piping and Instrumentation Diagrams (P&ID) for system alignments for the various shutdown cooling system configurations will be developed. This will assist Operators in identification of proper valve alignment positions. This will be completed by July 2, 1984.

d. Operating procedures will be revised to include an additional valve alignment checklist, wherever required. The existing checklist will be split and one will include all valves in the main process flow stream for designated systems such as the Emergency Core Cooling System and Auxiliary Feedwater System. The other checklist will contain vents, drains, and instrument valves. This will provide for use of a preplanned partial system checklist when use of a complete checklist is not warranted, and it will reduce the need for preparing special partial valve alignment checklists. This will be accomplished by July 2, 1984.

e. Operating procedures will be revised to define when these partial checklists may be used in lieu of the complete system checklists. This will be accomplished through revisions to Procedures SO23-0-35 and SO23-0-36 and will be completed by July 2, 1984.

f. The training program is being re-examined and will be revised to provide additional emphasis on operator recognition of proper system alignments during various plant evolutions. This is intended to provide increased operator understanding of correct valve alignment position in differing system configurations. Increased emphasis will be provided in operator training programs on overviewing system operation and realignment evolutions associated with changes in mode and function. This training will be provided in the operator requalification program and is expected to be completed by July 9, 1984.

6. DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

Full compliance with the Technical Specifications was achieved at 0200 on March 17 when both containment spray system containment isolation valves were opened and locked open.

B. "Technical Specification 3.8.1.1 states, in part,

"As a minimum, the following A.C. electrical power sources shall be operable....

"b. Two separate and independent diesel generators...

"APPLICABILITY: MODES 1, 2, 3 and 4

"ACTION:...

"c. With one diesel generator inoperable in addition to ACTION a or b above, verify that:

"1. All required systems, subsystems, trains, components and devices that depend on the remaining OPERABLE diesel generator as a source of emergency power are also OPERABLE, and 2....

"If these conditions are not satisfied within 2 hours be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours."

"Contrary to the above requirements, on March 15, 1984 at approximately 0421 hours, the train B diesel generator was made inoperable (placed in maintenance lockout) while both trains of the Containment Spray System were inoperable due to the containment spray pump discharge stop check valve being locked in a closed position. This condition was corrected at 1736 hours on March 16, 1984 when Train B Diesel Generator was returned to service and declared operable. During this entire period Unit 3 was in OPERATIONAL MODE 1.

"This is a Severity Level III Violation (Supplement I)."

1. ADMISSION OR DENIAL OF THE ALLEGED VIOLATION:

SCE admits that on March 15, 1984, at approximately 0421, the train B diesel generator was made inoperable (placed in maintenance lockout) while both trains of the CSS were inoperable as described in Item A, above. However, SCE contends this citation should not be considered an independent violation from Item A, and should, therefore, be withdrawn. During the period March 15 to March 16, when the condition described above occurred, SCE was not aware, nor was sufficient information available as a consequence of activities performed in response to procedural or regulatory requirements, such that SCE should have been aware of the inoperability of the CSS. Had SCE been aware of the inoperability of the CSS, SCE would have immediately restored the system to operable status, as demonstrated by Operator action on March 17 when the condition was discovered, and what has been identified as a separate violation would not have occurred. Although SCE contends a separate violation should not be identified, the following sections have been included for completeness.

2. FACTS AND CIRCUMSTANCES SURROUNDING THE OCCURRENCES:

Prior to removing Train B Diesel Generator from service at 0421 on March 15, 1984, Operators reviewed equipment control records of inoperable equipment to assure all required systems, subsystems, trains, components, and devices that depend on the Train A Diesel were operable. The review did not identify the CSS as being inoperable.

3. REASONS FOR THE VIOLATIONS IF ADMITTED:

Inasmuch as what has been identified as Item B should not be considered a separate violation from item A, the cause of the condition identified as Item B is as described in Section A.3, above.

4. CORRECTIVE STEPS WHICH HAVE BEEN TAKEN AND THE RESULTS ACHIEVED:

See Section A.4.

5. CORRECTIVE STEPS WHICH WILL BE TAKEN TO AVOID FURTHER VIOLATIONS:

See Section A.5.

6. DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED:

See Section A.5.