TELEDYNE
ENGINEERING SERVICES

TECHNICAL REPORT

TR-5599-4

ADDENDUM TO
FINAL REPORT

INDEPENDENT DESIGN REVIEW
SUSQUEHANNA STEAM ELECTRIC STATION

OCTOBER 27, 1982

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P PDR

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TECHNICAL REPORT TR-5599-3

ADDENDUM TO FINAL REPORT

INDEPENDENT DESIGN REVIEW SUSQUEHANNA STEAM ELECTRIC STATION

OCTOBER 27, 1982

TELEDYNE ENGINEERING SERVICES

130 SECOND AVENUE
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Technical Report
TR-5599-4

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APPENDICES 1 - TES Letter Number 5599-17

2 - As-Built Reconciliation Program Review Objectives and Procedures Manual

1.0 INTRODUCTION

This report is submitted to serve two purposes. The first is to close out the two findings defined in the TES Final Report Number TR-5599-3 dated August 22, 1982 (Reference 1). The second is to act as an Executive Summary to the Independent Design Review performed by TES on the Susquehanna Steam Electric Station.

2.0 CLOSING OF FINDINGS

The following discussion presents the details behind the closing of Findings by TES.

2.1 Finding Number 1

This Finding was closed by Letter Number 5599-17, dated October 19, 1982, which is attached in Appendix 1.

The basis of Finding Number 1 was that the Design Specification categorization of plant operating conditions was not proper. In Bechtel Design Specification 8856-M-175, Revision 5, the transient condition "Loss of Feedwater Pumps, Main Steam Isolation Valves Closed" is classified as an Emergency Condition. Based on the requirements of ASME, BPVC Section III (Code) this classification precludes this event from consideration in the fatigue evaluation. However, the Code in Paragraph NB-3113.3 requires that an event classified as an Emergency Condition:

> "shall not cause more than 25 stress cycles having an S_a value greater than that for 10^6 cycles from the applicable fatigue design curves of Figures I-9.0."

This event, "Loss of FW Pumps MSIV Closed" is specified as occurring ten times. For each occurrence, three step changes in temperature from 546F to 40F and one step change in temperature from 546F to 100F is specified. Additionally recovery from 40F to 546F at various times is also specified. Based on the specified conditions, more than 25 stress cycles having an S_a value greater than that for 10^6 cycles from the applicable fatigue curves will occur. This event will have a significant impact on the fatigue life of components and must be considered in the fatigue evaluation. This can only be accomplished by classifying the event as an Upset Condition.

The information submitted by Bechtel in Reference 3 addressed the impact of the "Loss of Feedwater Pumps, MSIV Closed" transient on the Fatigue Usage Factor for the Main Feedwater System. Further, a study was done that determined the fatigue effect on all other Class 1 systems was negligible. A summary of that information follows:

	Usage Factor	
System	Stress Report	Study
Feedwater	0.8993	0.9494
Core Spray	0.8975	0.8985
RPV Drain	0.3576	0.3576
Standby Liquid Control	0.4332	0.4383
RCIC	0.6146	0.6151
HPCI	0.8290	0.8295
Head Vent	0.6021	0.6027
Head Spray	0.7956	0.7957
MSIV Drain	0.0384	0.0393

It is important to understand that the TES position on this Finding has always been that a safety concern did not exist. In fact, TES pointed out at two NRC staff meetings that our experience in analyzing

Class 1 BWR systems indicated that the requirements of the ASME, BPVC Section III would be met considering this event as an Upset Operating Condition. TES needed documentation from Bechtel verifying this position. That has been submitted in Reference 3.

Finding Number 1 has been addressed to the satisfaction of TES and is therefore revised to an Observation.

2.2 Finding Number 2

This Finding is related to the reconciliation process of as-built supports and results from the fact that further calculations were required by Bechtel to resolve as-built geometries for the Main Feedwater System. The following is a summary of the Finding as detailed in Reference 1.

Finding Number 2 (Phase 1 Finding Numbers 7, 9 and 10, and Observation Numbers 3, 4, 5, 6, 7 and 9)

A significant number of comments have been generated on the support design process. Most of these comments are related to reconciliation of as-built geometry by the support designer. The concern is basically associated with acceptability of the as-built support. Two major items (Finding Nos. 7 and 10) have been responded to by Bechtel in this Phase 2 portion of the review but they only tend to support that the process did not work.

The response to Phase 1 Finding No. 7 indicates that the pipe support reviewer and checker determine whether a relocated support was a significant enough change to warrant a Civil department review. In the case of the specific support of concern no Civil review is apparent. However, there is a new plate required in the as-built design which is the

responsibility of the Civil department. The support design group calculations indicate that the plate will be handled by the Civil group and the Civil calculations do not address the plate since they do not know the support is located on it without having the as-built geometry forwarded to them. In the final Bechtel submittal the plate has been analyzed by the Civil department as a result of the TES findings.

The response to Phase 1 Finding No. 10 indicates that the weld at the shield wall is acceptable after reducing the conservatism in the original analysis and performing a detailed computer solution of the support. It is apparent that this weld was not aceptable by inspection as originally stated by Bechtel.

Responses to Finding Number 9 and the Observations listed under this Finding were reviewed and in some cases indicate the Observation could have been closed if sufficient detail was provided in the Bechtel reconciliation process. During the August 10, 1982 meeting at TES, Bechtel indicated that group meetings and training sessions were held to explain procedures used in the reconciliation process. Further, the reviewer checks each item and determines acceptability and even crosses each item off that he judges is acceptable on a check print. None of this information is retained by Bechtel nor is there any record maintained of meetings or training sessions for this purpose.

In response to this Finding, PP&L undertook a review of the reconciliation process for an additional 20 supports on systems other than the feedwater system. That review indicated that one anchor would require extensive reanalysis. Essentially, the as-built anchor had approximately one-fourth of the as-designed weld length. As a result of this, PP&L elected to go to a sample of 400 supports. The breakdown of that sample is as follows:

Composition of Sample

Type	Population	Sample
Snubbers	25%	11%
Springs	15%	3%
Rigid Supports	54%	75%
Anchors	6%	11%
	100%	100%

The sample concentrated more heavily on rigid supports and anchors because the IDR Finding and the original PP&L sample indicated that these were the most critical type supports with respect to reconciliation.

A detailed procedure for the review of the 400 supports was developed by PP&L and reviewed by TES. A copy of that procedure is attached in Appendix 2. A TES observer was present at the Bechtel offices in San Francisco during the major part of this review related to Categorization. Our observation of that process included spot-checking of supports to determine if TES agreed with the categorization. TES concluded that the process as defined by PP&L and reviewed by TES was being carried out successfully and that the personnel involved in Categorization were allowed to reach decisions independently. Based on this, TES determined that a review of all Category III supports would be sufficient to reach our conclusion. Our review of 80 supports designated as Category III results in the following:

1. The original reconciliation process indicates weaknesses in the area of acceptance of as-built designs. This is primarily related to those supports that were reconciled based on engineering judgment. This is based on the fact that 14 supports required extensive reanalysis to determine adequacy and 40 supports required some simple recalculation. Extensive analysis includes detail computer analysis of the

support and/or reanalysis of the piping system to reduce loading conservatisms.

2. The categorization of 89 items in Category III was very conservative. It is TES' opinion that approximately one-half of these supports should have been Category II.

3. All supports other than anchors have been demonstrated to be adequate by the PP&L review and the Bechtel responses, including reanalysis. TES has sufficient evidence to remove these from further consideration.

4. A reconciliation problem related to weld capacity still exists for anchors. A program acceptable to TES has been presented in Section 3.0. Acceptance of this program by PP&L would satisfy Finding Number 2 of the IDR.

3.0 ANCHOR RECONCILIATION PROGRAM

In order for TES to remove Finding Number 2, the following program must be accepted by PP&L.

3.1 Definition of Anchor

An anchor is defined as any support that provides rotational as well as translational restraint to the piping system. One direction of rotational restraint is sufficient for a support to be categorized as an anchor. Anchors which are part of containment (flued heads) and anchors at equipment (pumps, vessels, etc.) are specifically excluded from this program. Essentially, this program is limited to intermediate anchors which use structural steel to provide restraint.

3.2 Program Division

The program should be divided into two phases, as follows:

1. Phase 1 - anchors inside containment.

2. Phase 2 - anchors outside containment.

The reason for this division is that TES feels the plant should be allowed to operate once the anchors inside containment have been reconciled. This is because the earthquake event (OBE or SSE) is a significant load for all anchors and, for the short time needed to reconcile anchors outside containment, the event probability should be very low.

3.3 Program Details

All anchors shall be subjected to the categorization process defined in Appendix 2. Those anchors which are placed in Category I and/or II will be acceptable by definition. For those anchors placed in Category III only analysis comparable to the as-designed analysis is allowable for reconciliation. If reconciliation cannot be reached in this manner the anchor will be modified to reflect as-designed. Where interference or access does not permit this approach, modifications to the anchor may be made which do not reflect as-designed but do provide the same design margin. It is noted that analysis techniques beyond those used in the original anchor design are not to be used to provide the design margin.

4.0 PROGRAM MONITORING

TES' review of the implementation of the PP&L program for reconciliation of the 400 support sample was quite extensive. Based on this

review, our confidence in the PP&L personnel involved and PP&L's commitment to this program, we feel there is no further need for TES participation.

5.0 CONCLUSIONS

The Independent Design Review performed on the Main Feedwater system at the Susquehanna Steam Electric Station was quite extensive in scope. This review provided TES with a detailed understanding of the following:

5.1 FSAR commitments,
5.2 Quality Assurance procedures, process and implementation,
5.3 Design procedures, process and implementation,
5.4 As-built configuration,
5.5 Reconciliation of as-built geometries versus as-designed, and
5.6 Implementation of FSAR commitments.

Based on the results of our Independent Design Review, it is TES' opinion that, upon completion of the program outlined in Section 3.0 of this report, the commitments of the FSAR have been complied with for the Susquehanna Steam Electric Station.

6.0 REFERENCES

6.1 TES Final Report TR-5599-3, "Independent Design Review - Susquehanna Steam Electric Station", dated August 23, 1982.

6.2 PP&L Letter Number ER100450, PLA-1328, dated October 4, 1982, from N. W. Curtis (PP&L) to A. Schwencer (USNRC).

6.3 Bechtel Letter Number 0176565, dated September 24, 1982, from E. B. Poser (Bechtel) to R. Enos (TES).

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APPENDIX 1

TES LETTER NUMBER 5599-17

TELEDYNE
ENGINEERING SERVICES

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WALTHAM, MASSACHUSETTS 02254

(617) 890-3350 TWX (710) 324-7580

October 19, 1982
5599-17

Mr. Robert J. Shovlin
Assistant Project Director - Susquehanna
Pennsylvania Power and Light Company
Two North Ninth Street
Allentown, Pennsylvania 18101

Subject: TES Independent Design Review - Susquehanna Steam Electric Generating Station

References: (1) PP&L Letter ER 100450 dated October 4, 1982
(2) Bechtel response to Phase 2, Finding No. 1 (Identification No. 0176565) dated September 24, 1982

Dear Mr. Shovlin:

Attached are six copies of this letter. We have also forwarded copies to the following parties in accordance with your instructions.

Mr. A. Schwencer
U. S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20014

Mr. Robert Perch (To Be Opened by Addressee Only)
U. S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20014

Mr. J. B. Violette (4 copies)
Bechtel Power Corporation
P. O. Box 3965, 50 Beale Street
San Francisco, California 94119

This letter is submitted as a preliminary reaction to References (1) and (2) responses to Phase 2, Finding No. 1, of the TES Final Report. This item will be addressed in greater detail in an Addendum to the TES Final Report. It is anticipated that the Addendum will be submitted upon completion of a review by TES of the Support Reconciliation Report being prepared by PP&L in response to Phase 2, Finding No. 2.

The basis of Finding No. 1 is that the Design Specification categorization of plant operating conditions is not proper. This is specifically related to "Loss of Feedwater Pumps, MSIV Closed" being classified as an

Emergency Condition. References (1) and (2) indicate that the inclusion of this transient in the Upset Condition category does not violate Code fatigue criteria. Further, a study of other systems indicates that this transient is less severe and would have negligible effect on fatigue usage factors for those systems.

TES has stated at two meetings with the NRC staff that our experience in analyzing BWR piping systems indicates that the results obtained by Bechtel could be expected and no safety concerns existed. Based on this knowledge, TES requested that sufficient documentation be presented to indicate that Bechtel reaches the same conclusion when this transient is considered as an Upset Condition. This documentation was presented in Reference (2).

It is apparent that the definition of Finding as used by TES in the IDR of Susquehanna is being misunderstood. A Finding does not necessarily mean that a safety concern exists. TES feels that any concerns resulting from Phase 2, Finding No. 1, with respect to safety should be eliminated. Based on the above, Phase 2, Finding No. 1, should be changed to an Observation that has been sufficiently addressed by PP&L.

If you have any questions concerning this please do not hesitate to contact me.

Very truly yours,

TELEDYNE ENGINEERING SERVICES

Donald F. Landers

Donald F. Landers
Senior Vice-President

DFL/lh

cc: R. A. Enos (TES)
D. Messinger (TES)
TES Document Control

TELEDYNE
ENGINEERING SERVICES

Technical Report
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APPENDIX 2

AS-BUILT RECONCILIATION PROGRAM REVIEW OBJECTIVES AND PROCEDURES MANUAL

Revision 0 10/9/82

Revision 1 10/9/82 WQR

Revision 2 10/12/82

AS-BUILT RECONCILIATION PROGRAM REVIEW

OBJECTIVES AND PROCEDURES MANUAL

SUSQUEHANNA STEAM ELECTRIC STATION

PENNSYLVANIA POWER & LIGHT COMPANY

R. V. Parekh - Bechtel

W. J. Rhoades - P. P. & L.

WP23/1-1

INTRODUCTION

It has been concluded by PP&L that additional review of the As-Built Reconciliation Program is necessary. The purpose of this review is to provide a very high confidence level to PP&L and the NRC that there exist no unsafe piping supports in the Susquehanna Steam Electric Station.

Accordingly, PP&L has selected a sample size of five hundred (500) seismic category one supports to be reviewed. This sample size provides us with the high degree of confidence we require. However, after we have reviewed several hundred supports, this sample size may be adjusted upwards or downwards depending on the results of the survey at that time.

Selection of the supports to be reviewed will be made by PP&L representatives. It is intended that the sample selected be random with respect to systems but skewed in favor of anchors, rigid and operationally active snubbers with less consideration towards dead weight type supports. A complete list of those supports selected will be documented in the final report.

DEFINITIONS

The following are the definitions of the categories of differences between the as-built and engineering drawings.

CATEGORY I: Are those differences which are considered insignificant, such as slight variation in dimensions.

CATEGORY II: Are those differences which may be of concern but upon further investigation are considered acceptable. The investigation, however, may be by engineering judgement or by simply referring to the as-designed calculation and noting what the requirements or actual stresses are.

CATEGORY III: Are those differences which are of concern and require further evaluation. The evaluation would require an additional analysis or a more detailed analysis of the original calculation.

REJECT: Reject is defined by PP&L as any support that, in the judgement of PP&L, requires a field hardware modification. 1/2

ORGANIZATION

This program is organized into three primary task groups plus a documentation retrieval group. Task group one will perform the function of comparing and clearly identifying all differences between the final "as-built" and the engineering analyzed support drawing. Group two will perform the judgements and determine to which category each item, highlighted by Group one, is to be put and document that category. Group three will take those Category III which require resolution and perform the necessary calculations or additional research work to verify acceptability of the support. If field walkdown for review of specific support is required it will be made and documented by the PP&L Resident Engineering. 1. 2

DOCUMENTATION RETRIEVAL

STEPS:

1. Check Pipe Support list against DOCRET to note the latest Engineering revision. (DOCRET is the log of engineering revisions issued and is generated from microfilm cards and was in existence at the time of as-built reconciliation.)

2. Copy of Engineering revision
   a. Retrieve copy
   b. Make 1 copy
   c. To be filed in binder later

3. Copy of the latest as-built from the ABR (As-Built Reconciliation) binder
   a. Check revision in binder reconciliation sheet
   b. Locate as-built P.S. detail in the ABR. Check to ensure that the sticker is signed-off by Engineering.
   c. Put marker in the ABR binder
   d. Sign-out out card
   e. Make 1 copy
   f. File back where marker was
   g. Sign-out ABR out-card.

GROUP 1

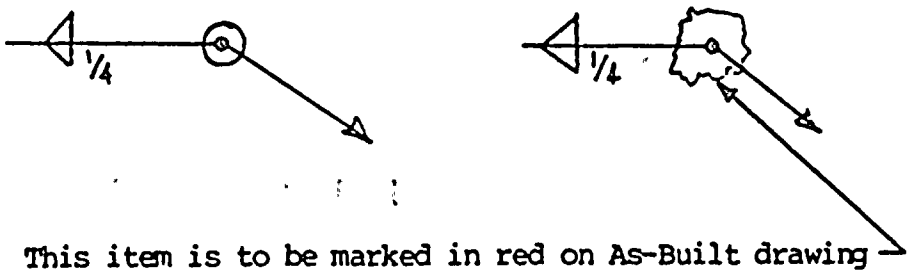
Comparison of Engineering and As-Built Pipe Support Details (Yellow-out Process):

1. Obtain copy of Engineering and as-built P.S. revision
2. Yellow-out all items that are identical on both Engineering and as-built pipe support detail.
3. Items not identical to the Engineering revision should be circled in red.

4. Identify items that are not identified on either of the drawings by a circle in green with an asterisk mark.

It is to be emphasized that no judgements are to be made by Group one personnel and that all differences, no matter how trivial they may appear, are to be marked in red or green. The following example is an illustration of this requirement:

Engineering Drawing "As Built"



This item is to be marked in red on As-Built drawing

Bill of Materials

Engineering	"As-Built"
4W13 x 6'-2"	4W13 x 6'-1"

This item is to be marked in red

5. Fill out the cover sheet completely
6. Package cover sheet, Engineering revision and yellowed-out as-built P.S. detail.
7. All packages returned to group one task coordinator for PP&L review.

GROUP 2

Review and Disposition of Differences Between Engineering and As-Built Drawings

1. Ensure that Group One Cover Sheet has been properly signed off prior to performing any reviews.
2. Record each difference on the prescribed sheet (attached).
3. Categorize each difference as Category I, II, III as described in Definitions Section.
4. Resolutions:

Category I differences are those that are insignificant such as slight variation in dimensions and thus, are acceptable by definition.

Category II differences are those that are acceptable by engineering judgement or reference to original calculations. For example, the design called for a 6" diameter pipe having a wall thickness of 3/8". The as-built shows a 6" x 6" x 1/4" thick square structural tube is used instead. This may be acceptable by engineering judgement by comparing the area and section modules of them in relation to the imposed load. Another example is the design has called for a 3/8" fillet weld all around a member. The as-built shows 5/16" fillet weld is used instead. By referring to the original calculation, it is noted that a 1/4" fillet weld is required and thus is acceptable. 2

(Note: The original calculations are QA documents and, as such, are considered valid and acceptable design basis calculations. Therefore, there would be no need to re-review the original calculations and would be beyond the scope of this task).

Category III differences are those that require additional calculations to resolve the difference between the as-designed and as-built. You should search the As-Built Reconciliation (ABR) book to see if there exist calculations that address each Category III difference. When there are no ABR calculations for an item or the calculations are not satisfactory, you should identify that additional calculations are required prior to acceptance or sign off. Please print your name and your team leader's name on the first sheet for identification purposes prior to submitting them to your team leader. When additional calculations are required, the necessary calculations will be performed by Group III and provided to you. If additional calculations are needed to resolve the difference(s), no matter how simple a calculation, you are requested not to make them yourself. This is because of two (2) reasons. First, the the calculations need to be verified in accordance with established procedures and be documented. Second, the Group III function is to make these calculations and they are available to do so. After you

are provided with the calculations the package will be considered complete if you concur with the calculations and all Category III differences have been addressed. If not, a resolution for them will be required. If there is an inpass, PP&L shall determine the final resolution for them. If rejects are identified (see definition) because hardware changes are required they would be identified and signed off. Needless to say, if there are no Category III differences, the "As-Built Reconciliation Judgement Verification" form shall be signed off based on acceptance of Category I and II differences, if any. 2

5. Items that need Field verification or clarification due to drawing ambiguity, clarity should be identified and brought to Team Leader's attention for resolution.

6. Forward package to PP&L representative for review and concurrence.

GROUP 3

Performance of Additional Calculations to Justify Adequacy of the Differences Designated as Category III by Group II

1. Generate calculations per PEPM as necessary to validate the differences and the as-built condition to the extent feasible. All packages forwarded to Group 3 require individualized disposition

to assure support adequacy. Once you receive a package identify what must be done, notify PP&L of your intended action, and proceed.

If a calculation needs to be run, proceed immediately and, once appropriate calculations are complete, attach them to the completed package, sign the cover sheet and forward them to PP&L. If field checking of an item is required, notify PP&L and they will make arrangements for PP&L Resident Engineering group to make necessary checks. If any support cannot be resolved by additional calculations, notify PP&L immediately. 2

FINAL DOCUMENTATION:

1. A sample selection of the Final Documentation Package will be made by PP&L to assure the following:

   a. As-Built Reconciliation Judgement Verification sheet comletely filled in.

   b. Copies of yellow-out cover sheets filled in.

   c. Copies of Engineering revision and as-built P.S. detail (yellow-out copy)

   d. Calculations as applicable, and when generated by Group 3 for each pipe support.

LIST OF ATTACHMENTS:

1. Sample signoff sheet for Group 1

2. Sample As-Built Reconciliation Judgement Verification Signoff sheet for Group 2.

HGR. NO. _____

AS-BUILT RECONCILIATION PROGRAM REVIEW

COMPARISON OF ENGINEERING AND AS-BUILT PIPE SUPPORT DETAIL
YELLOW-OUT PROCESS)

PERFORMED BY: _____ _____
PRINT NAME SIGNATURE

_____ _____
DATE ORGANIZATION

REVIEW PERFORMED: YES _____ NO _____

_____
SIGNATURE PP&L

REVIEWED BY: _____ _____
(IF YES) PRINT NAME SIGNATURE

_____ _____
DATE ORGANIZATION

AS-BUILT RECONCILIATION JUDGMENT VERIFICATION

SUPPORT TYPE

SHEET 1 OF _____

SUPPORT DWG. NO. _____

DATE _____

ISO DWG. NO. _____

PERFORMED BY: SIGN _____

PRINT _____

ENG'G DWG. REV. _____

REVIEWED BY: SIGN _____

PRINT _____

AS-BUILT REV. _____

SYSTEM _____

FCI _____

DIFFERENCES	RESOLUTION
CATEGORY I	CATEGORY I DIFFERENCES ARE DEEMED ACCEPTABLE BY DEFINITION.

AS-BUILT RECONCILIATION JUDGMENT VERIFICATION

SUPPORT DWG. NO. _____ SHEET OF _____

DIFFERENCES	RESOLUTION
CATEGORY	

AS-BUILT RECONCILIATION PROGRAM REVIEW

SUSQUEHANNA STEAM ELECTRIC STATION

UNIT - 1

CATEGORY III RESPONSE FORM

ABR CALC. _____

SUPPORT NO. _____ SEQUENCE NO. _____

ENG.DWG.REV. _____ AS-BUILT REV. _____

FCI _____ SYSTEM. _____

	YES	NO
ABR CALC. REVISION REQUIRED:	☐	☐

RESPONSE: _____

RESPONSE BY. _____

DATE. _____

APPROVED BY _____

DATE.

AS-BUILT RECONCILIATION JUDGMENT VERIFICATION

SUPPORT DWG. NO. _____ SHEET OF _____

DIFFERENCES	RESOLUTION
CATEGORY II	
CATEGORY III	

I. Issue

1. Effects of Local Encroachments on Pool Swell Loads

2. Safety Relief Valve Discharge Line Sleeves

II. Assessment/Response

The NRC dispositioned these concerns as N/A for SSES.

III. Future Action Required

None

8211060230

I. Issue

3. ECCS Relief Valve Discharge Lines Below the Suppression Pool Level

3.1 The design of the study plant did not consider vent clearing, condensation oscillation and chugging loads which might be produced by the actuation of these relief valves.

II. Assessment/Response

In preface to the response to the above concern, it should be noted that the steam condensing mode (SCM) is an operationally non-safety-related subsystem of the RHR system. It provides an optional method of removing reactor decay heat after shutdown by condensing reactor steam in the RHR heat exchanger. A relief valve is provided to provide overpressure protection to the heat exchanger and associated piping and components. The RHR SRV discharges into the suppression pool through a 10" diameter open-ended pipe at a submergence of 4' below low normal water level. During power operation the RHR heat exchanger is isolated from the steam supply by two independent and redundant safety-grade isolation valves. Therefore, lifting of the RHR SRV due to overpressure is only assumed to occur during SCM operation.

The steam flow to the RHR heat exchangers (Hxs) is controlled by two in-series pressure control valves (PCVs), which maintain an operating pressure of 200 psig in the Hxs. RHR SRV actuation occurs for the following two scenarios:

- Both PCVs fail open.
- Failed open RHR SRV.

For the first case, both PCVs are controlled by the same controller; thus, a single failure in the controller leads to possibly both PCVs actuating to the full open position. Following the failure, the downstream piping pressurizes to the relief valve setpressure and opens to relieve pressure. Since the RHR SRV steam flow exceeds the flow capacity of the two controllers, the pressure decreases and the RHR SRV quickly reseats. Once the RHR SRV recloses, the 6" VBs mounted on the RHR SRVDL open to allow air into the RHR SRVDL. The pressure again increases until the RHR SRV lifts to relieve pressure causing a mixture of air and steam to flow into the pool. This "cycling" of the SRV continues until the operator isolates the SCM mode. During this time, the steam flowing through the PCVs simultaneously condenses in the RHR Hx and flows through the RHR SRV. Furthermore, the RHR SRV cycles rapidly, so that the steam flow never reaches steady-state conditions. For the above reasons, the average steam flux in the RHR SRVDL is much lower than the theoretical maximum steam flux based on the rated flow through the RHR SRV under steady-state conditions.

The second scenario postulates a failure in the RHR SRV itself (i.e., broken spring) causing the RHR SRV to fail wide open. Under these conditions, the PCV will modulate open to attempt to maintain a downstream pressure of 200 psig. However, the controller to the PCVs electronically limits the PCVs to 60% full open; thus, the maximum flow through the PCVs will be less than the rated flow of the PCVs. Again, under steady-state conditions, the flow through the PCVs matches the flow to the Hx and RHR SRV. However, no SRV cycling occurs, since the RHR SRV failed open. Again, the RHR SRV steam flux is much lower than the steam flux based on the rated flow through the RHR SRV under steady-state conditions, since the PCVs limit the flow and steam condenses simultaneously in the RHR Hx.

For both failure modes, the RHR SRV discharges steam to the suppression pool until the operator isolates the system. We assume the operator will detect and isolate the SCM system 10 minutes after the failure occurs which leads to flow through the RHR SRV. Operator action based on 10-minute delay is justified since instrumentation is available to diagnose the situation and take appropriate corrective action. Once RHR SRV steam flow begins, the Suppression Pool Temperature Monitoring System (SPOTMOS) will alarm on high pool temperature and provide early warning of steam discharging to the pool. In addition, various indications of SCM operation, including RHR Hx level and pressure, are available to indicate to the operator that the RHR SRV lifted.

Our preliminary assessment of the effects of the loads caused by actuation of the RHR SRV follows.

From a global perspective, we believe the existing LOCA steam condensation and MSRV building responses bound the responses due to an actuation of the RHR SRV. That is, the building motion caused by the RHR SRV actuation would be much less than either 87 vent pipes chugging, or the response to the 16 valve MSRV load case (reference SSES DAR). Therefore, our evaluation of the RHR SRV loads will be confined to the most highly stressed (least design margin for current design basis) submerged structures and liner plate adjacent to the RHR SRV discharge.

Our evaluation consists of qualitatively comparing the original design basis and stress margins for the submerged structures and liner plate with the expected loads due to RHR SRV actuation when considering the appropriate load combinations. The hydrodynamic loads due to RHR SRV discharge have not been specifically calculated, since they are considered to be bounded by the existing design basis. However, we intend to quantify the loads and provide the results of our assessment by March 31, 1983. A more detailed task description is given in Section III of this response.

In order to compare the expected RHR SRV loads with the current design basis, we mechanistically determined the appropriate load combinations for the RHR SRV loads. We believe the load combination to be as follows:

RHR SRV + SSE + MSRV (low setpressure)

We eliminated the LOCA loads based on the following. If we assume a LOCA occurs during SCM operation, coincident with a failure in the SCM subsystem that leads to RHR SRV actuation, the RHR SRV discharge loads will be terminated prior to the time when the most severe loadings due to a LOCA occur.

The steam supply to the SCM subsystem automatically isolates via a LOCA signal to two, in series, independent and redundant safety grade, air actuated valves. These valves fail close when the LOCA signal vents off the air to the valve actuator. During startup testing, the closure times of the valves were measured and indicated a closure time of less than 15 sec. Based on our review of our GKM II-M data base (see Section 9.0 of the SSES DAR), the high amplitude chugging and lateral tip loads at the downcomer exit occur more than 15 sec after the break. (As will be shown later, for the submerged structures, the lateral tip load and chugging submerged structure drag load generate the highest stresses.) At this time, the SCM isolation valves will have terminated the steam flow to the RHR SRV.

In addition, post-LOCA SCM operation will normally not occur, unless all other safety-grade ECCS systems are not available for removing heat from the reactor. Under these conditions, multiple failures will have occurred in the ECCS systems, and as such, this event goes beyond the SSES design basis. Thus, the RHR SRV loads will not be combined with post-LOCA hydrodynamic loads.

For the same reasoning, the SRV ADS case need not be combined with the RHR SRV load, since the SCM isolation valves will close during the two-minute delay caused by the ADS timer prior to the initiation of ADS.

The MSRV load results from the SCM's inability to remove all the decay heat from the reactor immediately after shutdown. If the SCM operates immediately after shutdown, the low setpoint MSRVs will cycle to remove the excess decay heat until some time after shutdown when the SCM alone is sufficient to remove all the reactor decay heat. We assume actuation of the RHR SRV occurs during this time period.

For SSES, the two lowest setpoint MSRVs (1078 psig setpressure) discharge through quenchers E & B located approximately 67' and 56.5', respectively, from the previously described submerged structures adjacent to the RHR SRV discharge. Thus, from this distance, we expect that the submerged structure load on the downcomer and bracing nearest the RHR SRV discharge to be negligible. Since these submerged structures experience negligible loading from MSRV inertial loading (see Tables 3.1 and 3.2), we expect negligible loading on the critical downcomer and downcomer bracing due to cycling of the low setpoint MSRVs.

In addition, the suction load on the liner plate near the RHR SRV discharge due to the cycling of the low setpoint MSRV will be much less

than the design basis suction load. The quenchers E & B are located at azimuth angles 45° and 300°, respectively, compared to an azimuth angle of 180° for the liner plate adjacent to the RHR SRV discharge. Based on the one valve MSRV load documented in Subsection 4.1.3.2.1 of the DAR, the peak underpressure decreases as you move azimuthally away from the quenchers. Based on the azimuth pressure distribution for the one valve case (see DAR Figure 4-26), the underpressures caused by a firing of either quenchers E or B (angles 45° and 300°) decrease to 0.2 of the maximum underpressure at the quencher locations at the 180° azimuth angle location for the RHR SRV discharge. Thus, the suction pressure due to quenchers E and B firing result in lower loads at the liner plate adjacent to the RHR SRV discharge.

Based on the above, the loads due to the actuation of the low setpoint MSRVs result in negligible increase in the submerged structure load and liner plate suction pressure, when combined with the RHR SRV + SSE loads.

We combine the SSE loads based on previous design criteria.

The only submerged structures close to the RHR SRV discharge are the neighboring downcomer and associated bracing and the liner plate. Our current design margins for these submerged structures to be combined with the RHR SRV loads are as follows:

Downcomer

Table 3.1 provides the stress components in % of the total stress for the various loads, and the stress margin for the combination of SSE + SRV (ADS) + LOCA. As indicated, the stress margin is 53%, with SSE and LOCA lateral tip load contributing the most stresses. The SSE consists mostly of the submerged structure load due to seismic slosh (see Subsection 4.2.4.7 of the DAR). The inertial loads for all three dynamic loads are minimal, since disconnecting the downcomer bracing from the containment and pedestal wall eliminated the inertial loading from these sources. Table 3.1 indicates that by removing the LOCA load the stress margin increases to 71%. If we further remove the SRV (ADS) stresses, and assume a negligible submerged structure load on this downcomer due to the low setpoint MSRV cycling, then the stress margin increases to 82%.

TABLE 3.1

DOWNCOMER STRESSES AND STRESS

MARGIN FOR WORST-CASE

DOWNCOMER ADJACENT TO RHR

SRV DISCHARGE

Downcomer Bending Stress = 21 ksi

Allowable Stress = 45 ksi

Stress Margin = 1 - 21/45 = 53%

Seismic Contribution	=	38%	
SRV (Building Inertia)	=	0%	(Negligible)
SRV (Submerged Structure)	=	24%	
LOCA (Building Inertia)	=	3%	
LOCA (Submerged Structure)	=	9%	
LOCA (Tip Load)	=	26%	
		100%	

TABLE 3.2

DOWNCOMER BRACING STRESSES

AND STRESS MARGIN FOR

WORST-CASE BRACING ADJACENT

TO RHR SRV DISCHARGE

Bracing Member Combined Stress	=	1.6 ksi
Allowable Stress	=	20 ksi

Stress Margin = 1 - 1.6/45 = 92%

Seismic Contribution	=	0%	(Negligible)
SRV (Building Inertia)	=	0%	(Negligible)
SRV (Submerged Structure)	=	2%	
LOCA (Building Inertia)	=	0%	(Negligible)
LOCA (Submerged Structure)	=	60%	
LOCA (Tip Load)	=	38%	
		100%	

Bracing

Table 3.2 also provides the stress margin and % contribution to the total stress for each load for the most highly stressed bracing member adjacent to the RHR SRV discharge. This table indicates the stress margin to be 92%, with all loads except LOCA resulting in negligible stresses. Eliminating all loads, except seismic, as before, increases the stress margin to 100%.

Liner Plate

The worst-case suction load occurs during non-LOCA conditions, since a LOCA results in a pressurized wetwell airspace. This net positive pressure occurs statically and exceeds the sum of all dynamic suction loads caused by SRV(ADS) + LOCA chugging. For non-LOCA conditions, the liner plate was evaluated for the hydrostatic + SRV(ALL). But, when considering the suction loads on the liner plate due to RHR SRV discharge, the SRV(ALL) mechanistically need not be combined. As described above, cycling of the low setpressure SRVs results in a much lower suction load to be combined with the RHR SRV suction load.

Based on the above, much conservatism exists in the submerged structures adjacent to the RHR SRV discharge. Our preliminary evaluation of the various RHR SRV discharge loads when considering the above design margins is provided below.

The RHR SRV discharge phenomena causes several concerns as follows:

- water jet load during vent clearing
- air bubble loads during vent clearing
- steam condensation loads
- potential high amplitude steam condensation loads originating from high water temperature in the vicinity of the RHR SRV discharge.

Water Jet Load

There are no submerged structures in the vicinity beneath the RHR SRV discharge. Therefore, loads resulting from a column of water being ejected from the discharge line are not a concern.

Air Bubble Loads

Loads on the worst-case adjacent submerged structures and liner plate (see Tables 3.1 and 3.2) due to the RHR SRV air bubble load are considered to be bounded by those produced by the MSRV load used for design. This is based on comparing the parameters of the RHR SRV discharge to those of the MSRVs:

- The RHR discharge line volume is smaller than the MSRV discharge, therefore, the air bubble and its resultant energy would be smaller.

- The RHR SRV opens more slowly than the MSRV, decreasing the air bubble loading.

- As previously explained, the mass flux through the RHR SRV discharge line will be much less than the theoretical maximum steam flux based on the rated flow through the RHR SRV. This results in a lower bubble pressure relative to the MSRV load.

- The RHR SRV discharge line submergence is approximately 6' at high normal water level, as compared to a T-quencher submergence of 20.5' for high normal water level. This results in a reduced vent clearing pressure relative to the MSRV load.

In addition, as previously described, the submerged structures and liner plate contain sufficient design margin to accommodate any increase in the stresses due to RHR SRV discharge. Specifically, for the bracing and downcomer the RHR SRV bubble load must exceed the stresses due to SRV(ADS) + LOCA + DESIGN MARGIN to result in an overstressed condition. Similarly, for non-accident conditions, the RHR SRV suction load must exceed the hydrostatic pressure and the liner plate allowable stress, if we assume the suction load due to cycling of the low setpressure MSRV to be negligible.

Steam Condensation Loads

The steam flow through the RHR SRV results in steam condensation loads at the discharge pipe. Again, the steam mass flux through the RHR SRV for either failure mode will be much less than the steady-state steam mass flux based on the rated flow of the RHR SRV. Our preliminary analysis indicated that the expected steam mass flux and associated steam condensation loads resulted in stresses within the code allowables.

As with the air clearing load, significant design margin exists in the submerged structures and liner plate, which we believe exceeds the RHR SRV steam condensation load when combined with the appropriate loads.

High Pool Temperature Effects

Experimental data has shown that steam discharge into water that is at a very high local temperature can produce comparatively large loads. Based on our preliminary estimates of RHR SRV steam flux, an RHR SRV discharge event will not enter into such a regime, since it is considered that the steam flow will be terminated prior to significant local heatup in the area of the discharge. As previously described, the operator has several indications from which to determine whether an uncontrolled discharge of steam through the RHR SRV exists. We assume he detects and isolates the

SCM at 10 minutes after the failure that occurs which leads to the RHR SRV discharge.

Based on the above, we believe the water jet, air clearing, and steam condensation loads on the submerged structures and liner plate due to RHR SRV discharge, when combined with the appropriate loads, are within the SSES design basis.

III. Future Action Required

1. Calculate the loads on the submerged structures and liner plate due to the RHR SRV air clearing phenomena when combined with the appropriate loads. Compare these stresses to the code allowables.

2. Confirm our preliminary analysis that the RHR SRV steam condensation loads result in acceptable stresses on the liner plate and adjacent submerged structures.

3. Perform pool heatup calculation due to RHR SRV discharge to verify that the local temperature near the RHR SRV discharge remains below the transition temperature for unstable steam condensation phenomena.

4. Document above to the NRC by March 31, 1983.

I. Issue

3.2 The STRIDE design provided only nine inches of submergence above the RHR relief valve discharge lines at low suppression pool levels.

II. Assessment/Response

Interpreting this as a concern of direct steam discharge to wetwell environment, for SSES the RHR line is submerged 3.5' below the LNWL, hence this is of no concern to SSES.

III. Future Action Required

None

I. Issue

3.3 Discharge from the RHR relief valves may produce air bubble discharge or other submerged structure loads on equipment in the suppression pool.

II. Assessment/Response

See response to 3.1.

III. Future Action Required

See response to 3.1.

I. Issue

3.4 The RHR heat exchanger relief valve discharge lines are provided with vacuum breakers to prevent negative pressure in the lines when discharging steam is condensed in the pool. If the valves experience repeated actuation, the vacuum breaker sizing may not be adequate to prevent drawing slugs of water back through the discharge piping. These slugs of water may apply impact loads to the relief valve or be discharged back into the pool at the next relief valve actuation and apply impact loads to submerged structures.

II. Assessment/Response

SSES has performed a reflood analysis to calculate the maximum height of reflood (i.e., water slug) and consequential impact loads on the RHR SRV discharge piping following subsequent actuations of the RHR steam relief valve. Hydrodynamic loads on suppression pool submerged structures are described in the response to 3.1.

This analysis shows that the reflood does not reach the vacuum breaker (VRV) or the RHR SRV. Therefore, an impact load on the VRV or SRV due to a water slug does not occur, and the VRV sizing is shown to be adequate.

II. Future Action Required

None

I. Issue

3.5 The RHR relief valves must be capable of correctly functioning following an upper pool dump which may increase the suppression pool level as much as 5 ft creating higher back pressure on the relief valves.

II. Assessment/Response

The NRC dispositioned this concern as N/A for SSES.

III. Future Action Required

None

I. Issue

3.6 If the RHR heat exchanger relief valves discharge steam to the upper levels of the suppression pool following a design basis accident, they will significantly aggravate suppression pool temperature stratification.

II. Assessment/Response

Steam condensing is not a safety mode of RHR and is not used post-accident. It may be used during normal reactor shutdown mode for hot standby or vessel depressurization operations. The mode operates by drawing steam from the HPCI steam supply line, condensing in the RHR heat exchanger, and returning the condensate to the vessel via the RCIC pump. The relief valves discharge 3.5' below the pool surface (rather than 9" as in the Mark III design). If the RHR system was in this mode when a LOCA (while shutdown) occurred, the redundant, in series, safety-grade steam supply valves will automatically close (see response to 3.1).

In other safety-related modes of operation, the RHR system pressure is, at all times, lower than the relief valve setpoint. However, a single active failure (open) of the relief valve could be postulated while the RHR System is operating post-LOCA. If the system was in the LPCI, suppression pool cooling, or containment spray modes, the water source is the suppression pool; therefore, no temperature stratification could occur. The shutdown cooling mode (which could be in operation after an SBA) is interlocked from operation until vessel pressure is below 98 psig. In this case the reactor has already been depressurized and the pool has, therefore, already performed its pressure suppression safety function so that any presumed temperature stratification effects would be of no consequence.

Finally, the response to 4.4 indicated that thermal stratification poses no problems for equipment located in the wetwell airspace, since they were qualified to drywell conditions.

III. Future Action Required

None

I. Issue

3.7 The concerns related to the RHR heat exchanger relief valve discharge lines should also be addressed for all other ECCS relief lines that exhaust into pool (p. 132 of 5/27/82 transcript).

II. Assessment/Response

There are no other ECCS relief lines that discharge to the suppression pool other than small thermal reliefs.

III. Future Action Required

None

I. Issue

4. Suppression Pool Temperature Stratification

4.1 The present containment response analyses for drywell break accidents assume that the ECCS systems transfer a significant quantity of water from the suppression pool to the lower regions of the drywell through the break. This results in a pool in the drywell which is essentially isolated from the suppression pool at a temperature of approximately 135°F. The containment response analysis assumes that the drywell pool is thoroughly mixed with the suppression pool. If the inventory in the drywell is assumed to be isolated and the remainder of the heat is discharged to the suppression pool, an increase in bulk pool temperature of 10°F may occur.

Footnote 1: This concern is related to the trapping of water in the drywell.

II. Assessment/Response

For SSES, the amount of water "trapped" in the drywell is limited to the 18" vent risers in the drywell. This represents a much smaller proportion of the suppression pool water mass than for a Mark III containment design. This concern potentially affects the two containment analyses used for licensing SSES:

- The containment analysis documented in Section 6.2 of the FSAR.
- The Mass & Energy analysis documented in Appendix I of the SSES Design Assessment Report (DAR).

Our review of the containment analysis documented in Section 6.2 of the FSAR indicated that trapping of the suppression pool water in the drywell was not considered. However, we believe the conservatisms in the containment analysis exceed the potential non-conservatism due to the above concern, based on the following:

- The analysis neglected both the steam condensation on the drywell structures, as well as the heat transfer from suppression pool to the containment walls.
- The analysis assumed a service water temperature of 95°F for the entire transient. The Technical Specifications limit the initial service water temperatures to 88°F. In addition, as explained in the response to 4.6, our service water spray pond analysis indicates that the worst-case service water temperature never exceeds 92.25°F with one unit in LOCA condition and the other unit in forced shutdown.

- Finally, the decay heat curve assumed in the analysis was very conservative. The more recent curves provide for a lower integrated decay heat for the analysis.

The Mass & Energy analysis documented in Appendix I of the SSES DAR was completed to verify that the scenarios (i.e., stuck open relief valve, isolation/scram, and small break accident) which lead to abnormally high suppression pool temperature, coincident with main steam SRV actuation and steam flow through the T-quencher, would not result in a suppression pool temperature response which exceeds the maximum pool temperature of 207°F stipulated by the NRC for safe T-quencher operation. Of these scenarios, only the SBA cases result in a breach of the reactor pressure vessel, with the potential for trapping suppression pool water on the drywell floor. The SBA case did not consider the effects of a reduction in the suppression pool water due to drywell trapping. Our assessment of this concern is provided below.

Table I-2 of the DAR indicated a maximum calculated suppression pool temperature of 193°F for the SBA Case 3.a. Thus, there exists a margin of 207 - 193 = 14°F for this case.

As with the Section 6.2 analysis, the original Mass & Energy analysis contained numerous conservatisms as described below:

- The analysis neglected the water mass within the pedestal. This water is approximately 5.7% of the water mass used in the analysis.

- The analysis took no credit for energy absorbed by the containment structure.

- Again, the analysis assumed a service water temperature of 95°F.

For both scenarios, the calculated pool temperature considering the water trapped in the drywell would not increase by the same percent decrease in pool water lost to the drywell (i.e., 1% decrease in pool mass equals 1% increase in pool temperature). That is, the water trapped in the drywell would absorb some energy from the reactor system.

Based on the above, we believe this issue poses no concerns for SSES.

III. Future Action Required

None

I. Issue

4.2 The existence of the drywell pool is predicated upon continuous operation of the ECCS. The current emergency procedure guidelines require the operations to throttle ECCS operation to maintain vessel level below level 8. Consequently, the drywell pool may never be formed.

Footnote 2: This issue applies only to those facilities for which EPGs are in effect.

II. Assessment/Response

The SSES containment response analysis does not depend on the formation of a "drywell pool." As described in the response to 4.1, the water trapped in the drywell is limited to the 18" tall vent risers. If the drywell pool is not formed, as postulated herewith, then the actual pool temperature response would be consistent with the containment analysis documented in Section 6.2 of the FSAR, and the Mass & Energy analysis documented in Appendix I of the DAR.

III. Future Action Required

None

I. Issue

4.3 All Mark III analyses presently assume a perfectly mixed uniform suppression pool. These analyses assume that the temperature of the suction to the RHR heat exchangers is the same as the bulk pool temperature. In actuality, the temperature in the lower part of the pool where the suction is located will be as much as 7-1/2°F cooler than the bulk pool temperature. Thus, the heat-transfer through the RHR heat exchanger will be less than expected.

II. Assessment/Response

As shown in FSAR Figure 5.4-4b, the RHR pump suction penetrates the SSES containment at El. 10' above the basemat, and then T's vertically with suction taken at each end of the T approximately 8' and 12' above the basemat. This elevation corresponds to the mid-plane of the pool and, therefore, we expect the RHR pump suction temperature to be at least the bulk pool temperature. As a result, this concern does not apply to the SSES design.

III. Future Action Required

None

I. Issue

4.4 The long-term analysis of containment pressure/temperature response assumes that the wetwell airspace is in thermal equilibrium with the suppression pool water at all times. The calculated bulk pool temperature is used to determine the airspace temperature. If pool thermal stratification were considered, the surface temperature, which is in direct contact with the airspace, would be higher. Therefore, the airspace temperature (and pressure) would be higher.

II. Assessment/Response

In contrast to a Mark III containment design, the SSES peak pressure response to a DBA occurs at approximately 15 sec after the accident begins (see FSAR Figure 6.2-2 and Table 6.2-5). Therefore, potential pool thermal stratification will have no effect on the short term containment pressure response.

This concern also may increase the wetwell airspace temperature response. For SSES, this poses no concerns, since all equipment located in the airspace has been qualified to the drywell temperature profile (maximum temperature equal to 340°F) which envelopes any potential increases in the surface pool temperature.

III. Future Action Required

None

I. Issue

4.5 A number of factors may aggravate suppression pool thermal stratification. The chugging produced through the first row of horizontal vents will not produce any mixing from the suppression pool layers below the vent row. An upper pool dump may contribute to additional suppression pool temperature stratification. The large volume of water from the upper pool further submerges RHR heat exchanger effluent discharge which will decrease mixing of the hotter, upper regions of the pool. Finally, operation of the containment spray eliminates the heat exchanger effluent discharge jet which contributes to mixing.

Footnote 3: For Mark I and II facilities, confine your response on this issue to those concerns which can lead to pool stratification (e.g., operation of the containment spray).

II. Assessment/Response

In SSES, the containment spray falls to the diaphragm floor, flows through the downcomers and exits at the mid-plane of the pool, approximately 12' above the basemat. Thus, we believe containment spray will not aggravate any pool stratification. In addition, as described in the response to 4.4, any pool thermal stratification has no effect on the SSES containment design.

III. Future Action Required

None

I. Issue

4.6 The initial suppression pool temperature is assumed to be 95°F while the maximum expected service water temperature is 90°F for all GGNS accident analyses as noted in FSAR Table 6.2-50. If the service water temperature is consistently higher than expected, as occurred at Kuosheng, the RHR system may be required to operate nearly continuously in order to maintain suppression pool temperature at or below the maximum permissible value.

II. Assessment/Response

As stated, this issue appears to be an operational concern and is not related to the safe operation of the plant since continuous, frequent operation of the RHR and service water systems does not affect the safe operation of the plant.

The initial suppression pool temperature is assumed to be at 90°F for SSES accident analysis. RHR SW is used to cool the suppression pool which takes suction from the spray pond. The spray pond has an area of 8 acres and a depth of 10-1/2 ft with a maximum design temperature of 88°F (FSAR Tables 9.2-27 & 9.2-23). This temperature is based on a very conservative analysis of site meteorology and assumes that all the water in the spray pond will reach the worst ambient temperature without considering the effects of temperature stratification in the pond. Our spray pond analysis shows that even for the long-term post-accident condition with one unit in the LOCA condition and the other unit at forced shutdown, the maximum pond temperature is only 92.25°F (FSAR Table 9.2-12) for the minimum Heat Transfer case.

We do not expect the bulk temperature of spray pond to exceed 88°F. The Technical Specifications require that the plant be in shutdown condition if the average pond temperatures exceed 88°F. In addition, the Technical Specifications require a suppression pool temperature below 90°F (except during testing which adds heat to the pool). If the pool temperature exceeds 90°F, the Technical Specifications direct the operator to restore the temperature to less than or equal to 90°F within 24 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. Thus, if the SW and RHR systems fail to maintain the pool temperature below 90°F during hot weather, then the plant will be brought to an orderly shutdown, and this concern becomes an operational problem.

III. Future Action Required

None

I. Issue

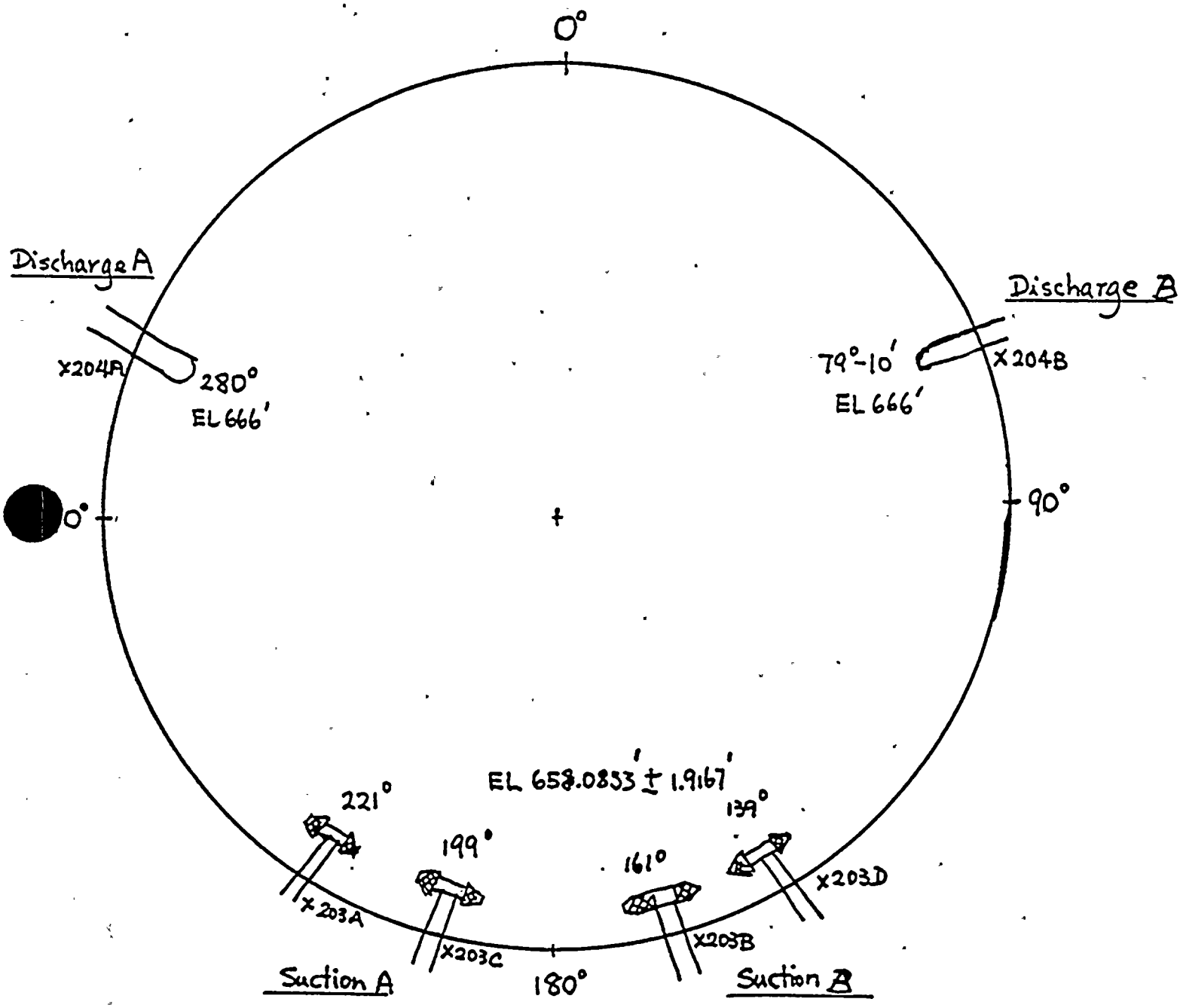
4.7 All analysis completed for the Mark III are generic in nature and do not consider plant specific interactions of the RHR suppression pool suction and discharge.

II. Assessment/Response

The sketch on the next page shows the relative positions of RHR suction and discharge. This configuration eliminates any concern with the discharge effluent short circuiting the pool and assures adequate pool mixing.

III. Future Action Required

None



Detail of suction, see next page

Basemat elevation 648'

Discharge : 18' above basemat, Suction : {12' / 8.1667'} above basemat

Sketch Showing Relative Positions of RHR Discharge & Suction

CALCULATION SHEET

CALC. NO. ____ REV. NO. ____

CHECKED ____ DATE ____

JOB NO. ____

SHEET NO. ____

DATE ____

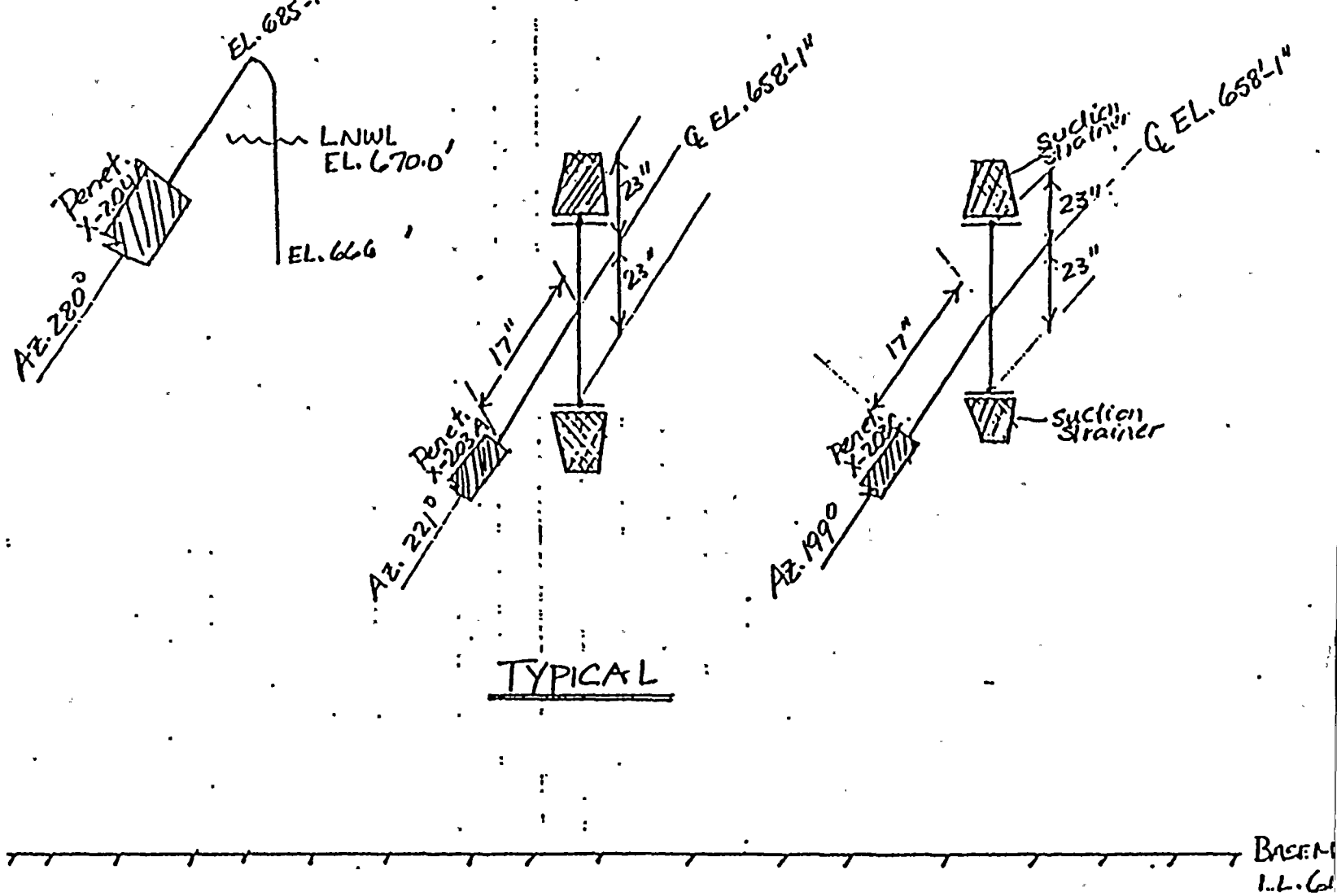
ORIGINATOR ____

PROJECT ____

SUBJECT ____

ISSUE 4.10

RHR Suction lines through Penetrations X-203A & X-203C Serve the discharge line through Penetration X-204A.



NOTE RHR Suction lines through penetrations X-203B & X 203D Serve the discharge line through Penetration X-204B. The above geometry is typical.

Az. X-203B 161° } Suction
X-203D 139° } Suction
[illegible] Discharge

References:
Dwgs: M-26-1 Rev. 6 HBD-[illegible]
HBB-110-1 Rev. 9 Rev. [illegible]
HBB-110-2 Rev. 4 Rev. [illegible]

I. Issue

4.8 Operation of the RHR System in the containment spray mode will decrease the heat transfer coefficient through the RHR heat exchangers due to decreased system flow. The FSAR analysis assumes a constant heat transfer rate from the suppression pool even with operation of the containment spray.

II. Assessment/Response

This issue is interpreted as being concerned with the potential for increased bulk pool temperature and corresponding wetwell airspace pressure and temperature.

As discussed in the response to 4.4, the peak containment pressure is governed by the short-term DBA LOCA response, and not by the long-term response. Also, as discussed in the response to 4.4, the only concern related to increased suppression pool/wetwell airspace temperatures has to do with environmental qualification. Since equipment in the wetwell has been qualified to drywell temperature conditions, which bounds the wetwell conditions, any presumed decrease in heat removal rate from the suppression pool is not of concern.

Nevertheless, it can be demonstrated that the operation of containment sprays would have negligible effect on peak bulk suppression pool temperature. As opposed to the standard Mark II design where containment spray and suppression pool flow rates are identical, SSES has a smaller (9000 gpm) containment spray rate than suppression pool cooling flow rate (10,000 gpm). However, as shown in FSAR Table 6.2-6, the worst-case suppression pool peak temperature occurs when no containment spray is assumed (Case "D"), i.e., the RHR system is always in the suppression pool cooling mode.

Although the values in FSAR Table 6.2-6 were calculated prior to the modification that resulted in the decreased containment spray rate, it can be seen that a nominal change in spray flow rate has little effect on peak pool temperature. Comparing Case "B" to Case "C" (all spray cases) where spray flow rate is decreased by 5000 gpm, it is seen that the pool temperature increases by only 3.1°F. A decrease from 10,000 gpm to 9000 gpm, then, would lead to an insignificant change in pool temperature, and would clearly be bounded by the peak (no spray, Case "D") temperature of 208.2°F.

III. Future Action Required

None

I. Issue

4.9 The effect on the long-term containment response and the operability of the spray system due to cycling the containment sprays on and off to maximize pool cooling needs to be addressed. Also provide and justify the criteria used by the operator for switching from the containment spray mode to pool cooling mode, and back again (pp. 147-148 of 5/27/82 transcript).

II. Assessment/Response

Our assessment of the above concern is provided below:

1. Containment Pressure Response

As discussed in 4.4, the peak pressure response to a DBA occurs during the short-term blowdown. For the long-term pressure response, the response to 4.8 indicated that SSES analyzed for both the all spray and no spray cases. Both cases were acceptable. These cases envelop the containment response due to cycling the containment sprays on and off as postulated above.

2. Suppression Pool Temperature Response

For SSES, the cycling of the containment sprays to maximize pool cooling is not required. Again, as discussed under 4.8, both the all spray and no spray cases were evaluated. FSAR Figure 6.2-8 indicates that either case results in an acceptable pool temperature response. Thus, these two cases envelope the pool temperature response to any potential cycling from pool cooling to the sprays.

In addition, emergency procedure EO-00-023, "Containment Control," provides the criteria for operation of the spray mode or pool cooling mode of the RHR system. The procedure was prepared from the emergency procedure guidelines developed by the BWR Owners and GE.

This procedure requires initiation of pool cooling when the suppression pool temperature exceeds 90°F, and is the preferred mode for containment heat removal. However, the procedure requires initiation of the drywell and suppression pool sprays, if the containment temperature and pressure exceed predetermined values.

For SSES, before the drywell temperature reaches 340°F, but after drywell temperature reaches 320°F, the procedure directs the operator to initiate the drywell sprays.

The procedure directs the operator to initiate wetwell spray within 30 minutes of reaching 30 psig drywell pressure. This action is required to be consistent with the SSES-unique steam bypass analysis.

In addition, the procedure directs the operator to initiate suppression pool spray, if the suppression pool chamber pressure approaches the Suppression Pool Spray Limit (see figure next page). Furthermore, the procedure directs the operator to initiate drywell sprays, if the suppression chamber pressure approaches the Pressure Suppression Limit (see figure next page).

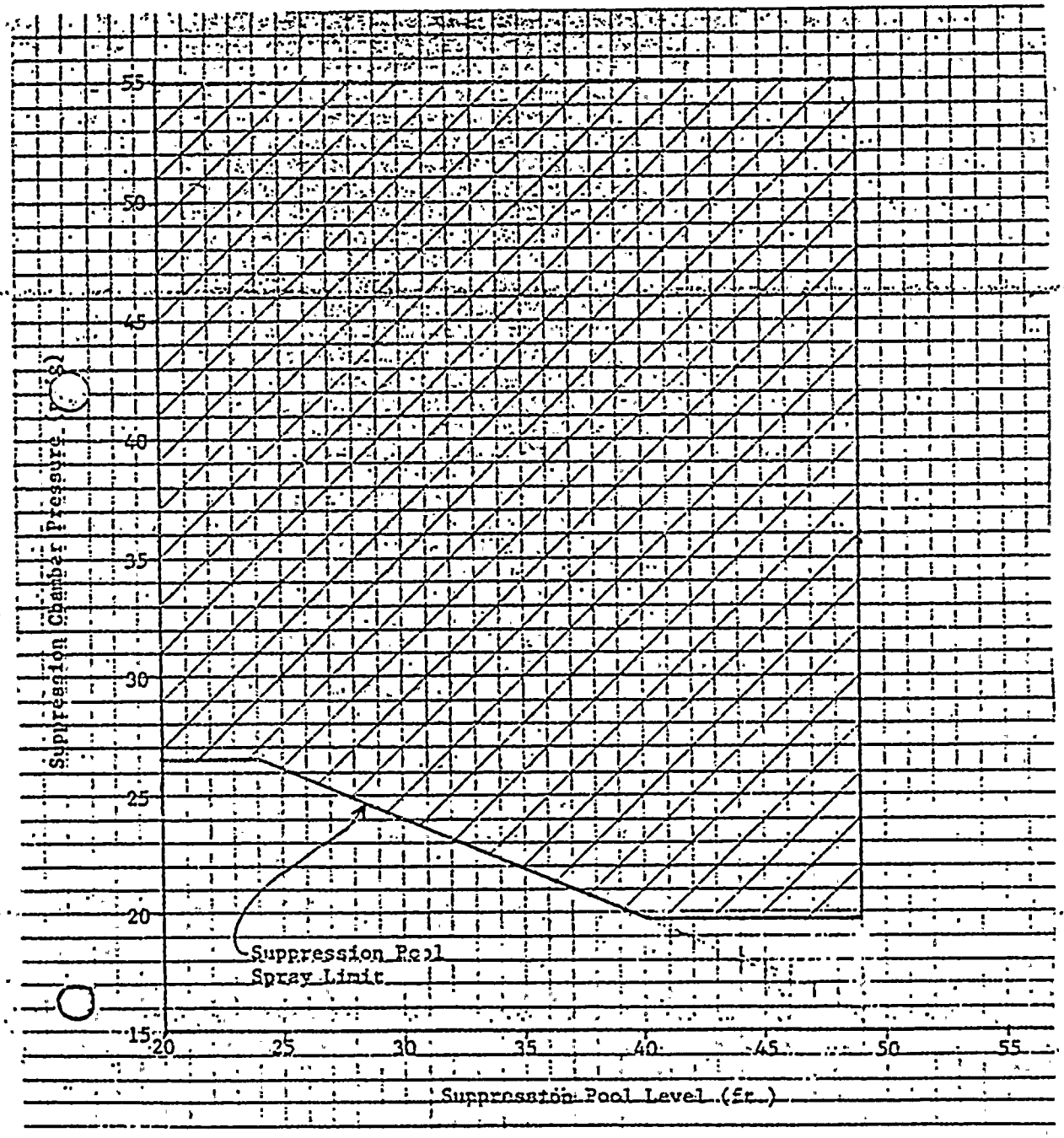
The Suppression Pool Spray Limit insures suppression pool spray before reaching 50% of the suppression chamber design pressure. The Pressure Suppression Limit insures drywell spray initiation before suppression chamber pressure indicates that pressure suppression has become ineffective.

To accommodate any required cycling of the containment sprays, the RHR system and piping have been designed for approximately 7,000 thermal cycles.

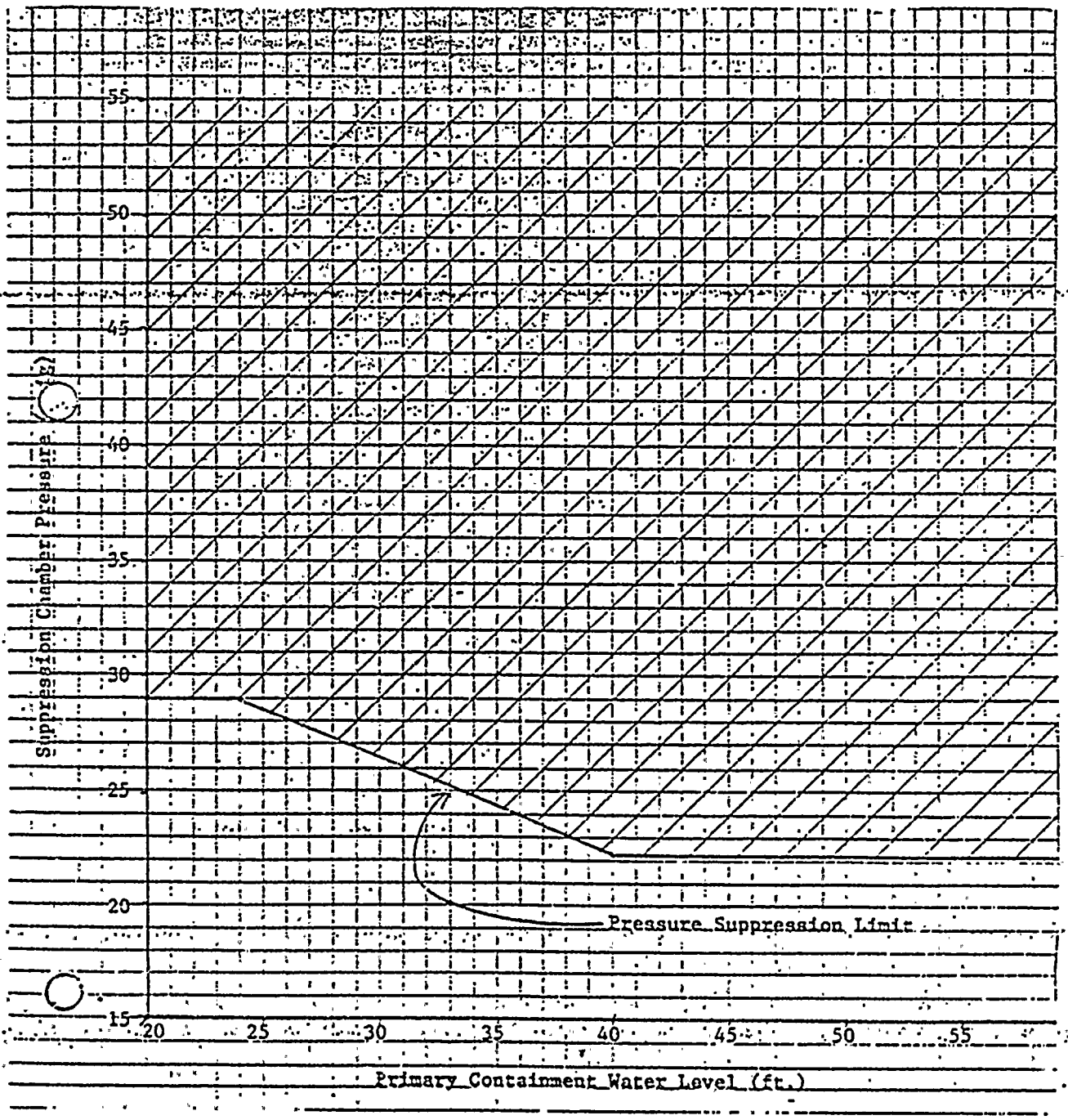
III. Future Action Required

None

SUPPRESSION POOL SPRAY LIMIT



PRESSURE SUPPRESSION LIMIT



I. Issue

4.10 Justify that the current arrangement of the discharge and suction points of the pool cooling system maximizes pool mixing.

II. Assessment/Response

The figures attached to the response to 4.7 show the relative positions of the RHR suction and discharge. These figures indicate the RHR design will provide adequate pool mixing.

III. Future Action Required

None

I. Issue

5. Drywell to Containment Bypass Leakage

5.1 The worst-case of drywell to containment bypass leakage has been established as a small break accident. An intermediate break accident will actually produce the most significant drywell to containment leakage prior to initiation of containment sprays.

II. Assessment/Response

As required by Section 6.2.1.1.c of the Standard Review Plan, PP&L completed a steam bypass calculation for a postulated steam bypass area of $A/\sqrt{K}$ equal to 0.0535 ft^2 for SBA conditions. PLA-923 dated September 3, 1981, transmitted to you the results of these calculations. The SBA conditions provided a conservative analysis based on the following:

- The analysis maximized the drywell-to-wetwell ΔP, which drives the steam into the wetwell airspace. From 11 sec after the break occurs, it assumed that pure steam at a drywell-to-wetwell ΔP equal to the vent submergence was available for steam bypass.

- The analysis also maximized the time period over which the steam bypass occurred. It assumed that no vessel depressurization occurred, and that the drywell-to-wetwell ΔP equal to the submergence existed for the entire steam bypass calculation.

The analysis indicated that sufficient time exists for the containment pressure to go from 30 psig to the design pressure of 53 psig for the operator to manually initiate the containment spray. Once initiated, the spray heat removal rate is sufficient to terminate the containment pressure increase.

Furthermore, Supplement No. 3 to the SSES Safety Evaluation Report documented your review and acceptance of the above analysis.

III. Future Action Required

None

I. Issue

5.2 Under Technical Specification limits, bypass leakage corresponding to $A/\sqrt{K} = 0.1\ ft^2$ constitutes acceptable operating conditions. Smaller-than-IBA-sized breaks can maintain break flow into the drywell for long-time periods, however, because the RPV would be depressurized over a 6-hour period. Given, for example, an SBA with $A/\sqrt{K} = 0.1$, projected time period for containment pressure to reach 15 psig is 2 hours. In the latter 4 hours of the depressurization the containment would presumably experience ever-increasing overpressurization.

Footnote 4: For Mark I and II facilities, refer to Appendix I to Section 6.2.1.1.c of the Standard Review Plan (SRP).

II. Assessment/Response

As described in the response to 5.1, PP&L performed a SSES unique steam bypass calculation per the requirements of Appendix I to Section 6.2.1.1.c of the SRP. These calculations assumed no vessel depressurization and a drywell-to-wetwell ΔP equal to the submergence for the duration of the transient. This analysis, as any steam bypass calculation would, showed that the "containment would presumably experience ever-increasing overpressurization," if no containment spray initiation occurred. However, when the operator initiates the containment sprays, the pressure increase terminates. The subject analysis showed that sufficient time exists for the operator to initiate the containment sprays, while the containment pressure increases from 30 psig to the design pressure of 53 psig.

III. Future Action Required

None

I. Issue

5.3 Leakage from the drywell to containment will increase the temperature and pressure in the containment. The operators will have to use the containment spray in order to maintain containment temperature and pressure control. Given the decreased effectiveness of the RHR system in accomplishing this objective in the containment spray mode, the bypass leakage may increase the cyclical duty of the containment sprays.

II. Assessment/Response

The responses to 4.8 and 4.9 discussed the effects on the long-term containment analysis of cycling the RHR system between the spray and pooling modes. As noted there, the SSES containment design can accommodate either all or no sprays with no adverse effects on the long-term containment transients. These cases envelope the containment response with cycling of the containment sprays.

Furthermore, if steam bypass requires cycling between the sprays and pool cooling, the system design will not suffer, since the sprays were designed for up to 7000 thermal cycles.

III. Future Action Required

None

I. Issue

5.4 Direct leakage from the drywell to the containment may dissipate hydrogen outside the region where the hydrogen recombiners take suction. The anticipated leakage exceeds the capacity of the drywell purge compressors. This could lead to pocketing of hydrogen which exceeds the concentration limit of 4% by volume.

Footnote 5: This concern applies to those facilities at which hydrogen recombiners can be used.

II. Assessment/Response

In SSES, two hydrogen recombiners are located in the drywell and two in the wetwell airspace. For an inerted containment such as SSES, the pertinent concentration limit is 5% oxygen. While operating the drywell recombiners, drywell mixing is provided by operating the safety-related drywell fans. For the wetwell airspace, pocketing of hydrogen is not expected, since the airspace is a large, unpartitioned, open volume. However, mixing in the wetwell can be accomplished by operation of the wetwell sprays.

III. Future Action Required

None

I. Issue

5.5 Equipment may be exposed to local conditions which exceed the environmental qualification envelope as a result of direct drywell to containment bypass leakage.

II. Assessment/Response

As explained in the response to 4.4, all equipment located in the wetwell airspace has been qualified to drywell conditions, which envelope any concerns due to drywell-to-wetwell bypass leakage.

III. Future Action Required

None

I. Issue

5.6 and 5.7

II. Assessment/Response

Dispositioned by the NRC as not applicable for Mark II.

III. Future Action Required

None

I. Issue

5.8 The possibility of high temperatures in the drywell without reaching the 2 psig high pressure scram level because of bypass leakage through the drywell wall should be addressed (pp. 168-174 of 5/27/78 transcript).

II. Assessment/Response

The drywell design temperature is governed by a small reactor steam break. The FSAR SBA analysis (see Section 6.2.1) demonstrates it takes about 6 hours to cease reactor blowdown following an SBA which is accomplished by an orderly reactor shutdown with a cooldown rate limited to 100°F per hour. During this blowdown period, steam entering the drywell is in a superheated condition due to constant enthalpy depressurization of high pressure saturated steam. The drywell design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum superheated steam temperature. This temperature is then assumed to exist for the entire six-hour period. The resultant maximum superheated steam temperature is 340°F corresponding to the primary system pressure of approximately 450 psia and an assumed maximum drywell pressure of 35 psig. This 340°F is therefore chosen as the drywell design temperature.

Considering a postulated small break without initiating automatic high drywell pressure scram because of bypass leakage, it would not be possible to exceed the current design temperature for the following reasons:

1. The SSES Technical Specifications limit of drywell pressure is -1 psig to +2 psig. The scram setpoint is 1.72 psig. The post-SBA short-term transient without initiating scram at 1.72 psig drywell pressure is only possible for a case of "smaller-than-small-break -size" in which steam is weeping into the drywell and driving non-condensables into wetwell through the potential leakage paths. Due to this bypass leakage effect following a smaller-than-small-break, an automatic drywell pressure scram could be delayed for the time needed to slowly pressurize the drywell to the 1.72 psig scram level. The reactor steam entering the drywell prior to the initiation of scram is in the superheated condition which is less than 340°F predicted in FSAR analysis. (For example, as noted in FSAR Section 6.2.1, decompression of 1000 psia saturated steam into atmosphere will result in 298°F superheated steam.) Therefore, the drywell temperature could not exceed the current design temperature.

2. Any significant temperature excursion that could result from such a postulated event will be prevented by operator action. The operator is required by the Technical Specifications to maintain the drywell airspace temperature below 135°F. If the temperature rises and exceeds 135°F, emergency operating procedure EO-00-023, "Containment Control," requires the operator to start all available drywell

coolers. If the drywell coolers are unable to reduce the temperature, the emergency operating procedures require initiating the containment sprays for a containment temperature between 320 and 340°F.

3. Finally, there will be no significant delay of scram, since relatively small bypass leakage capacity exists in a Mark II design. Thus, the containment pressure will reach 1.72 psig in a short time period.

III. Future Action Required

None

I. Issue

6.1 We understand that GE has recommended for Mark III containments that the combustible gas control systems be activated if the reactor vessel water level drops to within one foot of the top of the active fuel. Indicate what your facility is doing in regard to this recommendation.

II. Assessment/Response

This is not applicable to SSES. No such action is required, since the SSES containment is inerted and short-term H_2 control is not required.

III. Future Action Required

None

I. Issue

6.2 General Electric has recommended that an interlock be provided to require containment spray prior to starting the recombiners because of the large quantities of heat input to the containment. Incorrect implementation of this interlock could result in an inability to operate the recombiners without containment spray.

Footnote 5: This concern applies to those facilities at which recombiners can be used.

II. Assessment/Response

There is no interlock between the containment sprays and the recombiners.

III. Future Action Required

None

I. Issue

6.3 The recombiners may produce "hot spots" near the recombiner exhausts which might exceed the environmental qualification envelope or the containment design temperature.

Footnote 5: This concern applies to those facilities at which recombiners can be used.

II. Assessment/Response

The SSES design has accounted for recombiner "hot spots." The recombiners are of a natural circulation type design with hot air exhausted from the top, so that "hot spots" are limited to the local area directly above the recombiners. In the drywell no equipment except a cable tray is near the recombiner exhaust. The cable tray has been provided with deflectors which are designed to insulate the cable tray and prevent its temperature from exceeding design limits. Temperature measurements at the cable tray while operating the recombiners have verified that the design and installation of the deflectors are adequate. The wetwell recombiners are located at a high elevation directly below the diaphragm slab, and all equipment (such as SPOTMOS RTDs) are located below the recombiners. Therefore, there are no environmental qualification concerns.

III. Future Action Required

None

I. Issue

6.4 For the containment air monitoring system furnished by General Electric, the analyzers are not capable of measuring hydrogen concentration at volumetric steam condensation above 60%. Effective measurement is precluded by condensation of steam in the equipment.

II. Assessment/Response

The containment air monitoring piping is provided with heat tracing powered from safety grade sources so that no condensation of steam will occur. Note that SSES uses Comsip-Delphi monitors rather than GE equipment.

III. Future Action Required

None

I. Issue

6.5 Discuss the possibility of local temperatures due to recombiner operation being higher than the temperature qualification profiles for equipment in the region around and above the recombiners. State what instructions, if any, are available to the operator to actuate containment sprays to keep this temperature below design values (pp. 183-185 of 5/27/82 transcript).

Footnote 5: This concern applies to those facilities at which recombiners can be used.

II. Assessment/Response

Emergency operating procedure EO-00-023, "Containment Control," requires the operator to initiate the H_2 recombiners before an H_2 concentration of 3% by volume. With an inerted containment, this occurs within approximately 24 hours after the break for the worst-case analysis (see FSAR Subsection 6.2.5.3). The heat output from the recombiners is a small fraction of the total heat input to the containment from the reactor vessel. Thus, recombiner operation will not affect the global temperature response of the containment. In addition, as described in the response to 6.3, the SSES design considered the local effects of recombiner operation.

In the event the containment temperature substantially increases, emergency operating procedure EO-00-023, "Containment Control," requires the operator to actuate the drywell sprays before the drywell temperature reaches 340°F, but after the drywell temperature reaches 320°F.

III. Future Action Required

None

I. Issue

7. Containment Pressure Response

7.1 The wetwell is assumed to be in thermal equilibrium with a perfectly mixed, uniform temperature suppression pool. As noted under topic 4, the surface temperature of the pool will be higher than the bulk pool temperature. This may produce higher than expected containment temperatures and pressures.

II. Assessment/Response

Refer to 4.4.

III. Future Action Required

None

I. Issue

7.2 The computer code used by General Electric to calculate environmental qualification parameters considers heat transfer from the suppression pool surface to the containment atmosphere. This is not in accordance with the existing licensing basis for Mark III environmental qualification. Additionally, the bulk suppression pool temperature was used in the analysis instead of the suppression pool surface temperature.

Footnote 6: This issue as phrased applies only to a Mark III facility. However, the concern can be generalized and applied to the earlier containment types. For Mark I and II facilities, indicate what methodology was used to calculate the environmental qualification parameters including a discussion of heat transfer between the atmosphere in the wetwell and the suppression pool.

II. Assessment/Response

As explained in 4.4, all equipment located in the wetwell airspace was qualified to the drywell temperature profile (T_{max} = 340°F). This envelopes any concerns related to pool thermal stratification.

III. Future Action Required

None

I. Issue

7.3 The analysis assumes that the wetwell airspace is in thermal equilibrium with the suppression pool. In the short term this is non-conservative for Mark III due to adiabatic compression effects and finite time required for heat and mass to be transferred between the pool and containment volumes.

Footnote 6: This issue as phrased applies only to a Mark III facility. However, the concern can be generalized and applied to the earlier containment types. For Mark I and II facilities, indicate what methodology was used to calculate the environmental qualification parameters including a discussion of heat transfer between the atmosphere in the wetwell and the suppression pool.

II. Assessment/Response

During pool swell following the DBA LOCA, the wetwell airspace is assumed to compress adiabatically (NEDE-21544-P, GE, December, 1976). Thus, the wetwell airspace and temperature are related via

$$PT^{\frac{\gamma}{1-\gamma}} = \text{constant}$$

For an initial wetwell airspace pressure and temperature of 14.8 psia and 130°F, the temperature at the time of maximum wetwell compression of 56.1 psia (SSES DAR Figure 4-39) can be determined to be 342°F. The compression and decompression of the airspace takes place in approximately 2 sec. During this time period no appreciable heat transfer can occur, since the final pressure (after pool fallback) is much less than 56.1, which reduces the peak temperature to less than 342°F. Thus, this event is not included in the environmental qualification design. However, as described in the response to 4.4, all equipment was qualified to the drywell profile with a peak temperature of 340°F.

II. Future Action Required

None

I. Issue

8. Containment Air Mass Effects

8.1 This issue is based on consideration that some Technical Specifications allow operation at parameter values that differ from the values used in assumptions for FSAR transient analyses. Normally analyses are done assuming a nominal containment pressure equal to ambient (0 psig), a temperature near maximum operation (90°F) and do not limit the drywell pressure equal to the containment pressure. The Technical Specifications operation under conditions such as a positive containment pressure (1.5 psig), temperatures less than maximum (60 or 70°F) and drywell pressure can be negative with respect to the containment (-0.5 psid). All of these differences would result in transient response different than the FSAR descriptions.

II. Assessment/Response

For SSES, the Technical Specifications limit the containment pressure to between -1.0 and 2.0 psig. The FSAR analysis assumed an initial wetwell and drywell pressure between 0.1 and 1.5 psig (see Table 6.2-4). The Technical Specifications also limit the normal operating suppression pool temperature to a maximum of 90°F. The FSAR analysis assumed an initial pool temperature of 90°F (see FSAR Figure 6.2-3). In addition, the Technical Specifications limit the average drywell temperature to a maximum of 135°F, while the FSAR assumed a drywell temperature between 135°F and 150°F. The analysis also assumed an initial wetwell airspace temperature between 90°F and 150°F.

The short-term pressure response to a DBA LOCA documented in FSAR Section 6.2 calculated a maximum drywell pressure of 44.2 psig, compared to a design pressure of 53 psig. In addition, the containment response ignored the heat absorbed by the containment structures.

In conclusion, the Technical Specifications limit the parameter values during operation to those assumed in the FSAR transient analysis.

III. Future Action Required

None

I. Issue

8.2 The draft GGNS technical specifications permit operation of the plant with containment pressure ranging between 0 and -2 psig. Initiation of containment spray at a pressure of -2 psig may reduce the containment pressure by an additional 2 psig which would lead to buckling and failures in the containment liner plate.

II. Assessment/Response

For the Mark III design, containment spray initiation occurs automatically on high drywell pressure. With automatic initiation, a spurious signal could result in an inadvertent spray actuation. However, for SSES, the containment sprays must be initiated by manual action. In order to initiate the sprays, both the inboard and outboard isolation valves must be opened. The operating procedures require permission from the Shift Supervisor to open the valves, and the keylock switch placed to MAN OVERRIDE. Based on the above, we believe inadvertent spray actuation during normal operation requires extraordinary circumstances beyond the design basis of the plant.

Nevertheless, we evaluated the worst-case depressurization analysis for non-accident conditions for SSES based on the minimum Technical Specification initial pressure of 13.7 psia, and the maximum Technical Specification drywell temperature of 135°F. These values minimized the partial pressure of the non-condensables and maximized the vapor pressure. Our analysis revealed that an inadvertent spray actuation with these initial conditions resulted in a containment negative pressure which does not exceed the containment negative design pressure of -5.0 psig (reference FSAR Table 6.2-1).

III. Future Action Required

None

I. Issue

8.3 If the containment is maintained at -2 psig, the top row of vents could admit blowdown to the suppression pool during an SBA without a LOCA signal being developed.

II. Assessment/Response

The NRC dispositioned this concern as N/A to SSES.

III. Future Action Required

None

I. Issue

8.4 Describe all of the possible methods, both before and after an accident, of creating a condition of low air mass inside the containment. Discuss the effects on the containment design external pressure of actuating the containment sprays (pp. 190-195 of 5/27/82 transcript).

II. Assessment/Response

During normal operation, the only way to create a condition of low air mass in the containment is to vent the containment following a steam leak, pool heatup or loss of drywell cooling which increases the containment temperature and vapor pressure. As described in the response to 8.2, rapid cooldown of the SSES containment during normal operation will not result in the final containment pressure exceeding the -5.0 psig design pressure. Since the Technical Specifications limit the maximum pool temperature to 120°F and the drywell temperature to 135°F, conditions which result in a lower containment air mass than the above analysis could not exist. Furthermore, the response to 8.2 indicated that an inadvertent spray actuate during normal operation is highly unlikely.

Following a LOCA, the Standby Gas Treatment System (SGTS) used to vent the containment isolates on high drywell pressure. Post-accident containment venting would only occur to relieve the containment pressure in the event of imminent containment failure.

In addition, FSAR Subsection 6.2.1.1.4 documented the SSES-unique post-LOCA inadvertent spray actuation (ISA) transient. This analysis provided the basis for the number and flow capacity of our drywell-to-wetwell VBs to limit the containment pressure response to less than the -5.0 psig design pressure. The analysis assumed all the non-condensables in the drywell were purged into the wetwell airspace, with steam only in the drywell.

Our review of the post-LOCA ISA analysis indicated that an initial pressure of 0.1 psig (see FSAR Table 6.2-23) was assumed, while the Technical Specifications allow a containment pressure equal to -1.0 psig. However, we re-analyzed the post-LOCA ISA analysis with an initial pressure equal to -1.0 psig, and determined the negative pressure transient does not exceed the -5.0 psig design pressure.

In addition, the BWROG's EPG program addresses the criteria for operator actions to prevent exceeding the containment negative design pressure for abnormal plant conditions outside the Technical Specification limits. These guidelines are contained in Revision 2 of the EPGs.

III. Future Action Required

None

I. Issue

9. Final Drywell Air Mass

9.1 The current FSAR analysis is based upon continuous injection of relatively cool ECCS water into the drywell through a broken pipe following a design basis accident. Since the operator is directed to throttle ECCS operation to maintain the reactor vessel water level to about the level of the steam lines, the break will be releasing saturated steam instead of releasing relatively cool ECCS water. Therefore, the drywell air which would have been purged and then drawn back into the drywell will remain in the wetwell, and higher pressures than anticipated will result in both the wetwell and the drywell.

II. Assessment/Response

As previously discussed in 4.4, the short-term pressure response to a DBA LOCA controls the maximum containment pressure, as opposed to a Mark III containment design, where the long-term pressure response yields the maximum pressure. Therefore, any ECCS throttling which prevents vacuum breaker actuation will have no effect on the short-term pressure response.

III. Future Action Required

None

I. Issue

9.2 The continuous steaming produced by throttling the ECCS flow will cause increased direct leakage from the drywell to the containment. This could result in increased containment pressure.

II. Assessment/Response

The SSES-unique steam bypass calculation described in the response to 5.1 assumed a continuous steam supply from the drywell, at a drywell-to-wetwell ΔP equal to the downcomer submergence for the entire transient. Therefore, the steam bypass analysis accounts for any increased direct leakage from the drywell-to-wetwell caused by throttling the ECCS flow.

In addition, the analysis showed that once the operator initiates containment spray, the pressure increase terminates. The responses to 4.8 and 4.9 documented that no adverse effects on the SSES containment design occur during operation of the containment sprays.

III. Future Action Required

None

I. Issue

9.3 It appears that some confusion exists as to whether SBAs and stuck open SRV accidents are treated as transients or design basis accidents. Clarify how they are treated and indicate whether the initial conditions were set at nominal or licensing values (pp. 202-205 of 5/27/82 transcript).

II. Assessment/Response

Appendix I of the SSES DAR documented the SBA and stuck open relief valve transients. The assumptions used in the subject analysis were developed within the Mark II Owners' Group and conform to the requirements of draft NUREG-0783. Supplement No. 1 of the SSES Safety Evaluation Report documented your review and acceptance of the analysis.

III. Future Action Required

None

I. Issue

10.1 and 10.2

II. Assessment/Response

The NRC dispositioned these concerns as N/A to SSES.

III. Future Action Required

None

I. Issue

11. Operational Control of Drywell to Containment Differential Pressures

Mark III load definitions are based upon the levels in the suppression pool and the drywell weir annulus being the same. The GGNS technical specifications permit elevation differences between these pools. This may affect load definition for vent clearing.

Footnote 8: For Mark I and II facilities, consider the water in the downcomers.

II. Assessment/Response

The water jet loads occurring during the water clearing phase of the pool swell phenomenon are obtained using the maximum water clearing velocity. The permissible difference in water elevation from the nominal value in the suppression pool and the downcomers are +1 ft (VB setpoint equal to 0.5 psid). This elevation difference generates a small difference in backpressure, which has been shown to have negligible effect on either vent clearing or pool swell loads.

III. Future Action Required

None

I. Issue

12 & 13

II. Assessment/Response

The NRC dispositioned these concerns as N/A for SSES.

III. Future Action Required

None

I. Issue

14. RHR Backflow Through Containment Spray

A failure in the check valve in the LPCI line to the reactor vessel could result in direct leakage from the pressure vessel to the containment atmosphere. This leakage might occur as the LPCI motor-operated isolation valve is closing and the motor-operated isolation valve in the containment spray line is opening. This could produce unanticipated increases in the containment spray.

II. Assessment/Response

Operation of the drywell sprays is not automatic and requires operator action to initiate. The RHR operating procedure requires the LPCI injection valve to the vessel to be closed and permission from the Shift Supervisor prior to opening the two isolation valves to the drywell sprays.

In addition, the LPCI injection valves are interlocked such that they will not open until the reactor pressure decreases below 430 psig. At this low reactor pressure, no appreciable flow from the reactor to the sprays via the failed check valve could occur unless the RHR pump tripped.

Thus, operator error and two single failures (failed check valve and pump trip) are required to establish flow from the vessel to the spray header. This scenario exceeds the design basis of the SSES plant.

III. Future Action Required

None

I. Issue

15. Secondary Containment Vacuum Breaker Plenum Response

The STRIDE plants had vacuum breakers between the containment and the secondary containment. With sufficiently high flows through the vacuum breakers to containment, vacuum could be created in the secondary containment.

II. Assessment/Response

For SSES, there are no VBs between the primary containment and secondary containment.

III. Future Action Required

None

I. Issue

16. Effect of Suppression Pool Level on Temperature Measurement

Some of the suppression pool temperatures sensors are located (by GE recommendation) 3 in to 12 in below the pool surface to provide early warning of high pool temperature. However, if the suppression pool is drawn down below the level of the temperature sensors, the operator could be misled by erroneous readings and required safety action could be delayed.

II. Assessment/Response

The SSES Suppression Pool Temperature Monitoring System (SPOTMOS) has 16 sensors at 8 locations (2 per division) at El. 20 ft. In addition, 4 more sensors are located at El. 3.5 ft (T-quencher elevation). The control room panel displays the average of the 8 upper sensors; but the pool temperatures from the 4 lower sensors can be displayed, if required.

The Technical Specifications require a suppression pool level between 22 and 24 ft. An alarm sounds in the control room if the pool level drops to El. 22.25'. Emergency operating procedure EO-00-23, "Containment Control," instructs the operator to restore the suppression pool level to between 22 and 24 ft per the Technical Specifications.

The Mass and Energy analysis (see Appendix I of the DAR) requires the operator to scram the reactor at a pool temperature of 110°F and depressurize the reactor at a pool temperature of 120°F. These scenarios (i.e., isolation/scram, stuck open relief valve and small break accident) result in an increase, not a decrease, in pool level due to combinations of feedwater, HPCI, RCIC and rod drive flow from the condensate storage tank. Large breaks, on the other hand, could decrease the level in suppression pool. However, if the break occurred at the Technical Specifications minimum level of 22 ft, a maximum decrease in pool level of 1.5 ft corresponding to the 1.5 ft tall vent risers in the drywell would still result in submerged upper sensors.

Depressurizing the reactor via the alternate mode of shutdown cooling could reduce the suppression pool level to below the upper 16 sensors. Again, the operator is instructed to restore the suppression pool level via the condensate storage tank. If level cannot be restored, the 4 lower sensors and the temperature sensor at the suction to the RHR heat exchangers could be used to monitor the suppression pool temperature.

III. Future Action Required

None

I. Issue

17. Emergency Procedure Guidelines

The EPGs contain a curve which specifies limitations on suppression pool level and reactor pressure vessel pressure. The curve presently does not adequately account for upper pool dump. At present, the operator would be required to initiate automatic depressurization when the only action required is the opening of one additional SRV.

II. Assessment/Response

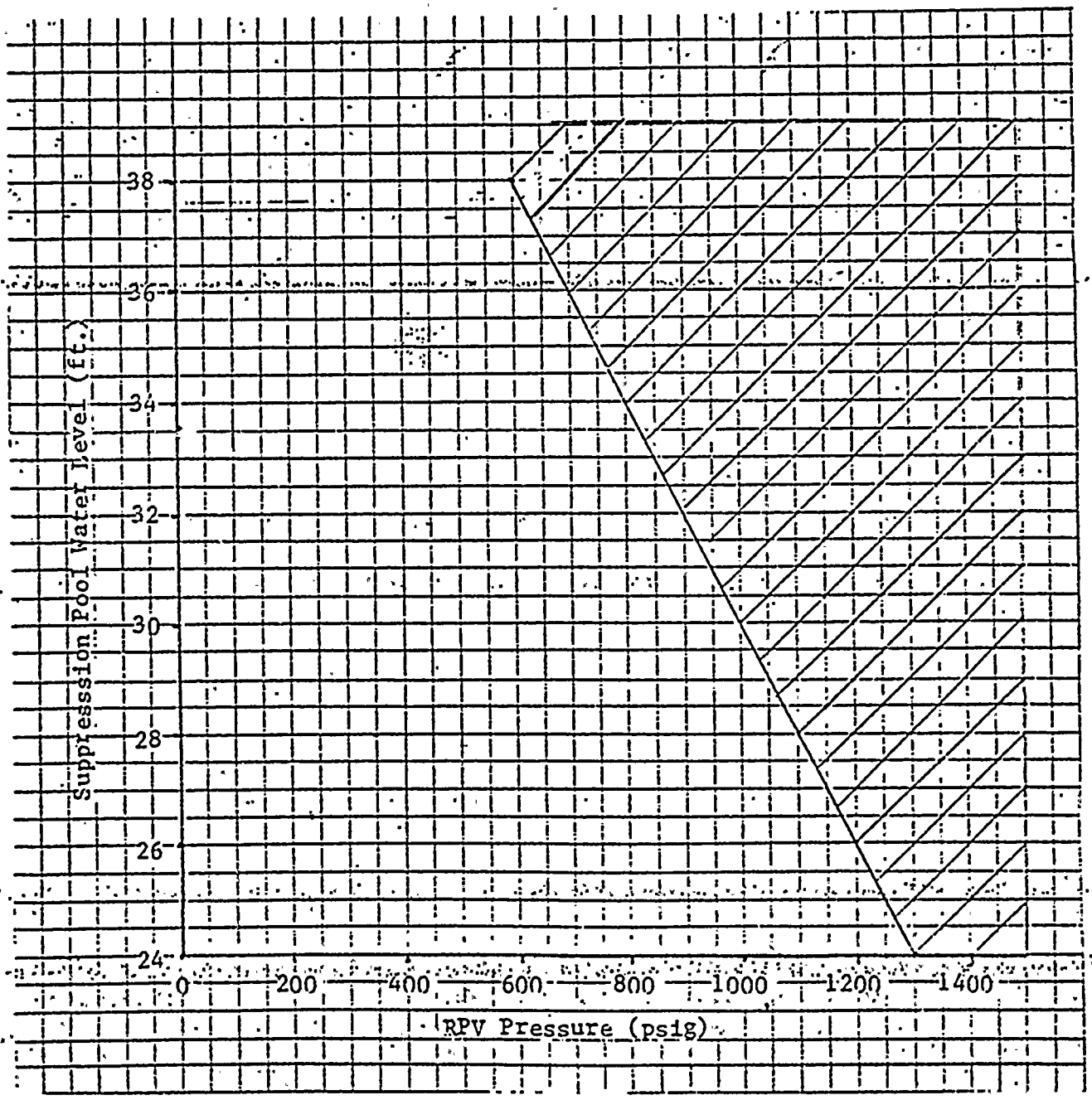
SSES Technical Specifications require that the pool level be maintained within the normal operating limits (22 to 24 ft). If they cannot be restored within 1 hour, then the operator is required to be in hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

In addition, emergency procedure EO-00-023, "Containment Control," directs the operator to maintain the reactor pressure and pool level below the Suppression Pool Load Limit (see figure next page), if the level exceeds 24'. This can be accomplished by manually actuating one or more SRV, however, if the level and pressure cannot be maintained below the curve, then the operator is instructed to initiate ADS.

III. Future Action Required

None

SUPPRESSION POOL LOAD LIMIT



I. Issue

18. Effects of Insulation Debris

18.1 Failures of reflective insulation in the drywell may lead to blockage of the gratings above the weir annulus. This may increase the pressure required in the drywell to clear the first row of drywell vents and perturb the existing load definitions.

Footnote 10: This issue as phrased applied only to a Mark III facility. However, the concern can be generalized. Accordingly, discuss how the effects of insulation debris could perturb existing load definitions or could block suction strainers. In responding to this issue, you may refer to existing generic studies, e.g., the study done for the Cooper facility.

II. Assessment/Response

For SSES, the peak downward pressure on the diaphragm slab occurs during vent clearing at approximately 1 sec after the break. This is insufficient time for any insulation debris to transit to and block the downcomers. Subsequent to the initial pressurization, any minor blockage that might occur would have an insignificant effect on pool swell and the peak drywell pressure (see response to Issue 18.2 for description of the insulation).

III. Future Action Required

None

I. Issue

18.2 Insulation debris may be transported through the vents in the drywell wall into the suppression pool. This debris could then cause blockage of the suction strainers.

Footnote 10: This issue as phrased applies only to a Mark III facility. However, the concern can be generalized. Accordingly, discuss how the effects of insulation debris could perturb existing load definitions or could block suction strainers. In responding to this issue, you may refer to existing generic studies; e.g., the study done for the Cooper facility.

II. Assessment/Response

This issue is discussed in FSAR Section 6.2.2.3 (in response to NRC Question 021.20) and is summarized as follows:

The insulation used within the containment is the all metal, reflective type. The insulation consists of large assemblies held in place by stainless steel latches. The latches are equipped with positive locking devices. It would be unlikely that the relatively larger pieces of metallic insulation would pass through the small openings at the top of the 87 downcomers. These openings are made smaller by the presence of jet deflectors as shown in FSAR Figure 6.2-56. Very little, if any, of the insulation would find its way into the suppression pool. The suction strainers of the ECCS pumps are designed to sustain 50% clogging without affecting system performance.

In addition to the FSAR discussion above, it should be noted that the suction strainers are located midway up the suppression pool wall. Since any metallic insulation entering the pool will either float or sink, the likelihood of any strainer clogging is extremely remote.

III. Future Action Required

None

I. Issue

21. Containment Makeup Air For Backup Purge

Regulatory Guide 1.7 requires a backup purge H_2 removal capability. This backup purge for Mark III is via the drywell purge line which discharges to the shield annulus which in turn is exhausted through the standby gas treatment system (SGTS). The containment air is blown into the drywell via the drywell purge compressor to provide a positive purge. The compressors draw from the containment; however, without hydrogen lean air makeup to the containment, no reduction in containment hydrogen concentration occurs. It is necessary to assure that the shield annulus volume contains a hydrogen lean mixture of air to be admitted to the containment via containment vacuum breakers. For Mark I and II facilities, discuss the possibility of purge exhaust being mixed with the intake air which replenishes the containment air mass.

II. Assessment/Response

In the SSES design the purge exhausts through the SGTS system and exits on the west side of the reactor building roof (El. 872'). The supply intake is located on the east side of the reactor building at approximately El. 790', and the reactor building is 160' wide. Based on this separation, exhaust air should not mix with intake air.

III. Future Action Required

None

I. Issue

22. Miscellaneous Emergency Procedure Guideline Concerns

The EPGs currently in existence have been prepared with the intent of coping with degraded core accidents. They may contain requirements conflicting with design basis accident conditions. Someone needs to carefully review the EPGs to assure that they do not conflict with the expected cause of the design basic accident.

II. Assessment/Response

The SSES Emergency Operating Procedures have been developed in accordance with the BWR Owners' Group EPGs. As such, these guidelines underwent a rigorous review within GE and the Owners' Group. This process assured the preparation of EPGs which will respond to, and mitigate, any scenarios which result in degraded plant conditions.

III. Future Action Required

None

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