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February 28, 1991

Mr. Roy Zimmerman, Director
Division of Reactor Safety and Projects
U. S. Nuclear Regulatory Commission
1450 Maria Lane, Suite 210
Walnut Creek, California 94596-5368

Dear Mr. Zimmerman:

Subject: **Docket Nos. 50-206, 50-361 and 50-362**
Notice of Significant Licensee Meeting
San Onofre Nuclear Generating Station

Your letter dated February 22, 1991 provided an agenda for a meeting at your offices on March 1, 1991. An expanded agenda was received by us yesterday, following several telephone discussions.

In order to ensure that we address the desired topics as fully as possible in the meeting, and to provide you with some advanced information to make the meeting as productive as possible, this letter provides an indication of the intended scope and content of our discussion.

I. **Update on Design Basis Documentation (DBD)**

A. Feedwater Pump Restart Delay Following LOP/SIS

1. Conduct of Safety Analyses

Operation of the Safety Injection System following LOCA is analyzed on the basis that LOP timing is coincident with reactor trip. The time after LOP when SIS occurs is then a function of the break size.

2. Undervoltage Protection Scheme

Prior to the recently completed modification, the undervoltage protection scheme resulted in an approximately 14 second delay in Feedwater Pump restart, if the LOP preceded the SIS signal by more than about 11 seconds. This delay would not affect the limiting analyses for Unit 1 that involve large break scenarios since SIS is generated very soon following reactor trip and the assumed LOP.

IE-45

Review of small break analysis results also indicate that SIS would occur prior to about 11 seconds following LOP when the undervoltage protection delay would have become effective. Therefore, although the delay had not been identified in the small break analyses performed previously, it would not have affected the results.

SIS also occurs following LOP in a MSLB scenario. The effect of the undervoltage protection delay in Feedwater Pump restart in this scenario is under evaluation.

In addition to introducing a delay in the Feedwater Pump restart, the undervoltage protection scheme also resulted in a lockout of the charging pumps if the LOP preceded the SIS signal by more than about 11 seconds. Safety analyses performed to date do not credit operation of the charging pumps.

It is expected that the charging pump lockout feature, and perhaps the feedwater pump restart delay, would have been recognized during the evaluation which was to be performed in response to Information Notice 88-75, if it had not been identified during the testing conducted during the current outage.

3. Single Failure Analysis

The single failure analysis was performed on the basis of simultaneous SIS and LOP, consistent with the design and licensing bases. Single component failures within the undervoltage protection scheme were considered.

B. <u>Design Basis Documentation Program</u>

1. Undervoltage Protection Scheme

The functioning of the undervoltage protection scheme, and its impact on Safety Injection System operation, will be considered as part of the electrical systems design basis documentation package which is scheduled to be completed in April 1991.

2. Program Status

Six DBD packages have been completed for Unit 1. An additional 22 packages for all 3 units are on schedule to be completed by the end of 1991.

II. Highlights of Unit 1 Single Failure Analysis

A. Previous Analyses

Single failure analyses were performed in 1976 for ECCS and in 1987 for ESF/RPS. These analyses were of limited scope and performed in accordance with criteria in effect at the time.

B. Current Analysis

A failure modes and effects analysis has recently been completed in accordance with current criteria. Approximately 3,000 interactions were evaluated, and 9 problems required modifications to resolve. Modifications have been completed addressing 8 of the problems. The remaining 1 involves a very low probability event and will be resolved during the Cycle 12 refueling.

The overall safety significance of the problems identified was low, involving an increase of only about 2% in the core damage frequency.

III. Other Unit 1 Issues

A. Improper Assembly of Containment Spray Valve CV-518

The improper assembly occurred in February 1989, and an opportunity to identify it at that time was missed. Thereafter, the condition was not apparent until detected during testing conducted as part of the current outage.

Containment spray flow during the injection and transition phases would not have been significantly affected. During the recirculation phase, spray flow would have been greater than expected. Control Room operators would be expected to have recognized the condition as a decrease in spray flow was not observed when manually shifting to recirculation, or following periodic tripping of the operating spray pump due to overcurrent.

Except for the expected pump tripping due to overcurrent, system performance during recirculation would be expected to have been acceptable, even if the misalignment of CV-518 were not recognized and corrected by the operators. (Correction of the valve misposition would then rely on use of the Instrument Air System.)

B. Potential Sodium Silicate Blockage of Containment Spray Rings

1. Coating Application

The coating was applied in the mid-'70s for protection of the carbon steel interior of the spray piping from corrosion. Surveillance testing has been performed every other refueling outage to demonstrate that the nozzles are not blocked.

2. Extent of Concern

The size and arrangement of flow paths in the spray piping is such that blockage of the rings by excessive coating thickness was not of concern. Concern was limited to flaking of the coating which could result in blockage of spray nozzles.

The spray system contains 71 nozzles. Analysis shows that only 39 are required to meet all design basis performance requirements and only 10 are required to meet best estimate performance requirements. The surveillance test identified that 7 nozzles were blocked to low pressure air flow and 64 were open. (The blockage of only 7 nozzles has no effect on spray system performance.)

3. Evaluation of Safety Significance

Testing of the blocked nozzles indicated that the differential pressure during system operation would be expected to result in satisfactory system performance in any realistic transient requiring containment spray.

IV. **Discussion of On-Line Maintenance**

A. Impact on Operator Attentiveness

The need to clear systems and return them to service, including within Technical Specification Action Statements where applicable, in order to support on-line maintenance diverts operator attention from monitoring plant status. Therefore, the impact on operator resources must constitute one of the restraints to the performance of maintenance on-line which could be deferred.

B. Statistics On Safety System Unavailability (Corrective/Preventive)

Statistics are maintained on the basis of planned and unplanned system unavailability. Unplanned system unavailability is associated with corrective maintenance. Planned system unavailability is associated with preventive maintenance, although any needed corrective maintenance will also be performed in parallel. Statistics are not maintained on the relative impact on unavailability of corrective and preventive maintenance.

In addressing control of outage work scope, industry guidance states that, "Generally, only work that cannot be done on-line should be scheduled for an outage." However, excessive safety system unavailability must constitute a second restraint to the performance of maintenance on-line.

C. Review of Boundary-of-the-Week Program

This program was established to maximize the amount of work that is accomplished when a system is taken out of service. This is a positive objective, and our program is very effective. However, it must be restrained by the two considerations discussed above. Namely:

1. Impact on operator resources.

2. Impact on safety system unavailability.

In August 1990 we recognized that our emphasis over the past two years on increasing preventive maintenance accomplishment was not being sufficiently restrained by its impact on operator resources. This has since been corrected, however we are currently developing a systematic strategy for determination of on-line maintenance work to be performed in the future.

V. **Probabilistic Risk Assessment (PRA)**

A. Status of PRAs In Progress

SCE uses PRAs extensively to support licensing, design and outage planning evaluations. PRA is also used to monitor safety system unavailability.

B. Significant Conclusions to Date

Important decreases in risk have been achieved based on PRA results which supported changes in design and outage planning. With respect to operational decisions, SCE has commenced work to develop an on-line, integrated risk management capability which would be compatible with future use of risk-based Technical Specifications.

C. How Considered In Scheduling of On-Line Maintenance

PRAs have not been used to date in the scheduling of on-line maintenance. We believe that planned safety system unavailability should be limited such that total unavailability does not significantly impact plant risk, as monitored by the plant PRA. This is monitored on a historical basis.

VI. Mid-Loop Operations (With Fuel In the Reactor Vessel)

A. Full-Core Offload Conditions

We currently expect that the upcoming refueling of Unit 2 will include a full core offload. However, owing to the delayed restart of Unit 1, we have not yet completed planning of this outage.

In the event of a full-core offload, mid-loop operations can be avoided by delaying drain-down for steam generator work, or other work requiring low RCS water level, until after the offload occurs, and then not commencing core reload until after the work is entirely completed. However, this places the steam generator work on the outage critical path which can result in a less complete program of inspection and repair than would otherwise occur.

SCE believes it is important to ensure that ample time is provided for steam generator inspection and repair. Under many situations, this is best accomplished when the work is not subjected to the pressure of being conducted on the critical path.

With respect to full core offload, we have not yet determined whether - absent any other reason for doing so (e.g., required work on common heat removal equipment) - full core offload should be performed as a matter of policy. We intend to evaluate this in the future, however full core offload may be required during the upcoming Unit 2 outage.

B. Use of Nozzle Dams

Nozzle dams are provided in most plants to permit the water level to be above mid-loop when the steam generator channel heads are open. Mid-loop operation is only required when the nozzle dams are being installed or removed.

Assuming that we decide on a full core offload during the upcoming Unit 2 refueling, we will retain the capability to install nozzle dams to permit core reload in the event that steam generator work needs to continue significantly beyond the time allowed in the outage schedule. This would result in the requirement for a brief period of mid-loop operation (with fuel in the reactor vessel) to remove the nozzle dams following core reload.

C. Overall Risk/Benefit Assessment

SCE recognizes there is risk associated with mid-loop operation when fuel is in the reactor vessel, particularly for a design such as Units 2 and 3 where the margin in level available is very small. However, there may also be risk associated with the additional fuel handling required by full core offload scenarios and with the schedule restraints imposed on steam generator work conducted on the outage critical path.

Opinions differ in the industry as to how these risks should be balanced. We believe that objective analysis is needed to arrive at a correct overall risk/benefit assessment.

VII. Setpoint Methodology Team Inspection Issues

A. Current Status

As we discussed by telephone, our current understanding of the setpoint methodology team inspection issues is limited to the information provided during the exit interview. Based on this information, we conclude that we did not effectively communicate with the NRC team during the course of the inspection, and we wish to engage in further discussion accordingly.

B. Background

In general, SCE did not acquire or itself review the calculations which numerous vendors and contractors used in performing instrument setpoint calculations. (Note: Regulatory Guide 1.105, "Instrument Setpoints for Safety-Related Systems", was not implemented in general during the design of Units 2 and 3. Of course, it did not exist during the design of Unit 1.) However, in the wake of the electrical SSFI which was conducted in November 1989, SCE committed to reconstitute the setpoints in accordance with current requirements.

A three-year long, $10 million effort was initiated for this purpose, and an internal standard for the conduct of the work, based on the 1988 revision of the applicable ISA standard, was issued for use in June 1990.

C. Recent NRC Team Inspection

Most of the work performed by SCE to date has been on Unit 1. Since the inspection focused on Units 2 and 3, it did not significantly evaluate the performance of our program. We do not believe the inspection issues include findings in this regard.

Nevertheless, based on the exit interview, we do believe that the team may not have been able to clearly separate problems which are similar to those identified in the 1989 SSFI, and which led to the commitment described above, from any problems which may be associated with the current SCE program established in response to that commitment.

Also, our engineers apparently experienced some difficulty in providing information requested by the team. As noted, in general we did not have possession of all the requested information. Also, in some cases we have not digested vendor and contractor information, as we plan to reconstitute the work in accordance with our ongoing program.

Nevertheless, during the inspection, an effort was made to obtain and provide whatever information was requested, in some cases incorrectly and without appropriate management involvement. As a result, the status and use of the information may not have been clear to the inspection team, at least based on the exit interview.

Therefore, we feel the need for further discussion of the results of the inspection, and of the actions we are undertaking.

I trust the foregoing summary of our planned discussion topics tomorrow will be useful to you and your staff. If any adjustment is required, please let me know as soon as possible.

Sincerely,

Harold B. Ray

HBR:bam

cc: Mr. John B. Martin, Administrator, USNRC Region V
Mr. C. W. Caldwell, USNRC Senior Resident Inspector, SONGS