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

SEP 27 1983

MEMORANDUM FOR: Thomas Novak, Assistant Director for Licensing

FROM: Darrell G. Eisenhut, Director
Division of Licensing

SUBJECT: BOARD NOTIFICATION NO. 83-144

I have determined that the attached report (Staff Evaluation of the CE PORV Issue) and the attached transcript and slides from the San Onofre Commission briefing of September 16, 1983 should be transmitted to the Boards and parties for CE plants according to the procedures of Office Letter No. 19.

Issue this as Board Notification 83-144.

Darrell G. Eisenhut

Darrell G. Eisenhut, Director
Division of Licensing

Enclosure:
As Stated

cc: S. Black
J. Wilson

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

SEP 2 0 1983

MEMORANDUM FOR: Raymond F. Fraley, Executive Director
Advisory Committee On Reactor Safeguards

FROM: Roger J. Mattson, Director
Division of Systems Integration

SUBJECT: STAFF EVALUATION OF THE CE PORV ISSUE

The staff evaluation of the adequacy of the recent CE plants without PORVs is enclosed for your review. The evaluation has received the concurrence of the NRR Division Directors, but may undergo minor changes.

We understand we are currently scheduled to present the staff's evaluation to the Decay Heat Removal Subcommittee on October 4, 1983 and to the full Committee during the October 13-15 meeting. We are planning on forwarding the staff's evaluation to the CRGR by October 31 and to the EDO by December 15.

Roger J. Mattson

Roger J. Mattson, Director
Division of Systems Integration

Enclosure

cc: w/o enclosure

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STAFF EVALUATION OF THE NEED FOR A RAPID

DEPRESSURIZATION CAPABILITY FOR CE PLANTS

September, 1983

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SUMMARY

This report documents the NRC staff evaluation of the need for providing a rapid primary system depressurization capability, in particular by using a power-operated relief valve(s), in the current 3410 MWth and 3800 MWth classes of plants designed by Combustion Engineering (CE).

This evaluation was performed because (a) informal reviews conducted since the accident at TMI-2 (in particular by the ACRS) have suggested that power-operated relief valves (PORVs) enhance the overall capability of PWRs to accommodate transients and accident events, and (b) all PWRs designed by other vendors (i.e., Westinghouse and Babcock and Wilcox) include at least one PORV in their design.

The evaluation confirms the ability of these current designs without PORVs to meet regulatory requirements. It also compares the expected performance with and without PORVs for events that are outside the scope of those traditionally considered for licensing purposes. The evaluations performed are largely deterministic in nature and reflect engineering analysis and judgment. Also included are the results of some probabilistic risk analyses and estimates of value-impact associated with the potential addition of PORV capability.

The results of the probabilistic analyses indicate that the frequency of core melts could be reduced from about $6x10^{-5}$ per reactor year to about $3x10^{-5}$ per reactor year due to PORV installation. The value and impact assessment suggests that there is a real but not overwhelming advantage in equipping these plants with a rapid depressurization capability. The value in such a retrofit is not so large as to suggest unambiguous cost-effectiveness, nor does it suggest an urgent need for risk reduction.

Based on our evaluation of multiple failure accident scenarios, and of possible malfunctions of the mitigation systems, our overall conclusion is that the prudent course of action would be to install pressurizer PORVs on the current CE plants. Although the value-impact assessment does not fully support such a conclusion, the uncertainties associated with the quantification of benefits are large enough to mask a definitive conclusion on this basis alone.

One of the principal prospective benefits of having PORVs is the capability they provide for decay heat removal in the so-called feed-and-bleed mode in the unlikely event of total loss of availability of the steam generators to remove decay heat. The subject of decay heat removal reliability is a current Unresolved Safety Issue, A-45. Since the technical resolution of this issue is scheduled for completion within about one year, the staff concludes that while PORVs should be required on CE plants, the actual PORV procurement and installation should await a USI A-45

resolution. At this time, we expect that the USI A-45 resolution will result in a requirement no less effective than PORV addition in improving decay heat removal capability.

In the latter stages of the staff review of the need for PORVs, it was recognized that a rapid depressurization capability may effect the severity of core melts in progress. The consequences of core melts at high and low pressure were not compared. The technical aspects in this problem are complex and we will task the Severe Accident Research Program to evaluate this aspect.

I. INTRODUCTION/BACKGROUND

Following the TMI-2 accident, the purpose and use of PORVs has been the subject of considerable analyses and discussions. All PWRs designed by Westinghouse and Babcock and Wilcox have at least one PORV included in the design. While older Combustion Engineering (CE) plants also have PORVs, the current designs by CE do not include PORVs. There are two groups of CE designed PWRs without PORVs: the 3410 MWT plants (San Onofre Units 2 and 3, and Waterford Unit 3); and the 3800 MWT plants (Palo Verde Units 1, 2 and . d other CE System 80 plants). Although Arkansas Nuclear One (ANO) Unit 2 also does not have a PORV, it was not part of this assessment since a large, manually actuated vent valve is presently installed on the ANO-2 pressurizer and would enable rapid depressurization capability.

Although our preliminary review indicated that these plants met almost all current regulatory requirements without the PORVs, other considerations, primarily accident management for beyond design basis events and potential core melt risk reduction prompted further consideration. The ACRS issued a letter stating its belief that a rapid depressurization capability should be considered for the current CE plants. The steam generator tube rupture in the Ginna plant emphasized the role of the PORV in accident management, and an internal memo from RES/DRA indicated the potential risk reduction benefits of a PORV (Ref. 32). Appendix B chronologically lists the events and issues leading to the staff study.

Because of the potential adverse effects on safety, the potentially significant costs and the schedular impacts that could result, the staff embarked on a detailed systematic study of the need for a rapid depressurization capability in current CE plants without PORVs. In particular, this study focused on PORVs providing this depressurization capability since we believe that PORVs would provide the most flexible system.

During the course of this study, the San Onofre plant was brought before the Commission for license application. The Commission expressed considerable interest in the study and the relationship of the study and its conclusions to the decision before them. Although approving the San Onofre license, the Commission requested the staff to formally report back to them with the results of the study. This report documents the results of the study and the conclusions drawn.

II. AREAS OF CONSIDERATION

As stated previously, our preliminary review indicated that the current design without PORVs met all of the current regulatory requirements. Therefore, a major aspect of the study was to perform a more detailed review of the current design to confirm that our preliminary conclusion was valid.

A second area of the review involved the "unquantifiable" benefits associated with a rapid depressurization capability for example, enhanced accident management capability and reduced accident and transient severity.

A third aspect of the review, was the evaluation of the risk reduction potential afforded by a rapid depressurization capability (or increased pressure relieving capability). This involved probabilistic risk assessments both with and without PORVs.

Finally, from these three types of assessments, combined with other considerations, overall conclusions were drawn.

III. EVALUATION

This section presents the staff's overall evaluation of the need for a rapid depressurization capability in current CE designed PWRs. As stated above, the staff focused its review on the need for a PORV as a rapid depressurization means. The staff evaluation consisted of reviewing the licensee, applicant and vendor responses to staff questions supplemented by independent analyses. This evaluation was then augmented with an additional overall evaluation taking into consideration not only the responses to the questions, but all review facets believed to be relevant. The overall evaluation was grouped into four topic areas. First, the staff determined if the CE plants met current regulatory requirements without a PORV. Second, the staff determined if the existing systems can mitigate events that are beyond the design basis and if a PORV would substantially improve the ability of the plant to accommodate these events. Third, a probabilistic risk assessment (PRA) was performed to estimate the change in core melt probability if a PORV were installed. And fourth, the cost and benefits were assessed and compared.

A. COMPLIANCE WITH CURRENT REGULATORY REQUIREMENTS

The question of whether recent CE plants should install a rapid depressurization capability in general, and in particular a PORV, is evaluated in this section with respect to current regulatory requirements. That is, are there any design basis conditions or events in which a PORV is required in order for the consequences to remain within acceptable limits (e.g., DNBR and maximum pressure limits in the case of transients and 10 CFR 100 guidelines in the case of accidents)?

1. Steam Generator Tube Ruptures

In the event of a steam generator tube rupture, leakage from the primary system to the secondary system will eventually overfill and pressurize the secondary system such that the secondary safety valves will lift, allowing the leaked primary coolant to escape directly to the environment. To prevent this situation from occurring, the primary pressure must be rapidly decreased to stop the primary to secondary leakage. This depressurization can be accomplished in a variety of ways, including use of the normal pressurizer spray which is available when the reactor coolant pumps are running, the auxiliary pressurizer spray which does not require the reactor coolant pumps, but rather derives its flow from the charging pumps, or opening the PORV and discharging steam from the pressurizer steam space.

The Westinghouse, B&W and early CE design PWRs rely on the pressurizer PORV to accomplish this depressurization whenever the reactor coolant pumps are not operating. However, the current CE plants rely on the auxiliary pressurizer spray system (APS) to limit the offsite radiological consequences to the regulatory limits. Because of its safety importance in accident mitigation, the APS system is considered to be a safety related system and should meet the single failure criterion. During our review of the APS systems for CE plants without PORVs, the staff identified a number of possible single failures that could defeat the spray function. These potential failures are identified in Appendix A, Section 1.B. Our review also determined that there are no technical specifications for the APS system, despite its importance in mitigation of the SGTR accident. As stated in 10 CFR 50.36, technical specifications are required for systems required for safe operation of the plant. These technical specifications ensure equipment availability and operability and ensure that the plant is operated within the envelope of conditions assumed in the accident analyses. The staff is pursuing these matters on the affected cases.

The capability of the APS system to depressurize the RCS following a design basis SGTR was evaluated by CE, the staff and Argonne National Laboratory (ANL) under contract to the staff. The evaluations, described in detail in Appendix A, Section 1.B, showed that mitigation using either the APS system or a PORV results in acceptable offsite radiological consequences. Further, the consequences are about the same using either technique.

ANL also analyzed the consequences of the operator inadvertently filling the pressurizer water solid while depressurizing the RCS with the APS system. The Analyses showed that recovery from a water-solid pressurizer would be difficult but possible for the current CE plants. Calculations performed by ANL showed that the recovery could be enhanced by opening a PORV. The pressure would drop more rapidly, thus minimizing primary to secondary break flow. Also, the steam volume in the pressurizer would reform, thus regaining the use of the APS as a means of continuing the depressurization. However, the rapid drop in reactor coolant system pressure results in a rapid increase in the reactor vessel upper head void size which may result in operator concern regarding core uncovery and potentially cause an operator error.

The utilization of the APS rather than a PORV to manage SGTRs has some advantages. The APS provides better pressure control and does not result in a net inventory loss from the primary system. Overall, no clear improvement in the management of a single SGTR using a PORV was determined.

The current CE design PWR SGTR accident analysis assumes a double ended guillotine rupture of a single tube in a single steam generator. Based on recent PWR experience with tube failures, the staff reviewed the continued acceptability of the single tube failure assumption. Information on water chemistry, corrosion, steam generator materials and preheater section tube vibration was reviewed. These aspects are evaluated in detail in Appendix A, and summarized in Section III.A.2, Steam Generator Integrity below.

2. <u>Steam Generator Integrity</u>

Steam Generator integrity plays an important role in determining the need for a rapid depressurization capability in current CE plants without PORVs. In the event that the integrity of both steam generators was lost, rapid depressurization and initiation of feed and bleed cooling might be the only actions that would prevent either excessive offsite doses or loss of all ECC water.

Additionally, steam generator integrity has special relevance to steam generator tube rupture (SGTR) accidents. Should the steam generator materials, water chemistry, inspection program or susceptability to flow induced vibration combine to significantly increase the likelihood of multiple tube ruptures, then the adequacy of the current CE plant's mitigation techniques would have to be assessed under these multiple tube rupture scenarios. Currently, only a single broken tube in a single steam generator is assumed in the safety analysis.

In response to questions regarding water chemistry, corrosion and preheater section tube vibration, licensees and applicants supplied information which is described and evaluated in Appendix A, Section 7, 13 and 14.

The combination of water chemistry controls, inservice inspection, preventive plugging of degraded tubes and primary to secondary leak rate limits lead CE and the staff to the conclusion that multiple tube ruptures (in a single or both SGs) do not lead to high estimates of public risk.

This conclusion also applies when taking into account the possibility of flow induced vibration in the preheater section of the CE System 80 steam generators. A full scale test of the economizer region was performed to investigate the vibrational response of the tubes when subjected to cross flow from feedwater inlet. From these tests, it is concluded that no detrimental tube vibration will occur.

However the current inability to accurately quantify both the probability and the consequences of multiple failures supports the argument that PORVs would provide an unquantifiable margin for safety to protect against unforeseen multiple tube ruptures or other losses of steam generator integrity.

3. Low Temperature Overpressure Protection

When PWR reactor coolant system is in a cold shutdown condition, the reactor vessel maximum allowable pressure is low as a result of vessel irradiation and embrittlement. Overpressure transients can occur as a result of inadvertently starting a HPSI pump. To ensure the maximum pressure in these situations remain below the limits specified in the ASME Boiler and Pressure Vessel Code, and specified in the license technical specifications, a low temperature overpressure protection system must be available. The Reactor Systems Branch Technical Position 5-2 of the Standard Review Plan states the functional requirements for this system, but does not specify the particular mitigation technique.

Most PWR designs utilize the pressurizer PORV as the means of mitigating low temperature overpressure transients. In these plants, the PORV setpoint is manually lowered to around 500 psig at low reactor coolant system (RCS) temperatures, and should the RCS pressure reach this value, the PORV opens to limit system pressure.

In the CE plants without PORVs, low temperature overpressure protection is provided by relief valves on the shutdown cooling system (SDCS).

The SDCS design pressure is 650 psig and the SDCS relief valves are set to open at 450 psia. The RCS design pressure is 2500 psia and the pressurizer safety valves are set to open at 2500 psia. When the RCS is in a cold shutdown condition, the maximum RCS allowable pressure is significantly below the RCS design pressure, as stated above, due to the reduced reactor vessel strength. The allowable pressure varies with RCS temperature and the amount of accumulated fluence the reactor vessel has received.

These aspects were evaluated by the staff for the various plants and the findings were reported in the respective Safety Evaluation Reports. Although the staff did not ask the licensee and applicants questions regarding low temperature overpressure protection, the staff reviewed this aspect of plant design for two reasons. First, concerns were expressed by the Commission during the April 4, 1983 staff briefing to the Commission on the status of the CE PORV study. Second, the French PWRs have experienced operational problems on their SDCS safety valves that may have relevence to the current CE design PWR SDCS relief valves. Each aspect is described further and evaluated below.

During the April 4, 1983 staff briefing, the Commission expressed concerns regarding the use of the relatively low design pressure SDCS for overpressure protection of the relatively high design pressure RCS. Keeping this concern in mind, the staff rereviewed the current CE design for providing low temperature overpressure protection. The staff's review determined that the SDCS relief ~~safety~~ valves provide mitigation for all credible events identified in the guidance in Branch Technical Position 5-2 of the Standard Review Plan. The relieving capacities and setpoints of the SDCS relief valves ensure that the maximum SDCS pressure remain below the SDCS design pressure for these overpressure transients. Further, the SDCS RVs provide acceptable RCS overpressure protection. However, one question did arise that the staff brought to the ASME for clarification.

The SDCS and RCS are isolated by safety related motor operated isolation valves (MOVs). Each MOV is provided with an automatic interlock that opens and closes the valves at predetermined RCS pressures.

The setpoint for the open permissive circuit is the SDCS design pressure. The setpoint for automatic closure is about 750 psig, which is above the design pressure of the SDCS. The autoclosure signal must be set above the SDCS relief valve setpoint to ensure the SDCS is not isolated before the relief valves open to relieve pressure on a postulated overpressure transient. The ASME Boiler and Pressure Vessel Code specifies the open permissive setpoint but does not discuss the auto closure setpoint feature. Since the SDCS isolation valve autoclosure feature provides some measure of protection against overpressurization of the SDCS, the setpoint in the current CE plants is above the SDCS design pressure and the ASME code is silent on this aspect, the staff could not readily resolve the question of whether the CE plants are in compliance with the code requirements.

In a recent meeting of ASME Section III Subgroup on Pressure Relief (Reference 34) the NRC staff member discussed the RCS and shutdown cooling system isolation design interface using motor operated isolation valves with auto closure interlocks. The Subgroup unanimously agreed that the configuration meets the intent of the ASME code, even though the isolation valves are interlocked to close at somewhat higher pressure than SDCS design pressure. As long as SDCS safety valve is sized to ensure the pressure in the SDCS remains below 110% of design pressure during all credible overpressure transients, the design is adequate. The current CE plant's SDCS relief valves meet this criterion as stated above.

Based on the staff's review of the adequacy of the current CE plant design for RCS low temperature overpressure protection, the staff concludes that the use of the SDCS for RCS overpressure protection is acceptable, and the SDCS itself will not be overpressurized.

At the recent international meeting on decay heat removal systems in Wurenlingen, Switzerland (See Marchese trip report, July 14, 1983, Reference 30), operational problems in the French PWR shutdown cooling systems were described. The French systems currently use Fisher code safety valves, and there have been occasions where the valves have stuck open. The French are considering replacing these valves with SEBIM pilot operated safety valves (see Marsh trip report, June 8, 1983, Reference 31).

The staff reviewed the domestic PWR shutdown cooling system operational experience reported in the last 3 years and found no cases where relief valves had stuck open. However there have been two cases where relief valves of similar design have lifted and stuck open in other reactor auxiliary systems. Additionally, the staff has learned informally that the French safety valves that malfunctioned were qualified only for steam, but not water discharge. In this case some malfunction would not be unusual. The current CE plants SDCS relief valves are ASME certified for water relief, and are not the same type of valve as the French SDCS safety valve. A recent overpressure event at San Onofre Unit 2 resulted in actuation of one SDCS relief valve. The valve operated properly during this event, although the overpressure transient was not severe and it is unlikely the valve was exposed to maximum flow conditions. Although certified for liquid flow and apparently different in design than the French SDCS valves, the current CE SDCS relief valves are much larger in relieving capacity than those on other PWR plants.

At the time these relief valves were manufactured, the ASME Code permitted such valves to be capacity certified based solely on calculations performed by the manufacturer. The recently completed EPRI tests performed on full size PWR primary system safety valves, in response to NUREG-0737, Item II.D.1, suggest that the manufacturers cannot obtain a complete understanding of valve performance capability without at least some full size test or operational experience.

While the staff is not recommending a complete full size test program for the current CE plant SDCS relief valves, the staff has concluded that because of their very large size, applicants and licensees using or intending to use such valves should be required to confirm through evidence supported by test or operational experience that these relief valves will operate, open and close for all fluid conditions that they could be exposed to in the plants.

Subject to receipt of the valve confirmatory information, the staff concludes that the low temperature overpressure protection systems for CE plants meet the functional requirements of Branch Technical Position 5-2 and are acceptable.

In the course of rereviewing the LTOPs design for the current CE plants, the staff noted that although the LTOPs meets the current regulatory criteria, there is a potential operation problem. As described above, the LTOPs relies on the relieving capacity of the SDCS relief valve which is set at 450 psia. CE informed the staff that to satisfy Reactor Coolant Pump (RCP) minimum suction pressure and seal pressure requirements, the RCS pressure must be above about 400 psig. Thus, there would be only about 50 psig to absorb any pressure increase while starting the RCPs. The setting of the SDCS relief valve may not be exactly 450 psig, and the valve may open at a lower pressure. SDCS relief valve leakage may occur at pressures slightly below the open setpoint.

CE informed the staff that during the SONGS-2 testing program, this operational problem had actually occurred. The RCPs could not be run as a result of SDCS relief valve weepage when the RCS (and SDCS) pressure was raised to satisfy the minimum pressure requirements for the RCPs. Apparently, the problem was solved at SONGS-2 by correcting the leaking SDCS relief valve. However, the staff notes that if the LTOPs were provided by a pressurizer PORV, as it is in virtually all other PWRs, this operational problem would not arise. If a PORV leaked, Technical Specifications permit the upstream block valve to be closed on that PORV, and the other PORV would provide overpressure protection. In summary, the use of the SDCS relief ~~safety~~ valve for RCS low temperature overpressure protection, while meeting the current regulatory requirements, may result in operational problems which would not necessarily arise if a pressurizer PORV were used.

4. Residual Heat Removal Systems

Branch Technical Position 5-1 of the Standard Review Plan states that for current PWRs, there should be safety grade systems capable of maintaining the reactor coolant system (RCS) in the hot standby condition for four hours followed by a cooldown to the cold shutdown condition. Depressurization of the RCS in other PWR designs is accomplished utilizing either RCS fluid contraction caused by the cooldown, heat losses from the pressurizer to ambient, or, by a safety related PORV. The current CE plants rely in part on the safety related auxiliary spray system (APS).

No specific questions were asked of CE or the CE owners regarding this aspect of plant operations, however the capability of current CE plants to achieve cold shutdown using only safety related equipment (and in particular to accomplish depressurization using the safety related APS) has been re-verified by the staff.

The capability of the APS to depressurize the RCS is discussed and evaluated in Appendix A, Section 1.B. Neither the CE nor the Argonne National Laboratory (ANL) evaluations analyzed the performance of the APS in depressurizing the RCS to the cold shutdown condition. However, steady state and transient calculations performed by CE assessed and suitably demonstrated the performance of the APS in depressurizing the RCS. Based on our evaluation of these calculations, the staff concludes that depressurization to the cold shutdown conditions with the APS is viable.

The staff requires that the single failure vulnerabilities of the APS identified and discussed above be corrected on the current CE plants. Without these corrections, the staff cannot conclude that the current CE plants meet the functional requirements of Branch Technical Position 5-1 nor can they be considered to have demonstrated their ability to meet the part 100 guidelines for the steam generator tube rupture event in the presence of a single failure, since the APS has single failures that defeat its ability to depressurize the reactor coolant system. The staff also requires that suitable technical specifications governing the APS be developed and implemented.

5. Auxiliary Feedwater Reliability

As part of the staff consideration of the need for a rapid depressurization capability, in this case in the context of effecting decay heat removal by the feed and bleed process, the staff reexamined the reliability of the existing auxiliary feedwater systems. The intent of this review was to ensure that no new information came from the staff's or CEOG's probabilistic risk assessments that would alter the staff's previous reliability and deterministic assessments of the current CE plant's auxiliary feedwater systems.

On the basis of this review, the staff concluded that the previous assessments remain valid and the staff's conclusions unchanged. No new information has been learned that alters the staff's previous analyses. The staff believes that the current CE plant's auxiliary feedwater systems meet the reliability criterion of 10^{-4} to 10^{-5} per demand and deterministic criteria specified in the Standard Review Plan Section 10.4.9.

6. Conclusions

Based on the above considerations, the staff concludes that, with exception of the single failures identified in the auxiliary spray system and the lack of adequate technical specifications for the auxiliary spray systems, the current CE plants meet the current regulatory requirements. Mitigation of a single SGTR with either a PORV or with the APS results in acceptable offsite radiological consequences that are essentially the same. Further, mitigation using the auxiliary spray system has the advantages of providing a controllable depressurization technique and of adding fluid to the reactor coolant system. Multiple tube ruptures, as either an initiating event or as a consequence of other accidents are sufficiently low probability that they need not be considered as a design basis accident.

B. CAPABILITIES BEYOND THE CURRENT REGULATORY REQUIREMENTS

This section contains the staff's analysis of the capabilities of the current CE designed plants without PORVs to mitigate multiple failure scenarios that are beyond the regulatory requirements. The staff's analyses were conducted in two ways. First, the staff assessed the capabilities of the existing equipment and systems to mitigate specific multiple failure accident scenarios. Second, based on the first analyses, the staff identified mitigation system failures and described how a PORV could either enhance or provide the necessary mitigation. The second part of the staff's evaluation is a qualitative assessment and describes how the PORV could aid both the operator and the plant in managing accidents beyond the current design basis.

The purpose of these evaluations is to determine if the existing systems are able to mitigate low probability (and perhaps high consequence) multiple failure accident sequences, and if a PORV would offer any significant net safety benefits.

1. Multiple Failure Accident Scenarios

The staff requested CE to assess the ability of the existing systems, including a PORV, to mitigate multiple failure accident scenarios beyond the design basis. CE's response is described in detail in Appendix A, Section 5 and 8, and is summarized below.

a. Multiple Steam Generator Tube Ruptures (MSGTRs)

Should tubes rupture simultaneously in both steam generators, the offsite consequences could be greater than the design basis SGTR since one of the damaged SGs would have to be continually steamed to the atmosphere (assuming loss of offsite power so the condenser was not available) to remove core decay heat. The staff and CE evaluated these multiple tube rupture scenarios, and the staff compared the mitigation abilities of the APS to an assumed PORV. These analyses, described in Section 5.B of Appendix A generally showed that the offsite consequences would be about the same, whether a PORV or the APS were used for mitigation.

Both the staff and CE evaluated a simultaneous single tube rupture in each SG, and CE evaluated 3 tubes simultaneously rupturing in each SG. The results of all these assessments, contained in Section 5.B of Appendix A, show that the offsite doses are below the 10 CFR 100 limits.

Neither the staff nor CE evaluated tube ruptures beyond 3 tubes in each SG although we have indications that ruptures beyond 3 tubes results in unacceptable consequences. CE stated that further analyses were not performed due to the extremely low probability of these scenarios. The staff evaluation of steam generator integrity (Section III.A.5), resulted in the same qualitative conclusion.

The ANL analyses investigated the viability of performing feed and bleed decay heat removal, rather than continually steaming one of the damaged SG's. While feed and bleed was successful in terms of limiting offsite consequences, the calculations showed that cooling of the RCS was slowed significantly as a result of the heat input from the damaged steam generator. The slow RCS cooldown would necessitate high pressure recirculation due to the expenditure of RWST water. This operation would involve the containment sump supplying water to the shutdown cooling system (SDCS) pumps, which would supply the suction of the high pressure injection (HPI) pumps. There are many undesirable aspects to this approach. First, the containment has been contaminated. Second, a small break LOCA has been created thus placing extra reliance on the HPI pumps for inventory control. Third, long term recirculation requires valve alignments and equipment configurations not normally used. When considering the relatively low offsite dose using the normal means of cooling the RCS and the drawbacks associated with the feed and bleed operation, the staff believes that feed and bleed is not the preferred means of mitigating this scenario.

The staff did not assess the viability of feed and bleed in mitigating more than a single ruptured tube in each SG. For larger numbers of broken tubes the offsite dose could be significant, thus feed-and-bleed may become a desirable means of mitigating multiple broken tubes occuring simultaneously in both steam generators. However, the probability of such scenarios is considered to be extremely low.

b. Total Loss of Feedwater Events

The AFW systems for the current CE plants have been reviewed by the staff and meet both the deterministic and reliability criteria (Section III.A.4) However, since the CE design initially relies exclusively on the steam generators for the removal of decay heat, the staff asked CE to describe how a total loss of feedwater (TLOFW) could be mitigated.

CE responded that alternate low pressure feedwater systems could be used for adding inventory to the steam generators. CE also addressed the mitigation capabilities of an assumed pressurizer PORV. These responses and the staff's evaluations are described in Appendix A, Sections 6 and 8.B.

While we acknowledge the CE approach of providing alternate emergency sources of feedwater to the generators, we recognize that reliance on the secondary side for decay heat removal involves not only the AFW system, but also requires steam generator integrity and safety/relief valve operability. Therefore, we examined the viability of feed and bleed as an emergency decay heat removal method. The staff contracted ANL to analyze a spectrum of TLOFW scenarios. Two PORV sizes were studied; a small, Calvert Cliffs size PORV and a large St. Lucie Unit 2 size PORV. The actual flow area could be achieved by a single valve or by a combination of many smaller valves. The ANL and Combustion Engineering calculations determined the time of core uncovery without any operator action and the latest time the following action could be initiated to avoid core uncovery: (1) open PORV(s) to initiate feed and bleed (2) steam generator blowdown to effect condensate pump supplied feedwater, or (3) regain AFW flow.

The ANL and CE results generally agreed, and showed that feed and bleed must be initiated within about 20-25 minutes after the TLOFW for core uncovery to be avoided. Without feed and bleed, initiating SG blowdown as late as 55 minutes following TLOFW will avoid core uncovery. Therefore, the initiation of feed and bleed must begin about 30 minutes before the latest time SG blowdown could be initiated. The initiation of feed and bleed may, therefore, be unnecessary if AFW system was restored, or if the SG blowdown were successful. However, the condensate pumps rely on offsite power and, as described in Appendix A, Section 6.C, the emergency powered fire pump discharge pressure is too low to ensure that core uncovery is avoided.

The use of the condensate system depends on the availability of offsite power, local manual operation of selected condensate valves and the operation of control grade components. These limitations have been factored into the Probabilistic Risk Assessment (PRA), Section III.D. Procedures are not now available for the use of the condensate system in this situation, although the licensee and applicant described general guidelines from which procedures could be developed.

Calculations performed by RES for another NRC program indicated that the use of the Auxiliary Pressure Spray would not significantly alter the course of a total loss of feedwater accident, without any condensate flow, on the current CE plants without PORVs. The initial depressurization by the APS is not enough to lower RCS pressure to the point where significant high pressure injection flow is added to the system. The APS would only slightly delay the time of core uncovery in the 3800 MWt plants by about 15 minutes.

A condition associated with alternate secondary side cooling is the addition of cold water to a hot, dry, steam generator. CE evaluated the effects of cold feedwater (condensate) addition to a hot, dry steam generator and determined that the SGs would be able to withstand the resulting thermal shock. Also, the SG structural integrity would not be compromised even if condenser cooling water (a lower grade water) was used as steam generator feedwater during this situation.

In summary, the TLOFW event in which offsite power is retained can be mitigated by the condensate pumps as long as the steam generator atmospheric dump valves and the condensate system operate properly. There are uncertainties associated with the use of the condensate system for low pressure feeding of the steam generators. For example, there are no explicit procedures available in the plants for this technique. The staff will require the development and implementation of these procedures and of operator training.

SG structural integrity is not compromised by the thermal shock associated with cold condensate water addition, or by the possible accelerated corrosion due to condenser cooling water addition, if it were used.

For other scenarios including a TLOFW with loss of offsite power and in order to account for uncertainties, such as the operation of the condensate and ADV system, a PORV which can rapidly depressurize the primary system and allow feed and bleed cooling is very beneficial.

c. Small Break LOCA Without HPSI

Among the scenarios considered beyond the design basis is a small break loss of coolant accident (SBLOCA) without high pressure safety injection (HPSI). CE analyzed three cases: (1) no operator action, (2) RCS depressurization with a PORV and (3) RCS depressurization by aggressively cooling the RCS with the steam generator atmospheric dump valves (ADVs). These are described and evaluated in Section 5.B of Appendix A.

The results showed that core uncovery did not occur when the plant was depressurized by aggressive steam generator blowdown using the ADVs, and, in contrast, core uncovery did occur (but no excessive fuel heatup occurred) when the plant was depressurized using PORVs. Based on these analyses, the staff agrees with CE that an aggressive secondary side cooldown is the preferred method of mitigating a SBLOCA without HPI. However, use of the PORVs to depressurize the system will also mitigate the event, but the increased inventory loss through the PORV results in more core uncovery.

As for other conditions, the PORV provides an added margin of safety in the event the ADV blowdown is not completely effective.

d. Pressurized Thermal Shock

The concern that the reactor vessel may experience excessive thermal shock as a result of cooldown and pressurization transients is currently being addressed as an Unresolved Safety Issue (USI A-49). Scenarios presently thought to be of principal concern are multiple failure scenarios.

Because the PORV could be useful in limiting system repressurization, the staff requested CE to evaluate the usefulness of the PORV for the mitigation of PTS events. CE's response, discussed and evaluated in Section 4.B of Appendix A, contained analyses of steam line breaks accidents with break areas of 0.5 ft^2 and 1.29 ft^2, without the use of PORVs. The results of the analyses indicated that no crack initiation would occur for either transient even when analyzed at a vessel radiation level corresponding to more than twice the design life of the plant. Preliminary results from the Pressurized Thermal Shock Unresolved Safety program, which did not include credit for use of a PORV to limit system repressurization, indicate no concerns for CE designed plants. As long as the end-of-life reactor vessel nil-ductility transition reference temperature does not exceed the PTS screening criteria in the proposed PTS rule now in rulemaking (270°F for longitudinal welds or plate material, or 300°F for circumferential wells), the staff believes no further actions are necessary to address the PTS concern. The end-of-life reference temperature for CE plants, without PORVs, are not expected to exceed the screening criteria.

e. Anticipated Transients Without Scram (ATWS)

The staff requested CE to address the potential benefits from a PORV in terms of mitigating Anticipated Transients Without Scram (ATWS). The CE response and staff evaluation is contained in Appendix A, Section 3.B. ATWS is currently beyond the regulatory requirements design basis, although there is pending rulemaking regarding the prevention and mitigation of ATWS scenarios.

A major safety concern in an ATWS event is excessive primary system pressure which can result in a major leak in the primary system and defeat of the high pressure injection system because of deformed check valves in the injection line of the high pressure boundary. The limiting pressure for an ATWS is assumed to be 3200 psia which corresponds to ASME Boiler Pressure Vessel Code Stress Level C. However, it is recognized that there is capability of the plant to withstand pressures in excess of level C.

The pending ATWS rule would require a diverse turbine trip for CE plants. The CEOG calculations show that when taking credit for the turbine trip but no credit for a PORV, the peak RCS pressure is greater than 3200 psia for only the 3410 class plants. The peak pressure for the 3800 class plants is about 2900 psia. Therefore, extra relieving capacity would be necessary for only the 3410 class plants. CE has calculated that an additional 0.10 ft^2 relieving area would be necessary to lower the peak RCS pressure to 3200 psia. This is about four times the relieving area of each St. Lucie Unit 2 PORV.

We note that the use of a rapid depressurization capability to help mitigate the pressure peak in an ATWS requires a continuously aligned, fast-acting PORV. This may result in an increased risk from a small-break LOCA induced by stuck-open PORV's. This will be considered in the probabilistic risk analysis section III.D, and also in Appendix, A.

We note further that the moderator temperature coefficient (MTC) used by CE in their ATWS calculations is a conservative value. The MTC will be more negative 95% of the time. Even though, for this MTC, the peak pressure reached in an ATWS exceeds 3200 psia (for the 3410 plants), the addition of St. Lucie Unit 2 sized PORV's would be of benefit for ATWS sequences. The addition of the PORV's would increase the fraction of reactor operating time in which the peak pressure were less than 3200 psia.

In summary, additional relieving capacity would be necessary for only the 3410 class plants since the 3800 class plants meet the 3200 psia limit for 95% of the reactor operating times when turbine trip is credited. The installation of the St. Lucie Unit 2 size PORVs would lower the peak pressure for the 3410 class plants to below 3200 psia for about 1/3 of the operating cycle, while without the PORVs, the peak pressure would be above 3200 psia for virtually all of the operating cycle, even when turbine trip is credited.

Again, it is pointed out that there could be other ATWS scenarios that result in excessive peak pressures (i.e., greater than 3200 psia) that have not been identified or are currently considered to be too low in probability to be considered. The addition of PORVs of both the 3410 and 3800 classes of plants would increase their margin to accommodate a wide spectrum of ATWS events.

2. Additional Multiple Failure Scenarios

This section describes other mitigation system failure scenarios beyond those considered in Section III.B.1 above. These failures are beyond the regulatory requirements since the mitigation systems generally meet the regulations. The failures are general and qualitative, and are more system functional failures than specific equipment failures. They are presented as an additional aspect the staff believes to be appropriate in the consideration of the need for a PORV on current CE design plants.

The staff contacted plant operators and NRC training personnel to gain their perspective on possible mitigation techniques with these failure scenarios and the potential benefits of a PORV. These considerations have been factored into the discussions below.

a. Limitations of the Auxiliary Pressurizer Spray System

The utilization of the auxiliary pressurizer spray (APS) spray system for the mitigation of scenarios both within and beyond the current regulatory requirements is dependent on the ability of the APS to depressurize the reactor coolant system. The staff review determined that certain single failures in the APS could defeat the system's ability to reduce system pressure. In order for credit to be given for the APS, these vulnerabilities must be corrected. The multiple failure scenarios described below deal with the loss of the APS function as a result of additional malfunctions or operator errors, that are beyond the regulatory requirements.

1. Water Solid System or Excessive Pressurizer Insurge

As discussed in Section 1.B of Appendix A, system depressurization using the APS system is only viable when there exists a steam space in the pressurizer. During situations when there is a large pressurizer insurge, the depressurization capability of the APS is reduced significantly. Further, in scenarios where the pressurizer steam space is lost altogether (i.e., operator error in continually spraying while the safety injection system is in use), the APS is incapable of depressurizing the RCS. This results in extra reliance on the operator. To recover from this situation, APS must be stopped, RCS cooldown continued with the SG ADVs, and careful monitoring and control of the safety injection flow and reactor vessel upper head steam void size. Having a PORV in this situation may help. A PORV will always be able to lower system pressure, but may not efficiently regain the pressurizer steam space. However, plant operators and OIE training staff noted that in terms of controlling plant pressure, an approximately designed PORV would provide another means of lowering system pressure if the system became water solid or if there were an excessive pressurizer insurge.

2. <u>Unforeseen Malfunctions</u>

With the exception of the single failure previously identified, the APS system meets the staff's deterministic criteria and is judged to be an acceptable, safety related system. No additional malfunctions could be identified that totally defeat system operation. However, the auxiliary spray system relies on manual operator actions to align the fluid system valves, start the charging pumps (Palo Verde Units 1,2, & 3), and initiate and control the flow. A number of components must properly function, and the operator must take appropriate actions. Compared to the operation of a PORV, which would involve opening the block valve if normally closed, and the PORV itself, operation of the APS involves more alignments, and operator actions. Should unforeseen malfunctions or operator errors occur that are not discovered by the staff's deterministic assessment, the APS may be limited or unable to lower system pressure.

3. <u>Pressurizer Nozzle Fatigue</u>

The fatigue usage of the pressurizer spray nozzle was evaluated and the results reported in Appendix A, Section 1.B. The staff generally agreed with the techniques and assumptions associated with the CE analyses. The CE calculations are generally conservative, however, the staff notes that plants may operate in a manner that makes the fatigue calculation less of a conservative, bounding type calculation, and more of a best-estimate calculation. There is nothing in the technical specifications or FSAR that limits the number of spray cycles, and plants may choose to cycle the spray system (auxiliary spray or main spray), more frequently. This, in and of itself, may not necessitate the addition of a PORV, but the staff considers the fatigue usage uncertainty as one factor that should be considered when assessing limitations associated with the APS. A PORV, or other means of rapidly reducing system pressure could always be used, and is not limited by pressurizer nozzle fatigue.

b. Redundant/Diverse Means of Core Decay Heat Removal

As discussed in Section III.B.2, should there be a total loss of feedwater, which both the staff and the CEOG agree is highly unlikely, the condensate system could supply steam generator makeup. However, the condensate system relies on offsite power and a number of local manual valve operations. In terms of plant safety, a rapid depressurization capability provided by a PORV or other relief path would provide the capability for feed and bleed cooling. Although not required by the current regulatory requirements, feed and bleed cooling is a redundant means of removing decay heat.

The use of the steam generators for the removal of decay heat is effective as long as the steam generators are available for energy removal. Without attempting to specify scenarios in which the steam generator becomes unavailable, should serious malfunctions occur, the PORV could provide a means of avoiding core damage in situations where the steam generators are not capable of removing core decay heat. A feed-and-bleed capability adds to the plant safety by enabling the removal of decay heat by a means other than the steam generator. It should be noted that a mission of reliable decay heat removal could dictate different design constraints on a PORV than would a mission of rapid RCS depressurization.

c. Prevention of Pressurizer Safety Valve Loss of Coolant Accidents

CE has stated that the high pressure reactor trip, together with the steam dump system, will prevent lifting the pressurizer safety valves for most anticipated operational occurrences. The staff evaluated this in Appendix A, Section 2.B., and generally agreed that if the steam dump system works properly, the safety valves would not lift. However, there are situations where the steam dump system does not provide sufficient core decay heat removal. In addition, there is a small probability that pressurizer safety valves (SV) may fail to reclose after opening.

The safety significance of pressurizer SV lifts under these situations must be considered since SVs cannot be isolated should they fail to close. A stuck open SV following a transient is a multiple failure scenario since the combination of a passive failure in conjunction with a transient is beyond the current regulatory requirements. An automatically actuated PORV, with upstream block valves normally open, and with a setpoint above the normal high pressure reactor scram, may avoid pressurizer safety valve LOCAs. It must be pointed out however, that PORVs can leak, and, in fact, many plants with PORVs currently run with the block valves closed, negating this benefit of a PORV in this application.

C. Conclusions

Based on the analyses of selected multiple failure accident scenarios that are beyond the current regulatory requirements, the staff concludes that with the exception of anticipated transients without scram for the 3410 CE plants, and loss of all feedwater in either CE models, the existing systems should be able to mitigate the spectrum of multiple failure accidents considered. However, there are known and unknown limitations associated with the mitigation systems.

The capability of the APS to depressurize the reactor coolant system depends on the presence of a steam space in the pressurizer, and on a number of operator actions. Also, while we have confidence in the deterministic assessment of the APS system, we recognize that there may be unforeseen malfunctions that render the system unable to control plant pressure.

Similar limitations can be expressed regarding the decay heat removal systems. The CE analyses showed that the condensate system is able to supply sufficient steam generator feedwater to avoid core uncovery. However, the condensate system relies on offsite power. Also, the steam generators themselves must be able to remove decay heat. In the event of loss of all feedwater, the steam generators may become unable to remove decay heat, and a suitably sized and properly operated pressurizer PORV could remove decay heat and avoid core damage. Similarly, the PORV could keep the pressurizer safety valves from lifting and prevent an unisolable LOCA.

On balance, while the staff recognizes that the existing systems afford mitigation of a number of multiple failure accident scenarios that are beyond the current regulatory requirements, there are considerable uncertainties in this ability, and a properly sized PORV with a carefully chosen setpoint could provide defense in depth for many unforeseen events.

C. PROBABILISTIC RISK ASSESSMENT (PRA)

The staff, in order to obtain some quantitative measure of the change in safety from the addition of PORV's, asked Combustion Engineering several questions in order to obtain the information necessary to estimate this change in safety in a probabilistic way. The staff has reviewed C.E.'s responses to these questions. In addition, the staff's consultant, Sandia National Laboratory, has performed an independent analysis. Finally, the staff has performed its own probabilistic assessment. CE performed plant specific for each member of the CEOG. The staff and the Sandia National Laboratory analyses considered only SONGs-2 and 3 design except that the staff ATWS analysis also considered the 3800 MWth class plant.

1. Scope of Considerations

All three studies included a quantitative analysis of the loss of main feedwater event, including the loss of main feedwater caused by loss of offsite power. Steam generator tube ruptures (SGTR) were considered quantitatively in the CE and Sandia analyses. Only the staff analysis includes a quantification of the benefits from additional pressure relief for ATWS sequences. External events, fires, and floods were not considered in any of the studies.

Several additional potential benefits from the addition of PORV's were not quantified by either CE, the staff, or Sandia. These benefits include the possible limitation of challenges to the safety valves. The possible benefits also include the ability to depressurize the reactor coolant system while a core melt is in progress, thereby decreasing the probability of failure of the steam generator tubes from steam overpressure when the core slumps into the lower reactor vessel plenum.

2. PORV Design Consideration

C.E., in its CEN-239 submittal, considered only one type of "feed and bleed" system, one in which the PORV block valves were normally closed, and in which each block valve required power from a separate diesel generator. Since both PORVs were required for success of feed and bleed, this limited the value of the feed and bleed system on loss of offsite power events. In addition, because the block valves were closed, the PORVs are not beneficial in reducing the peak pressure in an ATWS; such a design does, however, limit the frequency of PORV LOCA's.

Later results were communicated to the staff by telephone. These later results, for San Onofre Units 2 and 3 included the case of an automatic PORV design, in which the PORV block valves are normally open. (C.E. had, in its original CEN-239 submittal, considered the increase in PORV-LOCA frequency from the automatic PORV design, but had not considered the improvement in feed and bleed performance.)

Both the Sandia analysis and the staff analysis considered feed and bleed systems which were more reliable than the system originally considered by Combustion Engineering. The Sandia analysis assumed the block valves were normally closed, but that either diesel generator could power either block valve. The staff analysis assumed that the block valve were normally open. Thus, in both the Sandia and staff feed and bleed system, feed and bleed success is possible on loss of offsite power with failure of one diesel generator, while failure of a single diesel generator for the CE system on a loss of offsite power transient fails feed and bleed.

3. Core Melt Sequence Frequencies

a. PORV - LOCA Sequences

The staff believes that with proper design and operation, the frequency of LOCAs due to stuck open PORVs can be made negligible, even for the case where the PORV block valves are normally open. The sequences of most concern would be the lifting of a PORV on a loss of offsite power transient. If the PORV should stick open, and if neither diesel generator were to start, there would be a LOCA with no way of mitigating it. The high pressure injection system would be unavailable and the block valves (operated by AC) could not be operated. To avoid this potential scenario, the opening setpoint of the PORV could be chosen such that the PORV would lift for only a small fraction of loss of offsite power transients. Moreover, it is possible to power the block valves by D.C. to permit isolation if the PORV sticks open. The PORV system arrangement in which the block valves are always open possesses the advantage of reducing the challenge frequency to the safety valves, and gives additional pressure relief for ATWS sequences.

Combustion Engineering in its original CEN-239 submittal, had not correctly considered the lifting of PORVs on loss of offsite power transients. In revised results for San Onofre, transmitted by telephone from C.E., C.E. estimated the frequency of PORV-LOCAs, including those caused by loss of offsite power, as $4.1X10^{-6}$/yr (median value) for the automatic PORV design, and as $7x10^{-8}$/yr for the case where the PORV block valves are normally closed.

Sandia National Laboratory, because it considered a PORV system in which the block valves are normally closed, obtained a negligible core melt frequency from PORV-LOCAs.

b. Loss of Secondary Heat Sink Sequences

The staff and C.E. has given credit for decay heat removal by use of the condensate pumps after depressurization of the steam generators (called the "alternate secondary decay heat removal system by C.E.). The assumption has been made in the staff analysis that there are procedures in place for the depressurization of the steam generators and use of the condensate pumps, on loss of main feedwater transients in which the auxiliary feedwater system is available. Sandia National Laboratory gave no credit for the alternate secondary decay heat removal system.

Tables C.1, C.2 and C.3 give a summary of the results for the loss of heat sink sequences. Table C.1 gives the core melt frequency for loss of heat sink sequences, for San Onofre Units 2 and 3 as corrected by C.E.; the corrected results were transmitted by telephone. Appendix A.11 gives both the corrected results and those supplied in CEN-239. Table C.2 gives the results for the loss of heat sink sequences as calculated by Sandia, and Table C.3 the results for the loss of heat sink sequences as calculated by the staff.

The importance of procedures for use of the alternate secondary decay heat removal system can be seen from the fact that if no credit is given for this system, the core melt frequency from loss of main feedwater transients, for a plant without PORVs, would be about 6×10^{-5}/yr (mean value), instead of the value of 9×10^{-6}/yr given in the table. The net gain from adding PORVs, from the loss of secondary heat sink sequences, would then be 7×10^{-5}/yr, instead of 1.5×10^{-5}/yr.

c. Small LOCAs

Both Sandia and C.E. obtained the results that the frequency of core melt sequences initiated by small LOCAs is not appreciably changed by adding PORVs. However, both analyses assumed that a small LOCA followed by failure of the High Pressure Injection System would lead to core melt. There is, however, the possibility that PORVs could be used to depressurize the primary system, and low pressure injection systems used. Also, as described in Section II.B, an aggressive cooldown of the RCS using the steam generator atmospheric dump valves also would avoid core uncovery. Thus, assuming a small break LOCA without HPSI results in core melt is a significant conservatism that ignores the thermal-hydraulic work performed for Section III.B above.

However, before credit can be given for aggressive cooldown for the RCS, it is necessary to have procedures in place. The frequency of small break LOCAs with failure of the High Pressure injection system is approximately 1×10^{-5}/yr, assuming a small break LOCA frequency of 2×10^{-2}/yr and a High Pressure Inejection System unavailability of 5×10^{-4}/per demand. Thus there would be appreciable benefit from having the procedures in place, and to have training in the use of the procedures

d. ATWS

For ATWS sequences the staff quantified the benefits by estimating the reduction in the frequency of ATWS events in which the peak primary pressure exceeds 3200 psia. This frequency reduction ranged from $3.2x10^{-5}$/year for a 3410 plant without implementation of the ATWS rule to $2x10^{-6}$/year for a 3800 plant in which the ATWS rule was implemented. The assumption was made that two PORVs sized for decay heat removal were added. The results are given in table C.4.

4. Net Change in Core Melt Frequency From Adding PORVs

The overall net change in core melt frequency from the addition of PORVs, as given by CEOG in CEN-239, was less than 10^{-6}/yr for San Onofre Units 2 and 3. After C.E. corrected certain inconsistencies identified by the staff the core melt frequency from loss of heat sink sequences was decreased by $2x10^{-6}$/yr from adding PORVs, for the C.E. automatic PORV system. (This is an approximate result obtained by taking the differences of median values).

However, PORV LOCA sequences more than counterbalanced this reduction in the revised C.E. analysis, with the result that adding the C.E. automatic PORV design resulted in an increase in the core melt frequency of $1.4x10^{-6}$/yr (median value). Adding manual PORVs (block valves normally closed) leads to a decrease in core melt frequency of $1.3x10^{-7}$/yr, according to the C.E. analysis.

The analysis by SNL indicated, for their PORV system, that the net decrease in core melt frequency was $4x10^{-6}$/yr; this is a point estimate based on median value of component failure rates, as opposed to a true median value of the decrease in core melt frequency.

The staff obtained a net decrease in core melt frequency of $1.5x10^{-5}$/yr (mean value), from non ATWS sequences; the median value was $1.4x10^{-6}$/yr. Differences among these results are very likely largely attributable to differences in the frequency of loss of offsite power and the probability of recovery of offsite power, and to differences in the PORV and the block valve design/configuration assumptions.

The ATWS sequence core melt frequency reduction are given in table C.4.

5. Conclusions

The staff's best estimate calculation showed that if PORVs were installed on CE plants, the core melt frequency would be reduced by about a factor of 2, from $6x10^{-5}$ per reactor year to $3.5x10^{-5}$ per reactor year for the loss of heat sink and ATWS sequences. These are mean value estimates that combine the results of ATWS and non-ATWS sequences, the latter being the principal contributor. The staff considers the mean value to be more appropriate for use in the value/impact assessment given in the next section.

The accident sequences for which PORVs could avert core melt are primarily those for which some AC power is available. Containment heat removal system are likely to be operable so that offsite radiological consequences are not judged to be large. Therefore a large part of the incentive for PORV addition lies in providing greater operational flexibility in upset events and in averting core damage generally associated with modest offsite consequences.

Table C.1

Combustion Engineering Core Melt Frequency Results

Core Melt Frequency - San Onofre Unit 2 and 3

	With PORVs	Without PORVs
Loss of MFW combined with Loss of Offsite Power initiators	1.1×10^{-6}/yr, auto PORV	3.1×10^{-6}/yr
	2.8×10^{-6}/yr, manual PORV	

1. Corrected values supplied by C-E, not reported in CEN-239.

2. Because of the PORV-LOCA sequences, C.E., in their corrected analysis, obtains an increase in core melt frequency 1.4×10^{-6}/yr from adding PORVs, for the automatic PORV design.

Table C.2

Sandia National Laboratory Results
Core Melt Frequency

Initiator	With PORV's	Without PORV's
Loss of MFW	7.2×10^{-8}/yr	2.6×10^{-6}/yr.
Loss of Offsite Power	5.5×10^{-6}/yr	7×10^{-6}/yr

Note to Table D.2

1. The values quoted are point estimate values, obtained from median point estimates of individual component failure probabilities.

2. The core melt probability due to SGTRs and small break LOCAs was calculated to be the same both with and without PORVs. The Sandia analyses did not quantify the ATWS sequences

Table C.3

Staff Analysis-Non ATWS Sequence
Core Melt Frequency

Initiator	With PORV's	Without PORV's
Loss of MFW	1.7×10^{-6}/yr.	9×10^{-6}/yr.
Loss of Offsite Power	6×10^{-6}/yr.	1.4×10^{-5}/yr.

Net gain from PORV's is 1.5x10-5/yr (mean with an Error Factor of 36), from these sequences. The median value is 1.4×10^{-6}/yr.

Table C. 4

Staff Analysis - ATWS Sequences

Change in the Frequency of ATWS Sequences in which pressure exceeds 3200 psi, by adding 2 PORVs, with .0228 ft2 area per valve.

	3410 plants	3800 plants
1. ATWS Rule not implemented	3.2×10^{-5}/yr.	5×10^{-6}/yr.
2. ATWS Rule implemented	1×10^{-5}/yr.	2x10-6/yr. (below 3200 psi 95% of the time without additional relief area.)

The estimates provided in Table C.4 are for exceedance of 3200 psi primary system pressure. The value/impact analyses, provided in Section III. D of this report, are based on the following assumptions.

1. ATWS rule is implemented.

2. Although the conditional probability of core melt given high primary pressure (in excess of 3200 psi) is likely to be less than 1, the value/impact assessment assumes this value to be 1. A some what lower value would have negligible impact on the results.

D. VALUE/IMPACT ANALYSIS

1. Background

This section presents a summary of the staff's evaluation that was made to determine if the backfit of PORVs to C-E plants lacking such capability represents an important safety improvement, including assessing the value/impact or benefit/cost of such a backfit. Although the method used has a quantitative emphasis, the calculated numerical values are only used as an aid to the decision making process, and are not intended to be used as the final decision making criterion on this issue. It is therefore considered as a supplementary tool used to provide additional insight in an overall evaluation of this issue.

The safety importance is represented as a reduction in the probability of core melt, and reduction in risk (man-rem) to the public that would result from the backfit of PORVs to those C-E plants lacking such capability.

This evaluation utilizes the results of the staff's probabilistic risk assessment (PRA) and cost evaluation presented separately in Section III.C and Appendix 12, respectively. The reader is referred to those parts for details of the evaluations. In addition to those results, the methods developed in Reference 20 are used to estimate the consequences of potential nuclear power reactor accidents with specific application to the C-E/PORV issue.

A comparison of the staff's independent cost/benefit results with those of the C-E owners group is shown in Table D-1. Besides the change in core melt frequency and PORV installation costs, we have also shown a comparison of the installation time and estimated replacement power costs. With respect to the change in core melt frequency caused by adding PORVs, there is a considerable difference between the staff and the C-E Owners Group results. The reason for the differences are discussed in detail in Section III.C. Considering the implementation costs for adding a controlled depressurization system, there is reasonable agreement between the staff and the CE Owners Group results, except for the owners group estimates for replacement power costs which the staff considers to be conservatively high and unsubstantiated as discussed in Appendix A, Section 12.

2. Risk Reduction

Table D-2 summarizes the results of the risk reduction from installation of PORVs. The core melt release categories are based on CRAC-2 results for SONGS-2, as described in Reference 20. Release category SST1 essentially involves loss of all installed safety features and direct breach of the containment. Release category SST2 involves failure of the containment to isolate with operation of the fission product release mitigation systems.

TABLE D-1
COMPARISON OF COST/BENEFIT RESULTS

ORGANIZATION	CHANGE IN CORE MELT FREQUENCY (PER REACTOR-YR)	PORV INSTALLATION COSTS PER PLANT ($ MILLION)	TIME TO INSTALL PORVs (DAYS)	REPLACEMENT POWER COSTS PER PLANT TO INSTALL PORVs ($ MILLION)
NRC STAFF:				
CASE 1-BEFORE PLANT OPERATION	$2x10^{-5}$	2.5	60	0 TO 3
CASE 2-AFTER PLANT OPERATION		4.3	60	
SCE Co.				
(SONGS - 2 & 3)	$(1x10^{-7})$ (1)	2.3	42	2 TO 35
LP&L				
(WATERFORD - 3)	$(1.1x10^{-6})$ (2)	2.3	80	3 TO 30
APS Co.				
(PALO VERDE - 1,2&3)	$(1.6x10^{-7})$ (2)	5.54 (FOR ALL 3 UNITS) DURING A REFUELING OUTAGE		2 PER UNIT

NOTES:

(1) THIS IS A REVISED NUMBER, OBTAINED FROM CE BY TELEPHONE FOR THE CASE OF MANUALLY OPERATED PORVS. FOR THE CASE OF AUTOMATIC PORVS CE PREDICTS AN INCREASE IN CORE MELT FREQUENCY FROM THE ADDITION OF PORVS, BECAUSE OF THE PORV-LOCA SEQUENCES.

(2) THESE CHANGES IN CORE MELT FREQUENCY ARE UNDERGOING REVISION BY CE.

TABLE D-2

RISK REDUCTION FROM PORV INSTALLATION (SONGS - UNIT 2)

PLANT	RELEASE CATEGORY	RELEASE (MAN-REM)	PROBABILITY OF CONTAINMENT FAILURE	REDUCTION IN CORE MELT FREQUENCY PER RY	REMAINING PLANT LIFE (YEARS)	AVERTED RISK (MAN-REM)
SONGS-2	SST 1	3.3 E+7	3.0E - 2	2.0 E-5	40	790
SONGS-2	SST 2	2.8 E+6	1.0E - 2	2.0 E-5	40	20
SONGS-2	SST 3	8.8 E+3	9.6E - 1	2.0 E-5	40	70
TOTAL	—	—	—	—	—	880

Release category SST3 involves failure of the containment by basemat melt-through with release mitigation systems operational. The release values provided in Reference 20 for the above release categories were calculated using the population distribution and meteorology for the SONGS site. The man-rem dose calculated for SONGS-2 in Reference 20 represents the total population dose commitment

For the above radioactivity release categories of SST1, SST2 and SST3, as used in Reference 20, the probability that containment failure would lead to a release in those categories was assumed to be 0.03, 0.01 and 0.96, respectively. The value of 0.03 represents the probability of early containment failure (Reference 21); the value of 0.01 represents the probability of containment isolation failure (Reference 22); and the value of 0.96 represents the probability of containment failure by basemat melt-though and/or long term containment leakages (Reference 21). The justification for these probabilities is presented in References 21 and 22. Examination of Table D-2 shows that the averted risk (man-rem), with the installation of PORVs, considering a 40 year plant life for SONGS-2, is about 880 man-rem.

3. Implementation Costs

The implementation costs for installing a depressurization system, such as PORVs, range from about $2.5 million in a plant that has not operated to $4.3 million in a plant that has operated for some time. As discussed in Appendix 12, there exists the possibility that testing of the depressurization system could be on the critical path and, therefore, could extend a normal outage by two to three days. The replacement power cost based on $800,000 per day for two days of system testing is 1.6 million dollars.

4. Maintenance Costs

The costs due to maintenance and repair of the installed PORVs over the plant-life were considered. Maintenance and repair times for PORV/Block valves are expected to require approximately fifty man-hours per reactor year. Generally, maintenance and repair, based on operational history from two PWRs over a total of six years, involves lapping valve seats, recalibrating, testing, repacking, and repairs to miscellaneous valve parts. The maintenance labor, overhead, and materials costs, are estimated at $5,300 per reactor year. This estimate is based on a $100,000/man-year labor and overhead costs. The overhead costs ($600) is estimated at thirty percent of the labor cost ($1,900). The materials costs ($2,800) are placed at 1.5 times the labor costs. The maintenance costs are assumed as yearly recurring costs extending for forty years into the future. The present value, based on a four percent real discount rate (difference between rate of inflation and the rate of interest debt), for forty years totals 0.1 million dollars.

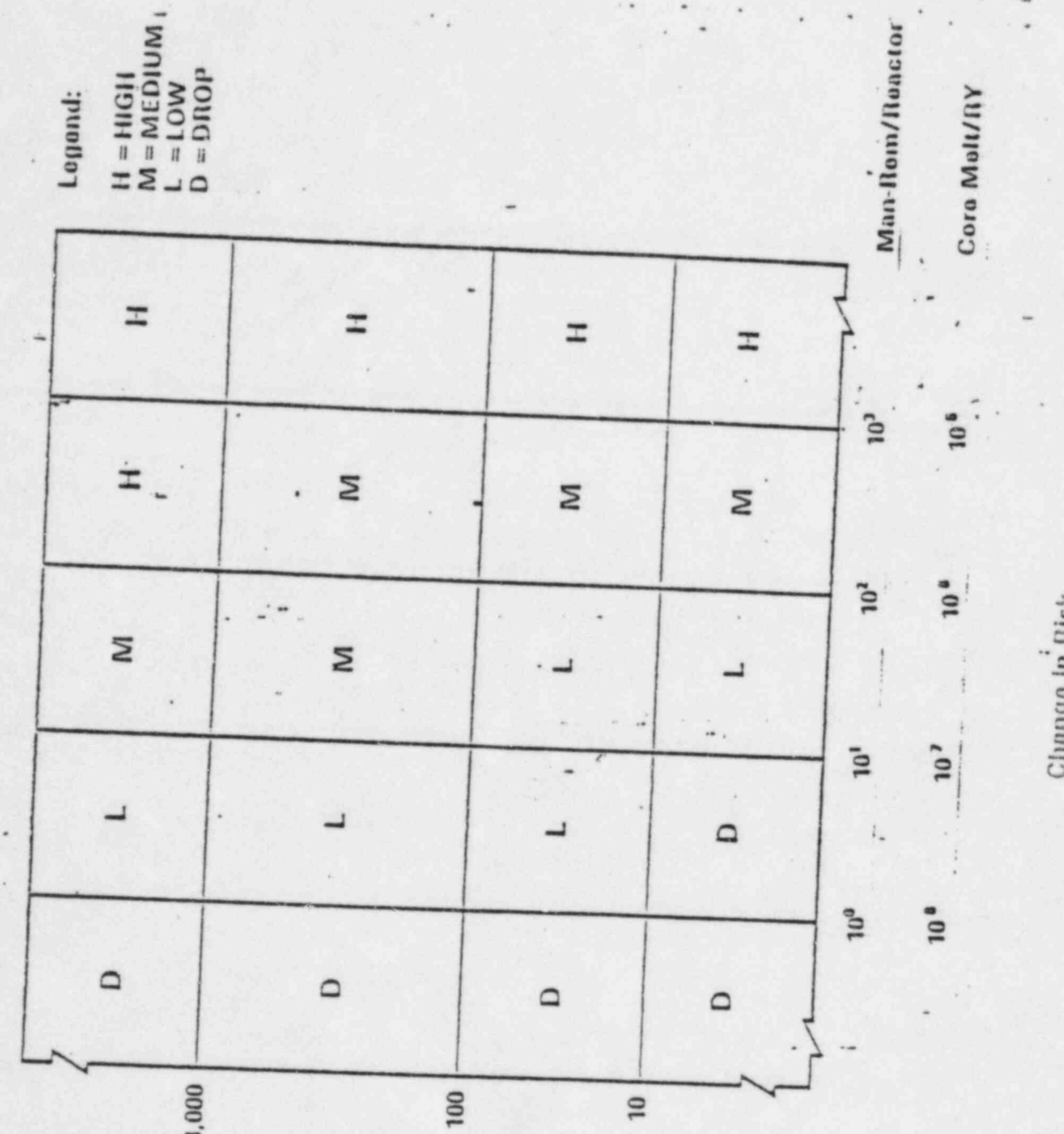

Figure D-1 Value/Impact versus Change in Risk Matrix

Table D.-3

Summary - Value/Impact (Benefit/Cost) Results

Values (Benefits) (1)		Impacts (Costs) (2) (3)	
Reduction in Core Melt Frequency ... $2x10^{-5}$/RY			$M**
	man rem	Installation	4.3
Public Risk Reduction	880	Replacement Power (Testing)	1.6
		Recurring Maintenance	0.1
		Replacement Power.............. (Outages)	3.2
Subtotal	880	Subtotal.............	9.2
ORE* (Installation)............	-400		
ORE* (Maintenance).............	-300	Accident Avoidance.............. (i.e., Cleanup & Replacement Power)	-1.4
ORE* (Accident Avoidance)......	16		
Subtotal	-684	Subtotal.............	-1.4
Total........................	196	Total..........	7.8
*ORE: Occupational Radiological Exposure		** $M: Million Dollars	

Value/Impact (Neglecting ORE & Accident Avoidance) $= \frac{880}{9.2} \sim 96$ $\frac{\text{man rem}}{\$ \text{M}}$

NET VALUE/IMPACT = $\frac{196}{7.8} \sim 25$ $\frac{\text{man rem}}{\$ \text{M}}$

Notes (1) Postive value indicates man-rem averted; negative value indicates a man-rem burden incurred during installation and maintenance.

(2) Negative Impacts indicate cost savings

5. Outage Costs

The outage costs resulting from PORV/Block valve malfunctions have contributed to plant capacity losses of approximately 0.11 percent in operating PWRs (from EPRI-1139). If we assume that the PORV/Block valves will be safety grade, we estimate these losses to be reduced by fifty percent and the capacity losses for PORVs installed in the CE-system design should not exceed 0.2 outage days per reactor year. Considering a replacement power cost of 0.8 million dollars per day, for SONGS Unit 2, the replacement power cost resulting from outages attributed to the installed PORV is estimated at 0.16 million dollars per plant year. The replacement power cost is assumed to be a recurring cost extending for forty years into the future. The present value, based on a four percent real discount rate, is therefore 3.16 million dollars.

6. Accident Avoidance Cost

The accident avoidance cost resulting from the potential reduction in core melt frequency, using cleanup and replacement power costs as described in Reference 20 as "onsite costs" , adjusted to $800,000 per day for replacement power costs, result in an accident avoidance cost of $1.4 million.

7. Occupational Radiological Exposure

The aboved described installation and maintenance work will result in an Occupational Radiological Exposure (ORE) to persons working in the radiation field (about 0.15 R/hr.) near the pressurizer relief and block valves. The ORE resulting from installing PORVs in an operating plant is estimated at 400 man rem. The ORE burden from PORV maintenance and repair, assuming 50 hours per reactor year, over forty years, as discussed above, is 300 man rem.

Occupational Radiological Exposure (ORE) in post core melt accident cleanup, repair, and refurbishment is estimated at $2X10^4$ man-rem (ref. 23). Installation of PORV's that result in a reduction in core melt frequency of $2.0X10^{-5}$/Ry results in an avoided ORE of $(2X10^4)$ $(2.0X10^{-5})(40)$ = 16 man rem considering a 40 year reactor life. Therefore, the ORE risk of post core melt accident cleanups is not a major factor with respect to installation of PORVs..

8. Procedures

It should be noted that the value/impact evaluation gives credit for decay heat removal by depressurizing the steam generators and using the condensate pumps. This credit is not appropriate if there are no procedures in place, and if the operators are not trained in the use of the procedures. Reference to Section C shows that if no credit is given for the condensate pumps (alternate secondary decay heat removal system) the core melt frequency for the case of no PORVs is increased by $5x10^{-5}$/yr. The dollar worth of this reduction in core melt frequency is about 2 to 5 million dollars per unit.

It is our judgement that developing and implementing these procedures would be highly cost-effective; however significant accident analysis may be needed to develop these procedures.

Moreover, as noted in Section C, procedures for aggressive cooldown of the RCS for small LOCAs with failure of the high pressure injection system would result in a 1×10^{-5}/yr reduction in core melt frequency. The dollar worth of this reduction in core melt frequency is about $500,000 to $1,000,000 per unit. Therefore, it is the staff judgement that developing and implementing procedures for aggressive cooldown would be cost-effective. Again, significant accident analysis may be needed to develop the procedures.

9. Value/Impact Assessment

The above results summarized in Table D-3 can be placed on the matrix provided in Figure D-1 taken from Reference 23 to aid in assessing the value/impact and the safety importance of a given issue. The matrix provides visual goals that limit the risk to the most at-risk individual in the vicinity of a reactor site, and the societal risk within a 50 mile radius. The matrix also shows the safety importance of the potential reduction in core melt frequency and the value/impact relative to the ALARA principle of $1000 per man-rem averted. A more detailed discussion of staff evaluations and prioritizations that use the Figure D-1 matrix for assessing safety related generic issues is provided in Reference 23.

The above information is used to estimate the ratio of the safety benefits (or values) in terms of averted risk (man-rem) to costs (or impacts). The averted risk resulting from a reduction in core melt frequency of 2.0×10^{-5} per reactor year is 880 man-rem for SONGS-2 (see Table D-2). The PORV cost per plant (after operation) is $9.2 million. The resulting value/impact ratio (or "S" score from Ref. 23) to be used in Figure D-1 (see Table D-3) is 96 man-rem/$million.

If we consider the NET VALUE/IMPACT, as shown in Table D-3, the S score is approximately 25 man-rem/$million. However, in either case, as evidenced from Figure D-1, the resultant "S" score provides only a marginal value/impact if compared to the ALARA goal of 1000 man-rem averted per $million (i.e., reciprocal of $1000 per man-rem).

Note that in Figure D-1, the risk reduction (or safety benefit) scales are shown orthogonal to the value/impact (or "S" score) scale. For the SONGS site, the "S" score does not change if Units 2 and 3 are considered either separately or combined. Likewise, the change in core melt frequency shown in the risk scales of Figure D-1 is reactor specific. Examination of Figure D-1 shows that for a reduction in core melt frequency of 10^{-5}/Ry, for any given issue, the priority ranking (or safety importance) is considered high. This ranking is predicated on the assumption that any given single issue that provides greater than a ten per cent reduction in a total core melt frequency of 10^{-4} per reactor year is considered an important safety benefit. Therefore, the safety benefit related to a reduction in core melt frequency of $2.0X10^{-5}$ per reactor year, which is attributed to PORV installation, represents an important safety improvement.

The risk scale labelled man-rem per reactor in Figure D-1 is primarily based on the principle that the individual most at risk in the vicinity of a reactor site will not incur a risk greater than 0.1 per cent of the individual, or societal, risk from all other accidents or all other causes of cancer. Thus, for a multi-plant site like San Onofre, the scale for man-rem/reactor can be interpreted as man-rem/reactor site. This interpretation is based on the same population being subjected to the summed probable release for Unit 2 and 3. The result is entered in Figure D-1 as 1760 man-rem/ reactor site. Based on this interpretation, the potential reduction of 1760 man-rem per reactor site for the SONGS site represents an important (or High priority) safety benefit from installation of PORVs.

10. Summary

In summary, Table D-3 which shows the values and impacts of installing PORVs into SONGS-2 and 3, shows a positive but small value/impact. However, based on a potential reduction in core melt frequency of $2.0X10^{-5}$ per reactor year and a potential site specific risk reduction of 1760 man-rem, the installation of PORVs can provide important safety benefits. However, it must be recognized that there are significant and certain Occupational Radiation Exposure (ORE) impacts. These ORE impacts have been factored into the value/impact analysis. The above assessment, which is based on SONGS-2 and 3, bounds the consequences for the same issue relative to the Palo Verde (Units 1,2 and 3) site and the Waterford-Unit 3 site.

IV. Conclusions

This section presents the main conclusions from the preceding sections.

In order to verify the staff's earlier conclusions that the CE plants without PORVs meet the current regulatory requirements, the staff reassessed the ability of the plants to meet these criteria. The following conclusions come from the staff's assessments.

1. The auxiliary pressurizer spray system (APS), together with the other design features, enable mitigation of a postulated single SGTR accident such that radiological consequences remain below the guidelines dose value of 10 CFR 100. Further, a PORV would also provide adequate mitigation capability, and result in about the same offsite radiological

consequences as the SGTR mitigated by the existing APS.

2. Single failures have been identified in the auxiliary pressurizer spray systems on the current CE design PWRs that would render the system unable to supply charging fluid to the pressurizer spray nozzle. Specifically, on plants other than San Onofre 2 and 3, the loop charging valves are manually operated, control grade components that must be closed for charging flow to be diverted to the pressurizer for spray flow. Similarly, on San Onofre Unit 2 and 3, a malfunction in the normal pressurizer spray valve, which which is a control grade component, diverts auxiliary pressurizer spray flow. The staff requires these single failures to be corrected.

3. There are no technical specifications associated with the APS to ensure its operability and surveillance. Without such technical specifications, the staff cannot conclude that the system would be available when needed. The staff requires the development and implementation of these technical specifications.

4. In situations where the pressurizer becomes water solid, the pressurizer steam space will reform upon continuation of the cooldown with the safety grade atmospheric dump valves (ADVs). The recovery would be a challenge to the plant operators but within the capability of the existing systems. The size of the reactor vessel upper head void may be of a concern to the operator, although calculations show that at no time is core cooling jeopardized. A PORV may help, but no net advantage using this technique was determined.

   In general, the staff believes that depressurization using the APS is preferable to a PORV since the process involves the addition of mass to the system and the depressurization is more controllable. Use of the PORV results in a more rapid depressurization with the accompanying contamination of containment and the possibility of a SBLOCA. However, the staff believes that procedures and training should emphasize the recovery actions should the pressurizer be inadvertently filled water solid during a SGTR.

5. The staff's reassessment of the conformance of the current CE designed PWRs to Branch Technical Positions 5-1 and 5-2 of the Standard Review Plan confirmed that subject to receipt of licensee and applicant confirmatory relief valve performance information, the current CE plants are in conformance with these Branch Technical Positions. Similarly, the licensee's, applicant's and staff's probabilistic risk assessments did not result in any new information that would alter the staff's earlier conclusion that the current CE design PWR auxiliary feedwater systems meet the reliability and deterministic criteria.

6. The water chemistry programs, corrosion susceptibility and the pre-heater section tube vibration (3800 class plants only) have been evaluated by CE and by the staff. The staff believes that the SG integrity is adequate for these plants, that the assumption of only a single ruptured tube in a single SG is adequate and the probability of multiple tube ruptures as either an initiating event or as a consequence of the accident is very low. However, we recognize the uncertainties that exist in these determinations may be large.

Overall, the staff concludes that the current CE designed PWRs meet the current regulatory requirements. However, the single failure and technical specifications deficiencies identified are required to be corrected.

As an additional review aspect, the staff reviewed the capabilities of the existing systems and components to mitigate accident scenarios that are beyond the current regulatory requirements. The capabilities of a PORV were also assessed in these accident scenarios. In this assessment, the staff considered the operational aspects of multiple failure accident scenarios, as well. The following conclusions come from the staff's assessments.

7. The current CE plants can mitigate multiple SGTR accidents up to 3 broken tubes in each steam generator. The calculations indicated that there were no unsatisfactory offsite doses, the plant was adequately cooled and the operator could perform mitigative actions. Further, the staff determined that feed and bleed cooling using a PORV is a viable means, although not the preferable means, of mitigating multiple SGTRs (single ruptured tube in each SG) since the steam generator water and metal thermal energy act as a heat source to the primary and severely limit the RCS cooldown. Long term recirculation using the containment sump would be necessary to continue the RCS cooldown to the RHR system entry conditions. Since the offsite doses in the MSGTR accident analyzed were relatively low when using the normal means of plant cooldown (SG blowdown), the staff believes that feed and bleed would not be the preferred means of mitigating this accident, although it does provide a diverse, additional means for cooling.

8. Mitigation of a total loss of feedwater can be accomplished using the safety grade steam generator atmospheric dump valve (ADVs) to reduce the pressure significantly to enable the non safety grade condensate system to supply water to the steam generators. However, the condensate system is powered only from offsite power and is not a safety related system. The staff believes that the addition of PORVs for feed and bleed cooling can contribute significantly in mitigating the total loss of feedwater event.

9. For mitigation of a total loss of feedwater, the emergency firewater pump at Waterford Unit 3 may not be able to add

sufficient feedwater to prevent core uncovery due to the limited ADV capacity and the relatively low fire pump discharge head. However, scoping calculations showed that, although some uncovery did occur, the PCT does not go above 2200°F. No credit was taken for the emergency firewater pumps of the other current CE designed PWRs.

10. Using the most limiting TLOFW accident two large size PORVs of the St. Lucie Unit 2 type would have to be opened 20-25 minutes after the initiation of the event, or about 30 minutes before the latest time that AFW recovery would keep the core from being uncovered. However, should the secondary heat sink not be recoverable for any reason, calculations performed by both CE and ANL show that feed-and-bleed is a viable means of removing core decay heat.

11. Small break loss of coolant accidents (LOCA) coupled with total loss of HPI can be mitigated by performing an aggressive reactor coolant system (RCS) cooldown using the safety related steam generator atmospheric dump valves (ADVs). No uncovery occurs and the low pressure safety injection tanks (SITs) and pumps (LPSIPs) provide makeup when RCS pressure is low enough. This conclusion however, assumes no analyses uncertainties. A PORV would provide significant defense in depth in protecting against this event.

12. The staff believes that there are no significant concerns regarding pressurized thermal shock on the CE plants without PORVs. Results of conservative calculations showed that no crack initiation would occur for the worst case steam line break PTS scenarios.

13. Assuming the implementation of the anticipated transient without scram (ATWS) rule, only the 3410 MWT class CE plants would need extra relieving capacity to ensure the peak pressure following a LOFW ATWS remains below the ASME service level C limit, 3200 psia. The addition of PORVs, sized to successfully accomplish feed-and-bleed, would limit the pressure in the 3410 plants to below the 3200 psia limit for about 1/3 of the operating life. Without the PORVs, the peak pressure would be above 3200 psia throughout plant life. PORVs would expand the range of ATWS scenarios that both the 3410 class of plants could safely accommodate.

From the above assessments and calculations, the staff concludes overall that a number of accident scenarios beyond the current regulatory requirements can be mitigated by the existing systems. Further, a PORV is also able to mitigate a total loss of feedwater by providing a feed and bleed capability. Also, a fast acting, normally aligned PORV can mitigate ATWS scenarios to limit peak reactor coolant system pressure to below the ASME Service level C limit of 3200 psia.

Although the staff's and licensee's assessments showed that the existing systems are capable of mitigating selected multiple failure accident scenarios, there are both known and certainly unknown limitations associated with these mitigation systems. The staff attempted to qualitatively assess these limitations and potential failure scenarios.

14. There are known limitations of the APS system that have been both calculated in thermal hydraulic analyses, and observed during LOFT and SONG-2 tests. If the pressurizer insurge rate becomes excessive, the rate of depressurization from the APS is significantly reduced. Also, if the pressurizer becomes water-solid, the APS is unable to depressurize the system. A properly sized and reliably powered PORV would be capable of lowering system pressure without these limitations.

15. There may be malfunctions associated with the APS that have not been identified in either the staff's deterministic or the probabilistic risk analyses. The pressurizer nozzle fatigue is one example of a limitation of the APS which may restrict the use of this system. There may be others that are unknown and unforeseen. The staff believes that the PORV would provide another means of depressurizing the RCS. Although the CE plants without PORVs meet the licensing basis considerations, assuming the single failures in the APS system are corrected, the PORV could provide a redundant and diverse means of depressurization for SGTRs and SBLOCA accident scenarios.

16. The PORV, if suitably sized, would provide a redundant and diverse means of core decay heat removal. Calculations by CE and ANL have shown that feed-and-bleed is a viable means of core cooling for total LOFW scenarios.

17. As an additional improvement in plant safety, an automatically actuated PORV may avoid pressurizer safety valve actuations in situations where the steam dump system does not function properly after loss of loads or when the ultimate heat sink is lost altogether. However, the possibility of a PORV LOCA must be considered in both the probabilistic risk assessments, and in the assessments of possible costs due to inadvertent or accidental PORV openings.

Overall, while the staff recognizes that a number of multiple failure accident scenarios can be mitigated using the existing systems, the mitigation systems themselves have both known and, unknown malfunctions that may limit or even totally defeat their mitigation capabilities. A properly sized, reliably powered PORV would overall, be a net addition in plant safety. A PORV would provide a redundant and diverse means of controlling reactor coolant system pressure for any accident scenario in which primary pressure is important.

However, the staff recognizes that the value of a PORV must be compared to the potential costs. This can be done using engineering judgment and deterministic calculations. The above conclusions come from these assessments. The staff also used probabilistic and value/impact assessments to measure the potential benefits of a PORV. The following conclusions apply to those assessments.

18. Probabilistic risk assessments performed by the staff, which incorporated the potential for common mode malfunctions, determined that the overall core melt probability for San Onofre Units 2 and 3 would be reduced by about $2x10^{-5}$ per reactor year as a result of the installation of properly sized, powered and configured PORVs. This reduction in core melt probability comes from the total loss of feedwater accidents, in which the condensate system fails, and from the ATWS accidents on the 3410 MWT class CE plants.

19. Additionally, the staff believes that the probability of a small break LOCA due to a stuck open PORV can be minimized by properly designing and powering the PORV and its block valve. It is the staff's judgment that the probability is approximately the same as the probability of a pressurizer safety valve LOCA, which cannot be isolated using block valves.

20. The staff's probabilistic risk assessment was limited to the benefits obtained in reduced core melt frequency. No attempt was made to examine the potential risk reduction associated with the consequences of core melt accidents.

    For example, system depressurization using a PORV prior to core melt during a severe accident could reduce the consequences of the event.

21. The staff's consultant, Burns & Roe, determined that the installation of a supplementary depressurization system, ie. a PORV, would cost from \$2.5 million for a new, unoperated plant to \$4.3 million for an operational plant. However, the testing program, which must accompany a PORV installation, could extend the normal outage by two to three days, which could add an additional \$3 million for replacement power.

22. There is good agreement between the staff consultant's and the CEOG's PORV installation cost estimates, with the exception of the CEOG's estimate for replacement power. The CEOG's estimates for this cost is considered to be overly conservative.

23. For the installation of a PORV on a plant that has operated, total personnel exposure during a PORV installation is estimated at approximately 400 man-rem.

24. The staff performed a value/impact analysis for installing PORVs based on the change in core melt probability, averted public risk, and resulting occupational radiological exposure (ORE) impacts. The evaluation shows that a positive, but

small, value/impact ratio is obtained by the installation of PORVs on the current CE system design.

25. Procedures for aggressive cooldown of the reactor coolant system for small LOCAs with failure of the High Pressure Injection systems are cost-effective, in the staff's judgement leading to a benefit of $500,00 to $1,000,000 from averted core melts. Similarly, procedures for depressurizing the steam generators and using the condensate pumps to supply feedwater to the steam generators, for accident sequences in which main feedwater and auxiliary feedwater are lost are cost effective, in the staff's judgement. The benefit from averted core melts, for plants without PORVs, is about 2 to 5 million dollars. The staff will require these procedures be developed.

The probabilistic risk analyses showed that a PORV could reduce the core melt probability by an appreciable amount. The accident scenarios whose core melt probabilities were reduced are the total loss of feedwater and ATWS accidents. However, when assessing the overall value versus impact should PORVs be installed, only a small value/impact ratio resulted. This assessment, which considered all costs and man rem averted and incurred, indicated that PORV installation would not be justified. However, the assessment could not quantify all the values such as operational aspects like increased flexibility in avoiding significant offsite radiological releases in accidents not leading to core melt. Similarly, the value/impact could not quantify the benefits associated with extra flexibility afforded to the operator in managing other less severe accidents in which the normal depressurization means fails. On balance, recognizing the incompleteness of the analyses and the large uncertainties, while the value and impact analyses do not necessarily support the installation, the composite of the potential benefits in a PORV, both quantified and unquantifiable lead the staff to conclude that the prudent regulatory decision would be to install pressurizer PORVs.

However, we recognize that the USI A-45 program will evaluate and rank various alternate measures for improving decay heat removal system reliability based on value-impact evaluations to determine the most effective fix or backfit solution. Use of PORVs, in a feed and bleed mode of decay heat removal will be one of the alternate measures that will be ranked to determine its desirability compared to other alternatives. The technical resolution of USI A-45 is scheduled for completion in about a year (November, 1984). Therefore, we conclude that while PORVs should be required on CE plants, the actual PORV procurement and installation should await a USI A-45 resolusion.

VI. ACKNOWLEDGEMENT

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SGTR, MSGTR and TLOFW; PRA and engineering feasibility, cost, operational impacts and net benefits of PORV installation cost to support the staff overall evaluation.

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L. Marsh and C. Liang of the Reactor Systems Branch, DSI coordinated overall review of the CE/PORV issue and preparation of this report under the direction of B. Sheron, Chief of the Reactor Systems Branch. A significant amount of resources from the Task A-45 program was directed to provide input to this issue in terms of evaluating engineering feasibility, costs, operational impacts and net benefits of adding PORVs to CE plants lacking such capability. A. Marchese, Task Manager for USI A-45, directed those activities. Substantial effort was provided by the Reliability and Risk Assessment Branch, DST in the PRA aspects of the staff review. The secretarial staff of the Reactor Systems Branch particularly Bonita Gray and Gwendolyn Davis provided much-appreciated typing support. The Phillips Building Central Word-Processing Unit typed the Appendices to this report.

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33. Letter from E.E. Van Brunt to G. W. Knighton, "Rapid Depressurization and Decay Heat Removal for Palo Verde 1, 2 and 3", dated July 28, 1983.

34. Memorandum from F.C. Cherny to R.J. Bosnak, "Trip Report - Meeting of ASME Subgroup on Pressure Rlief; July 13-14, 1983," dated September 12, 1983.

APPENDIX A

Detailed Staff Evaluations
of the Responses to Fourteen Questions
Regarding Need for Rapid Depressurization Capability
for CE Plants

August 1983

This section of the report contains a discussion and the staff's evaluation of the applicant's responses to the fourteen questions (Ref. 4). Since the questions involved technical aspects associated with a variety of NRR review branches, a matrix was developed to ensure that the staff review of each response was conducted by the appropriate branches. This matrix is shown below.

CE PLANT PORV STUDY

REVIEW RESPONSIBILITIES FOR PARTICIPATING BRANCHES

	RSB	ASB	CEB	RRAB	MEB	GIB	PSRB	EQB	SPEB	AEB
I. Evaluation of CE SONGS & Waterford responses to 14 questions										
1. Auxiilary Pressurizer Spray	P		X							X
2. Limiting Plant SCRAMS	P			X						
3. ATWS	X			P		X				
4. PTS	P					X				
5. PORVs for low probability events	P	X		X	X	X				X
6. Low pressure feed	X	P					X			
7. SG tube corrosion			P		X					
8. LOFW, Feed & Bleed	X	X		P						
9. Risk due to SGTRs				P	X		X			X
10. PORV LOCA Risk				P						
11. Net Risk gain/loss w/PORVs				P		X				
12. PORV installation costs					X	P		X	X	
13. SG tube structural integrity					P					
14. Preheater section tube vibration					P					
II. Evaluation of ANL report	P			X		X				X
III. Evaluation of SNL & B&R reports	X	X		X	X	P	X	X	X	

P = Primary Review Branch

X = Secondary Review Branches

1. Question 1 This question asks each applicant to fully describe the auxiliary pressurizer spray system and to assess its depressurization capabilities under a variety of conditions, including the design basis steam generator tube rupter (SGTR). The SGTR requires early operator intervention to rapidly depressurize the RCS using the APS. The staff also asked for an assessment of the thermal stresses of the pressurizer spray nozzle.

1.A CEOG Responses In response to this question, the CEOG assessed the performance capabilities of the APS, and reported the results in the report, Depressurization and Decay Heat Removal, Response to NRC Questions, June, 1983, CEN-239. This document was forwarded to the staff in the following applicant and licensee letters:

CE-80	Ref. 7
SONGS-2,3	Ref. 8
Waterford-3	Ref. 9
Palo Verde-1, 2, 3	Ref. 33

CEN-239, in response to the staff's question, contains a description of each of the plant's APS systems, an evaluation of the depressurization capabilities (based on calculations performed by CEFLASH) under a variety of conditions including the SGTR, and an assessment of the thermal stresses in the pressurizer spray nozzle due to APS. The staff's evaluation of each area is discussed below.

1.B Staff Evaluations

1.B.1 Auxiliary Pressurizer Spray Design

During plant normal operation conditions, pressurizer spray flow is provided via the main spray valves. For conditions in which the reactor coolant pumps (RCP) are not available, main spray connot be used to control system pressure. The APS provides a means to reduce RCS pressure should main spray not be available. For CE plants without PORVs, the APS system has been designed to safety related standards. This system, which is a part of the chemical and volume control system (CVCS), consists of two safety related auxiliary spray valves in parallel and associated piping. The redundant auxiliary spray valves in conjunction with the loop charging valves divert charging flow at the outlet of the regenerative heat exchanger through the piping downstream of the main pressurizer spray valves into the pressurizer spray nozzle at the pressurizer.

The configurations of the APS for SONGS Units 2 and 3 is shown in Figure 2.1-2 of CEN 239 (Figure A1-1 and A1-2). The APS flow is initiated from the control room by opening the auxiliary spray valves (2HV-9201) ensuring the two main spray valves are closed and closing the two loop charging valves (2HV-9202 and 2HV-9203). For SONGS 2 & 3, the charging pumps are automatically started after they are automatically loaded to the diesels following a loss of offsite power. In the event that either the auxiliary spray valve (2HV-9201) fails to open or one of the loop charging valve fails to close, a bypass line has been provided with a manually operated auxiliary spray valve (130-C-334) could be initiated from outside containment. In this APS design, a potential vulnerability was identified. One of the two main spray valves failing to close could cause insufficient APS flow to the pressurizer. This staff concern was not addressed in the response to Staff Question No. 1. In the meeting of July 7, 1983 with

CEOG, (see meeting summary, Reference 6), Southern California Edison (SCE) indicated that a system modification is being considered to install a check valve at the main spray discharge line to prevent back flow of the APS flow into main spray lines. This system modification should resolve the above staff concern and the staff will require that the SCE planned APS system modification to be completed.

The configurations of the APS for Waterford 3 is shown in Figure 2.1-3 of CEN 239 (Figure A1-3 and A1-4). The APS flow is initiated from the control room by opening one of the redundant auxiliary spray valves (CH-517 or ICH-E2505B) and closing the two loop charging valves (CH-518 and CH-519). A check valve has been provided in the main spray piping to prevent APS flow back into the main spray line in case a single active failure of the main spray valve. The charging pumps A and B are automatically started after they are automatically loaded to the diesels. The two loop charging valves which must be closed in order to prevent flow into the RCS loops during auxiliary spray operations, are Class IE solenoid valves which are designed to fail in the closed position upon loss of motive power. The control system for these valves is a control grade system, and the valves do not receive an SIAS signal for automatic closure upon ECCS initiation. Further, if one of the valves control system went to the full open position, insufficient charging flow to the pressurizer would result. The staff believes the current design is such that the loop charging valves could fail into fully open position due to a control system failure and thus cause insufficient APS flow toward pressurizer.

The configurations of the APS for CE system 80 plants (Palo Verde 1, 2 and 3, WPPSS 3) are shown in Figures 2.1-4 and 2.1-5 of CEN 239 (Figure A1-5 and A1-6). The APS flow is initiated from the control room by opening one of the redundant auxiliary spray valves (CH-203 or CH-205) and closing the loop charging valve (CH-240). A check valve has been provided in the main spray piping to prevent APS flow back into the main spray line in case a single active failure of the main spray valve. The charging pumps are manually initiated after they are automatically loaded to the diesels. The loop charging valve (CH-240) which must be fully closed in order to get full auxiliary spray flow is air operated with a Class IE Solenoid. The valve is designed to fail closed on loss of air and loss of power to the solenoid. However, as in the Waterford 3 design, the system controlling the charging valve's position is a control guide system, and the valves do not receive an SIAS signal for autoclosure upon ECCS initiation. Further, if the valve (CH-240) went to a full open position, insufficient spray flow would result. The staff believes the current design is such that the loop charging valve could fail into fully open position due to a control system failure and thus cause insufficient APS flow toward pressurizer.

Although not specifically discussed in the CE-80 responses to the staff's questions, during the July 7-8 meeting with the CEOG, the staff learned that on the CE-80 charging systems, flow to the reactor coolant pump (RCP) seals is controlled via control grade valves outside containment. Should there be a malfunction of these valves or the associated control systems, during situations where APS flow is needed, some charging flow would be directed from the APS system. It is not believed that the reduction in APS flow in this case would be as significant as in the case where the loop charging valves failed to close. Nonetheless, this is another case where performance of the APS depends

FIGURE A1-1
SIMPLIFIED SCHEMATIC OF SONGS CVCS SHOWING AUXILIARY
SPRAY PORTION AND SORUCES OF BORATED WATER

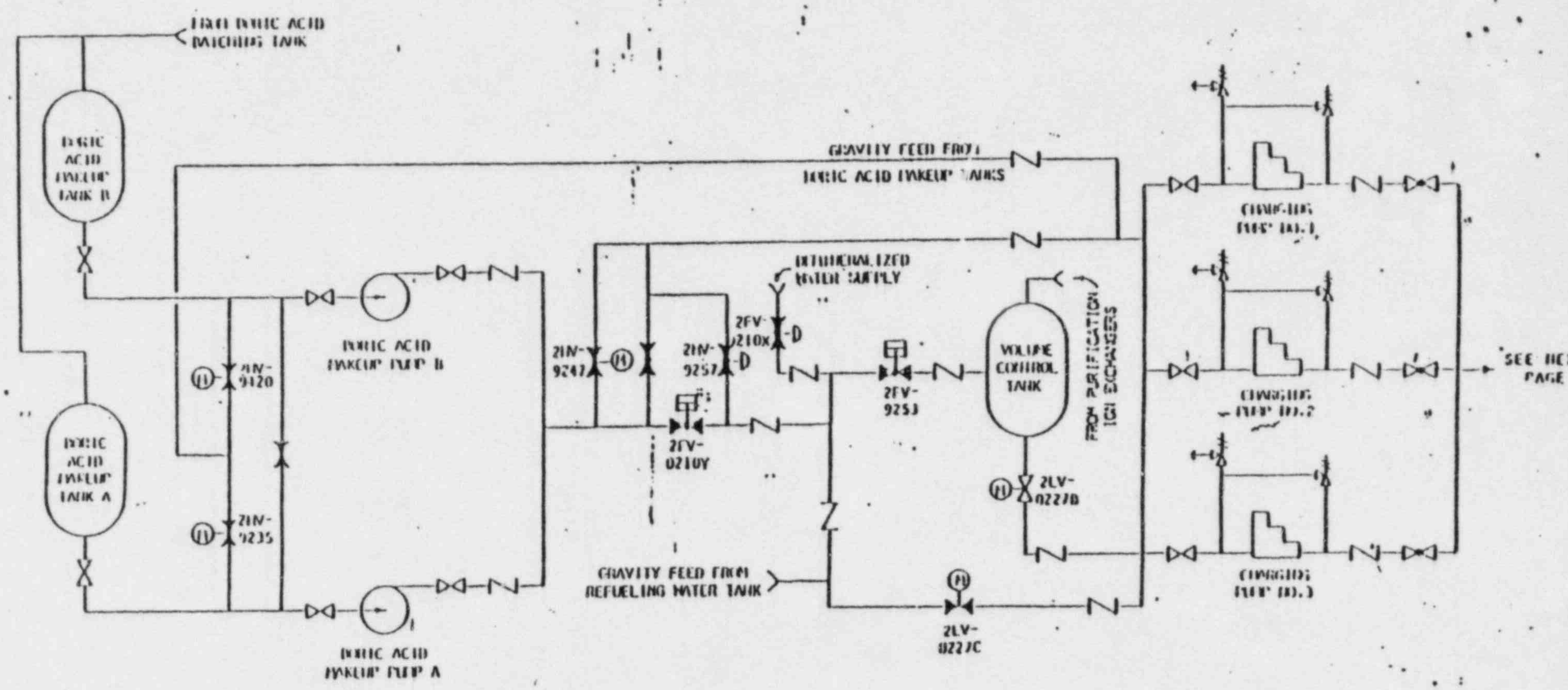


FIGURE A1-2
SIMPLIFIED SCHEMATIC OF SONGS CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

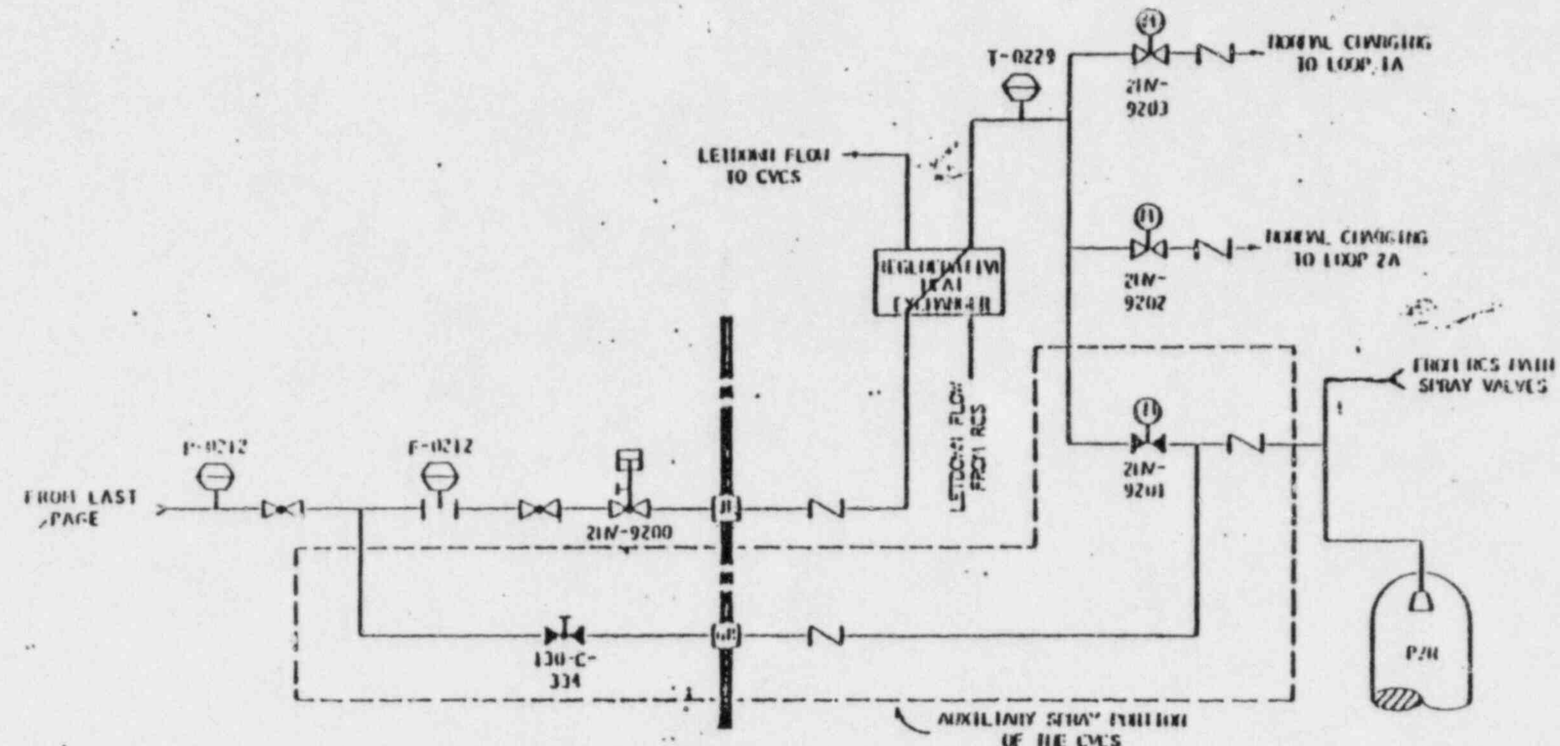


FIGURE A1-3

SIMPLIFIED SCHEMATIC OF WATERFORD CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

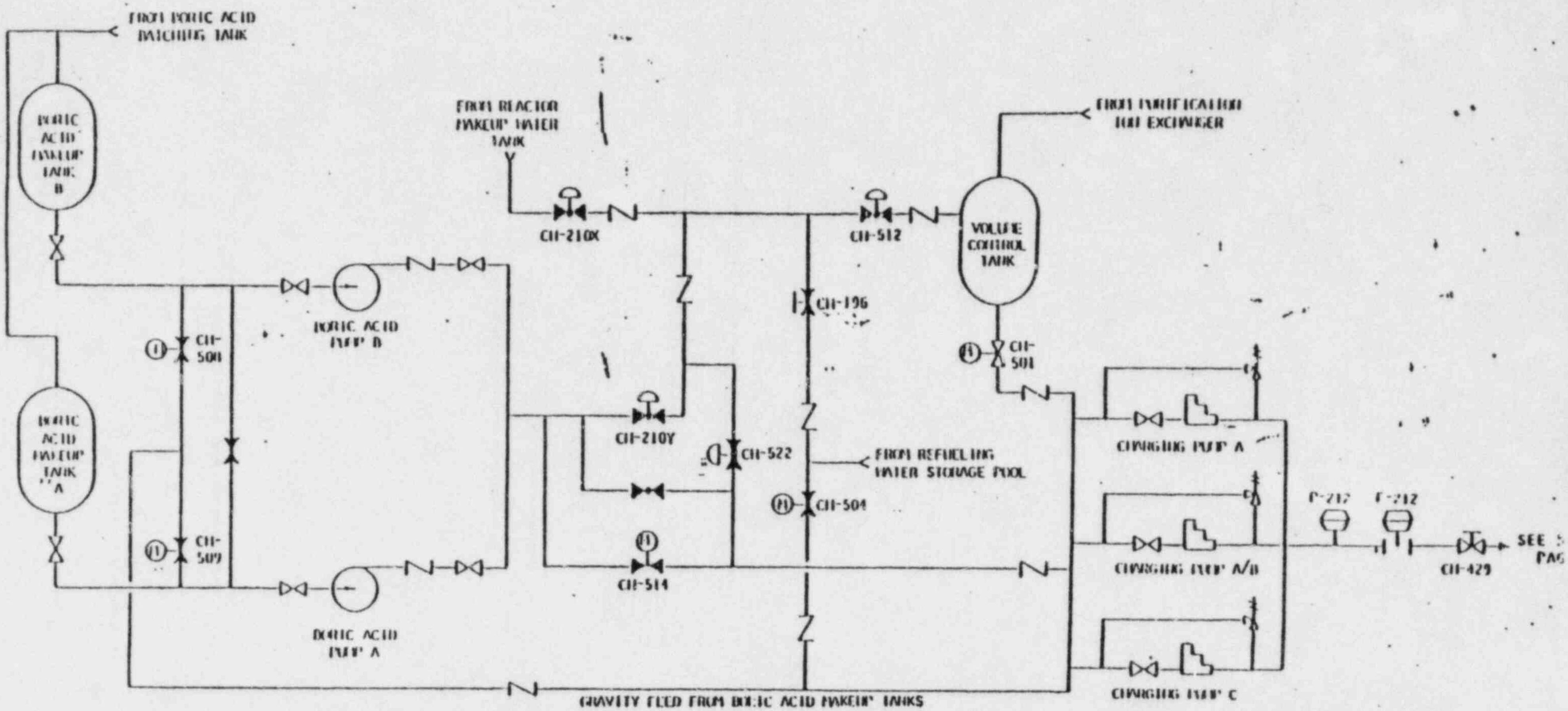


FIGURE A1-4

SIMPLIFIED SCHEMATIC OF WATERFORD CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

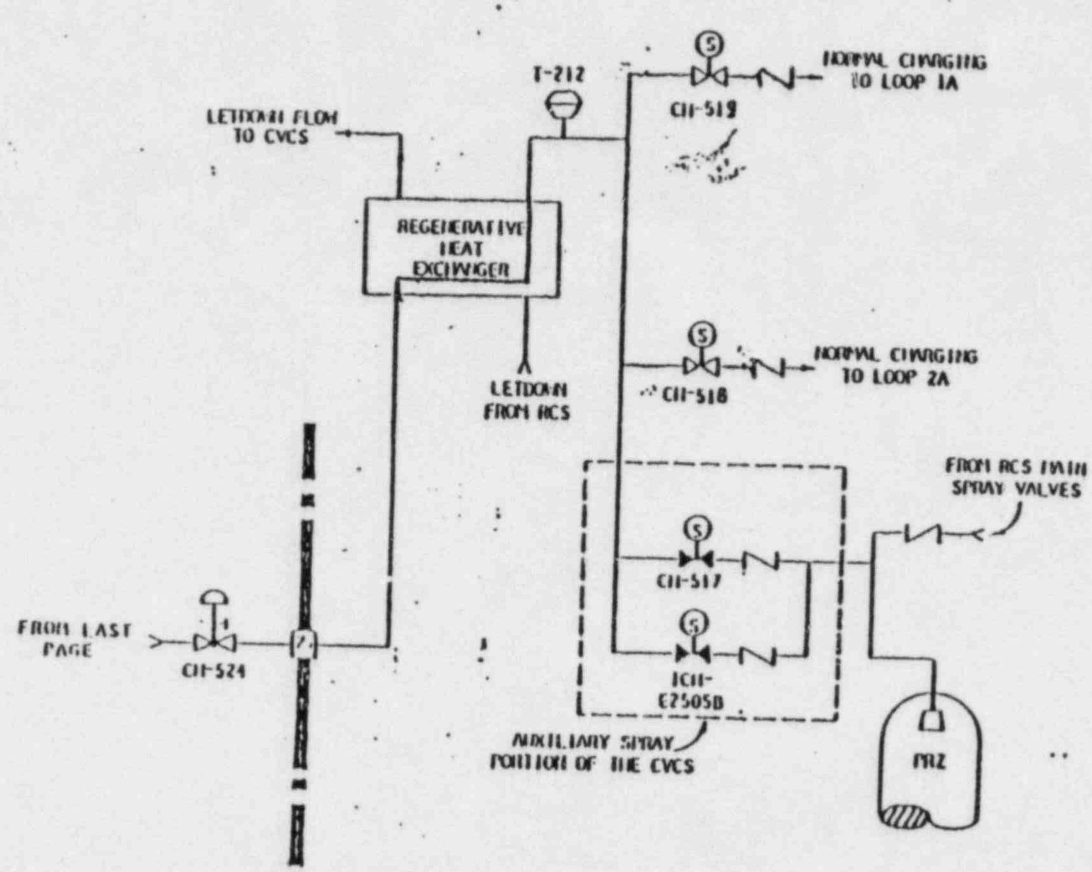


FIGURE A 1-5
SIMPLIFIED SCHEMATIC OF PALO VERDE CVCS SHOWING AUXILIARY SPRAY PORTION AND SOURCES OF BORATED WATER

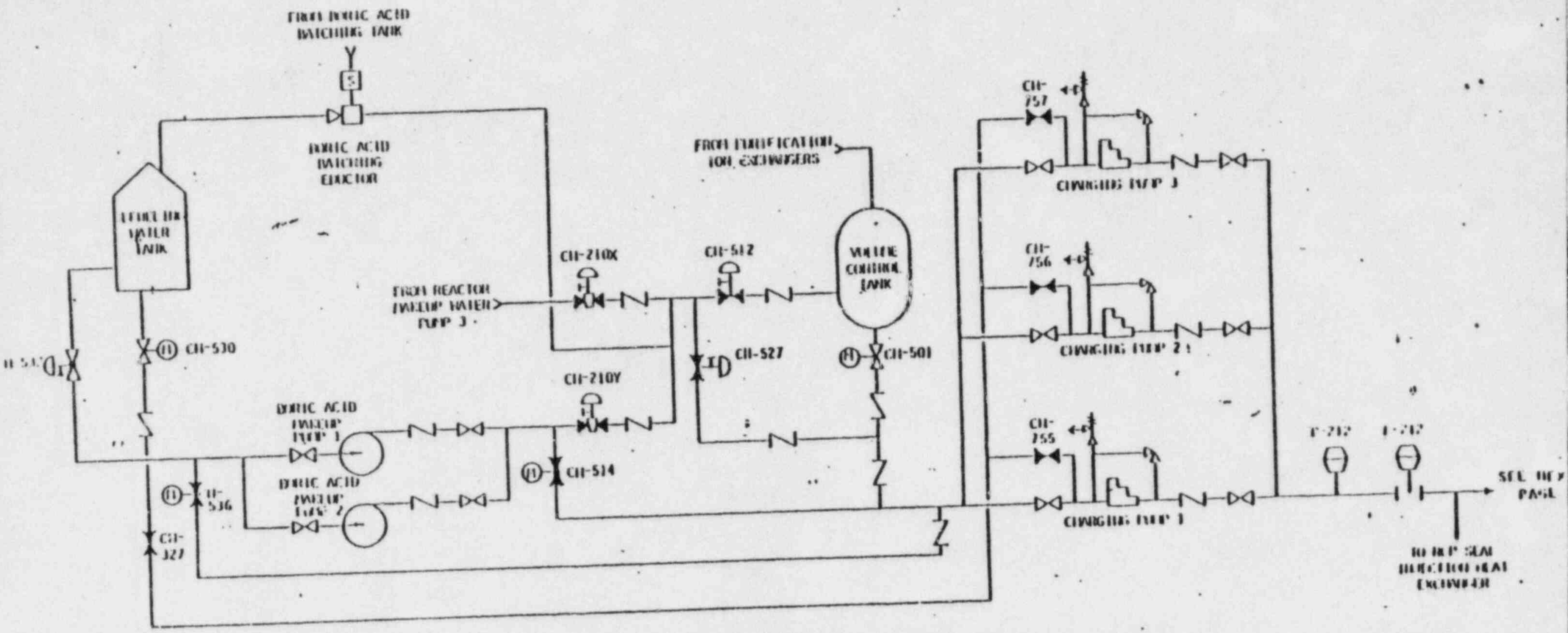
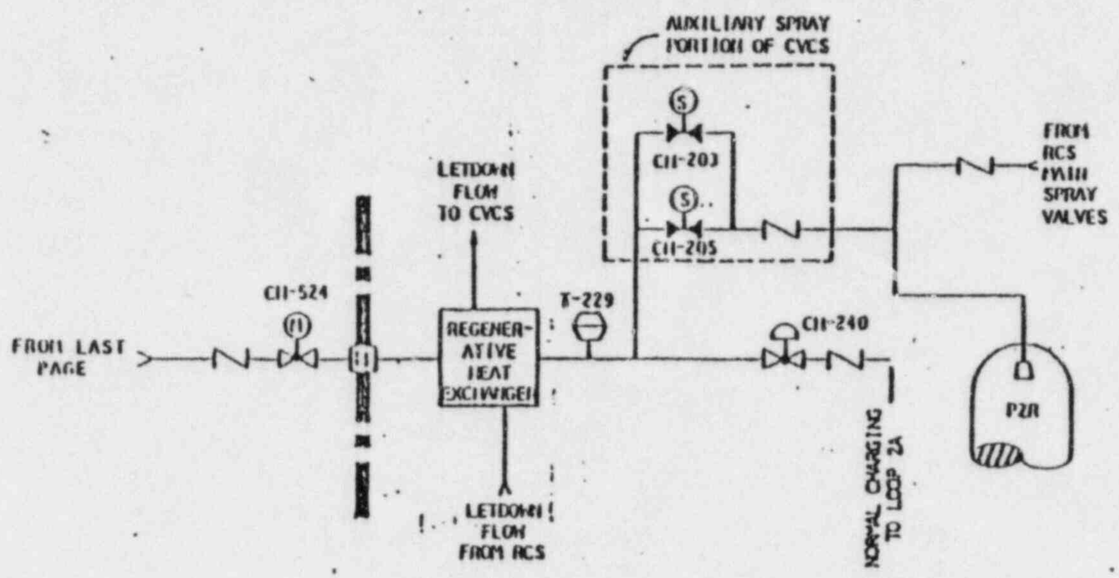


FIGURE A 1-6
SIMPLIFIED SCHEMATIC OF PALO VERDE CVCS SHOWING AUXILIARY PORTION AND SOURCES OF BORATED WATER



on the functioning of a control grade system. The staff notes that, unlike the loop charging valves, malfunctions in the seal injection portion of the charging system can be corrected by manual valve operation outside containment. However, the staff continues to believe that safety systems should not require local, manual operation of a control system and these deficiencies should be corrected. However, the flow to the RCP seals is less than the flow to the loops should the loop charging valves fully open. Thus the impact on APS performance would be less due to malfunctions in the RCP injection line.

The staff notes that for all plants, SONGS-2&3, Waterford-3, Palo Verde 1, 2, and 3, there are no technical specifications associated with the APS despite its importance in mitigation of design basis accidents and its safety classification. There are no technical specifications regarding the operability of the system overall, the associated LCOs, and surveillance requirements. The staff notes that there are technical specifications for the charging pumps, but these specifications are associated with the boron injection requirements, and there are no discussion or requirements for the charging pumps with respect to APS function.

The staff will develop new technical specifications for the APS system and its support systems. These technical specifications will be generic, but will probably have to be taylored to each plant in some respects due to the slightly different designs.

In summary, the Waterford-3, Palo Verde 1, 2 and 3 and CE-80 APS systems contain single failures that may significantly limit its spray capability. These failures are associated with control grade loop charging valves. Further, the CE-80 plants APS systems rely on the isolation of charging flow to the RCP seals, which is accomplished using control grade valves. The staff believes these are single failure vulnerabilities and should be corrected or analyses modified to assume the failure of these components. Further, the APS systems for all plants do not have associated technical specifications to ensure proper equipment operability, availability and surveillance. The staff will develop these technical specifications. With the exception of these items, the APS systems meet safety related standards.

1.B.2 APS Performance

1.B.2.a Steady State RCS Conditions

The depressurization capability of the APS depends on a variety of factors. Assuming a steady state sub-cooled RCS, where the reactor vessel upper head (RVUH) is relatively far from saturation, the depressurization ability of the APS depends on (1) APS flow, (2) APS temperature, (3) pressurizer steam space temperature and (4) pressurizer steam volume. CE evaluated the APS depressurization rates considering variations in the first two of these factors, and determined the effect on depressurization rate should there be a large and expanding RVUH. This latter condition will be evaluated in Section 1.B.2.b, Transient RCS performance. CE did not consider parametrically the effect of initial pressurizer steam volume or temperature, however, the staff believes that the main factors affecting APS depressurization rate are APS flowrate, APS fluid temperature, and the effects of RVUH steam void expansion.

The CE analysis was performed for the 3800 MWT and 3410 MWT class plants, since the pressurizer steam volume and other RCS parameters differ somewhat between these plants. The results of the CE analysis, shown in Table 2.1-1 and in Figures 2.1-6, 2.1-7, 2.1-9 and 2.1-10 of CEN 239, show that the depressurization rates, under a steady state RCS temperature and volume condition, vary from 30 psi/min to 148 psi/min for the 3410 MWT class plants and from 27 psi/min to 126 psi/min for the 3800 MWT plants. The depressurization rates are somewhat lower for the 3800 MWT plants due to the somewhat larger steam space in the 3800 MWT pressurizer.

These results were compared to thermal-hydraulic calculations performed for the staff by Argonne National Laboratory and reported in Reference 10, and to depressurization rates observed during natural circulation tests at SONGS-2 on September 6 thru 9, 1982 (Reference 11).

The ANL calculations, which were performed to investigate the system performance and offsite consequences during a variety of SGTR scenarios, predicted depressurization a rate of approximately 120 psi/min for the 3800 MWT plant (Fig. 4.1.1.1, Ref. 10), for the same set of conditions that CEN-239 used for the prediction of 126 psi/min. ANL did not calculate depressurization rates for the other conditions assumed in the CEN-239 report.

During the natural circulation tests at SONGS-2 in September 1982, Test A2 was performed to determine the pressurizer heat loss with the reactor critical at low power, RCS in a natural circulation mode at near normal operating temperature and pressure and with both steam generators removing decay heat through their Atmospheric Dump Valves (ADVs). At the completion of this test, one charging pump was started and auxiliary spray flow, heated by letdown flow through the regenerative heat exchanger, was initiated. The staff observed a depressurization rate of about 20 psi/min, which is comparable to the rate calculated by CE for 3410 MWT class plants under this condition.

CE also determined, for comparison purposes, the depressurization rates for a range of PORV sizes, since the staff asked wherher a PORV would provide more effective mitigation of events both within and beyond the design basis. These depressurization rates, the valve flow area, are presented in Table 2.1-1 of CEN-239, and are given below:

Table A1-1

Valve Size	Plant	Depressurization Rate
0.0021 ft^2	Palo Verde (Vent System)	54 psi/min
0.0095 ft^2	Calvert Cliffs PORV	270 psi/min
0.0341 ft^2	CEN-239 Feed & Bleed PORV	822 psi/min

In summary, the staff concludes that the CEN-239 depressurization rates predicted for the 3410 and 3800 MWT class reactors, under conditions where there is adequate steam void volume and minimal pressurizer insurge rate appear to be reasonable, and are sufficient to control system depressurization during normal plant, non-transient conditions.

1.B.2.b Transient RCS Conditions

As noted earlier, the APS is effective as a means of system depressurization if a steam space exists in the pressurizer, and if the rate of pressurizer insurge is not so large that it overcomes the depressurization caused by APS induced steam condensation. The steam space could be lost by a number of mechanisms. (1) RVUH steam void expansion, caused by RCS depressurization, displacing RCS hot leg fluid into the pressurizer, (2) filling the pressurizer with APS fluid, or (3) filling the RCS, hence the pressurizer, with safety injection fluid. With respect to the pressurizer insurge rate effect on APS depressurization rate, CEN-239 calculations for SGTR determined (Case 4, pg 41, CEN-239, Fig 2.1-44 to 47) that with a pressurizer insurge rate of approximately 0.1%/scc (about 20 ft^3/sec), and an APS rate of 88 gpm, the RCS depressurization rate is about 20 psi/min. The steady state depressurization analysis, discussed above and shown in Table 2.1-1 of CEN-239, predicted an initial depressurizaton rate (3800 MWT plant, without letdown and 88 gpm APS flow) of about 87 psi/min.

The ANL calculations (Ref. 10) showed the effect of pressurizer insurge more clearly. The CE calculations seem to show that the depressurization rate is constant while the insurge is taking place. That is, the pressure linearly drops at 20 psi/min while there is a 50% increase (from about 30% to 80%) in level - or about 900 ft^3. The linearity of the depressurization is questionable. The ANL calculations show a more reasonable depressurization. Figures 4.1.4-2 and -3 of Ref. 10 show the depressurization rate dropping from an initial value of about 127.8 psi/min while the pressurizer is almost empty, to about 18 psi/min with a nearly full pressurizer.

Both the CE and ANL calculations do show the reduction in depressurization rate due to pressurizer insurge. Therefore, for the APS to remain effective in depressurizing the RCS, not only must there be an adequate steam void in the pressurizer, the pressurizer insurge cannot be excessive.

The importance of the insurge rate on APS performance was demonstrated in the LOFT experiments L9-1 and LP-FW-1. Both experiments were LOFW events in which the steam generators were steamed without feedwater flow, with the reactor critical. (Ref. 12 & 13). When the SG inventory was reduced to a point where the energy removed did not equal the reactor power, the RCS began to heatup and pressure began to increase. (Figure 1 of Ref. 12 and Figure 1, 4, 22 of Ref. 13). The pressurizer spray was able to control system pressure until the insurge rate, due to the RCS heatup rate, exceeded the spray depressurization capability and pressure continued to rise to the reactor trip point.

In summary, during transient conditions where there might be excessive pressurizer insurges, or if the steam void is lost altogether the APS performance is significantly reduced. This limitation has been both observed and calculated. The staff notes that the APS is not intended as a means of removing energy from the RCS, which these two experiments demonstrated. As the RCS heats up due to the loss of heat sink, the combination of pressurizer level and insurge rate will reach a point where depressurization is no longer possible. Under such circumstances, pressure would rise to the pressurizer code safety valve setpoints, and decay heat would be removed through that flowpath.

1.B.2.c Design Basics SGTR

The capability of the APS to depressurize the RCS following a design basis SGTR is important since the SGTR accident is the only design basis accident in which rapid, manually controlled RCS depressurization is mandatory for mitigation. The use of the APS in this event, rather than the PORV, was examined by both CE and by the staff. The CE evaluation, presented in CEN-239, compared the depressurization rates of the APS to an assumed PORV during a design basis SGTR. Five cases were performed for the 3800 MWT reactor:

Table A1-2 Single SGTR Cases Analyzed by CE

Case Number	Comments
1	Base case, no APS or PORV depressurization
2	88 GPM APS at 15 min, 30°F subcooling limit
3	PORV at 15 min., 30°F subcooling limit
4	Large RVUH void following continuous 88 gpm APS flow
5	Large RVUH void following PORV opening

In general, these calculations showed that the system performance using a PORV was the same as with an APS system, however the PORV provided a more rapid system depressurization when open. However, as CEN-239 points out, the depressurization is limited by the subcooling limit and not by the abilities of the PORV or APS. As long as there exists a steam void of adequate volume in the pressurizer, and there is no significant insurges (as could occur if the heat transfer to the SGs were lost) CE asserts the APS and PORV performance characteristics are essentially the same for the design basis SGTR.

This assertion cannot be evaluated without an appraisal of the offsite consequences using both techniques of depressurization. Because the CE report did not assess the radiological consequences, the staff used the thermal-hydraulic calculations performed by its contractor, ANL, to assess the offsite doses for the SGTR accidents using the two techniques of depressurization (i.e., APS or PORV).

SGTR analyses were performed by ANL in an attempt to examine the APS and PORV capabilities under a variety of single failures and operator errors. It should be noted that SRP Section 15.6.3, the Standard Review Plan Section associated with the SGTR, does not specify the necessity for assuming any single failures beyond the loss of offsite power, or operator errors. Therefore, some of the analyses performed by ANL are, strictly speaking, beyond the SRP guidance.

The cases performed by ANL are described in Reference 10 and are listed below:

Table A1-3 Single SGTR Cases Analyzed by ANL

Case Number	Comments
1	Single SGTR with APS for depressurization
2	Single SGTR with PORV for depressurization
3	Single SGTR with APS, stuck open ADV on the ruptured steam generator for 20 min.
4	Single SGTR with continuous APS (operator error), continued HPSI flow, stop APS flow after water solid.
4a	Single SGTR with continuous APS (operator error), stop APS and HPSI flows after water solid.
5	Single SGTR with continuous APS (operator error)
6	Single SGTR with ADV stuck open on ruptured SG for the duration of the calculation

The staff used the ANL predicted primary and secondary systems parameters from the above listed calculations to determine the offsite radiological consequences.

The SGTRs were assumed to be double-ended guillotine breaks of a single tube. The SGTR accident results in a reactor scram and turbine trip. The turbine trip is assumed to cause a loss-of-offsite power which makes the condenser unavailable for mitigating the releases. The primary system activity is transported to the secondary system at a rate which is a function of the primary and secondary system pressures and the tube diameter. Because the primary system is at a higher pressure and temperature than the steam generator, some of the primary fluid leaked to the generator is estimated to flash to steam. The staff assumed that all the activity in the flashed primary coolant is released to the environment via either the open safety valves or the atmospheric dump valves.

The primary coolant fluid that did not flash was assumed to mix with the steam generator water. The iodine in the steam generator was assumed to be released at a rate proportional to the partition coefficient identified in Standard Review Plan Section 15.6.3.

Two estimates of the potential offsite consequences were calculated for ANL cases 1 and 2. One estimate assumed an initial coolant activity of 1.0 μCi/gm dose-equivalent iodine-131 (DEI-131), and an event generated iodine spike. The other estimate assumed that a pre-accident iodine spike had occured and raised the primary system activity to the maximum value permitted by the technical specifications (60 μCi/gram DEI-131). The second estimate did not include any additional iodine spiking. The release pathways for both estimates were the same. A summary table of assumptions used in the staff's evaluation is provided as Table A1-4.

Table A1-4 Staff Assumption's Used in Evaluating the Radiological Consequences Following Postulated Steam Generator Tube Rupture Accidents

1. Initial primary coolant system activity - 1.0 μCi/gram dose equivalent I-131 (DEI-131).

2. Initial secondary coolant system activity - 0.1 μCi/gram DEI-131.

3. Iodine spiking factor of 500 times the normal release rate.

4. Iodine partition coefficient of 100 between secondary steam and secondary water in the steam generators.

5. Atmospheric dispersion factor for the exclusion are boundary of $1.08X10^{-3}$ sec/m^3 (3800 class plant).

6. Flash Fraction for primary to secondary leakage in the damaged steam generator determined by pressure and temperature conditions of the primary and secondary system. All activity in the flashed fluid is assumed released directly to the environment.

7. Primary to secondary leakage from the unaffected steam generator of one gallon per minute for the duration of the accident.

8. No flashing of the primary system leakage was assumed in the unaffected steam generator.

9. For the case of the preaccident iodine spike, the initial primary system activity was assumed to be 60 μCi/gram DEI-131. No additional iodine spiking was assumed for the preaccident iodine spike event.

The staff's evaluation of ANL Cases 1 and 2 indicated that the radiological consequences following the design basis SGTR are essentially the same for the mitigation of the accident using either the APS or the PORV method. Use of either method would not result in radiological consequences that would exceed the acceptance criteria described in Standard Review Plan Section 15.6.3.

ANL performed Case 3 to investigate the significance of a stuck open ADV on the ruptured SG. CE emergency procedure guidelines (EPG), described in Reference 14, specify that if offsite power is lost following the design basis SGTR, the operator is to use the Atmospheric Dump Valves (ADVS) on both steam generators to cool the RCS to below 565°F. This method of SGTR mitigation is different from other PWR techniques because it results in early continuous releases from the damaged SG. Should the ADV stick open, and the operator not recognize it, the offsite consequence could be significant. The capability of the APS under this situation was examined.

Case 6 was run in order to investigate the same equipment malfunction, a stuck open ADV, followed by an operator error in not recognizing the continuous release and taking the proper mitigative action to isolate the stuck open ADV by closing its upstream block valve. Here again, th. capabilities of the APS to mitigate the event were studied.

In Case 3, Argonne evaluated the primary and secondary system responses for an APS system assuming that an atmospheric dump valve on the affected steam generator was stuck in the 30% open position for a period of 20 minutes. It was assumed that after 20 minutes, the operator would have identified the malfunction and have taken action to close the ADV. The failure of the ADV for a short duration lowers the pressure in the affected steam generator. This results in continued primary-to-secondary leakage after the affected ADV has been closed and the primary to secondary leakage cannot be readily terminated. The above circumstance creates a larger primary to secondary leakage, a larger primary fluid flash fraction and a substantially larger ADV flow than the design basis SGTR.

Another problem encountered with Case 3 is the ability to control the water level in the affected steam generator. In Case 3, ANL assumed that the auxiliary feedwater to the affected steam generator would be isolated as part of the S.G. isolation procedure. This assumption permits the level in the steam generator to drop below the top of the tube bundle during some of the time period that the ADV was stuck open. Consistent with previous staff practice, the staff conservatively assumed that all primary to secondary activity leaked to the affected steam generator during the tube uncovery period and prior to the ADV isolation was released directly to the environment.

The impact of the assumption of iodine transport during the tube uncovery period is that the estimated radiological consequences are significantly larger than those calculated for Cases 1 and 2. The estimate of the radiological consequences of an SGTR with an accident-generated iodine spike, would be less than the guideline values of 10 CFR Part 100. However, the more conservative estimate using the preaccident iodine spike would result in potential radiological consequences which slightly exceed the guideline values of 10 CFR Part 100.

ANL performed Case 6 in order to investigate an equipment malfunction, followed by an operator error in not recognizing the malfunction.

In Case 6, Argonne evaluated the primary and secondary system response for an APS system assuming that an atmospheric dump valve on the affected steam generator failed in the 100% open position for the accident duration. The inability to maintain pressure in the secondary system results in a larger primary to secondary system pressure differential and a significantly larger primary to secondary flow through the ruptured tube. The stuck-open ADV permits a blowdown of the affected steam generator to the atmosphere and hence all the activity in the primary to secondary leakage is assumed released directly to the environment.

The larger tube leakage in combination with the assumed inability to isolate the steam releases from the affected steam generator, result in larger radiological consequences than those predicted for Case 3 and significantly larger than those from a design basis SGTR (i.e. Cases 1 or 2). Because the ADV release rate and affected steam generator pressure were controlled for the multiple SGTR case described in Section 5.B below. The potential radiological consequences for Case 6 are larger than those predicted for the multiple SGTR. In both staff estimates the potential radiological consequences exceeded the guideline values of 10 CFR Part 100.

With respect to the capability of the APS or an assumed PORV to mitigate either of these accidents, the staff notes that continued ADV flow (for 20 min in Case 3 or for the accident duration in Case 6) aids in system depressurization by the contraction caused by system cooldown. The following table A1-5 summarizes the ANL Case 1, 3 and 6 with respect to depressurization times and APS flowrates.

Table A1-5 SGTR Depressurization Times With APS

Case	Description	Time to Reach 1200 psig	Integrated APS Flow	RCS Temp (TAVE)
1	Base Case, APS	4700 sec	2750 lbm	535°F
3	ADV stuck 30% open (20 min)	3800 sec	4600 lbm	532°F
6	ADV stuck 100% open (duration)	3600 sec	5500 lbm	510°F

The integrated APS is larger for the larger cooldown rate events since more spray flow was permitted as the more rapid cooldown raised the subcooling.

This is demonstrated by noting that the time to reach 1200 psig is less for the larger cooldown rate events. If there were a PORV in place, rather than an APS system, the times to reach 1200 psig might be slightly less as a result of the more rapid depressurization capability for the PORV. However, the effect would probably not be significant since the depressurization is principly effected by the subcooling limit, not by the rate of depressurization per cycle (i.e. PORV lift or APS flow).

To evaluate situations in which the pressurizer could be filled water solid and the resulting effects on offsite consequences and plant control, the ANL conducted Cases 4, 5 and 4A in which operator error was assumed to result in filling the pressurizer solid.

With respect to the radiological consequences of these cases, the staff notes that Cases 4, 4A and 5 are not significantly different from the design basic SGTR described in Cases 1 and 2. The effect of filling the pressurized solid with water inhibits the plant ability to continue primary system depressurization and therefore would result is slightly larger primary to secondary leakage that would be expected for the design basis SGTR case. Also there would be slightly higher integrated flow through the atmospheric dump valve.

While the actual radiological consequences for these cases have not been evaluated, it would be expected that the increase in primary to secondary leakage in combination with the increase in the releases though the atmospheric dump valves would result in radiological consequences slightly larger than those for the design basis SGTR represented by Cases 1 and 2 but well below the radiological consequences expected for the multiple SGTR case described in Section 5 or the guideline values of 10 CFR Part 100.

The staff evaluated the system performance predicted by the ANL analyses since these cases represent situations where the APS depressurization capability would be lost until the pressurizer steam void were regained. The capability of the PORV to continue the depressurization was evaluated, too.

The results of ANL Case 4 showed that if the operator erred and continued safety injection flow and full APS flow, the pressurizer would be filled in about 500 sec. The ANL calculation assumed that, despite the solid pressurizer, APS continued for 10 min longer, then the operator terminated APS and continued the 75°F/hr cooldown using the ADVs. HPSI was assumed to continue if the subcooling limits allowed.

Fig. 4.1.4-2 and -3 (Ref 10) show the pressurizer level and RCS pressure. The RVUH void reach a maximum size of about 1400 ft^3 (Figure 4.4.4-17), which was well above the top of the hot legs. The calculations showed that the cooldown rate induced contraction was enough to regain the pressurizer steam space about 10 minutes after APS flow was stopped. The calculation shows that once the pressurizer is filled, the HPSI flow collapses the RVUH steam void until the cooldown induced depressurization causes the RVUH void size to increase to maximum of about 900 ft^3. At no time did the void extend down into the hot legs and core cooling was always provided. The calculation shows that, as long as the cooldown continues, pressure reduction will take place.

ANL Case 5 examined the potential benefits of a PORV in this situation. That is, would opening a PORV at the time the pressurizer became water-solid better enabled the continued depressurization? Figure 4.1.5-7 shows that the use of the PORV, once the system became water solid, did result in a more rapid RCS depressurization. The results did not show any appreciable difference in the RVUH void size as a result of using this means of mitigation. Also, the pressurizer level plot, Figure 4.1.5-2, showed a slightly earlier restoration of the pressurizer steam space, thus the APS could have been used to continue the depressurization.

ANL ran one additional case, similar to Case 4, to maximize the RVUH void size. At the time the pressurizer went water solid, the APS and HPSI were both secured, and the RCS cooldown was continued at 75°F/hr. This case, 4A, showed that the RVUH void stayed large, about 1440 ft^3, and the pressurizer steam space did not readily reform. The staff recognized that this would be a very confusing situation for the operator. The pressurizer level indicates a full RCS, but the RVUH void is large. If the operator properly diagnoses the RVUH void presence, he may be able to manage the RCS pressure and cooldown. However, to collapse the RVUH void, the operator must continue HPSI flow, which, under normal circumstances would raise system pressure, a response the operator is trying to avoid in the recovery from a SGTR. A delay in the cooldown in an attempt to understand the plant status may result in RCS heatup, and potentially lifting the damaged SG safety valve. (Figure 4.1.4-6 of Ref. 10 shows the damaged SG dome pressure has not appreciably dropped below about 1110 psig, only 90 psi below the safety valve setpoint). While not a significant safety concern, the staff notes that the indications and parameters in this situation are confusing, and may result in further operator errors.

1.B.3 Fatigue Analysis of Pressurizer Spray Nozzle

In response to the staff's question regarding fatigue usage of the pressurizer spray nozzle, CE responded in CEN-239 that records of normal and auxiliary spray cycles and the ΔT would be kept and the fatigue usage of the nozzle would be calculated. Further, CE stated that is the cumulative usage exceeded 0.65, an engineering evaluation would be conducted before further auxiliary spray cycles. At the July 7-8 meeting with CE, (Meeting summary, Ref. 6) the staff requested a more definitive argument to ensure that the pressurizer spray nozzle would not have to be replaced as a result of excessive fatigue usage.

A fatigue analysis of the pressurizer spray nozzles was performed by Combustion Engineering to determine the Cumulative fatigue usage factor on this nozzle. In the analysis 150 cooldown cycles were assumed for the 40 year plant life. During each cooldown, four main spray and four auxiliary spray cycles were assumed to occur. The differential temperature during these cycles varied depending on the plant conditions at the time the spray cycle was assumed to occur. In addition, two natural circulation cooldowns were assumed with eight auxiliary cycles during each cooldown. The cumulative fatigue usage factor for the nozzle based on the above mentioned cycles was calculated to be 0.79.

The maximum allowable fatigue usage factor allowed by the ASME code is 1.0. Therefore, CE concluded that the pressurizer spray nozzle fatigue would not reach 1.0.

The staff reviewed this information and notes that although the assumed nozzle fatigue calculation performed by CE appears conservative, there are no technical specification or procedural limits to restrict or in any way limit the differential temperature, or the number of cycles. Thus, despite CE's calculation, there is nothing to ensure the calculation bounds all possible cases. It should be noted that other PWR designs (W, B&W and earlier CE plants) have pressurizer nozzle differential temperature technical specifications, and the current CE designs do not. The staff is still reviewing the necessity for technical specifications associated with a differential temperature limit.

1.B.4 Conclusion

The APS systems in the recent CE designed plants rely on the safety related charging pumps. Although stated to be a safety related system, the staff determined that there are single failures within the APS that would significantly limits its ability to perform its safety function. Also, there are no technical specifications regarding equipment availability, surveillance, etc. for the APS. The staff believes the single failures identified should be corrected, and the staff will develop technical specifications for the APS.

The APS performance is similar to a nominally sized PORV, and is able to efficiently reduce system pressure as long as the pressurizer insurge is not excessive, and the pressurizer steam space remains sufficiently large to allow efficient steam condensation.

The APS is able to efficiently mitigate the design basis SGTR, as is an assumed PORV. The APS has the benefit of adding mass to the RCS during the SGTR accident, whereas the PORV accomplishes its depressurization function by mass removal, with the associated contamination of containment. However, the APS is limited to situations in which there is a pressurizer steam void. If the operator makes an error and inadvertently fills the pressurizer water solid, recovery would be possible but complicated, and possibly enhanced with the addition of a PORV. However, in general, the optional means of recovery from a design basis SGTR is with an APS system.

The pressurizer nozzle fatigue induced by normal or auxiliary spray at high differential temperatures, has been calculated by Combustion Engineering to not exceed the ASME code allowable value of 1.0. However, the calculation can not be stated to bound all possible methods of plant operation since, unlike other PWRs, there are no technical specifications to restrict the differential temperature. This issue is still being studied by the staff.

2. Question 2 This question asks if a PORV would provide any benefit in terms of avoiding plant scrams by limiting plant pressure.

2.A CEOG Response Members of the CEOG responded to this question by referencing CEN-239, section 2.2 which discusses the CE philosophy regarding PORVs. The response gives a table of peak pressures during a number of events at CE plants. In general, CE stated that the CE plants have never relied on the PORV to avoid high RCS pressure reactor trips, as the B&W plants did before the TMI-2 accident. The CE plants with PORVs are designed such that upon high RCS pressure trip, the PORVs are also opened. That is, the bistables in the reactor protective system that actuate high RCS pressure trip also actuate the PORVs.

The response also gives an overall philosophy of why PORVs were included in older CE plants and why PORVs have been eliminated in the current CE plants.

2.B Staff Evaluations

The CEN-239 response reiterates an earlier CE position regarding PORV setpoints. Unlike the pre TMI-2 B&W design, the earlier CE plants have PORVs with setpoints at the high RCS pressure setpoint. Thus, whenever there was a high pressure trip, the PORVs would open. After the TMI-2 accident, CE, like all PWRs, was asked about methods of avoiding PORV openings. Their responses, which were accepted by the staff, indicated that the design employing concurrent high pressure trip and PORV opening optimized the goals of minimizing challenges to the pressurizer safety valves and avoiding PORV lifts.

However, the newer CE plants do not have PORVs as a result of operational experience evaluated in the mid 70s indicated that the performance of other RCS pressure reducing systems was such that even without the PORV, the safety valve setpoint would not be reached. The control grade normal pressurizer spray (NPS) and steam bypass control systems (SBCS) acted to quickly lower RCS pressure and remove RCS decay heat respectively, during RCS pressurization events (i.e., loss of loads, turbine trip, loss of feedwater, etc.). Furthermore, CE stated that experience indicated the safety valve leakage occurred without pressure reaching the safety valve setpoint. Thus, the PORV would be helpful in limiting SV leakage only if it limited pressure for below the SV setpoint, which it was not designed to do.

While the staff realizes that PORVs have not been assumed in safety analyses, it has provided a useful but not essential function in limiting RCS pressure during rapid pressure transients. The removal of the PORV from the current CE plants places extra reliance on the SBCS and NPS systems to keep from lifting the pressurizer safety valves. Furthermore, there are design basis events where the SBCS and NPS would not be able to keep from lifting the SVs. A loss of offsite power (LOOP) event results in a turbine trip, loss of condenser and loss of forced RCS flow. Thus, a LOOP renders the NPS and SBCS systems unable to limit RCS pressure, however, a LOOP normally results in a direct reactor trip and the RCS pressure rise is minimal.

The closure of both main steam isolation valves, MSIVs, is an event that removes the turbine and the SBCS as energy removal paths. This event, which occurred at St. Lucie, would result in a rapid RCS pressure rise, a high pressure reactor trip and a pressurizer safety valve lift. However, even if a PORV was installed, the SVS would probably lift in this rapid loss of heat sink event.

While the staff agrees that the normally available SBCS and NPS systems limit RCS pressure to below the SV setpoint during many events, other events may occur in which the SBCS may not be available. In these events, the PORV may be able to keep from lifting the pressurizer SV, with the possibility of a stuck open SV and SBLOCA.

The staff also notes that the SBCS and NPS have no technical specifications specifying equipment availability, limits and surveillance. However, these components are not relied upon in any FSAR safety analyses. Thus, from a regulatory conformance standpoint, technical specifications are not required. The staff believes the absence of a PORV and the possibility of SV SBLOCAs should be addressed in the probabilistic risk analyses and defense-in-depth perspectives.

2.C Conclusion

In terms of design basis pressurization events, the PORV may be useful (by limiting SV lifts) but not relied on or necessary. However, the absence of a PORV places extra reliance in the SBCS and NPS systems. These systems do not have technical specifications, but need not since they are not taken credit for in any FSAR safety analyses.

3. Question 3 This question asks for a discussion of the advantages and disadvantages of PORVs from the ATWS standpoint.

3.A CEOG Response In response to this question, the CEOG evaluated the pressure response to an ATWS (loss of main feedwater) in the 3410 and 3800 class plants to determine the additional relief capacity required to limit the peak reactor coolant system pressure to less than 3200 psi. They noted that this additional relief capacity for the 3410 class plants is three to eight times larger than two PORVs typically installed in operating CE plants and would increase the susceptibiilty to a relief valve initiated SBLOCA.

3.B Staff Evaluation

The additional pressure relief capacity needed to limit the reactor coolant system pressure to 3200 psi following a severe ATWS is highly dependent on the plant characteristics and the analytical model used in the calculations. The CEOG used a modified version of their best estimate ATWS code to analyze an AWTS from a loss of main feedwater (LOFW) events. They cited CENPD-158, Rev. 1 as the basis for identifying LOFW as the limiting ATWS event. In NUREG-0460, Vol. 4, the staff noted that the LOFW event may be bounding; however, the existence of other transients (e.g., zero power CEA withdrawal) which are close to the LOFW in peak pressure (as shown in NUREG-0460, Vol. 2) precludes making a definitive finding on this issue.

The analytical model used by the CEOG for estimating the plant response to an ATWS has not been reviewed by the staff. This model, which includes vessel head O-ring seal leakage to relieve the pressure, was presented in CENPD-263-P. In NUREG-0460, Vol. 4, the staff noted that insufficient description and justification of the O-ring seal leakages model was presented to permit the staff to make a definitive finding on this model which had a significant impact on the calculated peak RCS pressures. The modified version of the ATWS code used by the CEOG contains other thermal-hydraulic modeling changes which have not been reviewed by the staff.

In CEN-239, the CEOG presented the following estimated peak reactor coolant system pressures for plants without PORVs

Table A3-1 Peak RCS Pressure (PSIA)

Plant Class	No turbine trip	With turbine trip
3410	4290	3843
3800	3800	2918

The proposed ATWS rule (SECY-83-293) requires a diverse turbine trip for all PWRs. Based on this assumption, the CEOG concluded that additional relief capacity would benefit only the 3410 class plants with respect to limiting the peak RCS pressure to 3200 psi. The staff concurs that additional relief capacity would be beneficial for the 3410 class plants (for ATWS); however, because of the aforementioned unknowns associated with the calculational model, the staff can not conclude that additional relief would not be beneficial for the 3800 class plants as well

The CEOG cited as a disadvantage of adding PORVs, the increased susceptibility of SBLOCAs due to stuck open PORVs. The staff also shares a concern about the increased susceptibility for SBLOCA; however, we believe that adequate technology is available to minimize this susceptibility through the use of more reliable valves, automatic isolation capability, and broader scope design criteria for the added relief capacity system. On balance, the staff believes that additional relief capacity would be beneficial from an ATWS standpoint. This benefit is quantified by the staff under staff evaluation of question 11.

4. <u>Question 4</u> This question asks for a discussion of the possible benefits that derived from use of PORVs for mitigating pressurized thermal shock (PTS).

4.A <u>CEOG Responses</u> In response to this question, the CEOG evaluated two very severe postulated overcooling events without the use of PORVs with the system assumed to repressurize to the RCS safety valve set pressure of 2500 psia. The two events considered were an intermediate size main steam line break and a small main steam line break. The analyses were performed for the 3800 class plants, and the results are applicable to the 3410 class plants. The results of the CE analysis are reported in CEN-239. The staff's evaluation is discussed below.

4.B <u>Staff Evaluations</u>

The analysis was performed for an steam line break during hot zero power operation for conservativeness. This mode of plant operation will maximize the primary coolant system cooldown because steam generator water inventory is large and core decay heat is low. Also, the analysts assumes no moisture carryover during the blowdown through breaks. This assumption will maximize total energy removal from the affected steam generator and thus maximizes integral RCS halt removal to further bound effects of PTS.

A break was assumed in a main steam piping upstream of the main steam isolation valve. The break initially increases steam flow from both steam generators, steam generator pressure and temperature decreases, and heat removal from the RCS increases. Low steam generator pressure initiated a reactor trip and a main steam isolation. A low steam generator level presented in the uneffected steam generator will start the auxiliary feedwater flow to the intact steam generator. During the transient, pressurizer pressure decreases to the safety injection actuation setpoint. Two HPSI pumps and three charging pumps will be started and the operator will manually trip all four reactor coolant pumps following the SIAS. The HPSI pumps will rapidly repressurize the RCS to the HPSI pump shutoff head and the charging pumps will further pressurize the RCS. The PTS concern arises due to the rapid decrease of RCS temperature an the subsequent repressurization of the RCS by the HPSI and charging pumps.

The staff has evaluated the assumptions and plant parameters used for the steam line break analysis and concluded that they are reasonably conservative and the results of the analysis could provide an upper bound on the cooldown rate during the transient. Fracture mechanics evaluations of the transients were performed using conservative assumptions. The results of the analysis shown that no crack initiation would occur for these transients and therefore, from a PTS point of view, PORVs are not required in the CE 3410 class and 3800 class plants.

The studies performed by the staff Unresolved Safety Issue A-49 on Pressurized Thermal Shock also indicated that there are no significant concerns to the CE plant without PORVs with respect to PTS.

5. Question 5 This question asks each applicant to address multiple failure scenarios, such as multiple SGTRs and small break LOCA with failure of HPSI, to ensure they are satisfactorily handled without the use of the PORVs.

5.A CEOG Response In response to this question, the CEOG evaluated the systems response and offsite consequences for both the 3410 MWT class and 3800 MWT reactors under two multiple SGTR scenarios: one double ended guillotine SGTR in each SG, and three double ended guillotine SGTR in each SG. To address the SBLOCA without HPSI, CE performed thermal hydraulic calculations for the 3410 MWT class plants and reported the results in CEN-239. The evaluation of a total loss of feedwater accident, which is also a multiple failure event, is contained in Section 6, Low Pressure feedwater systems during TLOFW and Section 8, TWFW and Feed and Bleed. The staff's evaluation follows.

5.B Staff Evaluations

5.B.1 Multiple SGTRs

CEN-239 evaluated the system response and offsite consequences for the 3410 MWT class and 3800 MWT class reactors assuming one or three broken tubes in each steam generator. In evaluating the CEN-239 analysis and in discussion with the CEOG, the staff noted that, in general the analyses followed the guidelines specified in CEN-152, (Ref. 15). However, contrary to CEN-152, the analyses assumed, in that both steam generators would be continually steamed throughout the RCS cooldown and depressurization process. The CEN-152 instructs the operator to isolate the most effected SG, and cooldown using only one SG. The CE analyses is probably conservative in this assumption, but the staff asked CE to determine the system performance and offsite consequences if the operator followed the guidelines exactly.

The CE analyses, Section 2.5.2 of CEN-152, assumes depressurization with only the APS, and did not compare the results assuming mitigation with a PORV as the staff noted in Reference 5. The CE analysis did not address other multiple failure scenarios, such as main steam line break (MSLB) or main feedline break (MFLB) coupled with consequential single or multiple SGTRs in the effected SG. However, in general these events are mainly depressurization events, with the exception of the early phases of the MFLB, and the APS or PORV mitigability aspects are probably not relevant.

The CEN-239 thermal-hydraulic and offsite radiological consequences analyses were performed for one or three broken tubes in each SG. Analyses were not conducted for assymetric conditions, that is, different numbers of broken tubes in each SG. However, the CE method of assuming continuous steaming from both steam generators in symmetric multiple SGTRs probably bounds situations in which the operator properly isolates a damaged SG which contains more broken tubes. That is, the CE analysis is probably conservative with respect to asymmetric multiple SGTRs.

The CE analyses assumed no more than three broken tubes in each SG, although CE informally told the staff that the offsite radiological consequences would be much more severe for the case of five tubes broken in each SG. The analyses in CEN-239 shows the following offsite radiological consequences for the multiple SGTRs scenarios.

Table A5-1 CEN-239 MSGTR results

Parameter	3410 Class 1 Tube/SG	3410 Class 3 Tubes/SB	3800 Class 1 Tube/SG	3800 Class 3 Tubes/SB
RCS pressure (psia)	232	326	314	350
RCS temperatures (°F)	370	390	388	398
Integrated primary-to-secondary leak (lbm)	313,400	717,100	360,400	860,126
Integrated HPSI (lbm)	384,800	806,580	434,100	897,600
Integrated auxiliary feed-water to both SGs (lbm)	292,900	0	275,000	0
Integrated MSSV flow from both SGs (lbm)	101,300	111,300	112,200	97,700
Integrated ADV Flow-from both SGs (lbm)	487,400	401,000	507,000	513,900
Dose - 2 Hours (REM) (1)				
GIS	55	45	105	95
PIS	95	80	230	220

(1)In calculating the dose results the site dispersion factor for Waterford was used for the 3410 case and the site dispersion factor for Washington was used for the 3800 case.

In evaluating these results, the staff noted that the predicted offsite doses for the 3 tube in each SG cases were always less than the single tube in each SG cases, despite the fact that the integrated leakage from the primary to secondary was always greater in the 3 tube cases. In discussing this with CE, it was pointed out that due to the greater break flow in the 3 tube case, the HPSI flow was larger, thus more RCS cooling was being afforded by the HPSI flow, and less ADV flow was necessary for RCS cooling. The offsite doses are a function of the primary-to-secondary, the ADV and the Main Steam Safety Valve (MSSV) flows, and in the multiple SGTRs cases performed by CE, the offsite dose results seem reasonable.

The staff asked CE why no more than 3 tubes in each SG were evaluated, especially since CE indicated that the offsite doses for 5 tubes in each SG may be significantly higher. In response, CE informally stated that the probability analyses, contained in CEN-239 Supplement I for each applicant (Ref. 8, 9), showed that the probability of multiple SGTRs coupled with loss of offsite power is very low, and didn't justify continuing analyses of larger numbers of broken tubes. The staff's analyses of the frequency and rate associated with multiple SGTRs is in Section 9 of Appendix A.

The staff's contractor, ANL, performed specific multiple SGTR analyses for the 3800 MWT plant, and followed verbatum the CEN-239 guidance. The analyses were conducted for three cases.

Table A5-2 Matrix of multiple SGTR Cases Analyzed by ANL

Case Number	Comment
7	Dual SGTR with APS
8	Dual SGTR with PORV
9	Dual SGTR with PORV -- feed and bleed (early isolation of both steam generators)

In general, the results of ANL Case 7 agreed with the results performed by CE for the equivalent case, however, there were a number of differences in the analyses, as shown in Table A5-3. The resultant effects in these differences are also shown.

Table A5-3 Comparison of CE and ANL MSGTR Analyses,[1] Differences and Resultant Offsite Dose Effects

Item	CEN-239	ANL	Effects on Dose
HPSI pumps	2	1	CE less than ANL
RCS cooldown rate	100°F/hour	75°F/hour	CE less than ANL
Reactor trip	600 sec (auto)	400 sec (auto)	CE less than ANL
Break location	Hot leg	Cold leg	?
First operator action	1800 sec	1200 sec	CE more than ANL
Operator actions	Both SG used heaters APS	Single SG used no heaters APS	CE more than ANL
Charging pumps	Only APS, on or off	Alternate APS to cold legs	CE more than ANL

Using the time-dependent primary and secondary conditions and release data, the staff estimated the potential offsite radiological consequences for a 3800 Class plant using the assumptions previously identified in Table A1-4. Since ANL had performed analyses assuming mitigation with either the APS or the PORV, the staff analyzed the radiological consequences under both mitigation schemes. The staff calculations showed that the offsite doses, using either the PORV or the APS, for one SGTR in each SG on the 3800 MWT plant, would be less the 10 CFR 100 guideline values. Because the Argonne analyses did not include a case having 3 SGTRs per steam generator, the staff can not substantiate the CE results. Similarly the staff can not substantiate the CE results for the 3410 class plants because no system performance analyses were performed by ANL using a 3410 Class plant.

The ANL performed an analysis to determine if feed and bleed operation, using an assumed PORV and the existing HPSIPs, would be a viable means of limiting offsite consequences in multiple SGTR accidents. Case 9, as described in Reference 10, assumed both SG APVs were closed when hot leg temperature reached 565°F, and feed and bleed was initiated. The details of the transient are discussed in the ANL report. In general, break flow is rapidly reduced then stopped, but the long term recovery is extremely complicated due to the steam generators, acting as an energy and mass source to the primary during the cool-down and depressurization to the SDCS entry conditions. It should be noted that the code calculated unstable, oscillating RCS flow at various times, which may not be valid. However, the conclusion regarding this potential method of multiple SGTR (one broken tube in each SG) seems to be that it is not a viable technique as a result of the SGs acting to significantly retard the RCS cooling and depressurization from the PORV and HPSI flow.

The staff did not evaluate the viability and desirability of feed-and-bleed as a means of mitigating other, more complicated SGTR scenarios. For example, the offsite radiological consequences for a single SGTR with a stuck fully open ADV are above 10 CFR 100 guidelines. This case is important because Palo Verde does not have block valves upstream of their ADVs. Also, the mainsteam safety valves (MSSVs) will lift initially after the scram, and should a MSSV stick open, the release rate and pathway is the same as the fully stuck open ADV case analyzed.

The staff did not analyze the viability and desirability of feed-and-bleed in tube ruptures beyond one broken tube in each SG, and a possible stuck open ADV or MSSV in these situations.

While the staff realizes these events are low probability events, feed-and-bleed to mitigate these scenarios has not been assessed. It can be stated qualitatively, however, that in these scenarios, the use of feed-and-bleed would conserve the RWST inventory. That is, by opening the PORV and establishing feed-and-bleed, less RWST water is lost out the broken tubes since the depressurization rate would be greater with a PORV than with an APS or by contraction caused by the ADV cooldown.

5.B.1.a Conclusions - MSGTRs

In general, with respect to multiple SGTRs, the offsite doses for single SGTRs in each SG for the 3800 MWT plants are less than the 10 CFR 100 limits, regardless which mitigation technique is used. Although not substantiated, the staff believes the results for the 3410 MWT class plant, have been suitably analyzed by CE and are also below the 10 CFR 100 limits.

The viability and desirabiilty of feed-and-bleed, as a means of mitigating single SGTRs or multiple SGTRs with a stuck open ADV or MSSV was not assessed. In these cases, feed-and-bleed may be able to limit offsite doses and provide adequate core cooling. However, the desirability of using long term recirculation in these scenarios must also be evaluated.

5.B.2 Small Break LOCA Without HPSI

To answer the question of how a SBLOCA without HPSI is satisfactorily mitigated without PORVs, an analysis was performed for this accident scenario both with and without the use of PORVs. For the case in which PORVs were not used, RCS depressurization was accomplished by means of agressive steam generator cooldown with the ADVs. For the case in which PORVs were used, no steam generator cooldown was assumed.

Case 1 No Operator Action - An analysis was performed for the SBLOCA without HPSI when no action is taken by the operator to depressurize the RCS. The sequence of events during the transient is similar to those of a SBLOCA with HPSI except that the RCS inventory is negatively impacted by the absence of HPSI. The results of this transient indicated that the core begins to uncover at approximately 2600 seconds. The cladding temperature of the hottest fuel rod reaches 2200°F at approximately 3600 seconds and the reactor inner vessel two-phase mixture level decreases below the bottom of the core at approximately 4100 seconds. At this time, the RCS is still above the pressure of 600 psia at which the safety injection tanks (SITs) begin to inject water into to the RCS. This base case shows unsatisfactory results for this accident scenario.

Case 2 Steam Generator Cooldown Via ADVs - In this case, operator action was assumed at fifteen minutes following the accident. Both ADVs are manually opened to initiate a rapid steam generator cooldown at the rate of 100°F/hour in response to the accident. The steam generator cooldown causes the RCS to cooldown and depressurize. At approximately 3500 seconds the RCS depressurizes to 600 psia at which time the SITs begin to inject water into the RCS. The SIT injection rate exceeds the leak rate and the RCS inventory begins to increase and keep the core covered. At 200 psia the LPSI pumps begin to inject water into RCS after the SITs are depleted. The staff concluded that the assumptions made in this analysis were very conservative since the charging pump flow and auxiliary spray were not assumed to function during the transient.

Case 3 RCS Depressurization Via PORVs - In this case operator action was assumed at fifteen minutes following the accident. Both PORVs was manually opened to initiate a rapid primary system depressurization in response to the accident. However, it was assumed that the operator does not cooldown the steam generators or initiate the charging pumps during the transient. At approximately 1900 seconds the core begins to uncover and at approximately 2300 seconds the SITs begin to inject water into RCS. The SITs do not provide sufficient flow to reflood the core.

5.B.2.a Conclusions - SBLOCA Without HPSI

The analysis shows that only the second case has satisfactory results which do not cause core uncovery. If the charging flow or the APS was assumed in the third case analysis, the transient using PORVs might be more favorable than that in case 2. However, the results of the analysis in case 2 have demonstrated the fact that a SBLOCA without HPSI could be mitigated without the use of PORVs. It must also be noted that the use of the ADVs relies on the SGs as a means of cooling. If not available, for whatever reason, the PORV would provide a means of RCS depressurization.

6. Question 6 Use of Low Pressure Pumps for Feeding Steam Generators

6.A Question 6a Describe the system and its use, including water supplies and their capacity, flow paths, pumps, power supplies to components, control equipment and procedures.

6.A.1 CEOG Responses

The use of existing low pressure pumps such as condensate pumps may provide a useful capability to an operator to supply feedwater to the steam generators during certain low probability scenarios which are essentially beyond the design bases of the plant. For example, a scenario that started with a loss of main feedwater (MFW) due to a realtively minor failure in the MFW system or feedwater control system could result in a total loss of feedwater if the first failure were followed by a multiple failure in the auxiliary feedwater system (AFWS) which prevented this system from functioning. In such a situation where the AFWS is no longer available, an operator would have only about ten to fifteen minutes to find and correct the problem in the MFW system and restore that system prior to inventory depletion in the steam generators to the point where the turbine driven MFW pumps could not be restarted, i.e., steam generator dryout. At this point with both main and auxiliary feedwater down and with insufficient inventory in the steam generators to restart a turbine driven main feedwater pump, one or both steam generators could be depressurized via the atmospheric dump valves (ADVs) to the point where a substitute pump such as a condensate pump could be used to supply feedwater for decay heat removal and, if desired, a recovery of the MFW system could be performed.

Generic analyses were performed for the 3410 MWT and 3800 MWT CE plants evaluating this method of operation. The results of these analyses indicated that it is a viable method for decay heat removal for which specific procedures and training could be developed. The results indicated that time to initiate depressurization and feed via a low head pump to prevent core recovery is 50 minutes for 3410 MWT plants and 59 minutes for 3800 MWT plants. According to this analysis a flow rate of 2300 gpm at a shutoff head of 350 psia can provide sufficient decay heat removal to prevent core uncovery. In addition, initial review indicates that the best suited pump for use a a substitute feedwater pump is probably a condensate pump. This pump appears to be ideally suited for this application since system lineup for feedwater delivery can be readily accomplished, pump flow characteristics are usually such that only modest steam generator depressurization need be accomplished prior to delivery, and the supply of available feedwater is of high quality. The condensate pumps are powered from the offsite power source. A second possible candidate for use as a subsitute feedwater pump would be an emergency firewater pump. The advantage of using this pump would be the availability of an emergency onsite power supply; however, the system lineup necessary to initiate feed is somewhat more difficult than with the condensate pump and the water would be of a lesser quality.

The actual equipment and interface requirements for this application are plant specific and have been supplied by individual utilities. Further discussion of the generic analyses including assumptions and results are provided under question 6c.

6.A.1.a San Onofre Responses

In the unlikely event of a loss of both main and auxiliary feedwater at San Onofre Units 2 and 3, there are several sources of low pressure water available for use as makeup to the steam generators. The preferred source would be the condensate system of the affected unit. The four condensate pumps have a shut-off head of 500-600 psig, supply water from multiple sources (e.g., hotwell, condensate storage tanks, demineralizer make up) and through use of the feed pump bypass line can deliver makeup directly to each steam generator. Each condensate pump has a rated capacity of 7750 GPM. The condensate pumps are powered from the offsite power source. The normal condensate makeup sources (hotwell and condensate storage tanks) contain 746,600 gallons. If additional makeup is required, there are several alternate means to refill the condensate storage tanks. Makeup grade water is available from the condensate system of the companion unit through the condensate cross tie line and from the onsite demineralizer system. As a backup to these sources, service grade water is available from the fire protection system of Units 2 and 3 as well as Unit 1. The fire protection reserve for Units 2 and 3 is 750,000 gallons and Unit 1 has a 3 million gallon reservoir. This means that there is over 5 million gallons of onsite condensate makeup water available to the San Onofre Units 2 and 3 steam generators to supplement the AFWS. There is also a virtually unlimited supply of potable water available from the domestic water system.

The licensee also suggested the use of a condensate transfer pump (100 gpm @ 65 psig) for operation in the depressurized mode.

The alternate means of using condensate pumps to remove decay heat from the core involves only a minimal change in the normal feed valve lineup in conjunction with depressurization of a steam generator by means of the atmospheric dump valves (ADVs). The condensate system is lined up to directly feed a steam generator with the main feed pumps bypassed and isolated.

The licensee has provided a detailed outline of the steps that may be followed for a loss of main and auxiliary feedwater. The alignment of the condensate pumps to the steam generator can be completed from the control room with the exception of opening the two main feed pump bypass valves which must be accomplished by local manual operator action. All other operations, including control of steam generator pressure and water level, are completed following existing San Onofre 2 and 3 procedures.

6.A.1.b <u>Staff Evaluation of San Onofre</u>

The use of condensate pumps for alternate decay heat removal in the event of loss of main and auxiliary feedwater pumps is a viable method to provide flow to the steam generators for decay heat removal in accordance with the CEOG generic analysis for total loss of feedwater event with offsite power assumed available. The San Onofre Units 2 and 3 condensate pumps with a rated capacity of 7750 gpm and the shutoff head of above 500 psig can satisfy the analyses requirements. Therefore, these pumps are adequate for the alternate decay heat removal purpose. The licensee in response to the staff's question in the meeting held on July 7 and 8, 1983, confirmed that the flow could be throttled to avoid overcooling. The capacity of the water supply source to the pump is also adequate for long term operation in this mode.

However, use of condensate transfer pump at 65 psig is not a viable technique as is does not meet the analysis requirements, and therefore, no credit can be given for this pump.

The staff has reviewed the plant-specific guidelines submitted by San Onofre Nuclear Generating Station, Units 2 and 3. We have concluded that there is sufficient information contained in the plant-specific guidelines so that procedures can be written to use the condensate pump to supply feedwater to the steam generator. Based on the above referenced analysis and draft ANSI N660, we also conclude that adequate time would be available to perform the indicated manual actions. The licensee should factor this new operator guidance into the overall response to supplement 1 to NUREG-0737.

6.A.2.a Waterford Unit 3 Responses

Two low pressure systems have been identified as providing the potential capability for alternate decay heat removal (ADHR) in the event that the emergency feedwater system (EFWS) is not available after a loss of main feedwater. It should be noted that the EFWS in Waterford Unit 3 is the same as AFWS in other plants. The preferred method, in the event that offsite power is available, is to use the condensate pumps to supply water to the steam generators. If offsite power is not available, the licensee has proposed the use of a diesel driven firewater pump at low pressure. The applicant has also described the possibility of adding an auxiliary feedwater pump as part of the ADHR capability. The ADHR capability is described below:

(1) Condensate System

The condensate system is composed of three 50% capacity condensate pumps, several trains of feedwater heaters, and the required piping and valves. Each pump has a rated flow capacity that exceeds 10,000 gpm and a shutoff pressure of about 500 psia. Power for the condensate pumps is obtained only from offsite power. These pumps can supply sufficient water to the steam generator through the normal feedwater path. The main feedwater pumps and various heater stages can be bypassed if necessary.

The normal condensate make-up sources include the condensor hotwell and condensate storage tank. These sources contain 368,500 gallons of make-up grade water. If additional make-up water is required, a virtually unlimited supply of potable water is available from the domestic water system through the demineralized water system.

(2) Firewater System

The firewater system can be modified to provide supplemental water to the steam generators if offsite power is not available. A diesel driven firewater pump with a shutoff pressure of 120 psig and maximum flow rate of 2000 gpm is available. Some piping modifications would have to be made in order to provide a flow path from the firewater pump to the blowdown line of the steam generator. Special flanges could be used to allow quick connection of fire hoses or more permanent piping could be installed. The procedure guidelines for use of the firewater system assumes that special flanges would be used. However, the applicant has indicated that a permanently installed connection with shutoff valves would be found to be a better arrangement.

Two firewater storage tanks provide a total of 520,000 gallons of water. Additional make-up water is available from the domestic water system through the Primary Water Treatment System.

(3) Auxiliary Feedwater Pump

The use of an additional feedwater pump which could serve as part of the ADHR capability is currently being evaluated by the applicant. This pump would have a discharge pressure equivalent to normal operating pressure and a steam generator delivery flow rate equivalent to an auxiliary feedwater pump. A dedicated diesel generator is being considered so that the pump could be operated if offsite power were lost. Suction would be taken from a source of clean, demineralized water such as the condensate storage tank. This auxiliary feedwater pump would be capable of providing enough water to the steam generators to first depressurize and remove decay heat from the RCS without the need to depressurize the steam generators. The Waterford 3 Safety Review Committee has recommended that additional studies be continued on the use of an auxiliary feedwater pump for ADHR.

6.A.2.b Staff Evaluation of Waterford

The use of condensate pumps for alternate decay heat removal in the event of loss of main and auxiliary feedwater pumps is a viable method to provide flow to the steam generators for decay heat removal in accordance with the CEOG generic analysis for total loss of feedwater event with offsite power assumed available. The Waterford pumps have a flow rate which exceed 10,000 gpm and a shutoff head of 500 psia (Vs. 2300 gpm and 350 psia in the CEOG analysis). The licensee in response to the staff's question in the meeting held on July 7 and 8, 1983, confirmed that the flow could be throttled to avoid overcooling. Therefore, the results of the CEOG generic analysis are bounding for Waterford 3.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from total loss of feedwater transient. However, analyses presented to date do not support this conclusion for the fire pumps. Consequently, no credit should be taken for fire pump operation. A detailed discussion of the staff scoping calculation for fire pump availability is discussed in part (c) of this question.

The use of an auxiliary feedwater pump as an ADHR system with an independent onsite power source is a useful concept, particularly since it does not require steam generator depressurization. We encourage the licensee to continue to pursue this option.

The staff has reviewed the plant-specific guidelines submitted by Waterford 3. We have concluded that there is sufficient information contained in the plant-specific guidelines so that procedures can be written to use the condensate pump to supply feedwater to the steam generator. Based on the above referenced analysis and use of draft ANSI N660, we also concluded that adequate time would be available to perform the indicated manual actions. The licensee should factor this new operator guidance into their overall response to Supplement 1 to NUREG-0737.

6.A.3.a Palo Verde Response

In the unlikely event of a loss of main and auxiliary feedwater at Palo Verde Units 1, 2, and 3, the operator would proceed to feed the steam generators with the low pressure condensate system of the affected unit. The condensate system of each unit consists of three 50% capacity condensate pumps, several trains of feedwater heaters, and the required piping and valves. Each pump has a rated flow capacity of 9100 gpm and a shutoff pressure of 540 psia. Power for the condensate pumps is obtained only from offsite power. These pumps can supply sufficient water to the steam generator through the normal feedwater path.

The condensate pumps take their suction from the condenser hotwell which has a nominal normal inventory of 100,000 gallons. Makeup to the hotwell is made up via gravity feed from the condensate storage tank (CST) which has a capacity of 550,000 gallons. However, 330,000 gallons is dedicated storage for auxiliary feedwater, leaving 220,000 gallons for condensate makeup. As a backup to the CST, the Demineralized Water Tank (capacity 125,000 gallons) supplies makeup to the CST via the two Demineralized Water Transfer Pumps (capacity 312 gpm each). Therefore, approximately 455,000 gallons of condensate quality water is readily available to feed the S/Gs within the affected unit. Identical amounts are available from the other two PVNGS units via a common condensate crosstie line.

In addition to the condensate storage capabilities, the Demineralized Water Makeup System is designed to supply condensate grade water to each Demineralized Water Tank at a design rate of 400 gpm continuously, and a maximum rate of 600 gpm.

The applicant has also suggested the use of the unaffected units condensate pumps to feed the affected units steam generators. A detailed procedure guideline and valve line-up describing use of the affected or unaffected units condensate pumps has been provided by the applicant. The line-up requires some manual operation outside the control room but most of the alignments can be performed from the control room.

6.A.3.b Staff Evaluation of Palo Verde

The use of condensate pumps for alternate decay heat removal in the event of loss of main and auxiliary feedwater pumps is a viable method to provide flow to the steam generators for decay heat removal in accordance with the CEOG generic analysis for a total loss of feedwater event with offsite power assumed available. The Palo Verde pumps have a flow rate of 9100 gpm and a shutoff head of 540 psia (vs. 2300 gpm and 350 psia assumed in the CEOG analysis). The flow could be throttled to avoid overcooling. Therefore, the results of the CEOG generic analysis are satisfied for Palo Verde units 1, 2, and 3.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from a total loss of feedwater transient.

The staff has reviewed the plant specific guidelines submitted by Palo Verde 1, 2, and 3. We have concluded that there is sufficient information contained in the plant-specific guidelines so that precedures can be written to use the condensate pump to supply feedwater to the steam generator. Based on the above referenced analysis and use of draft ANSI N660 we also conclude that adequate time would be available to perform the indicated manual actions. We require that the ~~licensee~~ applicant factor this new operator guidance into their overall resposne to Supplement to NUREG-0737.

6.B Question 6b Describe the water chemistry interface requirements for the proposed low pressure system in order to assure that its use will not cause unacceptable steam generator integrity degradation or heat transfer capability.

6.B.1 CEOG Responses

The concern is addressed in Question 7.

6.B.1.a San Onofre Responses

Of the alternate sources of water discussed in Question 6a, the limiting worst case water chemistry (to be utilized after all secondary condensate makeup is expended) is drawn from the fire protection system without water treatment.

6.B.1.b Staff Evaluations of San Onofre

A detailed discussion is provided in Question 7. The normal condensate makeup can provide secondary grade water for approximately 6 hours and therefore the probability of corrosion and heat transfer degradation due to service grade water is limited.

6.B.2.a Waterford Unit 3 Responses

As discussed in Question 6a, demineralized water is used to feed condensate and feedwater pumps and potable water is used for the firewater pumps. Additional discussion is provided in Question 7.

6.B.2.b Staff Evaluations of Waterford

A detailed discussion is provided in Question 7. The use of deminearlized water to supply the condensate pumps is acceptable since it is secondary grade water. As discussed in 6a, the firewater pump cannot be used due to low shut-off head and therefore, lower grade water will not be used by Waterford.

6.B.3.a Palo Verde Response

All the alternate sources of water discussed in Question 6a are of high quality, secondary grade.

6.B.3.b Staff Evaluation of Palo Verde

A detailed discussion is provided in Question 7. The use of secondary grade water to supply the condensate pumps is acceptable. No unacceptable steam generator integrity degradation or loss of heat transfer capability would be anticipated using the identified water sources for the alternate decay heat removal schemes.

6.C Question 6c Show that blowdown of the steam generator is a viable technique without adverse core cooling consequences. Show that a concurrent rapid primary system cooldown and potential primary system contraction does not result in inadequate core cooling or a return to power.

6.C.1 CEOG Responses

In response to this question, CEOG performed analyses to demonstrate that steam generator depressurization, actuated in the late stages of a total loss of feedwater event (TLOFW), could depressurize the primary system and remove decay heat, without resulting in core uncovery or a return to power. The analyses were performed for both the 3410 class and the 3800 class plants. The complete transient results for the 3410 class plant are presented in the CEOG report. The results for 3800 class plant are very similar and therefore not reported.

In the TLOFW event analyzed (for a 3410 class plant), offsite power was assumed available. Consequently the reactor tripped after 20 seconds and the Reactor Coolant Pumps (RCP) were manually tripped at 10 minutes. The steam generator dried out at 10 minutes, the primary system safety valves opened shortly thereafter, and primary system inventory began to deplete. At 50 minutes into the transient, the steam generator contained a dry steam at 2500 psia, and the two-phase mixture level in the reactor vessel was less than four feet above the top of the core. At this point, one atmospheric dump valve (ADV) in each steam generator loop was opened.

Secondary pressure fell rapidly to 200 psia, and feedwater injection commenced at 52 minutes at a rate of 2300 gpm. The assumed condensate pump shutoff head was 350 psia. Over the ensuing 600 seconds, condensate pump injection cycled on and off as steam generator pressure oscillated above and below the shutoff head due to alternating pulses of rapid feedwater injection and rapid steam relief. Steam generator level rose steadily with each succeeding cycle.

The CEOG submittal demonstrated that the steady state steam relief capacity of the ADV's was more than a factor of two greater than would be required to remove decay heat 30 minutes after trip (1.87% of full power) plus the Reactor Coolant Pump power (20 MW). Under the aforementioned oscillatory conditions, the ADV relief rate averaged less than the steady state value. However, with the decay heat reduced (50 minutes vs. 30 minutes) and the RCP's tripped, the ADV's were able to remove decay heat and cool the primary system. RCS pressure dropped rapidly from 2500 psia at 52 minutes to the HPSI shutoff heat (1420 psia) at 56 minutes, and to the Safety Injection Tank setpoint (615 psia) at 62 minutes. At this point, the calculation was terminated.

Although the rapid cooldown would tend to reduce core voiding and suppress the two-phase mixture level, the CEOG submittal presented calculations to show that this reduction in level would be more than compensated for by steam condensation, and that under certain circumstances the cooldown would result in the transfer of pressurizer water to the reactor vessel. Consequently the core did not uncover.

The rapid reduction in RCS temperature would result in a sizable positive reactivity insertion, particularly at the end of a cycle. THe CEOG submittal asserts that this effect would be offset by the high boron concentration due to two factors (1) charging pump injection of borated water and (2) the concentration of boron due to boiloff of reactor coolant (boron has very low volatility). Furthermore, the core would still be partially voided after depressurization. The submittal presented no numerical analysis of these competing effects. In response to a telephone inquiry, CEOG provided preliminary calculations of the actual boron concentrations in the RCS compared with the concentrations required to prevent return to power.

At a conservatively low temperature of 40°F, using conservative values for the moderator and Doppler temperature coefficients, with no credit for voiding or xenon buildup, and with one control rod assembly stuck in the out position, the necessary boron concentration to prevent criticality is 370 ppm for the 3410 Class plant and 360 ppm for the 3800 class Plant (CESSAR 80). The actual estimated concentration, assuming zero initial concentration and minimum technical specification concentrations for HPSI and charging, would be 1154 ppm for the 3410 class plants and 538 ppm for CESSAR 80. The basis for these calculations will be documented by the applicant.

6.C.2 Staff Evaluations

The total loss of feedwater transient analyzed by the CEOG represents the most challenging credible test of the proposed steam generator blowdown technique. The analysis was performed in a best-estimate mode using accepted analytical methods (CEFLASH-4AS). The results have been examined by the NRC staff and found to be reasonable. Hand calculations have been performed to verify some of the assumptions.

The CEOG conclusion that recovery of the heat sink late in the transient can reduce primary pressure without core uncovery is supported by confirmatory calculations performed by the Argonne National Laboratory. In case 2I of the reference ANL calculations of the TLOFW event for System 80 (ANL/LWR/NRC 83-6), ANL demonstrated that recovery of auxiliary feedwater (AFW) 50 minutes into a TLOFW with offsite power available will rapidly reduce system pressure and avoid core uncovery. The ANL results are not directly applicable, however, because recovery of AFW does not require opening of the ADV's and there is no oscillation in feedwater flow.

The success of the steam generator depressurization method depends on the steam relieving capacity of the ADV's. If there is water in the steam generator, and if the pressure is maintained in the vicinity of 350 psia, the ADV's steam relief rate will be sufficient to remove decay heat and rapidly cool the primary system. The CEOG submittal demonstrates that steam generator water level rises steadily, in spite of the oscillatory behavior of the pumps. Furthermore, steam generator pressure oscillates about the assumed pump shutoff head (350 psia), and the ADV relief rate oscillates accordingly, with an average relief rate in the vicinity of the steady state relief rate for 350 psia. For a pump of lower shutoff head, the relief rate will be proportionally lower.

The CEOG calculations demonstrate to our satisfaction that the steam generator depressurization technique is viable for pumps which are capable of delivering 350 psia water to the steam generator. However, scoping calculations performed by the staff indicate that the technique will not work below 120 psia. Calculations performed by CEOG but not presented in the CEOG submittal, showed that the 120 psia shutoff head fire pumps at Waterford, if used in the depressurization model, could remove decay heat, but were unable to depressurize the primary system below 2200 psia. Core uncovery was observed for a period of 500 seconds in those calculations, but clad temperatures did not reach 2200°F. Given the uncertainties in initial conditions, analytical methods and modelling assumptions, this result does not constitute sufficient assurance that SG blowdown with the Waterford fire pumps can successfully recover from a TLOFW transient.

The staff concludes that steam generator depressurization with feedwater injection from one condensate pump is a viable method of recovering from a TLOFW. However, analyses presented to date do not support this conclusion for the fire pumps. Consequently, no credit should be taken for fire pump operation in this mode of operation. (Reference: Waterford PRA; Page 6-121).

The staff concurs in the CEOG analysis demonstrating that core uncovery will not result from coolant skrinkage during the rapid cooldown.

Finally, the CEOG has demonstrated with a sufficient degree of conservatism that there will not be a return to power following the rapid cooldown.

6.D Question 6d Show that there are no adverse consequences while feeding a dry stream generator with the low pressure system.

6.D.1 CEOG Responses

Early C-E NSSS designs which relied upon manually initiated auxiliary feedwater were specified to include a limited number of feedwater initiations to a hot, dry steam generator. Although this specification was deleted with the inclusion of automatically initiated AFW, calculations have indicated that the 3410 and the 3800 plants are capable of accepting a limited number of initiations of 70°F feedwater to a hot and dry steam generator via the feedwater ring and downcomer. Initiation of the feedwater in such an *in extremis* situation would represent a last resort effort to provide for core cooling and prevent core damage. Following such an initiation, the structural integrity of the steam generators would be evaluated on a plant specific basis as necessary once the RCS was safely cooled down prior to resuming operation.

CE was asked to address a potential waterhammer concern under the above conditions by a telephone call on July 26, 1983. In response to this telephone call, CE responded that the waterhammer test performed in every plant prior to operation simulates more conservative test conditions than that which exists in a boiled day steam generator. Furthermore procedures will be written to initiate feedwater to a hot, dry steam generator at a lower flow rate than that which existed in the waterhammer test.

6.D.2 Staff Evaluations

The staff concludes that the above response and evaluation of the structural integrity of the steam generator for thermal shock considerations on a plant specific basis as necessary once the RCS is safely cooled down prior to resuming operation is acceptable. Also, our concerns regarding waterhammer have been satisfied by the above response.

6.E Question 6e If steam generator pressure rises above the shutoff head of the low pressure pumps intended to be used, describe the method of regaining feed flow without compromising core cooling.

6.E.1 CEOG Responses

As described above in the response to question 6c, the CEOG analysis of the TLOFW events showed that steam generator pressure repeatedly exceeded the condesate pump shutoff head, and feedwater flow ceased. In each instance, steam flow out of the ADV continued and eventually reduced pressure to below the shutoff head. Renewed feed flow would then produce a new surge of steam production, pressure would rise, and the cycle would repeat. Nevertheless, the CEOG calculations showed uninterrupted decay heat removal, system depressurization, and continuous core coverage.

6.E.2 Staff Evaluations

With the ADV's open, the steam generator pressure cannot remain above the pump shutoff head for very long. As long as steam flow out of the ADV is sufficient to remove decay heat and cool the primary, cyclic flow to the steam generator is acceptable. The recirculation line for the condensate pump prevents dead heading of the pump while cycling, and assures pump operability.

6.F Conclusions

The staff concludes that steam generator depressurization and feedwater injection using the condensate pumps is a viable method of recovering from a total loss of feedwater transient. These pumps provide a useful capability to the operator to supply water of secondary quality to the stema generators assuming offsite power is available for the identified event of a loss of all main and auxiliary feedwater beyond the design bases of the plant. Plant specific procedures should be developed for guidance on use of this decay heat removal method. However, use of a firewater pump or condensate transfer pump as an alternate decay heat removal source is not feasible under the assumed conditions as insufficient decay heat removal is provided to prevent core uncovery.

In addition, the staff recommends that Waterford continue to investigate the practicality and advantages of adding the proposed additional auxiliary feedwater pump in order to increase the reliability of the secondary side decay heat removal capability.

Note: The staff evaluation of the Palo Verde responses will be provided later.

7. Question 7 This question asks each applicant and licensee to fully describe chemistry affects to steam generator tube integrity.

7.A CEOG Responses

In the absence of a power operated relief valve (PORV) capability, greater reliance is placed on steam generator tube integrity to accomplish safe shutdown. By reporting No. CEN-239, dated June, 1983 CEOG provided information on staff concerns for plants which do not have PORV's. By draft memo dated July 21, 1983, additional information was provided.

7.B Staff Evaluation

The steam generator tubes are alloy-600, fabricated in the mill annealed condition. CEOG has performed high temperature isothermal and heat transfer corrosion testing of alloy-600 in environments faulted with sea water and fresh water. These tests included exposure to sea water for several weeks at operating temperature pressure and fresh water simulating emergency plant cooldown conditions. Only pitting of less than 5% throughwall penetration was observed in both the sea and fresh water tests. Additionally, field experience has shown only minor corrosion in operating steam generators where condenser tube ruptures have resulted in highly faulted secondary water chemistry. Based on these tests, we have reasonable assurance that tube integrity will not be imparied due to corrosion during a cooldown in which main condenser cooling water faulted feed-water is used as makeup to the steam generators.

The steam generator tube supports and structural members which are not part of the primary pressure boundary are fabricated of a variety of carbon and stainless steels. These steel components are more susceptible than alloy-600 to general and localized corrosion mechanisms. Based on expected corrosion rates, short-term exposures to faulted water chemistry are unlikely to cause structural failure of steel components. However, after operation with highly faulted water chemistry, steam generator inspections will be necessary to verify steam generator operability prior to re-start.

The steam generators are fabricated with approximately 110% of rated heat transfer surface area. The total heat load is less than 3% during an emergency cooldown when condenser cooling water faulted impurities would be injected to the steam generators. Therefore, a significant excess of heat transfer surface area exists during cooldown conditions. Because of the excess of heat transfer area under cooldown conditions, heat flux through the tube walls is only a fraction of operating heat flux. The reduced heat flux produces only a small amount of boiling in the steam generators. As a result, concentration gradients and dry-out regions are minimized on the alloy-600 heat transfer tubing, and the potential for fouling of heat transfer surfaces is significantly reduced. Based on the above, we have reasonable assurance that the heat transfer surface will not be fouled to the extent that cooling functions are impeded during a cooldown using main condenser cooling water as feedwater to the steam generators.

7.C Conclusions

Based on the above evaluation, we conclude that the structural integrity and heat transfer capabilities of the steam generators will not be impaired during the time it takes to reach safe shutdown using main condenser cooling water as feed water. Therefore, we have reasonable assurance that the steam generators can be relied on for heat removal during emergency cooldown conditions when main condenser cooling water needs to be used as feed-water. However, the steam generators should be inspected prior to re-start, to verify steam generator integrity.

8. Question 8 Extended Loss of Main Feedwater

a. Part (a) of this question asks for the frequency of loss of main feedwater; and asks that this frequency be broken down into initiators that affect more than loss of main feedwater.

8.A.a CEOG Response

The frequency of loss of main feedwater estimated by CE was 1.23/year (median value) for SONGS 2-3, and .71/year for Waterford from a combination of operating experience and fault tree analysis. The response to this question does not explicitly identify the contribution to this frequency from loss of offsite power events, or of other events which may also degrade mitigating systems.

8.B.a Staff Evaluation

The staff estimates the frequency of total loss of main feedwater at about 1/yr, at both these sites. The staff's estimate is taken from the ANO-1 IREP study, NUREG/CR-2787, and is based on an analysis of historical data. Of the events that can cause loss of main feedwater, loss of offsite power is of special interest. On loss of offsite power the unavailability of the auxiliary feedwater system is increased, and also the condensate pumps are unavailable, so that the use of the condensate pumps to supply water to the steam generators, after depressurizing the steam generators, is not possible. Combustion Engineering estimated the frequency of loss of offsite power at San Onofre Units 2 and 3 to be .04/year, and at Waterford to be .2/year. The staff estimates the frequency of loss of offsite power at both these sites to be about .1/year. The staff estimate of .12/year for the loss of offsite power frequency was taken from the station blackout analysis report, NUREG/CR-3226, and corresponds to an average over the entire population of U.S. plants.

Loss of D.C. power, either as an initiator or subsequent to loss of A.C. power, is not a significant issue with regard to the issue of installing PORVs in CE plants. This is a consequence of the multiple redundancy of DC bases, combined with the separation of D.C. loads.

b. Part (b) of this question asks for the probability of recovery of main feedwater.

8.A.b CEOG Response

Combustion Engineering gave no credit for recovery of main feedwater except insofar as they considered implementation of an alternate secondary decay heat removal capability. At SONGS 2 and 3 this requires the use of the condensate pumps, and therefore requires the availability of offsite power. For the Waterford plant, Combustion Engineering gave some credit for a diesel-driven fire pumps,

8.B.b Staff Evaluation

For loss of main feedwater transients not caused by loss of offsite power, Combustion Engineering estimated, by fault tree analysis, that the probability of failure of the alternate secondary decay heat removal path (i.e., depressurization of the steam generators and using the condensate pumps) was .056, for the SONGS 2 and 3 plants. A .05 probability of human error was assumed. The staff, from the examination of historical data on loss of main feedwater events, has made a rough estimate of the fraction of all loss of main feedwater events in which the condensate pumps would be unavailable, and estimates this fraction as 0.1 (given offsite power available). If we add to this the same human error probability used by Combustion Engineering, we obtain an estimate of unavailability of the alternate secondary decay heat removal path of .15, instead of the value of .056 used by Combustion Engineering, for loss of main feedwater transients not caused by loss of offsite power.

The staff does not concur with the CEOG that the diesel-driven fire pumps at Waterford provide an effective alternate water-source. The staff believes there is considerable uncertainty as to whether this pump would function properly, because of its low shutoff head.

None of the analyses gave credit for recovery of main feedwater following a loss-of-offsite power event. If offsite power is recovered after the steam generator dry out, it will not be possible to drive the turbine-driven main feedwater pumps. Any possible conservatism introduced is small, since recovery of offsite power permits recovery of the auxiliary feedwater system with high probability.

The staff has identified certain discrepancies in the C-E calculation of the probability of failure of the alternate secondary decay heat removal system which will increase this failure probability by a factor of five, for San Onofre Units 2 and 3.

c. Part (c) of this question asks for the probability of losing all auxiliary feedwater, given loss of main feedwater.

8.A.c CEOG Response

Combustion Engineering in their original submittal, CEN-239, estimated the failure probability of the auxiliary feedwater system to be 2×10^{-6}/demand, for SONGS Units 2 and 3, including credit for recovery actions. This is a failure probability averaged over all initiators. For Waterford, the value obtained by Combustion Engineering for the auxiliary feedwater system failure probability was 3×10^{-5}/demand, including recovery actions. These values are subject to correction by C-E.

8.B.c Staff Evaluation

The staff also performed an assessment of the unavailability on demand of the auxiliary feedwater system at San Onofre, and obtained a mean value of 6×10^{-5}/demand, for a loss of main feedwater transient with offsite power available, and obtained a mean value of 2.5×10^{-4}/demand for the case where offsite power is not available.

One should note that there is a contribution to the unavailability on demand of the auxiliary feedwater system, given a loss of offsite power, from sequences involving station blackout. Averaging over the possible ways of losing main feedwater one obtains approximately 8×10^{-5}/demand, which ~~gets~~ meets the goal.

Sandia National Laboratory, consultants to the staff, estimated (Ref. 25) the unavailability of the auxiliary feedwater system at San Onofre to be 2.2×10^{-6}/demand, for a loss of main feedwater system transient (with offsite power available), and estimated the unavailability to be 8×10^{-5}/demand, for a loss of offsite power transient.

Certain types of dependent failures are very difficult to model explicitly in fault tree models and to quantify properly through explicit modeling. One way of quantifying such dependent failures is through the beta factor method of Fleming (Ref. 27). The staff calculation of the reliability of the auxiliary feedwater system used this method. The beta factors for the auxiliary feedwater system pumps were taken from the work of Atwood (Ref. 28) and those for the High Pressure Injection System pumps were taken from the Sandia Review of the Indian Point Probabilistic Safety Study (Ref. 29). These beta factors were used for component failures, not command faults.

Part of the difference in the estimated AFW unavailabilities is the statistical procedure used in the calculations. The estimates of Sandia National Laboratory are point estimates, where the estimates of the basic component failure rates are median values. The estimates of Combustion Engineering are median values, obtained by propagating the uncertainty distributions on the basic failure data, and obtaining the median for the resulting system failure probability. The staff calculations are mean values using data from NUREG/CR-2815.

On the basis of this review, the staff has reconfirmed that the reliability of the auxiliary feedwater system designs for CE plants under consideration remains in the high ($\sim 10^{-4}$/demand) category.

d. Part (d) of this question asks for the uncertainty in the estimates of the frequency of loss of main feedwater events, of the probability of recovering main feedwater, and of the probability of recovering auxiliary feedwater.

8.A.d CEOG Response

Combustion Engineering gives the uncertainty bands on the frequency of the loss of main feedwater initiator, and on the probability of losing all auxiliary feedwater before recovery. The uncertainty is expressed as an error factor equal to the ratio of the 95th percentile to the median, or 50% percentile. Combustion Engineering estimated, for San Onofre Unit 2 and 3, that the Error factor on the loss of main feedwater frequency was 3. The recovery of main feedwater, in the C-E calculation, is done only through the use of the condensate pumps and the depressurization of the steam generators. The error factor on the auxiliary feedwater system failure probability is about 15, in the C-E calculations.

8.B.d Staff Evaluation

We note that the logarithm of the variable under consideration (e.g., the failure probability for the auxiliary feedwater system) may not be symmetrically distributed, so that the ratio of the 50th percentile to the 5th percentile may be different than the error factor, defined as the ratio of the 95th percentile to the 50th percentile.

The staff concurs in the estimated error factor for the loss of main feedwater. The staff estimates that the error factor for the probability of failure of the auxiliary feedwater system, given loss of offsite power, is about 20, and the error factor for the probability of failure of the auxiliary feedwater system, given offsite power is available, is 43. The staff estimates the probability of the recovery of main feedwater including implementation of the alternate secondary decay heat removal path, as lying between .07 and .25. (5th and 95th percentile values).

e. Part (e) of this question asks for the length of time it would take for core melt to initiate.

8.A.e <u>CEOG Response</u>

Combustion Engineering found that the onset of core melt, defined as the time at which at 2200°F peak clad temperature was reached, was 60 minutes for a 3410 plant, and 70 minutes for a 3800 plant, after a total loss of main feedwater.

8.B.e <u>Staff Evaluation</u>

These calculations have not been reviewed by the staff, but the results appear reasonable.

f. Part (f) of this question asks for the likelihood of steam generator tube ruptures due to steam pressure from a slumping core.

8.A.f <u>CEOG Response</u>

This part of the question was not addressed by Combustion Engineering.

8.b.f <u>Staff Evaluation</u>

The staff has not performed a formal analysis of this issue; however, we do not believe the conditional probability of tube rupture to be impacted significantly with or without PORVs.

g. Part (g) of this question asks for a characterization of the consequences of a core melt initiated by total loss of main feedwater, and in which steam generators tube ruptures occurred on core slumping.

8.A.g <u>CEOG Response</u>

The CEOG did not respond to this question.

8.B.g <u>Staff Evaluation</u>

Previously published PRAs have not considered this type of consequential failure from core melt sequences and the staff also has not analyzed this case.

The staff judgment is that the benefit of PORVs in reducing risk is likely to be small for such sequences. The staff judgment is based on the following considerations:

(1) Probability of multiple tube failure following core melt is not believed to be high.

(2) There is difficulty in relying on operator action in a short time period following core melt and before multiple tube ruptures to reduce primary pressure via manual opening of PORVs.

8.C <u>Conclusions</u>

The estimated likelihood of core melt from loss of feedwater events is presented in response to Question 11 for situations with and without PORVs available.

9. Question 9 a and b: What is the risk from steam generator tube failures?

9.A.a/b CEOG Response

Combustion Engineering found that the core damage frequency due to steam generator tube rupture (SGTR) in one or both steam generators, for SONGS, assuming offsite power is available, is 1.5×10^{-5}/yr (median value) with an error factor of 5. If offsite power is not available, the core damage frequency contribution due to a SGTR in one or two steam generators is 1.5×10^{-6}/yr (median value) with an error factor of 11. Combustion Engineering found that PORVs would not appreciably change the frequency of core damage events due to SGTRs.

9.B.a/b Staff Evaluation

The dominant accident sequences for the SGTR initiator, in the Combustion Engineering analysis, consisted of sequences in which a main steam safety valve (MSSV) stuck open or the high pressure injection system failed. In sequences in which a MSSV stuck open, there is a direct path to atmosphere for the reactor coolant. If the reactor coolant system is not cooled down and depressurized to atmospheric pressure before the refueling water storage tank is emptied, core uncovery will result. However, the staff estimates that there is considerable time before the refueling water storage tank is depleted-about 35 hours for the case of a single tube rupture. During that time it may be possible to cooldown and depressurize the reactor coolant system to atmospheric conditions, or to find a means for refilling the refueling water storage tank with borated water. Accordingly, the assumption that a stuck-open MSSV after a SGTR leads to core melt is conservative.

The sequences in which failure of the high pressure injection system occurs after a steam generator tube rupture may also have been treated conservatively. It is possible that the reactor coolant system could be cooled down and depressurized to the point where the pressure differential across the ruptured steam generator tube was sufficiently small that makeup could be supplied by the charging pumps, or, as suggested in the C-E submittal (CEN-239 supplement 1 for San Onofre, p. 9-1) the primary pressure could be brought down to where the safety injection tanks could prevent or mitigate core uncovery and prevent core damage.

Combustion Engineering, using the U.S. experience on steam generator tube ruptures, estimated the median frequency of a single tube rupture as 9.7×10^{-3}/yr, and estimated the error factor as 2.6. These appear to be reasonable estimates. We note that the maximum likelihood estimate for the frequency is 4/361/yrs, or 0.011/yr.

Combustion Engineering used an analytical model to determine the frequency of multiple steam generator tube ruptures. The assumption is made in the C-E analysis that there is no tube degradation beyond the degradation that existed at the last inspection. Of the four SGTR's that have occurred in U.S. plants, two (one at Ginna and the other at Prairie Island Unit 1 on October 2, 1979) were caused by foreign objects, one was likely caused by changes in water chemistry (Point Beach Unit 1 on February 26, 1975) and one (at Surry Unit 2 on September 15, 1976) was a result of stress corrosion cracking. In all of these events, degradation of the tubes after the last inspection was a factor, and it would not be prudent to employ a model intended to predict the frequency of multiple tube ruptures which did not take this degradation into account. Some other aspects of the model in particular, the distribution used for the burst pressure of an undefected tube, and the dependance of the burst pressure on the percent remaining wall thickness, are judged to be adequate approximations. Another aspect of the model which appears somewhat arbitrary is the probability distribution for the degree of degradation of a tube. However, the sensitivity of the results for the frequency of multiple tube ruptures to the distribution assumed is not known.

The Combustion Engineering model yields, for the frequency of two tube ruptures in a single steam generator, a value of 6×10^{-3}/yr. An equally plausible value would be about 2×10^{-3}/yr, corresponding to a 50% confidence limit for an event which has not occurred in 361 reactor years. The Combustion Engineering result is conservative with respect to this value. The Combustion Engineering model predicts a probability of 6×10^{-5}/yr for 6 simultaneous steam generator tube ruptures in one steam generator, and lower probabilities for larger numbers of ruptured tubes; the probability decreases with increase in the number of tubes ruptures (at least, when the number of ruptured tubes succeeds 4). Analyses by the staff have assumed, as a conservative upper bound estimate, that the frequency of 10 or more tubes rupturing simultaneously is 2×10^{-4}/reactor-year. With this conservative upper bound frequency for multiple steam generator tube ruptures, multiple tube ruptures do not lead to high estimates of public risk.

The risk from steam generator tube ruptures, in the Combustion Engineering analysis, is dominated by the risk from single tube ruptures, because the sequences considered for multiple tube ruptures are the same as those for single tube ruptures, and the frequencies of multiple tube ruptues are smaller. Staff analyses have obtained a relatively higher contribution from multiple steam generator tube ruptures, but the core melt frquency due to the SGTR initiator was 4×10^{-6}/yr, as opposed to the C-E estimate of 1.7×10^{-5}/yr.

c) Part (c) of this question asks for the likelihood of steamlines filling with liquid water and any consequential failures.

9.A.c CEOG Response

Combustion Engineering obtained a value of 2.5×10^{-4}/yr (median value) for sequences leading to steam generator overfill after a steam generator tube rupture.

9.B.c Staff Evaluation

Since there has already been a steam generator event in which a steam generator has overfilled (Ginna event), in some 360 years of PWR experience, this estimate is an order of magnitude low, when compared to historical experience. The only consequences of overfilling steam generator considered by Combustion Engineering was the unnecessary challenges to the atmospheric dump valves and safety valves. Informal communication with Combustion Engineering has indicated that the conditional failure of the steam lines, given that they are filled with water, is small. The staff concurs with this judgment.

d) Part (d) of this question asks for a discussion of uncertainties.

9.A.d CEOG Response

CEOG propagated uncertainties on the individual failure rates to obtain the error factors mentioned in 9.A.a/b.

9.B.d Staff Evaluation

In general, the CEOG approach to the treatment of uncertainty is reasonable. We note, however, that the human errors of failing to throttle the high pressure injection system and failing to initiate blowdown were assumed independent, and no sensitivity analysis was performed on the effects of coupling these errors. Coupling these errors would increase the probability of overfilling the steam lines. In addition, no sensitivity analysis was performed on the assumptions that a steam generator tube rupture followed by failure of the high pressure injection system leads to core melt, or the assumption that a steam generator tube rupture followed by a stuck open main steam safety valve on the affected generator leads to core melt. These omissions in the uncertainty analysis do not affect the conclusion that the addition of PORVs makes no appreciable change in the core melt frequency due to steam generator tube rupture.

9.C Conclusion

The staff agrees with CEOG that the addition of PORVs would not result in any appreciable change in overall risk if one considers only steam generator tube rupture events.

10. Question 10: What is the core melt frequency from PORV initiated LOCA? Characterize the consequences.

10.A CEOG Responses

The response of Combustion Engineering to this question stated that the core melt frequency from a PORV LOCA was about 7×10^{-8}/yr (median value) if the plant is operated with the PORV block valves closed, and the error factor on this frequency is a factor of 10. If the plant is operated with the PORV block valves open, Combustion Engineering estimates the frequency of PORV-LOCAs to be about 8×10^{-7}/yr.

10.B Staff Evaluation

The staff concurs with Combustion Engineering in their assessment of a very small core melt frequency from PORV LOCAs if the plant is operated with the PORV block valves closed. However, closer analysis is required for the case where the PORV block valves are open.

A sequence whose core melt frequency was underestimated in the C-E analysis is one initiated by loss of offsite power, followed by a PORV lifting and sticking open, followed by failure of both diesel generators. The importance of the sequence depends on the specific design of the PORV system. We are considering here the case where the PORV block valves are open. In the PORV system design considered in supplement 1 of CEN-239, the block valves are powered by AC, with one diesel generator assigned to each block valve. Moreover, consider a typical C-E PORV system in which the pressure at which the

PORV opens is the same as the high pressure reactor trip setpoint. Then the PORV will lift on a loss of offsite power transient, because of the unavailability of turbine bypass to the condenser, according to information obtained informally from Combustion Engineering. Consider then the following sequence:

Event Sequence	Frequency of probability
Loss of offsite power	.1/yr
PORV lifts	1
Failure of both diesel generators	2×10^{-3}
PORV sticks open	2×10^{-2}
Power not restored in 30 minutes	.7

This sequence has a frequency of 3×10^{-6}/yr, and has been conventionally assumed to lead to core melt since the high pressure injection system is without power, and since there is no power to operate the block valves. The loss of offsite power frequency is a generic value consistent with that in the Station Blackout Analysis Report (NUREG/CR-3226), and the failure of both diesel generators is consistent both with this report and the ORNL accident sequence precursor study, NUREG/CR-2498. The Combustion Engineering analysis overlooked the dependencies involved in this sequence, and arrived at an overall core melt frequency due to PORV LOCA of 8×10^{-7}/yr. However, the frequency of this sequence involving a transient-induced PORV LOCA on loss of offsite power can be reduced by increasing the opening setpoint pressure of the PORV. Moreover, it would be possible to power the block valves by D.C. The frequency of this sequence would be reduced by at least a factor of 10, with proper design.

The staff believes that, with a properly designed PORV system, and proper operator training, the frequences of core melt sequences due to PORV LOCAs may be made small, even with the plant operated with PORV block valve open. Suppose, that the frequency of transients involving the lifting of PORVs is .28/yr, the probability a PORV fails to close is 2×10^{-2}, and the operator error in closing the block valve is also 2×10^{-2}. The frequency of transients lifting PORVs is estimated in CEN-145, and the staff concurs with the estimate of .28/yr given there. Then the frequency of small break LOCAs due to stuck-open PORVs would be about 2×10^{-4}/yr; for a high pressure injection system (HPIS) failure probability of 10^{-3}, one obtains 2×10^{-7}/yr for the frequency of core melt due to transient-induced PORV LOCA's, for sequences in which power is available to the block valves.

Section 5.B.2 of Appendix A of this report shows that a small break LOCA of .02 ft^2 (approximately the same size as the PORV area) followed by failure of the HPIS does not lead to core melt of the primary system is aggresively cooled down. Thus the assumption that a PORV-LOCA followed by failure of HPIS leads to core melt is likely conservative.

The consequences of a core melt induced by a PORV LOCA would most probably be those of a core melt where the containment fails by basemat melt-through, and hence be less serious. For the case of a PORV LOCA combined with station blackout, discussed earlier, the containment could fail from overpressure if power is not restored for eight hours. Morever, there is a small probability (about 3%) of the containment failing from a hydrogen burn at the time AC electric power is restored, if AC power is restored after core melt. Finally, there is a possibility of containment isolation failure. For these cases the consequences could be more severe.

10.C Conclusion

Based on consideration of a reliably designed automatic PORV system, the staff believes that the frequency of core melt caused by an unisolated stuck-open PORV is small compared to the decrease in core melt frequency, from adding PORVs, in the loss of heat sink sequences and ATWS sequences.

11. Question 11: This question asks for the net gain or loss in safety due to the installation of PORVs.

11.A CEOG Response

The response to this question noted that the installation of PORVs would not significantly increase or decrease the core melt frequency due to the steam generator tube rupture accident initiator, but that loss of heat sink sequences and PORV LOCA sequences might contribute significantly to the change in safety on the addition of PORVs. No other potential benefits were considered. Two cases were considered - the case of automatic PORVs, where the PORVs are continuously aligned to the reactor primary system, with block valves open, and the case where the PORVs are normally blocked off, and manually operated. Table A11-1 gives the median change in core melt frequency, if PORVs were added, as given in the CEOG submittal:

Table A11-1 Median Change in core melt frequency

	Manual PORVs	Auto PORVs
San Onofre, Units 2 & 3	$< 1\times10^{-8}$ change	6×10^{-7} increase
Waterford	1.1×10^{-6} decrease	1.5×10^{-7} increase

Through interaction with the staff, an incomplete approximation associated with the treatment of dependent failures was discovered. The revised results for San Onofre were communicated to the staff by CE, in a telephone conversation. This difficulty with the CEOG submittal will be discussed below in the staff evaluation.

11.B Staff Evaluation

Scope of CEOG Analysis, of the staff analysis and the SNL analysis

The response of CEOG was limited in scope in several ways:

(1) No external events, fires, or internal floods were considered.

(2) The benefit of PORVs in limiting challenges to the pressurizer safety valves was not quantified.

(3) The benefit of PORVs for the mitigation of ATWS events was not quantified.

(4) The benefits of PORVs in depressurizing the primary system during a core melt were not considered.

The calculations of the staff's consultants, Sandia National Laboratory (ref. **25**), were similarly limited in scope. The staff performed its own calculations; these calculations included the effects of PORVs in the mitigation of ATWS events, but otherwise had the same limitations as the CEOG and SNL calculations.

The C-E methodology was of the fault tree/event tree type, but with a novel treatment of dependent failures. The C-E method of treatment of dependent failures of system due to shared components is described on pages 2-17 and 2-18 of CEN-239 supplement 1 for San Onofre. There was a difficulty with the application of this methodology. The probability that two systems (say A and B) will fail, and the first not be recovered, is the probability that the first fails, and is not recovered, multiplied by the conditional probability that the second system fails, given that the first system is failed and not recovered. The major difficulty with the original C-E calculation is that the conditional probability of the failure of the second system was not conditional on the nonrecovery of the first system. The error introduced is about a factor of five, in some of the loss of heat sink sequences.

PORV system designs considered

The CEOG primarily considered a manual PORV design in which the PORV block valves are normally closed. Each PORV block valve is powered by a diesel generator (on loss of offsite power) and it is not possible to power a PORV block valve from the other diesel generator, in the PORV system considered in CEN-239. Therefore, on loss of offsite power, failure of either diesel generator fails feed and bleed if the PORV block valves are closed, but feed and bleed success is still possible if the PORV block valves are normally open. The CEOG originally considered the effects of an automatic PORV (i.e., one in which the block valves are normally open, and the PORV opening setpoint is below the safety valve setpoint) on PORV-LOCA sequences, but did not take into account the improvement of such a design for feed and bleed. The new results of C-E, communicated to the staff by telephone, accounted for the improvements in feed and bleed of an automatic PORV. The PORV system assumed by Sandia National Laboratory was one in which the PORV block valves were normally closed, but either diesel generator could power either block valve. This is a substantially more reliable system (for feed and bleed) than the manual PORV system evaluated by C-E.

The SNL feed and bleed system has a high probability of success on loss of offsite power and failure of one diesel generator.

The PORV system design considered by the staff was one in which the PORV block valves were normally open, so that the PORVs could afford some pressure relief on ATWS sequences. Moreover, it is desirable to minimize the possibility of common mode failure between the reactor trip system and the PORV opening system. At present, in C-E plants, the signal to open the PORV comes from the same bistable comparator that actuates the high pressurizer reactor trip. It would be desirable to actuate the PORV opening system from a different bistable comparator. This would also afford the opportunity to change the opening pressure setpoint of the PORV to some optimum point which limits unnecessary PORV openings while at the same time still providing protection against unnecessary safety valve liftings.

The staff PORV design, like the SNL design, is one which gives a high probability of feed and bleed success on loss of offsite power with failure of one diesel generator. In order to limit the frequency of PORV-LOCAs on station blackout, the PORV block valves can be powered by D.C.

Calculational Assumptions in the CEOG, SNL, and Staff Analyses

A comparison between various assumptions made in the C-E, Sandia, and staff analyses is given in Table A11-2.

Discussion of Results in the CE, SNL and Staff Analyses

The results obtained by CEOG for the loss of heat sink sequences, and the PORV LOCA sequences for San Onofre are given in Table A11-3. The column labelled "new results" are the results communicated by telephone, while the old results are the results given in CEN-239. Note that, for the new results, with the automatic PORV design, the loss of heat sink sequences show a reduction in core melt frequency of 2×10^{-6}/yr.

The results obtained by SNL for the loss of heat sink sequences are given in Table A11-4. Since SNL considered only a manual PORV, with block valves closed, the PORV LOCA frequency is negligible.

The results obtained by the staff for the non-ATWS sequences are given in Table A11-5. Both the C-E and SNL analyses give no benefit (reduction in core melt frequency) from adding PORVs for steam generator tube rupture events.

The calculation of the reduction in core melt frequency from ATWS sequences by adding PORVs was performed as follows. The variation of the ATWS peak pressurizer pressure as a function of moderator temperature coefficient (MTC) was available from curves in CENPD-263. These curves were for the case of no turbine trip, and without additional pressure relief. From the data in CEN-239, it was possible to estimate the pressure change associated with turbine trip, and with the addition of PORVs, for a particular value of MTC (about -6 percent mil). These pressure differentials were assumed independent of MTC. It was therefore possible to estimate the peak reactor coolant system pressure during an ATWS, for the cases of turbine trip and no turbine trip, and for the cases of no additional pressure relief and additional pressure relief. Then the change (from adding PORVs) in the fraction of the operating cycle in which the peak pressure on an ATWS would be above 3200 psi was estimated. Combining this information with estimates of the ATWS frequency with turbine trip and without turbine trip, (ATWS rule, SECY-83-293) for cases where the pending ATWS rule is implemented, and it is not implemented, it was possible to estimate the change in the frequency of ATWS events in which the peak pressure exceeds 3200 psi.

The staff results for ATWS sequences are given in Table A11-6.

Table A11-2 Comparison of Assumptions in the CE, SNL, and Staff Studies

	CE	SNL	Staff
1. Type of PORV considered	Man. & Auto	Manual (but DG Crossovers)	Automatic
2. Credit for condensate system	Yes	No	Yes
3. Probability of failure of condensate system, given loss of main feedwater not due to loss of offsite power and excluding human error probability of failing to align properly.	$\lesssim$1%	---	10%
4. Probability of failing to align condensate system properly.	.05	---	.05
5. Mean, median, or point value of frequencies based on median values of basic probabilities.	Median	Point	Mean
6. Use of Beta-factor for treating common-mode pump failures.	No	No	Yes
7. Probability of not restoring offsite power in 50 minutes.	.23	.23	.5
8. Loss of Offsite Power Frequency	.04/yr	.09/yr	.12/yr
9. Human error probability for failing to initiate feed & bleed.	.025	.003	.025
10. ATWS sequence considered quantitatively	No	No	Yes

Table A11-3 CEOG results for San Onofre

	New Results	Old (CEN-239)
(1) Loss of Heat Sink Sequences		
Frequency, core damage, w/o PORV, w/o condensate system	4.6×10^{-6}/yr	2.1×10^{-6}/yr
Frequency, core damage, w/o PORV, with condensate system	3.1×10^{-6}/yr	3.1×10^{-7}/yr
Frequency, core damage, manual PORV, w/c condensate	2.8×10^{-6}/yr	1.6×10^{-7}/yr
Frequency, core damage, auto PORV	1.1×10^{-6}/yr	-----------
(2) PORV LOCA Sequences		
Core melt frequency, PORV LOCA, manual design	7.2×10^{-8}/yr	7.2×10^{-8}/yr
Core melt frequency, PORV LOCA, automatic design	4.1×10^{-6}/yr	1.4×10^{-6}/yr

Table A11-4 Sandia National Lab Results

	Core melt frequency	
Initiator	With PORV	Without PORV
Loss of Main Feedwater	7.2×10^{-8}/yr	2.6×10^{-6}/yr
Loss of Offsite Power	5.5×10^{-6}/yr	7×10^{-6}/yr

Table A11-5 Staff Results - Non-ATWS Sequences

	Core melt frequency	
Initiator	With PORVS	W/O PORVS
Loss of MFW	1.7×10^{-6}/yr	9×10^{-6}/yr
Loss of Offsite Power	6×10^{-6}/yr	1.4×10^{-5}/yr
PORV LOCA	($<5 \times 10^{-7}$/yr)	

Net decrease in core melt frequency from adding PORVs is:

1.5×10^{-5}/yr., not including ATWS Sequences

EF = Error factor = 36

Median decrease = 1.4×10^{-6}/yr.

95% upper confidence limit = 5×10^{-5}/yr.

Table A11-6 Staff Analyses - ATWS Sequences

		$P_{ATWS/Yr.}$ Change by adding PORVs 3410 Plants	3800 Plants
1.	ATWS Rule Not Implemented	3.2×10^{-5}/yr.	5×10^{-6}/yr.
2.	ATWS Rule Implemented	1×10^{-5}/yr.	2×10^{-6}/yr. (Below 3200 psi 95% of the time w/o addt'l relief area)

NOTES

1. The frequency changes in the above table are the changes in the frequency of exceeding 3200 psia in an ATWS event.

2. The PORVs added are sized for decay heat removal, and have a relief area of .0228 ft^2 per valve.

It should be noted that the staff results are mean frequencies, and the C-E results are median frequencies. The error factor associated with the staff results for non-ATWS sequences is rather large (error factor =EF=36); part of the reason for this is that (for the most part) the data used was from the final draft of the NREP procedures guide, NUREG/CR-2815. The distribution suggested there for the failure rates was loguniform, and the minimum (0^{th} percentile) and maximum (100^{th} percentile) bounds were given there. The propagation of uncertainties employed in the staff calculations was by the method of moments, and assumed that these 0^{th} and 100^{th} percentile bounds were the 5^{th} and 95^{th} percentile points for a lognormal distribution. The error factors obtained by C-E, as given in CEN-239 supplement 1 for San Onofre, were 21 for the loss of heat sink sequences without PORVs and 28 for the loss of heat sink sequences with PORVs.

The beta factors used by the staff for the motor-driven auxiliary feedwater system pumps had an appreciable effect on the results for the loss of main feedwater sequences with offsite power available, but had a rather small effect on the loss of offsite power sequences. The reduction in core melt frequency in the staff calculations, from the non-ATWS sequences, was about equally divided between the loss of main feedwater (not due to loss of offsite power) sequences and the loss of offsite power sequences. The loss of offsite power frequency and the time to restore offsite power, are important parameters in the analysis.

Once the errors in the Combustion Engineering analysis are corrected, the major differences in results (for the automatic PORV case) can likely be accounted for by the facts that (1) the staff analysis presents mean estimates, not median estimates, as does C-E, (2) the use of the beta-factor for the mechanical failures of motor-driven auxiliary feedwater system pumps, (3) the data on loss of offsite power and time to restore offsite power used, and (4) the staff believes that with proper design and operation the core melt frequency from

PORV LOCAs may be made negligible. Supporting analysis for this last point is given in the evaluation of the response to question 10. One may note that the NREP Procedures Guide give a mean frequency for loss of offsite power for the San Onofre site (Unit 1) of .235/year, while the value given for the regional council is .26/year. The value the staff used was .12/year, based on an average over the entire U.S., and was thought more appropriate. The quantification of reduction in core melt frequency by the addition of PORVs has not considered external events, fires, or floods. The additional diversity of a feed and bleed path would also be useful for such accident initiators. Although the staff analysis was for San Onofre only, the results for the non-ATWS sequence are thought to apply to the other plants as well. The ATWS sequences were considered separately for the 3410 and 3800 plants.

11.C Conclusions

The staff estimates that, from non-ATWS sequences, the reduction in core melt frequency from adding PORVs is about 1.5×10^{-5}/yr, while from ATWS sequences the reduction frequency ranges from 2×10^{-6}/yr to 3.2×10^{-5}/yr, depending on whether one is considering a 3800 plant with ATWS rule implemented or a 3410 plant with ATWS rule not implements.

12. Question 12: If the results of the risk analysis (Question 11) yield appreciable gain in safety, what would be the cost of installing PORVs?

12.A CEOG Response

Although the CE owners have concluded that the installation of PORVs has a negligible safety benefit, cost estimates were made to determine the expected installation costs. The engineering, design, installation and replacement power costs were considered.

The Southern California Edison (SCE) Company estimated (Ref. 8) the cost to install PORVs at SONGS 2 and 3 to be $4.6 million, excluding replacement power costs. They estimated the time required to complete the installation of the PORVs to be six weeks or 42 days. Replacement power costs based on $800,000 per day per plant were estimated to be in the range of $2 million to $35 million per plant. The lower estimate is for extending a normally scheduled outage by two to three days for system testing after all other work in the plant had been completed. The higher replacement power estimate is for a situation where the PORVs are installed during an outage scheduled specifically for this design change.

For Waterford-Unit 3, Louisiana Power & Light (LP&L) estimated (Ref. 9) the cost for installing PORVs to be $2.3 million, excluding replacement power costs. LP&L estimated the time required to install PORVs to be 80 days. Replacement power costs were estimated to be in the range of $3 million to $30 million depending on the duration of additional downtime beyond a normal refueling outage. Replacement power costs for Waterford-3 during 1985 were estimated to be $1,540,000 per day during the summer and $950,000 per day during nonsummer periods; therefore, the minimal replacement power costs for an additional three day outage extension would amount to about $3 million.

12.B Staff Evaluation

The staff and its consultants performed an independent evaluation of the engineering feasibility, costs and operational impacts of installing a system for controlled depressurization of the primary system in CE plants lacking PORVs. The details of the evaluation are provided in Reference 25, and only a summary will be provided here. Basically, the study consisted of developing a conceptual depressurization system design that can be retrofitted into an already constructed plant, and then the estimating associated engineering, design and installation costs.

The San Onofre Nuclear Generating Station-Unit 2 (SONGS-2) was selected as a plant not currently having a PORV depressurization capability to determine the feasibility and costs of implementing such a capability. However, at the same time, the applicability of implementing the installation of PORVs in other plants of similar design was examined to determine what aspects of the design could make a significant difference on a plant specific basis. In addition, two cases were considered that include: 1) installation of PORVs in a new plant during the final stages of its construction, and 2) installation of PORVs in a plant that had been operating for some time.

For the purpose of investigating the engineering feasibility and implementation costs, a conceptual system design was developed for a primary system depressurization capability utilizing PORVs or other types of relief valves that can be retrofitted into SONGS-2. The system design, a schematic of which is shown in Figure A12-1, consists of two dedicated PORVs and two block valves mounted at the top of the pressurizer using the nozzles provided for the existing safety relief valves (SRVs), a quench tank (similar to the existing quench tank), and connecting piping. The PORVs or other types of relief valves would be large enough, with relieving capacity well in excess of that required for decay heat removal, to depressurize the system as rapidly as possible to permit an existing HPSI pump to initiate flow injection. Valve capacity and time of opening after a total loss of feedwater event would be consistent with the thermal-hydraulic evaluation performed in Reference 26. Reference 25 also investigated a case involving the addition of a new HPSI pump to permit flow injection to be initiated near full system pressure, in addition to adding PORVs. This case was investigated for the broader objectives of the Task A-45 program on, "Shutdown Decay Heat Removal Requirements," in which a feed and bleed mode of decay heat removal will be ranked against other alternative measures for improving decay heat removal system reliability based on value-impact evaluations. The Task A-45 recommendations are expected in November 1984.

The more important system design criteria would include the requirements that the system equipment and piping must be consistent with the existing components with respect to ASME-Code Class, Nuclear Safety Class, Quality Group Class and Seismic Category; the new PORVs would be fully safety grade and environmentally qualified; the system must be capable of operation when offsite power sources are unavailable (e.g., from a single existing diesel generator); and the new system must in no way affect the functions of the existing safety systems.

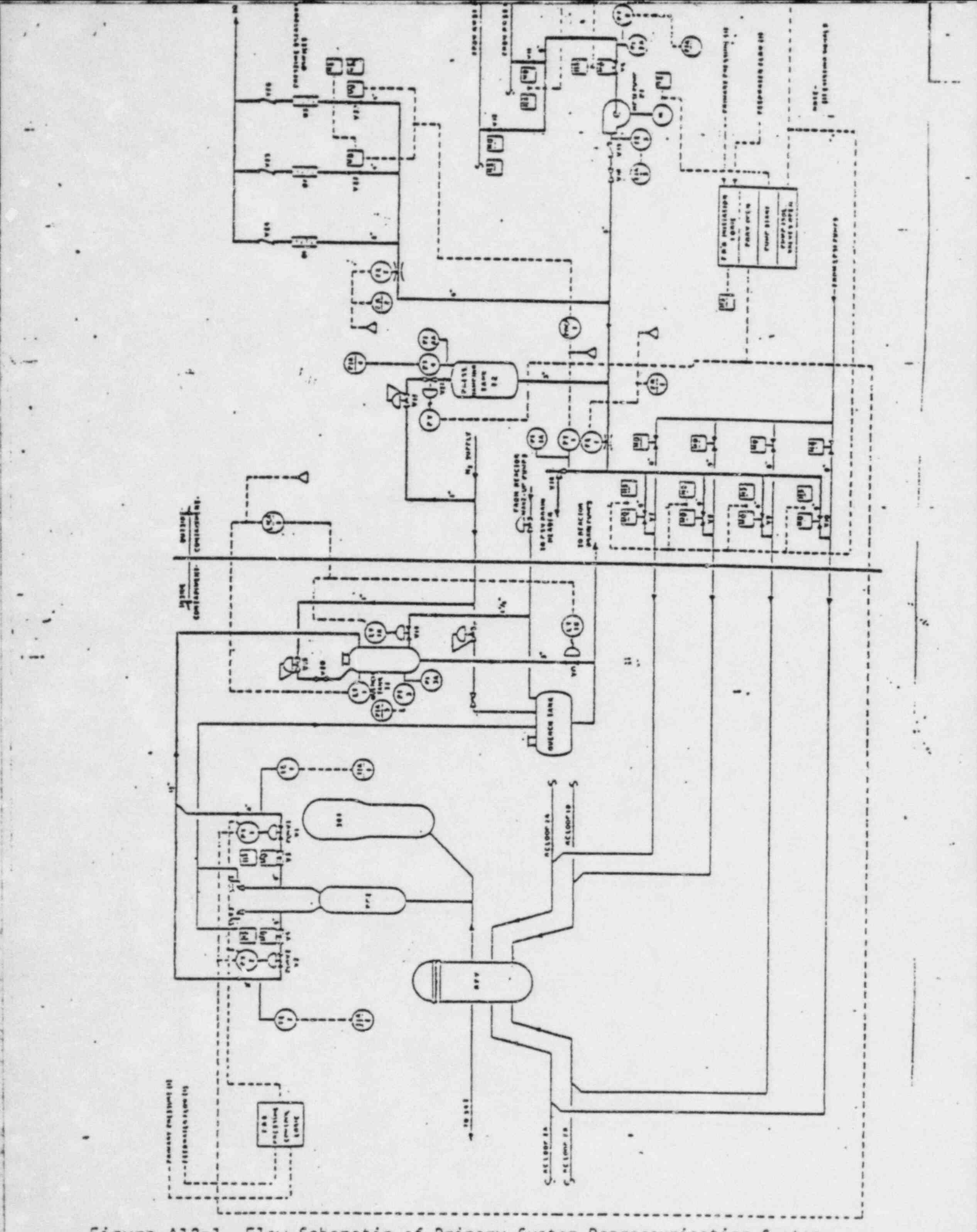


Figure A12-1 Flow Schematic of Primary System Depressurization System

It was determined that the supply of electrical power from an existing diesel generator to the new PORVs and block valves poses no problems. No major structural changes or additions would be required to accommodate the depressurization system. Structural work would consist mainly of additional pipe supports, platforms, walkways and railings.

The conceptual design is based on an automatic control scheme. At a certain pressure setpoint, the PORVs would be fully opened automatically to reduce the primary system pressure to a level where the existing HPSI pump would initiate flow to prevent core uncovery. In the final design phase of the control system, consideration should be given to an all-manual control system because of: (1) simplicity of control and avoidance of spurious actuation, (2) elimination of the need to interface with existing primary pressure and feedwater flow instrumentation channels (thus, no possibility of jeopardizing these channels, and (3) lower implementation costs. However, costs would not be a primary consideration in selecting automatic versus manual control. Full instrumentation for flows, pressures, temperatures and levels are included in the design, including special instrumentation to sense accidental opening of the valves.

The detailed engineering and design of a primary system depressurization system would be of the type normally performed for nuclear power plant safety systems. Because of the expectation that a system for a particular plant would either be designed and installed during the later stages of overall plant construction, or retrofitted into an operating plant, the engineering and design would have to be organized as a separate project with a dedicated project team.

Before proceeding into the final design phase, the nature of the depressurization system application will require a significant amount of special analysis, including (1) thermal-hydraulic transient analyses to determine the correct relief valve size and initiation time, (2) studies to support selection of the best type of relief valve and valve installation for this application, (3) stress analyses due to added loads on critical piping, and (4) analyses of actual radiation levels for controlling personnel exposure.

Coordinated schedules for 1) engineering, design and analysis, and 2) construction have been developed. The former has a span of 18 months and the latter 12 months. There is a six month overlap resulting in an overall project schedule of 24 months. The schedule is keyed to an annual outage for refueling and scheduled maintenance which is considered to be of 60 days duration. For an operating plant, the schedule and costs are based on doing as much of the work as possible while the plant is operating in order to minimize that to be done during the scheduled outage. This would require very careful planning to complete the installation within the allocated time frame.

In retrofitting a primary system depressurization capability to a plant that has been in operation for some time, occupational radiation exposure to personnel will be a concern. The problem area is around the pressurizer within containment. For a plant that has been operating for a number of years (about 3 to 6), shutdown radiation levels can be as high as 0.4 R/hr at certain specific locations like the pressurizer spray line. Such levels would severely limit the time that personnel could spend in the area during installation. It appears feasible to install temporary shielding in the area of the pressurizer which would reduce the radiation levels to about 0.15 R/hr. It has been assumed in the cost estimate that allowance would be required for installation personnel receiving their maximum permitted whole body dose without violating the regulations. The total accumulated doseage for all personnel during installation of the depressurization capability is estimated to be about 400 man-rems.

Although the feasibility and costs of installing a system for primary system depressurization was investigated specifically for SONGS-2, the conceptual design and evaluation developed in Reference 25 would have a generic applicability to other plants lacking a PORV capability. However, an important factor that could be expected to affect the feasibility and cost for a specific plant would be the arrangement of equipment and piping around the pressurizer and the availability of a suitable connection for the installation of PORVs or other types of relief valves.

Cost estimates were made for installing a primary system depressurization capability in 1) a new plant under construction, and 2) a plant that had been in operation for some time. The total installation costs for these two cases are $2,495,000 and $4,254,000, respectively. The details of these estimates are presented in Tables A12-1 and A12-2. As is shown in Tables A12-1 and A12-2, construction costs and costs for supporting services were estimated separately. Construction costs were subdivided into mechanical equipment and piping, structural, electrical and instrumentation and control work. Included under supporting services were project management, engineering design and analysis, quality assurance, construction management, testing and startup, training, and costs related to health physics and radiation exposure control.

Prevailing construction labor rates in the San Diego area were used and allowances were made for three shift operation, premium time on weekends, overtime at shift changes for work during the scheduled plant outage, and travel allowances for construction workers. In the case of installation in an operating plant, allowance was made for the additional manhours and other costs associated with burnout of craft labor personnel in high radiation areas and also for the general difficulties associated with working in an operating plant.

Present day costs were used and escalation applied at six percent per year using the developed schedule. Allowance was made for interest during construction at an annual rate of 12%. An overall contingency allowance of 25% was used.

In the case of an operating plant, replacement power costs incurred by prolonging a scheduled annual outage by the installation of the depressurization system could result in costs that would exceed the total of all other implementation costs in just a few days, considering that replacement energy costs are typically in the range of $500,000 to 1,000,000 per day. In an actual installation, if the work could not be all completed in the period of one annual outage, it could be completed during the following year's outage. The necessity for hydrotesting (in accordance with Section XI of the ASME code) at the completion of system installation may extend the outage by two to three days. This would add about $3 million in replacement power costs to the above installation cost estimates. However, as is often the case, major turbine-generator maintenance work may be on the critical path in determining the outage time.

Table A12-1 Cost estimate for controlled depressurization system for installation in a new plant under construction

Item	Estimate cost ($)
1. Construction	
1.1 Mechanical Equipment & Piping	665,000
1.2 Structural	35,000
1.3 Electrical	27,000
1.4 Instrumentation & Control	236,000
Total Construction	963,000
2. Services	
2.1 Project Management, Planning & Scheduling & Cost Estimating	52,000
2.2 Engineering, Design & Analysis	423,000
2.3 Quality Assurance	20,000
2.4 Construction Management	40,000
2.5 Test and Startup	20,000
2.6 Training	18,000
Total Services	573,000
3. Total Present Estimated Costs	1,536,000
4. Escalation	246,000
Sub-Total	1,782,000
5. Interest During Construction	214,000
Sub-Total	1,996,000
6. Contingency	499,000
7. Total Estimated Costs at Completion	2,495,000

Table A12-2 Cost estimate for controlled depressurization system for installation in an operating plant

Item	Estimated costs ($)
1. Construction	
1.1 Mechanical Equipment & Piping	1,132,000
1.2 Structural	126,000
1.3 Electrical	117,000
1.4 Instrumentation & Control	556,000
Total Construction	1,931,000
2. Services	
2.1 Project Management, Planning & Scheduling & Cost Estimating	65,000
2.2 Engineering, Design and Analysis	425,000
2.3 Quality Assurance	24,000
2.4 Construction Management	48,000
2.5 Testing & Startup	24,000
2.6 Training	58,000
2.7 Health Physics	45,000
Total Services	688,000
3. Total Present Estimated Costs	2,619,000
4. Escalation	419,000
Sub-Total	3,038,000
5. Interest During Construction	365,000
Sub-Total	3,403,000
6. Contingency	851,000
7. Total Estimated Costs at Completion	4,254,000

A comparison of the staff's independent cost estimates with those of the CE owners group is shown in Table A12-3. Besides the PORV installation cost, we have also shown a comparison of the installation time and estimated replacement power costs. As is evident from Table A12-3, for a new plant that has not been placed into operation, the staff installation cost estimate ($2.5 million) is close to the CE owners cost estimate ($2.3 million). For a plant that had been in operation for some time, the staff installation cost estimate ($4.3 million) is about $2 million higher than the CE owners group results for a plant like SONGS-2. However, since SONGS-2 has less than one year of operational time at power, the staff's cost estimate is considered to be conservative. For the estimates of the time required to install the depressuirzation system, the staff's estimate (60 days) falls about midway between the CE owners group results (42 days to 80 days). However, the staff considers that with careful planning, the installation can be completed within a normal refueling and maintenance outage. With respect to the cost estimates for replacement power, the staff estimates fall in the range of zero to $3 million depending on whether the normal outage has to be extended several days for testing the depressurization system. However, as mentioned above, turbine-generator maintenance is usually on the critical path in determining the total outage time, and if this is the case, testing of the depressurization system would not add to the normal outage time. The CE owners group estimates for replacement power cover the range of $2 million to $35 million depending on the extra plant downtime attributed to PORV installation, testing, and actuations over the plant lifetime. The staff considers the CE owners group low side estimates of $2 million to $3 million for replacement power costs due to PORV testing to be reasonable. However, we believe that the CE owners group high side estimates ($30 million to $ 35 million) to be unreasonable and have not been adequately justified.

As part of our independent evaluation of the engineering feasibility, costs and operational impacts, the staff has reached the following conclusions:

- For PWR plants lacking primary system PORV capability, addition of a system to permit controlled depressurization would be feasible.

Table A12-3 Comparison of cost results

Organization	PORV Installation Costs per Plant ($ Million)	Time To Install PORVs (days)	Replacement Power Costs per Plant to Install PORVs ($ Million)
NRC Staff:			
Case 1 - Before Operation	2.5	60	0
Case 2 - After Operation	4.3	60	0 to 3.
SCE CO. (SONGS-2&3)	2.3	42	2 to 35
LP&L (Waterford-3)	2.3	80	3 to 30

- Installation of a depressurization system would have to be very carefully planned and executed particularly in an operating plant. An overall schedule of two years from start of engineering and design to completion of installation and testing is considered feasible. For an operating plant keying of schedule to an annual scheduled outage would be essential to complete the installation within a normal 60 day outage and to avoid any extra plant downtime.

- Occupational radiation exposure to personnel for installation in an operating plant will have to be taken into account, but appropriate allowances can be made. Total personnel radiation exposure to complete the installation is estimated to be about 400 man-rems.

- Implementation costs for installing a depressurization system range from $2.5 million in a plant that has not operated to $4.3 million in a plant that has operated for some time. There exists the possibility that testing of the depressurization system could extend a normal outage by two to three days and would result in an added replacement power cost of about $3 million.

13. <u>Question 13</u>: This question asks CE to fully describe C.E. Systems 80 Steam Generator Tubes-Structural Integrity

13.A <u>CEOG Responses</u>

An important consideration in determining whether or not PORV's are needed for emergency decay heat removal is the availability of alternative water sources to the steam generators for decay heat removal purposes. An inherent assumption in this approach is that steam generator integrity will be maintained throughout the life of the plant. One method of assuring steam generator integrity is by periodic in service inspections and plugging of excessively degraded tubes. Regulatory Guide 1.121 "Bases for plugging Degraded PWR Steam Generator Tubes" describes the plugging criteria and the methodology for determining plugging limits.

An evaluation was performed by Combustion Engineering on the System 80 steam generator to determine the allowable tube wall degradation. This evaluation shows that 43% tube wall degradation is acceptable at the most limiting tube locations. This value is determined by conservative comparisons to analyses performed on other CE steam generator designs. Some tests results that substantiate the validity of the analytical methodology used by Combustion Engineering to determine tube plugging limits have also been provided.

13.B <u>Staff Evaluations</u>

It has been previously demonstrated in the ASME Code stress reports for six Combustion Engineering pre System 80 power plants that a tube wall degradation ranging from 31% to 64% can be tolerated and still meet desing basis criteria and the provisions of Regulatory Guide 1.121. The range is higher yet (50% to 64%) for those units which have not received a "rim-cut" modification to mitigate support plate denting.

The C-E system 80 steam generator tubes (see Figure A14-1) have also been evaluated for most design and pipe break accident criteria. Since most C-E steam generators are similar in design concept, an estimate of the permissible tube thinning for the System 80 steam generator units can be made based on previously performed work on other units and supporting experimental data.

The margin of safety against tube failure under a postulated LOCA accident concurrent with SSE has been shown to be consistent with the margin of safety determined by stress limits specified in Subsection NB-3225 of Section III of the ASME Boiler and Pressure Vessel Code.

As a result of a postulated LOCA accident a steam generator U-tube will experience an inplane frame type deformation due to the rarefaction wave in the primary coolant which propagates away from the break location. This loading, when combined with SSE, LOCA impulse and differential pressure, causes severe bending stress in the tube at the uppermost horizontal support.

Geometries evaluated thus far sustain maximum tube bending stresses in healthy tubes of between 26.0 ksi and 52.1 ksi for the LOCA plus SSE accident.

In addition, it has been determined that tubes having local uniform degradation at the worst possible locations of between 31% and 64% of the nominal tube wall can withstand this accident condition and still meet the criteria established in Appendix F of the ASME Code Section III for faulted conditions.

The margin of safety against tube failure under a postulated steam line break accident concurrent with an SSE has been shown to be consistent with the margin of safety determined by the stress limits specified in Subsection NB-3225 of Section III of the ASME Boiler and Pressure Vessel Code.

In the event of a postulated main steam line break accident, the top of the tube bundle is subjected to extremely high velocity, high density crossflow of the secondary coolant. In a U-tube steam generator this loading when combined with SSE, MSLB impulse and internal pressure, causes vertical bundle deflection with interaction among the various tube rows. The resulting tube stress is highest at the top mid span position. The tube row of maximum stress is design dependent.

Geometries evaluated thus far sustain mazimum tube bending stresses of 27.2 ksi or less for the steam line break plus SSE Accident acting on healthy tubes. In addition, it has been determined that tubes having local uniform degration at the worst possible locations of 63% or less of the nominal tube wall can withstand this accident condition and still meet the criteria established in Appendix F of the ASME Code Section III for faulted conditions.

The margin of safety against tube failure under a postulated feedwater line break accident concurrent with an SSE has been shown to be consistent with the margin of safety determined by the stress limits specified in Subsection NB-3225 of Section III of the ASME Boiler and Pressure Vessel Code.

The economizer divider plate, support cylinder, cold leg flow distribution plate and feedwater box are subjected to a hypothetical feedwater line break during 100% power operation. The pressure distribution acting on the economizer divider plate during a postulated FWLB event was determined by applying the peak pressure differences between nodes. Reactive forces acting on the divider plate along the lugs which are attached to the support cylinder were applied to the support cylinder. These forces along with the pressure differential acting on the cylinder between the hot leg and cold leg comprised the active forces on the support cylinder. The peak pressure difference of 660 psi was assumed to act uniformly over the feedwater box.

The primary stresses of concern in the divider plate and blowdown assmebly are maximum membrane plus bending stress of 34.2 ksi which is less than the allowable of 1.5(0.7 Su) = 73.5 ksi for the SA-515, GR 70 material. The blowdown duct has maximum membrane plus bending stress of 47.4 ksi and the allowable is 60.9 ksi.

The membrane plus bending stress intensity at the base of the stay cap assembly is 14.5 ksi which is less than the allowable of 1.5(0.7 S_u) = 77.3 ksi for the SA-508, CL 2 material. At the bimetal wall the membrane plus bending stress intensity is 9.4 ksi and the allowable is 67.5 ksi for the SA-516, GR 70 material.

The flow distribution plate has maximum ligament membrane plus bending stress intensity in the perforated region of 49.6 ksi and in the solid rim 34.8 KSI. The allowable for the SA-240, TY 405 material is 1.5 (0.7 S_u) = 58.7 ksi.

The inner cylinder of the feedwater distribution box has maximum membrane plus bending stress intensity of 38.4 ksi with the allowable for the SA-515, GR 70 material of 1.38 (0.7 S_u) = 67.6 ksi.

The direct loading of the escaping fluid on the tubes is small (G < 1.0 ksi) The danger to the tubes is that if one of the above four structures fails, it would put the adjacent tubes in jeopardy. However as noted above these structures are very conservatively designed therefore, they will have no impact on thinned tubes.

13.C Conclusions

System 80 is comparable to plants which have been calculated to possess an allowable tube wall thinning of from 50% to 64%. System 80 allowable tube wall thinning limit is conservatively estimated to be 43%.

Units which have had their upper support plates detached from the shell, in order to mitigate "denting" effects, have somewhat lower permissible tube thinning values in the upper tube bundle region (there is no effect near the tubesheet). To date, C-E plants have not experienced "denting" and tube attack in the same region of the steam generator.

Experimental results, from several sources, demonstrate that for degradation other than uniform thinning, additional conservatism is introduced by "reinforcement" supplied by the material surrounding the degradation. Further conservatism is introduced by the fact that most of the tests show a benefit from a greater than minimum ultimate strengths.

Simulated full scale LOCA testing has verified the accuracy and conservatism of C-E's current methodology and analytical computer codes in determining steam generator tube loading due to a hypothetical loss of primary coolant accident (LOCA). This event is controlling for tubing in C-E steam generators.

Analysis results show that the economizer divider plate, support cylinder, cold leg flow distribution plate and feedwater box are adequately designed to withstand a hypothetical feedwater line break accident. Thus, the tubes in the economizer region will not be damaged, because being lightly loaded hydraulically, only failure of an adjacent structures would harm the tubes.

Basis on our review of the C-E analysis of System 80 steam generators the staff concludes that adequate margins of safety exist against tube failures both under accident and normal operating conditions.

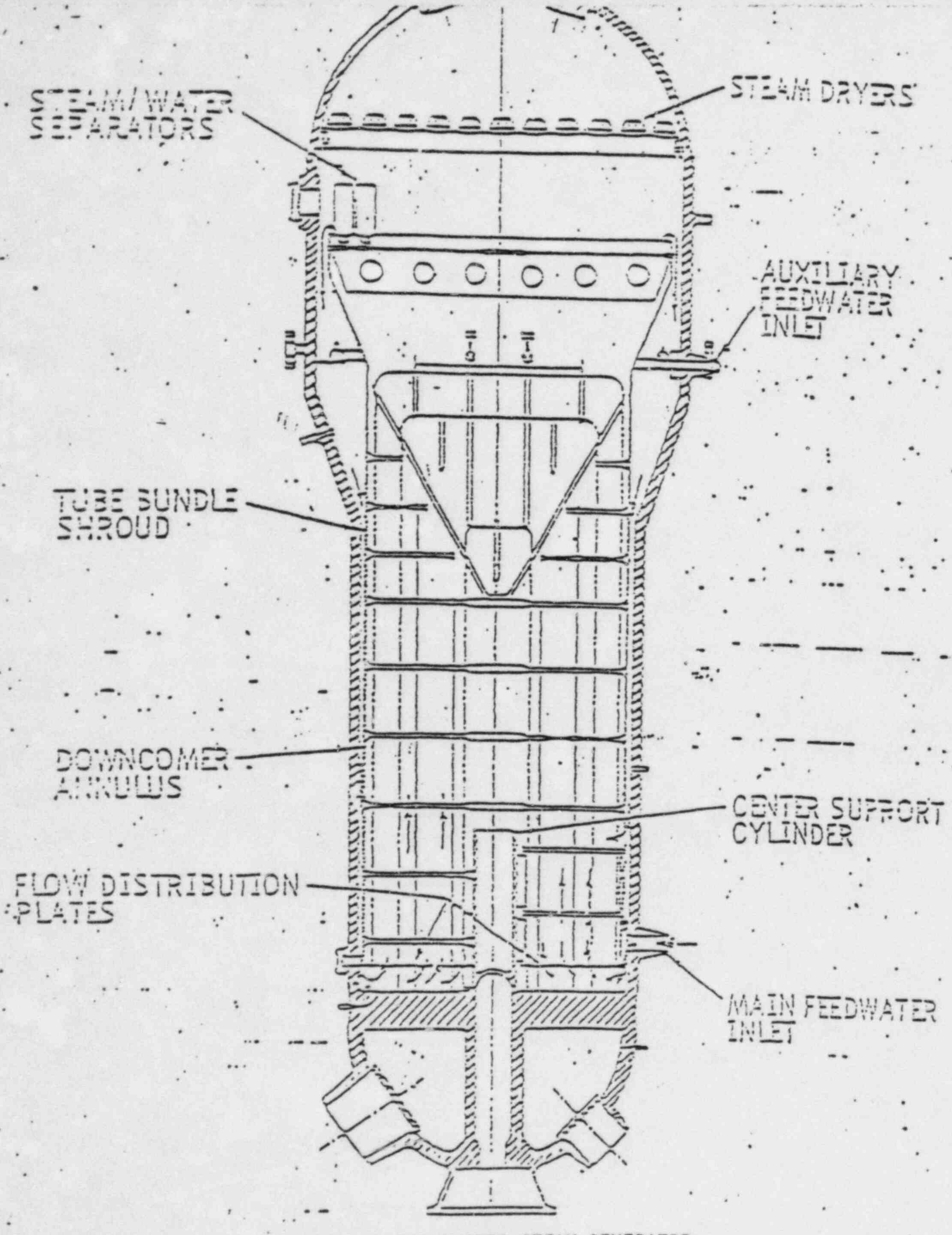
14. Question 14: This question asks CE to fully describe tube vibrations in the economizer region of system 80 steam generators.

14.A CEOG Responses

Recent occurrences of excessive flow-induced vibrations in the economizer region of some Westinghouse steam generators of similar design prompted the NRC staff to assess the susceptibility of the System 80 steam generators design to similar damage mechanisms. Combustion Engineering (C-E) has conducted experimental investigations of flow induced vibrations in the economizer region of the C-E System 80 steam generator. Scoping tests were first conducted with a 30° sector of a full-scale model and no tube vibrations of consequence were measured. More recent test results obtained from an expanded test program confirm that the tubes experience no potentially harmful vibrational motion.

14.B Staff Evalutions

The System 80 steam generator design incorporates an integral axial flow economizer on the cold leg side of the tube bundle as shown in Figure A14-1. The economizer region is formed by a divider plate located in the tube lane and



INTEGRAL ECONOMIZER STEAM GENERATOR
AXIAL FLOW
FIGURE A14-1

attached to the support cylinder and shell extending to a height of 100 inches above the tubesheet. There are two locations in this region where water enters the tube bundle shown in Figure A14-2. At the tubesheet, feedwater enters from the feedwater distributor below the flow distribution baffle and flow upward through the bundle. At the top of the economizer, auxiliary feedwater mixed with the cold leg recirculated water enters from the downcomer through an opening in the shroud.

The region of the steam generator which was modelled includes both the feedwater and cold leg downcomer inlets to the tube bundle. Tubes, tube support spacing, and shell side inlet openings are the same as for the System 80 steam generator. The model is rectangular in shape and constructed from structual steel with plexiglas sides to permit visual studies. It consists of 144 tubes, each 175 inches long which are arranged in a 7 line pattern as shown in Figure A14-3. The tube array is representative of a bundle with a depth of 20 rows of tubes from the periphery.

Selected tubes near the flow inlets are instrumented with semi-conductor strain gages and bi-directional accelerometers. Penetrations through the plexiglas side are provided at eight elevations downstream of the two inlet openings for insertion of a pitot probe which can be moved horizontally for measuring velocities at positions across a seciton.

The test model is installed in a loop which consists of a holding tank, a centrifugal pump, flow control valves, flow meters, and orifice plates.

Inlet flow may be admitted to both economizer and downcomer inlet regions. System control valves are manipulated to achieve predetermined axial and radial mass fluxes through the tube bundle.

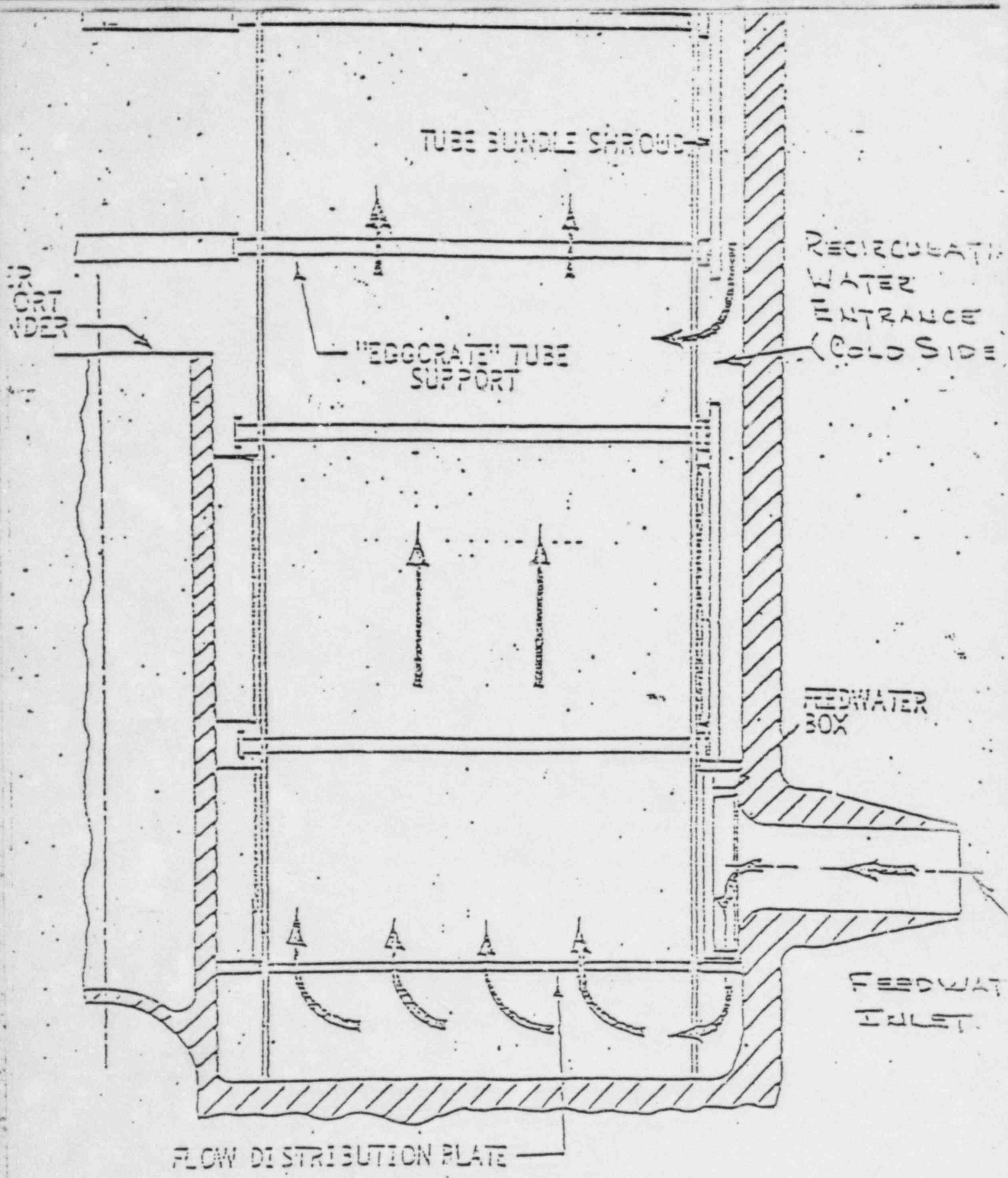
Hydraulic testing was performed at room temperature with nominal flow rates equivalent to 100% power and for downcomer flows up to 200% nominal. Modeling similitude was based on equality of dynamic pressure. For the 100% case, the specified System 80 feedwater flow was used.

Velocity distributions of the shell side fluid downstream of the two inlet openings were established from measurements made at eight vertical and four horizontal intersecting locations. A two-dimenstional "wedge" pitot probe was used for measuring the direction and magnitude of flow velocity at each grid point. Measured deflections and vibration amplitude profiles have been provided (Figure A14-3). Based on the review of the data the following observations may be made

(1) The tube motion was elliptical with the major axis in the transverse direction.

(2) The largest observed vibration amplitudes occured in the span above the cold side downcomer fluid entrance region.

(3) The level of vibration in the tube span subjected to cold side downcomer fluid (Span 4) was relatively constant at 0.4 mil up to approximately 150% flow. The bending stress is less than 1 ksi for 100% flow.



AXIAL FLOW ECONOMIZER
FIGURE A14-2

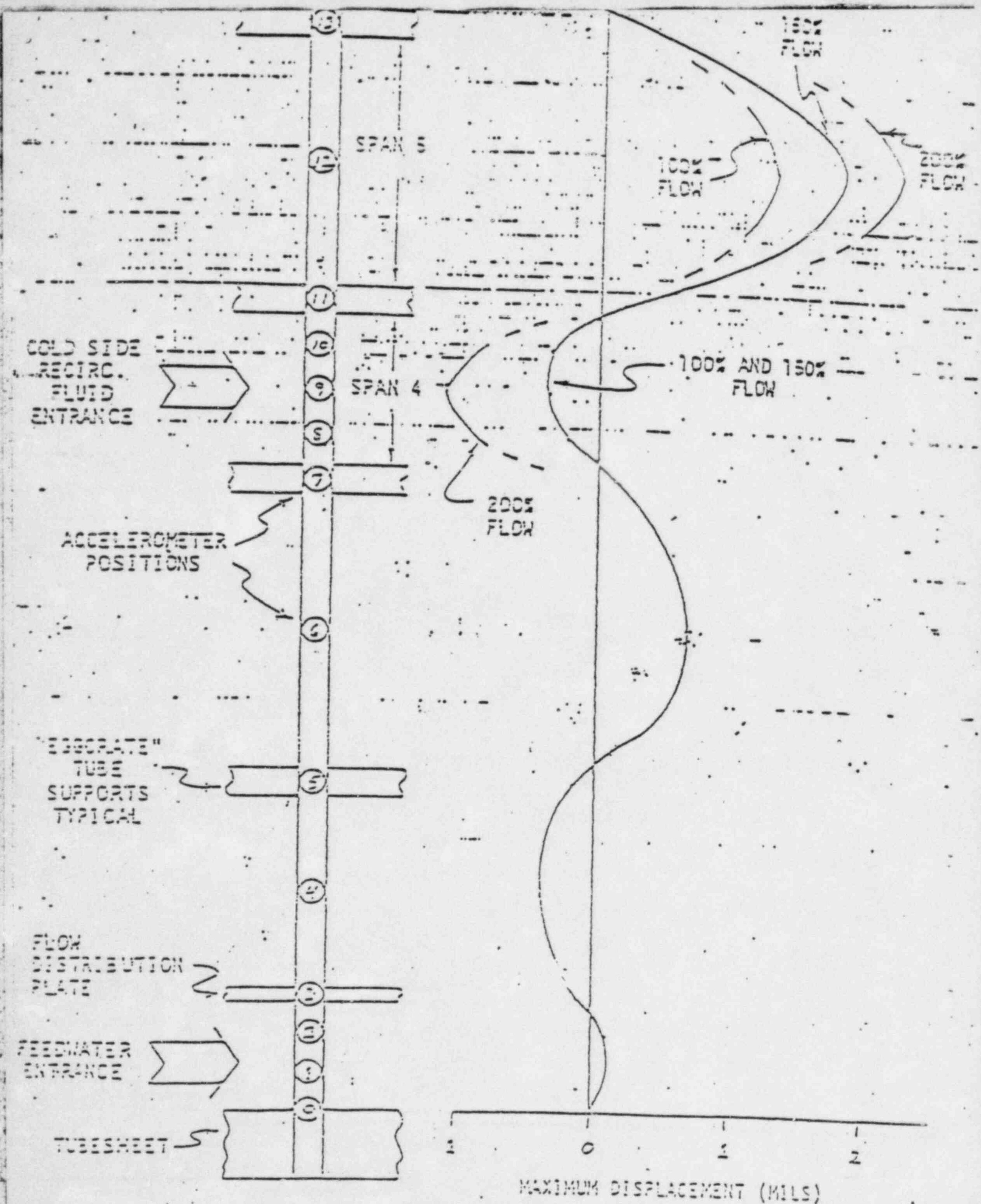


FIGURE A14-3 TUBE VIBRATION AMPLITUDE PROFILE

(4) No vortex shedding induced vibration was observed for two reasons: (1) the fluid approaching the bundle was too turbulent, and (2) the triangular pitch tube array is so tightly packed that vortices cannot be sustained.

(5) When the velocity profiles were examined, it was concluded that there is at least 50% margin to instability at 100% power.

(6) Vibration of tubes in the feedwater entrace region of the tube bundle are extremely small as was predicted. All of C-E's operating steam generators have higher levels of vibration at the bundle entrance regions than will exist at the System 80 feedwater entrance region, due to the greater velocity of the recirculating fluids.

14.C CONCLUSION

A full scale test of the System 80 steam generator economizer region was performed to investigate the vibrational response of tubes when subjected to cross flow due to water issuing from inlet openings. Both the feedwater inlet at the tubesheet and the recirculated water inlet at the top of the economizer region were included in the model. Test runs were made for nominal prototypic flow conditions and for recirculated water flow up to 200% nominal. It is concluded from results of the tests that tubes in the System 80 economizer region will experience no detrimental vibrational motion during normal operation.

APPENDIX B

Chronology of Issues And Events
Associated With The Study of
CE Plants Without PORVs

December 15, 1981	ACRS letter to Chairman Palledino expressing concern regarding CE plants without PORVs.
January 25, 1982	Ginna SGTR Accident
January 29, 1982	Office Research, cursury PRA for CE plants without PORVs.
February 8, 1982	Staff requested CE address the adequacy of design without PORVs and to comment on RES PRA.
March 4, 1982	CE response to 2/8/82 staff letter.
March 16, 1982	Staff met with ACRS Subcommittee on status of CE PORV issue.
September 6-9, 1982	SONGS-2, Natural Circulation Tests (first phase)
December 6, 1982	Meeting with respsentatives for SONGS-2 on viability of installing PORVs on SONGS.
January 12, 1983	Meeting with NRC staff, contractors, and CEOG in Bethesda on status of PORV efforts.
January 27, 1983	CE and NRC staff met with ACRS subcommittee on status of PORV issue.
March 22, 1983	Letter to CEOG forwarding questions/comments from January 12 meeting.
April 4, 1983	Staff briefed Commission on status of PORV issue.
June 30, 1983	Receipt of CESSAR, Waterford, and SONGS-2&3 responses to staff's questions.
July 7-8, 1983	Meeting with CEOG in Windsor, Conn. to discuss response to questions.
August 24, 1983	Meeting with ACRS subcommittee on conclusions and recommendations regarding need for PORV on recent CE plants.

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

DISCUSSION/POSSIBLE VOTE ON FULL POWER OPERATIONS

LICENSE FOR SAN ONOFRE 3

- - -

PUBLIC MEETING

- - -

Room 1130
1717 H Street, N.W.
Washington, D.C.

Friday, September 16, 1983

The Commission met, pursuant to notice, at 10:10 o'clock a.m.

COMMISSIONERS PRESENT:

NUNZIO PALLADINO, Chairman of the Commission
VICTOR GILINSKY, Commissioner
THOMAS ROBERTS, Commissioner
JAMES ASSELSTINE, Commissioner
FREDERICK BERNTHAL, Commissioner

STAFF AND PRESENTERS SEATED AT COMMISSION TABLE:

SAM CHILK
HARRY ROOD
DARRELL EISENHUT
HAROLD DENTON
JOHN B. MARTIN
JOHN E. ZERBE
RICHARD BLACK

AUDIENCE SPEAKERS:

KEN BASKIN
DAVE FOGARTY
RICHARD DeYOUNG
ROGER MATTSON

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DISCLAIMER

This is an unofficial transcript of a meeting of the United States Nuclear Regulatory Commission held on Friday, September 16, 1983, in the Commission's offices at 1717 H Street, N.W., Washington, D.C.

The meeting was open to public attendance and observation. This transcript has not been reviewed, corrected, or edited, and it may contain inaccuracies.

The transcript is intended solely for general informational purposes. As provided by 10 CFR 9.103, it is not part of the formal or informal record of decision of the matters discussed. Expressions of opinion in this transcript do not necessarily reflect final determinations or beliefs. No pleading or other paper may be filed with the Commission in any proceeding as the result of or addressed to any statement or argument contained herein, except as the Commission may authorize.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

DISCUSSION/POSSIBLE VOTE ON FULL POWER OPERATIONS

LICENSE FOR SAN ONOFRE 3

PUBLIC MEETING

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6″

P R O C E E D I N G S

CHAIRMAN PALLADINO: Good morning, ladies and gentlemen.

This morning, we are taking up the matter of full power authorization for San Onofre, Unit 3. The unit was granted a license to operate up to five percent of full power by the staff last November.

It is my current understanding, that low power testing has been completed and the licensee is ready to commence power ascention above five percent upon authorization by the NRC.

In accordance with our current procedures, approval by the Commissioners is required before the staff can grant full power authorization. Therefore, at the conclusion of today's meeting, I will be asking the Commissioners to decide on whether to grant that authorization.

Before we begin, do any of my fellow Commissioners have any opening remarks?

COMMISSIONER GILINSKY: I have a comment. These slides, I understand, came up last night. I hope we are not flipping into that practice. I hope we can get them up here earlier so that we can reflect on them sometime before the meeting.

CHAIRMAN PALLADINO: Okay. Any other comments?

If not, then I will turn the meeting over to Mr.

Denton.

MR. DENTON: Thank you.

I have with me this morning Jack Martin, the regional administrator from Region V; Darrell Eisenhut and Harry Root, who is the project manager.

This unit is essentially identical in design to Unit 2. Unit 2 has achieved full power recently. During the startup of Unit 2, they experienced some difficulty in managing the startup of one plant and the completion of a second one that led to enforcement actions during the spring.

We think the actions taken by the company have been effective and have effected the turn-around. So, we are prepared today to recommend that you approve full power operation of this unit.

There are several issues that need to be considered, though, before you reach a decision.

One is the actions that were taken during this enforcement conference and that had been taken by the company to strengthen their management capabilities.

A second issue is the location of the EOF. The EOF that they propose is beyond the Commission's guidelines. Harry and I visited the proposed facility. I think it would be worthwhile if you could hear a brief presentation from the company on why they think their location should be approved.

We want to discuss with you the --

CHAIRMAN PALLADINO: May I ask a question? Is it necessary to settle that as part of today's meeting or is that an item that we could settle after we receive whatever recommendations we are going to get from the staff? Is it something separable, that is what I want to know.

MR. DENTON: I think it needs to be settled one way or another before we issue the license. The facility they propose does not meet your requirements, but personally I think their proposal has considerable merit and it would merit hearing why they think so.

We want to discuss the status of the PORV. I think we sent down a staff report on the PORV to Commissioner Bernthal and to the other Commissioners. We have not reached a firm decision within NRR as to what our position will be on that yet.

COMMISSIONER GILINSKY: Let's see, what triggered that getting sent down last night?

MR. DENTON: A request from a Commissioner.

COMMISSIONER GILINSKY: I see. It is a draft which is --

MR. DENTON: It is a draft.

COMMISSIONER GILINSKY: -- still in the process of --

MR. DENTON: It is still under consideration and I do not have all my division's comments on it. I have not made a decision on it yet. We plan to meet with the ACRS when they meet in October and then, based on their input, we would go to CRGR the next opportunity in October, and we could have a final position on that sometime late in October.

But if you looked at the report, it says that in any event we don't think it is worthwhile to require it be put on as a condition of going up in power at this time.

CHAIRMAN PALLADINO: Is that not a generic item, so to speak?

MR. DENTON: It is a generic item. I just wanted to hit the items that we are going to discuss, rather than discuss them at this time.

Then, if I could go to slide No. 2. You see the list I am just going down. I have covered the EOF and the PORV.

In discussing the PORV requirements, I also want to discuss the three questions raised by Commissioner Gilinsky which are somewhat related to the PORV question. So, we will cover your questions, Commissioner, at that time in the briefing.

Then I want to cover some resolved issues which are ones I think you should be aware of, on how we handled reactor trip breakers and those types of questions.

So, we will cover certain resolved issues.

Then there are some allegations that we would like

PAGES 7 - 38 have been omitted since the discussion did not relate to the issue of this BN.

surveillance? Maybe I should ask D[illegible] on what goes on at San Onofre.

MR. DENTON: I think that what it will require is that we watch it very carefully, the operation, and take that into account during the next systematic appraisal. We have not had much experience in this area before and it can be argued either way.

So, I think it is just a fact for Jack to take into account the next appraisal session.

CHAIRMAN PALLADINO: Okay, any other questions?

Well, thank you, Mr. Fogarty.

MR. DENTON: Let me turn it back to Harry Rood.

MR. ROOD: Well, I guess that concludes the EOF discussion.

The next area would be PORV requirements. As you know, San Onofre 2 and 3 do not have PORVs at this time. They had a license condition that was put on Unit 2 and also on Unit 3 - carried it forward -- that the utility had to send in a detailed study, answer 14 questions on the desirability of the PORV by June 30, 1983. They did that, they met that deadline. They concluded that PORV was not necessary.

Our review of that is underway and I would like to get Roger Mattson to disucss this particular subject in more detail. I think he will also address the questions raised by Commissioner Gilinsky in a recent letter.

Roger?

MR. MATTSON: Will you go to Slide 9A, please?

As Harry said, the technical work to support the reaching of a decision on PORVs for the System 80 design and for San Onofre 2 and 3 was essentially finished in June of this year. You remember, we were back with you on Unit 2 roughly a year before that, where we had had a last-minute issue, whether we ought to require PORVs as a condition of licensing or it required study.

We had intended to finish our work in the staff, reviewing the CE owners group work and the work by our contractors, and get down to you by the first of October, I think it said on Slide 9.

That slipped somewhat. One because we did a good job and two, because it is a harder task than you might imagine.

COMMISSIONER GILINSKY: Let's see, the last time we talked about this you were going to accelerate the schedule.

MR. MATTSON: Yes. We did. This is still accelerated from what we told you it was going to be -- not quite as accelerated as we hoped we could achieve.

This slide said we will have the report to the ACRS on the 20th. We fully intend to meet that. The subcommittee briefing is scheduled for the 4th, the full committee meets a little late in October this year.

Then we would go to CRGR and, as you can see, the steps required to complete these reviews take some time.

Yesterday, as Harold said earlier, Commissioner Bernthal asked to step into this process a little bit by seeing the draft staff report.

For those in the audience who have not seen it, it is a big thing like this that the Commissioners and the staff now have, but it is not a public document at this point.

But to facilitate this discussion, I would like to turn to a slide you do not have in your package but which is in the projectionist's hand; it is Slide 9B.

This slide summarizes the work that is presented in this draft report. Let me say one more thing about the status of that draft.

It is in the form of a memorandum from Dr. Spiess, the of Safety Technology, and me to the other division directors in NRR, asking for their concurrence.

The steps required to get a final NRR position are to take into account their comments; take it forward to Harold, get his decision; go from there to CRGR and ACRS. So, these are Dr. Spiess' conclusions and mine.

We looked at the PORV question from three points of view. The first bullet, the classic licensing point of view, does it meet the regulations in the Standard Review Plan? Does the design meet it without the PORV?

The second bullet, what about beyond the classical design basis accidents which are required by the Standard Review Plan?

The third bullet from a probabilistic risk assessment point of view.

There were actually three PRA analyses done of this question, one by the CE owners group, another by Sandia Labs in connection with Unresolved Safety Issue 845, and a third by the Reliability and Risk Assessment Branch in the Division of Safety Technology.

Taking into account those three approaches to the question it comes out, much as it did a year ago when we were here on San Onofre 2, a close call in the staff's view in favor of adding PORVs to this design.

I must say that the CE owners group, following much the same logic, comes to a close call against there being PORVs for this design.

Now, I do not want to get into a final decision on this thing yet because it is tentative. The reason I put it up is because I can from this slide now go to Commissioner Gilinsky's three questions.

If you have his memo of September 14 in front of you, there were three points that he asked us to address today

One is the reliability of the aux feedwater system. The second is low temperature overpressure protection, and third is whether there have been any site-specific tests of the auxiliary spray system. I think it means the auxiliary pressurizer spray system.

Let me take the first of those, auxiliary feedwater reliability and say that it relates to this question through the second bullet on this slide.

You notice that total loss of all feedwater is one of the places where having a PORV and a capability to feed and bleed, cool this pressurized water reactor, would be of value to you.

How much value you place on that depends upon how reliable you think the normal feedwater, the auxiliary feedwater, and any backup to auxiliary feedwater might be in the case of San Onofre 2 and 3, or in the case of Cumbustion Engineering reactors generally.

Let me address aux feedwater reliability then in that context. We do two kinds of reviews of auxiliary feedwater systems since Three Mile Island.

One, let me call a deterministic review is; we use the Commission's regulations, the Standard Review Plan, the design basis accident approach to looking at the safety grade auxiliary feedwater system to see whether it meets the body of requirements. That has been done in this case and this design meets all of those requirements.

But added after TMI was a reliability assessment review of the auxiliary feedwater system. This is the only system that we perform such a review for in our normal licensing review. Thatis a new Standard Review Plan Section 10.4.9 that in simple terms sets a reliability goal for aux feedwater performance for a limited number of design events for that system.

The target that it sets is ten to the minus fourth to ten to the minus fifth unreliability of the auxiliary feedwater system for those events.

In the case of San Onofre, it measured in sum 3.8 times ten to the minus fifth for that unreliability test. To benchmark that, that is a good aux feedwater system measured in this reliability assessment method. It is about the same as other Combustion Engineering plants. It is better than some other recent PWRs that we were reviewing.

The question also asked what common mode failures protection there was for this system. Of course, in the normal review we look a. -e protection, pipe breaks, internal flooding, internal miss. tornado missiles, seismic and external flooding as the tra. -al common mode failure effects, possible effects, on this system.

The aux feedwater system at San Onofre has three pumps, two electric, one steam driven. They are all located in one room.. So that there has been some difficulty in c--ing to closure on fire protection and pipe breaks.

You can imagine that with these complicated pumps and associated equipment that it can get quite tight as things are added on in the course of construction. So, there has been some debate -- now settled -- over the degree of separation, the protection of one train of aux feedwater from a fire in another train. But we believe those points are all settled.

There was another one on pipe breaks, having to do with the possible failure of a steam supply line for the aux feedwater turbine that could severely stress equipment in that room. The equipment all came out looking all right except for one problem that is a license condition in ithis license. That is some bearings in the electric-driven aux feedwater pumps that have to have a lube oil cooling system installed by the first refueling outage to protect against that very low probability of a steam supply line break in the aux feedwater compartment.

Maybe that is a good place to pause, Commissioner Gilinsky, and see if we have hit the first of your three questions. I was going to go to the second one.

COMMISSIONER GILINSKY: Let me ask you, to what extent do you take into account possible maintenance errors of the kind that we saw at Salem, that we had not foreseen as contributing to common mode failures, possible common mode failures?

MR. MATTSON: Well, to the extent that the maintenace program is reviewed for these plants, both by the region and by the Division of Human Factors -- you know since the Salem event that is an area we have said we want to bring more attention to.

I would say at this point that NRC can do better in its review of maintenance contributions to common mode failures, but there wasn't anything special done for this plant.

COMMISSIONER GILINSKY: It makes me think that these conclusions at a couple of significant places are kind of "iffy."

When all is said and done, the most important reason, I think, for considering the PORVs is precisely is to the total loss of all feedwater.

The argument on the other side is the reliability of the feedwater system.

I don't know that we can settle this on a purely quantitative basis. Do you mind if I read one sentence out of your report here that I came across while you were declaiming?

The slide says that there is a small net positive gain in doing this. You do conclude that the PORV can contribute significantly to mitigating total loss of feedwater

You end up with a small net positive gain when you start adding in the cost of installing the valve as against the possible health and safety, and so on.

But there you are comparing numbers which are really pretty uncertain, I think. This is something that is going to have to get decided more on the basis of experience and judgment because what you are protecting against is the possibility -- which you hope obviously will never arise -- of the water just boiling off and in the event that you lose all feedwater and not be able to do anything about it.

MR. MATTSON: That is a very important point, I agree with you.

COMMISSIONER GILINSKY: Yes. Now, I guess the conclusion I come to here, if there is a disinclination to go forward with PORVs, that we ought to look very much harder at the reliability of the auxiliary feedwater system. Several points come to mind.

One is that I think we ought to insist that there be essentially a hundred percent reporting on all events, all failures, related to that system. I think under our new LER rule we have relaxed the reporting requirements, many of these would go to INPO and not to us.

I think in this case we ought to insist that there be full reporting and that we review this again at the time when the PORV issue is coming to a head. That is what I propose in this case.

I also think we ought to look a little harder at the possibility -- that, as I said, arose in the case of Salem, maintenance errors where the same thing was done on a number of what we believed to be independent redundant devices, cuasing them all to fail. We have come across things like that more than once.

So, I think we ought to take a renewed and deeper look at the systems that we are talking about here, again reporting back at some suitable time.

CHAIRMAN PALLADINO: Do any CE plants have PORVs?

COMMISSIONER GILINSKY: Oh, yes.

MR. MATTSON: Yes. This is the first two units that have no venting capability. There are no PORVs on Arkansas Unit 2, but it does have a rather large valve that could be used for the same depressurization function.

COMMISSIONER GILINSKY: And St. Lucie, that we reviewed recently, had --

MR. MATTSON: They have the PORV.

CHAIRMAN PALLADINO: What is this other valve that could be used?

MR. MATTSON: It does not exist on the San Onofre plant, only at Arkansas Nuclear.

All subsequent EP plants -- the Palo Verde plant or any other System 80 plants -- would not have PORVs unless this conclusion turns out to be your conclusion when all the reviews are done.

CHAIRMAN PALLADINO: Are you recommending that we not put one on, or put one on?

MR. DENTON: We don't think you need to decide that for the issuance of this license. On balance, the staff view -- as Roger and Timmy see it -- is that it should be required. But I need to get the Human Factor Division factored into it, as you mentioned, the maintenance errors, and be sure that I develop a position on it. Then take it to the ACRS and get their comments. Then go through CRGR before we reach a final position.

If we decide that one is necessary, it could be required at the appropriate refueling time. I hoped to have it resolved by this time, but because of the complexity and the differing views between ourselves and other parties on it -- in effect, it is a fairly close call.

We have put a lot of work into it and used consultants, trying to pin down the answers as well as we could. So, we will have a position to you, as Roger said, later this year.

COMMISSIONER GILINSKY: What I was suggesting is that in the meantime we have a hundred percent reporting on failures of all components in those systems so we get a good idea of just what the reliability of the auxiliary feedwater systems is.

MR. DENTON: I will certainly try to get that accomplished. I don't know --

CHAIRMAN PALLADINO: When you say "all these systems" you mean the auxiliary feedwater?

COMMISSIONER GILINSKY: The auxiliary feedwater, yes. I would suggest we have that as a condition of approval of this plant.

MR. DENTON: I will talk to Jack Helton who operates the reporting system and see what he can do in getting it reported. I would think we could get the data if it is reported to anyone, like INPO, we can certainly get it from them and have it available at the meeting.

COMMISSIONER GILINSKY: No, I am suggesting that we gather that data over the next year or so.

MR. DENTON: On this plant?

COMMISSIONER GILINSKY: On this plant.

MR. DENTON: Oh, I see.

COMMISSIONER GILINSKY: Right, on this plant.

MR. DENTON: Yes, we can certainly --

MR. EISENHUT: Of all component failures on the auxiliary feedwater system.

COMMISSIONER GILINSKY: Specifically in that system because it is that system, the reliability of that system which is the alternate defense, so to speak, against the severe accidents we are talking about.

MR.MATTSON: There were two other points raised. One was low temperature overpressure and the other was tests of the auxiliary pressurizer spray system.

If you refer to the first bullet on this slide, the bullet that concerns whether the plant with no PORV meets the current regulations.

Both the low temperature overpressure protection and the auxiliary pressurizer spray system are needed in order to meet the current regulation and contend with the design basis accidents that we used to implement the current regulation -- low temperature overpressure obviously being a design basis event in this design. That protection, unlike a plant that has PORVs, is provided by release valves in the shutdown cooling system.

The question arose in our briefing of you last spring as to whether the use of those valves and the automatic isolation feature that protects that low pressure system from the high pressure system, were proper. Whether they comported with the code, the ASME code or not. We have re-reviewed that whole area through the Standard Review Plan again, convinced ourselves that it is okay from that point of view.

This new report will document that we have gone to the ASNE subcommittee that has cognizance in this area and have their agreement that this design meets the intent of the

ASNE code, and we believe that the design is satisfactory from that point of view.

COMMISSIONER GILINSKY: And you are satisfied that it covers the entire pressure range?

MR. MATTSON: Yes, the pressure range of interest. Yes.

Now, low temperature overpressure, then tests of the auxiliary pressurizer spray system.

There have been tests at San Onofre 2, conducted as part of the natural circulation testing required during startup of these units.

We have observed two tests -- Tad Marsh who sponsored this staff report that we are referring to -- and we have had a contractor from Brookhaven National Laboratory at subsequent tests. The tests do confirm the capability of the auxiliary pressurizer spray system to control volume and pressure in a cooldown following a steam generator tube rupture, for example, where aux feedwater capability is still available.

We learned some things in conducting the tests that were worth doing, but they were not surprises in the sense that if analyses are done they are consistent with our understanding of the system.

We believe that auxiliary pressurizer spray, when some single failures in that system are corrected -- some single failure vulnerabilities in that system -- are an acceptable way of meeting the regulation. That is a recommendation that is contained in the generic report that we will ask to be implemented generically on all CE plants where this reliance is placed on the auxiliary pressurizer spray.

COMMISSIONER GILINSKY: As dealing with the single failure problems?

MR. MATTSON: For the steam generator tube rupture, yes, sir. Yes, the single failure is the sticking open of the normal pressurizer spray valve, diverting flow from the auxiliary pressurizer spray, and thus defeating the function of the system for a loss of power.

I think that covers the three points in your memo, if you have no other questions.

CHAIRMAN PALLADINO: Okay, thank you.

CHAIRMAN PALLADINO: Do you have some more?

MR. EISENHUT: Yes, if we could go to the next slide.

The rest of the presentation was basically what we call resolved issues. We just highlighted a couple of issues to be sure that the Commission was familiar with them/

The first one was -- I will just summarize them here. The first one is the reactor trip breaker issue. Recall that back in February we had the Salem event. We had a considerable debate after that.

Pages 54 - 60 have been omitted since the material did not relate to the issue of this BN

(Whereupon, the meeting was reopened to the public at 12:05 o'clock p.m.)

CHAIRMAN PALLADINO: The Commission has completed its closed session and determined the information it received would not impair our ability to make a decision on whether or not San Onofre Unit 3 should be allowed to go above five percent power.

Now, at this time, I would like to ask the Commission if it is ready to vote on the issue. As I understand it, based on what we had heard early this morning, if we authorize it, the staff would proceed in authorizing the San Onofre Unit 3 plant to go above five percent power when the staff feels it is ready, with the additional caveat that we ask them for a 100 percent report on the failure or non-fully operational components of the auxiliary feedwater system and that the staff accumulate that information. So that, when we get the PORV issue, we would have it.

Are there any other caveats or points?

COMMISSIONER GILINSKY: I think I would just assume that this is including what you suggested rather than include operator errors and that sort of thing, and I think it probably ought to be gathered for some period of time such as a year and have the staff report back, and that would give a reasonable assessment of the state of things.

CHAIRMAN PALLADINO: Now, I understand that, if we were to authorize ascension beyond five percent, that would not necessarily imply settlement of the EOF at this time, unless you want to make that decision this morning, too.

Do you want to make the EOF decision at this meeting? I would be ready.

COMMISSIONER GILINSKY: I would say, just to personally repeat again, I would prefer to see one facility at an intermediate distance, but I'm prepared to approve this as a compromise, given that the facility has been built close by and so on and the other one does have certain advantages.

CHAIRMAN PALLADINO: Would you be ready?

COMMISSIONER ASSELSTINE: Yes, I'm ready.

CHAIRMAN PALLADINO: Why don't we tak a vote on the EOF separately right now?

Would the Commission approve the back-up EOF as proposed by Southern California Edison, as described by Harold and the San Onofre people. If you would approve it, would you say "aye."

(Chorus of ayes.)

CHAIRMAN PALLADINO: I gather it's unanimous. Now, so why don't I pose the question, do you authorize power ascension above five percent for San Onofre Unit 3 when the staff feels it is ready to go above five percent, with the caveat upon the reporting of any failures or operational errors on the auxiliary feedwater system.

(Chorus of ayes.)

CHAIRMAN PALLADINO: I gather that's unanimous. So, when the staff feels you're ready, you've been authorized in proceeding above five percent.

Anything more that should come before us at this time on this subject?

(No response.)

CHAIRMAN PALLADINO: Let me say one other thing. Before I adjourn this meeting, I'm going to ask you in the audience to please be patient for another two minutes. I would like to adjourn this meeting and immediately convene an affirmation session on which I think we need to take action on two items. It would not take very long and that would save us a great deal of time.

So I will adjourn this meeting and convene an affirmation meeting and ask the Secretary to walk us through the items on the agenda.

(Whereupon, the foregoing meeting was adjourned at 12:10 o'clock, p.m.)

CERTIFICATE OF PROCEEDINGS

This is to certify that the attached proceedings before the NRC COMMISSION

In the matter of: Discussion/Possible vote on full power Operating License for San Onofre

Date of Proceeding: 16 September 1983

Place of Proceeding: Washington, D. C.

were held as herein appears, and that this is the original transcript for the file of the Commission.

Elizabeth Hansen
Official Reporter - Typed

Elizabeth Hansen
Official Reporter - Signature

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

NRC Commission

in the matter of: Discussion/Possible Vote on Full Power Operating License for San Onofre - pp. 61-63

Date of Proceeding: Friday, September 16, 1983

Docket Number:

Place of Proceeding Washington, D. C.

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

Elizabeth Ann Tipton

Official Reporter (typed)

Elizabeth Ann Tipton

Official Reporter (Signature)

COMMISSION BRIEFING

SAN ONOFRE NUCLEAR GENERATING STATION,

UNIT 3

FULL POWER AMENDMENT

CONTACT: D. EISENHUT
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SLIDE 1

PORV REQUIREMENT

- UNITS 2 AND 3 ARE CE PLANTS WITHOUT PORV's
- SAN ONOFRE LICENSE CONDITION REQUIRED PORV EVALUATION BY JUNE 30, 1983
- REPORT RECEIVED PRIOR TO JUNE 30, 1983
- LICENSEE ADOPTS CE OWNER's GROUP STUDY RESULTS THAT FIND PORVs NOT NECESSARY
- STAFF REVIEW OF STUDY SCHEDULED TO BE COMPLETE OCTOBER 1, 1983

SCHEDULE OF REPORT ON

NEED FOR PORVs

SEPTEMBER 20	STAFF REPORT TO ACRS
OCTOBER 4	ACRS SUBCOMMITTEE BRIEFING
OCTOBER 13-15	ACRS FULL COMMITTEE BRIEFING
OCTOBER 31	STAFF REPORT TO CRGR
NOVEMBER 16	CRGR PRESENTATION
NOVEMBER 23	CRGR REVIEW COMPLETE
DECEMBER 15	COMMISSION PAPER TO EDO

PRELIMINARY RESULTS OF STUDY ON
NEED FOR PORVs

- o CE PLANTS WITHOUT PORVs, INCLUDING SONGS 2, 3 MEET ALL CURRENT REGULATORY REQUIREMENTS WITH EXISTING SYSTEMS. A SINGLE FAILURE VULNERABILITY IDENTIFIED IN AUXILIARY PRESSURIZER SPRAY SYSTEM WILL NEED TO BE CORRECTED.

- o PORVs PROVIDE IMPORTANT DEFENSE-IN-DEPTH CAPABILITY FOR PREVENTING MORE SEVERE ACCIDENTS AND MITIGATING OTHER MULTIPLE FAILURE ACCIDENTS
  - PREVENT SAFETY VALVE LIFTS
  - MULTIPLE STEAM GENERATOR TUBE RUPTURES
  - TOTAL LOSS OF ALL FEEDWATER
  - ATWS MITIGATION
  - SMALL LOCA WITHOUT HPI

- o PORVs ARE ESTIMATED TO LOWER CORE MELT PROBABILITY FROM 6×10^{-5}/RY TO 3.0×10^{-5}/RY DUE TO LOSS OF FEEDWATER AND ATWS ACCIDENTS

- o VALUE/IMPACT ASSESSMENT INDICATED A SMALL POSITIVE NET VALUE

- o NRR STAFFS TENTATIVE VIEW IS THAT PORVs BE REQUIRED FOR ALL CE PLANTS, INCLUDING SONGS 2 AND 3. IMPLEMENTATION SHOULD BE DELAYED UNTIL USI A-45 RESOLUTION FINALIZED. USI A-45 RESOLUTION COULD IMPOSE REQUIREMENTS WHICH CHANGE CURRENT ASSESSMENT.

- o POSITION WILL BE EVALUATED BY CRGR IN NEAR FUTURE.