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SUBJECT: Responds to 980123 RAI re NRC GL 87-02, "Verification of Seismic Adequacy of Mechanical & Electrical Equipment in Operating Reactors,Unresolved Safety Issue (USI) A-46."

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July 27, 1999

AEP:NRC:1040G

Docket Nos. 50-315
50-316

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Mail Stop O-P1-17
Washington, DC 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)-NRC GENERIC LETTER 87-02, "VERIFICATION OF SEISMIC ADEQUACY OF MECHANICAL AND ELECTRICAL EQUIPMENT IN OPERATING REACTORS, UNRESOLVED SAFETY ISSUE (USI) A-46." (TAC NOS. M69437 AND M69438)

References: (1) Letter, John B. Hickman to E. E. Fitzpatrick, "SECOND REQUEST FOR ADDITIONAL INFORMATION ON THE RESOLUTION OF UNRESOLVED SAFETY ISSUE (USI) A-46, D.C. COOK NUCLEAR PLANT, UNIT NOS. 1 AND 2 (TAC NOS. M69437 AND M694380), dated January 23, 1998.

(2) Letter AEP:NRC:1040A, "RESPONSE TO SUPPLEMENT 1 TO GENERIC LETTER 87-02 ON SQUG RESOLUTION OF USI A-46", dated September 21, 1992.

(3) Letter AEP:NRC:1040C, RESPONSE TO NRC GENERIC LETTER 87-02, "VERIFICATION OF SEISMIC ADEQUACY OF MECHANICAL AND ELECTRICAL EQUIPMENT IN OPERATING REACTORS, UNRESOLVED SAFETY ISSUE (USI) A-46", dated January 30, 1996.

Gentlemen:

In accordance with the provisions of 10 CFR 50.54(f), Indiana Michigan Power Company (I&M) submits this response to a January 23, 1998 request for additional information regarding Generic Letter (GL) 87-02 (Reference 1).

On February 19, 1987, the NRC issued GL 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46." The GL encouraged utilities to participate in a generic program to resolve the seismic verification issues associated with USI A-46. As a result, The Seismic Qualification Utility Group (SQUG) was formed, and the Generic Implementation Procedure (GIP) was developed for seismic verification of mechanical and electrical equipment in nuclear power plants. NRC review and approval of the GIP is documented in GL 87-02, Supplement No. 1, dated May 22, 1992, and includes the Supplemental Safety Evaluation Report No. 2 (SSER-2).

A025 //

In our letter dated September 21, 1992, (Reference 2), I&M committed to implement GIP-2 at Donald C. Cook Nuclear Plant including clarifications, interpretations and exceptions in SSER-2.

The USI A-46 walkdowns for Cook Nuclear Plant Units 1 and 2 were completed during the 1993-1995 time period. Seismic verifications of the equipment performed under the SQUG-GIP criteria reflect the status of the equipment at the time of the walkdown. In accordance with the GIP, summary reports of the safe shutdown path selection, equipment selection, and results of the evaluation of the USI A-46 program have been developed and were submitted to the NRC (Reference 3).

The attachment to this letter responds to the request for additional information.

This letter contains one commitment:

> All of the outlier resolutions (including modifications as required) are presently scheduled to be completed prior to the restart of Units 1 and 2.

Sincerely,

MW Rencheck

M. W. Rencheck
Vice President Nuclear Engineering

/rgv

Attachment

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 27th DAY OF July 1999

Patricia A. Eddie
NOTARY PUBLIC

My Commission Expires: PATRICIA A. EDDIE

c: A. C. Bakken, III
J. E. Dyer, w/attachment
MDEQ - DW & RPD
NRC Resident Inspector, w/attachment
R. Whale

bc: G. P. Arent/J. Burford/M. J. Gumns
T. P. Beilman, w/attachment
J. J. Euto
FOLIO, w/attachment
S. A. Greenlee/J. R. Glass/J. Sekaran
W. G. Harland
G. Honma
J. F. Stang, Jr., NRC - Washington, DC, w/attachment

ATTACHMENT NO. 1 TO AEP:NRC:1040G

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

Responses to Request For Additional Information

1. *In page 4 of the letter in Reference 1, the licensee indicates its intent to apply the USI A-46 methodology to future verification of seismic adequacy of the repair/replacement of equipment, including the scope of equipment identified as part of Regulatory Guide 1.97. However, the staff position in Item 2 of Section I.2.3 of the SSER-2, which clarifies Section 2.3.3 of the GIP-2 regarding revision of plant licensing bases, is that any previous licensing commitments, such as for RG 1.97 and TMI Action Plan item II.F.2, are not superseded by the resolution methods of the GIP. Clarify your position regarding the means you intend to employ for incorporating the GIP-2 methodology into your licensing basis for verification of the seismic adequacy of new and replacement equipment. As an example, also clarify your commitment with regard to the applicability of the A-46 methodology to new and replacement Category 1 equipment included in the SSEL that are associated with RG 1.97 or TMI Action Plan item II.F.2.*

Response to Question 1:

We have re-evaluated the applicability of the Seismic Qualification Utility Group (SQUG) program to new and replacement equipment and we will continue to qualify the new and replacement equipment as per the requirements of IEEE-344-1975. This also applies to Category 1 equipment included in the Safe Shutdown Equipment List (SSEL) that is associated with R.G. 1.97 or TMI Action Plan item II.F.2.

We will decide on the use of the SQUG methodology for new and replacement equipment after a satisfactory resolution is reached between the SQUG and the NRC and the plant specific SER is received. We will, however, make use of the provision of the EPRI document NP-7148-SL (Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality, December 1990) to screen the relays based on ruggedness.

The verification of the seismic adequacy of the SSEL components performed using the SQUG methodology is retained as part of the seismic qualification documentation for the SQUG components.

2. *Section 3.3 of Attachment 2 (Reference 1) indicates that a peer review was performed which covered all seismic evaluation areas, including review of draft reports, sample walkdowns and review of documentation. Provide a summary of the peer review, including a description of major findings, recommendations, and the basis for the peer reviewer's conclusion, especially on USI A-46 program adequacy and verification of conformance to GIP-2 and SSER-2 guidelines in the licensee's screening walkdowns and seismic evaluation. Is this an independent review action, or a joint action with the licensee's review team? Describe your follow up actions as a result of this peer review.*

Response to Question 2:

The peer review effort was an independent (third party) review action that included a walkdown of areas outside containment within the protected area of Cook Nuclear Plant Units 1 and 2, review of the equipment specific anchorage inspection documentation, review of the walkdown teams during a portion of the walkdown, review of draft

reports, and review of completed Seismic Evaluation Work Sheets (SEWS) with the accompanying anchorage calculations.

An independent outside consultant, RPK Structural Mechanics Consulting Company (RPK), performed the peer review at the Cook Nuclear Plant site during the weeks of July 20, 1992 and November 1, 1993. During that time, RPK inspected the major electrical equipment items including:

- T11C1, T11C2, T11C3, T11C4 Medium Voltage Switchgears;
- 1-TR11B 600 VAC BUS Supply Transformer;
- 1-CRID-1-CVT, 1-CRID-2-CVT, 1-CRID-3-CVT and 1-CRID-4-CVT Constant Voltage Transformers;
- 1-EZC-B, 1-AZ-BC and 1-ABV-A Motor Control Centers;
- 11-C1 and 11-C3 Low Voltage Switchgears;
- 1-CRID-IV-INV and 1-DGAB-INV Inverters;
- 1-TR-ELSC Emergency Local Shutdown Distribution Transformer; and
- several other Control Panels and Cabinets (Class 20).

RPK inspected the Refueling Water Storage Tank (RWST) and several other Class 21 and Class 0 items. RPK inspected cable tray supports for areas outside containment for both units.

RPK's inspection was performed independent of the Seismic Review Teams. RPK was not included as a member of any team and had access to all areas of the plant with the exception of the containment.

In addition to the walkdown independent of the Seismic Review Teams, RPK followed the teams for a portion of the walkdowns during a November 1, 1993 visit. RPK reviewed completed SEWS with the accompanying anchorage calculations.

RPK concluded that the anchorage inspections, screening walkdowns and seismic evaluations conformed to the GIP-2 and SSER-2 guidelines. The documentation for the walkdowns including the SEWS with the attached anchorage calculations and draft reports met the USI A-46 requirements. There were no major findings; however, there were several recommendations made regarding specific issues at the plant that were included in the final reports. Examples of the issues identified by RPK included in the final results of the evaluation include:

a) The generic interaction issue regarding the portable fire extinguishers mounted on small hooks - this mounting should be replaced with longer hooks. Fire extinguisher mounting hooks in control room and 4 kv room will be replaced with longer hooks during the current forced outage.

b) The inspection of the large transformers 1-TR11A, 1-TR11B, 2-TR21A, 2-TR21B, that were qualified using shake table testing to the requirements of IEEE 344-1975 Standard. Initially the SRT were going to use the testing as the basis for caveat compliance. However, based on RPK's experience and recommendation, inspections of coil supports were included in the list of items to be performed when the transformers were out of service. This was completed during the walkdown inspections.

b) The RWST strap supports were rusty - the supports were cleaned and painted.

Additional recommendations and follow-up actions are provided in Tables 4.5, 4.6, and 4.8 of attachment 2 to letter AEP:NRC:1040C

3. *Referring to the in-structure response spectra provided in your 120-day-response to the NRC's request in Supplement No. 1 to Generic Letter 87-02 dated May 22, 1992, the following information is requested:*

   a) *Identify structure(s) which have in-structure response spectra (5% critical damping) for elevations within 40-feet above the effective grade, which are higher in amplitude than 1.5 times the SQUG Bounding Spectrum.*

Response to Question 3.a):

A comparison of the design ground response spectra (GRS) to the SQUG bounding spectrum as a method for evaluating the seismic adequacy of equipment is included as Method A in Table 4-1 of GIP-2. The GIP allows this method to be used under the restriction that the equipment must be located at an elevation below about 40 feet above the effective grade of the building, and the equipment fundamental frequencies (other than equipment mounted on distribution systems, e.g., valves) must be above about 8 Hz.

One of the advantages of GIP Method A is that the various effects associated with in-structure responses are inherently included in the method. The GIP approach differs from current seismic licensing criteria in that in GIP Method A the seismic capacity of equipment and the seismic demand on the equipment are anchored to ground response spectra. Further, the GIP method is not based on the performance of a single item of equipment subjected to an artificial time history on a shake table. Instead the GIP method is based on successful performance of numerous items of equipment subjected to several real earthquakes.

For these reasons, the GIP method, based on comparing ground response spectra at data base sites to SSE ground motion response spectra at nuclear plants, was accepted by recognized independent experts (e.g., SSRAP report), including the NRC staff (e.g., SSER #2), as an acceptable method of verifying the seismic adequacy of equipment installed in operating nuclear power plants. Therefore, method A was used for evaluating Seismic Capacity vs. Seismic Demand for a very large number of equipment items (on the order of 800 for Units 1 and 2). This is documented in the column "Capacity vs. Demand Basis" on the Screening Verification Data Sheets (SVDS) that were provided as Appendix C of the Seismic Evaluation and Walkdown Report submitted to the NRC as Attachment 2 under letter AEP:NRC:1040C, dated January 30, 1996.

Grade elevation for the Cook Nuclear Plant is at El. 608'. Figures 1 to 9 (Appendix A of this submittal) provide a comparison of the 5% damped in-structure response spectra to 1.5 times the Bounding Spectrum (for all elevations within about 40' above grade). These include Elevations 587', 633', and 650' in the Auxiliary Building, Elevation 609' in the Diesel Generator Building, Elevation 591' in the Turbine Building, and Elevations 597', 612', 625' and 651' in the Containment Building. As shown in the figures, 1.5 times the Bounding Spectrum envelopes the 5% damped in-structure response spectra for the frequency range of interest (2 Hz. to 33 Hz.) with the only exception being Elevation 651' in Containment, where the in-structure response spectrum is larger than 1.5 times the Bounding Spectrum from 2 to 2.5 Hz and from 29 Hz. and above.

Because 1.5 times the Bounding Spectrum envelopes the 5% damped in-structure response spectra, with the exception noted above, the use of GIP Method A was determined to be acceptable for use at Cook Nuclear Plant.

b) *With respect to the comparison of equipment seismic capacity and seismic demand, indicate which method in Table 4-1 of GIP-2 was used to evaluate the seismic adequacy for equipment installed on the corresponding floors in the structure(s) identified in Item (a) above. If you have elected to use method A in Table 4-1 of the GIP-2, provide a technical justification for not using the in-structure response spectra provided in your 120-day response. It appears that some A-46 licensees are making an incorrect comparison between their plant's safe shutdown earthquake (SSE) ground motion response spectrum and the SQUG Bounding Spectrum. The SSE ground response spectrum for most nuclear plants is defined at the plant foundation level. The SQUG Bounding Spectrum is defined at the free field ground surface. For plants located at deep soil or rock sites, there may not be a significant difference between the ground motion amplitudes at the foundation level and those at the ground surface. However for sites where a structure is founded on shallow soil, the amplification of the ground motion from the foundation level to the ground surface may be significant.*

Response to Question 3.b):

Table 1 below includes equipment at Elevation 651' in the Containment Building where 1.5 times the Bounding Spectrum is exceeded. However, the table includes a lower bound estimate of the equipment natural frequency. At that frequency 1.5 times the Bounding Spectrum envelops the in-structure response spectrum.

Table 1
Equipment Located at Containment El. 651' Where GIP Method A
Was Used to Evaluate Capacity Vs. Demand

ID	Class	Frequency Estimate
1-XRV-RACK-152	18	8.00
1-XRV-RACK-153	18	8.00
2-XRV-152	18	13.60
2-XRV-153	18	13.60

The GIP-2 procedure and the SSER from the NRC endorsing its use provide the technical justification for use of Method A. Method A of GIP Table 4-1 provides a methodology to evaluate the seismic adequacy of equipment by comparing equipment capacity based on earthquake experience ground response spectra at database sites with the plant's SSE ground response spectrum (GRS). The composite earthquake experience ground response spectrum from the database sites (reference spectrum) is reduced by a factor of 1/1.5 to account for possible additional amplification of motion in nuclear plants compared to database plants and is referred to as the "Bounding Spectrum" in the GIP.

The seismic capacity of equipment defined by the Bounding Spectrum is compared to the seismic demand at the effective grade using the plant licensing basis SSE GRS. The GIP method conservatively limits use of this approach to equipment, which has natural frequencies above about 8

Hz and is located lower than about 40 feet above the effective grade of the building. These restrictions prohibit the use of GIP Method A for equipment with natural frequencies less than 8 Hz and for those higher elevations in buildings where equipment amplified responses are typically higher.

Additional details justifying the use of GIP Method A may be found in the report "Use of Seismic Experience in Nuclear Power Plants," prepared by the Senior Seismic Review and Advisory Panel (SSRAP), February 28, 1991. This report, included as Reference 5 in GIP-2, summarizes SSRAP's judgment on this subject by stating on pages 102 and 103 that:

"...the use of very conservative floor response spectra should be avoided when assessing the seismic ruggedness of floor-mounted equipment. . . . Only for cases of equipment mounted more than 40 feet above grade or equipment with as-anchored frequencies less than about 8 Hz., is it necessary to use floor spectra."

The licensing basis ground response spectrum at Cook Nuclear Plant Units 1 and 2 are defined at ground level. Section 2.5.2 of the UFSAR for Cook Nuclear Plant states that "Assuming such a shock might have a focal depth as shallow as 10 kilometers, it is estimated that the maximum ground acceleration at foundation level (within the lake or beach sand deposits) at the site would be about 15 percent of gravity. However, additional margin has been provided for by designing the engineered safety features to be operative under a maximum horizontal ground acceleration of 20 percent of gravity and maximum vertical acceleration of 13.33 percent of gravity."

Cook Nuclear Plant is a deep soil site and as indicated in the RAI question there is not a significant difference between the foundation and ground level. The ground spectrum includes possible amplification from foundation level and has been traditionally and correctly applied throughout the life of Cook Nuclear Plant at the base of the structures at several elevations since all foundations are "within the lake or beach sand deposits". Therefore, it was concluded that the definition of ground is not an issue.

c) *For the structure(s) identified in Item (a) above, provide the in-structure response spectra designated according to the height above the effective grade. If the in-structure response spectra identified in the 120-day-response to Supplement No. 1 to the Generic Letter 87-02 was not used, provide the response spectra that were actually used to verify the seismic adequacy of equipment within the structures identified in Item (a) above. Also, provide a comparison of these spectra to 1.5 times the Bounding Spectrum.*

Response to Question 3.c):

The comparisons requested of 1.5 times the bounding spectrum to the in-structure response spectrum is provided in Figures 1 to 9 (Appendix A) as discussed in response to question number 3.a) above. The in-structure response spectra submitted by the Cook Nuclear Plant in the 120-day response to Supplement No. 1 of GL 87-02 were used to verify the seismic adequacy of equipment when Method A was not used. No other spectra were developed for use in the USI A-46 program at Cook Nuclear Plant Units 1 and 2.

4. *In a letter dated May 31, 1996 the licensee submitted its commitment regarding the outlier resolution schedule. The proposed time frame to complete all outlier resolution ranges from the end of 1996 to the end of 1999, depending on the determination whether a specific outlier will be resolved by analysis or by modification. As a number of safety-related components in the safe shutdown path have been identified as outliers, their seismic adequacy may be rendered questionable and their conformance to the licensing bases uncertain. Elaborate on your plans for scheduling the resolution of identified outliers and your evaluation in support of the conclusion that the licensing bases for the plant will not be affected by the outlier resolution schedule.*

Response to Question 4:

We have been unable to identify a letter dated May 31, 1996 in which the above commitment was made. However, in our previous submittal, AEP:NRC:1040C dated January 30, 1996, we voluntarily committed to resolving the outlier issues by the end of the scheduled refueling outages in the year 2000.

All of the outlier resolutions (including modifications as required) are presently scheduled to be completed prior to the restart of Units 1 and 2.

5. *Describe the extent to which the seismic margin methodology, described in the report EPRI NP-6041, was used in the Donald C. Cook A-46 program, including outlier resolutions for tanks and heat exchangers. Since this methodology is known to yield analytical results that are not as conservative as what might be obtained by following the GIP-2 guidelines, it is generally not acceptable for the A-46 program. Therefore, for each deviation from the GIP-2 guidelines, in situations where the margin methodology is utilized, identify the nature and extent of the deviation, and provide the justification for its acceptance.*

Response to Question 5:

Review of the data bases (SEWS, notes, calculations etc.) did not identify any evaluations which used the seismic margin methodology, described in the EPRI NP-6041 report, including resolution for tanks and heat exchangers. However, it is noted that there are several similarities between the GIP-2 methodology and Seismic Margins evaluations. Specifically allowable load limitations for bolts and steel structural members are similar. The evaluations performed to evaluate the seismic adequacy of equipment at Cook Nuclear Plant Units 1 and 2 use the GIP defined loads for seismic demand and the GIP defined allowable stress criteria for the capacity. Detailed descriptions of the evaluations performed for tanks and heat exchangers included in the A-46 evaluation of Cook Nuclear Plant Units 1 and 2 have been previously forwarded. These descriptions are contained in Tables 2 and 3 of the first RAI on USI A-46 that were submitted under letter AEP:NRC:1040E, dated March 10, 1997. Tables 2 and 3 that are included in this response (Appendix B) to support questions 5, 6 and 8 in this RAI provide similar information for Class 0 equipment items. These evaluations used the GIP defined loads for seismic demand and the GIP defined allowable stress criteria for the capacity.

6. *A note under Table 2-1 in Section 2.3 of Attachment 2 (Reference 1) indicates that the damping values defined in GIP-2 were used for the USI A-46 effort, and that for the majority of equipment classes, 5% damping was used. Identify the cases in which damping values higher than those specified in GIP-2 were used. Provide the basis of using such damping values.*

Response to Question 6:

Table 2.1 of Section 2.3 of the Seismic Evaluation and Walkdown Report submitted to the NRC as Attachment 2, under letter AEP:NRC:1040C, dated January 30, 1996, was included to describe the seismic design basis for Cook Nuclear Plant Units 1 and 2. The note below the table was included as a clarification. GIP-2 damping ratios were used for USI A-46 evaluations. There were no cases where higher damping values than those specified in GIP-2 were used. Five percent (5%) equipment damping was used for the Class 0 equipment items described in Appendix B of this submittal.

7. *Items 44 and 45 in Table 4-5 of Attachment 2 (Reference 1) indicate that batteries identified as 1-BATT-AB and 1-BATT-CD are just over 10 years old and were designated as outliers. The report further indicates that the outlier resolution was achieved in both cases by conducting evaluation to determine their seismic adequacy. Provide details of how the seismic adequacy was verified for these batteries.*

Response to Question 7:

I&M has adopted the replacement criteria stated in ANSI/IEEE Std 450-1987, "IEEE Recommended Practices for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations". Based on this standard, the condition of safety related batteries had been reviewed considering both the physical condition of the batteries and their ability to hold a charge. Based on this review, the decision was made to replace the 2AB batteries during the 1994 Unit 2 refueling outage, and not to replace the other batteries (the 1AB, 1CD and 2CD batteries were manufactured in 1985/1986). Future replacement of safety related batteries will be based on ongoing maintenance and inspection in accordance with IEEE-450-1987.

The SRT reviewed EPRI TR-100248 "Station Battery Maintenance Guide", Appendix E "Overview of Battery-Related NRC Documents". This document contains a summary of NUREG/CR-5448 "Aging Evaluation of Class 1E Batteries", which concludes that the tests recommended by IEEE Std 450 provide an indication of adequate seismic capability when the batteries are maintained and operated in accordance with the standard.

Based on the above, it was concluded that AEP has an acceptable procedure for replacing batteries and the outlier was resolved.

8. *Item 1 in Table 4-7 of Attachment 2 (Reference 1) indicates that a total of 101 equipment items were similar to but different from components in the class of 21 equipment, and that necessary evaluation were made to meet the intent of the GIP caveats. Provide details regarding these evaluations and how the intent of caveats was met. These details should*

include the following information in a tabular form for each of these equipment items:

a) Equipment description
b) Caveat Number in the GIP-2
c) Description of deviation from the GIP-2 caveat
d) Justification for resolution

Response to Question 8:

Item 1 in Table 4.7 of the Seismic Evaluation and Walkdown Report submitted to the NRC as Attachment 2 of letter AEP:NRC:1040C, dated January 30, 1996, indicates that the class 0 equipment items were primarily passive and were similar to items considered in the "box" of the class of 21 equipment. These equipment items were evaluated to applicable caveats for the item. In addition the GIP Seismic Capacity vs. Demand, anchorage and interaction criteria were met for the items. The applicable criteria for these three GIP-2 screening criteria are met. Tables 2 and 3 (Appendix B of this response) provide the equipment description, applicable caveats and justification for resolution for each item. It was concluded that the intent of the applicable caveats was met and, therefore, deviations from the GIP-2 caveats are not included in the caveat descriptions. The remaining caveats were considered by the SRT to be not applicable.

9. *In Appendix E of Attachment 3 (Reference 1), provide the basis for Footnotes (6) and (10) at the end of the tabulation of the Unit 1 essential relays' capability vs. demand summary, which indicate that these type of relays use only normally open contracts for essential functions, thus, increasing the seismic capability, and removing the low ruggedness restriction for these relays. In addition, explain the distinction between the two footnotes.*

Response to Question 9:

The subject of Footnotes (6) and (10) are General Electric type HFA and HGA relays, respectively. The seismic capacities (ruggedness) of these relays are derived from Electric Power Research Institute (EPRI) Report NP-7148-SL, Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality, dated December 1990 and General Electric (GE) Test Report RN-150. The use of these documents to develop the determination of seismic capacity of these relays was previously provided in AEP:NRC:1040C Attachment 3, Section 4.0.

AEP:NRC:1040C Attachment 3, Appendix E, Footnote (6) states "These General Electric type HFA relays use only normally open contacts for essential relay functions, therefore, the seismic capacity is increased." The intent of this footnote was to convey that the GE HFA relays, which Footnote (6) is associated with, do not make use of their single normally closed contact for an essential function, therefore the relay seismic qualification is not limited by the reduced seismic capacity of the normally closed contacts. Rather, the seismic capacity of the normally open contacts in the deenergized state is listed since only these contacts are used for an essential function. GE Test Report RN-150 states that normally closed contacts on GE HFA relays have lower

seismic capacities than normally open contacts in the de-energized state.

AEP:NRC:1040C Attachment 3, Appendix E, Footnote (10) states "These General Electric type HGA relays use only the normally open contacts, therefore, the Low Ruggedness restriction does not apply." This footnote describes the use of the GE HGA relays to demonstrate that their use does not conflict with the known low ruggedness operating mode of the GE HGA relay. EPRI Report NP-7148-SL, Appendix E (Low Ruggedness Relays) describes the low ruggedness operating mode of GE HGA relays as the use of normally closed contacts in the de-energized state only. This is also described in GE Test Report RN-150 which lists the seismic capability of the de-energized, normally closed contacts of the GE HGA relay as 0.5g ZPA which is far less than the Cook Nuclear Plant plant-specific demand for this relay. Therefore, by not using normally closed contacts, the low ruggedness quality of the GE HFA relay is avoided.

Additional Comments: In January 1999, a concern was raised regarding the fact that I&M had not been following the General Electric recommendation that HFA relays should be calibrated after they have been modified. I&M cook the position that the seismic performance of essential HFA relays that had been modified would be indeterminate and subsequently declared affected systems inoperable. To correct this condition, I&M has developed calibration and test procedures to regain confidence in the ability of these relays to perform their essential function in a seismic event. Successful implementation of these calibration and test procedures is necessary to properly utilize the seismic capacity parameters listed for the GE HFA relays in GE Test Report RN-150.

10. *In Appendix E of Attachment 3 (Reference 1), Footnote (9) of the Unit 1 essential relays' capability vs. demand summary table indicates that the amplification of certain relay panel was calculated using case specific analysis. Considering relay panel under Tag Number 2-88X1-BCB as an example, provide an illustration how the case specific analysis was performed.*

Response to Question 10:

The subject relay is housed in cabinet 2-BC-B-PNL. An outline drawing of the cabinet and the calculated in-cabinet response spectrum was provided in Appendix D of Attachment 3 to AEP:NRC:1040C and is also provided here.

The cabinet consists of a small junction box (12"x12"x 6") containing two relays. The box is mounted on a flexible stand constructed of 2"x2"x1/4" steel angles (see Figure 2a on page 11). The cabinet is modeled as a single-degree-of-freedom (SDOF) system with a stiffness of 384 lb/in (two 4.5' long 2x2x1/4 cantilevers), a weight of 64 lbs (31 lbs for the box, 10 lbs for the contents, and 23 lbs for half the weight of the steel). This yields a frequency of 7.7 Hz, which is reduced by 20% to 6 Hz to account for any uncertainties in the calculation (the reduction is conservative because the floor response spectrum increases with decreasing frequency). The in-cabinet response spectrum (ICRS) is calculated using 3% cabinet damping and using the same direct generation calculation embodied in GENRS (which was accepted by the NRC on page 26 of GIP SSER No. 2). The 5% damped ICRS and FRS (floor response spectrum) are shown in Figure 2b. The ICRS has a peak value between 4

Hz and 16 Hz of 2.2g and a ZPA of 0.42g. These values are multiplied by 1.5 and the resulting values of 3.3g peak / 0.63g ZPA are used as the relay demand.

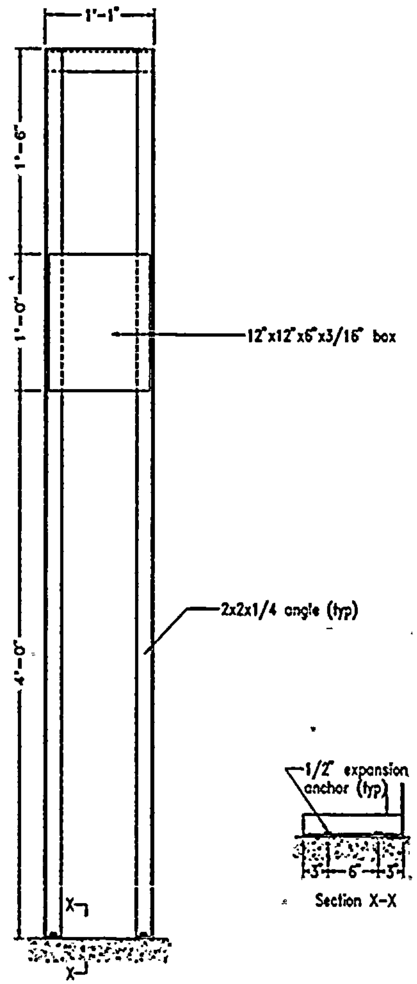


Figure 2a 2-BC-B-PNL outline drawing.

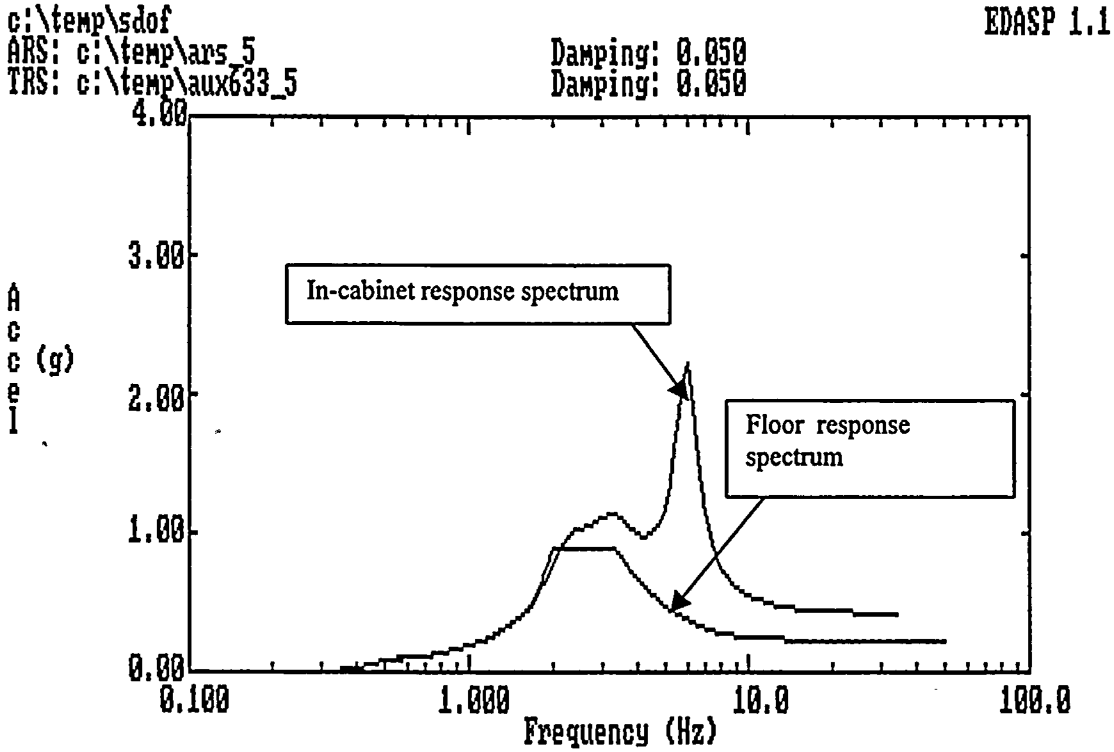
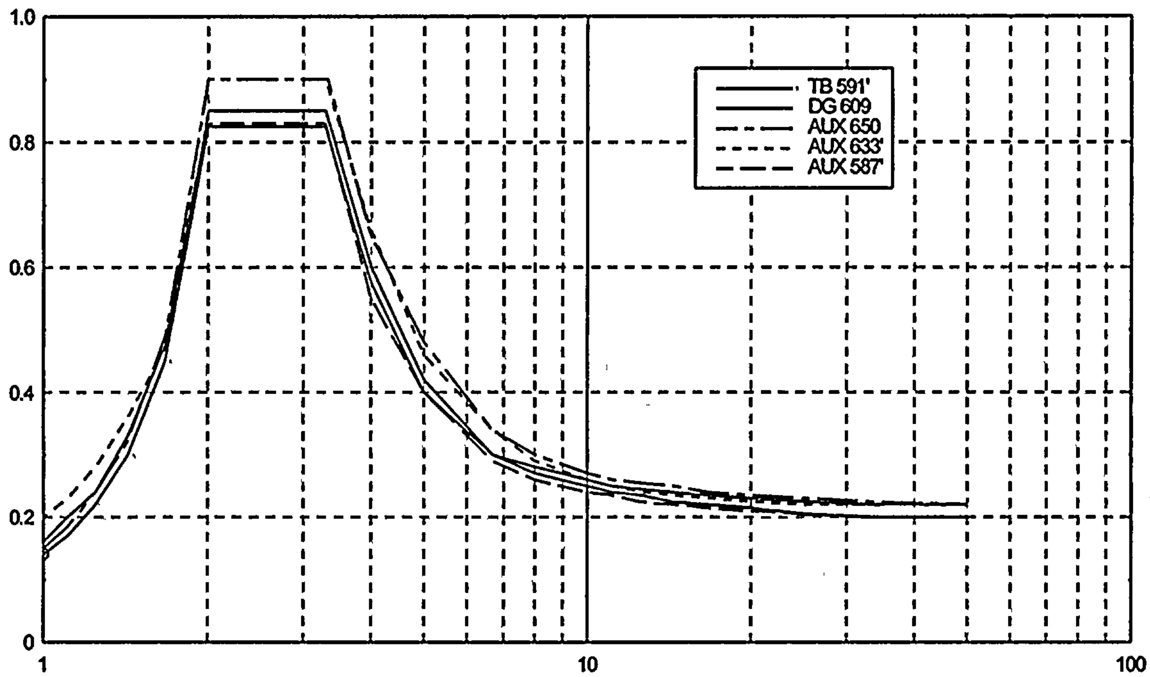


Figure 2b 2-BC-B-PNL floor response spectrum (FRS) and in-cabinet response spectrum (ICRS)

11. *In Appendix E of Attachment 3 (Reference 1), Footnote (20) of the Unit 1 essential relays' capability vs. demand summary table indicates that for relays located between elevations for which floor response spectra were developed, the next highest elevation was used. As indicated in many cases, the developed response spectra may not pertain to the same building in which the relays to be seismically verified are located. Explain how the pertinent response spectra were selected for this population of relays.*

Response to Question 11:

The A-46 floor response spectra for structures other than the Containments are shown in the following figure.



The Auxiliary and Diesel Generator Buildings are independent reinforced concrete structures founded on a common mat. The top of the mat is at elevation 587' except for a portion of the Auxiliary Building where it drops down to elevation 562'. As can be seen from the floor response spectra, the seismic response of these structures is typical of deep soil sites: the entire foundation mat translates uniformly at a low frequency, with little inter-story building deformation - note that there is little difference in the response spectra for different elevations.

The majority of the electrical equipment housing essential relays are in the electrical equipment areas on elevation 587' and 609' of the Diesel Generator Buildings and in the Control Rooms on elevation 633' of the Auxiliary Building. There are a few cabinets in the Control Room HVAC area on elevation 650'.

The majority of cabinets are floor mounted - the corresponding floor response spectrum was used to calculate the seismic demand on the relay.

Some of the cabinets are wall mounted or floor mounted in an area not at one of the standard elevations; in these cases, the floor response spectrum for the next higher elevation was used. As noted in the above figure, the floor response spectra for the different elevations are only slightly different and do not have a very significant impact on the relays' seismic demand.

12. *Provide the basis for Footnote (17) of the Unit 1 essential relays capability vs. demand summary table (Reference 1), which indicates that the floor response spectrum at elevation 591 ft. of the Turbine Building was used for relays located at elevation 594 ft. of the Screenhouse. Explain the inconsistency between this footnote and Footnote (20), which indicates that the spectrum at the higher elevation was used for the relays' evaluation.*

Response to Question 12:

The Screenhouse is appended to the West side of the Turbine Building. They are steel frame structures anchored at elevation 591' to a substantial reinforced concrete substructure that extends down to elevation 546' at the Screenhouse and elevation 562' below the Turbine Building. The only floor response spectrum available is for elevation 591' of the Turbine Building - it is shown in the above figure (RAI Question 11) and is essentially identical to the floor response spectrum for elevation 587' of the Auxiliary Building.

The subject essential relays are housed in four MCCs (1-PS-A, 1-PS-D, 2-PS-A, 2-PS-D) that are located in two cubicles in the northwest and southwest corners of the Screenhouse. The MCCs are anchored to stiff structures that elevate them 3' above the general area floor elevation of 591'. The SCEs (seismic capability engineers) judged that the motion at the base of the MCCs would not differ substantially from that at elevation 591'. As there are no floor spectra for higher elevations in this area of the plant, the Turbine Building 591' floor spectrum was used for the evaluation of the relays.

13. *The NRC staff has concerns about the way the A-46 cable trays and conduit raceways issue was being dispositioned by licensees. We issued Requests for Additional Information (RAI) to several licensees on this issue. SQUG responded instead of the licensees because SQUG considered the RAI to be generic in nature. The staff issued a subsequent RAI to SQUG as a follow up to their response. However, the staff found that the correspondence with SQUG did not achieve the intended results in that they did not address the technical concerns of the staff. Therefore, we are stating our concerns in the following discussion.*

The GIP procedure recommended performing what is called a limited analytic evaluation for selected raceways and cable trays. The procedure further recommended that when a certain cable tray system can be judged to be ductile and if the vertical load capacity of the anchorage can be established by a load check using three times the dead weight, no further evaluation is needed to demonstrate lateral resistance to vibration from earthquakes. The staff has concerns with the manner in which these simplified GIP criteria were implemented at your plant.

The GIP procedure eliminates horizontal force evaluations by invoking ductility. However, all the so called non-ductile cable trays would eventually become ductile by inelastic deformation, buckling or failure of the non-ductile cable tray supports and members. If this procedure was followed for eliminating cable trays for further assessment at your plant, then all the cable trays could conceivably be screened out from A-46 evaluation. We are requesting your response to the following items to elicit information that would support our safety evaluation of cable trays at your plant.

a) Define ductility in engineering terms. Clarify how this definition is applied to actual system configurations consistently for the purpose of analytical evaluation.

Response to Question 13.a)

Ductility, as used in the GIP procedures for evaluating raceway supports, is best illustrated by a simple example: consider a raceway support that consists of a single steel post hanging from building steel. The post is welded to the building steel. If the moment capacity of the weld pattern anchoring the post to the building steel is greater than the plastic moment of the post (as would typically be the case with an all-around weld), then the support is ductile and the GIP procedure does not require a lateral load evaluation. If, on the other hand, the moment capacity of the weld pattern is less than the plastic moment of the steel post (as may be the case with an intermittent weld pattern), then the support is non-ductile and must meet the GIP's requirements for a lateral load evaluation or be declared an outlier.

The GIP states this requirement in the first paragraph of Section 8.3.3:

> "...Supports suspended only from overhead may be characterized as ductile if they can respond to lateral seismic motion by swinging freely without degradation of primary vertical support connections and anchorage. Ductile, inelastic performance such as clip angle yielding or vertical support yielding is acceptable so long as deformation does not lead to brittle or premature failure of overhead vertical support."

The GIP states that if non-ductile failure of the overhead support would occur prior to the support reaching its fully plastic state, then a lateral load evaluation is required.

c) Provide the total number of raceways that were selected for worst-case analytical calculations and were classified as ductile in your A-46 evaluation and for which you did not perform a horizontal load evaluation. Indicate the approximate percentage of such raceways as compared with the population selected for analytical review. Discuss how the ductility concept is used in your walkdown procedures.

Response to Question 13.b)

In accordance with GIP-2, Section 8, a limited analytical review was conducted for selected worst case supports. A total of 29 supports were selected for limited analytical review. They are categorized as follows:

#	Type	Ductile
14	Rigid wall mounted supports; dead weight analysis only	N/A
7	Rod trapeze hangers; dead weight analysis, vertical capacity check, and fatigue evaluations.	Yes
4	Floor mounted; dead weight analysis and lateral load evaluation	No
2	Ductile trapeze frames; dead weight analysis and vertical capacity check	Yes
2	Floor-to-ceiling supports; dead weight analysis and lateral load evaluation	No

No raceway population data was collected during the A-46 walkdowns as this is not required by the GIP. The following is a general description of the raceway populations:

Rigid wall mounted supports: found throughout the plant, many different details were used resulting in the high number selected for analytical review.

Rod trapeze hangers: found throughout the plant, the most common non-rigid support.

Floor-to-ceiling supports: found in the cable vaults above the switchgear areas, large number of these supports in this area, but they are of a consistent design.

Floor mounted supports: small number of unique design found in several areas of the plant.

Ductile trapeze frames: small number of unique design found in two areas of the plant.

The walkdown procedures used are described in Section 8.2 of GIP-2. These procedures do not require the ductility concept to be used during the walkdown. The only place where the ductility concept is used is in the Limited Analytical Review. The procedure used for this review is contained in GIP-2, Section 8.3.

d) *Describe the typical configurations of your ductile raceways (dimension, member size, supports, etc.)*

Response to Question 13.c):

Rod trapeze hangers: 5/8" threaded rods, 2"x2"x1/4" steel angle cross members, 1 to 6 tiers, up to about 15' long, rods anchored by bolting to embedded Unistruts or threading into shell-type concrete expansion anchors.

Trapeze frames (cable vaults below the control rooms): 3"x3"x1/4" steel angle vertical members and cross pieces, two tiers, 4' total height, anchored with clip angles bolted into embedded Unistruts.

Trapeze frames (containment basement): 2"x2"x1/4" steel angle vertical members and cross pieces, three tiers, 4' total height, anchored by welding to building steel.

e) *Justify the position that ductile raceways need not to be evaluated for horizontal load. When a reference is provided, state the page number and paragraph. The reference should be self-contained, and not refer to another reference.*

Response to Question 13.d):

The justification for stating that ductile raceways need not be evaluated for horizontal load is provided in Section 8 of the GIP and in the Senior Seismic Review and Advisory Panel (SSRAP) report upon which the GIP is based. The GIP, Section II.8.3, Limited Analytical Review Guidelines, states the following:

> "As shown in Figure 8-6, supports characterized as ductile do not require an explicit lateral load check. Instead, seismic ruggedness for ductile raceway supports is assured by the Vertical Capacity Check (Section 8.3.2). The high vertical capacity of the ductile data base raceway supports is the main attribute credited for their good seismic performance." (GIP-2, Part II, pg. 8-19)

The basis for not evaluating horizontal loads during the Limited Analytical Review of raceway systems with ductile supports is described further on page 17, paragraphs 1 and 2 of the SSRAP report where it states the following:

> "A limited analytical review shall be performed on those cable tray supports selected by the SRT and the walkdown engineers as representative of conditions within the plant with the lowest estimated seismic margin. The intent of this limited analytical review is not to simulate potential seismic performance or stresses, but to correlate, approximately, conditions within the plant analytically with conditions that performed well in the experience database.
>
> It is important for the analyst to understand the philosophy behind this limited analytical review. As previously discussed within this report, cable trays and supports have performed extremely well in past earthquakes and shaking table tests with few exceptions. The trays and their supports typically act as pendulums and wiggle and sway but do not fail. Ductile inelastic performance such as yielding of clip angle supports or steel vertical support members is completely acceptable as it allows the cable tray to deform and move without brittle or premature failure. The high damping inherent in cable tray systems reduces the dynamic motions resulting from the inelastic performance and maintains integrity." (SSRAP Report, pg. 17)

The SSRAP report goes on to say on page 26, paragraph 1, that earthquake experience and shake table tests show that if the ductile raceway supports have a large dead load margin (i.e., they pass the GIP three times dead load check), no lateral load check is required:

> "It must be kept in mind that this limited analytical review is not intended to simulate potential seismic performance or stresses, but to correlate approximately conditions within the plant analytically with conditions that performed well

in the experience data base. The rationale for the checks is as follows: . . . The 3.0 times dead load without eccentricity check is a simple check to insure that the basic connectors have a large dead load margin. The experience data base supports pass this check and verification of a large dead load margin provides assurance that if an isolated support should fail for some unforeseen situation, that a progressive support failure mechanism is unlikely. For ductile mechanisms, no lateral load check is required consistent with the experience data base and shake table test experience." (SSRAP Report, pg. 26)

The NRC staff reviewed the GIP methodology during the period of time from 1987 to 1992. As a result of that review, the staff took the position on pages 30 and 31 of SSER No. 2 that:

"... the plant walkdown guidelines represent an acceptable approach for evaluating the seismic adequacy of existing cable and conduit raceways in USI A-46 plants. Also, the staff agrees that the proposed analytical procedure is a reasonable approach to ensure that the cable and conduit raceways and supports in USI A-46 plants, when all the guidelines are satisfied, are as rugged as those observed in the past earthquake experience data. Although the proposed guidelines would not require detail analyses and, therefore, would not predict the structural response of the raceway support systems, they should provide the needed rationale to judge the seismic adequacy of the raceway support systems with a reasonable factor of safety. Therefore, the staff concludes that the proposed guidelines for evaluation of seismic adequacy of cable and conduit raceways and their supports are acceptable subject to the staff evaluations described in this supplement." (SSER No. 2, pgs. 30, 31)

We conclude from the above statement that the NRC staff position is that the GIP method is acceptable for evaluating the seismic adequacy of cable and conduit raceways and their supports. We consider our review of the effect of lateral loads on cable and conduit raceway systems to be in accordance with the requirements and intent of GIP-2 as approved for use by the NRC staff in SSER No. 2.

f) *In the evaluation of the cable trays and raceways, if the ductility of the attachments is assumed in one horizontal direction, does it necessarily follow that the same system is ductile in the perpendicular direction?*

Response to 13.e):

The ductility of supports for cable and conduit raceway in the longitudinal direction is addressed using the procedure in GIP, Section II.8.2.3, where our raceway systems were evaluated for "hard spot" supports. No other analyses for longitudinal forces are required for cable tray supports hung from above or attached to a wall. Aside from this check for "hard spots," the GIP does not require an evaluation of raceway support ductility in the longitudinal direction. The basis for this is found in the SSRAP report, page 27, paragraph 2, which states:

"SSRAP also does not intend that the cable tray supports hung from above or attached to a wall be checked for

> longitudinal lateral forces, i.e., lateral forces parallel to the long run of the cables. There are numerous cases of this condition in the experience data base without damage or distress to the cables (Reference 7), and SSRAP does not believe that analytical checks are needed for this condition. The experience data base justifies this situation, and ductile pendulum action will be sufficient for good performance." (SSRAP Report, pg. 27)

Reference 7 cited in the above quotation is the same as GIP Reference 19, EPRI Report NP-7153, "Longitudinal Load Resistance in Seismic Experience Data Base Raceway Systems," March 1991.

As discussed in response to NRC RAI Question 13.d) above, the GIP method, including the loadings on the raceway supports in the longitudinal direction, was reviewed and accepted by the NRC staff in SSER No. 2. We consider our review of the effect of longitudinal loads on cable and conduit raceway systems to be in accordance with GIP-2 as approved for use by the NRC staff in SSER No. 2.

g) Discuss raceways and cable trays including supports in your plant that are outside of the experience data. Explain what criteria are used for establishing their safety adequacy and specify your plan for resolution of outliers that did not meet the acceptance criteria. Provide examples of the configurations of such raceways and cable trays including supports. Also, indicate the percentage of cable trays and raceways outside the experience data in relation to the population of raceways and cable trays examined during the walkdowns of the safe shutdown path. How are they going to be evaluated and disposed?

Response to Question 13.f):

All the cable and conduit raceway systems in the plant are within the scope of the seismic review procedures contained in the GIP except those that were identified as outliers. GIP Section II.8.0, page 8-2, paragraph 2 describes the scope of raceway systems which are covered by the GIP as follows:

> "The seismic review guidelines contained in this section are applicable to steel and aluminum cable tray and conduit support systems at any elevation in a nuclear power plant, provided the Bounding Spectrum (shown in Section 4, Figure 4-2) envelopes the largest horizontal component of the 5% damped, free-field, safe shutdown earthquake (SSE) ground response spectrum to which the nuclear plant is licensed." (GIP-2, pg. 8-2)

The raceways that were classified as outliers did not meet the "Inclusion Rules," had "Significant Other Seismic Performance Concerns," or did not satisfy the "Limited Analytical Review Guidelines" contained in the GIP. Descriptions of the raceway outlier configurations are summarized in the following table.

Unit 2 - Containment - Accumulators 2, 3 Area (RACE003)

In this area, two cable trays are rigidly supported from steel columns that are about 15′ apart. 2x2x1/4 steel angle framing spanning between the columns supports the cable trays at mid-span. The Limited Analytical Review showed that the framing alone does not meet design allowables for the dead weight of the cable trays. If the framing is ignored, the trays do not meet the Inclusion Rule requirement of 10′ between supports.

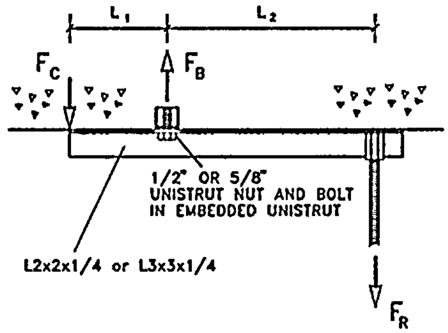
The outlier was resolved analytically by showing that the combination of the trays and the framing can support the required load.

Unit 1 - Aux Building - Startup Blowdown Flashtank Room & Vestibule Area (RACE101)

A 1″ conduit in this area is missing several conduit clamps, resulting in an overspan condition. The recommended resolution was to replace the clamps. The clamps have been replaced; see Cook Nuclear Plant action request A/R #0108046.

Unit 1 - Aux Building - Area around Containment from Az 90° to Az 360° (RACE103)

A common (but not prevalent) rod hanger anchorage detail used at Cook is shown below. In most cases it has an acceptable configuration: $L_2 \leq L_1$ and $L_2+L_1 \leq 12''$. The worst-case configuration consisted of a heavily loaded hanger (1200 lb dead weight) with $L_2 = 10''$ and $L_1 = 2''$. This configuration does not meet the LAR requirements.



The recommended resolution to this outlier was to walk down the plant and document all occurrences of this detail, screen the specific configuration of each detail using acceptance criteria based on the LAR requirements. Fifty occurrences were found and documented, 12 did not meet the screening criteria. All supports not meeting the screening criteria will be modified to satisfy the GLP-2 requirements. This work is being carried out under Design Change No. 208 and it is presently scheduled to be completed during the current plant outage.

Unit 1 - Containment - Outside Crane Wall El 609' - 638'

Two small-diameter conduits in this area are unsupported over a length of about 30′. The recommended resolution was to support the conduit so that they meet the Inclusion Rules′ requirements. This condition has been corrected; see Cook Nuclear Plant action request A/R #A0102439.

The RAI question also asks for the percentage of raceways that are outliers with respect to the whole population of raceways. This information was not collected during the raceway walkdown since it is not part of the GIP, however, based on the outlier information provided in the above table, the percentage is small.

g) Submit the evaluation and analysis results for four of the representative sample raceways (one single non-ductile, one single ductile, one multiple non-ductile, and one multiple ductile raceway), including the configurations (dimension, member size, supports, etc.).

Response to Question 13.g):

The GIP raceway procedure only requires that single supports be evaluated. The evaluations for four supports - two ductile (a trapeze rod hanger and a trapeze frame) and two non-ductile (a floor-to-ceiling support and a floor-mounted support) are attached to this response as Appendix C, which consists of the following:

1. Pages 3-9 through 3-16 of an internal report documenting the A-46 raceway effort. These pages contain the design inputs referenced in the Limited Analytical Reviews (LAR).

2. LAR #1: Rod trapeze hanger

3. LAR # 11: Floor mounted support

4. LAR # 13: Floor-to-ceiling support

5. LAR # 28: Trapeze frame

14. In your program were there any deviations from the GIP guidance? Provide the worst-case items (from the safety point of view) which deviate from the GIP-2 guideline but were categorized as not being significant. In addition, you are requested to submit the definition of "safety significant" that the walkdown crew used and provide a justification of why the definition is adequate.

Response to Question 14:

Our review determined that there were no significant or programmatic deviations from the GIP guidance that required a declaration in the final USI A-46 summary report. Section I.1.3 of the GIP states that it was not necessary to notify the NRC of minor deviations from the GIP guidance or to justify these deviations. However, Cook Nuclear Plant personnel identified minor deviations from the GIP-2 guidance by including Table 4-7 "Commentary on Equipment Items Meeting the Intent of GIP Caveats" in the Attachment 2 report, sent under letter AEP:NRC:1040C, dated January 30, 1996. These are considered minor deviations. In addition the SEWS are available for NRC review and audit. The determination that these deviations were "minor" were made by qualified, experienced engineers who had each completed the appropriate SQUG training courses on the use and application of judgment for resolution of USI A-46. I&M personnel implemented equivalent methods in completing the USI A-46 effort. These included the

technically detailed anchorage inspections, SEWS development and anchorage evaluations using computerized techniques.

A definition of "safety significant" was not mentioned in the GIP-2 or the NRC SSER that endorsed its use. Therefore, a definition was not made available to the walkdown crews during the evaluation process. As stated above, examples of what are considered "insignificant" deviations from the GIP-2 guidance are contained in Table 4-7 of the original submittal. I&M would consider use of lower safety factors for anchorage evaluations (for example use of a factor of safety of 2 for expansion bolts), or use of fluid holddown force for evaluating large flat bottom tanks as examples of "significant" deviations. The I&M effort did not include these types of deviations.

15. *Indicate whether you found an anchor type (e.g. lead cinch anchor) not covered by the GIP-2 during the walkdown. If yes, how did you resolve the issue?*

Response to Question 15:

SQUG databases (SEWS, notes, calculations etc.) were reviewed to identify whether any equipment in the Safety Shutdown Equipment List (SSEL) was anchored with an anchor type that is not specifically covered by the GIP-2. This review indicated that the large Condensate Storage Tanks and Refueling Water Storage Tanks are the only equipment that are anchored with an anchor type that is not specifically covered by the GIP-2.

As shown in item 16 of Table 4-7 of the original submittal report (letter AEP:NRC:1040E dated March 10, 1997), the large Condensate Storage Tanks and Refueling Water Storage Tanks were anchored with metal straps. These straps were converted to equivalent bolts to meet the GIP criteria. This was done by calculating an allowable load for the strap based on 1.7 times normal allowables which is equivalent to the bolt allowable for cast in place bolts. The embedment into the concrete was checked using ACI 318-63 (the licensing basis for Cook Nuclear Plant), and the weld to the tank wall was checked using AISC criteria times 1.7 (the GIP-2 criteria).

APPENDIX "A"
TO
ATTACHMENT NO. 1 TO AEP:NRC:1040G

COMPARISON OF 5% DAMPED
IN-STRUCTURE RESPONSE SPECTRA
TO 1.5 TIMES THE BOUNDING SPECTRUM

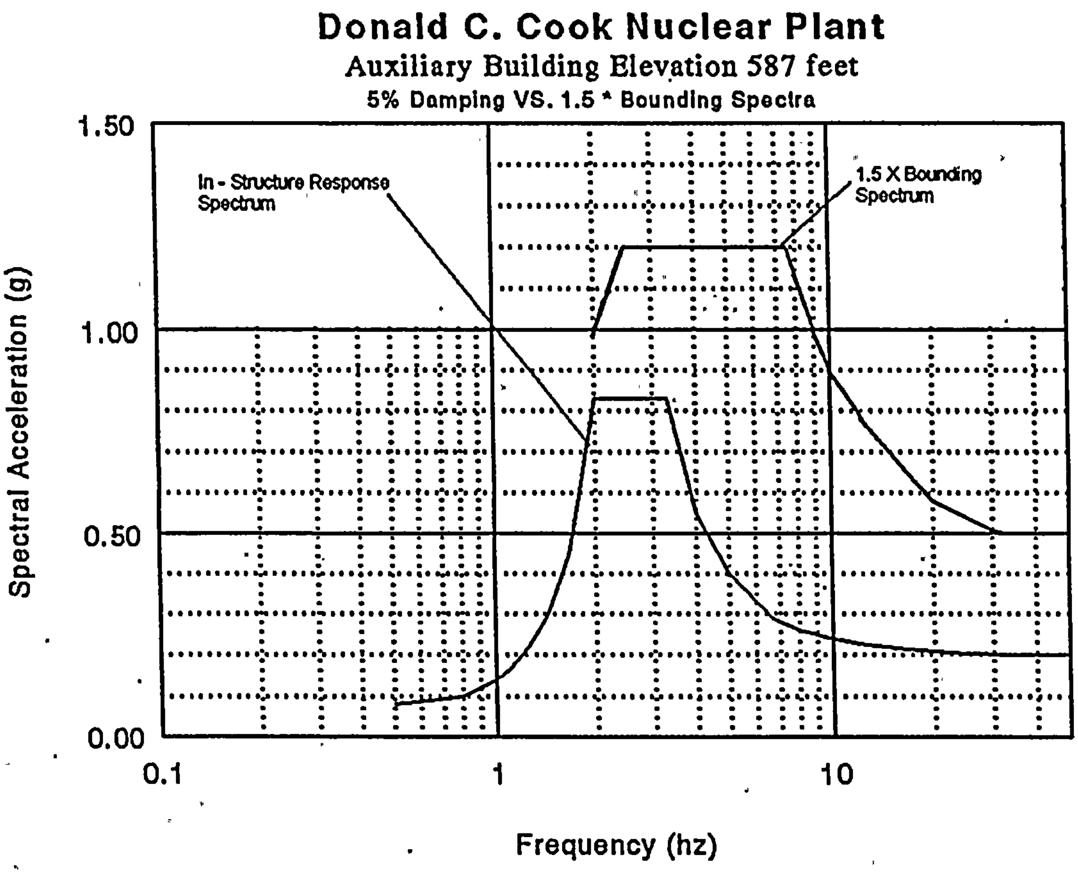

Donald C. Cook Nuclear Plant
Auxiliary Building Elevation 587 feet
5% Damping VS. 1.5 * Bounding Spectra
In - Structure Response Spectrum
1.5 X Bounding Spectrum
Spectral Acceleration (g)
1.50
1.00
0.50
0.00
0.1
1
10
Frequency (hz)

Figure 1

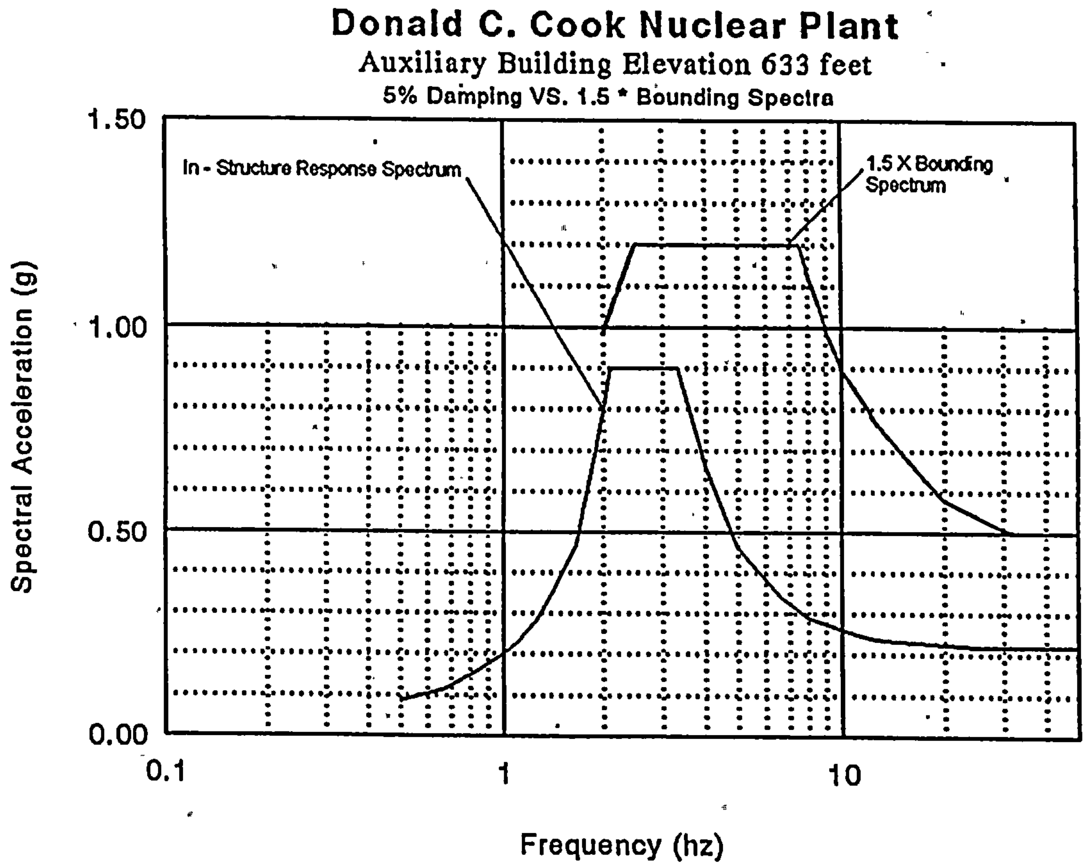

Donald C. Cook Nuclear Plant
Auxiliary Building Elevation 633 feet
5% Damping VS. 1.5 * Bounding Spectra
In - Structure Response Spectrum
1.5 X Bounding Spectrum
Spectral Acceleration (g)
1.50
1.00
0.50
0.00
0.1
1
10
Frequency (hz)

Figure 2

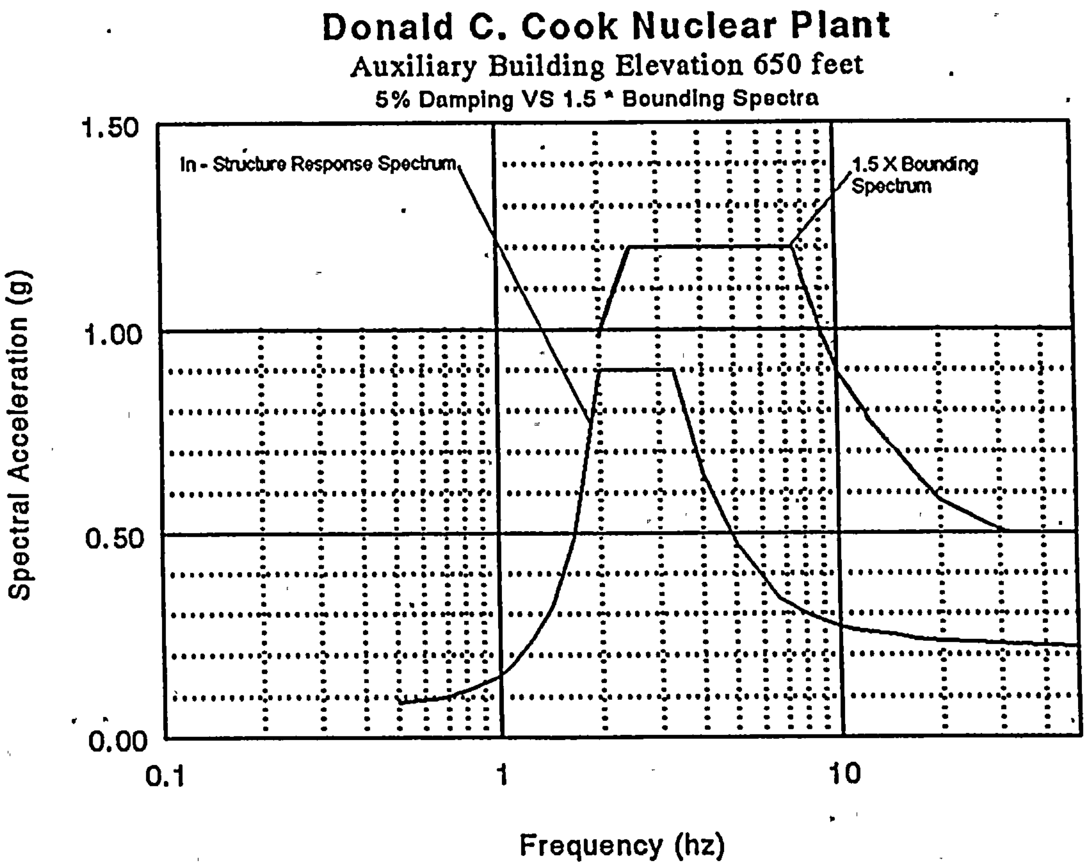

Donald C. Cook Nuclear Plant
Auxiliary Building Elevation 650 feet
5% Damping VS 1.5 * Bounding Spectra
In - Structure Response Spectrum
1.5 X Bounding Spectrum
Spectral Acceleration (g)
1.50
1.00
0.50
0.00
0.1
1
10
Frequency (hz)

Figure 3

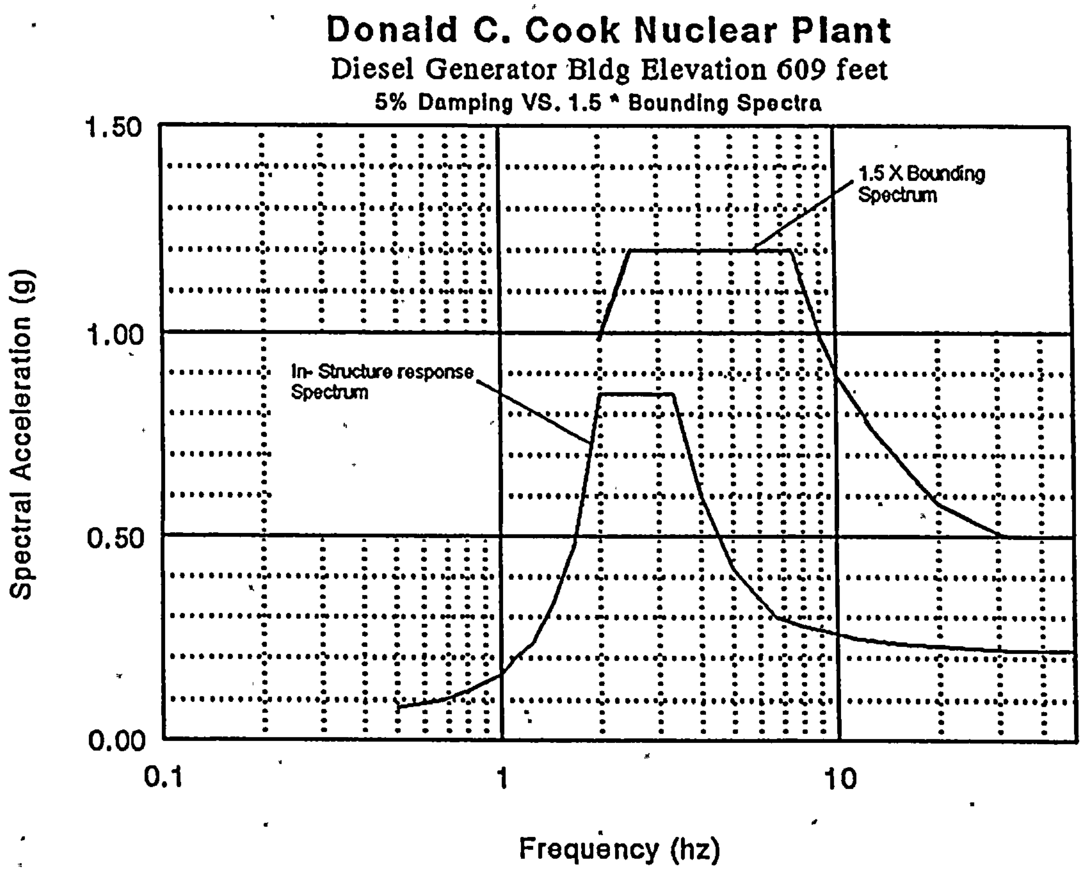

Donald C. Cook Nuclear Plant
Diesel Generator Bldg Elevation 609 feet
5% Damping VS. 1.5 * Bounding Spectra
1.50
1.00
0.50
0.00
0.1
1
10
Spectral Acceleration (g)
Frequency (hz)
1.5 X Bounding Spectrum
In- Structure response Spectrum

Figure 4

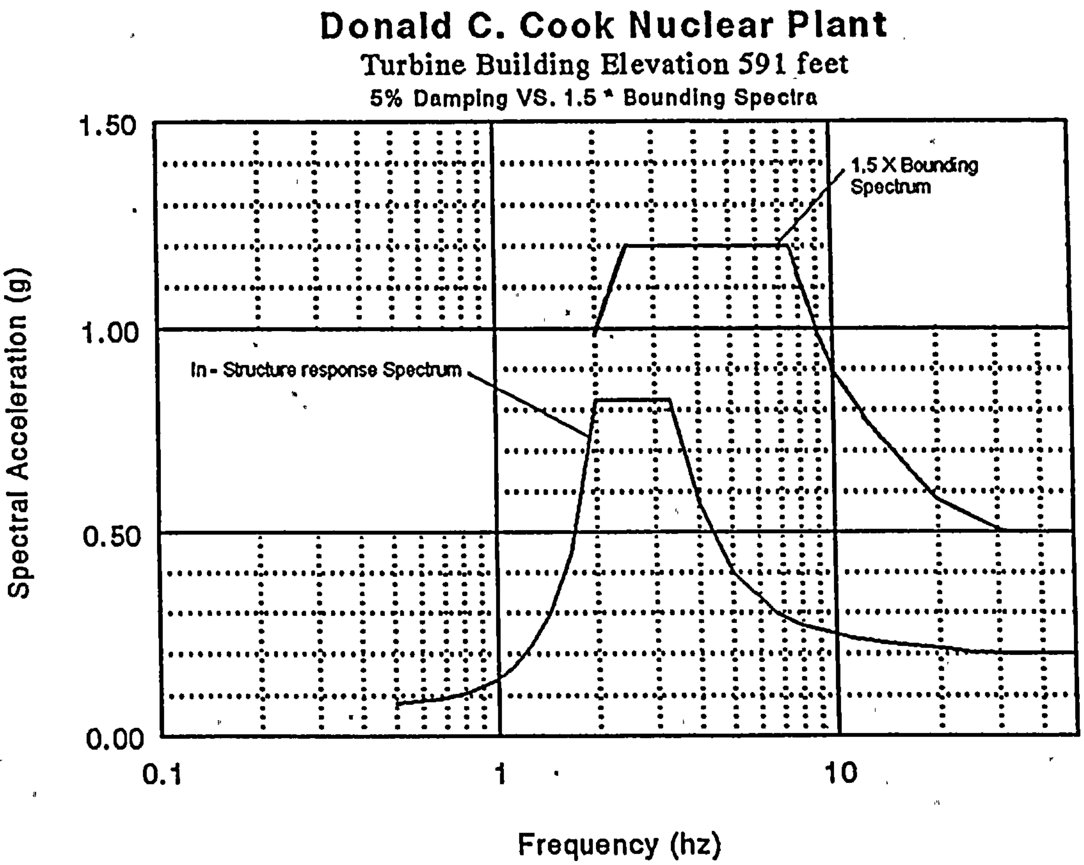

Donald C. Cook Nuclear Plant
Turbine Building Elevation 591 feet
5% Damping VS. 1.5 * Bounding Spectra
1.50
1.00
0.50
0.00
0.1
1
10
Spectral Acceleration (g)
Frequency (hz)
1.5 X Bounding Spectrum
In - Structure response Spectrum

Figure 5

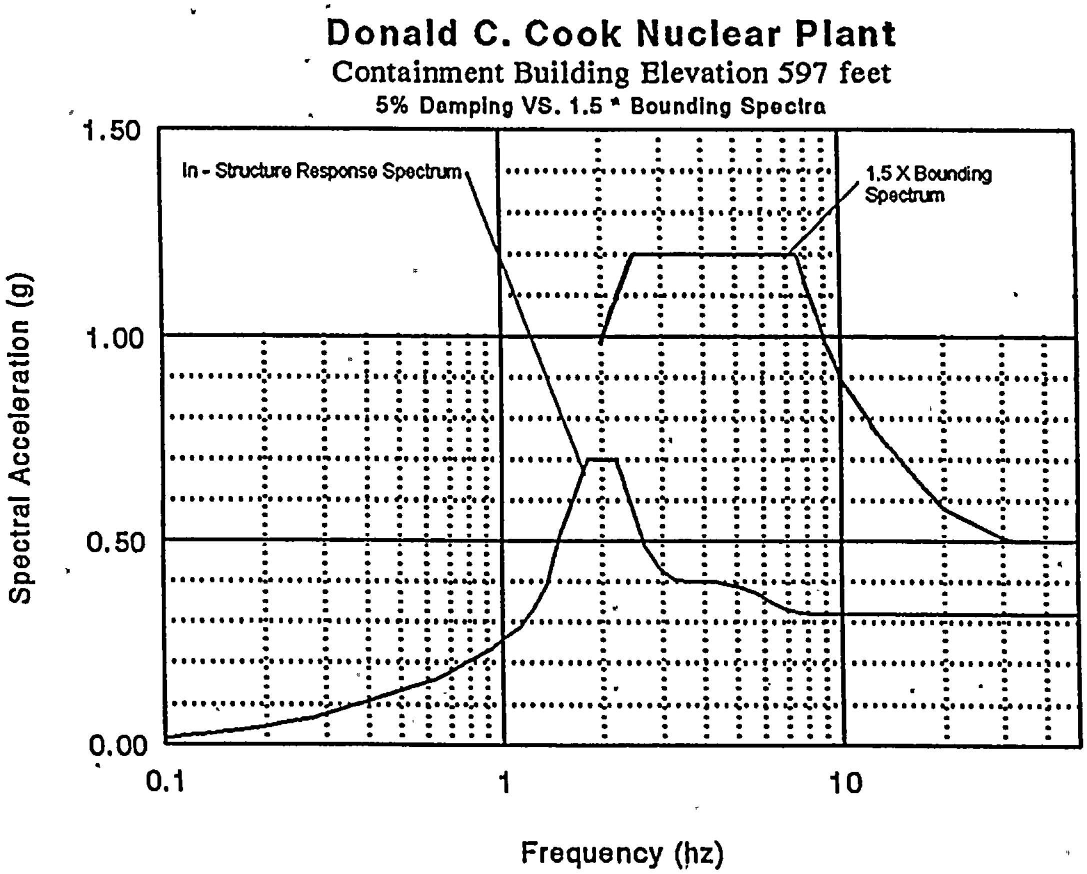

Donald C. Cook Nuclear Plant
Containment Building Elevation 597 feet
5% Damping VS. 1.5 * Bounding Spectra
In - Structure Response Spectrum
1.5 X Bounding Spectrum
Spectral Acceleration (g)
1.50
1.00
0.50
0.00
0.1
1
10
Frequency (hz)

Figure 6

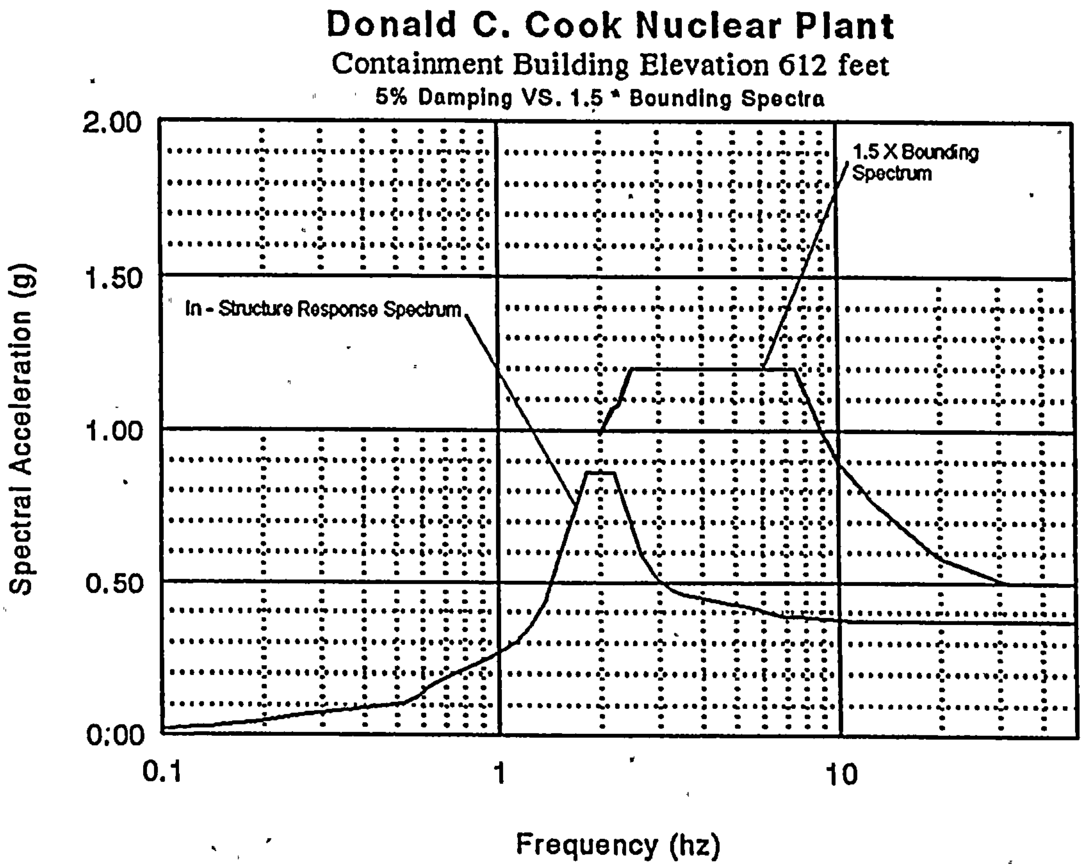

Donald C. Cook Nuclear Plant
Containment Building Elevation 612 feet
5% Damping VS. 1.5 * Bounding Spectra
2.00
1.50
1.00
0.50
0.00
Spectral Acceleration (g)
1.5 X Bounding Spectrum
In - Structure Response Spectrum
0.1
1
10
Frequency (hz)

Figure 7

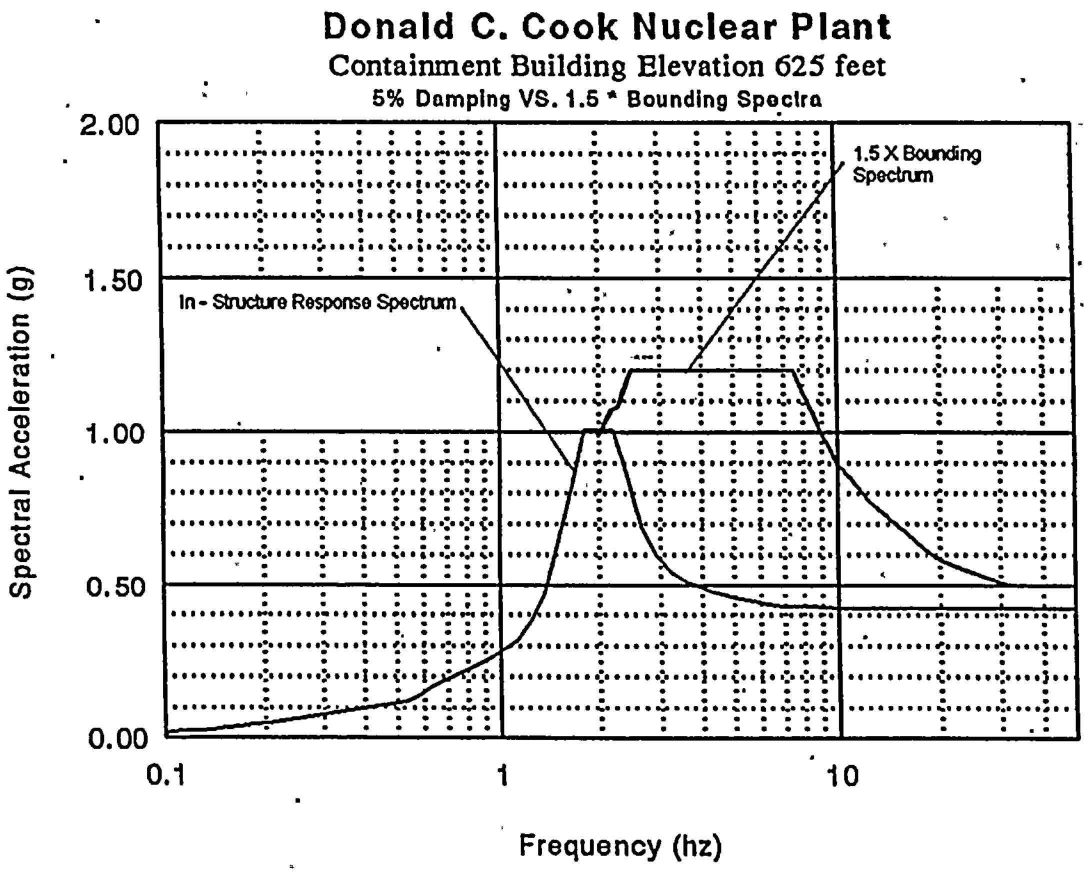

Donald C. Cook Nuclear Plant
Containment Building Elevation 625 feet
5% Damping VS. 1.5 * Bounding Spectra
1.5 X Bounding Spectrum
In - Structure Response Spectrum
Spectral Acceleration (g)
2.00
1.50
1.00
0.50
0.00
0.1
1
10
Frequency (hz)

Figure 8

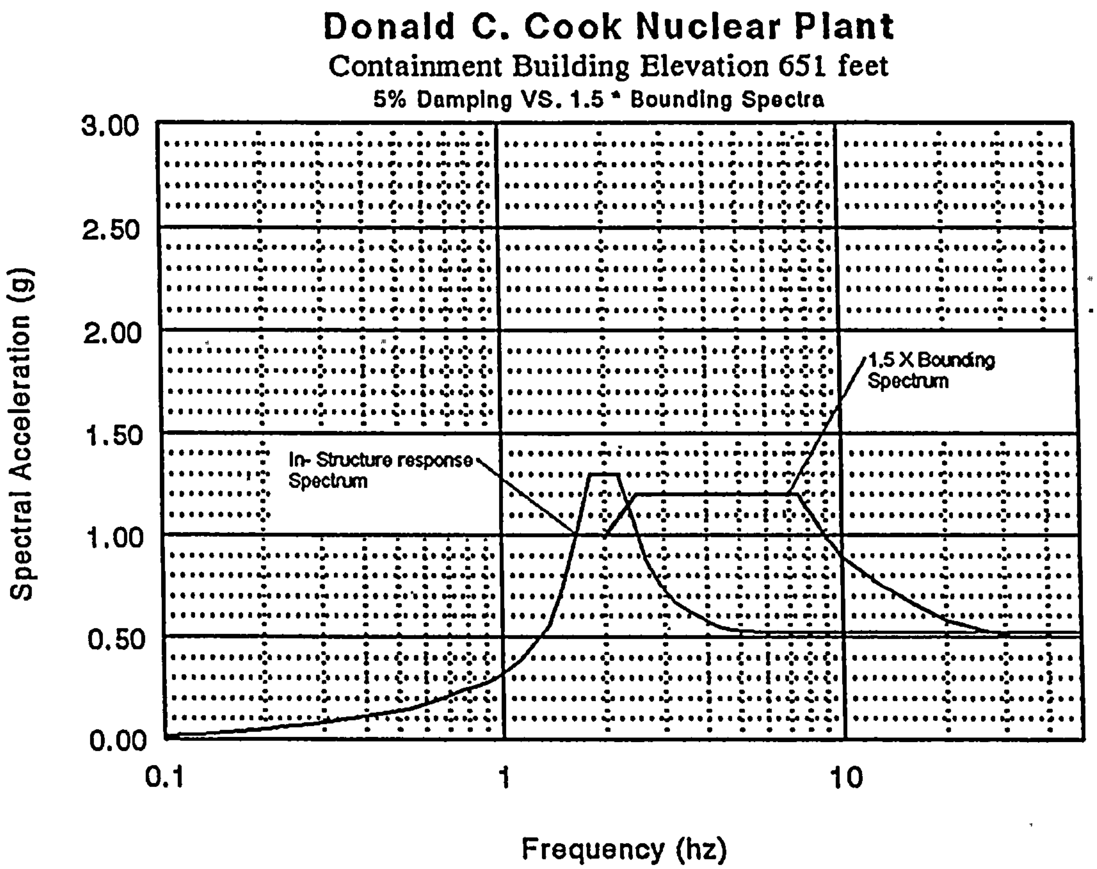

Donald C. Cook Nuclear Plant
Containment Building Elevation 651 feet
5% Damping VS. 1.5 * Bounding Spectra
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Spectral Acceleration (g)
1.5 X Bounding Spectrum
In- Structure response Spectrum
0.1
1
10
Frequency (hz)

Figure 9

APPENDIX "B"
OF
ATTACHMENT NO. 1 TO AEP:NRC:1040G

CLASS '0' EQUIPMENT
TABLES 2 AND 3

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-MRV-210	STEAM GENERATOR OME-3-1 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.
0	1-MRV-220	STEAM GENERATOR OME3-2 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.
0	1-MRV-230	STEAM GENERATOR OME-3-3 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.
0	1-MRV-240	STEAM GENERATOR OME-3-4 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads. A potential seismic interaction was reported as an outlier.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-OME-34E	EAST ESW PUMP PP-7E DISCHARGE STRAINER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Large passive strainer independently anchored, weight = 14,060 lbs. The anchorage was judged to be the weak link of the component for seismic capacity. Anchorage pedestals are 18" long x 10" wide x 19.75" high. They have a 2" deep x 6" wide x 14" long shear key into the base slab, and are reinforced with eight vertical #6 bars into the base slab, and three #4 bar ties in the pedestals. The J-bolts extend through the pedestal into the base slab, and protrude 6" above the top of the pedestals. An anchorage analysis indicates a factor of safety of 2.6.
0	1-OME-34W	WEST ESW PUMP PP-7W DISCHARGE STRAINER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Large passive strainer independently anchored, weight = 14,060 lbs. The anchorage was judged to be the weak link of the component for seismic capacity. Anchorage pedestals are 18" long x 10" wide x 19.75" high. They have a 2" deep x 6" wide x 14" long shear key into the base slab, and are reinforced with eight vertical #6 bars into the base slab, and three #4 bar ties in the pedestals. The J-bolts extend through the pedestal into the base slab, and protrude 6" above the top of the pedestals. The anchorage analysis for 1-OME-34E, which indicated a factor of safety of 2.6, was also used to address this component.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-OME-39	AUXILIARY FEED PUMP TURBINE AND GOVERNOR VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	This turbine driver (1-OME-39) is mounted on the same skid with Auxiliary Feedwater Pump 1-PP-4. The anchorage of the turbine was evaluated with 1-PP-4. The Governor valve is supported on 4" diameter pipe to a casting on the turbine driver. The valve is similar in size and mass characteristics but exceeded Bounding Spectrum MOV Caveat 5 limits Therefore a seismic evaluation of the valve based on previous seismic qualification calculations were used to assess the seismic adequacy of the valve.
0	1-POV-1-AB	PILOT OPERATED 4 WAY VALVE FOR AIR START XRVS FOR DIESEL ENGINE	SOV/BS Caveats 1 to 7.	1-POV-1-AB is a very small solenoid valve; mounted on, and part of box for 1-XRV-221.
0	1-POV-1-CD	PILOT OPERATED 4 WAY VALVE FOR AIR START XRV'S FOR DIESEL ENGINE	SOV/BS Caveats 1 to 7.	1-POV-1-CD is a very small solenoid valve; mounted on, and part of box for 1-XRV-226.
0	1-POV-2-AB	PILOT OPERATED 4 WAY VALVE FOR AIR START XRVS FOR DIESEL ENGINE	SOV/BS Caveats 1 to 7.	1-POV-2-AB is a very small solenoid valve; mounted on, and part of box for 1-XRV-222.
0	1-POV-2-CD	PILOT OPERATED 4 WAY VALVE FOR AIR START XRV'S FOR DIESEL ENGINE	SOV/BS Caveats 1 to 7.	1-POV-2-CD is a very small solenoid valve; mounted on, and part of box for 1-XRV-227.
0	1-QC-12	NORTH BORIC ACID FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Passive filter independently anchored, weight = 500 lbs. full. The anchorage was judged to be the weak link of the component for seismic capacity. The strainer is anchored by 3 column legs with ¾" J-bolts anchored through a 6" high pedestal. The embedment length of the bolts is 19-1/4". The anchorage evaluation indicated a high factor of safety of 10.7, even when conservatively assessing a prying factor of 2 on the bolt demand.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-100-AB	AB EMERG DIESEL AIR INTAKE FILTER	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This passive filter is supported off of a vertical truss. The upper lateral restraint has recently been added to increase tornado wind resistance. This also increased the fundamental frequency above 8 Hz. The intake pipe provides additional support. Based on this support the filter was judged adequate.
0	1-QT-100-CD	CD EMERG DIESEL AIR INTAKE FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This passive filter is supported by 4 legs with either one or two anchor bolts each leg. The upper lateral restraint has recently been added to increase tornado wind resistance. This also increased the fundamental frequency above 8 Hz. The intake pipe provides additional support. Based on this support the filter was judged adequate.
0	1-QT-101-AB	AB EMERG DIESEL AIR INTAKE SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The silencer is a passive component that is part of the piping system running from Diesel. The system adequately restrained in each direction. The silencer is hung by two 5/8" rod trapezes for deadweight. It frames through a R/C wall on one end and into turbocharger at other end. Total span is 20'. The trapeze legs are attached to plates that are then anchored to embedded unistruts. One trapeze is anchored by 4 - 5/8" shell type exp. anchors, 2 per mounting plate, and the other trapeze is anchored by 4 - 5/8" bolts with unistrut nuts, 2 per mounting plate. The concrete is in good condition. In an anchorage analysis for the silencer, 5/8" CIP anchors are used to model the anchorage to concrete of the 4 unistrut bolts. The anchorage analysis for 2-QT-101-AB used reduction factors for cracks in concrete and indicated that the anchorage is adequate. Therefore, that analysis bounds this one (since the concrete is in good condition.) and the anchorage is adequate.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-101-CD	CD EMERG DIESEL AIR INTAKE SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The silencer is a passive component that is part of the piping system running from Diesel. The system adequately restrained in each direction. The silencer is hung by two 5/8" rod trapezes for deadweight. It frames through a R/C wall on one end and into turbocharger at other end. Total span is 20'. The trapeze legs are attached to plates that are then anchored to embedded unistruts. One trapeze is anchored by 4 - 5/8" shell type exp. anchors, 2 per mounting plate, and the other trapeze is anchored by 4 - 5/8" bolts with unistrut nuts, 2 per mounting plate. The concrete is in good condition. In an anchorage analysis for the silencer, 5/8" CIP anchors are used to model the anchorage to concrete of the 4 unistrut bolts. The anchorage analysis for 2-QT-101-AB used reduction factors for cracks in concrete and indicated that the anchorage is adequate. Therefore, that analysis bounds this one (since the concrete is in good condition.) and the anchorage is adequate.
0	1-QT-104-AB	AB EMERG DIESEL EXHAUST SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The weight of the silencer is 8500 lb. There are 4 support legs on the ground and lateral restraints at two locations (top and bottom of the silencer) on the wall. The support legs are also diagonally braced. Each vertical support and the lower lateral restraints have a stiffened base plate with six wedge type expansion anchors of 1-1/4" diameter. The upper lateral restraints each have stiffened baseplates with four 1" Hilti expansion anchors. The upper lateral restraints have recently been added to increase tornado wind resistance. This also increases fundamental frequency above 8 Hz. The anchorage is very seismically rugged.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-104-CD	CD EMERG DIESEL EXHAUST SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The weight of the silencer is 8500 lb. There are 4 support legs on the ground and lateral restraints at two locations (top and bottom of the silencer) on the wall. The support legs are also diagonally braced. Each vertical support and the lower lateral restraints have a stiffened base plate with six wedge type expansion anchors of 1-1/4" diameter. The upper lateral restraints each have stiffened baseplates with four 1" Hilti expansion anchors. The upper lateral restraints have recently been added to increase tornado wind resistance. This also increases fundamental frequency above 8 Hz. The anchorage is very seismically rugged.
0	1-QT-112-AB	AB EMERG DIESEL FULL FLOW LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The filter is a small tank-like component, with a height of about 5', and a diameter of 3'. It is anchored by three 3/8" diameter J-bolts and three 5/8" wedge anchors at 60 degree intervals (i.e., evenly spaced). The tank contains oil and has a total weight of about 2700 lbs. The anchorage analysis that includes inlet and outlet nozzle loads indicate a high margin.
0	1-QT-112-CD	CD EMERG DIESEL FULL FLOW LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The filter is a small tank-like component, with a height of about 5', and a diameter of 3'. It is anchored by three 3/8" diameter J-bolts and three 5/8" wedge anchors at 60 degree intervals (i.e., evenly spaced). The tank contains oil and has a total weight of about 2700 lbs. The anchorage analysis that includes inlet and outlet nozzle loads indicate a high margin.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-113-AB1	AB EMERG DIESEL FULL FLOW LUBE OIL STRAINER 1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage evaluation was performed for 1-QT-113-AB1 and 1-QT-113-AB2 together, since they are connected by a relatively rigid piping segment. The frequency was judged to be greater than 8 Hz. The total weight of the strainer is 1730#, with the CG located at an approx. mid-height = 33". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying), the anchorage has a high margin of safety (2.5).
0	1-QT-113-AB2	AB EMERG DIESEL FULL FLOW LUBE OIL STRAINER 2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage evaluation was performed for 1-QT-113-AB1 and 1-QT-113-AB2 together, since they are connected by a relatively rigid piping segment. The frequency was judged to be greater than 8 Hz. The total weight of the strainer is 1730#, with the CG located at an approx. mid-height = 33". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying) , the anchorage has a high margin of safety (2.5).

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-113-CD1	CD EMERG DIESEL LUBE OIL FULL FLOW STRAINER 1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg of 1-QT-113-CD1 is anchored by one 1/2" J-bolt anchor, each leg of 1-QT-113-CD2 is anchored by one 3/8" bolt, but the anchor type is unknown. The anchorage evaluation was performed for 1-QT-113-CD1 and 1-QT-113-CD2 together, since they are connected by a relatively rigid piping segment. The frequency was judged to be greater than 8 Hz. The total weight of the strainer is 1730#, with the CG located at an approx. mid-height = 33". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying, unknown anchor bolt type), the anchorage has a high margin of safety (1.6).
0	1-QT-113-CD2	CD EMERG DIESEL FULL FLOW LUBE OIL STRAINER 2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg of 1-QT-113-CD1 is anchored by one 1/2" J-bolt anchor, each leg of 1-QT-113-CD2 is anchored by one 3/8" bolt, but the anchor type is unknown. The anchorage evaluation was performed for 1-QT-113-CD1 and 1-QT-113-CD2 together, since they are connected by a relatively rigid piping segment. The frequency was judged to be greater than 8 Hz. The total weight of the strainer is 1730#, with the CG located at an approx. mid-height = 33". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying, unknown anchor bolt type), the anchorage has a high margin of safety (1.6).

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-116-AB	AB EMERG DIESEL LUBE OIL HEATER(TANK)	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small heater/tank is approximately 150 lb., and the location of the C.G. from the floor is at approximately mid-height of the tank = 28". The heater is anchored by three 3/8" J-bolts at 120 degrees apart (is evenly spaced), on a 5" high concrete pad. Minimum embedment for the anchorage is 9.5". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying) , the anchorage has a high margin of safety (3.3).
0	1-QT-116-CD	CD EMERG DIESEL LUBE OIL HEATER (TANK)	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small heater/tank is approximately 150 lb , and the location of the C.G. from the floor is at approximately mid-height of the tank = 28". The heater is anchored by three 3/8" non-shell type expansion anchors at 120 degrees apart (is evenly spaced), on a 5" high concrete pad. Minimum embedment for the anchorage is 9.5". The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying) , the anchorage has an adequate margin of safety (1.3).
0	1-QT-118-AB	AB EMERG DIESEL BYPASS LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The approximate weight of this passive tank like filter is estimated to be the same as that of 1-QT-112-CD (Wt =2707#), because the tanks are of the same manufacturer, and size, and both hold oil. The filter is anchored by three 3/8" J-bolts with a minimum embedment of 10.25", at 120 degrees (i.e., evenly spaced). The analysis indicates that with the highest anchorage reduction factors (for prying) , the anchorage is adequate.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-118-CD	CD EMERG DIESEL BYPASS LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The approximate weight of this passive tank like filter is estimated to be the same as that of 1-QT-112-CD (Wt =2707#), because the tanks are of the same manufacturer, and size, and both hold oil. The filter is anchored by three 3/8" J-bolts with a minimum embedment of 10.25", at 120 degrees (i.e., evenly spaced). The analysis indicates that with the highest anchorage reduction factors (for prying), the anchorage is adequate.
0	1-QT-143-AB1	AB EMERG DIESEL CONTROL AIR DRYER 1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.
0	1-QT-143-AB2	AB EMERG DIESEL CONTROL AIR DRYER 2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-QT-143-CD1	CD EMERG DIESEL CONTROL AIR DRYER 1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.
0	1-QT-143-CD2	CD EMERG DIESEL CONTROL AIR DRYER 2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.
0	1-QT-144-AB	AB EMERG DIESEL FUEL OIL TRANSFER FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small filter is 10" in diameter, 44" in height and is mounted on three angle legs anchored by three 5/8" Phillips Red Head Wedge/coupling anchorage anchors. The frequency is judged greater than 10 Hz. The anchorage evaluation indicated a high safety factor of 4.8.
0	1-QT-144-CD	CD EMERG DIESEL FUEL OIL TRANSFER FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small filter is 10" in diameter, 44" in height and is mounted on three angle legs anchored by three 5/8" Phillips Red Head Wedge/coupling anchorage anchors. The frequency is judged greater than 10 Hz. The anchorage evaluation indicated a high safety factor of 4.8.
0	1-TK-253-1	PRESSURIZER TR "B" PRESSURE RELIEF VALVE NRV-152 RESERVE CONTROL AIR TANK	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This horizontal tank contains air and is supported by other than standard saddles, and is therefore classified as Equipment Class 0. The tank is well welded to building steel, and was judged adequate by the SRT.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-TK-253-2	PRZ TR "A" PRESSURE RELIEF VALVE NRV-153 RESERVE CONTROL AIR TANK	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This horizontal tank contains air and is supported by other than standard saddles, and is therefore classified as Equipment Class 0. The tank is well welded to building steel, and was judged adequate by the SRT.
0	1-TK-253-3	PRESSURIZER TR "B" PRESSURE RELIEF VALVE NRV-152 EMERG. AIR TANK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The air bottle is well strapped to framing that is attached to wall by 12 (or more) 3/4" bolts. The anchorage was judged acceptable by SRT inspection.
0	1-TK-253-4	PRESSURIZER TR "A" PRESSURE RELIEF VALVE NRV-153 EMERG AIR TANK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The air bottle is well strapped to framing that is attached to wall by 12 (or more) 3/4" bolts. The anchorage was judged acceptable by SRT inspection.
0	1-TT-DGAB	1 AB DIESEL GEN TUBE TRACK	Caveats for Engine Generators assessed. EG/BS Caveat 1 and 4 are OK. The remaining caveats are N/A.	The tube tracks could have been evaluated with the Diesel Generator using the Rule of the Box. However, a separate SEWS has been developed. The tube tracks support tubing associated with the Diesel Generator. These tracks were inspected and analyzed as part of the close out commitments of PR 89-395. As built sketches were included in the anchorage package. The SRT also reviewed the tubing and support and found it adequately supported and free from potentially damaging interactions.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	1-TT-DGCD	1 CD DIESEL GEN TUBE TRACK	Caveats for Engine Generators assessed. EG/BS Caveat 1 and 4 are OK. The remaining caveats are N/A.	The tube tracks could have been evaluated with the Diesel Generator using the Rule of the Box. However, a separate SEWS has been developed. The tube tracks support tubing associated with the Diesel Generator. These tracks were inspected and analyzed as part of the close out commitments of PR 89-395. As built sketches were included in the anchorage package. The SRT also reviewed the tubing and support and found it adequately supported and free from potentially damaging interactions.
0	12-HE-19N	NORTH BORIC ACID CONCENTRATOR UNIT SKID AND FRAMING	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	A common skid assembly supports the 12-HE-19-AN Boric Acid Condenser, the 12-HE-19-BN Cooler, 12-HE-19-CN Boric Acid Evaporator Vent Condenser, Feed Preheater, and many other components. All components are well supported and are judged to be seismically adequate.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	12-QC-3	SPENT FUEL PIT FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The weight of the filter is 500 lb. wet. The attached piping is laterally unrestrained and needs to be evaluated for anchorage loads. The component has been designated as an outlier pending the anchorage loads. There are also two additional outlier interaction issues: the overhead crane trolley needs to be parked, and the blockwall enclosure needs to be evaluated. Trolley was parked and in a position which was not over the block wall cubicle for 12-QC-13. For block wall enclosure, it has not yet been determined whether these walls were included in the IE 80-11 program; however, the walls are restrained out-of-plane by steel wide-flange sections which are integral with the walls. Drawings of the walls were also obtained. An evaluation was performed to demonstrate the seismic adequacy of these walls with the existing restraint system. Isometrics were obtained for the attached piping from which conservative nozzle loads were estimated and used for evaluation of the anchorage.

Table 2 - Cook Nuclear Plant Unit 1 Class 0 Equipment

CLASS	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	12-TK-207	REACTOR PLANT NITROGEN BULK STORAGE TANKS #3,4,5,6,7,8	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Similar to horizontal heat exchanger; each tank is approximately 2' in diameter and 20' long (about 15' between supports). The tank weight is 4740 lb (empty--gas adds about 50-55 lb), thickness is .817" (minimum). Assuming tank as a simple beam between supports, frequency of the tank is approximately 62 Hz. Rack supports are made from 8" x 5/8" plate, however, and the frequency attributed to the supports is approximately 2.2 Hz. Hence, the peak of the ground response spectrum was used in the anchorage evaluation. The anchorage consists of four cast-in-place (in buried concrete pedestals) 3/4" diameter J-Bolts. The anchorage evaluation indicates a factor of safety of 1.59.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	12-HE-19S	SOUTH BORIC ACID EVAPORATOR SKID	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	A common skid assembly supports the 12-HE-19-AS Boric Acid Condenser, the 12-HE-19-BS Cooler, 12-HE-19-CS Boric Acid Evaporator Vent Condenser, Feed Preheater, and many other components. All components are well supported and it is judged to be seismically adequate.
0	12-HE-25A	15GPM RADIOACTIVE WASTE EVAPORATOR HE-25 CONDENSER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The Condenser is supported off shell of much larger (about 4.0') diameter tank 12-TK-148. The component was designated as an outlier pending resolution of the physical anchorage data, the inlet and outlet piping nozzle loadings, and an interaction issue. The heat exchanger is being abandoned and therefore, these issues no longer require resolution.
0	12-HE-25B	15 GPM RADIOACTIVE WASTE EVAPORATOR HE-25 DISTILLATE COOLER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The cooler is about 14'' in diameter and 10 feet long, supported by stiffened saddles and anchored to a steel platform with two 3/4'' diameter anchor bolts in each saddle. The weight is less than 2000 lbs. The capacity exceeded demand for saddles, support frame and platform by inspection.
0	12-HE-25C	15 GPM RADIOACTIVE WASTE EVAPORATOR HE-25 CONCENTRATES COOLER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The cooler is about 14'' in diameter and 10 feet long. Support for the cooler is from a steel frame that is bolted to floor. The frame is hung off of the steel platform. The capacity exceeded demand for saddles, support frame and platform by inspection.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-MRV-210	STEAM GENERATOR OME-3-1 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design-operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.
0	2-MRV-220	STEAM GENERATOR OME-3-2 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads. There was an outlier issue identified regarding a tube off of hydraulic controller on the piston bearing on a railing.
0	2-MRV-230	STEAM GENERATOR OME-3-3 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.
0	2-MRV-240	STEAM GENERATOR OME-3-4 STOP VALVE	All caveats were N/A. Seismic adequacy based on the evaluation described.	Stop valve is supported off MS line and substantial structural steel framing. Installation is extremely rugged to carry design operating loads. Judged that the valve had a much greater capacity than the potential demand from seismic inertia loads.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-OME-34E	EAST ESSENTIAL SERVICE WATER PUMP PP-7E DISCHARGE STRAINER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Large passive strainer independently anchored, weight = 14060 lbs. The anchorage was judged to be the weak link of the component for seismic capacity. Anchorage pedestals are 18" long x 10" wide x 19.75" high. They have a 2" deep x 6" wide x 14" long shear key into the base slab, and are reinforced with eight vertical #6 bars into the base slab, and three #4 bar ties in the pedestals. The J-bolts extend through the pedestal into the base slab, and protrude 6" above the top of the pedestals. An anchorage analysis indicates a factor of safety of 2.6.
0	2-OME-34W	WEST ESSENTIAL SERVICE WATER PUMP PP-7W DISCHARGE STRAINER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Large passive strainer independently anchored, weight = 14060 lbs. The anchorage was judged to be the weak link of the component for seismic capacity. Anchorage pedestals are 18" long x 10" wide x 19.75" high. They have a 2" deep x 6" wide x 14" long shear key into the base slab, and are reinforced with eight vertical #6 bars into the base slab, and three #4 bar ties in the pedestals. The J-bolts extend through the pedestal into the base slab, and protrude 6" above the top of the pedestals. An anchorage analysis indicates a factor of safety of 2.6.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-OME-39	AUXILIARY FEED PUMP TURBINE	All caveats were N/A. Seismic adequacy based on the evaluation described.	This turbine driver shares the same skid with 2-PP-4. The anchorage of the turbine was evaluated with 2-PP-4. The anchorage analysis indicates a factor of safety of 5.3 for the applied seismic loads. The Governor valve is supported on 4'' diameter pipe to casting on the turbine driver. The valve is similar in size and mass characteristics to a motor operated valve but exceeded Bounding Spectrum MOV Caveat 5 limits Therefore a seismic evaluation of the valve based on previous seismic qualification calculations were used to assess the seismic adequacy of the valve.
0	2-QC-12	SOUTH BORIC ACID FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	Passive filter independently anchored, weight = 500 lbs. full. The anchorage was judged to be the weak link of the component for seismic capacity. The strainer is anchored by 3 column legs with 3/4" J-bolts anchored through a 6'' high pedestal. The embedment length of the bolts is 19 1/4 ''. The anchorage evaluation indicated a high factor of safety of 10.7, even when conservatively assessing a prying factor of 2 on the bolt demand.
0	2-QT-100-AB	AB EMERGENCY DIESEL AIR INTAKE FILTER	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This passive filter is supported off of a vertical truss. The upper lateral restraint has recently been added to increase tornado wind resistance. This also increased the fundamental frequency above 8 Hz. The intake pipe provides additional support. Based on this support the filter was judged adequate.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-100-CD	CD EMERGENCY DIESEL AIR INTAKE FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This passive filter is supported off of a vertical truss. The upper lateral restraint has recently been added to increase tornado wind resistance. This also increased the fundamental frequency above 8 Hz. The intake pipe provides additional support. Based on this support the filter was judged adequate.
0	2-QT-101-AB	AB EMERGENCY DIESEL AIR INTAKE SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The silencer is a passive component (weight = 18,000 lbs.) that is part of the piping system running from Diesel. The system adequately restrained in each direction. The silencer is hung by two 5/8" rod trapezes for deadweight. It frames through a R/C wall on one end and into turbocharger at other end. Total span is 20'. The trapeze legs are attached to plates that are then anchored to embedded unistruts. One trapeze is anchored by 4 - 5/8" shell type exp. anchors, 2 per mounting plate, and the other trapeze is anchored by 4 - 5/8" bolts with unistrut nuts, 2 per mounting plate. In the anchorage analysis, 5/8" CIP anchors are used to model the anchorage to concrete of the 4 unistrut bolts. There is a crack in the concrete, running next to embedded unistrut, and one going west from unistrut. The anchorage analysis used a reduction factor for cracks in concrete for the bolts affected by cracks. The threaded rods were checked for dead weight load, showing a large safety margin.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-101-CD	CD EMERGENCY DIESEL AIR INTAKE SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The silencer is a passive component (weight = 18,000 lbs.) that is part of the piping system running from Diesel. The system adequately restrained in each direction. The silencer is hung by two 5/8" rod trapezes for deadweight. It frames through a R/C wall on one end and into turbocharger at other end. Total span is 20'. The trapeze legs are attached to plates that are then anchored to embedded unistruts. One trapeze is anchored by 4 - 5/8" shell type exp. Anchors, 2 per mounting plate, and the other trapeze is anchored by 4 - 5/8" bolts with unistrut nuts, 2 per mounting plate. In the anchorage analysis, 5/8" CIP anchors are used to model the anchorage to concrete of the 4 unistrut bolts. There is a crack in the concrete, running next to embedded unistrut, and one going west from unistrut. The anchorage analysis used a reduction factor for cracks in concrete for the bolts affected by cracks. The threaded rods were checked for dead weight load, showing a large safety margin.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-104-AB	AB EMERGENCY DIESEL EXHAUST SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The Exhaust silencer is a passive component (Weight = 8500 lb.) supported by four short 5"x 5"x1/2" angle legs. The base of each leg has a six inch square 1/2" thick baseplate with one 1" diameter J-Bolt anchor. Upper lateral restraints have recently been added to increase tornado wind resistance. This also increases the fundamental frequency above 8 Hz. The anchorage is seismically rugged.
0	2-QT-104-CD	CD EMERGENCY DIESEL EXHAUST SILENCER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The Exhaust silencer is a passive component (Weight = 8500 lb.) supported by four short 5"x 5"x1/2" angle legs. The base of each leg has a six-inch square 1/2" thick baseplate with one 1" diameter J-Bolt anchor. Upper lateral restraints have recently been added to increase tornado wind resistance. This also increases the fundamental frequency above 8 Hz. The anchorage is seismically rugged.
0	2-QT-112-AB	AB EMERGENCY DIESEL FULL FLOW LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This filter is a small tank-like component, with a ht of about 5', and a diameter of 3'. The filter is anchored by 6- 1/2" expansion anchors at 60 degree intervals (i.e., evenly spaced). The tank contains oil and has a total weight of about 2700 lbs. The anchorage analysis that includes inlet and outlet nozzle loads indicate a high margin.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-112-CD	CD EMERGENCY DIESEL FULL FLOW LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This filter is a small tank-like component, with a ht of about 5', and a diameter of 3'. The filter is anchored by 3- 5/8" expansion anchors at 120 degree intervals (i.e., evenly spaced). The tank contains oil and has a total weight of about 2700 lbs. The anchorage analysis that includes inlet and outlet nozzle loads and prying effects indicate a high margin.
0	2-QT-113-AB1	AB EMERGENCY DIESEL FULL FLOW LUBE OIL STRAINER #1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage analysis for 2-QT-113-AB1 and 2-QT-113-AB2 was performed together, since they are connected by a relatively rigid piping segment. The frequency is judged to be greater than 8 Hz. The total weight of the strainer is 1730 lbs., with the CG located at an approx. mid-height = 33". The anchorage analysis including nozzle loads indicate a high margin of safety.
0	2-QT-113-AB2	AB EMERGENCY DIESEL FULL FLOW LUBE OIL STRAINER #2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage analysis for 2-QT-113-AB1 and 2-QT-113-AB2 was performed together, since they are connected by a relatively rigid piping segment. The frequency is judged to be greater than 8 Hz. The total weight of the strainer is 1730 lbs., with the CG located at an approx. mid-height = 33" . The anchorage analysis including nozzle loads indicate a high margin of safety.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-113-CD1	CD EMERGENCY DIESEL FULL FLOW LUBE OIL STRAINER #1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage analysis for 2-QT-113-CD1 and 2-QT-113-CD2 was performed together, since they are connected by a relatively rigid piping segment. The frequency is judged to be greater than 8 Hz. The total weight of the strainer is 1730 lbs., with the CG located at an approx. mid-height = 33". The anchorage analysis including nozzle loads indicate a high margin of safety.
0	2-QT-113-CD2	CD EMERGENCY DIESEL FULL FLOW LUBE OIL STRAINER #2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This tank like strainer component is supported on 4 angle legs. Each leg is anchored by one 1/2" J-bolt anchor. The anchorage analysis for 2-QT-113-CD1 and 2-QT-113-CD2 was performed together, since they are connected by a relatively rigid piping segment. The frequency is judged to be greater than 8 Hz. The total weight of the strainer is 1730 lbs., with the CG located at an approx. mid-height = 33". The anchorage analysis including nozzle loads indicate a high margin of safety.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-116-AB	AB EMERGENCY DIESEL LUBE OIL HEATER TANK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small heater/tank is approximately 150 lbs. , and the location of the C.G. from the floor is at approximately mid-height of the tank = 28". The heater is anchored by three 3/8" J-bolts at 120 degrees apart (is evenly spaced), on a 5" high concrete pad. Note that the anchors are only embedded in the concrete pad; they do not reach the floor concrete. There is also a 1/4" J-bolt, 1" away from each expansion anchor. The J-bolts have been cut flush with the mounting plate. The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying) , the anchorage has a high margin of safety (3.3).
0	2-QT-116-CD	CD EMERGENCY DIESEL LUBE OIL HEATER TANK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small heater/tank is approximately 150 lbs. , and the location of the C.G. from the floor is at approximately mid-height of the tank = 28". The heater is anchored by three 3/8" J-bolts at 120 degrees apart (is evenly spaced), on a 5" high concrete pad. Note that the anchors are only embedded in the concrete pad; they do not reach the floor concrete. There is also a 1/4" J-bolt, 1" away from each expansion anchor. The J-bolts have been cut flush with the mounting plate. The analysis indicates that with the highest nozzle loads and anchorage reduction factors (for prying) , the anchorage has a high margin of safety (3.3).

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-118-AB	AB EMERGENCY DIESEL BYPASS LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The approximate weight of this passive tank like filter is estimated to be the same as that of 2-QT-112-CD (Wt =2700 lbs.), because the tanks are of the same manufacturer, and size, and both hold oil. The filter is anchored by 9 anchors, in 3 groups of three (two 5/8″ anchors and one 1/2″ anchor). So each group is 120 degrees for the next (i.e., evenly space).. The analysis indicates that with the highest anchorage reduction factors (for prying and unknown bolts) , the anchorage is adequate.
0	2-QT-118-CD	CD EMERGENCY DIESEL BYPASS LUBE OIL FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	The approximate weight of this passive tank like filter is estimated to be the same as that of 2-QT-112-CD (Wt =2700 lbs.), because the tanks are of the same manufacturer, and size, and both hold oil. The filter is anchored by three 3/8″ anchors evenly spaced. The analysis indicates that with the highest anchorage reduction factors (for prying), the anchorage is adequate.
0	2-QT-143-AB1	AB EMERGENCY DIESEL CONTROL AIR DRYER #1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 3/8" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-143-AB2	AB EMERGENCY DIESEL CONTROL AIR DRYER #2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 3/8" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.
0	2-QT-143-CD1	CD EMERGENCY DIESEL CONTROL AIR DRYER #1	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.
0	2-QT-143-CD2	CD EMERGENCY DIESEL CONTROL AIR DRYER #2	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small air dryer tank is the size of fire extinguishers, (approx. 89# filled weight each), and is mounted on a 2-1/2" x 2-1/2" x 1/4" angle steel frame with the other air dryer tank. The frame anchored by eight 1/2" non-shell type expansion anchors, 4 per base plate. The nozzle loads are not a concern. There was no explicit anchorage analysis necessary for the SRT to judge the dryers seismically adequate.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-QT-144-AB	AB EMERGENCY DIESEL FUEL OIL TRANSFER FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small filter is 10" in diameter, 44" in height and is mounted on three angle legs anchored by three 5/8" Phillips Red Head Wedge anchors. The frequency is judged greater than 10 Hz. The anchorage evaluation for 1-QT-144-AB indicated a high safety factor of 4.8, therefore the anchorage for this component is acceptable by comparison.
0	2-QT-144-CD	CD EMERGENCY DIESEL FUEL OIL TRANSFER FILTER	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This small filter is 10" in diameter, 44" in height and is mounted on three angle legs anchored by three 5/8" Phillips Red Head Wedge anchors. The frequency is judged greater than 10 Hz. The anchorage evaluation for 1-QT-144-AB indicated a high safety factor of 4.8, therefore the anchorage for this component is acceptable by comparison.
0	2-TK-253-1	PRESSURIZER TRAIN 'A' PRESSURE RELIEF VLV NRV-153 RESERVE CONTROL AIR BOTTLE RACK	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This small horizontal tank (about 4.5' long x 16" diameter, 250 lbs.) contains air. The tank is horizontally mounted (welded) on a short length of I beam which in turn is welded to building steel. The anchorage analysis indicated that the anchorage is adequate.
0	2-TK-253-2	PRESSURIZER TRAIN 'A' PRESSURE RELIEF VALVE NRV-153 RESERVE CONTROL AIR BOTTLE RACK	Caveats for Tanks assessed: Flexibility of attached piping. The remaining caveats are N/A.	This small horizontal tank (about 4.5' long x 16" diameter, 250 lbs.) contains air. The tank is horizontally mounted (welded) on a short length of I beam which in turn is welded to building steel. The anchorage analysis indicated that the anchorage is adequate.

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-TK-253-3	PRESSURIZER TRAIN 'B' PRESSURE RELIEF VLV NRV-152 EMERGENCY AIR BOTTLE RACK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This component is a cylindrical compressed air "bottle" about 12" in diameter and 60" tall, secured to the crane wall with steel straps that are attached to a very stout steel bracket arrangement, secured to the wall with a number of expansion anchors. The SRT judged that the anchorage is adequate, and AEPSC Structural & Analytical Design Nuclear Section reviewed the as-found condition of the support for this tank, and found it to be adequate for design loads. (Ref. AEP letter, from J. A. Reiniger/J.L. Ball to L. H. VanGinhoven, dated 10-27-92--included in equipment package.)
0	2-TK-253-4	PRESSURIZER TRAIN 'A' PRESSURE RELIEF VLV NRV-153 EMERGENCY AIR BOTTLE RACK	Caveats for Tanks assessed: Anchor bolts and embedment, Flexibility of attached piping. The remaining caveats are N/A.	This component is a cylindrical compressed air "bottle" about 12" in diameter and 60" tall, secured to the crane wall with steel straps that are attached to a very stout steel bracket arrangement, secured to the wall with a number of expansion anchors. The SRT judged that the anchorage is adequate, and AEPSC Structural & Analytical Design Nuclear Section reviewed the as-found condition of the support for this tank, and found it to be adequate for design loads. (Ref. AEP letter, from J. A. Reiniger/J.L. Ball to L. H. VanGinhoven, dated 10-27-92--included in equipment package.)

Table 3 - Cook Nuclear Plant Unit 2 Class 0 Equipment

	ID	DESCRIPTION	CAVEATS SATISFIED	EVALUATION DESCRIPTION
0	2-TT-DGAB	2AB DIESEL GENERATOR TUBE TRACK	Caveats for Engine Generators assessed. EG/BS Caveat 1 and 4 are OK. The remaining caveats are N/A.	The tube tracks could have been evaluated with the Diesel Generator using the Rule of the Box. However, a separate SEWS was developed. The tube tracks support tubing associated with the Diesel Generator. These tracks were inspected and analyzed as part of the close out commitments of PR 89-395. As built sketches were included in the anchorage package. The SRT also reviewed the tubing and support and found it adequately supported and free from potentially damaging interactions.
0	2-TT-DGCD	2CD DIESEL GENERATOR TUBE TRACK	Caveats for Engine Generators assessed. EG/BS Caveat 1 and 4 are OK. The remaining caveats are N/A.	The tube tracks could have been evaluated with the Diesel Generator using the Rule of the Box. However, a separate SEWS was developed. The tube tracks support tubing associated with the Diesel Generator. These tracks were inspected and analyzed as part of the close out commitments of PR 89-395. As built sketches were included in the anchorage package. The SRT also reviewed the tubing and support and found it adequately supported and free from potentially damaging interactions.

APPENDIX "C"
OF
ATTACHMENT NO. 1 TO AEP:NRC:1040G

LIMITED ANALYTICAL REVIEW (LAR)
OF
CABLE TRAY SUPPORTS

3.3 Method of Solution

Hand calculations are performed employing the methodology outlined in Section 8 of Reference 3.6.4, "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment." Support structures are broken down, where applicable, into subsections which lend themselves to common, closed form solutions for structures subjected to static loading.

3.4 Allowables and Assumptions

The following is a compilation of allowable stress and load criteria used throughout the raceway support evaluations.

Structural Steel: All structural steel support members are assumed to be ASTM A36 with a minimum yield strength of 36 ksi. AISC Specification allowables for Allowable Stress Design (Ref. 3.6.1) are used for the dead load analysis. For other analyses, the allowable stress is increased to 0.9 Fy = 32.4 ksi.

Weld Filler Metal: All welds are assumed to be E60xx. The allowable weld shear stress, based on Table J2.5 of Ref. 3.6.1, is 0.3 x 60 = 18 ksi for dead load analysis. For all other analyses, 1.7 x 0.3 x 60 = 30.6 ksi is used.

Unistrut Channels and Accessories: Dimensions, properties, and allowables used to analyze various Unistrut support system components are based on the Manufacturer's Catalog Data provided in Refs. 3.6.2 and 3.6.3. These values are used for the dead load analysis and all other analyses. Values for Unistrut components commonly used at D.C.Cook are summarized below:

Unistrut bending moment: Ref. 3.6.3, p.23

P1000: 5080 in-lb (allowable bending stress of 25 ksi)

Channel nuts/bolts: Ref. 3.6.3, p.69

5/8" : pullout in P1000 or P3000	:	2500 lb
5/8" : slip in P1000 or P3000	:	1500 lb
1/2" : pullout in P1000 or P3000	:	2000 lb
1/2" : slip in P1000 or P3000	:	1500 lb
3/8" : pullout in P1000 or P3000	:	1000 lb
3/8" : slip in P1000 or P3000	:	800 lb

Bolts are assumed tightened to manufacturer's recommended values.

Embedded Unistrut Channels: D.C. Cook embedded channels are Unistrut P1000 (or equivalent) galvanized, 12 ga. channels with a material yield strength = 33 ksi, modified by the addition of 3/8" ϕ x 4"L Nelson Studs at 12" o.c. Results of tests of modified channels (Ref 3.6.20) indicate a minimum pullout capacity of 6400 lb/ft. The mode of failure was ripping of strut material around the stud; stud remaining in concrete. Using the AISC Allowable Stress Design allowable shear stress of 0.4 x Fy = 13.2 ksi on a 45° cone shaped slip surface results in an allowable pullout
of 13.2 ksi x π x (D + t) x t = 13.2 x 3.14 x (0.375 + 0.105) x 0.105" = 2090 lb, therefore use the standard catalog value of 2000 lb, but not more than the allowable value for pullout of Unistrut channel nuts/bolts as listed above. For all other load cases, use an allowable stress of 1.7 x 0.4 x Fy resulting in an allowable pullout of 3550 lb, but not more than the catalog allowable value for the pullout of Unistrut channel nuts/bolts as listed above.

To summarize:

Pullout of embedded strut:	2000 lb	5/8" channel nut/bolt
(dead load analysis)	2000 lb	1/2" channel nut/bolt
	1000 lb	3/8" channel nut/bolt
Pullout of embedded strut:	2500 lb	5/8" channel nut/bolt
(all other analyses)	2000 lb	1/2" channel nut/bolt
	1000 lb	3/8" channel nut/bolt

Concentrated loads may not be spaced closer than 12" apart unless the sum total of concentrated loads on any 12" of Unistrut length does not exceed the single load allowable.

Conduit Weights: The following estimated weights per foot for rigid steel conduit, as provided by Reference 3.6.14, will be used unless noted otherwise within the individual LAR's.

1/2"	1.1 lb/ft
3/4"	1.3 lb/ft
1"	2.0 lb/ft
1-1/2"	3.5 lb/ft
2"	4.9 lb/ft
3"	11.1 lb/ft
4"	16.6 lb/ft

Cable Tray Weights: The weight per foot used in these LARs for the standard D.C.Cook cable tray (12" wide by 6" high) is 25 pounds per linear foot, unless noted otherwise within the individual LAR's.

Concrete Anchor Bolts: Concrete anchor bolt allowables used in all analyses are based on Tables C.2-1 and C.2-2 of the GIP, Ref. 3.6.4. The anchor bolt type must be known to use the maximum values.

If anchor bolts are identified as "non-shell" type anchors on the PASS, then, per Ref. 3.6.12, the anchors are either 5/8" Hilti "Kwik-Bolts" or 5/8" Phillips wedge-type anchors. All other anchors must be identified on the PASS or they will be considered "unknown." Unknown anchors require a reduction factor of 0.6 on the allowable loads provided in Ref. 3.6.4, Tables C.2-1 and C.2-2.

All concrete anchors, known or unknown, shell or non-shell type, which are not loaded in tension by dead weight, require an additional reduction factor of 0.75 for the "Reduced Inspection Alternative", and, because one third of the anchor bolts (there must be a minimum of six) must be assumed to be "not available", another reduction factor of 0.67 must be taken.

The design concrete strength at D. C. Cook is 3500 psi. This requires a reduction factor of 0.875 to be applied to the pullout capacity of all anchors. No reduction is required for the shear capacity.

If a tightness check has been performed, it will be so stated on the PASS and the "Reduced Inspection Alternative" reduction factors may be waived.

Concrete Anchor Bolts (cont'd)

To summarize:

"Known" concrete anchors such as 5/8" Hilti "Kwik-Bolts", 5/8" Phillips Wedge-type, or 5/8" Phillips Red Head "self drills":

Pall = 3.17 kips x 0.875 x 0.75 x 0.67= 1.39 kips (not in tension by deadweight)
Vall = 3.79 kips x 0.75 x 0.67= 1.90 kips

Pall = 3.17 kips x 0.875 = 2.77 kips (in tension by deadweight)
Vall = 3.79 kips

All other 5/8" concrete anchors:

Pall = 3.17 kips x 0.875 x 0.6 x 0.75 x 0.67 = 0.83 kips (not in tension by deadweight)
Vall = 3.79 kips x 0.6 x 0.75 x 0.67= 1.14 kips

Pall = 3.17 kips x 0.875 x 0.6 = 1.66 kips (in tension by deadweight)
Vall = 3.79 kips x 0.6 = 2.28 kips

All 3/4" concrete anchors:

Pall = 4.69 x 0.875 x 0.6 x 0.75 x 0.67 = 1.23 kips (not in tension by deadweight)
Vall = 5.48 x 0.6 x 0.75 x 0.67 = 1.65 kips

Pall = 4.69 x 0.875 x 0.6 = 2.46 kips (in tension by deadweight)
Vall = 5.48 x 0.6 = 3.29 kips

All 1/2" concrete anchors:

Pall = 2.29 x 0.875 x 0.6 x 0.75 x 0.67 = 0.60 kips (not in tension by deadweight)
Vall = 2.38 x 0.6 x 0.75 x 0.67 = 0.72 kips

Pall = 2.29 x 0.875 x 0.6 = 1.20 kips (in tension by deadweight)
Vall = 2.38 x 0.6 = 1.43 kips

All 3/8" concrete anchors:

Pall = 1.46 x 0.875 x 0.6 x 0.75 x 0.67 = 0.39 kips (not in tension by deadweight)
Vall = 1.42 x 0.6 x 0.75 x 0.67 = 0.43 kips

Pall = 1.46 x 0.875 x 0.6 = 0.77 kips (in tension by deadweight)
Vall = 1.42 x 0.6 = 0.85 kips

Shear-tension interaction limitations per the GIP, Ref. 3.6.4, Section C.2.11 will be used to evaluate the effect of combined anchor bolt loading.

3.5 Input Data

Plant Area Summary Sheets

The hangers evaluated in this calculation were selected by the Seismic Review Team (SRT) that performed the raceway walkdown. The selections are documented in the Plant Area Summary Sheets (PASS), which are part of the project documentation.

Plant Seismic Response Spectra

Horizontal seismic accelerations are required for the Lateral Load Evaluation and the Rod Hanger Fatigue Evaluations as defined in the GIP, Ref. 3.6.4.

Lateral Load Evaluations:

Three options are presented in the GIP, Ref. 3.6.4, Section 8.3.4 for determining the horizontal seismic acceleration to be used in lateral load evaluations. Acceleration values for D.C.Cook corresponding to each of the options are summarized below.

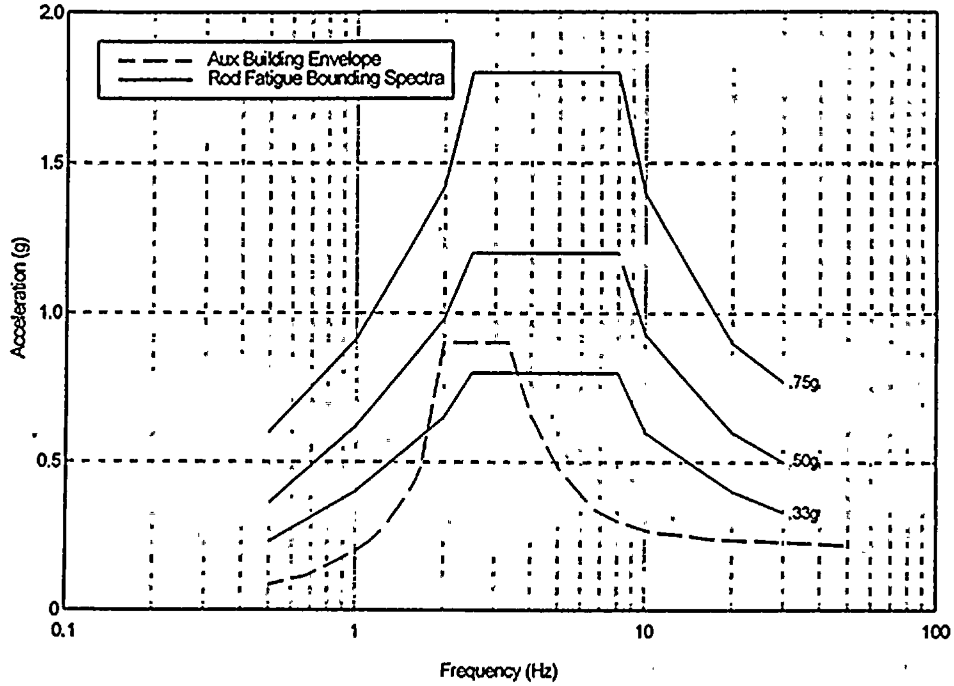
Elevation	ZPA	Building	Option 1	Option 2	Option 3
587	0.20	Aux	1.21	0.63	0.94
633	0.22	Aux	1.21	0.69	0.94
650	0.22	Aux	1.21	0.69	0.94
609	0.22	DGB	1.21	0.69	0.94
598	0.32	Cont	1.21	1.00	0.94
612	0.37	Cont	1.21	1.16	0.94
625	0.42	Cont	1.21	1.31	0.94
651	0.52	Cont	1.21	1.63	0.94
699	0.80	Cont	1.21	2.50	2.50

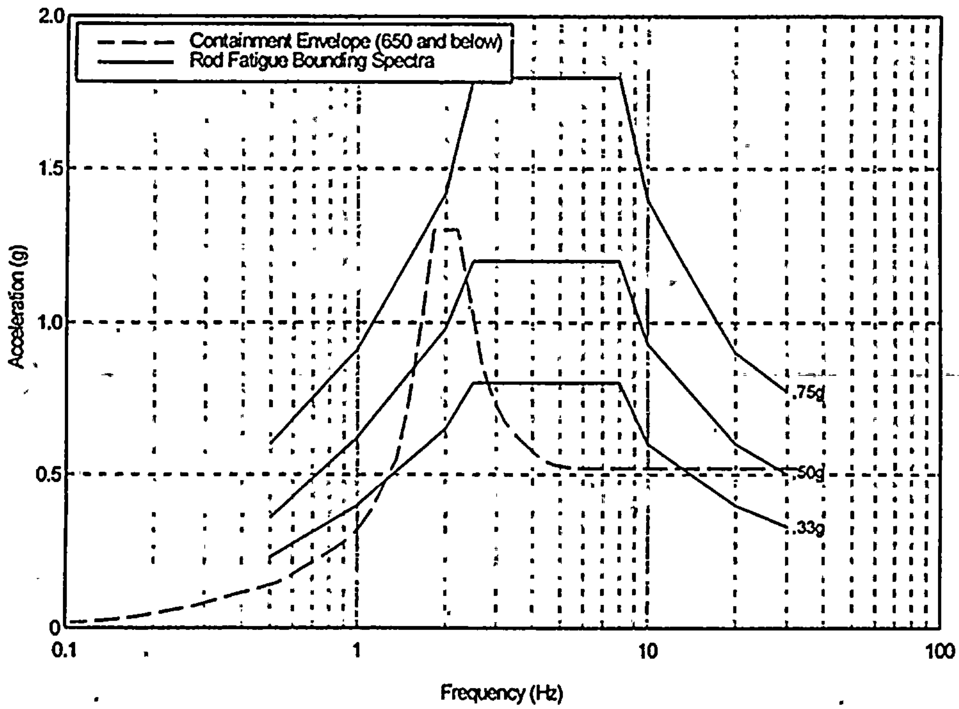
Option 1: 2g scaled by the maximum of SSE/Bounding Spectrum (ZPA value controls)
Option 2: 2.5*1.25*Floor ZPA (1.25 is for 'realistic' floor spectra)
Option 3: 2.5*1.25*1.5*SSE ZPA (within 40' of grade)

Conclusion: Option 2 for Aux and DGB, Option 3 for Containment

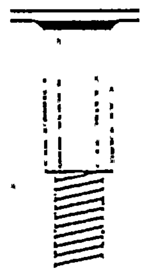
Rod Hanger Fatigue Evaluations:

The rod fatigue bounding spectra provided in the GIP, Ref. 3.6.4, Figure 8-9, are plotted below vs. the envelope of the D.C.Cook 5% damping spectra for the Auxiliary Building and the envelope for Containment at El. 650' and below. These curves are used to determine the applicable bounding curve in the Fatigue Evaluation Screening Charts, Figure 8-10 to 8-14 of the GIP.





Fatigue Evaluation Screening Charts and Procedures



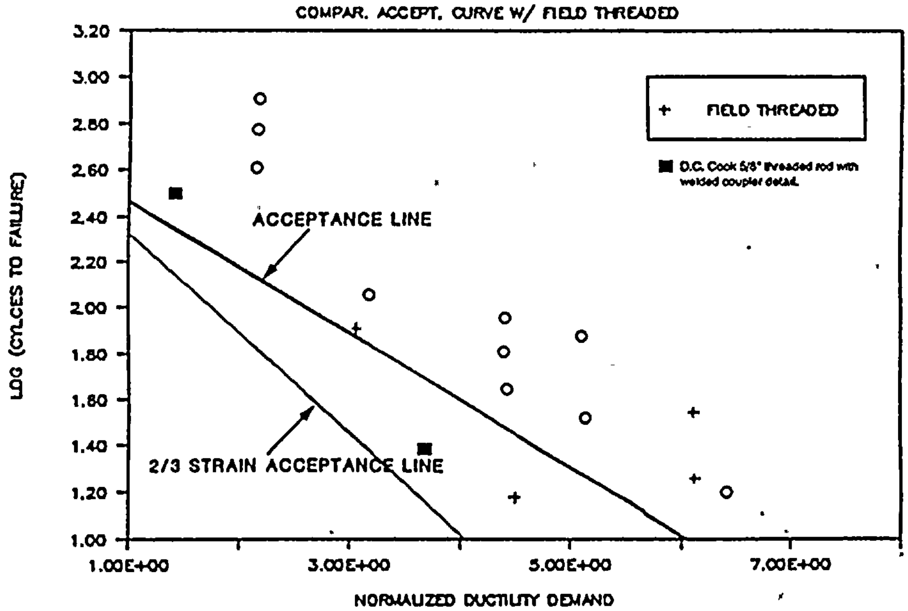
All threaded rods used in raceway supports at D.C.Cook are manufactured all-thread rods. Some rods, however, are anchored using the welded rod coupler detail shown to the right. The SRT was concerned that the coupler material is not as ductile as the rod material, particularly after being welded.

Fatigue tests were performed on D.C.Cook threaded rods with the welded rod coupler detail (Ref.3.6.23). These tests show that for the same ductility demand, the number of cycles to failure using the welded coupler detail is approximately half the number of cycles to failure using typical "nutted" rod connection details at D.C. Cook (Ref. 3.6.6, Table 8-2).

The test data points for the welded coupler detail are plotted below on Figure 8-5 from Reference 3.6.6 (this figure was used to develop the fatigue evaluation screening charts in the GIP). Each test data point represents 3 tests (6 tests total) on 5/8" rods with an applied axial tensile preload (σ_T) of 2.2 ksi (500 lb.) The test data points lie above the "2/3 Strain Acceptance Line", which represents the ductility demand vs. cycles to failure acceptance criteria for field-threaded rods. Therefore, in these LAR's, in order to cover rod-hung raceway supports that have not been selected as LAR candidates because of lower weight or longer length, but which may have welded coupler anchorage details, Rod Hanger Fatigue Evaluations will conservatively include the procedures specified in the GIP for field-threaded rods.

FATIGUE DATA FOR THREADED RODS

COMPAR. ACCEPT. CURVE W/ FIELD THREADED



3.6 References

3.6.1 "Manual of Steel Construction, Allowable Stress Design", 9th Edition, American Institute of Steel Construction, Inc. Chicago, IL, 1989.

3.6.2 "General Engineering Catalog", No. 10, Unistrut Building Systems, GTE Products Corporation, Wayne, MI, 1983.

3.6.3 "General Engineering Catalog", No. 12, North American Edition, Unistrut Corporation, Wayne, MI, 1992.

3.6.4 "Generic Implementation Procedure (GIP), for Seismic Verification of Nuclear Plant Equipment", Revision 2A, March, 1993, Seismic Qualification Utility Group.

3.6.5 "Design of Welded Structures", Omer W. Blodgett, James F. Lincoln Arc Welding Foundation, July 1976.

3.6.6 "Seismic Evaluation of Rod Hanger Supports for Electrical Raceway Systems", EPRI NP-7152-D, March, 1991.

3.6.7 "Cable Tray and Conduit System Seismic Evaluation Guidelines", EPRI NP-7151-D, March, 1991.

3.6.8 "The Performance of Raceway Systems in Strong-Motion Earthquakes", EPRI NP-7150-D, March, 1991.

3.6.9 "Seismic Verification of Nuclear Plant Equipment Anchorage" EPRI NP 5228-SL, Revision 1,Volume 1, June, 1991.

3.6.10 AEP Guideline No. 18.3, Rev. 4, 4/9/86: "Guide for Cable Tray Loading"

3.6.11 Test Report 91C1681-02, Testing of D.C.Cook typical Unistrut attachment brackets for rod hung cable trays.

3.6.12 AEP Drawing No. 1-2-EDS-633-14, Sheet 1 of 2, 5/31/91.

3.6.13 "Longitudinal Load Resistance in Seismic Experience Database Raceway Systems", EPRI NP-7153-D, March 1991.

3.6.14 AEP Document No. 02-0120-1097, Revision 0, Page 3 (Rigid Conduit Weights)

3.6.15 Letter from I.C.Huang of AEP Service Corporation to Steve Anagnostis of Stevenson and Associates, 1/10/94, re: as-installed conduit weights for raceway supports LAR011 and LAR017.

3.6.16 "Rigid Frame Formulas", A. Kleinlogel, Frederick Ungar Publishing Co., New York, 1952.

3.6.17 Donald C. Cook Nuclear Plant Drawings:

1-1594-4
1-1460-75
1-1528-51
1-1525-57
1-1464-83

3.6.18 AEP Guideline No. 18.2A, Rev. 0, 6/27/86: "Guide for Cable Tray System Design".

3.6.19 Telecopy dated 4/29/94 from I. Huang of AEP to Steve Anagnostis of Stevenson and Associates regarding as-installed cable tray and conduit weights for LAR's.1,3,5,9,10,16,18, and 22.

3.6.20 Letter from I.C.Huang/AEP to Steve Anagnostis/Stevenson and Associates, April 7, 1994--results of testing of D C Cook modified embedded Unistrut.

3.6.21 Stevenson & Associates Design Report, AEP Raceways 82C200-02, Cable Tray Testing--Analysis and Report, 9/30/83.

3.6.22 Telecopy from I.C.Huang/AEP to Steve Anagnostis/Stevenson and Associates, May 6, 1994--Field information concerning LAR011 (bolt spacing and conduit spans).

3.6.23 "Low Cycle Fatigue Tests on 5/8 inch Threaded Road" by Dario A. Gasparini, P.E./Ph.D., Dept. of Civil Engineering, Case Western Reserve University for Stevenson & Associates, March 25, 1992.

American Electric Power - D. C. Cook
A-46 Cable Tray and Conduit Raceway Review

Limited Analytical Review (LAR) Data Sheet

Room No.: n/a

Selection No.: LAR001

Plant Location: see attached

Description and Sketch: see attached

Reference Calculation: see attached

Result: **Pass**

Additional Notes:

Certification: (Signatures of at least two Seismic Capability Engineers are required; one of whom is a licensed professional engineer.)

Name	Signature	Date
I. C. Huang (AEPSC)	I Chen Huang	10-11-95
Steve Anagnostis (S&A)	[signature]	12/28/94

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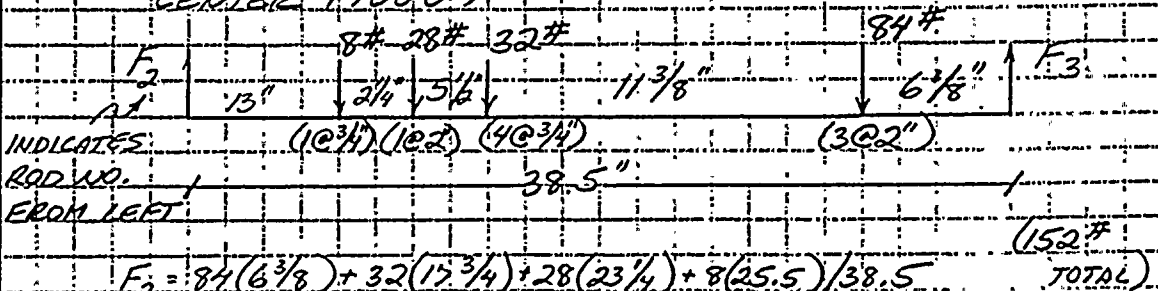
S&A Stevenson and Associates
A Structural-Mechanical Consulting Engineering Firm

CLIENT AEP JOB No. 89C1570 SHEET 1 OF 6

SUBJECT A46 LAR'S
DC COOK, LAR-001
(PASS ID# RACE-125, LAR #1)
AUX BLDG. EL. 609'-0"

REVISIONS 0 CCE 4/26/94 AK 5/25/94

REF	
	LOAD CALCULATIONS
P.A.S.S.	TRIBUTARY LENGTH = (5'-9 3/4" + 5'-9 1/4")/2 = 5.8'
6.14	CONDUIT WEIGHTS: USE DC COOK GENERIC CONDUIT WEIGHTS PER REFERENCE 6.14:
	4" = 16.6 #/FT × 5.8' = 96 #
	2" = 4.9 #/FT × 5.8' = 28 #
	3/4" = 1.3 #/FT × 5.8' = 8 #
6.19	CABLE TRAY WEIGHTS: USE SPECIFIC CABLE TRAY WEIGHTS AS PROVIDED BY REF 6.19, SEE FINAL PAGE OF THIS LAR
6.14 SECT. 8.3.1	**DEAD LOAD CHECK**
	CHECK BENDING IN CROSS-MEMBERS:
	CENTER P1000:

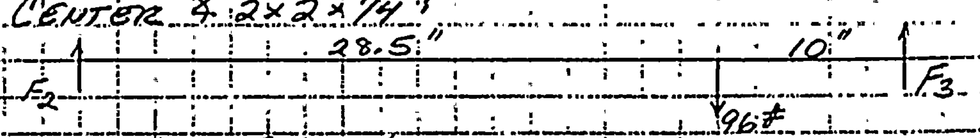


$F_2 = 84(6\,3/8) + 32(17\,3/4) + 28(23\,1/4) + 8(25.5)/38.5$

$F_2 = 51\#$ $F_3 = 101\#$

$M_{MAX} = 842$ IN-LB < 5080 IN-LB ∴ OK (INT = 0.17)

CENTER 4 2×2×1/4:



$F_2 = 25\#$ $F_3 = 71\#$ $M_{MAX} = 710$ IN-LB

$M/S = 710/0.247 = 2.9$ KSI < 21.6 ∴ OK (INT = 0.13)

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CLIENT AEP JOB No. 89C1570 SHEET 2 OF 6

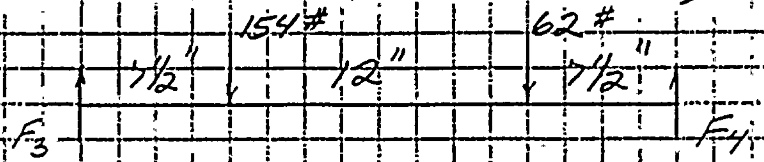
SUBJECT A46 LAR'S
DC COOK, LAR-001
(PASS ID # RACE 125, LAR #1)
AUX BLDG EL. 609'-0"

REVISIONS: 0 CCF 4/26/94; A.K. 5/25/94

REF.

DEAD LOAD CHECK (CONT'D)

RIGHT ∠ 2×2×1/4 WITH 2 TRAYS, BOTTOM TIER:



LEFT TRAY = 26.6 #/FT × 5.8' = 154#
RIGHT TRAY = 10.7 #/FT × 5.8' = 62#

F_3 = 128#, F_4 = 88#

M_{MAX} = 128(7.5) = 960 IN-LB

M/S = 960/0.247 = 3.9 KSI < 21.6 ∴ O.K.
(UNT = 0.18)

CHECK ANCHORAGE

TOTAL F_1 (ROD 1; LEFT-MOST ROD)

$F_1 = \frac{1}{2}(8.9 + 30.8 + 12.6 + 9.2 + 9.1 + 11.5)(5.8')$

F_1 = 238#

TOTAL F_2 (ROD 2)

F_2 = 238# + 51# + 25# = 314#

TOTAL F_3 (ROD 3)

F_3 = 101# + 71# + 128#

$+ 5.8'\left(\frac{19.5"}{27"}\right)(18.2 + 12.6 + 22.8)$ } (= 225#)

$+ 5.8'\left(\frac{7.5"}{27"}\right)(10.5 + 12.6)$ } (= 37#)

F_3 = 562#

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CLIENT AEP JOB No. 89C1570 SHEET 3 OF 6

SUBJECT A46 LAR'S
DC COOK, LAR-001
(PASS ID # RACE 125, LAR #1)
AUX BLDG EL. 609'-0"

REVISIONS
0 CCF 4/26/94
A.K. 5/25/94

REF.	
	DEAD LOAD CHECK (CONT'D.)
	TOTAL F_4 (ROD 4, RIGHT-MOST ROD)
	$F_4 = 5.8'\left(\frac{49.5''}{27''}\right)(10.7+10.5+12.6)$ } (= 142#)
	$+5.8'\left(\frac{7.5''}{27''}\right)(26.6+18.2+12.6+22.8)$ } (= 129#)
	$F_4 = 271$ #
	FOR 5/8" Φ ROD: ALLOWABLE PULLOUT LOAD ON EMBEDDED UNISTRUT FOR DEAD LOAD CASE = 2000 #
	WORST-CASE REACTION = 562# < 2000 # ∴ OK (INT = 0.28)
6.4 SECT. 8.3.2	VERTICAL CAPACITY CHECK (3 × DL)
	CHECK ANCHORAGE FOR 3 × DL:
	ALLOW. PULLOUT ON EMBEDDED STRUT FOR 3×DL CASE = 2500 # FOR 5/8" Φ ROD:
	3 × 562# = 1690 # < 2500 # ∴ OK (INT = 0.68)
6.4 SECT. 8.3.3	DUCTILITY CHECK
	FIXED-END ROD HANGER SUPPORT SYSTEMS ARE INHERENTLY DUCTILE. PROCEED TO ROD HANGER FATIGUE EVALUATION.

S&A Stevenson and Associates A Structural-Mechanical Consulting Engineering Firm	CLIENT AEP JOB No. 89C1570 SHEET 4 OF 6 SUBJECT A46 LAR'S DC COOK, LAR-001 (PASS ID # RACE 125, LAR # 1) AUX BLDG. EL. 609'-0"	REVISIONS 0 CCF 4/26/94 AK 5/25/94

REF.

ROD HANGER FATIGUE EVALUATION

6.4 SECT. 8.3.5

RIGHT-MOST RODS (3 + 4) ARE WORST-CASE.

TOTAL WEIGHT: $F_3 + F_4$ = 562 + 271 = 833#

ROD LENGTH: 4'-0 3/4"

APPLICABLE ROD FATIGUE BOUNDING SPECTRUM: 0.50g (SEE SECTION 5.2 TO THIS CALC.)

THE ABOVE WEIGHT/ROD LENGTH COMBINATION FALLS WITHIN THE ACCEPTABLE REGION OF THE FATIGUE EVALUATION SCREENING CHART FOR 5/8" DIAMETER MANUFACTURED ALL-THREAD RODS (FIG. 8-13 OF REF. 6.4)

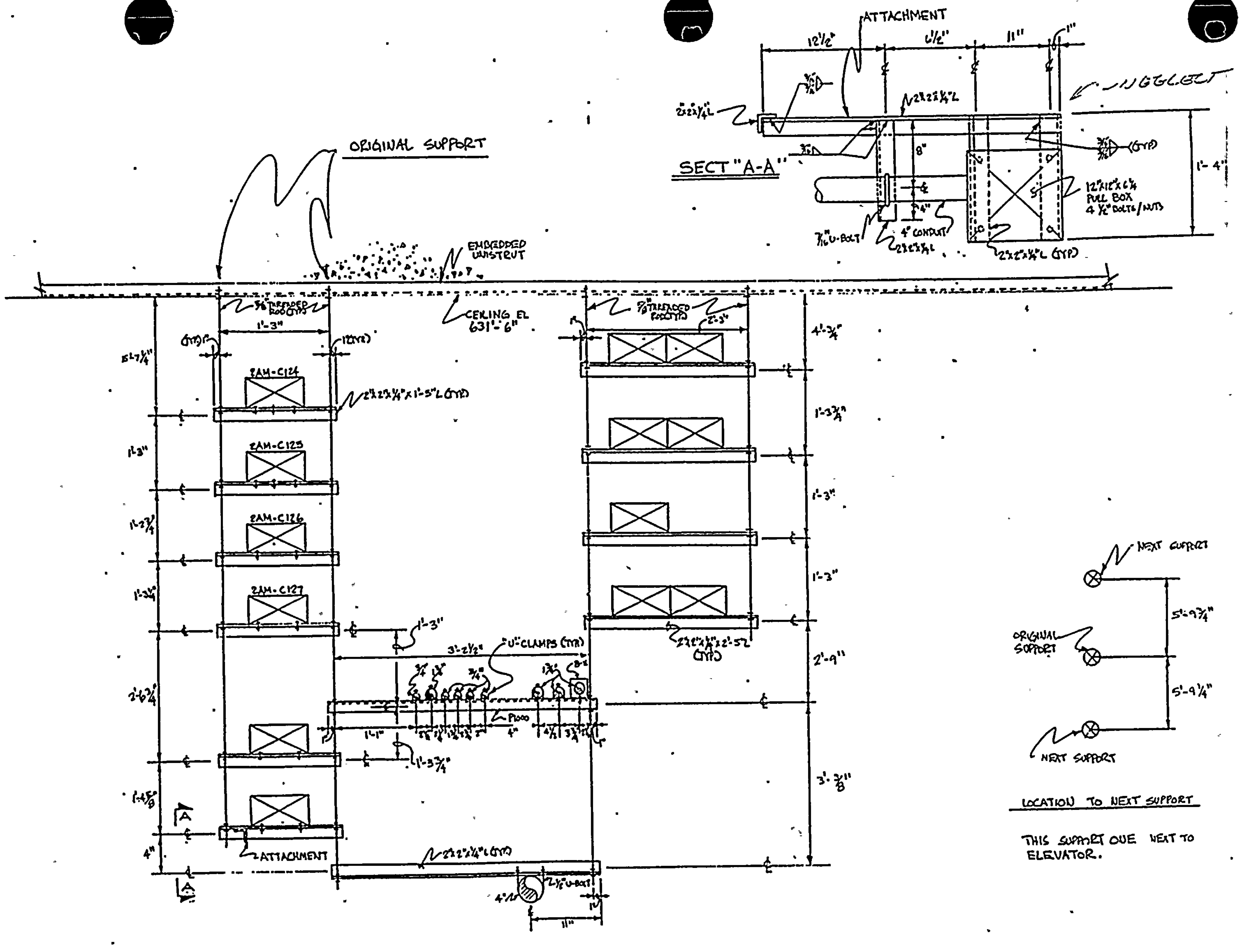
∴ OK

PERFORM FATIGUE EVALUATION ASSUMING WELDED ROD COUPLER ANCHORAGE DETAIL (FOLLOW PROCEDURE FOR FIELD-THREADED RODS - SEE SECTION 5.3 TO THIS CALC.):

$$\left.\begin{aligned} W &= 2 \times 833 = 1670\# \\ L &= 2/3 \times 48 = 32" \end{aligned}\right\} \Rightarrow \text{COMBINATION OK}$$

CONCLUSION

THIS SUPPORT SATISFIES THE LIMITED ANALYTICAL REVIEW REQUIREMENTS SET FORTH IN REF. 6.4 AND IS THEREFORE CONSIDERED TO BE SEISMICALLY ADEQUATE.



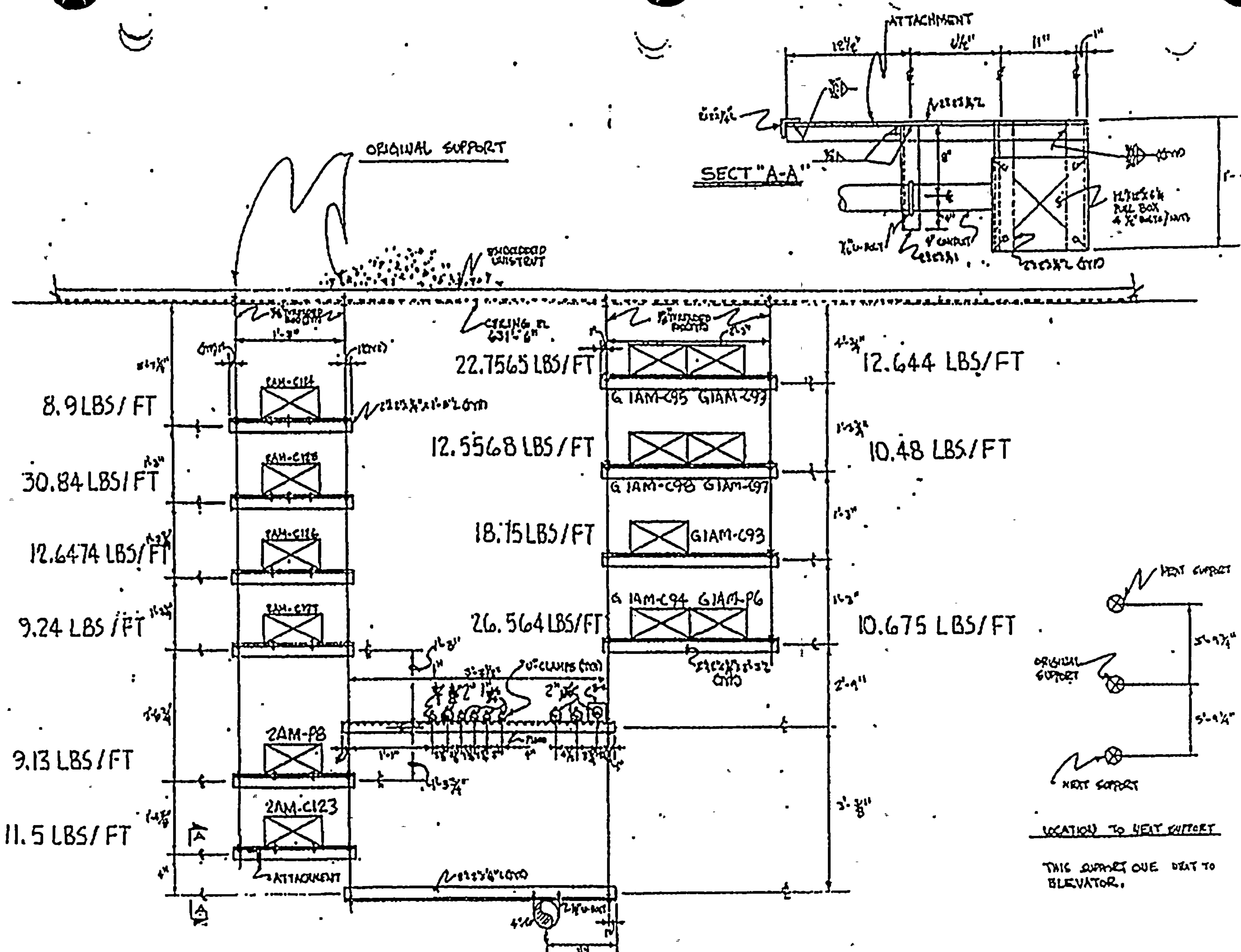
— SUPPORT № 1 —

LAR001

5/6

APPENDIX "C" ATTACHMENT NO. 1 TO AEP:NRC:1040G

Page 15



ACTUAL WEIGHTS FOR LAR# 1

CONDUIT IDENTIFICATION UNKNOWN

— SUPPORT No 1 —

ABOVE FL. EL 609'-0"

American Electric Power - D. C. Cook
A-46 Cable Tray and Conduit Raceway Review

Limited Analytical Review (LAR) Data Sheet

Room No.: n/a

Selection No.: LAR011

Plant Location: see attached

Description and Sketch: see attached

Reference Calculation: see attached

Result: **Pass**

Additional Notes:

Certification: (Signatures of at least two Seismic Capability Engineers are required; one of whom is a licensed professional engineer.)

Name	Signature	Date
I. C. Huang (AEPSC)	I Chen Huang	10-11-95
Steve Anagnostis (S&A)	[signature]	12/28/94

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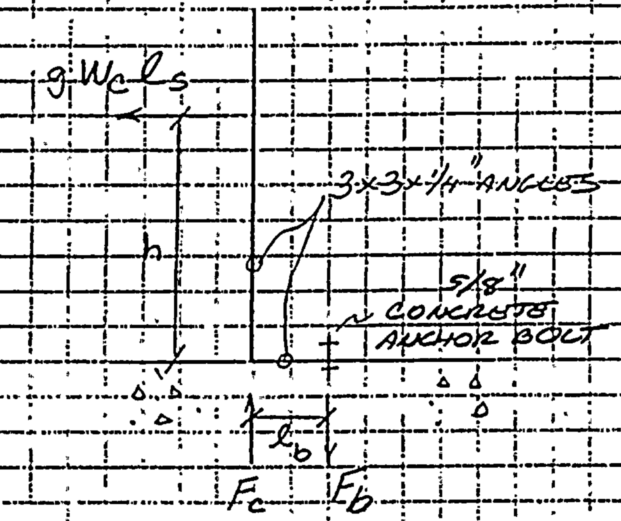
CLIENT AEP JOB No. 89C1570 SHEET 1 OF 9

SUBJECT A46 LAR'S
DC COOK UNIT 1
LAR-011
(PASS ID# RACE-101, LAR #1)
AUX. BLDG. EL. 586'

REVISIONS: 0 CCF 5/10/94; A.K. 5/26/94

REFE.	LOAD CALCULATIONS
6.22 AND PASS	THIS LAR EVALUATES A NUMBER OF FLOOR MOUNTED CANTILEVER SUPPORTS OF THE SAME BASIC GEOMETRY BUT WHICH HAVE VARYING CONDUIT SPANS AND ANCHOR BOLT POSITIONS - SEE pp. 10 & 11 OF THIS LAR. THE REPRESENTATIVE CASE FOR ANALYSIS IS SELECTED BELOW.

THE BASIC GEOMETRY OF THESE SUPPORTS IS AS FOLLOWS:



W_c = CONDUIT WGT.
l_s = SPAN BETWEEN SUPPORTS
F_c = BEARING FORCE ON CONCRETE FLOOR
F_b = TENSION IN CONC ANCHOR BOLT
l_b = DISTANCE FROM CONCRETE BEARING POINT TO ℄ CONCRETE ANCHOR
g = SEISMIC ACCELERATN FOR LATERAL LOAD CHECK

A LATERAL LOAD CHECK IS REQUIRED FOR FLOOR MOUNTED SUPPORTS. THE ANCHOR BOLT WILL BE THE CRITICAL SUPPORT ELEMENT.

$$F_b = \underbrace{(g W_c h)}_{\text{CONSTANT, ALL CASES}} \underbrace{\frac{l_s}{l_b}}_{\text{VARIES}} \Rightarrow F_b \sim \frac{l_s}{l_b}$$

E-W DIRECTION: USE $l_s = 5'-1"$ AND $l_b = 3"$ AS COMPOSITE VALUES.

N-S DIRECTION: USE $l_s = 6'$ AND $l_b = 4\frac{1}{4}"$ AS COMPOSITE VALUES.

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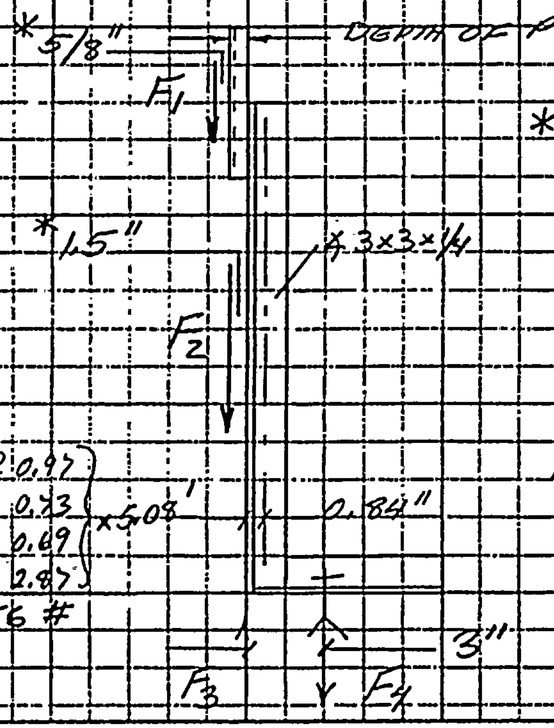
SUBJECT AEP/ A46 LAR'S DC COOK, UNIT 1 LAR-011 (PASS ID# RACE-101, LAR #1) AUX BLDG. EL. 586'

JOB No. 89C1570 SHEET 2 OF 9

REVISIONS: 0 CCF 5/10/94 A.K. 5/26/94

REF.	LOAD CALCULATIONS
	E-W DIRECTION: $l_s/l_b = 5.08'/3'' = 1.69$ '/"
	N-S DIRECTION: $l_s/l_b = 6'/4.25'' = 1.41$ '/"
	THE CRITICAL COMBINATION OF CONDUIT SPAN AND DISTANCE FROM BOLT TO CONCRETE BEARING POINT OCCURS FOR THE E-W SUPPORTS. THEREFORE USE $l_s = 5.08'$ AND $l_b = 3''$ IN THE EVALUATIONS.
6.15	CONDUIT WEIGHTS: USE ACTUAL CONDUIT WEIGHTS AS PROVIDED IN REF. 6.15. SEE LAST TWO PAGES OF THIS LAR.
6.4 SECT. 8.3.1	DEAD LOAD CHECK



*ECCENTRICITIES OF F_1 & F_2 ARE CONSERVATIVELY TAKEN AS 1/2 THE NOMINAL OD OF THE LARGEST CONDUIT IN THE GROUP.

F_1 = (1@0.97, 1@0.73, 1@0.69, 3@2.87) × 5.08'

F_1 = 56 #

F_2 = (1@3.81, 1@3.72, 2@7.91, 1@3.92, 1@3.72, 1@8.39) × 5.08'

F_2 = 200 #

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SUBJECT AEP/ A46 LAR'S DC COOK UNIT 1 LAR-011 (PASS ID# RACE101, LAR#1) AUX. BLDG EL. 586'
JOB No. 89C1570 SHEET 3 OF 9
REVISIONS: 0 CCF 5/10/94 A.K. 5/26/94

REF. DEAD LOAD CHECK (CONT'D)

REACTIONS:

$F_4(3.0) = F_1(1.5) + F_2(1.5)$

$F_4 = [56(1.5) + 200(1.5)]/3.0$

→ $F_4 = 128$ #

→ $F_3 = F_1 + F_2 + F_4 = 384$ #

MAX MOMENT IN ∠3×3×1/4:

$M_{MAX} = (56+200)(1.5+.84) = 599$ IN-LB

CHECK (2) 3/16" HEX BOLTS CONNECTING P3300 TO ∠3×3×1/4:

A_B (BASED ON NOMINAL DIAMETER) = 0.0276 IN²

6.1 USING ALLOWABLE STRESS F_V = 10KSI FOR A307 BOLTS ∴ V_{ALL} = 276 #/BOLT

APPLIED D.L./BOLT = 56/2 = 28 # ∴ OK

BOLT BEARING STRESS ON P3300 AND ∠3×3×1/4 OK BY INSPECTION

CHECK COMPRESSIVE BEARING STRESS ON ∠3×3×1/4

FLANGE AREA @ F_3 = 3" × 1/4" = 0.75 IN²

$F_3/A = 384/0.75 = 0.51$ KSI LOW

STEVENSON & ASSOCIATES
a structural-mechanical consulting engineering firm

SUBJECT AEP / A46 LAR'S
DC COOK UNIT 1
LAR-011
(PASS ID# RACE 101, LAR#1)
AUX BLDG EL 586'

JOB No. 89C1570 SHEET 4 OF 9

REVISIONS 0 CCF 5/10/94 A.K. 5/26/94

REF.	DEAD LOAD CHECK (CONT'D)
	CHECK MAX. BENDING STRESS IN ∠ 3x3x1/4:
6.1	M_{MAX}/S = 599 IN-LB / 0.577 = 1.0 KSI LOW ∴ OK
	CHECK ANCHOR BOLT:
6.4 APP. C	MAXIMUM ALLOWABLE TENSILE LOAD ON AN UNSPECIFIED 5/8"Φ CONCRETE ANCHOR BOLT, TIGHTNESS CHECK PERFORMED PER THE PASS, IS 1900 #.
	F_y = 128 # < 1660 # ∴ OK
	DUE TO THE LIGHT LOADING CONDITION AS EVIDENCED BY THE PRECEDING CALCULATIONS, THE WELDS AT THE BASE OF THE ∠ 3x3x1/4 ARE ADEQUATE BY INSPECTION.
	THIS SUPPORT CONFIGURATION SATISFIES THE DEAD LOAD CHECK WITH SIGNIFICANT MARGIN.

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SUBJECT AEP/ A46 LAR'S DC COOK UNIT 1 LAR-011 (PASS ID# RACG101, LAR#1) AUX BLDG EL 586' JOB No. 89C1570 SHEET 5 OF 9

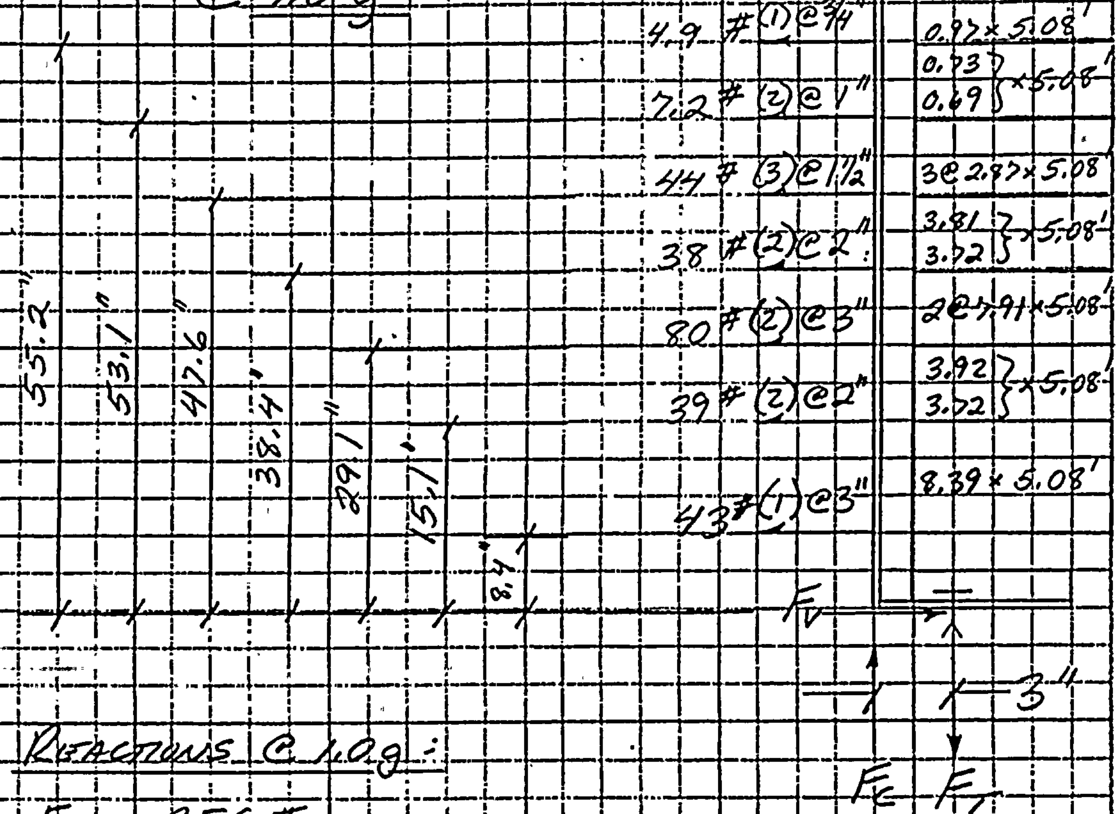
REVISIONS 0 CCC 5/10/94 AK 5/26/94

REF	
	VERTICAL CAPACITY CHECK
6.4 SECT. 8.3.2	THIS CHECK IS N/A FOR FLOOR MOUNTED SUPPORTS.
6.4 SECT. 8.3.3	DUCTILITY CHECK BASE MOUNTED SUPPORTS ARE CONSIDERED NON-DUCTILE. A LATERAL LOAD CHECK IS REQUIRED.
6.4 SECT. 8.3.4	LATERAL LOAD CHECK UNDER HORIZONTAL SEISMIC LOADING, THE ANCHOR BOLT IS THE WEAKEST SUPPORT ELEMENT. FOR LOADING IN THE SIDE-TO-SIDE DIRECTION (PERPENDICULAR TO THE CONDUIT RUN;) THERE IS A MOMENT ARM OF 3" FROM THE EDGE OF THE BASE ANGLE TO THE CENTERLINE OF THE ANCHOR BOLT. FOR LOADING IN THE FRONT-TO-BACK DIRECTION (PARALLEL TO THE CONDUIT RUNS), THE MOMENT ARM IS ONLY 1.5". IF THE LOADS MUST BE RESISTED SOLELY BY CANTILEVER BENDING OF THE VERTICAL MEMBER, THEN THE FRONT-TO-BACK CASE WOULD GOVERN. HOWEVER, THE SEISMIC REVIEW TEAM JUDGED THAT EVEN ASSUMING NO MOMENT CAPACITY AT THE FLOOR CONNECTION, THE CONDUIT/SUPPORT CONNECTIONS (U-BOLTS AND CONDUIT CLAMPS) WILL ALLOW THE SERIES OF SUPPORTS TO ACT AS A MULTI-BAY FRAME RATHER THAN AS A SERIES OF INDEPENDENT CANTILEVERS. THEREFORE, ONLY SIDE-TO-SIDE MOTION NEED BE EVALUATED FOR THE LATERAL LOAD CHECK.

S&A STEVENSON & ASSOCIATES a structural-mechanical consulting engineering firm	SUBJECT AEP / A46 LAR'S / DC COOK UNIT 1 / LAR-011 / (PASS ID# RACE 101, LAR #1) / AUX BLDG EL 586'	JOB No. 89C1570	SHEET 6 OF 9	REVISIONS: 0 CCF 5/10/94 A.K. 5/26/94

REF. LATERAL LOAD CHECK (CONT'D)

NOTE: LOADS SHOWN ARE @ 1.0 g



REACTIONS @ 1.0 g:

$F_{V_{1g}} = 256\ \#$

$$3F_T = 4.9(55.2) + 7.2(53.1) + 44(47.6) + 38(38.4) + 80(29.1) + 39(15.1) + 43(8.4) = 7495\ \text{IN-LB}_{1g} = M_{1g}$$

$F_{T_{1g}} = F_{C_{1g}} = 2500\ \#$

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CLIENT AEP JOB No. 89C1570 SHEET 7 OF 9

SUBJECT A46 LAR'S
DC COOK UNIT 1
LAR-011
(PASS ID# RA36101, LAR #1)
AUX BLDG EL. 586'

REVISIONS: 0 CCF 5/10/94 A.K. 5/26/94

REF.	LATERAL LOAD CHECK (CONT'D)
	IMPOSING A HORIZONTAL SEISMIC ACCELERATION OF 0.63g: (SEE SECTION 5.2 OF THIS CALCULATION)
	$F_V = 161\#$
	$F_T = F_C = 1575\#$
	$M_{MAX} = 4722$ IN-LB
	COMBINE DEAD LOAD AND LATERAL LOAD:
	$F_V = 161\#_{LL}$
	$F_T = 128\#_{DL} + 1575\#_{LL} = 1.70K$
	$F_C = 384\#_{DL} + 1575\#_{LL} = 1.96K$
	$M_{MAX} = 599^{IN-\#}_{DL} + 4722^{IN-\#}_{LL} = 5.32$ IN-K
	CHECK ANCHOR BOLT:
	FOR 5/8" CONCRETE ANCHOR, TIGHTNESS CHECK OK:
	$V_{ALL} = 2.28K \quad P_{ALL} = 1.66K$
6.4 APP C C.2.11	USING BI-LINEAR FORMULATION FOR SHEAR/TENSION INTERACTION:
	$V/V_{ALL} = 161/2280 < 0.3$,
	$\therefore P/P_{ALL} \leq 1.0 \Rightarrow 1700/1660 \approx 1.0$
	$\therefore$ OK
	(INT = 1.02)

REF. LATERAL LOAD CHECK (CONT'D)

CHECK ∠ 3×3×1/4 IN BENDING:

$f_B = M_{MAX}/S = 5.32/0.577$

$= 9.22\,KSI < 0.9F_y = 32.4\,KSI$

(INT = 0.28) ∴ OK

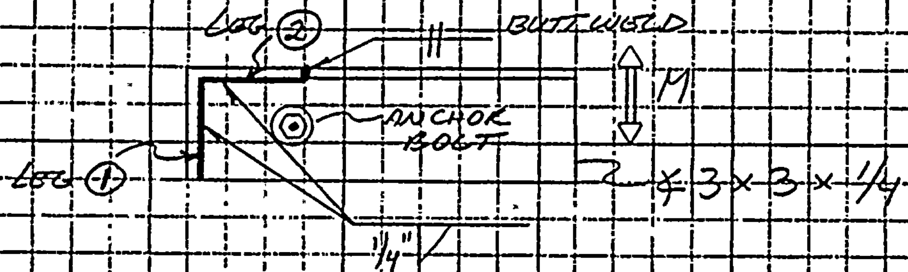
CHECK BEARING ON EDGE OF ∠ 3×3×1/4:

$F_c/A = 1.96/(.25 \times 3) = 2.6\,KSI$ LOW

∴ OK

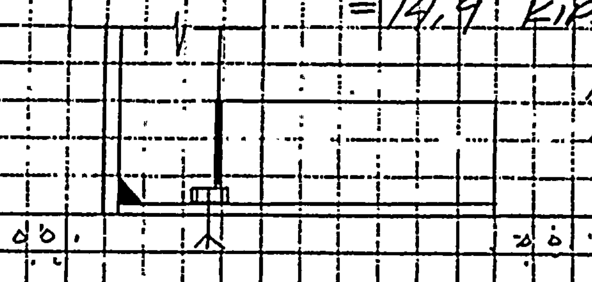
CHECK WELD @ BASE OF ∠ 3×3×1/4:

CONNECTION IN PLAN:



SHEAR CAPACITY OF ONE LEG OF 1/4" FILLET $= .707(.25 \times 2.25)(30.6\,KSI)$ $1.7 \times 18\,KSI$

$= 14.9$ KIPS.



BY INSPECTION, LEG ① OF THE 1/4" FILLET WELD IN COMBINATION WITH THE BUTT WELD IS SUFFICIENT TO TRANSFER LOADS TO THE ANCHORAGE

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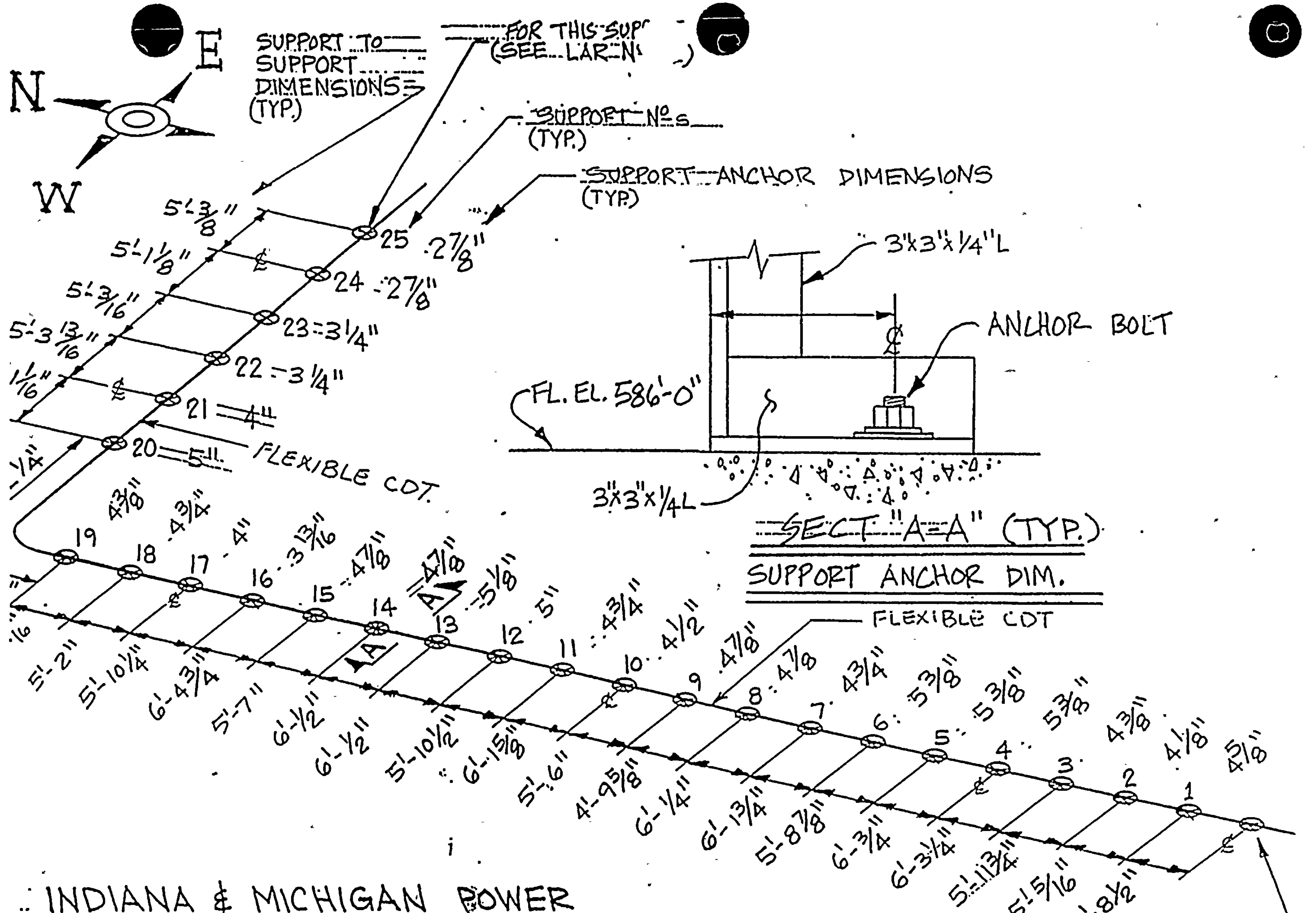
CLIENT AEP JOB No. 89C1570 SHEET 9 OF 9

SUBJECT A46 LAR'S
DC COOK UNIT 1
LAR-011
(PASS ID# RACE 101, LAR #1)
AUX BLDG. EL. 586'

REVISIONS
0 CLF 5/10/94 A.K. 5/26/94

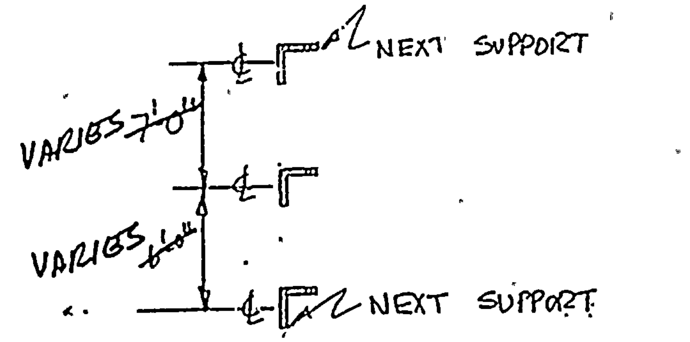
REF. CONCLUSION

THIS SUPPORT SATISFIES THE LIMITED ANALYTICAL REVIEW REQUIREMENTS OF REF 6.4 AND IS THEREFORE CONSIDERED TO BE SEISMICALLY ADEQUATE.



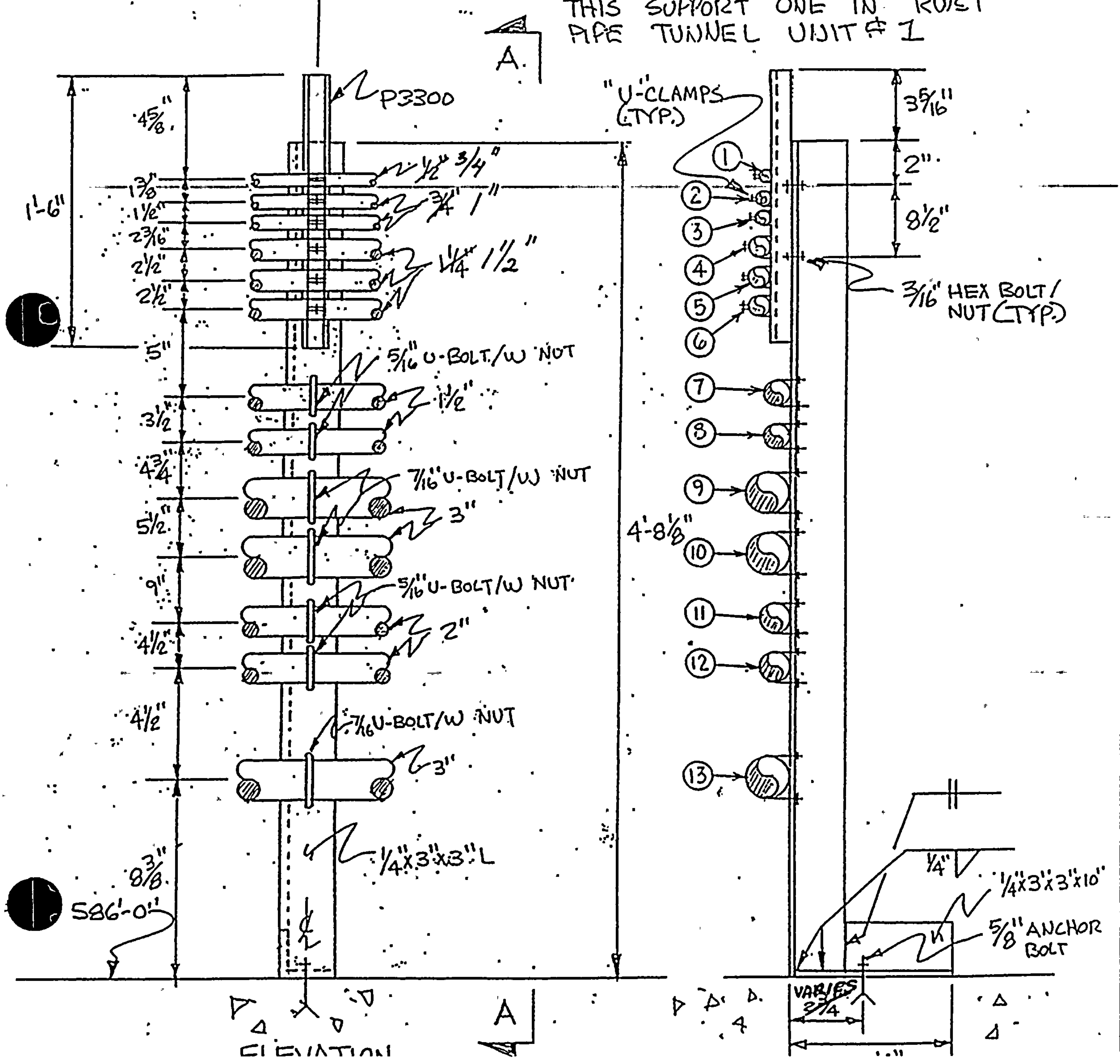
INDIANA & MICHIGAN POWER
DONALD C. COOK NUCLEAR PLANT
DR. BY. M. MARSH DATE 1-19-94
EL. 586'-0" BUILDING AUX.
LOCATION RWST. CST. PIPE TUNNEL UNIT # 1

ATTACHMENT NO. 3



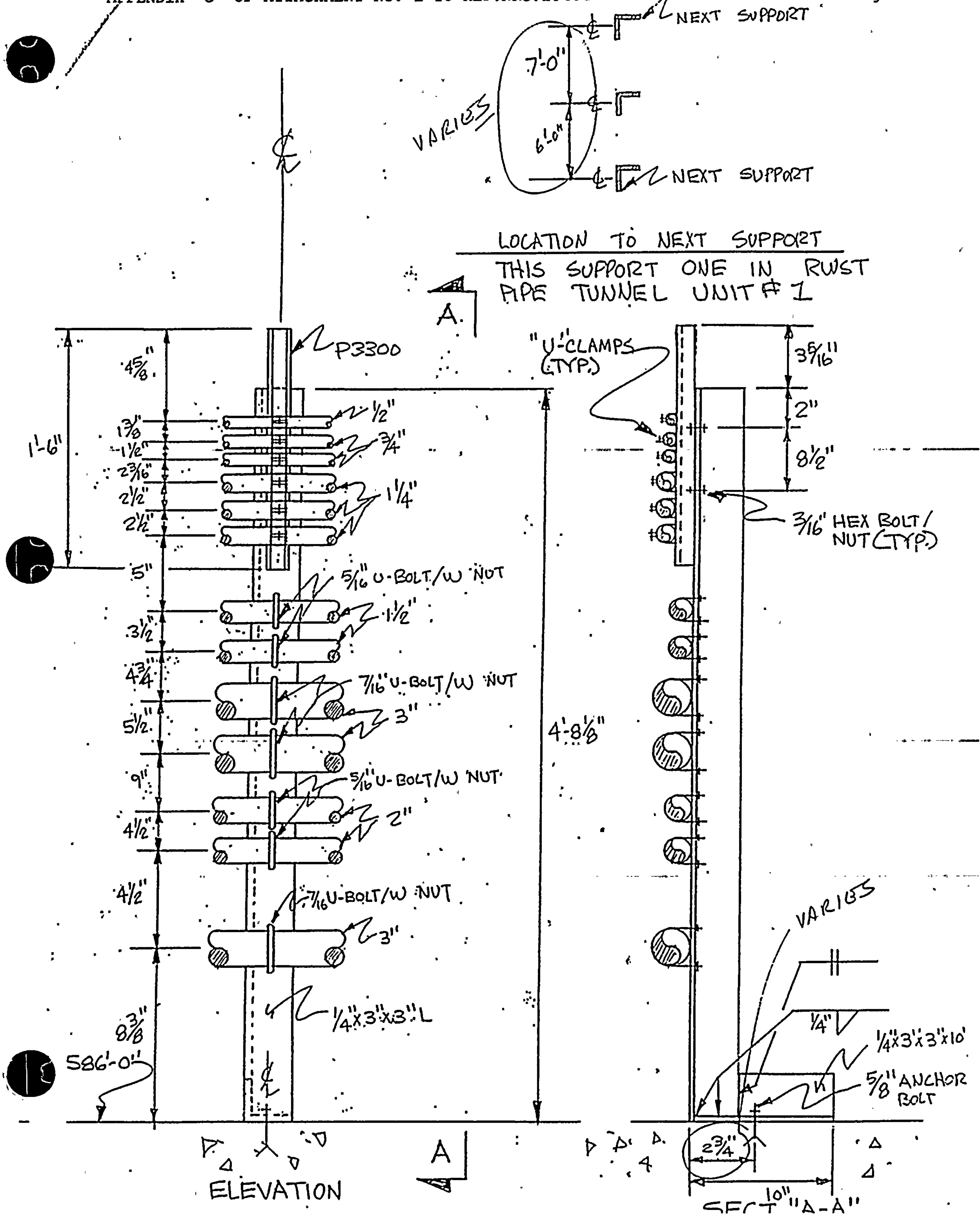
LOCATION TO NEXT SUPPORT

THIS SUPPORT ONE IN RUST PIPE TUNNEL UNIT # 1



ATTACHMENT NO. 1
COOK NUCLEAR PLANT
A-46 RACEWAY EVALUATIONS
LAR011

CONDUIT NO. (SEE ATTACH.3)	CONDUIT SIZE AND TYPE	CABLE TYPE AND SIZE IN CONDUIT	POUNDS PER FOOT OF CONDUIT AND CABLE	BASIS FOR WEIGHT CALCULATION (SEE LISTED ATTACH. NOS.)
1	3/4" EMT	1-12/C #12 XLA	0.97	5 & 7C
2	1" EMT	2-2T/C #16	0.73	5 & 8B
3	1" EMT	1-STP #16	0.69	5 & 13B
4	1 1/2" RIGID STEEL	1-4/C #7/18	2.87	6 & 7C
5	1 1/2" RIGID STEEL	1-4/C #7/18	2.87	6 & 7C
6	1 1/2" RIGID STEEL	1-4/C #7/18	2.87	6 & 7C
7	2" RIGID STEEL	1-3TC #4 1-1/C #4	3.81	6, 9, & 10
8	2" RIGID STEEL	1-4/C #12	3.72	6 & 7C
9	3" RIGID STEEL	1-3TC #2/0 1-1/C #2	7.91	6, 9, & 10
10	3" RIGID STEEL	1-3TC #2/0 1-1/C #2	7.91	6, 9, & 10
11	2" RIGID STEEL	1-3TC #2 1-1/C #4	3.92	6, 9, & 10
12	2" RIGID STEEL	1-4/C #12	3.72	6 & 7C
13	3" RIGID STEEL	1-3TC #4/0 1-1/C #2/0	8.39	6, 9, & 10



NEXT SUPPORT
7'-0"
VARIES
6'-0"
NEXT SUPPORT
LOCATION TO NEXT SUPPORT
THIS SUPPORT ONE IN RUST PIPE TUNNEL UNIT # 1
A
P3300
4 5/8"
1'-6"
1 3/8"
1 1/2"
2 3/16"
2 1/2"
2 1/2"
5"
1/2"
3/4"
1 1/4"
5/16" U-BOLT/W NUT
1 1/2"
3 1/2"
4 3/4"
7/16" U-BOLT/W NUT
3"
5 1/2"
9"
5/16" U-BOLT/W NUT
2"
4 1/2"
4 1/2"
7/16" U-BOLT/W NUT
3"
8 3/8"
1/4"x3"x3" L
586'-0"
4'-8 1/8"
A
ELEVATION
"U"-CLAMPS (TYP.)
3 5/16"
2"
8 1/2"
3/16" HEX BOLT/NUT (TYP.)
VARIES
1/4"
1/4"x3"x3"x10"
5/8" ANCHOR BOLT
2 3/4"
10"
SECT "A-A"

American Electric Power - D. C. Cook
A-46 Cable Tray and Conduit Raceway Review

Limited Analytical Review (LAR) Data Sheet

Room No.: n/a

Selection No.: LAR013

Plant Location: see attached

Description and Sketch: see attached

Reference Calculation: see attached

Result: **Pass**

Additional Notes:

Certification: (Signatures of at least two Seismic Capability Engineers are required; one of whom is a licensed professional engineer.)

Name	Signature	Date
I. C. Huang (AEPSC)	I Chen Huang	10-11-95
Steve Anagnostis (S&A)	[signature]	12/28/94

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SUBJECT AEP JOB No. 89C1570 SHEET 1 OF 6

A46 LAR'S
DC COOK UNIT 1
LAR-013
(RASS ID# RACE117, LAR #2)
AUX CABLE VAULT EL 620'-6"

REVISIONS: 0 CCF 5/11/94, A.K. 5/25/94

REF	LOAD CALCULATIONS
RASS	TRIBUTARY LENGTH: (3'-11" + 6'-3/4")/2 = 5.1'
6.14	CONDUIT WEIGHTS:
	4" = 16.6 #/FT × 5.1' = 85 #
	1¾" = 4.9 #/FT × 5.1' = 25 # (USE 2" VALUE)
	1¼" = 3.5 #/FT × 5.1' = 18 # (USE 1½" VALUE)
	¾" = 1.3 #/FT × 5.1' = 7 #
	½" = 1.1 #/FT × 5.1' = 6 #
	CABLE TRAY WEIGHTS:
	25 PLF × 5.1' = 128 #
4.4 SERT 8.3.1	DEAD LOAD CHECK
	EVALUATE P1080 ROD-HUNG/CANTILEVER ASSEMBLY

THE TOTAL WEIGHT OF THE SUPPORTED CONDUIT (1@4", 3@1¼", 1@¾" AND 3@½") = 160 #. THE ROD-HUNG/CANTILEVER PORTION OF THE SUPPORT IS OK BY INSPECTION.

NO OTHER ANALYSIS IS REQUIRED FOR THIS PORTION OF THE SUPPORT BECAUSE THE ∠3½ × 3½ × ¼ VERTICAL MEMBER OF THE FLOOR-TO-CEILING SUPPORT FRAME PROVIDES RIGID SUPPORT FOR THE CONDUIT SUPPORT.

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SUBJECT	AEP
JOB No.	89C1570
SHEET	2 OF 6

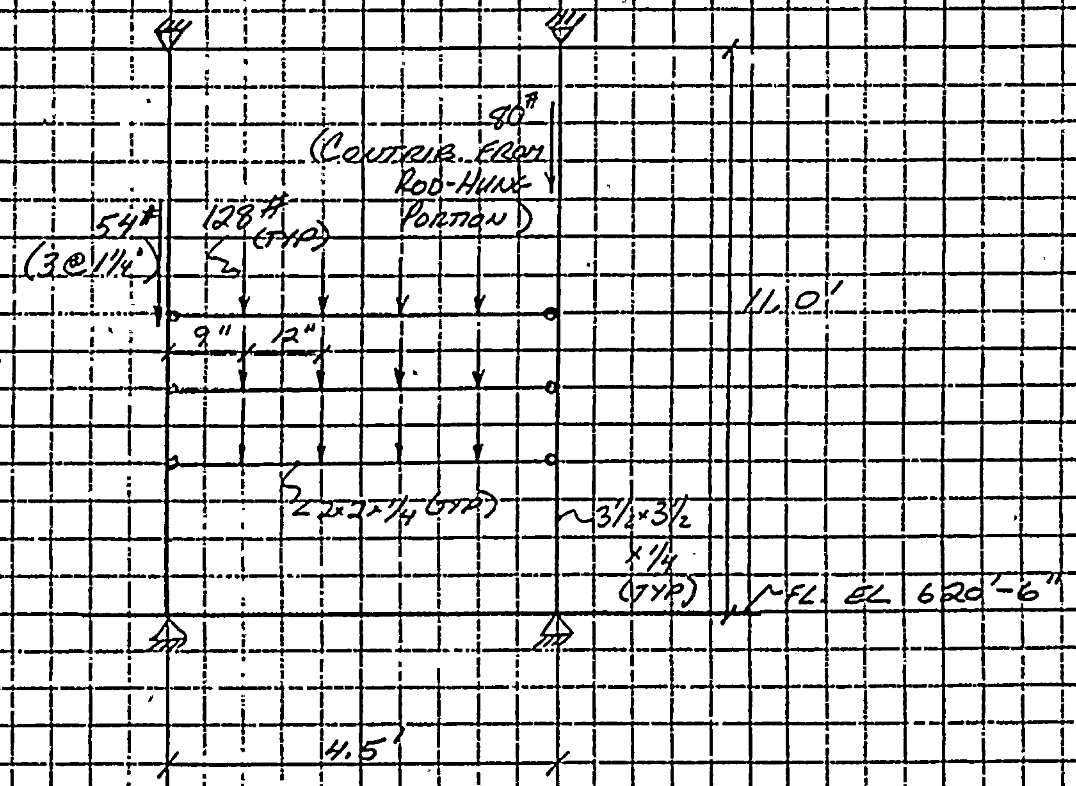
A46 LAR's
DC COOK UNIT 1
LAR-013
(PASS ID# RACE 117, LAR#2)
AUX CABLE VAULT EL. 620'-6"

REVISIONS: 0 CCF 5/11/94 A.K. 5/25/94

REF. DEAD LOAD CHECK (CONT'D)

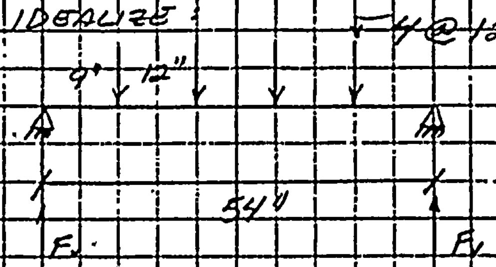
EVALUATE ∠3½×3½×¼ FLOOR-TO-CEILING FRAME:

SIMPLIFY FRAME AS SHOWN BELOW. DISREGARD ECCENTRICITIES (NEGLIGIBLE IN THIS CASE).



CHECK BENDING IN ∠2×2×¼:

IDEALIZE:



F1 = 256#

MMAX = 3840 IN-#

M/S = 3840/0.247
= 15.5 KSI < 21.6 ∴ OK
(INT. = 0.72)

REF.	DEAD LOAD CHECK (CONT'D)
	ALL OTHER SUPPORT CONSIDERATIONS = WELDS @ L2×2×1/4 TO L 3½×3½×1/4; STRESSES IN THE L3½×3½×1/4 COLUMNS; AND LOADS AT THE ANCHOR POINTS ARE JUDGED TO BE LOW BY INSPECTION FOR THE DEAD LOAD CASE.
6.4 SECT 8.3.6	FLOOR-TO-CEILING SUPPORT EVALUATIONS
	FLOOR-TO-CEILING SUPPORTS MAY BE EVALUATED BY EITHER NEGLECTING THE FLOOR ANCHORAGE AND ANALYZING THE SUPPORT AS A SUSPENDED RACEWAY, OR BY INCLUDING THE FLOOR CONNECTIONS IN THE EVALUATION.
	FOR THIS SUPPORT, THE FLOOR CONNECTIONS WILL BE INCLUDED IN THE REMAINING EVALUATIONS.
6.4 SECT 8.3.2	VERTICAL CAPACITY CHECK (3 × DL)
	FOR FLOOR-TO-CEILING SUPPORTS WHERE FLOOR CONNECTIONS ARE INCLUDED IN THE EVALUATION, THE LOWER SUPPORT COLUMN(S) ARE CHECKED FOR BUCKLING. CREDIT MAY BE TAKEN FOR THE PORTION OF 3×DL WHICH CAN BE RESISTED BY THE OVERHEAD ANCHORAGE, BUT, FOR THIS SUPPORT EVALUATION, NO CREDIT WILL BE TAKEN

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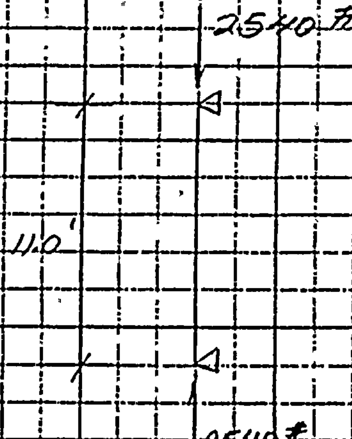
SUBJECT AEP JOB No. 89C1570 SHEET 4 OF 6

A46 LAR'S
DC COOK UNIT 1
LAR-013
(PASS ID# RACE117, LAR #2)
AUX CABLE VAULT EL. 620'-6"

REVISIONS: 0 CCF 5/11/94 A.K. 5/25/94

REF	
	VERTICAL CAPACITY CHECK (CONT'D)
	CHECK BUCKLING IN L 3½ × 3½ × ¼
	MAX COLUMN AXIAL LOAD FOR 3×DL CASE:
	$P = 3(6 \times 128^{\#}) + 80^{\#} = 2540^{\#}$
	ANALYZE A PIN-PIN COLUMN @ H = 11.0', CONSERVATIVELY APPLY THE FULL COMPRESSIVE LOAD OVER THE ENTIRE LENGTH. DISREGARD ANY IMPOSED BENDING MOMENTS FROM THE CROSS MEMBERS.



K = 1.0
L = 132"
r = 0.93 IN (USE VALUE FOR
A = 1.44 IN² L 3×3×¼ TO AVOID ANGLE FLANGE WIDTH/THICKNESS CONSIDERATIONS)

REF	
6.1 TABLE C-36	$KL/r = 142 \Rightarrow F_a = 7.4$ KSI
	$\frac{2540}{1.44} = 1.8$ KSI < 7.4 KSI
	VERTICAL MEMBER BUCKLING IS NOT A CONCERN FOR THIS SUPPORT.
6.4	LATERAL LOAD CHECK
SECT 8.3.4 & 8.3.6	FOR FLOOR-TO-CEILING SUPPORTS WHERE FLOOR CONNECTIONS ARE INCLUDED IN THE EVALUATION, THE TOP AND BOTTOM CONNECTIONS AND ANCHORS ARE CHECKED FOR DEAD LOAD PLUS THE EQUIVALENT STATIC LATERAL LOAD REACTIONS.

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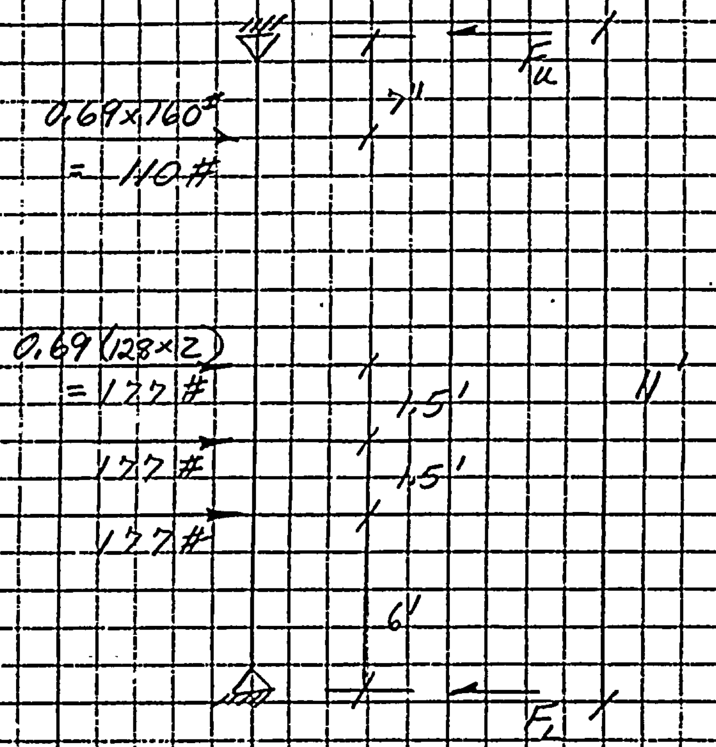
SUBJECT AEP JOB No. 89C1570 SHEET 5 OF 6

A46 LAR'S
DC COOK UNIT 1
LAR-013
(PASS ID# RACE 117, LAR #2)
AUX CABLE VAULT EL. 620'-6"

REVISIONS: 0 CCF 5/11/94, A.K. 5/25/94

REF. LATERAL LOAD CHECK (CONT'D)

HORIZONTAL SEISMIC ACCELERATION (SEE SECTION 5.2 OF THIS CALCULATION) = 0.69g



HORIZONTAL REACTIONS =

$F_u = [177(6' + 7.5' + 9') + 110(10.4')] / 11'$

$F_u = 466$ LB

$F_L = 175$ LB

THERE IS NO ADDITIONAL SHEAR LOAD DUE TO DEAD WEIGHT. ANY REACTION DUE TO LOAD ECCENTRICITY WILL BE VERY SMALL.

THE CONCRETE FLOOR IS ASSUMED TO TAKE THE FULL VERTICAL FORCE DUE TO DEAD WEIGHT.

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SUBJECT AEP JOB No. 89C1570 SHEET 6 OF 6

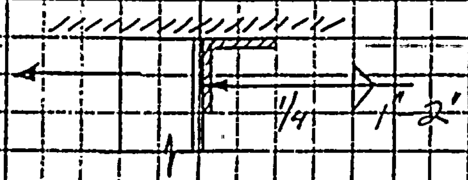
A46 LAR'S
DC COOK UNIT 1
LAR-013
(PASS ID# RACE 117, LAR#2)
AUX CABLE VAULT EL. 620'-6"

REVISIONS
0 CCF 5/11/94
A.K. 5/25/94

REF. LATERAL LOAD CHECK (CONT'D)

CHECK CONNECTIONS AND ANCHORAGES:

- WORST CASE WELD BETWEEN $L\,3\frac{1}{2}\times3\frac{1}{2}\times\frac{1}{4}$ AND CLIP ANGLE:



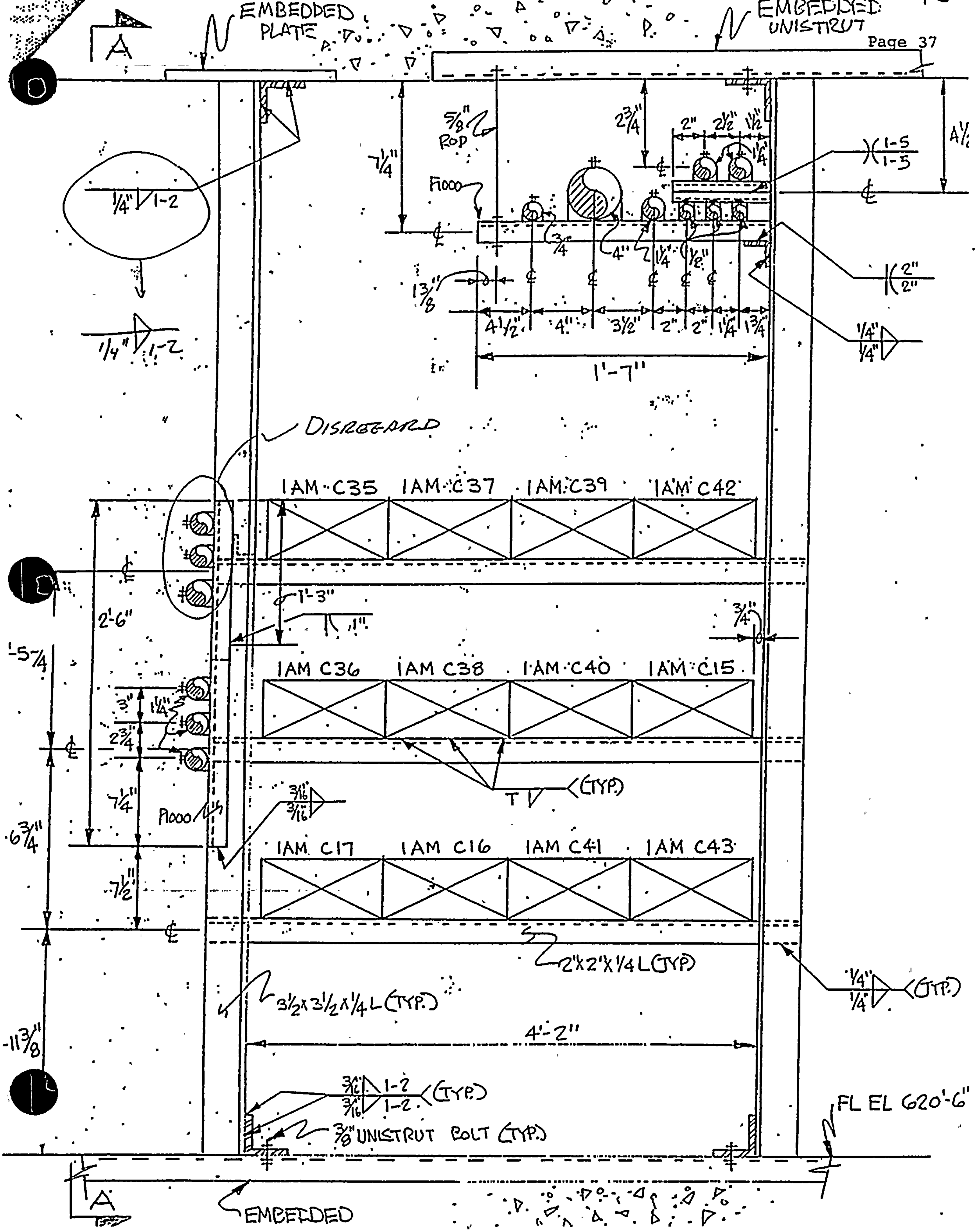
WELD CAPACITY (ANGLE WEB SIDE ONLY):
$F_w = 0.7071(2''L)(\frac{1}{4}''t)(18\,KSI)(1.7) = 10.8K$
$10.8K >> 466\,LB.$

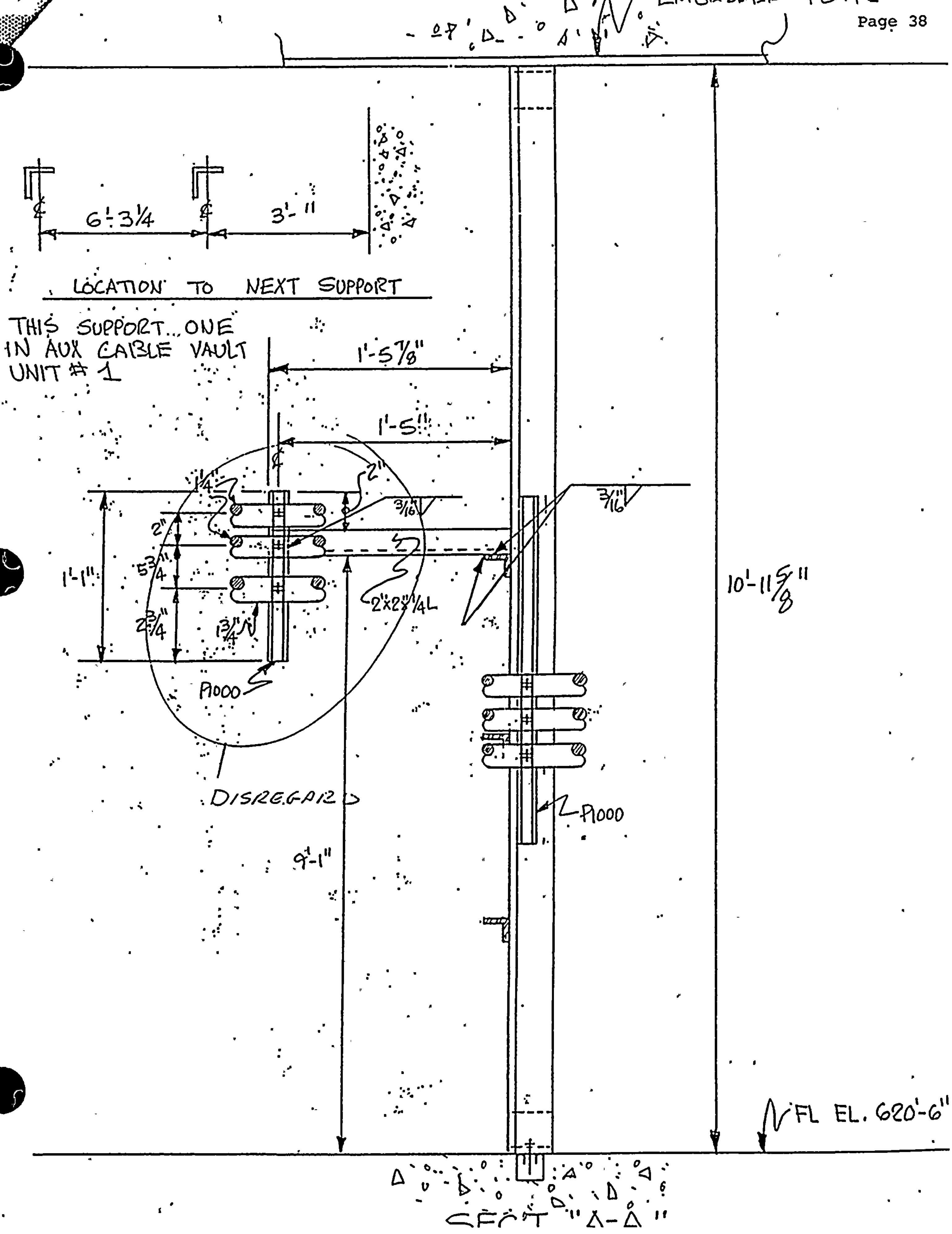
- WORST CASE ANCHORAGE: 3/8" UNISTRUT BOLT: RESISTANCE TO SLIP = 800# > 466 LB ∴ OK
(INT = 0.58)

466# LOAD IN SHEAR ON EMBEDDED PLATE OK BY INSPECTION

CONCLUSION

THIS SUPPORT SATISFIES THE LIMITED ANALYTICAL REVIEW OF REF. 6.4 AND IS THEREFORE CONSIDERED TO BE SEISMICALLY ADEQUATE.


A
EMBEDDED PLATE
EMBEDDED UNISTRUT
5/8" ROD
P1000
DISREGARD
1AM C35
1AM C37
1AM C39
1AM C42
1AM C36
1AM C38
1AM C40
1AM C15
1AM C17
1AM C16
1AM C41
1AM C43
1'-7"
4'-2"
2'-6"
1'-3"
T (TYP.)
2"x2"x1/4 L (TYP.)
3 1/2x3 1/2x1/4 L (TYP.)
3/8" UNISTRUT BOLT (TYP.)
FL EL 620'-6"
EMBEDDED


EMBEDDED PLATE
6'-3 1/4
3'-11
LOCATION TO NEXT SUPPORT
THIS SUPPORT...ONE
IN AUX CABLE VAULT
UNIT # 1
1'-5 7/8"
1'-5"
1 1/4"
2"
3/16
3/16"
2"
5 3/4"
1'-1"
2 3/4"
1 3/4"
2"x2"x1/4L
P1000
DISREGARD
P1000
9'-1"
10'-11 5/8"
FL EL. 620'-6"
SECT "A-A"

American Electric Power - D. C. Cook
A-46 Cable Tray and Conduit Raceway Review

Limited Analytical Review (LAR) Data Sheet

Room No.: n/a   Selection No.: LAR028

Plant Location: see attached

Description and Sketch: see attached

Reference Calculation: see attached

Result: Pass

Additional Notes:

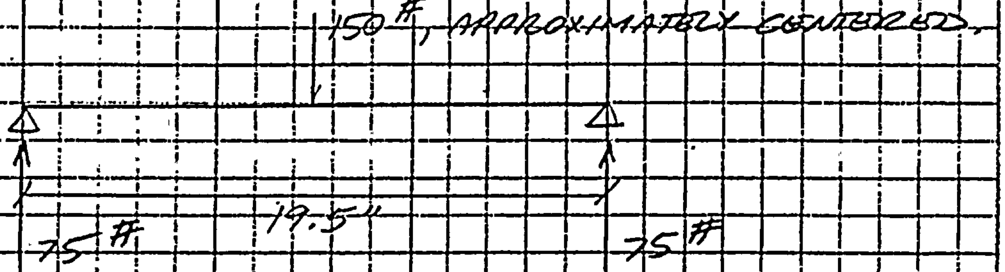
Certification: (Signatures of at least two Seismic Capability Engineers are required; one of whom is a licensed professional engineer.)

Name	Signature	Date
I. C. Huang (AEPSC)	I Chen Huang	10-11-95
Steve Anagnostis (S&A)	[signature]	12/28/94

S&A STEVENSON & ASSOCIATES a structural-mechanical consulting engineering firm	SUBJECT AEP JOB No. 89C1570 SHEET 1 OF 3
	A46 LAR'S
	DC COOK UNIT 2
	LAR - 028
	(PASS ID# RACE005, LAR #1)
	CONTAINMENT EL. 618'
REVISIONS	0 CCF 5/11/94
	R.K. 5/25/94

REF	
	LOAD CALCULATIONS
PASS	TRIBUTARY LENGTH = 6'
	CABLE TRAY WEIGHT = 25 PLF × 6' = 150#
6.4 SECT. 8.3.1	DEAD LOAD CHECK

EACH TIER:



$M_{MAX} = 75(9\tfrac{3}{4}") = 731$ IN-LB

$M/S = 731/0.242 = 3.0$ KSI < 21.6 KSI
∴ OK

(UNT = 0.14)

THIS SUPPORT IS LIGHTLY LOADED. VERTICAL ∠'S 2×2×1/4 ARE OK BY INSPECTION AS ARE WELDS AT HORIZONTAL ℄ TO VERTICAL ∠ CONNECTIONS AND VERTICAL ∠ CONNECTION TO STEAM GENERATOR SUPPORT STEEL.

PROCEED TO VERTICAL CAPACITY CHECK.

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SUBJECT AEP JOB No. 89C1570 SHEET 2 OF 3

A46 LAR'S
DC COOK UNIT 2
LAR-028
(PASS ID# RACE 005, LAR#1)
CONTAINMENT EL. 618'

REVISIONS: 0 CCF 5/11/94 A.K. 5/25/94

REF.	VERTICAL CAPACITY CHECK (3 × DL)
6.4 SECT. 8.3.2	CHECK THE WELDS @ VERTICAL ∠'S 2×2×1/4 TO STEAM GENERATOR SUPPORT STEEL:

CAPACITY OF 7" OF 3/16" FILLET WELD:

$(1.7)(7")(3/16")(.707)(18\ KSI) = 28.4\ KIPS$

VERTICAL LOAD EACH LEG:

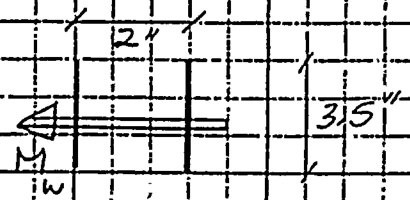
$(150\# \times 3 \times 3)/2 = 675\#$

$28.4K >> 675\# \therefore OK\ (INT = 0.02)$

REF.	
6.4 SECT. 8.3.3	DUCTILITY CHECK

THE DUCTILITY CONSIDERATION FOR THIS SUPPORT IS WHETHER THE WELD AT THE ∠ 2×2×1/4 CONNECTION TO THE STEAM GENERATOR SUPPORT STEEL IS STRONG ENOUGH TO ALLOW THE ∠ 2×2×1/4 VERTICAL MEMBERS TO DEFORM PLASTICALLY WITHOUT COMPROMISING THE ANCHORAGE.

LOOK AT WELD SECTION MODULUS =



SECTION MODULUS FOR ∠ 2×2×1/4 = 0.247 IN^3

$S_W = \frac{(3.5)^2}{3}\left(\frac{3}{16}\right)(.707)$

$0.54/0.247 = \underline{2.2}$

$S_W = 0.54\ IN^3$

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SUBJECT AEP JOB No. SHEET 3 OF 3

A46 LAR'S
DC COOK UNIT 2
LAR-028
(PASS ID# RACE 005, LAR#1)
CONTAINMENT EL. 618'

REVISIONS
0 CCF 5/11/94
A.K. 5/25/94

REF. DUCTILITY CHECK (CONT'D)

THE SECTION MODULUS OF THE WELD IS MORE THAN TWICE THAT OF THE L 2×2×1/4. THIS SUPPORT SYSTEM CAN BE CONSIDERED DUCTILE. NO FURTHER ANALYSIS IS REQUIRED

CONCLUSION:

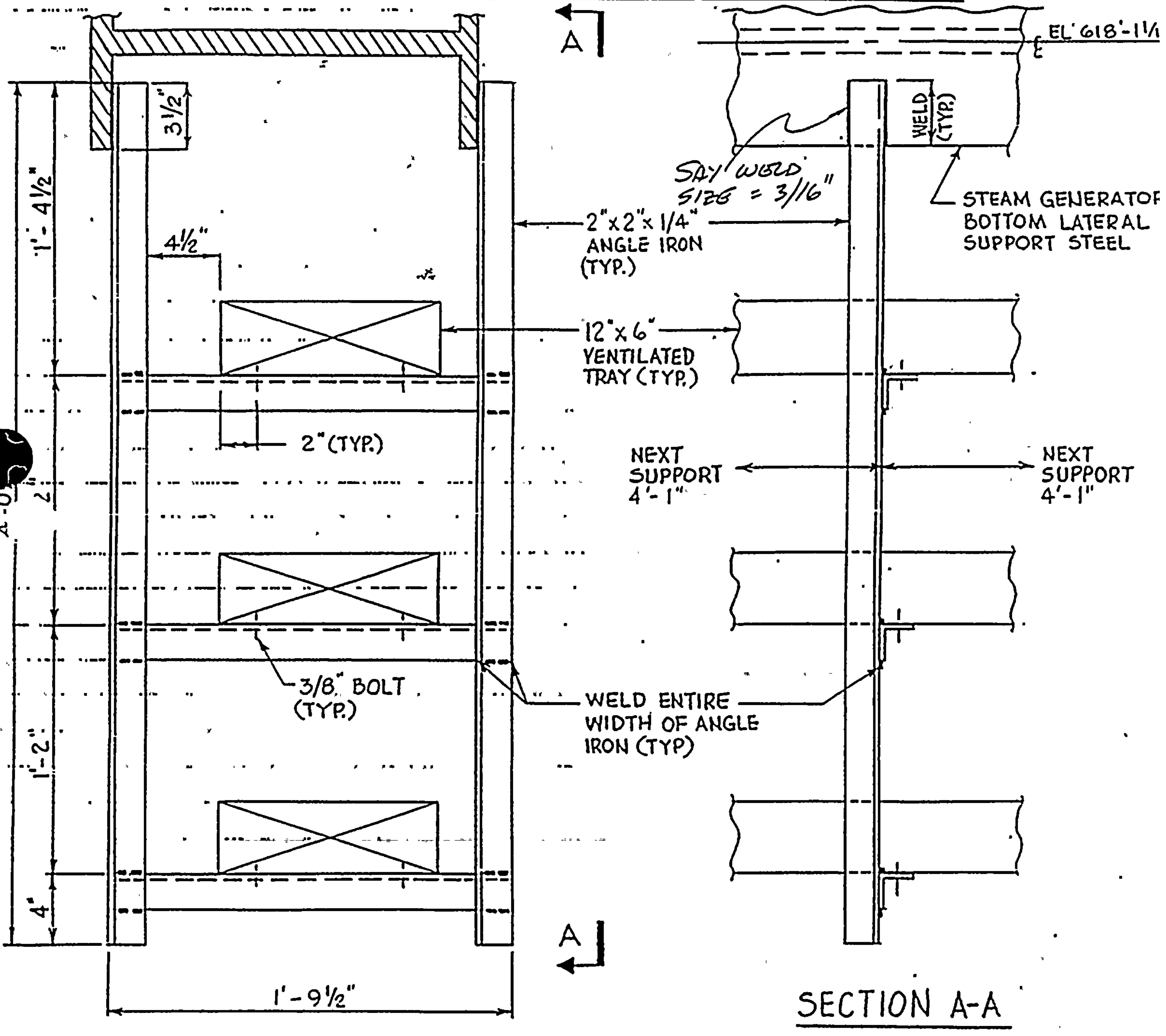
THIS SUPPORT SATISFIES THE LIMITED ANALYTICAL REVIEW CRITERIA OF REF 6.4 AND IS CONSIDERED TO BE SEISMICALLY ADEQUATE.

0890
7630(R4-89)IAP50

AMERICAN ELECTRIC POWER SERVICE CORP.
1 Riverside Plaza
Columbus, OH 43215

SHEET 1 OF 1
DATE 10/29/92 BY MB CK.
COMPANY AEP G.O.
PLANT DONALD C. COOK UNI'

SUBJECT ANGLE IRON TRAPEZE TRAY SUPPORT - CONTAINMENT BASEMENT INSIDE CRANE WALL - APPROXIMATE LOCATION BOTTOM OF STEAM GENERATOR #2



NOTES:

1. TRAY ARE LIGHTLY LOADED POWER TRAY.

PASS - HANGER SPACING = 5'-6'

(RACE 005 LAR #1)

46. LER 315/98-036

Event Description: Chemical and volume control system cross-tie flow indicator not calibrated within Technical Specification limits

Date of Event: July 1998

Plant: D.C. Cook, Unit 1

46.1 Summary of Issue

On July 23, 1998, during a verification of Technical Specification (TS) surveillance requirements, personnel discovered that flow indicator 12-QFI-201 had not been surveillance-tested since August 12, 1992. This flow indicator is on the cross-tie piping between units on the discharge lines for the charging pumps in the chemical and volume control system. The TS requirements are that this charging cross-flow indicator must be calibrated at least once every 549 days. Because the last surveillance test was performed on August 12, 1992, 12-QFI-201 was declared to be inoperable since June 29, 1994. To prevent a recurrence, the nuclear test scheduler database has been updated to reflect the requirement to calibrate the cross-tie flow-indicator on a refueling outage basis.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

46.2 Modeling and Affected Sequences

The charging cross-flow indicator provides a local readout of flow through the charging cross-tie piping. In the case of a fire event in one unit requiring shutdown from outside the control room (i.e., Title 10 of the Code of Federal Regulations, Part 50, Appendix R event), the cross-tie piping can be used as an alternate flow path from the opposite unit to provide seal injection flow to the reactor coolant pumps and make-up water to the pressurizer. Charging cross-flow indication is used to establish flow in the charging cross-tie piping. Other remote and local flow indications would identify whether adequate flow is maintained through the line. Failure to calibrate the charging cross-flow indicator would not have prevented the charging cross-tie from performing its function. Because charging cross-flow can be determined from other indicators (which would also indicate improper indication with indicator 12-QFI-210), there is essentially no safety significance for the failure to calibrate the charging cross-flow indicator.

No core damage sequences will increase in frequency as a result of this change.

DONALD C. COOK NUCLEAR POWER PLANT
UNITS 1 AND 2
INTEGRATED RISK ASSESSMENT

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This attachment consists of the following items:

- The document entitled "Framework for the Integrated Risk Assessment." This document outlines the methods used to group issues in order to assess the integrated risk.

- Appendix A of this document has grouped and tabulated issues affecting the core damage frequency (Table A-1) according to their impact on the mitigating functions and the initiating event frequency. Table A-2 of Appendix A of this attachment lists the specific analyses that will be performed (accident sequences and issues that are associated with those sequences) to assess the integrated risk. Table A-3 has grouped the containment related issues using their impact on specific containment failure modes.

- Appendix B to this attachment provides 1 analysis that was completed. This analysis could be completed since it involved a single issue and there were no synergistic effects from other issues.

- Appendix C to this attachment provides the bases for excluding 12 issues from the risk assessment. These 12 issues were screened out in accordance with the framework above because they had no impact on the risk-significant functions or because they had no synergistic effects and the probability of core damage associated with the events was less than 1×10^{-9} per year.

- Appendix D to this attachment provides analyses of 18 individual issues. None of these issues would be risk significant alone, but may be part of risk-significant sequences when the synergistic effects of other issues are considered. These issues will be incorporated into the integrated risk assessment to account for the synergistic effects of other issues on the overall risk significance. These analyses are provided to obtain comments on their technical treatment as inputs to the integrated assessments.

FRAMEWORK FOR THE INTEGRATED RiSK ASSESSMENT

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I. GOAL OF THE INTEGRATED RISK ASSESSMENT

The goal of the integrated risk assessment is to assess the risk associated with the issues identified at Cook Units 1 and 2 since their shutdown in August 1997. This assessment will include:

- Estimating the change in core damage frequency (CDF) associated with the degraded conditions; and
- Qualitative assessment of change to the probability of risk-significant containment failure modes due to degraded plant conditions.

The CDF change assessment will be carried out by executing the following steps:

- Identify issues[1].
- Group issues as outlined section II.1
- Screen issues using criteria described in section III.
- Assess the risk by using methods outlined in sections IV, and V.

The containment assessment will be carried out by executing the following steps:

- Identify issues[1].
- Group containment issues as outlined in section II.2.
- Screen issues using criteria described in section III.
- Assess qualitatively the change in containment performance using realistic (rather than design basis) failure limits, redundancies, and the magnitude of degradations.

II. Grouping Criteria

II.1 Grouping of Issues Affecting the CDF

The issues that affect the CDF will do so by affecting one or more mitigating functions or by affecting the initiating event frequency. Table A-1 in Appendix A shows how the issues are grouped according to their impact on the mitigating functions or the initiating event frequencies. Table A-1 shows how some issues apply to multiple initiators while others apply to a unique initiator. Information in Table A-1 is used to generate the list of analyses that need to be performed to assess the integrated risk. This list is provided as Table A-2 in Appendix A. Table A-2 lists each accident sequence initiator that will be quantified together with the issues which affect its associated sequences.

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[1] An issue may be an event, a failed or degraded component or system, or a condition such as a design deficiency identified in an inspection report, an LER, or a licensee's self assessment report.

II.2 Grouping of Issues Affecting the Containment

The issues that affect the containment performance will be grouped by the affected containment failure modes. Table A-3 of Appendix A shows how issues are grouped according to their impact on the containment failure modes.

III. Screening Criteria

Some issues can be screened out from the overall risk assessment after assessing their individual risk. The following criteria are used to screen out issues:

- An issue will be screened out if the component/system/function maintained its functionality even though the verbatim compliance requirements were not met (e.g.. Design basis fouling factor for ESW/CCW heat exchanger could have been exceeded due to wrong acceptance criteria. However, review of the operating experience and the "as found" condition of the heat exchanger proved that the heat exchanger was functional.)

- An issue will be screened out if (a) there are no mechanisms by which the issue can generate synergistic effects when considered with other issues, and (b) the issue has a CDF impact less than 1×10^{-9}/year. An example is the issue on the licensee's inability to meet the Tech Spec requirement to shut down within 36 hours. Thousands of issues like this are needed to create a risk significant situation ($1000 \times 10^{-9} = 10^{-6}$), and there aren't that many issues.

- A containment related issue will be screened out if (a) in isolation, the issue has essentially no impact on any risk-significant containment failure mode based on realistic failure limits, and (b) the issue cannot create synergistic effects when combined with other issues (e.g., The voluntary LER on the ice condenser bypass reported that the "as found" bypass area does not exceed the design allowable value).

IV. Assessing Synergistic Effects Due to Co-existent Conditions in Multiple Systems

Synergistic effects can result from co-existent conditions affecting more than one function in an accident sequence. For example, the failed condition of the back up air supply in a PORV has the potential to impact the feed and bleed capability. The undersized strainer in the ESW supply to AFW can affect the AFW reliability. These two conditions can generate a synergistic effect since both AFW and feed and bleed cooling can be used for removing decay heat during a loss of main feedwater event. The Cook standardized plant analysis risk (SPAR) model will be modified to account for these effects.

V. Calculation Method

The overall CDF change will be calculated as follows:

A. Modify Cook SPAR model by modifying fault trees or initiating event frequencies to include the impact of degraded conditions associated with issues.

B. Add event trees to the SPAR model to quantify initiators associated with Cook issues that are not already modeled (e.g., Medium LOCA, Large LOCA, HELB events).

C. Calculate CDF change associated with all issues using the modified SPAR models.

D. Separately model and quantify CDF change associated with issues for which the SPAR models are inappropriate such as issues associated with fire and seismic events.

E. Sum the CDF changes from (C), and (D) above.

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APPENDIX A

Grouping of Issues

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A.1: Grouping of Issues Affecting Core Damage Frequency

Table A-1 provides the results of grouping of issues affecting the core damage frequency. Each issue was examined to determine its potential impact on accident initiators or mitigating functions. Table A-1 uses a coding system to identify the accident sequences that are affected by a given issue. The codes are listed below. The method to interpret this table is illustrated using the following example. Issue #2, "The AFW suction strainers are not sized properly," may affect the reliability of the AFW system which may cause an increase in the CDF during the following sequence initiators: "x1", "H-2", "H-3", and "CCW." In another example, Issue #10, "Use of the design basis fouling factor as the acceptance criteria can cause ESW/CCW heat exchanger to exceed fouling limit," may increase the small LOCA initiating event frequency (due to reactor coolant pump seal failure), as well as affecting the reliability of several accident mitigating systems/capabilities (i.e., feed and bleed cooling; high, medium, and low head safety injection; long term heat removal). In addition to the issues that affect CDF, Table A-1 contains many issues that affect the ice condenser. These were included since water from ice is relied upon to ensure adequate inventory for sump recirculation.

List of Codes

- DC: The condition increases the likelihood of loss of vital DC power.
- I: The condition affects an Interfacing systems LOCA sequence or mitigating systems pertaining that initiator.
- CCW: The condition increases the loss of CCW frequency or mitigating systems pertaining that initiator.
- CNT: The condition increases the loss of control room ventilation frequency or mitigating systems pertaining that initiator.
- F: The dominant risk contribution will be from fire events.
- H-1: Applies to the special HELB initiator in the startup blowdown flash tank room affecting ESW supply to AFW system.
- H-2: Applies to the special HELB initiator in the common hall way that has 4" steam lines which supply the turbine driven AFW pumps and affects ESW supply to AFW.
- H-3: Applies to the special HELB initiator (a crack in the main steam line) that disables the CCW system in both units.
- LNP: The condition increases the loss of normal power frequency.
- S: The condition affects components that are relied upon to compensate for seismically fragile components in a nuclear plant (e.g: Offsite power, Instrument air lines)
- SFP: Applies to risk from spent fuel pool related issues only.
- SD: The condition increases the likelihood of a shutdown initiating event (i.e., Loss of RHR, loss of power) or mitigating systems pertaining those initiators.
- x1: Dominant CDF change contribution is associated with transients, small LOCAs, SGTR events, ATWS, or loss of offsite power events (excludes medium and large LOCA).
- x2: The condition increases the likelihood of a small LOCA.
- x3: Dominant CDF change contribution is associated with sequences requiring injection or recirculation from ECCS (LOCAs, feed and bleed sequences as well as SGTR sequences requiring injection.)
- x4: Dominant CDF change contribution is associated with sequences requiring sump recirculation (all LOCAs and feed and bleed sequences only.)
- x5: Dominant CDF change contribution is associated with the medium LOCA sequences.
- x6: Dominant CDF change contribution is associated with the sequences requiring feed and bleed (transients followed by loss of AFW).
- x7: This issue that affects a key support system may affect any initiator.
- x8: Dominant CDF change contribution is associated with the ATWS sequences.
- x9: Dominant CDF change contribution is associated with the loss of offsite power events.

Table A-1: Grouping of Issues that Affect Core Damage Frequency

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
1. HELB in the startup blowdown flash tank room could expose the motor control center to steam environment affecting AFW system. (Interim Cook 2 LER 316/98-007)	N				H-1 S							
2. The AFW suction strainers are not sized properly. (LER 315/98-046)	N				x1 H-2 H-3 CCW CNT							
3. Seismic event requires ESW supply to AFW when the suction strainers are undersized. (LER 315/98-046)	N				S							
4. During surveillance interval both component cooling water (CCW) system trains may be inoperable. (LER 315/98-041)	N	CCW SD					CCW	CCW	CCW	CCW	CCW	CCW
5. RWST level instrument uncertainty was not considered in the process used to select setpoint value listed in TS surveillance resulting in possibility of vortexing in RWST. (Design Inspection Report E1.1.1.2A(2))	Y										x4	
6. Restricted ice condenser flow passages. (Interim LER 315/98-004)	N										x4	
7. Piping code violation due to oversight in valve control requirement could lead to ISLOCA sequence via the CCW system. (LER 315/97-022)	N	I					I	I	I	I	I	I
8. Ice condenser weights do not comply with TS. (Interim LER 315/98-007)	N										x4	

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
9. Potential for over-pressurization of control air headers resulting in multiple equipment failures (LER 315/97-026). In LER 315/98-052, licensee reports that they are still analyzing the RHR heat exchanger outlet valves. Revised LER expected in June.	N									x3	x4	x1 SD
10. Use of the design basis fouling factor as the acceptance criteria can cause ESW/CCW heat exchanger to exceed fouling limit. (Design Inspection report E1.2.1.2H)	Y	x2					x1	x1	x1	x1	x1	x1 SD
11. CCW may not provide adequate cooling for SI, charging, RHR pump seals. (LER 315/97-012)	Y						x1	x1	x1	x1	x1	x1 SD
12. ESF actuation and start of EDG Unit 1 "CD" and Unit 2 "CD" due to faulted underground cable results in increased potential to cause a partial loss of offsite power. (LER 315/98-040)	N	LNP										
13. Offsite power breaker testing not performed in accordance with TS results in increased frequency of loss of offsite power. (LER 315/98-044)	N	LNP										
14. Use of reactor coolant pump seals as an alternate boron injection path potentially results in an unanalyzed condition and potential for seal damage. (LER 315/98-018)	N	x2		x8 S								
15. Operating both RHR trains while reactor coolant system is open to atmosphere could result in failure of both trains. (LER 315/97-016)	N	SD										

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
16. Potential single failure (loss of air) could result in failure of both ESF ventilation system trains. (LER 315/97-023)	N	SD					x3	x3	x3	x3	x4	SD
17. Single failure (single RHR train) could result in failure of all high and medium head injection during sump recirculation. (LER 315/97-021)	N										x4	
18. EOP procedure 01(02)-OHP 4023 ES 1.3 "Transfer to cold leg recirculation" was revised to raise the containment water level action setpoint. This revision was done without a proper 50.59 evaluation. (Design Inspection Report E1.5.2 A(1))	N										x4	
19. 12-OHP-4021.019.001 "Operation of the ESW system" was revised to reduce the maximum ESW operating temperature without a proper 50.59 evaluation. (Design Inspection Report E1.5.2 A(2))	Y	SD					x7	x7	x7	x7	x7	x7
20. Procedure 2-OHP-4021.016.003 "Operation of the CCW system during reactor startup and normal operation" was revised to delete a provision that allowed the licensee to operate CCW above the UFSAR maximum temperature without a proper 50.59 evaluation. (Design Inspection Report E1.5.2 A(3))	Y	SD					x7	x7	x7	x7	x7	x7
21. RHR pump miniflow line motor-operated valve potential failure due to cycling during a medium LOCA. (LER 315/98-031)	N									x5	x5	
22. HELB causes failure of AFW instruments. (LER 315/98-058)	N				H-2 S							

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
23. Impact of the CST floating bladder design on calculations. (AFW SSFI self assessment)	N				x1 H-2 H-3 CNT CCW							
24. CST floating bladder outer seal is deteriorating. (AFW SSFI self assessment)	N				x1 H-2 H-3 CNT CCW							
25. Lack of direct freeze protection for the CST. (AFW SSFI self assessment)	N				x1 H-2 H-3 CNT CCW							
26. Vortexing and air entrainment leading to the failure of RHR pumps when it takes suction from the containment (cont.) recirculating sump. (LER 315/97-011-entrance loss factor & LER 315/97-017-inactive cont. area trap water, cont. and cont. sump level instrument loop uncertainty)	N										x4	
27. Failure to maintain 1/4" particulate retention requirement can result in high pressure injection system failures leading to sump recirculation failure. (LER 315/97-018 & LER 315/98-012)	N										x4	

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
28. Material discovered in containment degrades recirculation capability by clogging up sump screens and creating NPSH problems during sump recirculation. (LER 315/97-024 & LER 315/98-017)	N										x4	
29. Control room emergency ventilation system capability to maintain control room temperature within TS limit is affected by high ESW temperatures. (LER 315/97-014)	N	CNT										
30. Adverse impact on plant cool down analysis (requirement to enter cold shutdown in 36 hours with only one train of CCW). (Design Inspection Report E1.2.1.2B)	Y	SD										
31. Containment peak pressure may be exceeded during a LOCA or MSLB due to high ESW temperature. (LER 315/97-010-02).	N										x4	
32. Spent fuel pool cooling operating outside design basis during full core offloading in 1996. (Design Inspection Report E1.2.1.2.C)	N	SFP										
33. Reactor coolant pump (RCP) thermal barrier is cooled by CCW at elevated temperature and the RCP seals do not get the flow specified in the UFSAR. (LER 315/97-01)	N	x2										
34. Potential for single failure (operator closing suction from the RWST prematurely or hot short) to isolate ECCS suction paths. (LER 315/98-038)	N										x4 F	
35. Degraded seismic ruggedness of master relay covers. (LER 315/98-002)	N		S	S	S	S	S	S	S	S		

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
36. Apparent failure to consider vortexing in the RWST due to not being able to complete transition before RWST level goes too low. (Cumulative impact of instrument uncertainty, drip catch, velocity correction factor) (Design Inspection report E1.1.1.2A).	N										x4	
37. Equipment (steam generator level transmitters and RVLIS) in containment rendered inoperable due to faulted flood-up tubes. (Cook 1 LER 315/ 97-006)	N				x1	x1						
38. A wrong indicator (the heat exchanger outlet temperature) used to trend the performance of the EDG heat exchanger. (Design Inspection report E1.2.1.2H)	N		x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT	x9 S SD CNT
39. UFSAR/TS Inconsistencies with RWST Volume may result in inadequate water in RWST. (Design Inspection Report E1.4.2B)	Y									x3	x4	
40. UFSAR states that the NPSH required for RHR at maximum flow rate is.11 ft. (Design Inspection report E1.4.2.C(3))	Y									x3	x4	
41. Improper splice configuration for pressurizer power-operated relief valve (PORV) limit switches. (LER 315/98-013)	N						x6 x8 H-1 H-2					
42. Appendix R Borated water requirement not met. (Design Inspection report E1.3.2.2A).	N						F	F	F	F	F	

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Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
43. Inconsistencies with ECCS level instrumentation and AOTs can lead to excessive outage times for the level transmitters. (Design Inspection Report E1.4.2D)	N										x4	
44. Two pressurizer safety valves fail to lift within setpoint tolerance. (Cook 2 LER 316/98-03).	N						x6 S x8 H-1 H-2					
45. Pressurizer power-operated relief valve (PORV) inoperability due to inoperability of the backup emergency air supply system. (Cook 2 LER 316/98-002)	N						x6 S x8 H-1 H-2					
46. CVCS cross-tie flow indicator not calibrated to meet TS. (LER 315/98-036)	Y								x1 F		x4 F	
47 Cable train separation issue. (Retracted LER 315/98-023)	N		F	F	F	F	F	F	F	F	F	F
48. RHR autoclosure interlock (ACI) defeated in Modes 4 and 5. (LER 315/97-019)	N	SD										
49. Westinghouse integral fuel burnable absorber fuel rods. (LER 315/97-027-01)	Y											
50. Oil drip pans not installed on reactor coolant pump motors results in Appendix R non-compliance. (LER 315/98-021)	N	F										
51. Appendix R, combustible material within 20 foot separation in auxiliary building. (LER 315/97-028)	N	F										

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
52. Ice condenser bypass potentially exceeded design basis limit. (Cook 2 LER 316/98-004).	Y										x4	
53. Potential for HELB to degrade CCW system. A postulated crack in a Unit 2 main steam line may degrade the ability of CCW pumps of both units to perform their function. (Cook 2 Interim LER 316/98-005)	N						H-3	H-3	H-3	H-3	H-3	H-3
54. Equipment in containment rendered inoperable due to faulted flood-up tubes (Cook 2 LER 316/97-006)	N				x1	x1						
55. Inadequate justification to demonstrate operability of the Unit 2 250V dc "CD" battery train. (Design Inspection Report E1.3.1.2)	Y	DC		x7	x7	x7	x7	x7	x7	x7	x7	x7
56. Dual CCW/ESW train outage during Unit 2 refueling inconsistent with design basis. (Design Inspection Report E1.2.1.2D)	N	S.P.										
57. O2-OHP 4021.082.003 Rev 3 "Feeding 600V buses through Bus Tie breakers," was not appropriate since under some circumstances it allowed placing excessive load on the emergency diesel generators. (Inspection report # 97-018)	N	SD										
58. O2-OHP 4021.082.013 Rev 2" Isolating, Transferring and Restoring a 250VDC Load" was not appropriate since under some circumstances battery cross ties could be overloaded. (Inspection report # 97-018)	N	SD										

Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
59. The 2AB D/G experienced a number of electrical and mechanical failures since May 1997. (Inspection report # 97-018)	N		x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD
60. The licensee physically and electronically blocked three control room annunciators without performing a safety evaluation. (Inspection report # 97-024)	N										x4	
61. The licensee did not have a procedure for manually back washing the ESW pump discharge strainers, a support system needed for the ESW system operability. (Inspection report # 97-024)	N						x7	x7	x7	x7	x7	x7
62. Potential for CCF of EDGs due to improper bolting in the exhaust manifold. (Inspection report # 98-008).	N		x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD	x9 S CNT SD
63. Failure of the turbine-driven AFW pump manual loader and single failure in motor-driven AFW train can put AFW outside of design basis. (LER 315/98-052)	N				x1							
64. Public address equipment inside the Unit 1 and Unit 2 ice condensers was not installed to withstand a design basis accident. (LER 315/98-050).	N										x4	
65. Defective and missing welds in ice condenser baskets. (LER 315/98-032)	N										x4	
66. Ice condenser lower inlet door shock absorber equipment found damaged due to poor work practices. (LER 315/98-035)	N										x4	

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Issue (see last page for list of acronyms)	Screen Out?	Initiating Event Frequency	Reactivity control		Decay heat removal			Inventory control			Long term heat removal	
			RPS	EB	AFW	MFW	F&B	SI	CHG	RHR	Sump Recirc	RHR
67. Ice condenser bypass leakage exceeds design basis limit. (LER 315/98-037)	N										x4	
68. Screws missing from ice condenser ice basket coupling rings. (LER 315/98-005)	N										x4	
69. Procedure allows up to 60 ice baskets to be unpinned. (Interim LER 315/98-006)	N										x4	
70. Damaged ice baskets cannot withstand operating basis earthquake and dead weight loadings. (LER 315/98-008)	N										x4	
71. Missing, damaged, or improperly installed shims, washers, bushings, and bolts could have created a potential for some of the intermediate deck doors to become misaligned. (LER 315/98-010)	N										x4	
72. Ice weight requirements potentially not met due to non-conservative assumption in software program. (LER 315/98-015)	N										x4	
73. Debris recovered from ice condenser. (LER 315/98-017)	N										x4	
74. Allegations concerning accuracy of 74 ice basket weights. (LER 315/98-024)	N										x4	
75. TS surveillance requirement not met while weighing ice baskets. (LER 315/98-026)	N										x4	

Acronyms

AFW	auxiliary feedwater system
CCW	component cooling water system
CHG	charging (high head safety injection system)
CNT	containment (primary)
CST	condensate storage tank
CVCS	chemical and volume control system
EB	emergency boration capability
ECCS	emergency core cooling system
EDG	emergency diesel generator
EOP	emergency operating procedure
ESF	engineered safety features
ESW	emergency service water system
F&B	feed and bleed capability
HELB	high energy line break
ISLOCA	interfacing system
LER	licensee event report
LHI	low head safety injectior system
LOCA	loss-of-coolant accident
LNP	loss of normal (offsite) power
MFW	main feedwater system
MSLB	main steam line break
NPSH	net positive suction head
RHR	residual heat removal system (decay heat removal)
RPS	reactor protection system
RWST	refueling water storage tank
SFP	spent fuel pool
SI	safety injection system (medium head)
SSFI	safety system functional inspection
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report

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A.2 Listing of the CDF Analyses

Information in the previous table (Table A-1) is used to generate the list of analyses that need to be performed to assess the overall risk. This table shows each initiator and the issues that affect sequences delineated from that initiator. Issues that affect a given initiating event are separated into three specific classes. The issues in Column 2 of Table A-2 have not been examined to date. After they are examined, they will be either screened out or included in the integrated risk analysis. The issues in Column 3 of Table A-2 have been examined. The probabilities or frequencies associated these issues have been calculated. These issues, even though each on its own was found to be non-risk significant (less than 1×10^{-6} change in CDF), could not be screened out due to their potential to create synergistic effects with other issues under consideration. Column 4 of Table A-2 contains issues that were screened out since their CDF impact was negligible (less than 1×10^{-9}/year change in CDF) and they are not capable of creating synergistic effects.

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Table A-2
Listing of the Cook Issues to be Analyzed

INITIATOR (Analysis)	All Issues affecting accident sequences associated with the initiator		
INITIATOR	Issues remaining to be analyzed.	Issues investigated and included in integrated analysis[2]	Issues screened out[1]
1. Transients (excludes LOCAs and LOSPs and included loss of power conversion system)	#9, #23, #24, #25, #26, #27, #28, #34, #36, #41, #44, #63, #60, #61, #64-#75,	#2, #6, #8, #16, #17, #18, #31, #37, #43, #45, #54	#5, #10, #11, #19, #20, #39, #40, #46, #52, #55
2. Small LOCA (includes seal LOCA, stuck open PORV, and stuck open SRV)	#9, #23, #24, #25, #26, #27, #28, #33, #34, #36, #60, #61, #63, #64-#75	#2, #6, #8, #14, #16, #17, #18, #31, #37, #43, #54	#5, #10, #11, #19, #20, #39, #40, #46, #52, #55
3. Medium LOCA	#9, #21, #26, #27, #28, #34, #36, #60, #61, #64-#75	#6, #8, #16, #17, #18, #31, #43	#5, #19, #20, #39, #40, #46, #52, #55
4. Large LOCA	#9, #26, #27, #28, #34, #36, #60, #61, #64-#75	#6, #8, #16, #17, #18, #31, #43	#5, #19, #20, #39, #40, #46, #52, #55
5. Loss of offsite power	#9, #23, #24, #25, #26, #27, #28, #34, #36, #38, #41, #44, #63, #59, #60, #61, #62, #64-#75	#2, #6, #8, #12, #13, #16, #17, #18, #31, #37, #43, #45, #54	#5, #10, #11, #19, #20, #39, #40, #46, #52, #55
6. Steam generator tube rupture	#9, #23, #24, #25, #26, #27, #28, #63, #34, #36, #41, #44, #60, #64-#75	#2, #6, #8, #16, #17, #18, #31, #37, #43, #45, #54	#5, #10, #11, #39, #40, #46, #52
7. ATWS	#9, #23, #24, #25, #41, #44, #63	#2, #14, #37, #45, #54	#10, #11, #46

8. Fire	#34, #42, #47, #50, #51, #61	None	#19, #20, #46, #55
9. Seismic	#3, #35, #38, #44, #59, #61, #62	#1, #14, #22, #45	#19, #20, #55
10. Shutdown	#9, #15, #38, #48, #57, #58, #59, #61, #62	#4, #16	#10, #11, #19, #20, #30, #55
11. Spent fuel pool	#32, #56, #61	none	#19, #20, #55
12. Loss of control room ventilation	#23, #24, #25, #38, #59, #61, #62	#2, #29	#19, #20, #55
13. Loss of CCW	#23, #24, #25, #61	#2, #4	#19, #20, #55
14. Loss of DC	none	none	#55
15. ISLOCA	none	#7	none
16. H-1. (HELB in startup blowdown flash tank room)	#41 #44, #61	#1	#19, #20, #55
17. H-2. (HELB in common hall way that has 4" steam supply to TDAFW)	#23, #24, #25, #41, #44, #61	#2, #22, #37, #45	#19, #20, #55
18. H-3. (HELB in room that can disable CCW of both units)	#23, #24, #25, #53, #61	#2	#19, #20, #55

1. Analyses to date have shown that these issues can be screened out. Appendix C to this attachment contains the basis for screening out these issues.

2. On their own, these issues were determined to be non-risk significant. However, due to synergistic effects, these will be included in integrated analysis. Appendix D to this attachment contains the analyses of these issues.

A.3 Listing of Containment Issues

Table A-3 lists how issues that affect containment performance are grouped by containment failure modes.

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Table A-3: Grouping of Issues that Affect Containment Failure Modes

Issue No and title	Screened out ?	Early-CHR	Late-CHR	Bypass	Hydrogen Ignition	Gross rupture
6. Restricted ice condenser flow passages (LER 315/98-004)	N	x				
8. Ice condenser weights do not comply with Tech Specs (LER 315/98-007).	N	x				
31. Containment peak pressure may be exceeded during a LBLOCA due to high ESW temperature (LER 315/97-010-02).	N		x			
37. Equipment in containment rendered inoperable due to faulted flood-up tubes - hydrogen skimmer ventilation fan and recombiner (Cook 1 LER 315/97-006).	N				x	
52. Ice Condenser bypass potentially exceeded design basis limit (Cook 2 LER 316/98-004).	Y	x				
54. Equipment in containment rendered inoperable due to faulted flood-up tubes-one of two hydrogen skimmer fans (Cook 2 LER 316/97-006).	N				x	
64. Public address equipment inside the Unit 1 and Unit 2 ice condensers was not installed to withstand a design basis accident (LER 315/98-050).	N	x				
65. Defective and missing welds in ice condenser baskets (LER 315/98-032).	N	x				
66. Ice condenser lower inlet door shock absorber equipment found damaged due to poor work practice (LER 315/98-035).	N	x				

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Issue	Screened out ?	Early-CHR	Late-CHR	Bypass	Hydrogen Ignition	Gross rupture
67. Ice condenser bypass leakage exceeds design basis limit (LER 315/98-037).	N	x				
68. Screws missing from ice condenser ice basket coupling rings (LER 315/98-005).	N	x				
69. Procedure allows up to 60 ice baskets to be unpinned (LER 315/98-006).	N	x				
70. Damaged ice baskets cannot withstand operating basis earthquake and dead weight loadings (LER 315/98-008).	N	x				
71. Missing, damaged, or improperly installed shims, washers, bushings, and bolts could have created a potential for some of the intermediate deck doors to become misaligned (LER 315/98-010).	N	x				
72. Ice weight requirements potentially not met due to non-conservative assumption in software program (LER 315/98-015).	N	x				
73. Debris recovered from ice condenser (LER 315/98-017).	N	x				
74. Allegation concerning accuracy of ice basket weights (LER 315/98-024).	N	x				
75. TS surveillance requirement not met while weighing ice baskets (LER 315/98-026).	N	x				
76. Debris of unknown origin found in west containment spray header (LER 315/98-027).	N		x			

Issue	Screened out ?	Early-CHR	Late-CHR	Bypass	Hydrogen Ignition	Gross rupture
77. Flow rates to CST headers are potentially lower than design basis values (LER 315/98-034).	N		x			
78. Incorrect installation of CTS header heat exchanger (LER 315/98-030). - Retracted LER since functionality unaffected.	Y		x			
79. Containment air locks testing not performed in accordance with TS (LER 315/98-043).	N			x		
80. Low air flow conditions in at least one localized portion of the containment. (LER 315/98-001).	N				x	
81. Pitting resulted in thickness of the containment structure liner to be less than 0.250 inches (LER 315/98-011).	N					x
82. Missed surveillance of hydrogen recombiner (LER 315/98-009).	N				x	
83. TS surveillance requirement on hydrogen recombiner not met (LER 315/98-019).	N				x	
84. Hydrogen recombiner watt meter circuit TS surveillance requirement not met (LER 315/98-033).	N				x	

CHR = Containment heat removal

APPENDIX B

Completed Analyses With No Synergistic Effects

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7.0 LER No. 315/97-022

Event Description: Failure to comply with USAS B31.1 power piping code could result in ISLOCA

Date of Event: September 1997

Plant: D.C. Cook, Unit 1

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7.1 Summary of Issue

LER 315/97-022 reported that the normally open stop valves (CCW-166, 385, 214, 220) between the reactor coolant pump (RCP) seal heat exchangers and their relief valve located in the component cooling water (CCW) surge tank are administratively uncontrolled. Figure 1 shows the CCW stop valves CCW-166, CCW-385, CCW-214, and CCW-220 with respect to the CCW surge tank and the RCP seal heat exchanger. This is an apparent piping standard B31.1 and ASME VIII code non-compliance. Since these valves are not administratively controlled, it has been postulated that they may be inadvertently be left in a closed position. The change in the frequency of the Interfacing Systems LOCA (ISLOCA) event associated with this condition is less than 1 x 10^{-6}/year making the issue non-risk significant.

7.2 Modeling and Affected Sequences

If a RCP seal heat exchanger (HEX) ruptures while (a) CCW-385 is in the closed position, or (b) CCW-166 is in the closed position, or (c) both CCW-214 & 220 are in the closed positions, then the CCW (whose design pressure is 150 psig) will be overpressurized since the relief valve sized to mitigate RCP thermal barrier rupture located in the surge tank is isolated from the ruptured RCP seal heat exchanger. Check valves isolate the path from the ruptured thermal barrier to the CCW surge tank relief valves via the CCW pump trains. Overpressurizing the CCW system can lead to an ISLOCA event and loss of CCW.

Mitigation of an ISLOCA requires injection from a high pressure or a low pressure pump depending upon the reactor coolant system (RCS) pressure. However, the lube oil for all high pressure injection pumps are cooled by CCW. Since that system is affected, lube oil cooling to the high pressure injection pumps will be unavailable. Seal cooling of the RHR pumps provided by CCW will also be lost. As a result, low pressure injection from the RHR pumps is also unavailable.

In consideration of the above, the three sequences of interest are as follows:

<u>Sequence(1)</u>:

- RCP seal heat exchanger rupture;

- Having CCW-385 left in a closed position during the rupture leading to an ISLOCA; and
- Failure to inject using high pressure or low pressure injection pumps.

Sequence (2):

- RCP seal heat exchanger rupture;
- Having CCW-166 left in a closed position during the rupture leading to an ISLOCA; and
- Failure to inject using high pressure or low pressure injection pumps.

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Sequence (3):

- RCP seal heat exchanger rupture;
- Having both CCW-214 & 220 left in a closed position during rupture leading to an ISLOCA;
- Failure to inject using high pressure or low pressure injection pumps.

7.3 Frequencies, Probabilities, and Assumptions

RCP seal heat exchanger rupture
The Cook plant is equipped with four RCPs. Ref.1 reports that the frequency of rupture of a RCP seal as 1.9E-03/yr/pump. Using this value for the Cook plant, the frequency of a RCP seal HEX rupture is 7.6×10^{-3}/yr (=$4 \times 1.9 \times 10^{-3}$).

Probability of having the valves in a closed position
The probability that the valves are left in a closed condition can be calculated by taking the ratio between the total time the valves have been in a closed condition to the total time that the plant operated at power. Cook Unit 1 commercial operation began in August of 1975. It was shut down in September of 1997. Therefore, it has operated approximately 22 years since it began commercial operation. The criticality factor for Cook Unit 1 is 0.79 (Ref. 2). The total duration of critical operation of Cook 1 is estimated to be 209 months (=22 x 12 x 0.79).

The total time that the valves were left in a closed position is calculated by taking the product of the probability of leaving the valves closed and the average time the valves would stay closed if they were left closed. The valves CCW-166, 385, 214, and 220 are not closed routinely during plant operation. As figure 1 shows, closure of CCW-166 or 385 will isolate CCW flow to the RCP seals. Closure of both CCW-214 and 220 will isolate the CCW surge tank from the CCW system. Therefore, it is assumed that only an infrequent need to perform a corrective maintenance activity during a mid-cycle equipment

failure will force closure of one or more of these valves, and the plant will be shut down to perform that corrective maintenance. After the mid-cycle outage, if power operation resumes with the valves in a closed position, it is assumed that it will be discovered during the subsequent refueling outage. Therefore, the product of the following will provide the duration for which the plant operated with the valves left closed:

- Number of times the operators placed CCW-166 or 385 or both 214 & 220 in a closed position since the start of the commercial operation
- Probability that the operators fail to restore CCW-166 or 385 or 214 & 220 at the completion of maintenance
- Probability that the operators fail to recognize wrong valve positions from alarms or other indication at power
- Average time spent with valves in a closed position, if power operation started with the valves in a closed position

<u>Number of times the operators closed CCW-166 or 385 or both 214 and 220 in a closed position</u>
The number of times the operators closed CCW-166 or 385 is unknown. The symbol 'n' will be used to represent this unknown. Concurrent closure of valves CCW-214 & 220 will isolate the surge tank from CCW and, based on discussions with the licensee, the plant has never entered this configuration. For this analysis, number of times both CCW-214 & 220 were closed during plant life is assumed to be 1.

<u>Operators fail to restore CCW-166 or 385 or 214 and 220 at the completion of maintenance</u>
Based on table 3.3.2 of the Cook IPE (Ref. 3), probability of failure to restore a stop valve after maintenance activity is estimated to be 6.1×10^{-4}. This failure probability is consistent with the values provided in section 14 and 16 of Swain and Guttman (Ref. 4). Therefore, in the analysis, the probability of failure to restore either CCW-166 or 385 is assumed to be 6.1×10^{-4}.

For the case where both CCW-214 and CCW-220 were closed and need to be restored, the failure to restore the first valve uses a probability of 6.1×10^{-4}. The probability for failing to restore the second valve is greater than 6.1×10^{-4} due to potential common cause effects. Since this probability is unknown, the symbol 'P1' will be used to represent that probability.

<u>Operators fail to recognize wrong valve positions from alarms or other indication</u>
Both CCW-166 and CCW-385 are located on the return path from the miscellaneous CCW header. If CCW-385 is closed, it isolates all CCW flow to containment (includes RCP seal thermal barrier, excess letdown heat exchanger CCW flow). This results in several alarms on annunciator panel 207 in the control room. Identical alarms will appear for CCW-166 as well. Swain and Guttmann (Ref. 4) recommends a probability of failure of 1×10^{-4} for failing to recognize a single alarm and recommends increasing this value by a factor of 10 for transient situations with high stress levels. Even though multiple alarms will result if the plant was at power up while CCW-166 and CCW-385 are closed, the probability of failure is conservatively assumed to be 1×10^{-3}.

Based on discussions with the licensee, if both CCW-214 and CCW-220 valves were closed simultaneously, the CCW system isolates from the surge tank. As a result, minor temperature fluctuations in the system would cause abnormal pressure fluctuations. This abnormal performance is expected to be apparent to the control room operators monitoring CCW system performance. Since the specific set of annuciators that will warn the operators of the undesirable valve configuration are unknown, the probability of failure to recognize this condition could not be estimated. This unknown probability will be represented by symbol 'P2' in the analysis.

Average time spent with the valves in a closed position

The valves CCW-166, 385, 214, and 220 are not closed during routine plant operation at power. It is assumed that they will be closed to accommodate an unanticipated corrective maintenance activity attributed to random equipment failure. The random equipment failure, and therefore the mid-cycle outage, can occur at any point in the 18 month cycle. It is assumed that after the mid-cycle outage, if power operation resumes the valves in a closed position, that condition will be discovered during the subsequent refueling outage. Therefore, the fault duration (duration in which the plant operates with the valves closed) may be as short as zero days or as long as 18 months. Therefore, the average fault duration is assumed to be 9 months (½ of the operating cycle).

Probability of having the valves in a closed position

Based on the information provided above the probability of leaving CCW-166 (or 385) in a closed position can be calculated using the following expression:

$$\frac{n(6.1 \times 10^{-4})(1 \times 10^{-3})(9) \text{ months}}{209 \text{ months}} = 2.6 \times 10^{-8} \times n$$

The probability of leaving both CCW-214 and 220 in a closed position can be calculated using the following expression:

$$\frac{(1)(6.1 \times 10^{-4}) \times P1 \times P2 \times (9) \text{ months}}{209 \text{ months}} = 2.6 \times 10^{-5} \times P1 \times P2$$

Probability of failing injection from High Pressure and Low Pressure Injection pumps

Mitigation of the ISLOCA requires injection from a high pressure or a low pressure pump depending upon the RCS pressure. However, the lube oil for all high pressure injection pumps are cooled by CCW. Since that system is affected, lube oil cooling to the high pressure injection pumps will be unavailable. Seal cooling of the RHR pumps provided by CCW will also be lost. As a result, low pressure injection from the RHR pumps is also unavailable. Therefore, this probability is assumed to be 1.0.

7.4 Core Damage Frequency Calculation or the Bounding Calculation

Sequence (1):

(7.6×10^{-3} ruptures/year)(prob valve CCW-385 left closed: $2.6 \times 10^{-8} \times n$)(prob injection fail: 1)

$$= (2 \times 10^{-10} \times n)/\text{year}$$

The value of 'n' must be greater than 500 for the sequence frequency to exceed 1×10^{-6}/year, and this is impossible since corrective maintenance requiring closure of CCW-385 is an infrequent activity. Therefore, frequency of this sequence is less than 1×10^{-6}/year.

Sequence (2):

Frequency of sequence (2) is identical to frequency of sequence (1).

Sequence (3):
(7.6×10^{-3} ruptures/year)(prob valve CCW-214 & 220 left closed: $2.6 \times 10^{-5} \times P1 \times P2$)(prob injection fail: 1)

$$= (2 \times 10^{-7} \times P1 \times P2)/\text{year}$$

Since P1 and P2 are less than 1.0, frequency of sequence (c) will be less than 1×10^{-6}/year.

7.5 References

1. LER 315/97-022, Rev. 1, "Failure to Comply with USAS B31.1 Power Piping Code Due to Oversight in Valve Control Requirements Results in Condition that Could Have Prevented Fulfillment of a Safety Function of a System," October 31, 1997.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 - 1995*, NUREG/CR-5750, December 1998.

3. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

4. A.D. Swain, and H.E. Guttman, *Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications*, NUREG - 1278, August 1983.

FIGURE: 1

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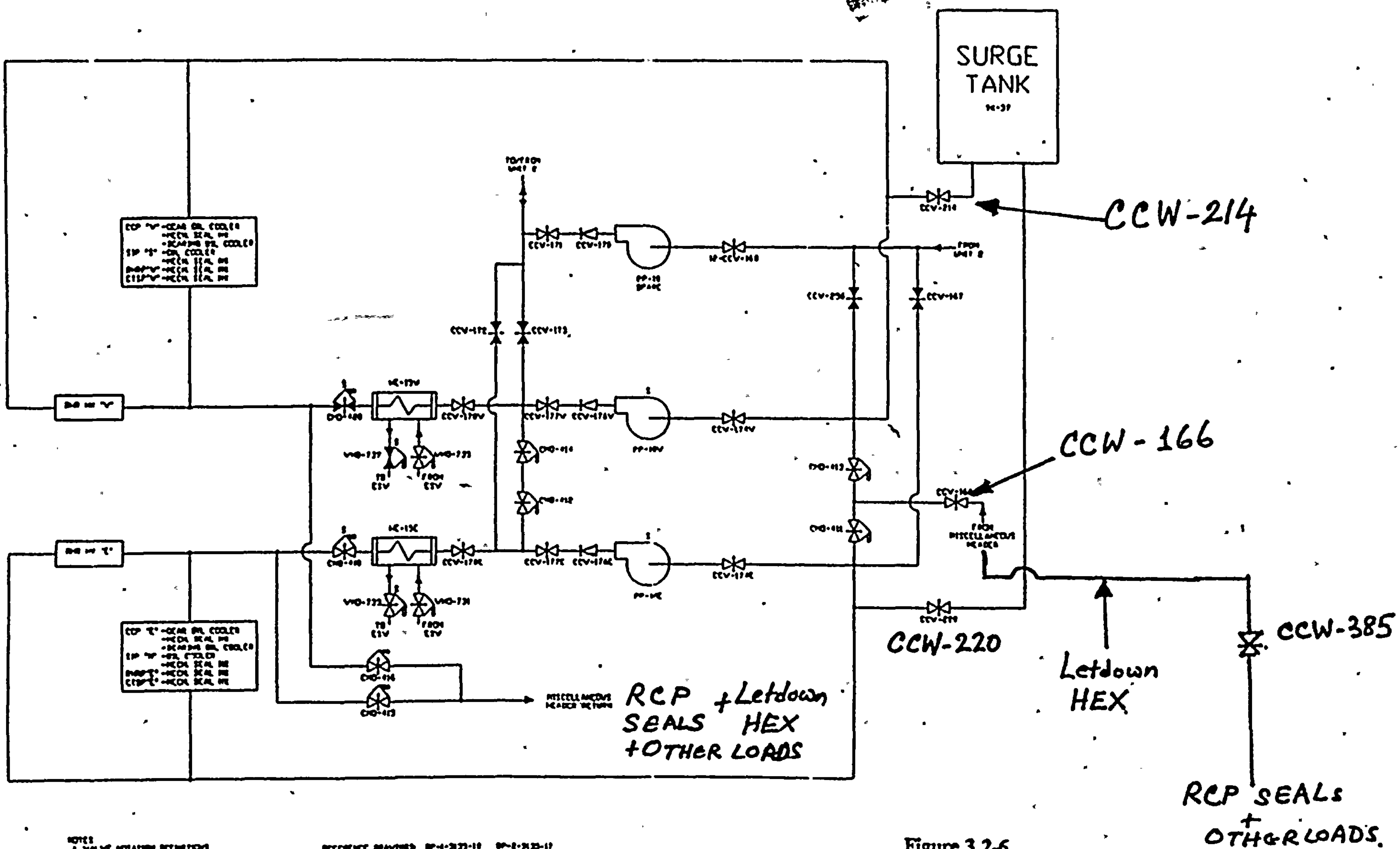

Figure 3.2-6
Component Cooling Water System Simplified Flow Diagram

APPENDIX C

ANALYSES OF ISSUES SCREENED OUT FROM INTEGRATED ASSESSMENT

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5.0 NRC Inspection Report No. 315, 316/97-201, Finding E1.1.1.2A(2)

Event Description: Apparent Failure to Account for Instrument Loop Uncertainty in the Technical Specification RWST Volume Surveillance Requirement

Date of Event: November 1997

Plant: D. C. Cook, Units 1and 2

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5.1 Summary of Issue

The issue deals with the fact that the licensee had not accounted for the refueling water storage tank (RWST) level instrument loop uncertainty when calculating the set point listed in the technical specification related surveillance procedure 01(02)-OHP 4030.STP.030, "Daily and Shift Surveillance Checks" (Ref. 1). The licensee had calculated the RWST level instrumentation uncertainty as +3.07%, -3.75% of span. Therefore, when the level indication is 89%, the actual level can be 85.25% (=89% - 3.75%). The 85.25% level relates to 349,000 gallons of water. This is 1000 gallons less than the 350,000 gallons required by the technical specifications.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

5.2 Modeling and Affected Sequences

The RWST supplies water for injection to the reactor during a LOCA of any size. In addition, the RWST water is used for feed and bleed cooling if main feed water and auxiliary feed water are unavailable to perform decay heat removal. Therefore, a reduction in the RWST inventory has the potential to affect accident sequences associated with LOCAs of any size or feed and bleed cooling.

After the RWST level reaches its low level set point (32% of the RWST level), the operators start changing the system alignments to take suction from the containment recirculation sump rather than the RWST. A 1000 gallon reduction in RWST inventory reduces the time available to establish sump recirculation. If the recirculation function is not fully established in a timely manner, the pumps may continue to take suction from the RWST while its level is low. This results in vortexing in RWST and pump failures. Therefore, the sequences of interest are:

<u>Sequence 1- Large LOCA</u>:

- Large LOCA; and

- Sump recirculation fails due to vortexing in RWST as a result of RHR pump cavitation.

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Sequence 2- Medium LOCA:

- Medium LOCA; and
- Sump recirculation fails due to vortexing in RWST as a result of high pressure injection pump cavitation.

Sequence 3 - Small LOCA or feed and bleed cooling situation:

- Small LOCA or feed and bleed cooling situation; and
- Sump recirculation fails due to vortexing in RWST as a result of high pressure injection pump cavitation.

5.3 Frequencies, Probabilities, and Assumptions

Sequence 1- Large LOCA:

- Large LOCA .

  Based on NUREG/CR-5750 (Ref. 2), the frequency of a large LOCA is 5 x 10^{-6}/year.

- Sump recirculation fails due to vortexing in RWST as a result of RHR pump cavitation .

  During a large LOCA, the total RHR and containment spray flow rate is approximately 15,600 gpm. At this flow rate, a reduction in 1000 gallons causes a reduction in flow time of 4 seconds. Based on the D.C. Cook UFSAR (Ref. 3) for a large break LOCA more than 10 minutes are available to establish recirculation. A 4 second reduction from a 10 minute time frame does not change the probability of failure to establish sump recirculation before vortexing occurs.

Sequence 2- Medium LOCA:

- Medium LOCA.

  Based on NUREG/CR-5750 (Ref. 2), the frequency of a large LOCA is 4 x 10^{-5}/year.

- Sump recirculation fails due to vortexing in RWST as a result of high pressure injection pump cavitation.

Based on the D. C. Cook Individual Plant Examination (IPE), Revision 1 (Ref. 4), for a small or a medium LOCA, the operator has 17 minutes to complete the switch over to sump recirculation after receiving the RWST low level signal to initiate switch over at 32% RWST tank level. That is, approximately 112,000 gallons (32% of 350,000) are injected over 17 minutes by the containment spray and the injection pumps. This equates to approximately 6000 gpm of flow from injection and containment spray. At this injection rate, a reduction of 1000 gallons in the RWST inventory reduces the time available to complete injection by approximately 10 seconds. A 10 second reduction from a 17 minute time frame does not change the probability of failure to establish sump recirculation before vortexing occurs.

Sequence 3 - Small LOCA or feed and bleed situation:

- Small LOCA or feed and bleed situation.

  Based on different contributors to small LOCA (pipe breaks, stuck open PORVs, RCP seal failures, and stuck open SRVs, using the frequencies provided in NUREG/CR-5750 (Ref. 2), the small LOCA frequency is approximated at 9×10^{-3}/year. Arriving at a feed and bleed situation requires failure of main feedwater and auxiliary feedwater following an accident. Therefore, when the frequency of the feed and bleed situation is added, the total frequency stays at 9×10^{-3}/year.

- Sump recirculation fails due to vortexing in RWST as a result of high pressure injection pump cavitation .

  Based on the D. C. Cook IPE Revision 1 (Ref. 4), for a small or a medium LOCA the operator has 17 minutes to complete the switch over to sump recirculation after receiving the RWST low level signal to initiate switch over at 32% RWST tank level. That is, approximately 112,000 gallons (32% of 350,000) are injected over 17 minutes by the injection and the containment spray pumps. This equates to approximately 6000 gpm of flow from injection and containment spray. At this injection rate, a reduction of 1000 gallons in the RWST inventory reduces the time available to complete injection by approximately 10 seconds. A 10 second reduction from a 17 minute time frame does not change the probability of failure to establish sump recirculation. For very small LOCAs where the containment sprays do not actuate, the RWST inventory depletes at a much slower rate. If the injection flow rate is 1000 gpm, the 1000 gallons of inventory reduction equates to approximately 1 minute of reduction in time available to establish sump recirculation. However, at this reduced flow, it will take approximately 100 minutes to deplete the 32% of the RWST inventory of 112,000 gallons. Again, a reduction of 1 minute from an available time of approximately 100 minutes, will not change the probability of failure to establish recirculation before vortexing occurs.

5.4 Core Damage Frequency Calculation or the Bounding Calculation

The probability of sump recirculation function does not change due to the reduction of 1000 gallons of RWST inventory. Therefore, the change in CDF is zero.

5.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201) November 26, 1998 and LER 316/97-022, Rev. 1, December 7, 1998.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Commercial Nuclear Power Plants 1987-1995*, NUREG/CR-5750, December 1998.

3 Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

4. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

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10.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.2.1.2.H(a)

Event Description: The Fouling Factor for the ESW/CCW Heat Exchangers May Exceed the Design Value over the Operating Cycle

Date of Event: August 1997

Plant: D. C. Cook, Units 1 and 2

DRAFT

10.1 Summary of Issue

The NRC staff conducted a design and performance review of the CCW/ESW heat exchangers at D. C. Cook, Unit 1 and 2 (Cook 1 and 2) from August 4 through September 11, 1997 (Ref. 1). This review was performed based on the preliminary team findings associated with the elevated lake temperatures. Its purpose was to determine the adequacy of the testing performed by the licensee and the associated acceptance criteria contained in the licensee's program guidance for complying with Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

The inspection team found that the licensee's maximum fouling acceptance criterion for the CCW/ESW heat exchangers was 0.00169 or less. This value is the maximum allowable fouling acceptable for the CCW/ESW heat exchanger in order to remove the design heat load. As specified in the licensee's GL 89-13 program guidance, the plant may operate at the maximum permitted fouling rate for the duration of an operating cycle. The team expressed concern that this approach could be non-conservative because there would be no margin to accommodate additional fouling, should fouling occur over the operating cycle. Since this maximum allowable fouling factor had been used in the licensee's accident and cooldown analyses, the licensee could potentially operate the plant with an actual fouling factor that exceeds the one used in the accident and cooldown analyses. The team also found that the licensee did not include instrument uncertainties in the test acceptance criteria, which could add an additional non-conservatism to the calculated fouling factor.

The design basis fouling factor for the ESW/CCW was used as the acceptance criterion. Therefore, during a test, if the fouling factor was near its maximum acceptable value, over the operating cycle the fouling factor might exceed the design value. The instrument uncertainties were overlooked in calculating the test acceptance criterion.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

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10.2 Modeling and Affected Sequences

The results of a review of operating experience at Cook do not support the increase in the probability of failure of the ESW/CCW heat exchangers due to excessive fouling that is implied by this finding, for the following reasons:

- The update of the AEOD service water study (Ref. 2) indicated that there were no reported ESW failures or degradations at Cook 1 and 2 due to problems with fouling during the period 1986-1995, nor were there any reported instances where ESW failures caused problems in a system served by ESW. There were only 3 ESW-related LERs submitted by the two Cook units during this period - two of them (9/88 and 6/90) reported design problems, and one (12/94) reported a problem involving a fire barrier.
- A search of the SCSS database (Ref. 3) for the period 1990-1998 yielded no LERs reporting problems with the ESW/CCW heat exchangers.
- A search of NPRDS (Ref. 4) for failure records regarding the essential service water system and the component cooling water system at the Cook plant for the period 1985-1995 yielded no reported ESW/CCW heat exchanger failures involving fouling. The one reported failure (1991) involving the ESW/CCW heat exchanger consisted of a problem with internal leakage which had no effect on system availability.
- From a discussion with the Cook licensee, it was learned that the results of the most recent physical inspection of the condition of the ESW/CCW heat exchangers gave no indication that the actual fouling factor had approached the maximum fouling factor acceptance criterion for the heat exchangers.

Therefore, no core damage sequences increased in frequency as a result of this condition.

10.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increased in frequency, frequencies and probabilities were not calculated.

10.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences increased in frequency as a result of this condition. Therefore, the change in core damage frequency was determined to be zero.

10.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. "Operating Experience Feedback from Service Water System Failures and Degradations (1986-1995), "AEOD/S98-01, Mohammed Shuaibi and James R. Houghton, Office for Analysis and Evaluation of Operational Data," U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, February 1998.

3. "Sequence Coding and Search System for Licensee Event Reports: User's Guide", NUREG/CR-3905, Nuclear Operations Analysis Center, Oak Ridge National Laboratory, Oak Ridge, Tennessee 37831, August 1984.

4. Nuclear Plant Reliability Data System, Institute of Nuclear Power Operations, Atlanta, Georgia.

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11.0 LER No. 315/97-012

Event Description: Operation of safety injection, centrifugal charging and residual heat removal pumps outside design basis for maximum seal cooling temperature

Date of Event: August 26, 1997

Plant: D. C. Cook, Units 1 and 2

DRAFT

11.1 Summary of Issue

In August 1997 with Units 1 and 2 at 100 percent power, an investigation identified that both units had operated outside the design basis for component cooling water (CCW) maximum temperature. Contrary to the FSAR (Ref. 2, Table 9.5-3) which states that the maximum CCW heat exchanger outlet temperature is 95 degrees Fahrenheit, guidance provided in the operations procedures since 1974 allowed CCW heat exchanger outlet temperature to reach 120 degrees Fahrenheit during the first three hours of residual heat removal (RHR) operation. This condition would reduce the heat removal capacity of the pump coolers to the safety injection, centrifugal charging and RHR pumps during the short duration of the elevated CCW temperature.

The LER stated that Westinghouse performed an evaluation to evaluate the operation of the CCW system at 120 degrees Fahrenheit for the duration of the cooldown. The evaluation addresses the accident analysis and concludes that the increased CCW temperature has no adverse impact on any portion of the accident analysis. Therefore, based on the results of the Westinghouse evaluation, it was concluded that, the temporary increase in the CCW temperature to a maximum temperature of 120 degree Fahrenheit for a three hour period during cooldown would not have adversely affected the safety function of the CCW system.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

11.2 Modeling and Affected Sequences

Since the temporary increase in the CCW temperature to a maximum temperature of 120 degree Fahrenheit for a three hour period during cooldown would not have adversely affected the safety function of the CCW system, a core damage sequence was not developed.

11.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increased in frequency, frequencies and probabilities were not calculated.

11.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences increased in frequency as a result of the licensee's action. Therefore, the change in core damage frequency was determined to be zero.

11.5 References

1. LER 315/97-012, Rev. 1, "Potential Operation of CCW System Above Design Basis Value for Heat Exchanger Outlet Constitutes Condition Outside Design Basis," November 14, 1997.

2. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

19.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.5.2A(2)

Event Description: Operating procedure "Operation of the ESW System," was changed without a proper safety evaluation

Date of Event: August 1997

Plant: D.C. Cook, Unit 1

DRAFT

19.1 Summary of Issue

The issue is that the licensee made temporary, "non-intent" changes to procedure," OHP 4021.019.001, "Operation of the ESW System," without performing a proper safety evaluation (Ref. 1). Part 50.59 of the code of federal regulations requires proper safety evaluations when making changes to safety parameters to ensure a comprehensive examination of the changes on the accident analyses and also to determine whether the changes exceed thresholds that would require the regulatory attention.

The ESW system operating procedure was revised to reduce the maximum ESW operating temperature limit from 87.5 to 85° F. This affects the maximum operating temperature of all components which are supported by ESW. This analysis focuses on the risk impact that could have resulted from the lack of a safety evaluation only. In addition to changing the ESW operating temperature limit without a safety evaluation, a second issue identified was that even with the reduced ESW operating temperature limit of 85° F, the design basis operating temperature limit of 76° F (Ref. 2)(UFSAR, accident analysis) could be exceeded. The risk associated with this second issue will be analyzed as issue# 29 (impact on control room ventilation), #30 (impact on plant cool down analysis), and #31(impact on containment peak pressure).

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

19.2 Modeling and Affected Sequences

The ESW system is the ultimate heat sink (UHS) for Cook in that it takes its supply from lake Michigan and supports all system heat removal needs directly or through the component cooling water (CCW) heat exchangers. Therefore, maximum operating temperature of ESW affects the maximum operating temperature of all accident mitigating systems supported by it. The premise of the licensee was that since the maximum temperature was reduced, the only impact of the change is an increase in the safety margin.

Based on the licensee's IPE (Ref. 3), the following systems are used to mitigate accidents, and they rely on ESW directly or indirectly via the component cooling water (CCW):

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- RHR,
- Charging,
- High pressure safety injection,
- Emergency diesels,
- Containment spray,
- Containment fans, and
- Auxiliary feedwater.

A reduction in the maximum ESW operating temperature limit increases the safety margin associated with any of the components in the above systems. Therefore, no core damage sequences will increase in frequency as a result of this change.

19.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

19.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences will increase in frequency as a result of the change to the procedure. Therefore, the change is determined to be zero.

19.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

3. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination, Revision 1*, October 1995.

20.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.5.2A(3)

Event Description: Operating procedure "Operation of the CCW System During Reactor Startup and Normal Operation," was changed without a proper safety evaluation

Date of Event: August 1997

Plant: D.C. Cook, Unit 2

DRAFT

20.1 Summary of Issue

The issue is that the licensee made temporary, "non-intent" changes to procedure 2-OHP 4021.016.003, "Operation of the CCW System During Reactor Startup and Normal Operation," without performing a proper safety evaluation (Ref. 1). Part 50.59 of the code of federal regulations requires proper safety evaluations when making changes to safety parameters to ensure a comprehensive examination of the changes to the accident analyses and also to determine whether the changes exceed thresholds that would require regulatory attention.

The ESW system operating procedure was revised to delete the allowance to operate the CCW system at 120°F, which was above the UFSAR-specified maximum operating temperature of 95°F. The licensee characterized this change as a "non-intent" change.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

20.2 Modeling and Affected Sequences

The CCW system is used to remove heat from a large number of safety related and non-safety related loads. Therefore, the maximum operating temperature of CCW affects the maximum operating temperature of all systems supported by it. The premise of the licensee was that since the maximum temperature was reduced, the only impact of the change was an increase in the safety margin.

Based on the licensee's IPE (Ref. 2), the following systems are used to mitigate accidents, and they rely on CCW:

- RHR,
- Charging,
- High pressure safety injection,
- Containment fans,
- Diesel generators,

In addition, CCW supports the cooling of reactor coolant pump seals whose failure leads to small LOCAs.

A reduction in the maximum CCW temperature increases the safety margin associated with all of the components in the above systems. Therefore, no core damage sequences will increase in frequency as a result of this change.

20.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

20.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences will increase in frequency as a result of the change to the procedure. Therefore, the change in core damage frequency is determined to be zero.

20.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. *Donald C. Cook Nuclear Plant Units 1and 2, Individual Plant Examination, Revision 1*, October 1995.

30.0 Adverse Impact on Plant Cooldown Analysis

Event Description: Adverse Impact on Plant Cooldown Analysis (Requirement to Enter Cold Shutdown in 36 Hours With Only One Train).

Date of Event: August 1997

Plant: D.C. Cook, Units 1 and 2

DRAFT

30.1 Summary of Issue

The issue, found during a 1997 design inspection (Ref. 1), is that if the reactor coolant system needed to be cooled down in 36 hours with only one train of the residual heat removal (RHR) system, the component cooling water (CCW) piping would exceed the Updated Final Safety Analysis Report (UFSAR) design temperature of 95 ° F. Three other issues uncovered during the inspection (high ultimate heat sink or emergency service water (ESW) temperature, instrument loop uncertainties in ESW (+/-3.5 ° F), and CCW heat exchanger outlet instrumentation) can exacerbate this situation.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

30.2 Modeling and Affected Sequences

The CCW system is used to remove heat from a large number of safety related and non-safety-related loads. One function of the CCW system is to remove heat from the RHR heat exchangers during plant cooldown. When the rate of plant cooldown increases, the rate of heat removal by CCW increases, and therefore the temperature of CCW increases. When the 36 hour cooldown requirement needs to be met with only one train of RHR, the CCW temperature may exceed 95 ° F. However, CCW temperature will not exceed 120 ° F. Westinghouse analysis has shown that the CCW piping would function acceptably at higher temperatures up to 120 ° F (Ref. 2), even though the UFSAR states the limit is 95 ° F (Ref. 3). Therefore, the inability to cool down within 36 hours does not affect (a) initiating event frequencies or (b) accident mitigation capabilities. Therefore, no core damage sequences are affected.

30.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

30.4 Core Damage Frequency Calculation or the Bounding Calculation

The inability to reach cold shutdown within 36 hours does not impact the core damage sequences. Therefore, the change in core damage frequency is determined to be zero.

30.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. LER 315/97-012, Rev. 1, "Potential Operation of CCW System Above Design Basis Value for Heat Exchanger Outlet Constitutes Condition Outside Design Basis" November 14, 1997.

3. Donald C. Cook Nuclear Plant, Units 1 and 2, *Updated Final Safety Analysis Report,* July 1997

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39.0 UFSAR and TS Inconsistencies With RWST Volume

Event Description: Updated Final Safety Analysis Report and Technical Specifications Inconsistencies with Refueling Water Storage Tank Volume

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Date of Event: August 1997

Plant: D.C. Cook, Units 1 and 2

39.1 Summary of Issue

The issue, found during a 1997 design inspection (Ref. 1), is that the Updated Final Safety Analysis Report (UFSAR), Section 6.2.2, states that there are 350,000 gallons of borated water available above the bottom of the refueling water storage tank (RWST) suction pipe (Ref. 2). However, 27,000 gallons are not usable since vortexing and air entrapment occur when the water level falls below the top of the discharge pipe.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

39.2 Modeling and Affected Sequences

No sequences are affected since the issue deals with verbatim compliance with the UFSAR statement which states that 350,000 gallons are "available," but all of the "available" volume is not "usable."

The RWST supplies water for injection to the reactor during a LOCA of any size. In addition, the RWST water is used for feed-and-bleed cooling if main feedwater and auxiliary feedwater are unavailable to perform decay heat removal. The set point used to direct the operator to start recirculation is above the point where this issue would impact the ability to inject. The accident analysis does not credit the entire 350,000 gallon inventory. The analysis credits the top 68 percent of the tank to be available in the containment recirculation sump to start the recirculation function (recirculation is initiated at the 32 percent set point). The time available to establish sump recirculation was always based on the water level between the 32 percent RWST level and the suction pipe level. That is, the RWST water below the suction pipe was never factored into the calculations.

A potential deficit of a supply of 27000 gallons from the RWST to the containment recirculation sump has the potential to adversely affect the inventory available in the containment recirculation sump to establish recirculation. The water that will become available to the containment recirculation sump from melting ice in the ice condenser will easily compensate for this adverse effect. Ice melt in the

containment would provide approximately 290,000 gallons of additional water to the sump. Therefore, the loss of 27,000 gallons would have no impact on recirculation sump inventory.

39.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

39.4 Core Damage Frequency Calculation or the Bounding Calculation

This issue does not impact the core damage sequences. Therefore, the change in core damage frequency is determined to be zero.

39.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. Donald C. Cook Nuclear Plant, Units 1 and 2, *Updated Final Safety Analysis Report,* July 1997

40.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.4.2C(3)

Event Description: Documentation Inconsistency between the UFSAR and the RHR Pump Vendor's Manual

Date of Event: August 1997

Plant: D. C. Cook, Units 1 and 2

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40.1 Summary of Issue

The NRC staff conducted a design inspection at D. C. Cook, Units 1 and 2 (Cook 1 and 2) from August 4 through September 11, 1997. (Ref. 1) During the inspection, the team observed that the Cook 1 and 2 UFSAR states in Table 9.3-2 that the RHR pump NPSH required at maximum flow rate is 11 ft. The team pointed out that this appeared to be inconsistent with the RHR pump vendor's manual, which states that this is the NPSH required at 3000 gpm (design flow). The vendor's manual also states that, at the maximum flow rate of 4500 gpm, the NPSH required is 19 feet.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

40.2 Modeling and Affected Sequences

In our review of this issue, we reviewed the licensee's analysis of the containment debris issue to determine how the subject discrepancy affected the results of that analysis. In the containment debris head loss analysis, the licensee used an NPSH requirement of 20 ft. at a maximum flow rate of 4600 gpm. This value is consistent with the 19 ft NPSH at 4500 gpm maximum flow rate requirement contained in the RHR pump vendor's manual. (Ref. 2) Additional information regarding both the available and the required NPSH for the RHR pumps is contained in the licensee's response to UFSAR Question 212.29. (Ref. 3) This information is also consistent with the RHR pump vendor's manual. Subsequent discussions with the licensee's staff confirmed that the inconsistency in Table 9.3-2 had indeed been identified as an editorial error. (Ref. 4)

Therefore, no core damage sequences increased in frequency as a result of this discrepancy.

40.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increased in frequency, frequencies and probabilities were not calculated.

40.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences increased in frequency as a result of the editorial error. Therefore, the change in core damage frequency was determined to be zero.

40.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. Document Number VTD-INCR-0012, Ingersoll-Dresser Publication #016-32294.

3. Updated Final Safety Analysis Report, Donald C. Cook Nuclear Plant, Units 1 and 2, Indiana Michigan Power Company, USNRC Docket Nos. 50-315 and 316.

4. March 15, 1999 e-mail message from W. A. Allen, Indiana Michigan Power Company, to S. Weerakkody, USNRC.

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46.3 Frequencies, Probabilities, and Assumptions

Because no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

46.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences will increase in frequency as a result of the missed surveillance. Therefore, the change is determined to be essentially zero.

46.5 References

1. Donald C. Cook, Unit 1, Licensee Event Report 315/98-036, "Flow Indicator Not Calibrated at Technical Specification Required Frequency," August 24, 1998.

2. *Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.*

3. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination, Revision 1*, October 1995.

49.0 LER No. 50-315/97-027

Event Description: Westinghouse integral fuel burnable absorber fuel rods may result in a degraded principal safety barrier (fuel cladding)

Date of Event: October 1997

Plant: D.C. Cook, Units 1 and 2

49.1 Summary of Issue

This is a generic issue applicable to all reactors with Westinghouse integral fuel burnable absorber (IFBA) fuel rods. On October 28, 1997, Westinghouse notified NRC that modification of its fuel cladding corrosion model in its fuel rod design code to reflect new data on Zircaloy-4 oxidation at high burnup may lead to code results that do not meet the Westinghouse criterion prohibiting fuel pellet to clad gap reopening. Gap reopening may be predicted for IFBA fuel rods as early as the second half of their duty cycle. In addition, code results may not meet the loss-of-coolant accident (LOCA) criterion in 10 CFR 50.46(b)(2). This maximum cladding oxidation criterion requires that the calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. The condition above is described in a Cook licensee event report (Ref. 1) and in an NRC Information Notice (Ref. 2). The issue is that a principal safety barrier, the fuel rod cladding, may be degraded

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

49.2 Modeling and Affected Sequences

This issue affects fuel integrity during normal operations, but does not impact core damage frequency because:

(a) The initiating event frequency for LOCAs, loss of offsite power, transients, and anticipated transient without scram is not affected;

(b) Mitigating system capability is not affected; and

(c) Containment performance is not affected.

Therefore, no core damage sequences will increase in frequency.

49.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increase in frequency, frequencies and probabilities are not calculated.

49.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences are affected. Therefore, the change in core damage frequency is determined to be zero.

49.5 References

1. LER 315/97-027, Rev. 1, "Westinghouse Integral Fuel Burnable Absorber (IFBA) Fuel Rods" January 16, 1998.

2. NRC Information Notice 98-29, "Predicted Increase in Fuel Rod Cladding Oxidation" August 3, 1998.

52.0 LER No. 316/98-004

Event Description: Ice Condenser Bypass Potentially in Excess of Design

Date of Event: March 19, 1998

Plant: D.C. Cook, Unit 2

52.1 Summary of Issue

According to the Cook UFSAR (Ref. 1), the design basis bypass flow around the ice bed in the ice condenser is 5 square feet. LER 316/98-004 (Ref. 2) was written since several degradations uncovered during a recent inspection brought the total known bypass area to 4.37 square feet. If more degraded conditions are revealed, a potential exists to exceed the design basis bypass flow.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

52.2 Modeling and Affected Sequences

Any accident that releases energy to containment relies on the ice condenser for heat removal from the containment. Containment heat removal is essential to keep the peak containment pressure below the design value. At Cook, containment heat removal is performed by the ice-condenser and two trains of the containment spray system which are equipped with a heat exchanger. If the steam generated during a LOCA bypasses the ice, the steam cannot condense. If steam does not condense, the pressure rise in the containment does not get arrested and the peak pressure may be exceeded. If the peak pressure exceeds the design value, there is a probability to fail the containment due to overpressure. As a result, the sump recirculation capability will be affected since a breached containment reduces NPSH available for the RHR pumps and allows water to bypass the recirculation sump.

The following accidents release energy to the containment: a) LOCAs of any size, b) Main Steam Line Breaks (MSLB) inside containment, and c) any accident condition which relies on the feed and bleed cooling capability. Of these accidents, only LOCAs and feed and bleed sequences resulting from MSLBs are considered since other systems or actions required to mitigate MSLBs (isolation of the break and cool down with unfaulted loops) are unaffected by loss of containment integrity.

Therefore, the sequence of interest is as follows:

- Any size LOCA or Feed & Bleed scenario; and

- Sump recirculation failure due to peak pressure exceeding containment failure pressure as a result of excessive steam bypass leading to inadequate inventory for sump recirculation.

52.3 Frequencies, Probabilities, and Assumptions

According to Table 5.3-1 of the UFSAR (Ref.1), the total inlet area to the ice condenser is 1000 square feet. The design allowable bypass area is 5 square feet. The total area of the known bypass paths is 4.37 square feet. This is less that the design allowable value of 5 square feet. The LER was written voluntarily since other yet unknown bypass paths may exist. Therefore, the probability of failure based on known conditions is zero. In addition, based on Reference 3, the failure pressure of the containment is much greater than the design allowable pressure of 12 psig. Reference 3 reports that the high condition low probability failure (HCLPF) limit for the containment is 36 psig. That is, there is 95% confidence that at 36 psig the probability of containment failure is less than 5%. Based on the above, unless, other bypass paths of substantial steam bypass capability are discovered, the probability of peak pressure exceeding the containment failure pressure leading to sump recirculation failure is zero.

52.4 Core Damage Frequency Calculation or the Bounding Calculation

Since the change in probability of containment failure is zero, the core damage frequency change associated with the affected sequences is zero.

52.5 References

1. Donald C. Cook Nuclear Plant, Units 1 and 2, Updated Final Safety Analysis Report.

2. LER 316/98-004, "Ice Condenser Bypass Potentially in Excess of Design," April 20, 1998.

3. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

55.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.3.1.2

Event Description: Inadequate Justification to Demonstrate Operability of the Unit 2 250 V dc CD Battery Train

Date of Event: August 1997

Plant: D. C. Cook, Unit 2

55.1 Summary of Issue

The NRC staff conducted a design inspection at D. C. Cook, Unit 2 (Cook 2) from August 4 through September 11, 1997 (Ref. 1). During a walkdown by the inspection team of the Cook 2 Train "CD" 250 Vdc Battery Room, the team noted that Battery Cell # 34 was on an individual cell equalize charge. On June 19, 1997, the licensee had found the voltage for Cell #34 to be less than the Technical Specification (TS)-required minimum voltage of 2.13 V. In response, the licensee had performed a temporary modification on the same day, installing a portable charger and cabling, which allowed the cell to be on a continuous equalize charge. As a result, the voltage for Cell #34 had increased to a value above the TS requirement within the TS-required limiting condition for operation (LCO) of 2 hours. The licensee had performed a prompt operability evaluation which concluded that the battery train was "Operable" because the TS-required voltage level had been restored within the LCO limit. The inspection team determined that the licensee's prompt operability evaluation was inadequate because the voltage readings for Cell #34, upon which operability of the cell had been based, were not taken with the cell on a float charge as required by TS Surveillance 4.8.2.3.2(b)1, but with the cell on an equalize charge. After the cell's voltage had been restored to above the TS-required value, it remained on a continuous equalize charge for 51 days, until the licensee replaced the cell on August 11, 1997. The decision to replace the cell was based partially on the inspection team's identification of this issue, and partially on the fact that the cell was still consuming significant amperage and was not at full charge.

The inspection team also expressed concern that the licensee's prompt operability determination did not consider that Cell #34 was in a degraded condition and showed physical signs of internal short-circuiting and end of life (dendrite formation on the positive plates and substantial sediment accumulation at the bottom of the cell). Further, the evaluation did not address whether the plant's Technical Specifications would allow a component to remain operable with a continuous equalize charge being applied beyond the 2-hour LCO. The team concluded that, although there was not enough evidence to suggest that the battery train could not perform its function, and the licensee had an analysis which concluded that the battery train could perform its function without the cell in question, there was no reasonable assurance that the licensee's actions had restored Cell #34 to an operable condition.

The change in core damage frequency associated with this issue is essentially zero and the issue has negligible synergistic effects with other issues. Therefore, this issue will be screened out from the integrated analysis.

55.2 Modeling and Affected Sequences

The basic question examined in our evaluation of this issue was whether the 250V dc "CD" Battery Train would have been able to perform its safety function if needed to mitigate the consequences of an initiating event. During our review, discussions with an NRC Senior Instrumentation and Controls Engineer, who has experience as a regional office-based inspector, confirmed that one cell of the battery being charged using an equalize charge, or even being in a degraded state, would not affect the functionality of the battery train (Ref. 2). In addition, as mentioned previously, the licensee's analysis had concluded that the battery train could perform its function without the cell in question (115 cells versus the normal 116 cells). Based on these results, our review found that this issue constituted only a violation of plant Technical Specifications, because an equalize charge was being used instead of the specified float charge to charge one cell of the 250 V dc battery train. Although the battery may have been inoperable according to the plant's Technical Specifications, it was still available to perform its safety function. Hence, no core damage sequences increased in frequency as a result of the licensee's action.

55.3 Frequencies, Probabilities, and Assumptions

Since no core damage sequences increased in frequency, frequencies and probabilities were not calculated.

55.4 Core Damage Frequency Calculation or the Bounding Calculation

No core damage sequences increased in frequency as a result of the licensee's action. Therefore, the change in core damage frequency was determined to be zero.

55.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201). November 26, 1997.

2. Discussion with J. G. Ibarra, Senior Instrumentation and Controls Engineer, Reactor Analysis Branch, Safety Programs Division, Office of Nuclear Regulatory Research, February 25, 1999.

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APPENDIX D

Completed Analyses of Individual Issues Incorporated into the Integrated Risk Assessment

1.0 LER No. 316/98-007

Event Description: High-Energy Line Break Could Affect Auxiliary Feedwater Function

Date of Event: July 1995

Plant: D.C. Cook, Unit 2

1.1 Summary of Issue

In July, 1995, personnel at D.C. Cook, Unit 2, blocked open for ~39 h the fire door/high-energy line break (HELB) door for the startup blowdown flash tank room. This door was blocked open to facilitate draining the essential service water (ESW) header for maintenance (Ref. 1). Subsequently, an engineering analysis determined that this activity could expose the motor control centers (MCCs) in the vicinity (but outside the startup blowdown flash tank room) to a steam environment with higher temperatures than the MCCs are qualified to withstand. The impacted MCCs control the motor-operated valves (MOVs) on the pipeline that connects the ESW system to the auxiliary feedwater (AFW) system. The ESW valves in question are used to align the ESW system to provide a backup to the normal water supply from the condensate storage tank (CST) for the AFW system. Should the normal AFW system water supply fail following an HELB, the ESW system could no longer provide a backup water supply if these valves failed closed. This would result in a failure of the AFW system to provide its safety function.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting residual heat removal (RHR) cooling and feed-and-bleed cooling capabilities.

1.2 Modeling and Affected Sequences

The premise taken by the licensee for allowing the original maintenance to proceed was that if the reactor is successfully tripped and main feedwater is available, there is no increase in the core damage probability (CDP) under any HELB circumstances. However, if the main feedwater system fails, the auxiliary feedwater system would be demanded to start and run. An HELB that could impact the operability of the AFW system would result in an increase in the CDP. The two most likely scenarios under these conditions are

Sequence 1 – HELB occurs:

- An HELB occurs in the startup blowdown flash tank room;
- A reactor trip with a subsequent loss of main feedwater occurs;

- The normal AFW system water supply fails (e.g., failure of the CST, system cross-tie, hot well, plant makeup) because of random failures;
- The MCC breakers that control the MOVs on the pipeline that connects the ESW to the AFW system fail because of the HELB; and
- Feed-and-bleed cooling fails because of random failures.

Sequence 2 – HELB occurs given an earthquake:

- An earthquake with sufficient magnitude occurs resulting in a reactor trip;
- An HELB occurs in the startup blowdown flash tank room because of an earthquake;
- The main feedwater system is lost because of the HELB and earthquake;
- The normal AFW system water supply fails (e.g., failure of the CST, system cross-tie, hot well, plant makeup) because of the earthquake;
- The MCC breakers that control the MOVs on the pipeline that connects the ESW to the AFW system fail because of the HELB; and
- Feed-and-bleed cooling fails because of random failures.

1.3 Frequencies, Probabilities, and Assumptions

Sequence 1 – HELB occurs:

- An HELB occurs in the startup blowdown flash tank room because of undetected equipment wear – *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2) indicates that the frequency for an HELB anywhere in the plant is 1.3×10^{-2} events/critical year. A more specific location (i.e., the startup blowdown flash tank room) would lower the initiating event frequency. However, this value represents a conservative upper-bound.
- A reactor trip with a subsequent loss of main feedwater occurs – The probability of an automatic reactor trip occurring may not be very likely unless the HELB is quite large. However, in order to minimize the safety hazard of an HELB, the probability that the operators would manually trip the reactor would be high. The probability of a reactor trip (either manual or automatic) is considered to be 1.0.

  Given a reactor trip, it is not unusual for the plant to experience fluctuations in the water level in the steam generators. For conservatism, it was assumed that the conditional probability of main

feedwater system failure given a HELB was 1.0. Consequently, the probability of a reactor trip with a subsequent loss of main feedwater occurring was assumed to be 1.0 (upper-bound).

- The normal AFW system water supply fails (e.g., failure of the CST, system cross-tie, hot well, plant makeup) because of random failures – The upper bound value for this probability is 2.4 x 10^{-5}. The basis for this probability is included in section 2.3 under issue #2 (product of RHR unavailable: 1 x 10^{-2} and failure to cross tie or make up from make up plant: 2.4 x 10^{-3}.) However, a number of other issues that can potentially affect RHR cooling must be resolved in order to assess the RHR unavailability.

- The MCC breakers that control the MOVs on the pipeline that connects the ESW to the AFW system fail because of the HELB – The probability of this occurring is unknown; however, the probability is likely to be less than 1.0 based on the ventilation in the area and the limited room connection (i.e., open fire door). However, for conservatism, this probability was assumed to be 1.0.

- Feed-and-bleed cooling fails because of random failures – From the Cook standardized plant analysis risk (SPAR) model, the overall failure probability of feed-and-bleed cooling is 2.9 × 10^{-2}. However, a number of other issues that can potentially affect feed-and-bleed cooling must be resolved in order to assess the feed-and-bleed cooling failure probability.

Sequence 2 – HELB occurs given an earthquake

- An earthquake with sufficient magnitude occurs resulting an a reactor trip – This initiating event is listed in the event summary sheet in the D.C. Cook individual plant examination (IPE) with a frequency of 5.8 × 10^{-5}/year (Ref. 3).

- An HELB occurs in the startup blowdown flash tank room because of an earthquake – This probability would be a function of the piping design and snubber design in this area and the strength of the earthquake. For conservatism, this probability is assumed to be 1.0.

- The main feedwater system is lost because of the HELB and earthquake – The occurrence of this event would be likely given a reactor trip has been initiated since main feedwater system is not a seismic category I system. Therefore, it was assumed that this probability is 1.0.

- The normal AFW system water supply fails (e.g., failure of the CST,[a] system cross-tie, hot well, plant makeup) because of the earthquake – For conservatism, it was assumed that the occurrence of an earthquake with sufficient magnitude to initiate an automatic reactor trip would result in the loss of the normal AFW system water supply with a probability of 1.0.

[a]The CST and the control air system are not considered seismically qualified by the IPE. However, the CST is generally considered to be a rugged component and many licensees have retroactively upgraded the CST survival expectancy following a seismic event for the purpose of enhancing their IPE.

- The MCC breakers that control the MOVs on the pipeline that connects the ESW to the AFW system fail because of the HELB – The probability of this occurring is unknown; however, the probability is likely to be less than 1.0 based on the ventilation in the area and the limited room connection (i.e., open fire door). However, for conservatism, this probability was assumed to be 1.0.

- Feed-and-bleed cooling fails because of random failures – Instrument air is not credited in the D.C. Cook IPE as being seismically qualified. Therefore, it must be assumed that a pressurizer power-operated relief valve would not be available following an earthquake. This probability of this event occurring is assumed to be 1.0.

1.4 Core Damage Frequency Calculation or the Bounding Calculation[b]

The frequencies associated with these sequences depend on the resolution of other issues affecting RHR cooling and feed-and-bleed cooling capabilities. To provide perspective on these sequences the following information is provided.

If the resolution of other issues results in no significant changes to the RHR and feed-and-bleed cooling failure probabilities, the change in core damage probability would be:

Sequence 1 – an HELB occurs

(Initiating event frequency of HELB events: 1.3×10^{-2}/critical year) x
(Criticality factor for Cook Unit 2--from Ref. 2, Table H-3: 0.68 critical year/reactor calendar year) x
(Window of opportunity: 39 h) x (1 year/8760 h) x
(Probability of reactor trip: 1.0) x
(Probability of normal AFW supply failure: 2.4×10^{-5}) x
(Probability ESW valves fail: 1.0) x
(Probability of feed-and-bleed cooling failure: 2.9×10^{-2}) = 2.7×10^{-11}.

Sequence 2 – an HELB occurs given an earthquake

(Earthquake frequency: 5.8×10^{-5}/year) x
(Window of opportunity: 39 h) x (1 year/8760 h) x
(Probability of HELB: 1.0) x
(Probability of main feedwater loss: 1.0) x
(Probability of AFW normal supply failure: 1.0) x
(Probability ESW valves fail: 1.0) x
(Probability of feed-and-bleed cooling failure: 1.0) = 2.6×10^{-7}.

[b]A revision to LER No. 316/98-007 is expected to be submitted by March 10, 1999. Although this update will likely not change the disposition of this issue, it should be reviewed for potential impacts on this analysis.

Therefore, the change to the core damage probability would not be risk significant.

1.5 References

1. LER 316/98-007, Rev. 0, "Interim LER – High Energy Line Break Effects On Auxiliary Feedwater System," December 7, 1998.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987- 1995*, NUREG/CR-5750, February 1999.

3. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

2.0 AFW System SSFI- Licensee self assessment: Finding #ENG5/LER No. 315/98-046

Event Description:	Lack of an Appropriate Design Basis for Auxiliary Feedwater Pump Suction Strainers
Date of Event:	November 3, 1998
Plant:	D. C. Cook, Unit 1

2.1 Summary of Issue

A safety system functional inspection (SSFI) performed by Duke Engineering and Services (Ref. 1) identified that the strainers in the auxiliary feed water (AFW) system have 1/32" holes whereas the strainers in the emergency service water (ESW) system have 1/8" holes. ESW will supply water to the AFW system if all other supplies to AFW (make-up plant, Unit 2 CST via a cross tie) fail or if an earthquake fails the CST. The risk associated with the CST failure resulting from an earthquake is include as a separate issue (Issue #3). Due to the difference between the strainer sizes between the ESW and AFW, when ESW supplies water to AFW, the AFW strainers can become clogged. The clogging rate may not accommodate the operator response time needed to swap, clean, and restore strainer baskets. If the strainers become clogged, the AFW system will fail to provide flow to the steam generators.

On November 3, 1998, a special test was conducted on the Unit 1 west AFW pump to determine the potential effect on suction strainer loading when ESW is used as a suction source. (Ref. 2). Approximately 60 seconds into the test, the differential pressure across the strainer exceeded the maximum allowed value, and flow dropped from its maximum value of 560 gpm to approximately 400 gpm. Since 400 gpm is below the design flow value (450 gpm) the test was terminated. On November 4, 1998, a second strainer test was performed using the same special test procedure. However, since the debris had been flushed out during the test performed on November 3; the flow rate and the strainer differential pressure stabilized at 500 gpm and 0.7 psig respectively, for 7 hours. This second test indicated that once the initial debris is removed, ESW is capable of providing continuous flow

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting residual heat removal (RHR) and feed-and-bleed cooling capabilities.

2.2 Modeling and Affected Sequences

The main feedwater system (MFW) or the AFW system feeds the steam generator to remove decay heat after a reactor trip. If the MFW system is lost as a result of the transient that causes the trip, then only the AFW system is available to feed the steam generators. Main feedwater system will be lost if the power conversion system fails or offsite power is lost. Therefore, the accidents that would require the use of AFW are reactor trips followed by : a) loss of offsite power, b) loss of power conversion system, and c) loss of main feedwater.

The condition discovered affects an alternate capability to supply water to the AFW. This capability is needed in the event of depleting CST water prior to achieving cold shutdown and aligning the RHR system. Under normal operating conditions, subsequent to a reactor trip, the CST has adequate inventory to accomplish the cool down to cold shutdown. Re-filling the CST will only be required if RHR is in a failed condition and the CST is needed for an extended duration.

If the CST is needed for an extended duration due to inability to align RHR, then it must be refilled by either the makeup plant or the CST of Unit 2. If both these actions fail, if ESW is unavailable to supply water to the systems, then AFW will fail. In the event of loss of AFW, decay heat can be removed from the core by bleeding the reactor coolant through opened pressurizer power operated relief valves (PORVs) and feeding the reactor coolant system (RCS) with either the safety injection pumps or the charging pumps. The following accident sequence is of interest:

- Reactor trip with loss of offsite power, loss of power conversion system, or loss of main feedwater;
- RHR Unavailable;
- AFW fails due to depletion of CST inventory and supply to the CST from the make-up plant or the Unit 2 CST fails;
- ESW fails to supply AFW;
- Feed and bleed cooling using the pressurizer PORVs and SI or the charging system fails.

2.3 Frequencies, Probabilities, and Assumptions

- Reactor trip with loss of offsite power, loss of power conversion system, or loss of main feedwater - *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 3) indicates that the frequency of loss of offsite power is 0.046/year. Total loss of feedwater frequency is 0.085/year. The frequency of total loss of heat condenser heat sink events (power conversion system) is 0.12/year. This adds up to a total frequency of 0.25/year. For Cook Unit 1, the criticality factor is 0.79. Therefore, frequency of reactor trip with loss of feedwater, offsite power, or the power conversion system is 0.2/year (0.79 x0.25).

- Unable to align RHR - After a plant trip, the AFW is used to cool down the reactor and achieve cold shutdown and get on the RHR system. The CST has 500,000 gallons (Ref. 6, Cook IPE). According to section 14.1.9 of the accident analysis section of the Cook FSAR (Ref. 7), the AFW water system including the CST is sized to cool down the reactor and achieve cold shutdown even when main feedwater is lost and steam generated is dumped to the atmosphere rather than recycled back to the CST. Therefore, if RHR is available, there is no need to re-fill the CST. From the Cook standardized plant analysis risk (SPAR) the RHR unavailability for long term heat removal is 1.0 x

10^{-2}. However, a number of issues that can potentially affect RHR cooling must be resolved in order to assess RHR unavailability.

- AFW fails due to depletion of CST inventory and supply to the CST from the make-up plant or the Unit 2 CST fails - Failure to provide make-up to the CST either from the make-up plant or from the Unit 2 CST will occur if the operator fails to recognize the need to do so or if hardware failures occur. There are three different alarms that will prompt the operator that there is a need to re-fill the CST. The CST low level alarm is set at 625'9". When this alarm is received, the tank has 250,000 gallons left. At 500 gpm, this inventory will give the operators more than 6 hours warning. A low-low level alarm is provided at 614'. This alarm also informs the operators of the need to re-fill the CST. At design flow, 29 minutes are available after receiving this alarm. The low suction pressure alarm of the AFW pumps will also warn the operators of the need to re-fill the tank. Even at full flow (2000 gpm), 13 minutes are available from the time of receiving this alarm to the point of level falling to the CST outlet pipe centerline. At more realistic flows such as 500 gpm, 52 minutes are available to establish alternate source. Based on Swain and Guttman (Reference 4) (NUREG/CR-1278, Table 11-13), failure to initiate action after one annunciator is 1×10^{-4}. For multiple annunciators, this probability is lower than 1×10^{-4}. Swain and Guttman (Ref. 4) recommends increasing this factor by an order of magnitude to 1×10^{-3} for transient conditions. Therefore, a conservative probability value of 1×10^{-3} is used for operator failure to recognize the need to refill the tank.

  Even if the operator successfully recognizes the need to re-fill the tank, failure of make-up will occur if mechanical failures or other actions occur to prevent make-up to the CST. Alignment to both sources (make-up plant or Unit 2 CST) must fail to prevent make-up to the CST. Alignment to the make-up plant is treated as a recovery action and, using the probabilities provided in Ref. 5 (NUREG/CR-4674), a probability of failure of 0.12 was used. A single AOV must be opened in order to cross connect the Unit 2 CST. Cook IPE (Ref. 6) assigns 2×10^{-3} to the probability of an AOV failing to open based on generic data. While most safety related AOVs are tested quarterly, the cross connect valve is tested once every refueling outage. Therefore, the valve failure probability was adjusted to 1.2×10^{-2} ($=6 \times 2 \times 10^{-3}$) due to the increased interval between tests.

  Based on the above probabilities, failure to establish a supply to the CST from either the makeup plant or the Unit 2 CST is the sum of the probability the operator fails to initiate action (1×10^{-3}) plus the product of the probability of failure to connect to the make-up plant (0.12) times the probability of failure to connect to the Unit 2 CST (0.012). Therefore, the probability is estimated to be 0.00244 ($= 1 \times 10^{-3} + .012 \times .12$).

- ESW fails to supply AFW - Based on Ref. 2, a special test showed that the AFW flow from the west AFW pump would have fallen below the design value due to clogging the strainer. It also showed that recovery is possible and that a one time strainer basket cleanup would have assured system success. In spite of this, it was pessimistically assumed that the probability of failure to use ESW as the supply source to the CST is 1.0.

- Feed and Bleed using the pressurizer PORVs and SI or the charging system fails - From the Cook SPAR model, the overall failure probability of feed-and-bleed cooling is 2.9×10^{-2}. However, a number of issues that can potentially affect feed-and-bleed cooling must be resolved in order to assess this failure probability.

2.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting RHR and feed-and-bleed cooling capabilities. To provide perspective on these sequences the following information is provided.

If the resolution of issues results in no significant changes to the feed-and-bleed and RHR cooling failure probabilities, the change in core damage frequency would be:

(Frequency of reactor trip with loss of feedwater, offsite power, or the power conversion system: 0.2/year) x
(Failure to establish RHR leading to long-term depletion of the CST: 1×10^{-2}) x
(Probability of failure to supply AFW from the make-up plant or the CST: 2.4×10^{-3}) x
(Probability of ESW failing to supply AFW: 1.0) x
(Probability of feed and bleed cooling failure: 2.9×10^{-2}) = 1.4×10^{-7}/year.

Therefore, the change to the core damage frequency would not be risk significant.

2.5 References

1. Auxiliary Feedwater System Safety System Functional Inspection (SSFI) Self Assessment, November 1998.

2 LER 315/98-046, "Auxiliary Feedwater System Unable to Meet Design Flow Requirement During Special Test," event date: November 3, 1998.

3. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

4. A.D. Swain, and H.E. Guttman, *Handbook of Human Reliability Analysis with emphasis on Nuclear Power Plant Applications*, NUREG/CR - 1278, August 1983.

5. *Precursors to Potential Severe Core Damage Accidents*, NUREG/CR-4674, December 1997.

6. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

7. *Donald C. Cook Nuclear Plant, Units 1 and 2, Updated Final Safety Analysis Report.*

4.0 LER No. 315/98-041

Event Description: Operating Plant with Both Trains of Component Cooling Water Inoperable

Date of Event: August 18, 1998

Plant: D.C Cook, Unit 1

4.1 Summary of Issue

D.C. Cook Unit 1 has two component cooling water (CCW) trains which supply cooling water to safety related as well as non-safety related loads. When the reactor is at power, if maintenance is needed on one of the two CCW trains, that train is taken out of service. After completing the maintenance, even though the CCW train is functional, it is labeled as "inoperable" until a test is performed to demonstrate its functionality. In order to demonstrate its functionality, operators establish adequate flow conditions to all loads supported by CCW using the "inoperable" as well as the operable train. At this point, in order to confirm that the "inoperable" train is capable of supporting the plant loads without the assistance of the operable train, the operators isolate the operable train by closing its heat exchanger outlet valve. Once this configuration is entered, all plant loads rely on the functional but "inoperable" CCW train. That is, the plant has no operable CCW trains. This constitutes an unplanned entry into Technical Specification (TS) 3.0.3 (Ref. 1).

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting the probability of core damage given the loss of CCW.

4.2 Modeling and Affected Sequences

The subject test is conducted if a corrective maintenance activity has been performed on a CCW train. The operators enter the configuration where the operable train is isolated and the "inoperable" train is supplying all loads, in order to demonstrate the functionality of the "inoperable" train and certify it as operable. While in this configuration, if the "inoperable" train incurs a failure, the plant will lose CCW to all equipment supported by the CCW train.

Based on the D. C. Cook Individual Plant Examination (IPE), Revision 1 (Ref. 2), the following systems which rely on CCW are used to mitigate accidents:

- Residual heat removal,
- Charging,
- High pressure safety injection,
- Containment fans, and
- Diesel generators.

In addition, CCW supports the cooling of reactor coolant pump seals whose failure leads to small LOCAs. When the CCW is lost, the performance of all these components as well as the core damage frequency (CDF) sequences associated with this equipment will be affected. The accident sequence of interest is:

- Entering into the post-maintenance test configuration at power;
- The "inoperable" train fails during the test; and
- Incurring core damage given the loss of CCW.

4.3 Frequencies, Probabilities, and Assumptions

- Entering into the post-maintenance test configuration at power - The need to enter the post maintenance test configuration is a random event caused by CCW equipment failures or degradations at power. Based on discussion with the licensee, the plant has entered this configuration 5 times since June 1995. Therefore, it was assumed that the frequency was 2.5/year (5 times in approximately two years).

- The "inoperable" train fails during the test - Before isolating the operable train from service, the operators start the inoperable train and stabilize flows from both CCW trains. That is, at the time of test the "inoperable" train has started and is running successfully. Therefore, only failures such as a motor operated valve spuriously closing, a check valve failing to stay open, or a pump failing to continue to run can cause the running CCW train to fail. Of these failures, the CCW pump failing to continue to run for the duration of the test dominates. Based on the D. C. Cook IPE, Revision 1, the CCW failure to run has a failure rate of 3×10^{-5}/hour. Based on the discussion with the licensee, the duration of this post-maintenance test has varied between 28- 35 minutes for 4 of the 5 tests. For the fifth test, the test duration was 2 hours. This results in an average test duration 0.8 hours. Therefore, the probability of CCW train failure to run during the test is 2.4×10^{-5} ($0.8 \times 3 \times 10^{-5}$).

- Incurring core damage given that CCW is lost - The D. C. Cook IPE, Revision 1, has analyzed the plant's response to a loss of CCW event. This analysis factors in the probabilities of failure to recover the CCW, the cross tie capability to the Unit 2 CCW system, and tripping the reactor coolant pumps to prevent a seal LOCA upon loss of CCW. The D. C. Cook IPE, Revision 1, was used to estimate the probability of a core damage when CCW is lost. This probability is 4.4×10^{-3}, which is calculated by taking the ratio between CDF due to loss of CCW of 3.25×10^{-6} and the frequency of loss of CCW of 7.36×10^{-4}. However, there are number of issues that can potentially affect the probability of incurring core damage given the loss of CCW. These issues must be resolved in order to assess this probability.

4.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting the probability of core damage given the loss of CCW. To provide perspective on these sequences the following information is provided.

If the resolution of issues results in no significant changes to the probability of core damage given the loss of CCW, the change in core damage frequency would be:

(Frequency of test: 2.5) x
(Probability of failure of the "inoperable" running CCW train: 2.4×10^{-5}) x
(Probability of core damage given loss of CCW: 4.4×10^{-3}) = 2.6×10^{-7}/year.

Therefore, the change to the core damage frequency would not be risk significant.

4.5 References

1. LER 315/98-041, "Component Cooling Water Pump Surveillance Testing Has Potential to Cause Unplanned Entry Into TS 3.0.3," October 2, 1998.

2. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination, Revision 1*, October 1995.

6.0 LER No. 315/98-004

Event Description: Restricted Ice Condenser Flow Passages

Date of Event: January 22, 1998

Plant: D.C. Cook, Unit 1

6.1 Summary of Issue

LER 315/98-004 (Ref. 1) reported that one of the ice condenser passages contained a large amount of frost and ice. Subsequent inspections of the ice condensers revealed that there were restricted flow passages in many radial rows adjacent to the containment wall. The Ice Condenser absorbs thermal energy released during a break inside containment to limit the containment pressure, and consists of 1944 ice baskets each filled with a required minimum of 1333 pounds of borated ice (over 2,500,000 lbs). Therefore, any condition that obstructs passage of steam through ice has the potential to affect the peak containment pressure reached after an accident. If the peak containment pressure exceeds the failure pressure, the containment will fail leading to the failure of the sump recirculation function due to loss of inventory through the breach.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting ice condenser performance and sump recirculation capability.

6.2 Modeling and Affected Sequences

Any accident that releases energy to containment relies on the ice condenser to keep the peak containment pressure below the design value. The following accidents release energy to the containment: a) loss-of-coolant accident (LOCA) of any size, b) main steam line break (MSLB) inside containment, and c) any accident condition which relies on the feed-and-bleed capability. Of these accidents, only LOCAs and feed-and-bleed sequences resulting from MSLBs are considered since other systems or actions required to mitigate MSLBs (isolation of the break and cool down with unfaulted loops) are unaffected by loss of containment integrity. Sump recirculation capability will be affected since a breached containment reduces NPSH available for the residual heat removel pumps and allows water to bypass the recirculation sump.

Therefore, the sequence of interest is as follows:

- Any size LOCA occurs, or feed-and-bleed scenario occurs; and
- Sump recirculation failure due to peak pressure exceeding containment failure pressure due to restricted flow passages leading to inadequate inventory for sump recirculation.

6.3 Frequencies, Probabilities, and Assumptions

At the Cook plant, the containment pressure is controlled by two systems. In the short-term, the ice condenser removes heat from the containment atmosphere by condensing steam. In the long-term, the containment spray system, which is equipped with a heat exchanger, recirculates water from the containment recirculation sump and removes heat from the containment. That is, the ice condenser is not relied upon for long-term pressure control in the containment.

If the "as found" condition is adequate to keep the peak pressure below 12 psig during a design basis LOCA, then it is assumed that the peak pressure will be below 12 psig for all other LOCAs. This is justifiable since the maximum heat addition rate to the containment in the short-term results from the large break LOCAs. Therefore, there is no increase in the containment failure probability that would in turn increase the sump recirculation failure probability. However, a number of other issues that can potentially affect ice condenser performance and sump recirculation must be resolved in order to assess the overall change to the sump recirculation failure probability.

6.4 Core Damage Frequency Calculation or the Bounding Calculation

The licensee performed an analysis (Ref. 1) to determine the peak containment pressure for a design basis LOCA for the "as found" condition. A 100% inspection of the ice condenser blockage was performed and the results of the inspection were analyzed by Westinghouse. The blockages ranged from 6.7% to 18.8% per bay. Using a "lumping" method, Westinghouse calculated the percent blockage of the ice condenser to be 12.5%. Westinghouse also determined that the ice condenser is operable (peak pressure does not exceed design limit of 12 psig) if the percent blockage is less than 15%. That is, in the "as-found" condition, the peak pressure would have remained below the design pressure of 12 psig. Further, based on reference 2, the failure pressure of the containment is much greater than the design pressure of 12 psig. Reference 2 reports that the high condition low probability failure limit for the containment is 36 psig. That is, there is 95% confidence that at 36 psig the probability of containment failure is less than 5%.

In light of this information, the probability of peak pressure exceeding the containment failure pressure leading to sump recirculation failure due to this condition alone is zero. Therefore, the core damage frequency change associated with the affected sequences is zero. However, a number of other issues that can potentially affect ice condenser performance and sump recirculation must be resolved in order to assess the overall change to this core damage sequence frequency.

6.5 References

1. LER 315/98-004, Rev. 2, "Inadequate Maintenance and Surveillance Practices Result in Restricted Ice Condenser Flow Passages," event date January 22, 1998.

2. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

8.0 LER No. 315/98-007

Event Description: Ice Condenser Weights Do Not Comply With Technical Specifications

Date of Event: February 11, 1998

Plant: D.C. Cook, Unit 1

8.1 Summary of Issue

LER 98-007 (Ref. 1) reported that the Technical Specification required ice basket weights were not being adequately maintained. The Ice Condenser absorbs thermal energy released during a break inside containment to limit the containment pressure, and consists of 1944 ice baskets each filled with a required minimum of 1333 pounds of borated ice (over 2,500,000 lbs). Therefore, any condition that reduces the amount of ice in the ice condenser has the potential to affect the peak containment pressure reached after an accident. If the peak containment pressure exceeds the failure pressure, the containment will fail leading to the failure of the sump recirculation function due to loss of inventory through the breach.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting ice condenser performance and sump recirculation capability.

8.2 Modeling and Affected Sequences

Any accident that releases energy to containment relies on the ice containment to keep the peak containment pressure below the design value. The following accidents release energy to the containment: a) loss-of-coolant accident (LOCA) of any size, b) main steam line break (MSLB) inside containment, and c) any accident condition which relies on the feed-and-bleed capability. Of these accidents, only LOCAs and feed-and-bleed sequences resulting from MSLB are considered since other systems or actions required to mitigate MSLB (isolation of the break and cool down with unfaulted loops) are unaffected by loss of containment integrity. Sump recirculation capability will also be affected since a breached containment reduces NPSH available for the residual heat removal pumps and allows water to bypass the recirculation sump.

Therefore, the sequence of interest is as follows:

- Any size LOCA occurs, or feed-and-bleed scenario occurs; and
- Sump recirculation failure due to peak pressure exceeding containment failure pressure due to inadequate ice inventory leading to inadequate inventory for sump.

8.3 Frequencies, Probabilities, and Assumptions

At Cook plant, the containment pressure is controlled by two systems. In the short-term, ice condenser removes heat from the containment atmosphere by condensing steam. In the long-term, and the containment spray system which is equipped with a heat exchanger recirculates water from the containment recirculation sump and removes heat from the containment. That is, ice condenser is not relied upon for long-term pressure control in the containment.

If the "as found" ice weight of the ice condenser is adequate to keep the peak pressure below 12 psig design basis LOCA, then it is assumed that the weight of ice is sufficient to keep the peak pressure below 12 psig for all other LOCAs. This is justifiable since the maximum heat addition rate to the containment in the short-term result from the large break LOCAs. Therefore, there is no increase in the containment failure probability that would in turn increase the sump recirculation failure probability. However, a number of other issues that can potentially affect ice condenser performance and sump recirculation must be resolved in order to assess the overall change to the sump recirculation failure probability.

8.4 Core Damage Frequency Calculation or the Bounding Calculation

The licensee performed an analysis (Ref. 1) to determine the peak containment for a design basis LOCA for the "as found" condition. This analysis concluded that the peak pressure would have remained below the design pressure of 12 psig. Further, based on reference 2, the failure pressure of the containment is much greater than the design pressure of 12 psig. Reference 2 reports that the high condition low probability failure limit for the containment is 36 psig. That is, there is 95% confidence that at 36 psig the probability containment failure is less than 5%. In light of this information, the probability of peak pressure exceeding the containment failure pressure leading to sump recirculation failure due to this condition alone is zero. Therefore, the core damage frequency change associated with the affected sequences is zero. However, a number of other issues that can potentially affect ice condenser performance and sump recirculation must be resolved in order to assess the overall change to this core damage sequence frequency.

8.5 References

1. LER 316/98-007, Rev. 1, "Interim LER-Ice condenser weights used to determine TS compliance not representative," December 7, 1998.

2. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination, Revision 1*, October 1995.

12.0 LER No. 315/98-040

Event Description: Engineered Safety Feature Actuation, Start and Load of One Emergency Diesel Generator in Units 1 and 2 Due to Faulted Underground Cable

Date of Event: August 31, 1998

Plant: D. C. Cook, Units 1 and 2

12.1 Summary of Issue

The LER 315/98-001 (Ref. 1) reported that in August 1998 with Units 1 and 2 in cold shutdown, one train of "preferred" offsite power source was lost to both units due to the failure of a station service transformer. The failed 500 KVA transformer caused a fault on the feed to the "CD" reserve auxiliary transformer in each unit. (One reserve auxiliary transformer supplies plant loads to one 4 kV safety through a 4 kV non-safety bus during startup and shutdown operations. Each unit has two reserve auxiliary transformers.) The protective relaying tripped the breaker to the "CD" reserve auxiliary transformers in Units 1 and 2. One emergency diesel generator in both units started and pickup load. The root cause of this event was the failure of a 12kV underground cable due to age degradation. The cable fault resulted in the catastrophic failure of the station service transformer. Even though the event occurred during cold shutdown conditions while decay heat levels were extremely low, the degraded cable could have resulted in the partial loss of offsite power while at power.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting the conditional likelihood core damage given that the degraded condition (degraded underground cable) exists.

12.2 Modeling and Affected Sequences

The safety significance of this event was evaluated for Unit 1 considering the failure of the offsite power supply to one 4 kV safety bus following a reactor trip. The limiting event sequence of interest assumes that a reactor trip initiates a latent fault in the switchyard (e.g., catastrophic failure of the station service transformer) which causes the loss of the reserve auxiliary transformer to one 4 kV safety bus train. It is assumed that offsite power to the bus can not be restored. The sequence of interest is

- A latent switchyard fault condition exists which would cause the loss of offsite power source to one 4 kV safety bus upon a reactor trip;
- The change in core damage frequency given that the condition exists that results in the loss of offsite power to one 4 kV safety bus train upon a reactor trip; and

- The failure to recover offsite power from the alternate offsite power source.

This issue is similar to issue no. 13 where offsite power to both 4 kV safety bus trains may be lost subsequent to a reactor trip.

12.3 Frequencies, Probabilities, and Assumptions

- A latent switchyard fault condition exists which would cause the loss of offsite power source to one 4 kV safety bus upon a reactor trip – For conservatism, a latent service transformer fault is assumed to occur when the safety and non-safety bus loads are automatically transferred from the "normal auxiliary" source (main turbine generator) to the preferred offsite power source upon a reactor trip. The fault trips one reserve auxiliary transformer and the automatic start and load of one emergency diesel generator. For conservatism, it was assumed that power to the reserve auxiliary transformer is non-recoverable. Therefore, the probability of occurrence is assumed to be 1.0.

- The change in core damage frequency given that the condition exists that results in the loss of offsite power to one 4 kV safety bus train upon a reactor trip – The Cook standardized plant analysis risk (SPAR) model[1] estimates the change in conditional core damage frequency given that the condition exists for a post-trip loss of offsite power to one 4 kV safety bus train to be 6.7×10^{-6}/year. However, there are number of other issues that can potentially affect the likelihood of core damage given the above condition exists. These must be resolved in order to assess this conditional core damage frequency.

  This core damage probability does not credit the plant specific design feature of the alternate offsite power source. That alternate source is credited as explained below.

- Failure to recover offsite power from the alternate offsite power source – The updated final safety analysis report (Ref. 2, Section 8.3.1) describes an "alternate" offsite power source which is independent to the unit switchyard. The alternate offsite transmission line terminates at two transformers (one can be used as a backup), in which one transformer is connected to all 4 kV safety buses in both units. The transformer is sized to provide necessary capacity to operate the engineered safeguards equipment in one unit while supplying safe shutdown power in the other. The results of the human failure analysis in the D. C. Cook individual plant examination (Ref. 3, Table 3.3-3) shows

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[1] The analysis includes a wide range of reactor trip initiators (e.g., steam generator tube rupture, small loss-of-coolant accident, general transient). The quantification of the event trees in the SPAR model assumes offsite power to one train fails after the initiating event. Typically, SPAR model assumes that offsite power is available after the reactor trip initiator (except for the loss of offsite power initiator.) For this quantification, it was assumed that offsite power was unavailable to one of the two safety related buses subsequent to a reactor trip..

the probability of human failure to recover power from the alternate offsite power source is 2.6×10^{-2}.

12.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depend on the resolution of other issues affecting the likelihood of core damage given that a degraded condition (potential failure of aged underground cable) exists. To provide perspective on these sequences the following information is provided.

If the resolution of other issues results in no significant changes to the core damage frequency given that a degraded condition (potential failure of aged underground cable) exists, the change to the core damage frequency would be:

(Probability of the latent switchyard fault condition exists: 1.0) x
(Change in conditional core damage frequency given the condition that fails the offsite power supply to one safety bus train: 6.7×10^{-6}/year) x
(failure to recover power from the alternate offsite power source: 2.6×10^{-2}) = 1.7×10^{-7}/year.

Therefore, the change to the core damage frequency would not be risk significant.

12.5 References

1. LER 315/98-040, Rev. 0, "ESF Actuation and Start of Emergency Diesel Generators 1 CD and 2 CD Due to Faulted Underground Cable," September 30, 1998.

2. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

3. *Cook Nuclear Plant Individual Plant Examination*, Revision 1, October 1995.

13.0 LER No. 315/98-044

Event Description: Offsite Power Testing Not Performed in Accordance With Technical Specifications

Date of Event: October 1, 1998

Plant: D. C. Cook, Units 1 and 2

13.1 Summary of Issue

According to LER 315/98-044 (Ref. 1), in October 1998, during a review of technical specification (TS) surveillance requirements for the offsite electrical power sources, it was discovered that the availability of the preferred offsite power source was not being verified in accordance with TS. Specifically, the surveillance procedure did not require verification of breaker alignment and voltage reading for the preferred offsite power source. This power source is used during startup and shutdown to supply offsite power to safety and non-safety buses. The TS requires that each of the circuits between the offsite electrical power sources, preferred and alternate offsite power sources, and the onsite 4 kV electrical distribution system be determined operable at least once per 7 days by verifying correct breaker alignments and indicated power availability. Since the availability of the preferred offsite power source up to the reserve auxiliary transformers is verified during shift turnover (via control room panel walkdowns), the risk-importance of the procedure deficiency from 1992 to the present would be limited to the possibility of a feeder breaker to the safety and non-safety buses not in the proper alignment for fast transfer to the preferred offsite power source upon a reactor trip.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting the conditional likelihood core damage given that the degraded condition (preferred offsite power supply to both 4kV buses potentially failed) exists.

13.2 Modeling and Affected Sequences

The safety significance of this event was evaluated for Unit 1 considering the failure of the preferred offsite power supply to both 4 kV safety bus trains following a reactor trip. All feeder breakers that supply power to the 4 kV safety buses (through the non-safety buses) from the preferred offsite power source (via the reserve auxiliary transformers) are assumed not to be in the proper alignment for fast closure upon a reactor trip. The sequence of interest is

- All feeder breakers from the preferred offsite power source not in proper alignment;
- The change in conditional core damage frequency given that the condition exists that results in the loss of offsite power upon a reactor trip; and

- The failure to recover offsite power from the alternate offsite power source.

This issue is similar to issue no. 12 where offsite power to only one 4 kV safety bus train is lost.

13.3 Frequencies, Probabilities, and Assumptions

- All feeder breakers from the preferred offsite power source not in proper alignment – Each Cook unit has four 4 kV safety buses (2 buses per train) and four 4 kV non-safety buses. Each 4 kV non-safety bus feeds one 4 kV safety bus. An emergency diesel generator provides emergency power to a pair of 4 kV safety buses (i.e., one train). Upon a reactor trip, the 4 kV non-safety buses automatically transfer from their normal auxiliary source (main generator) to the preferred offsite power source through two reserve auxiliary transformers (per unit). At least one feeder breaker from each transformers is assumed to be unavailable for fast closure upon a reactor trip. This failure could be due to a random failure of the circuit breaker or due to the breaker being left in the test mode after an unscheduled maintenance during power operations. Although maintenance on one or more feeder breakers during power operations is unlikely, for conservatism, it is assumed that two critical breakers were left in the unavailable state after unscheduled maintenance. Based on Swain and Guttman (Ref. 2, Table 20-7), the probability of an error of omission involving the failure to perform a procedure step (to restore the feeder breaker from the test or racked out position to operable status) is 1.0×10^{-2}. It was pessimistically assumed that the breaker failure was non-recoverable. Therefore, the probability of a loss of preferred offsite power due to a common mode failure two or more feeder breakers to transfer upon a reactor trip is 1.0×10^{-2}.

- The change in conditional core damage frequency given that the condition exists that results in the loss of offsite power upon a reactor trip – The Cook standardized plant analysis risk (SPAR) model[1] estimates the change in conditional core damage frequency given that the condition exists for a post-trip loss of offsite power to both 4 kV safety bus trains to be 1.3×10^{-5}/year. However, there are number of other issues that can potentially affect the likelihood of core damage given the above condition exists. These must be resolved in order to assess this conditional core damage frequency.

  This core damage probability does not credit the plant specific design feature of the alternate offsite power source. That alternate source is credited as explained below.

- Failure to recover offsite power from alternate offsite power source – The updated final safety analysis report (Ref. 3, Section 8.3.1) describes an "alternate" offsite power source which is

[1] The analysis includes a wide range of reactor trip initiators (e.g., steam generator tube rupture, small loss-of-coolant accident, general transient). The quantification of the event trees in the SPAR model assumes offsite power to both trains fails after the initiating event. Typically, normal cases assumes that offsite power is available after the reactor trip initiator (except for the loss of offsite power initiator.)

independent to the unit switchyard. The alternate offsite transmission line terminates at two transformers (one can be used as a backup), in which one transformer is connected to all 4 kV safety buses in both units. The transformer is sized to provide necessary capacity to operate the engineered safeguards equipment in one unit while supplying safe shutdown power in the other. The results of the human failure analysis in the D. C. Cook individual plant examination (Ref. 4, Table 3.3-3) shows the probability of human failure to recover power from the alternate offsite power source is 2.6×10^{-2}.

13.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting the likelihood of core damage given that a degraded condition (preferred offsite power supply to both 4kV buses potentially failed) exists. To provide perspective on these sequences the following information is provided.

If the resolution of other issues results in no significant changes to the core damage frequency given that a degraded condition (preferred offsite power supply to both 4kV buses potentially failed) exists, the change to the core damage frequency would be:

(Probability of misaligned feeder breakers : 1.0×10^{-2}) x
(Change in conditional core damage frequency given that the condition exists: 1.3×10^{-5}/year) x
(Failure to recover power from the alternate offsite power source: 2.6×10^{-2}) = 3.4×10^{-9}/year.

Therefore, the change to the core damage frequency would not be risk significant.

13.5 References

1. LER 315/98-044, Rev. 0, "Offsite Power Availability Not Verified as Required by Technical Specification Surveillance," November 2, 1998.

2. A.D. Swain, and H.E. Guttman, *Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications*, NUREG/CR-1278, August 1983.

3. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

4. *Cook Nuclear Plant Individual Plant Examination*, Revision 1, October 1995.

14.0 LER No. 315/98-018

Event Description: Use of Reactor Coolant Pump Seals as an Alternate Boron Injection Path Potentially Results in an Unanalyzed Condition

Date of Event: May 5, 1998

Plant: D. C. Cook, Units 1 and 2

14.1 Summary of Issue

The LER 315/98-018 (Ref. 1) reported a potential problem involving the use of the reactor coolant pump (RCP) seals as an alternate emergency boration flow path. This path utilizes the boric acid storage tank (BAST) as the injection source. The BAST is maintained at a temperature above the vendor's recommended maximum RCP seal water injection temperature. Operation of the alternate emergency boration flow path utilizing boric acid from the BAST at the high end of its possible temperature range could result in damage to the RCP seals, which in turn, could result in seal leak-off flow rates beyond the seal injection capabilities.

The change in core damage frequency associated with this event is less than 1 x 10^{-6}/year making this event non-risk significant.

14.2 Modeling and Affected Sequences

The safety significance of this condition was evaluated for Unit 1 considering the failure of the normal charging flow path to the reactor coolant system and the use of the RCP seal injection lines as the only emergency boration flow path. The initiating event of interest is an anticipated transient without scram (ATWS). In order for a RCP seal to fail due to the high temperature boric acid from the BAST, the initiation of emergency boration must be successful initially.

- Any initiating event that require a reactor trip occurs;
- The reactor protection system fails to trip (automatic and manual initiation);
- The primary path for emergency boration fails after successful emergency boration initiation;
- The alternate path for emergency boration successful (via RCP seal injection);
- RPS seals fail due to high temperature (compared to design) of BAST water; and
- Core damage occurs given an ATWS and catastrophic RCP seal failure.

14.3 Frequencies, Probabilities, and Assumptions

- Any initiating event that require a reactor trip occurs – *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995* (Ref. 2) indicates that the average industry frequency of any event that requires a reactor trip from all causes is 1.4 trips per critical year. When adjusted by the average criticality factor of 0.79 for Cook Unit 1 (Ref. 2, Table H-3) the initiating event frequency is 1.1 per reactor calendar year (1.4 x 0.79).

- The reactor protection system fails to trip (automatic and manual initiation) – *Reliability Study: Westinghouse Reactor Protection System, 1984-1995* (Ref. 5) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}.

- The primary path for emergency boration fails after successful emergency boration initiation – Since the emergency boration has been successfully initiated the operator error to initiate boration is not included in this probability. The primary path for emergency boration is the normal charging injection line, which starts at the point where the discharge line from the charging pumps branches to the RCP seal injection line (see Ref. 3, Figure 9.2-1 included as figure 1). This piping segment between the branch point and the regenerative heat exchanger consist of a series of two motor-operated valves, one air-operated valve and three manual valves. After the heat exchanger, the charging line splits into two redundant lines that connects to the reactor coolant system hot leg piping. Each redundant injection line has one air-operated valve. These air-operated valves fail open upon the loss of control air, whereas, the air-operated valve upstream of the heat exchanger fails closed. The latter valve, therefore, requires control air to continue to supply flow. Since the probability of a valve spuriously closing is around the order of 1×10^{-7} per hour (Ref. 4, Table 3.3-1), the failure of the control air system to the flow control valve upstream of the heat exchanger dominates the failure probability of the primary emergency boration path. From the D. C. Cook individual plant examination (Ref. 4, Table 3.3-5), the probability that the compressed air system fails during a 24 hour mission time is 6.2×10^{-4}. Therefore, the probability that the primary path for emergency boration fails (normal charging path) within 24 hours after an ATWS initiator is 6.2×10^{-4}.

- The alternate path for emergency boration successful (via RCP seal injection) - The probability of this success path was assumed to be 1.0.

- RPS seals fail due to high temperature (compared to design) of BAST water - The probability of this failure was pessimistically assumed to be 1.0.

- Core damage occurs given an ATWS and catastrophic RCP seal failure – The probability of this failure was pessimistically assumed to be 1.0.

14.4 Core Damage Frequency Calculation or the Bounding Calculation

Known frequencies yield an initial bounding value as follows:

(Frequency of an initiating event: 1.1/year) x
(Probability of RPS failure: 5.5×10^{-6}) x
(Probability of the primary emergency boration path failure: 6.2×10^{-4}) x
(Probability of alternate path for emergency boration successful: 1.0) x
(Probability of a catastrophic RPS seal failure: 1.0) x
(Probability of core damage given an ATWS and catastrophic RCP seal failure: 1.0) = 3.8×10^{-9}/year.

This sequence of events is well below the ASP acceptance criteria of 1.0×10^{-6}.

14.5 References

1. LER 315/98-018, Rev. 2, "Use of Reactor Coolant Pump Seals as Alternate Boron Injection Flow Path Potentially Results in Unanalyzed Condition," August 31, 1998.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

4. *Cook Nuclear Plant Individual Plant Examination*, Revision 1, October 1995.

5. S.A. Eide, et. al., *Reliability Study: Westinghouse Reactor Protection System,: 1984-1995*, NUREG/CR-5500, Vol. 2, April 1999.

FIGURE 1

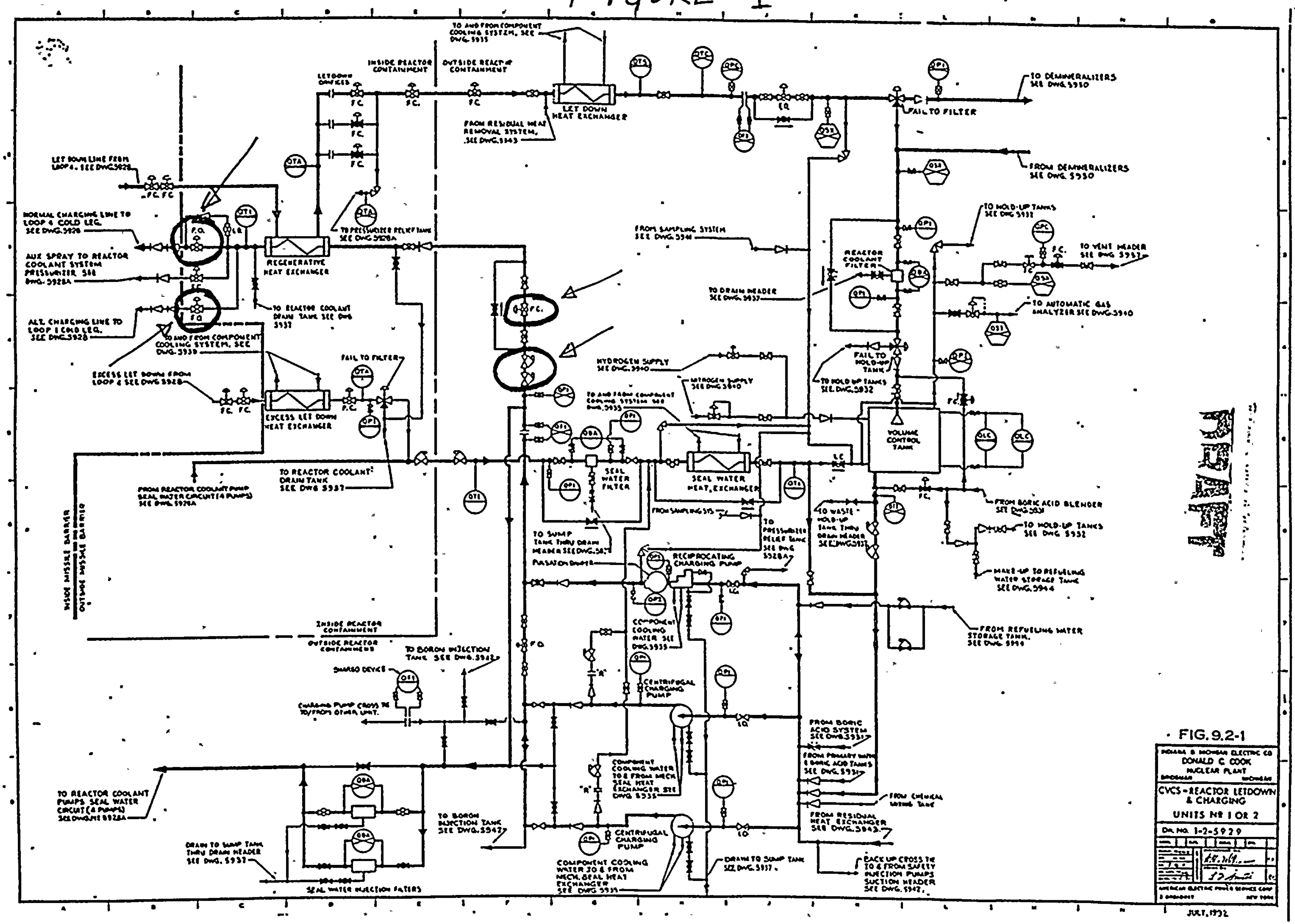

FIG. 9.2-1

JULY, 1972

16.0 LER No. 315/97-023

Event Description: Potential Single Failure Could Result in Failure of Both Trains of the Engineered Safety Feature Ventilation System

Date of Event: September 16, 1997

Plant: D.C. Cook, Units 1 and 2

16.1 Summary of Issue

Each engineered safety feature (ESF) ventilation train consists of an inlet damper and a bypass damper. The inlet damper is normally closed and the bypass damper is normally open. The control air system[1] supplies control air to the inlet and bypass dampers in both ESF ventilation trains. Prior to a design change that occurred between December 1996 and August 1997, the controllers for the inlet and bypass dampers in each train were all supplied from a common 20 psig air supply header (Ref. 1). Upon the loss of control air supply to these dampers, inlet dampers will fail open and bypass dampers will fail closed. This configuration allows for single failure protection against the loss of the common air supply header by having one damper in each train fail in the open position. The design change swapped the air supply to the bypass dampers from the 20 psig header to the 85 psig header. If a failure localized to the 85 psig air supply header occurs, the bypass damper will fail closed. Since the 20 psig air header is available, the inlet dampers will remain closed. As a result, both trains of the ESF ventilation will be lost. this condition applies to both units.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW), emergency core cooling system (ECCS) injection, and sump recirculation capabilities.

16.2 Modeling and Affected Sequences

The ESF ventilation trains cool the rooms that contain ECCS equipment. Failure to supply air to the ESF rooms could lead to overheating of ECCS equipment and their failure. Since ECCS equipment is needed to mitigate LOCAs of any size or to establish feed and bleed cooling, these accidents are affected by the design change. If the 85 psig air header is lost prior to an event, it will annunciate itself by the numerous indications in the control room. Therefore, only a failure that occurs subsequent to or immediately prior to a LOCA or a feed and bleed situation is of concern. The accident sequence of interest is:

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[1] The station control air system is supplied from the compressors at 100 psig and reduced in each unit to provide air to three additional headers with pressures of 20 psig, 50 psig, and 85 psig. These three headers are independent and they are provided with separate sets of regulators and isolation valves.

- Any size LOCA occurs, or feed-and-bleed scenario occurs;
- Failure of ECCS equipment to inject or perform sump recirculation as a result of room overheating caused by ESF room ventilation failure; and
- Failure to recover room ventilation by opening doors or by other recovery actions.

16.3 Frequencies, Probabilities, and Assumptions

- Any size LOCA occurs, or feed-and-bleed cooling scenario occurs - Using the frequencies associated with large pipe break (5×10^{-6}), medium pipe break (4×10^{-5}), small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a LOCA of any size is approximately 9×10^{-3}/critical year (Ref. 2, Table 3-1).

  The frequency of a feed-and-bleed scenario occurring is estimated as follows. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the frequency of a loss of offsite power is 0.046/critical year; the frequency of a total loss of feedwater flow is 0.085/critical year; and the frequency of a total loss of condenser heat sink events (power conversion system) is 0.12/critical year. This adds up to a total frequency of 0.25/critical year. For Cook Unit 1, the criticality factor is 0.79 critical year/reactor calendar year (Ref. 2, Table H-3). Therefore, the frequency of a reactor trip with a loss of feedwater, offsite power, or the power conversion system is about 0.2/year (0.79 x 0.25). From the Cook standardized plant analysis risk (SPAR) model, the failure probability of the AFW system is 1.1×10^{-4}. Therefore, the frequency of feed-and-bleed events requiring recirculation is 1.1×10^{-4} times 0.2, or about 2×10^{-5}. This frequency is negligible compared to the LOCA events frequency. Therefore, the total frequency of events requiring sump recirculation is about 9×10^{-3}/critical year or 7.1×10^{-3}/year ($0.79 \times 9 \times 10^{-3}$). However, a number of issues that can potentially affect the AFW failure probability must be resolved in order to assess this the frequency.

- Failure of ECCS equipment to inject or perform sump recirculation as a result of room overheating caused by ESF room ventilation failure - Since the 85 psig header is lost while the 20 psig header remains functional, the credible faults that cause the loss of the 85 psig header are:

  - Instrument air line failure downstream of the pressure regulator of the 85 psig header; or
  - The 85 psig header pressure regulator failure.

  Instrument air line failure probability is calculated by assuming a length of pipe of less than 1000 feet, a failure rate of 1×10^{-9}/hour-ft (Ref. 3, Table 1c), and a mission time of 24 hours. This probability is therefore 2.4×10^{-5}. Pressure regulator failure is 3.3×10^{-6}/hour (Ref. 4, page 1038), or, for a 24-hour mission time, 8×10^{-5}. However, a number of other issues that can potentially affect

sump recirculation and injection must be resolved in order to assess the overall change ECCS injection and sump recirculation failure probabilities.

- Failure to recover room ventilation by opening doors or by other recovery actions Pessimistically assumed to be 1.0.

16.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting AFW, ECCS injection and sump recirculation capabilities. To provide perspective on this sequence the following information is provided.

If the resolution of other issues results in no significant changes to the AFW, ECCS injection, and sump recirculation failure probabilities, the change in core damage frequency would be:

(Frequency of any size LOCA: 9.0×10^{-3}/critical year) x
(Criticality factor: 0.79 critical year/reactor calendar year) x
[(Probability of pressure regulator failure: 2.4×10^{-5}) + (Probability of airline rupture: 8×10^{-5})] x
(Probability of failure to recover: 1.0) = 7.4×10^{-7}/year.

Therefore, the change to the core damage frequency would not be risk significant.

16.5 References

1. LER 315/97-023, Rev. 1, "Design Change Introduces Possibility of Single Failure Which Could Result in Loss of Both Trains of ESF Ventilation Due to Failure to Identify Adverse Impact During Design Review," November 14, 1997.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. C. H. Blanton and S. A. Eide, *Savannah River Site, Generic Data Base Development (U)*, WSRC-TR-93-262, June 1993.

4. IEEE Standard 500-1984, *Reliability Data.*

17.0 LER No. 315/97-021

Event Description: Potential Loss of All Medium and High Head Injection Due to a Single Failure

Date of Event: September 10, 1997

Plant: D. C. Cook, Unit 1

17.1 Summary of Issue

During a design inspection conducted at D. C. Cook on August 4 through September 12, 1997, it was discovered that failure of a single residual heat removal (RHR) train, while switching the emergency core cooling system pumps from refueling water storage tank (RWST) suction to recirculation pump suction, could result in failure of all high and medium head injection (Ref. 1). Specifically, it was determined that if the West RHR train fails to continue to run during the brief time period when all high pressure injection (HPI) pumps take suction from its discharge, all HPI pumps would fail.

The D. C. Cook plant has two redundant RHR trains, which are named the West RHR train and the East RHR train. During the transition from the injection phase to the sump recirculation phase, the West RHR train is first aligned to take suction from the containment recirculation sump. After successfully aligning the West RHR pump, all HPI pumps are aligned to take suction from the West RHR pump until the East RHR pump suction is successfully aligned to the containment recirculation sump. During this brief period, if the West RHR pump fails, then all HPI pumps will lose their suction source. Unless the operators take action to trip the HPI pumps and recover, sump recirculation function will be lost.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW) and sump recirculation capabilities.

17.2 Modeling and Affected Sequences

During a loss-of-coolant accident (LOCA), the injection systems will inject into the reactor core from the refueling water storage tank (RWST). When the RWST inventory depletes, the injection pumps suction are transferred from the RWST to the containment recirculation sump. Therefore, the single failure discussed above affects all accidents and LOCAs, as well as feed and bleed cooling situations. The sequences of interest are as follows:

- Any size LOCA occurs, or feed-and-bleed scenario occurs;
- Sump recirculation failure due to failure of all HPI pumps as a result of failure of the West RHR pump train; and

- Operators fail to recover and re-establish sump recirculation.

17.3 Frequencies, Probabilities, and Assumptions

- Any size LOCA occurs, or feed-and-bleed cooling scenario occurs - Using the frequencies associated with large pipe break (5×10^{-6}), medium pipe break (4×10^{-5}), small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a LOCA of any size is approximately 9×10^{-3}/critical year (Ref. 2, Table 3-1).

  The frequency of a feed-and-bleed scenario occurring is estimated as follows. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the frequency of a loss of offsite power is 0.046/critical year; the frequency of a total loss of feedwater flow is 0.085/critical year; and the frequency of a total loss of condenser heat sink events (power conversion system) is 0.12/critical year. This adds up to a total frequency of 0.25/critical year. For Cook Unit 1, the criticality factor is 0.79 critical year/reactor calendar year (Ref. 2, Table H-3). Therefore, the frequency of a reactor trip with a loss of feedwater, offsite power, or the power conversion system is about 0.2/year (0.79 x 0.25). From the Cook standardized plant analysis risk (SPAR) model, the failure probability of the AFW system is 1.1×10^{-4}. Therefore, the frequency of feed-and-bleed events requiring recirculation is 1.1×10^{-4} times 0.2, or about 2×10^{-5}. This frequency is negligible compared to the LOCA events frequency. Therefore, the total frequency of events requiring sump recirculation is about 9×10^{-3}/critical year or 7.1×10^{-3}/year ($0.79 \times 9 \times 10^{-3}$). However, a number of issues that can potentially affect the AFW failure probability must be resolved in order to assess this the frequency.

- Sump recirculation failure due to failure of all HPI pumps as a result of failure of the West RHR pump train - During the transition to sump recirculation, the operators align the systems so that all HPI pumps take suction from the West RHR train for a brief period. When the alignment is performed, the West RHR train has successfully started. Therefore, only inadvertent closure of a motor-operated valve, a check valve failing to remain open, or the RHR pump failing to continue to run can cause the West RHR train to fail. Of these failures, the RHR pump failing to continue to run dominates the failure probability. Based on the D. C. Cook Individual Plant Examination (IPE), Revision 1 (Ref. 3), the failure rate for an RHR pump to continue to run is 7.2×10^{-5}/hr. The IPE also states that the operators have 17 minutes to complete all actions to change from injection mode to recirculation mode. Therefore, it is reasonable to assume that a maximum of 15 minutes will be spent in the alignment during which the West RHR pumps will feed all HPI trains. Therefore, the pump train failure probability during this time interval is estimated to be 1.8×10^{-5} (0.25 hour $\times 7.2 \times 10^{-5}$/hour). However, a number of other issues that can potentially affect the sump recirculation must be resolved in order to assess the overall increase in sump recirculation failure probability.

- Operators fail to recover and re-establish sump recirculation - If the west RHR pump train fails while it feeds all HPI pumps, the operator may be able to trip the HPI pumps before they incur damage and re-establish the sump recirculation. It is pessimistically assumed that this failure probability is 1.0.

17.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting the AFW and sump recirculation capabilities. To provide perspective on this sequence the following information is provided.

If the resolution of other issues results in no significant changes to the AFW and sump recirculation failure probabilities, the change in core damage frequency would be:

(Frequency of any size LOCA: 9.0×10^{-3}/critical year) x
(Criticality factor: 0.79 critical year/reactor calendar year) x
(Probability of sump recirculation failure: 1.8×10^{-5}) x
(Probability of failure to recover: 1.0) = 1.3×10^{-7}/year.

Therefore, the change to the core damage frequency would not be risk significant.

17.5 References

1. LER 315/97-021, Rev. 1, "Potential Loss of All Medium and High Head Injection Due to Single Failure Could Result in a Condition That Would Prevent the Fulfillment of the Safety Function of a System," November 14, 1997.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

18.0 NRC Inspection Report No. 50-315, 316/97-201, Finding E1.5.2A(1)

Event Description: Change to Operating Procedure "Transfer to Sump Recirculation" Without a Proper Safety Evaluation

Date of Event: August 1997

Plant: D. C. Cook, Unit 1

18.1 Summary of Issue

The issue is that the licensee made temporary, "non-intent" changes to procedure OHP 023.4023.ES-1.3, "Transfer to Cold Leg Recirculation," without performing a proper safety evaluation (Ref. 1). Part 50.59 of the code of federal regulations requires proper safety evaluations when making changes to safety parameters to ensure a comprehensive examination of the changes to the accident analyses and also to determine whether the changes exceed thresholds that would require regulatory attention. The above change relates to critical safety parameters that could have had a negative impact on plant safety.

The procedure was revised to raise the containment water level action setpoint from 15% to 29%. Operators use this setpoint to decide whether there is enough water in the containment recirculation sump to start transitioning to sump recirculation from the injection phase. As a result of this change, if the containment water level reached a value between 15% (elevation 601'6") and 32% (elevation 602'10"), when the RWST low level alarm is received instructing the operators to start transitioning to sump recirculation, they will not do so. This leads to a delay in starting and also completing the actions that must be taken to establish sump recirculation. Delaying the completion of transfer to sump recirculation increases the probability of RHR pump failure due to vortexing in the RWST. That is, while the change may reduce the possibility of vortexing in the containment recirculation sump, it will increase the likelihood of vortexing in the RWST.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW) capability and sump recirculation capability (by affecting the vortexing potential in the RWST).

18.2 Modeling and Affected Sequences

The emergency operating procedure ES 1.3 "Transfer to Sump Recirculation" instructs the operator to transition from the injection phase to the sump recirculation phase. Therefore, any changes to this procedure have the potential to affect LOCAs of any size or feed and bleed scenarios. Vortexing in the RWST due to the delay in starting and completing the transfer to sump recirculation is most likely when the RHR pumps are injecting, since the large flows from RHR minimize the time available to establish recirculation. However, we pessimistically assume that vortexing can occur for small LOCAs and feed and bleed cooling situations as well. Therefore, the following three sequences may be affected:

Sequence 1- Large LOCA:

- Large LOCA; and
- Sump recirculation fails due to vortexing in RWST leading to failure of RHR pumps.

Sequence 2- Medium LOCA

- Medium LOCA; and
- Sump recirculation fails due to vortexing in RWST leading to failure of high pressure injection pumps.

Sequence 3 - Small LOCA or feed and bleed cooling situation

- Small LOCA occurs, or feed-and-bleed cooling scenario occurs; and
- Sump recirculation fails due to vortexing in RWST leading to failure of high pressure injection pumps.

18.3 Frequencies, Probabilities, and Assumptions

Sequence 1- Large LOCA:

- Large LOCA - Based on reference 2, the frequency of a large LOCA is 5×10^{-6}/critical year.
- Sump recirculation fails due to vortexing in RWST leading to failure of RHR pumps - The operators start establishing sump recirculation when the RWST low level alarm occurs at 32% of RWST level. At this point, 68% of the RWST inventory (over 200,000 gallons) will be available to the containment recirculation sump. Figure 1 shows that only 117,000 gallons are needed to fill the containment sump up to the 29% level (equals to elevation 602'10"). In addition to approximately 200,000 gallons of water from the RWST, the following additional sources become available to the sump during a large LOCA: (a) approximately 290,000 gallons from ice dissolution (all of the ice dissolves within minutes after a large LOCA (Ref. 3)), (b) water from the RCS break, and (c) water from accumulators. These additional sources compensate for any inventory losses that occur as result of diversion of a fraction of the RWST flow to inactive sumps. Therefore, the probability of having a water level between 601'6" and 602'10" in the recirculation sump at the time of receiving the RWST low level set point alarm due to this condition alone is zero.

Sequence 2- Medium LOCA:

- Medium LOCA - Based on reference 2, the frequency of a medium LOCA is 4 x 10^{-5}/critical year.

- Sump recirculation fails due to vortexing in RWST leading to failure of high pressure injection pumps - The operators start establishing sump recirculation when the RWST low level alarm occurs at 32% of RWST level. At this point, 68% of the RWST inventory (over 200,000 gallons) will be available to the containment recirculation sump. Figure 1 shows that only 117,000 gallons are needed to fill the containment sump up to the 29% level (equals to elevation 602'10"). In addition to approximately 200,000 gallons of water from the RWST, the following additional sources become available to the sump during a medium LOCA: (a) over half of the total ice inventory (290,000 gallons) that dissolve within about 15 minutes after a medium LOCA (assumed to be a 6 inch break) (Ref. 3), (b) water from the RCS break, and (c) water from the accumulators. These additional sources compensate for any inventory losses that occur as result of diversion of a fraction of the RWST flow to inactive sumps. Therefore, the probability of having a water level between 601'6" and 602'10" in the recirculation sump at the time of receiving the RWST low level set point alarm due to this condition alone is zero.

Sequence 3 - Small LOCA or feed and bleed situation:

- Small LOCA occurs, or feed-and-bleed cooling scenario occurs - Using the frequencies associated with small pipe break (5 x 10^{-4}), stuck open power-operated relief valve (1 x 10^{-3}), stuck open code safety valve (5 x 10^{-3}), and reactor coolant pump seal LOCA (2.5 x 10^{-3}), the total frequency of a small LOCA is approximately 9 x 10^{-3}/critical year (Ref. 2, Table 3-1).

  The frequency of a feed-and-bleed scenario occurring is estimated as follows. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the frequency of a loss of offsite power is 0.046/critical year; the frequency of a total loss of feedwater flow is 0.085/critical year; and the frequency of a total loss of condenser heat sink events (power conversion system) is 0.12/critical year. This adds up to a total frequency of 0.25/critical year. For Cook Unit 1, the criticality factor is 0.79 critical year/reactor calendar year (Ref . 2, Table H-3) Therefore, the frequency of a reactor trip with a loss of feedwater, offsite power, or the power conversion system is about 0.2/year (0.79 x 0.25). From the Cook standardized plant analysis risk (SPAR) model, the failure probability of the AFW system is 1.1 x 10^{-4}. Therefore, the frequency of feed-and-bleed events requiring recirculation is 1.1 x 10^{-4} times 0.2, or about 2 x 10^{-5}. This frequency is negligible compared to the LOCA events frequency. Therefore, the total frequency of events requiring sump recirculation is about 9 x 10^{-3}/critical year or 7.1 x 10^{-3}/year (0.79 x 9 x 10^{-3}). However, a number of issues that can potentially affect the AFW failure probability must be resolved in order to assess this the frequency.

- Sump recirculation fails due to vortexing in RWST leading to failure of high pressure injection pumps -The operators start establishing sump recirculation when the RWST low level alarm occurs at 32% of RWST level. At this point, 68% of the RWST inventory (over 200,000 gallons) will be available to the containment recirculation sump. Figure 1 shows that only 117,000 gallons are

needed to fill the containment sump up to the 29% level (equals to elevation 602'10"). In addition to approximately 200,000 gallons of water from the RWST, the following additional sources become available to the sump during a small LOCA or a feed and bleed situation: (a) close to half of the total ice inventory (290,000 gallons) that dissolve within about 30 minutes after a small LOCA, and (b) water from the RCS break. These additional sources compensate for any inventory losses that occur as result of diversion of a fraction of the RWST flow to inactive sumps. Therefore, the probability of having a water level between 601'6" and 602'10" in the recirculation sump at the time of receiving the RWST low level set point alarm due to this condition alone is zero.

However, in all of the above sequences there are number of other issues that can potentially affect sump recirculation by affecting vortexing potential in RWST that must be resolved in order to assess the overall failure probability.

18.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with these sequences depend on the resolution of other issues affecting the AFW and sump recirculation capabilities. To provide perspective on these sequences the following information is provided.

If the resolution of other issues results in no significant changes to the sump recirculation failure probabilities, the probability of sump recirculation function failure due to vortexing in the RWST due to this condition alone is zero. Therefore, the change in core damage frequency is zero for all three sequences.

Therefore, the change to the core damage frequency would not be risk significant.

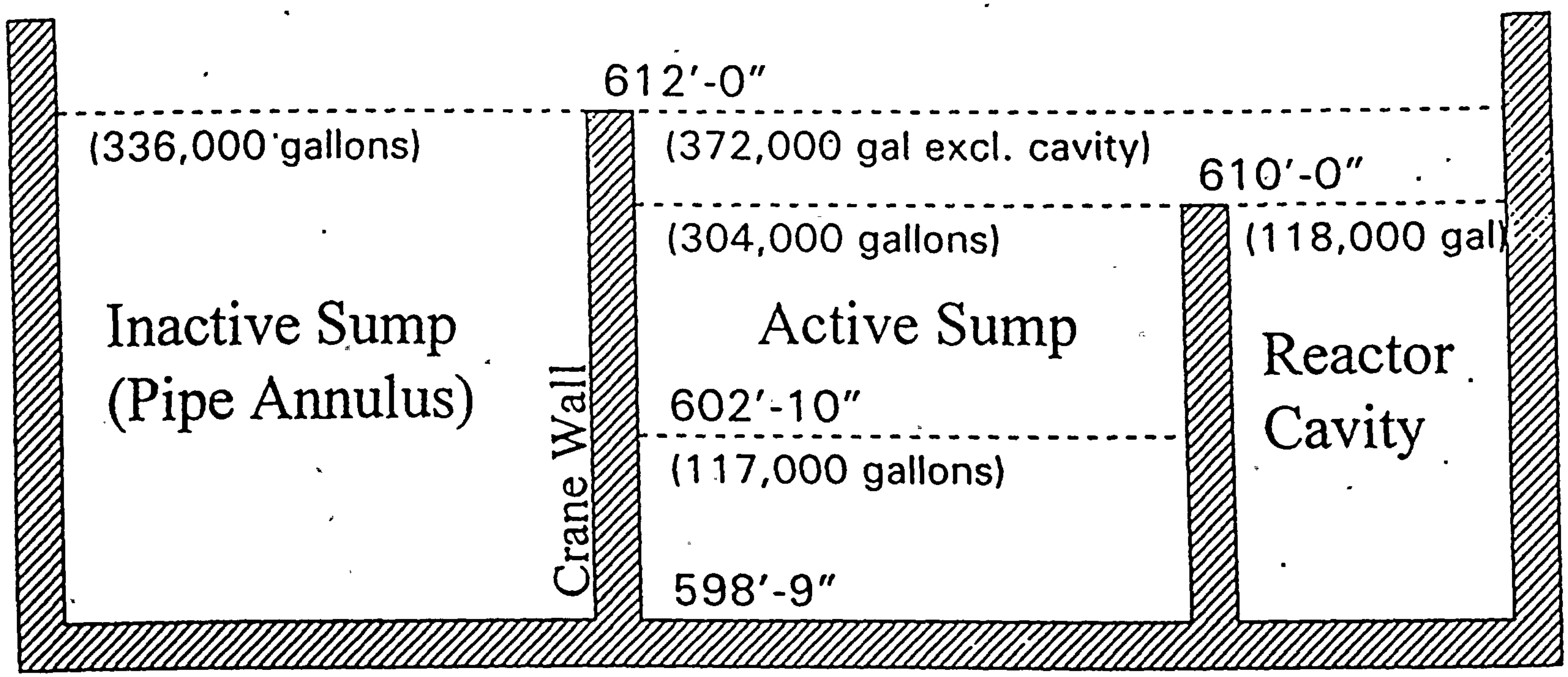
18.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201) November 26, 1998.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. Licensee report on sump inventory calculation, Westinghouse Report # FAI\97-104, Rev 0

Lower Containment Simplified Schematic



DRAFT

Figure 4-2-1 Important levels and volumes for the active and inactive sumps.

22.0 LER No. 315/98-058

Event Description: High Energy Line Break Affects on the Auxiliary Feedwater Instruments

Date of Event: November 16, 1998

Plant: D. C. Cook, Unit 1

22.1 Summary of Issue

According to LER 315/98-058 (Ref. 1), during a design review of the auxiliary feedwater (AFW) system, a request was made to review the high energy line break (HELB) analysis for the AFW pump room complex. The Unit 1 East motor-driven auxiliary feedwater pump (MDAFP), Unit 1 turbine-driven auxiliary feedwater pump (TDAFP), Unit 2 East MDAFP, and Unit 2 TDAFP are located adjacent to each other and share a common hallway. The Unit 1 West MDAFP is located in the turbine building outside of the TDAFP and East MDAFP complex (Ref. 2, Figure O-6). The investigation has revealed that no analysis could be located which evaluated the effects of the HELB on the electrical power cabling in the common hallway. Four valves were identified which may be rendered inoperable following a HELB of the 4 inch steam supply line to either TDAFP turbines. The power cabling to the four valves may not withstand the effects of the harsh steam-air environment. The failure of two valves would isolate the backup AFW supply via the emergency service water (ESW) system to the Unit 1 TDAFP and the East MDAFP. The other two valves are associated with the Unit 2 TDAFP. Therefore, the investigation concluded that this condition could lead to the failure the Unit 1 TDAFP and Unit 1 East MDAFP upon a HELB in the area. This could result in a failure of the Unit 1 AFW system to provide its safety function. (The Unit 2 East MDAFP would not be affected by the postulated HELB.)

The change in core damage frequency (CDF) associated with this issue is dependent upon resolution of the issues affecting West MDAFP train and feed-and-bleed cooling capabilities.

22.2 Modeling and Affected Sequences

The safety significance of this condition was evaluated for Unit 1 considering the loss of the TDAFP and a single MDAFP due to a HELB in a TDAFP room. The HELB causes the loss of TDAFP due to loss of steam supply. One MDAFP becomes unavailable if supply water from ESW is required. ESW supply is necessary if the condensate storage tank (CST) depletes, the makeup water system fails to refill the CST, and the cross-tie from Unit 2 CST fails. However, for conservatism, the MDAFP is assumed to fail due the harsh environmental conditions in the adjacent TDAFP room. The second MDAFP will fail as a result of a random failure.

The CDF sequences associated with earthquakes were not considered since an earthquake of a magnitude to cause a break in the (Category 1) TDAFP steam supply line and one train of the MDAFP will fail the second train of the MDAFP as well. Therefore, the change in CDF would be zero.

The sequence of interest is:

- An HELB to the TDAFP turbine steam supply line located inside the TDAFP room (either unit) occurs;
- A reactor trip with a subsequent loss of main feedwater occurs;
- AFW fails (TDAFP fails due to HELB. The Unit 1 East MDAFP fails due to adverse environmental conditions. The Unit 1 West MDAFP fails due to random failures); and
- Feed-and-bleed cooling fails.

22.3 Frequencies, Probabilities, and Assumptions

- An HELB to the TDAFP turbine steam supply line located inside the TDAFP pump room (either unit) occurs - *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995* (Ref. 3) indicates that the industry average frequency for an HELB anywhere in one unit is 1.3×10^{-2} events per critical year. The length of high pressure steam piping between the two units is approximately 2000 feet of which about 20 feet is located in the area of concern.[1] Since the initiating event can occur on the TDAFP steam supply line in either unit, the initiating event frequency of a HELB to a TDAFP steam supply line in either unit is 2.6×10^{-4}/critical year [(20/2000) x (1.3×10^{-2}) x (2)]. When adjusted by the average criticality factor of 0.79 for Cook Unit 1 (Ref. 3, Table H-3) the initiating event frequency is 2.0×10^{-4}/reactor calendar.year (2.6×10^{-4} x 0.79).

- A reactor trip with a subsequent loss of main feedwater occurs - The probability of an automatic reactor trip occurring may not be very likely unless the HELB is quite large. However, in order to minimize the safety hazard of an HELB, the probability that the operators would manually trip the reactor would be high. The probability of a reactor trip (either manual or automatic) is considered to be 1.0.

  Given a reactor trip due to a HELB, it would be expected that the plant would experience fluctuations in the water level in the steam generators. For conservatism, it was assumed that this would result in loss of main feedwater. Consequently, the probability of a reactor trip with a subsequent loss of main feedwater occurring was assumed to be 1.0 (upper-bound).

[1] The length of high pressure steam piping was provided by the licensee.

- AFW fails (TDAFP fails due to HELB. The Unit 1 East MDAFP fails due to harsh environmental conditions. The Unit 1 West MDAFP fails due to random failures) – Given that a HELB in the steam supply line has occurred to the TDAFP train, the failure probability for this train is 1.0. For conservatism, the East MDAFP is assumed to fail due to the harsh environmental conditions in the pump room. Therefore, the failure probability for this train is 1.0. From the Cook standardized plant analysis risk (SPAR) model, the failure probability of the West MDAFP train is 4.3×10^{-3}. Therefore, the failure probability of the AFW system is 4.3×10^{-3}. However, a number of issues that can potentially affect West MDAFP train must be resolved in order to assess this probability.

- Feed-and-bleed cooling fails - From the Cook SPAR model, the overall failure probability of feed-and-bleed cooling is 2.9×10^{-2}. However, a number of issues that can potentially affect feed-and-bleed cooling must be resolved in order to assess this probability.

22.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequence depends on the resolution of other issues affecting West MDAFP train and feed-and-bleed cooling capabilities. To provide perspective on this sequence the following information is provided.

If the resolution of issues results in no significant changes to the West MDAFP train and feed-and- bleed failure probabilities, the change in core damage frequency would be:

(Frequency of a HELB to a steam supply line in either unit: 2.0×10^{-4}/year) x
(Probability of reactor trip: 1.0) x
(Probability of AFW failure given the failure of the TDAFP and one MDAFP: 4.3×10^{-3}) x
(Probability of feed-and-bleed cooling failure: 2.9×10^{-2}) = 2.5×10^{-8}/year.

Therefore, the change to the core damage frequency would not be risk significant.

22.5 References

1. LER 315/98-058, Rev. 0, "Postulated High Energy Line Break Could Result in Condition Outside Design Bases for Auxiliary Feedwater," December 16, 1998.

2. Donald C. Cook Units 1 and 2 Updated Final Safety Analysis Report.

3. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

29.0 LER No. 315/97-014 and NRC Inspection Report No. 50-315, 316/97-201

Event Description:	Elevated Ultimate Heat Sink Temperature Could Affect Safety-Related Control Room Equipment
Date of Event:	August 1988
Plant:	D.C. Cook, Units 1 and 2

29.1 Summary of Issue

In August, 1997, an NRC architect-engineer (AE) design inspection team questioned the operability of electronic equipment in the control room under postulated high room temperature conditions (Ref. 1). The inspection team noted that during August, 1988, the temperature of the ultimate heat sink (UHS) exceeded the design basis limit of 76°F for 22 days. The average temperature of the UHS for this period was 81°F and the peak temperature recorded was 83.9 (±3.5)°F. Two 100% capable, non-safety related chillers provide normal cooling for the control room. If both normal chillers are lost, the cooling coils are supplied chilled water directly from the UHS (i.e., Lake Michigan). If the normal chillers had been lost with the UHS at 83.9°F, the temperature inside the control room could have reached 113.3°F (Ref. 2). At this temperature, the solid state protection system (SSPS) and the nuclear instrumentation system (NIS) would have a service life of 66 h (Fig. 1). If the normal chillers had been lost with the UHS at 87.4°F (upper-bound temperature with uncertainty), the temperature inside the control room could have reached 118°F. At a control room temperature of 120°F, the SSPS and the NIS were determined to have

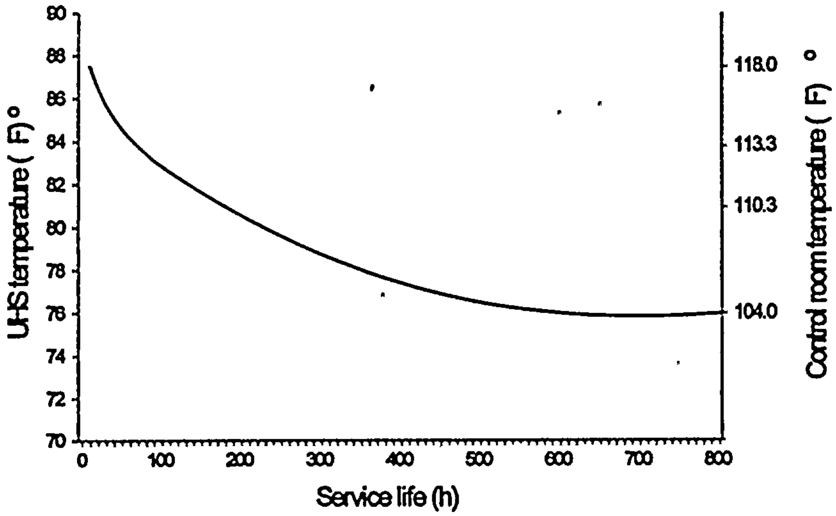


Fig. 1 Service life of components inside the control room based on the temperature of the ultimate heat sink (UHS).

a service life of just 12 h. This would affect the ability to meet the 36-hour cool down requirement when control room temperature exceeds the technical specification limit. Core protection may not be assured in the event of an accident or other malfunction when control room temperatures are excessive. Further, the licensee did not have an approved procedure in place to alert personnel as to a course of action if the chillers were lost, or to shutdown the plant if the temperature inside the control room rose above 95°F

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting normal and alternate plant shutdown capabilities, and the frequency of loss of offsite power.

22.2 Modeling and Affected Sequences

The limiting concern in this issue is the continued operation of the normal control room chillers. The chillers can be lost through random independent failures, a common-cause failure, or a loss of offsite power (LOOP) to the non-safety related buses. The sequences of interest because of elevated control room temperatures are

Sequence 1 – Elevated control room temperature following a LOOP

- UHS temperature exceeds the 76°F design basis temperature;
- A loss of offsite power to the non-safety related buses occurs;
- Power to the control room chillers cannot be recovered before control room equipment begins to fail;
- The operations staff does not complete plant shut down to Mode 5 from the control room;
- The operations staff does not complete plant shut down to Mode 5 from an alternate shutdown location; and
- An accident occurs without automatic safety system response.

Sequence 2 – Elevated control room temperature following multiple chiller failures

- UHS temperature exceeds the 76°F design basis temperature;
- Both control room chillers fail because of equipment problems;
- The control room chillers cannot be repaired before control equipment fails;
- The operations staff does not complete plant shut down to Mode 5 from the control room;

- The operations staff does not complete plant shut down to Mode 5 from an alternate shutdown location; and

- An accident occurs without automatic safety system response.

29.3 Frequencies, Probabilities, and Assumptions

Sequence 1 – Elevated control room temperature following a LOOP

- UHS temperature exceeds the 76°F design basis temperature – The potential for this exists during any summer. However, during the hot summer of 1988, the UHS exceeded 76°F for 22 consecutive days (Ref. 2). Based on this historical occurrence, the worst-case duration can be evaluated as 6×10^{-2} years (i.e., 22 days / 365 days / year).

- A loss of offsite power to the non-safety related buses occurs – *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 3, Table 3.3) indicates that the frequency of loss of offsite power events is 4.6×10^{-2} events/critical year. However, other issues that can potentially affect the loss of offsite power frequency must be resolved in order to assess the loss of offsite power frequency.

- Power to the control room chillers cannot be recovered before control room equipment begins to fail – *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996* (Ref. 4, Figure 3.3) indicates that in 102 evaluated loss of offsite power events, power was restored within 9-h 100 times. If the intake temperature were as high as 87.4°F (including instrument uncertainty) during the event, the control room temperature would approach 120°F. At this temperature, the limiting control room equipment has a rated life of 12 h. Therefore, if power is recovered within 9 h, the non-safety-related chillers could be returned to service before any equipment failed. The licensee estimated that the original control room heat load calculations overstated actual heat loads by approximately 35%. If the chiller failure were to occur with the UHS at the average temperature of 81°F (84.5°F with uncertainty), more than 50 h would be available before control room equipment begins to fail. Furthermore, it would take some time for the control room temperature to stabilize at temperatures approaching 120°F. Therefore, much more time may be available to recover a chiller. However, based on a 12-hour failure window, the non-recovery factor is estimated to be 2.0×10^{-2} (i.e., 2 events / 102 events).

- The operations staff does not complete plant shut down to Mode 5 from the control room – The *Cook Nuclear Plant Individual Plant Examination* (Ref. 5, Table 3.3-3) estimates the probability that an operator fails to cool down and depressurize the plant within 10–20 h following a steam generator tube rupture to be 3.4×10^{-2}. This would seem to most closely approximate the current event in terms of decisions required by the operator to achieve the appropriate plant shutdown conditions before control room equipment begins to fail. A loss of offsite power could be expected to initiate a plant trip, but the operator would still be required to continue to cold shutdown because the control room

temperature is approaching the 95°F technical specification limit (the limit was 120°F from 1988 to 1992). Exceeding the technical specification limit requires that the plant to be placed in Mode 5, where the SSPS and the NIS are no longer required. However, a number of other issues that can potentially affect plant shutdown capability must be resolved in order to assess this failure probability.

- The operations staff does not complete plant shut down to Mode 5 from an alternate shutdown location – Control room equipment could begin failing after 12 h. This could occur before the previous action is completed. The *Cook Nuclear Plant Individual Plant Examination* (Ref. 5, Table 3.3-3) estimates the probability that an operator fails to cool down the reactor coolant system within 1 h following a station blackout at 7.9×10^{-2}. This probability can be assumed to roughly bound the action required by an operator to rapidly shift control of the plant cool down to an alternate shutdown location. However, a number of other issues that can potentially affect alternate shutdown capability must be resolved in order to assess this failure probability.

- An accident occurs without automatic safety system response – All control room equipment was evaluated to have an adequate service life with 120°F temperatures except the SSPS and the NIS. The core will not be threatened by a LOOP-induced loss of the control room chillers unless some further accident occurs during the time the UHS is above the design basis temperature. Auxiliary feedwater (AFW) could be controlled from the control room at control room temperatures of 120°F or AFW could be controlled locally. Therefore, the plant could be placed in a stable condition following a LOOP with excessive control room temperature. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 3, Table 3.3) indicates that a loss of coolant accident of any size has a frequency of 9.0×10^{-3}/critical year and a steam generator tube rupture has a frequency of 7.0×10^{-3}/critical year. Therefore, the probability of an additional accident in the 22-day at-risk period that requires the use of the SSPS or the NIS is 9.6×10^{-4}. The actual period where the plant is vulnerable is limited to the time required to place the plant in Mode 5 following a loss of both chillers. However, the entire 22-day period is considered for conservatism.

<u>Sequence 2 – Elevated control room temperature following multiple chiller failures</u>

- UHS temperature exceeds the 76°F design basis temperature – The potential for this exists during any summer. However, during the hot summer of 1988, the UHS exceeded 76°F for 22 consecutive days (Ref. 2). Based on this historical occurrence, the worst-case duration can be evaluated as 6×10^{-2} years (i.e., 22 days / 365 days / year).

- Both control room chillers fail because of equipment problems – Reasonable values for the failure of a chiller unit are 8.0×10^{-3} start failures/demand and 5.0×10^{-5} run failures/h (Ref. 6, Table 3-2, Summary of Generic Data). One chiller unit is capable of removing all control room heat loads. The probability of failure of both chillers can be estimated by taking the product of the following: a) chiller #1 fails to run during the year, and b) chiller #2 fails to start and run for remainder of the 22 day window of exposure. The probability of the running chiller failing is 0.44 (= 5.0×10^{-5}/h × 24

h/day × 365 days). The probability of the second unit failing is 3.4×10^{-2} [= $8.0 \times 10^{-3} + (5.0 \times 10^{-5}$/h × 24 h/day × 22 days)]. Therefore, the probability of multiple random chiller failures during the 22-day period of interest is 1.5×10^{-2}. It was conservatively assumed in the above formula that both chillers must run for 22 days. Assuming an alpha factor of 0.02, the common-cause failure probability for both chillers to fail to run for 22 days is approximately 5.2×10^{-4}. The alpha factor of 0.02 was chosen after.examining the typical alpha factors for pumps failing to run from reference 7. Combing random and independent failure probabilities, the expected simultaneous failure rate for both chillers is 1.5×10^{-2}.

- The control room chillers cannot be repaired before control equipment fails – At least 12 h (plus the time to heat the control room to 120°F) would be available to repair one chiller unit. The probability that repair technicians fail to repair one control room chiller can be estimated by assuming the failure probability can be represented as a time-reliability correlation (TRC). Assuming technicians can repair one chiller unit in an 8-hour shift when unsure of the problem and responding with hesitancy (error factor 6.4), the probability that a chiller is not recovered within 12 h can be estimated to be 3.6×10^{-1}.

- The operations staff does not complete plant shut down to Mode 5 from the control room – The *Cook Nuclear Plant Individual Plant Examination* (Ref. 5, Table 3.3-3) estimates the probability that an operator fails to cool down and depressurize the plant within 10–20 h following a steam generator tube rupture to be 3.4×10^{-2}. This would seem to most closely approximate the current event in terms of decisions required by the operator to achieve the appropriate plant shutdown conditions before control room equipment begins to fail. The operator would be required to shutdown the plant and continue to cold shutdown because the control room temperature is approaching the 95°F technical specification limit (the limit was 120°F from 1988 to 1992). Exceeding the technical specification limit requires that the plant to be placed in Mode 5, where the SSPS and the NIS are no longer required. However, a number of other issues that can potentially affect plant shutdown capability must be resolved in order to assess this failure probability.

- The operations staff does not complete plant shut down to Mode 5 from an alternate shutdown location – Control room equipment could begin failing after 12 h. This could occur before the previous action is completed. The *Cook Nuclear Plant Individual Plant Examination* (Ref. 5, Table 3.3-3) estimates the probability that an operator fails to cool down the reactor coolant system within 1 h following a station blackout at 7.9×10^{-2}. This probability can be assumed to roughly bound the action required by an operator to rapidly shift control of the plant cool down to an alternate shutdown location. However, a number of other issues that can potentially affect alternate plant shutdown capability must be resolved in order to assess this failure probability

- An accident occurs without automatic safety system response – All control room equipment was evaluated to have an adequate service life with 120°F temperatures except the SSPS and the NIS. The core will not be threatened by an equipment failure that leads to a loss of both control room chillers unless some further accident occurs during the time the UHS is above the design basis

temperature. Auxiliary feedwater (AFW) could be controlled from the control room at control room temperatures of 120°F or AFW could be controlled locally. Therefore, the plant could be placed in a stable condition following a transient with excessive control room temperature. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 3, Table 3.3) indicates that a loss of coolant accident of any size has a frequency of 9.0×10^{-3}/critical year and a steam generator tube rupture has a frequency of 7.0×10^{-3}/critical year. Therefore, the probability of an accident in the 22-day at-risk period that requires the use of the SSPS or the NIS is 9.6×10^{-4}. The actual period where the plant is vulnerable is limited to the time required to place the plant in Mode 5 following a loss of both chillers. However, the entire 22-day period is considered for conservatism.

22.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with these sequences depend on the resolution of other issues affecting the frequency of loss of offsite power, and normal and alternate plant shutdown capabilities. To provide perspective on these sequences the following information is provided.

Sequence 1 – Elevated control room temperature following a LOOP

If the resolution of issues results in no significant changes to the frequency of loss of offsite power, and normal or alternate plant shutdown failure probabilities, the change in core damage frequency would be:

(Window of exposure: 6.0×10^{-2}-year) x
(Frequency of the loss of offsite power events: 4.6×10^{-2}/critical year) x
(Criticality factor--from Ref. 3, Table H-3: 0.79 reactor calendar year/critical year) x
(Probability of failing to recover chillers: 2.0×10^{-2}) x
(Probability of failing to cool down to Mode 5 from the control room: 3.4×10^{-2}) x
(Probability of failing to cool down to Mode 5 from the alternate location: 7.9×10^{-2}) x
(Probability of an additional malfunction requiring injection: 9.6×10^{-4}) = 1.1×10^{-10}/year

Sequence 2 – Elevated control room temperature following multiple chiller failures

If the resolution of issues results in no significant changes to the normal or alternate plant shutdown failure probabilities, the change in core damage frequency would be:

(Window of exposure: 6.0×10^{-2}-year) x
(Probability of both control room chillers failing: 1.5×10^{-2}) x
(Criticality factor--from Ref. 3, Table H-3: 0.79 reactor calendar year/critical year) x
(Probability of failing to recover chillers: 3.6×10^{-1}) x
(Probability of failing to cool down to Mode 5 from the control room: 3.4×10^{-2}) x
(Probability of failing to cool down to Mode 5 from the alternate location: 7.9×10^{-2}) x
(Probability of an additional malfunction requiring injection: 9.6×10^{-4}) $= 6.6 \times 10^{-10}$.

Therefore, the change to the core damage frequency would not be risk significant.

29.5 References

1. NRC Inspection Report No. 50-315, 316/97-201, "Donald C. Cook, Units 1 & 2 Design Inspection," November 26, 1997.

2. LER 315/97-014, Rev. 2, "Potential for Operation in Unanalyzed Condition Due to Postulated Elevated Control Room Temperatures," December 31, 1997.

3. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Commercial Nuclear Power Plants 1987 through 1995*, NUREG/CR-5750, December 1998.

4. C. L. Atwood, et. al., *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996*, NUREG/CR-5496, November 1998.

5. *Cook Nuclear Plant Individual Plant Examination Revision 1*, October 1995.

6. *Davis Besse Nuclear Power Station Individual Plant Examination*, February 1993.

7. F. M. Marshall, et. al., *Common-Cause Failure Parameter Estimations*, NUREG/CR-5497, October 1998.

31.0 LER No. 315/97-010

Event Description: Containment Peak Pressure Could Exceed the Design Pressure Due to Elevated Lake Temperature

Date of Event: August 8, 1997

Plant: D.C. Cook, Units 1and 2

31.1 Summary of Issue

The design basis operating temperature limit of the Cook station emergency service water (ESW) system is 76°F (Ref. 1, Chapter 9). LER 315/97-10 (Ref. 2) reports that the plants may have operated while the ESW temperature was as high as 87.5°F. One function of the ESW system is to remove heat from the containment spray heat exchanger. Therefore, elevated ESW temperature affects the containment heat removal and containment peak pressure after an accident. This issue investigates the impact of the elevated ESW temperature on the containment peak pressure, the containment failure probability, and the resulting increase in core damage frequency. The ESW system supports several other safety systems at D.C. Cook. The change in core damage frequency associated with those components are investigated under issues 11, 19, 29, 30, and 33.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting the sump recirculation capability.

31.2 Modeling and Affected Sequences

Any accident that releases energy to containment relies on the containment spray system for long-term heat removal from the containment. Long-term containment heat removal is essential to keep the peak containment pressure below the design value. At D.C. Cook, long-term containment heat removal is performed by two trains of the containment spray system. Each of these trains is equipped with a heat exchanger. These heat exchangers are cooled by ESW. Therefore, changes to the ESW temperature will affect the long -term containment heat removal rate leading to changes in the containment peak pressures.

The following accidents release energy to the containment: a) loss-of-coolant accident (LOCA) of any size, b) main steam line break (MSLB) inside containment, and c) any accident condition which relies on the feed and bleed cooling capability. Of these accidents, only LOCAs and feed and bleed sequences resulting from a MSLB are considered since other systems or actions required to mitigate a MSLB (isolation of the break and cool down with unfaulted loops) are unaffected by the loss of containment integrity. Sump recirculation capability will be affected since a breached containment reduces net positive suction head available for the residual heat removal pumps and allows water to bypass the recirculation sump.

Therefore, the sequence of interest is as follows:

- Any size LOCA occurs, or feed-and-bleed scenario occurs; and
- Sump recirculation failure due to peak pressure exceeding containment failure pressure as a result of high ESW temperature.

31.3 Frequencies, Probabilities, and Assumptions

At the D.C. Cook plant, the containment pressure is controlled by two systems. In the short term, the ice condenser removes heat from the containment atmosphere by condensing steam. In the long term, the containment spray system, which is equipped with a heat exchanger, recirculates water from the containment recirculation sump and removes heat from the containment. If the lake temperature is increased from 76° F to 87.5° F, the heat removal capability of the containment spray heat exchangers will be reduced. This will increase the containment peak pressure and the probability of containment failure due to overpressure.

The LER (Ref. 2) provides a summary of how the lake temperature has been utilized in the Chapter 14 and Chapter 9 analyses of the Updated Final Safety Analysis Report (Ref. 1). It points out that based on 1988 and 1989 reviews of Westinghouse analyses, operation at lake temperatures up to 87.5°F would not have resulted in exceeding the 12 psig (design pressure of the containment). Based on the individual plant examination (IPE) for D.C. Cook (Ref. 3), the failure pressure of the containment is much greater than the design pressure of 12 psig. The IPE reports that the high condition low probability failure (HCLPF) limit for the containment is 36 psig. That is, there is 95% confidence that at 36 psig the probability of containment failure is less than 5%. In light of this information, and the information provided in the LER, the probability of peak pressure exceeding the containment failure pressure leading to sump recirculation failure due to this condition alone is zero. However, a number of other issues that can potentially affect the sump recirculation failure probability must be resolved in order to assess the sump recirculation failure probability.

31.4 Core Damage Frequency Calculation or the Bounding Calculation

Since the change in probability of containment failure is zero, the core damage frequency change associated with the affected sequences due to this condition alone is zero. However, a number of other issues that can potentially affect the sump recirculation failure probability must be resolved in order to assess the change in core damage frequency associated with this sequence.

31.5 References

1. Donald C. Cook Nuclear Plant, Units 1 and 2, Updated Final Safety Analysis Report.

2. LER 315/97-010, Rev. 2, "Unit Operation with Lake Temperature in Excess of Design Basis Value Results in Condition Outside the Design Basis," December 31, 1998.

3. *Donald C. Cook Nuclear Plant Units 1 and 2, Individual Plant Examination, Revision 1*, October 1995.

37.0 LER No. 315/97-006

Event Description: Equipment in Containment Rendered Inoperable Because of Faulted Floodup Tubes

Date of Event: March 27, 1997

Plant: D.C. Cook, Unit 1

37.1 Summary of Issue

During a refueling outage at D.C. Cook, Unit 2, in 1996, personnel discovered moisture in several floodup tubes. A subsequent inspection of the floodup tubes at Unit 1 during its refueling outage in 1997, revealed that nine floodup tubes inside containment had through-wall defects (Ref. 1). The defects were caused by material stress cracks or welding activities. Seven of the floodup tubes contained cables connected to safety-related components. The safety-related components affected by the damaged floodup tubes are:

- Steam Generator 3 Narrow Range Level Transmitter (1-BLP-132) and Steam Generator 4 Narrow Range Level Transmitter (1-BLP-142),
- Reactor Coolant System (RCS) Loop 4 Hot Leg Wide Range Temperature Recorder Thermal Sensor (1-NTR-140) and RCS Loop 4 Hot Leg Wide Range Temperature Recorder Thermal Sensor (1-NTR-240),
- Hydrogen Recombiner (1-HR-1),
- Containment Hydrogen Skimmer Ventilation Fan HV-CEQ-2 Suction Shutoff Valve (1-VMO-102),
- Reactor Coolant System Post Accident Vent Train A Solenoid Valve (1-NSO-021),
- East Residual Heat Removal (RHR) and North Safety Injection to Reactor Coolant Loops 1 and 4 Hot Leg Shutoff Valves (1-IMO-315), and East RHR and North Safety Injection to Reactor Coolant Loops 1 and 4 Cold Leg Shutoff Valves (1-IMO-316),
- West RHR and South Safety Injection to Reactor Coolant Loops 2 and 3 Hot Leg Shutoff Valves (1-IMO-325),
- Pressurizer Relief Valve NRV-151 Upstream Shutoff Valve (1-NMO-151), and
- Pressurizer Train A Pressure Relief Valve NRV-153 Close Limit Switch (1-33-NRV-153).

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW) and feed-and-bleed cooling capabilities.

Because seven of the failed floodup tubes at Unit 1 contained circuitry needed for accident mitigation or post-accident monitoring, personnel conducted a visual inspection of the floodup tubes on Unit 2. Two damaged floodup tubes were discovered; one tube contained circuitry needed for accident mitigation or post-accident monitoring (Ref. 1). A more thorough inspection of the floodup tubes at Unit 2 was made in October, 1997, during a refueling outage (Ref. 2). The impact of the failed floodup tubes at Unit 2 is evaluated in the analysis associated with LER No. 316/97-006 (Issue 54).

37.2 Modeling and Affected Sequences

Because safety-related electrical penetrations are located below the predicted flooding level inside containment following a loss-of-coolant accident (LOCA), safety-related cables are routed through stainless steel tubes, known as floodup tubes, to prevent the water in the containment from contacting the cables. This precaution is necessary because the electrical cables have not been environmentally qualified for submergence in water, and Kapton insulated wires, the type used in electrical penetrations, are known to be susceptible to degradation when exposed to alkaline solutions. All Kapton wires below floodup levels needed for environmentally qualified equipment are contained in floodup tubes. Limited testing indicated that the cable insulation would protect the cable function for at least 2 h. Therefore, the affected equipment should function immediately following an accident, but operation would be suspect beyond the immediate response. Hence, the dominant core damage sequences of interest involve a LOCA coupled with the failure of equipment that is required to function later in the sequence of events.

The loss of the RCS Loop 4 temperature recorder inputs (1-NTR-140 and -240) affects the capability of the subcooling monitor. This is compensated by using the core exit thermocouples and the other loop inputs. No immediate reactor protection function is lost.

The loss of one of two hydrogen recombiners (1-HR-1) affects containment and primary system integrity. Hydrogen igniters and a second hydrogen recombiner compensate for the loss of one hydrogen recombiner. No immediate reactor protection function is lost. Ample time to repair the remaining hydrogen recombiner would be available, if necessary.

The containment recirculation fan valve (1-VMO-102) would be activated within ten minutes following a LOCA. This is well within the expected cable insulation survival time limit. When the cable insulation fails, the valve will fail as is. Therefore, no immediate reactor protection function is lost.

The loss of one of two reactor vessel head vent valves (1-NSO-021) affects the ability to vent a hydrogen bubble in the core head region following a core accident. No credit is taken in the plant's final safety analysis report (FSAR) for the expected operation of these valves following an accident. One vent valve is sufficient to vent a hydrogen bubble in the vessel head region.

Valves 1-IMO-315, 1-IMO-316 and 1-IMO-325 must be operable for the plant to transition from cold-leg recirculation to hot-leg recirculation. There is a potential for boron to precipitate out of solution in the core following a large hot-leg break (frequency less than 5×10^{-6}/critical year per Ref. 3) because the coolant could boil away without replacement causing the boron to become saturated. Hot-leg recirculation is then considered necessary to force this potentially stagnant, boron saturated solution out of the core. However, the LER (Ref. 1) references a Westinghouse study that indicates sufficient flow exists between the hot-leg nozzle and the core barrel to prevent boron precipitation under all conditions. Therefore, the increased likelihood of core damage resulting from a failure to transfer from cold-leg recirculation to hot-leg recirculation is considered negligible.

The affected block valve for a power-operated relief valve (PORV) (1-NMO-151) may fail to close following a PORV cycling open and failing to close (1-33-NRV-153). Following a LOCA, which causes

floodup tube wetting, the PORVs will not cycle to control pressure. Only a failure to remove decay heat via the auxiliary feedwater (AFW) system could require a PORV to be opened. This is unlikely and the added coolant loss would have little affect on the plant capability to protect the core from the initial LOCA.

The sequences of interest because of the damaged floodup tubes are

Sequence 1 – LOCA occurs with an anticipated transient without scram (ATWS)

- A LOCA of any size occurs; and
- The reactor fails to trip.

Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator

- A small LOCA occurs;
- The reactor trip is successful;
- The affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails;
- AFW system fails because the affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters); and
- Feed-and-bleed cooling fails because of a random equipment failure.

37.3 Frequencies, Probabilities, and Assumptions

Sequence 1 – LOCA occurs with an ATWS

This sequence is included because two inputs to the reactor protection system are affected by wetting. However, the licensee expects all cabling to operate normally in the short-term.

- LOCA of any size occurs – Using the frequencies associated with large pipe break (5×10^{-6}), medium pipe break (4×10^{-5}), small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of LOCAs of any size is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).

- The reactor fails to trip – *Reliability Sudy: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four) steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs.

<u>Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator</u>

- Small LOCA occurs – Using the frequencies associated with small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-7}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a small LOCA is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).

- The reactor trip is successful – *Reliability Sudy: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four) steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs. Therefore, for calculational purposes, the reactor trip success probability can be assumed to be 1.0.

- The affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails – For conservatism, it was assumed that the occurrence of a LOCA would eventually fail the two affected water level transmitters with a probability of 1.0.

- AFW system fails because the affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters) – The probability of ten level transmitters independently failing from random equipment failures is negligible. Adequate decay heat removal can be established from one steam generator with one operable level transmitter. In addition, there is one wide range level transmitter per steam generator that would allow rudimentary control of the water level in a steam generator if necessary. The common-cause failure probability factor (alpha factor) for six component electronic systems is

on the order of 1.0×10^{-3} (Ref. 4). Assuming this holds for a sixteen component system and assuming an individual level transmitter failure rate of 1.0×10^{-3} (Ref. 5), the common-cause failure probability for the steam generator level transmitters is approximately 1.0×10^{-6}. The potential for the operator to make an error due to conflicting indications from different level indicators is not credible due to the following: (a) each steam generator is equipped with 4 level transmitters (3 narrow range and 1 wide range), (b) only two narrow range transmitters in the total of 16 fail and these two are associated with two different steam generators, and (c) the wetting will cause the level to go off-scale high or low rather than indicating an inaccurate level which makes it obvious to the operator that the transmitter has failed. However, a number of other issues that can potentially affect AFW system must be resolved in order to assess the overall AFW failure probability.

- Feed-and-bleed cooling fails because of a random failure – From the Cook standardized plant analysis risk (SPAR) model, the overall failure probability of feed-and-bleed cooling is 2.9×10^{-2}. However, a number of other issues that can potentially affect feed-and-bleed cooling that must be resolved in order to assess this failure probability.

37.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with the sequences depend on the resolution of other issues affecting AFW and feed-and-bleed cooling capability. To provide perspective on these sequences the following information is provided.

If the resolution of issues results in no significant changes to the AFW and feed-and-bleed cooling failure probabilities, the change in core damage frequency would be:

Sequence 1 – LOCA occurs with an ATWS

(Frequency of any size LOCA: 9.0×10^{-3}/critical year) x
(Criticality factor: 0.79 critical year/reactor calendar year) x
(Probability of the reactor protection system failure to trip: 5.5×10^{-6}) = 3.9×10^{-8}/year

Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator

(Frequency of any size LOCA: 9.0×10^{-3}/critical year) x
(Criticality factor: 0.79 critical year/reactor calendar year) x
(Probability of reactor trip: 1.0) x
(Probability wetted level transmitters fail: 1.0) x
(Probability remaining level transmitters fail: 1.0×10^{-6}) x
(Probability of feed-and-bleed cooling failure: 2.9×10^{-2}) = 2.1×10^{-10}/year.

Therefore, the change to the core damage frequencies would not be risk significant.

37.5 References

1. LER 315/97-006, Rev. 1, "Equipment in Containment Rendered Inoperable Due to Cracked Floodup Tubes," May 30, 1997.

2. LER 316/97-006, Rev. 0, "Equipment in Containment Rendered Inoperable Due to Faulted Floodup Tubes," November 10, 1997.

3. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995*, NUREG/CR-5750, February 1999.

4. F. M. Marshall, et. al., *Common-Cause Failure Parameter Estimations*, NUREG/CR-5497, October 1998.

5. *Cook Nuclear Plant Individual Plant Examination Revision 1*, October 1995.

6. S.A. Eide, et. al., *Reliability Study: Westinghouse Reactor Protection System,: 1984-1995*, NUREG/CR-5500, Vol. 2, April 1999.

43.0 NRC Inspection Report No. 315, 316/97-201, Finding E1.4.2D

Event Description: Inconsistencies with ECCS Level Instrumentation and Equipment Allowed Outage Times

Date of Event: November 1997

Plant: D. C. Cook, Units 1 and 2

43.1 Summary of Issue

The NRC Inspection Report No. 315, 316/97-201 (Ref. 1) identified inconsistencies in the equipment allowed outage times (AOTs) for ECCS level instrumentation. For D.C. Cook, there are no automatic signals from the refueling water storage tank (RWST) level or containment sump level to actuate safety systems. However, indications from these channels are relied upon by the operators to perform important safety functions such as transitioning from injection to sump recirculation. The AOT for these instrument trains is 30 days, while the ECCS trains have AOTs of 72 hours. The NRC inspection team concluded that 72 hours is a more appropriate AOT for these level instruments.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting the auxiliary feedwater (AFW) capability.

43.2 Modeling and Affected Sequences

A 30-day AOT rather than a 3-day AOT could result in an increase to the probability of a RWST level instrumentation channel being out of service when it is needed. Affected sequences are those that require the transition from injection to sump recirculation. The RWST level instrumentation are the most important, since they are needed for initiating sump recirculation in emergency operating procedures. Therefore, the sequence of interest is:

- Any size LOCA occurs, or feed-and-bleed scenario occurs;
- Channel 1 RWST level indication out of service; and
- Channel 2 RWST level indication fails due to random failure;
- Sump recirculation fails due to the loss of both RWST level indications.

43.3 Frequencies, Probabilities, and Assumptions

- Any size LOCA occurs, or feed-and-bleed cooling scenario occurs - Using the frequencies associated with large pipe break (5×10^{-6}), medium pipe break (4×10^{-5}), small pipe break (5×10^{-4}), stuck open

power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a LOCA of any size is approximately 9×10^{-3}/critical year (Ref. 2, Table 3-1).

The frequency of a feed-and-bleed scenario occurring is estimated as follows. *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the frequency of a loss of offsite power is 0.046/critical year; the frequency of a total loss of feedwater flow is 0.085/critical year; and the frequency of a total loss of condenser heat sink events (power conversion system) is 0.12/critical year. This adds up to a total frequency of 0.25/critical year. For Cook Unit 1, the criticality factor is 0.79 critical year/reactor calendar year (Ref. 2, Table H-3). Therefore, the frequency of a reactor trip with a loss of feedwater, offsite power, or the power conversion system is about 0.2/year (0.79 x 0.25). From the Cook standardized plant analysis risk (SPAR) model, the failure probability of the AFW system is 1.1×10^{-4}. Therefore, the frequency of feed-and-bleed events requiring recirculation is 1.1×10^{-4} times 0.2, or about 2×10^{-5}. This frequency is negligible compared to the LOCA events frequency. Therefore, the total frequency of events requiring sump recirculation is about 9×10^{-3}/critical year or 7.1×10^{-3}/year ($0.79 \times 9 \times 10^{-3}$). However, a number of issues that can potentially affect the AFW failure probability must be resolved in order to assess this the frequency.

- Channel 1 RWST level indication out of service - The actual probability of Channel 1 being out of service depends on the test and maintenance history of that channel. However, in order to get an upper bound it is assumed that the channel is out of service once a year for its full AOT of 30 days. Therefore, the probability of the channel being out of service is 0.083 (30/365).

- Channel 2 RWST level indication fails due to random failure - The probability of a random failure of Channel 2 is estimated by taking the sum of the probability of failure of 120 VAC power and the probability of failure of the level transmitters, since these are the two dominant failures in this instrument channel. According to the D.C. Cook Individual Plant Examination (Ref. 3), the probability of failure of 120 VAC power within a 24-hour mission time is 2.8×10^{-6}.

  The probability of failure of level transmitters is derived from data from the Nuclear Plant Reliability Data System for pressurized water reactor (PWR) residual heat removal/low pressure injection systems transmitters in operation during the years 1987-1992. It was assumed that safety-related transmitters were energized approximately 90 percent of the calendar year because a large number of these transmitters remain energized for a significant portion of regularly scheduled outages. The component-hours of operation is then the product of the number of transmitters in the systems times the number of years the plants were in commercial operation during the period of 1987-1992 times 90 percent of the number of calendar hours per year. The point estimate of the mean rate of failure for these systems for all PWRs during the period is then the number of failures (6) divided by the component hours for all PWRs in the period ($5.52 \times 10^{+7}$), or 1.1×10^{-7}. The Bayes mean is then 1.2×10^{-7} failures per hour. For a 24-hour mission time, the failure rate is then 2.9×10^{-6}.

Therefore, the total channel failure probability over a 24 hour mission time is 5.7×10^{-6} (2.8×10^{-6}+ 2.9×10^{-6}).

- Sump recirculation fails due to the loss of both RWST level indications - It is assumed that the failure of both RWST level channels will result in the failure to transfer suction of emergency core cooling (ECCS) pumps from the RWST to the sump. Further, it is assumed that the failure to transfer will result in the unrecoverable damage to the ECCS pumps. Therefore, the probability of core damage given the failure of both RWST level channels is 1.0.

43.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with this LOCA sequence depends on the resolution of other issues affecting AFW capability and sump recirculation. To provide perspective on this sequence the following information is provided.

If the resolution of other issues results in no significant changes to the AFW and sump recirculation failure probabilities, the change in core damage frequency would be:

(Frequency of any size LOCA: 9.0×10^{-3}/critical year) x
(Criticality factor: 0.79 critical year/reactor calendar year) x
(Probability of Channel 1 RWST level indication out of service: 0.083) x
(Probability of a random failure of Channel 2 RWST level indication: 5.7×10^{-6})
(Probability of core damage given the failure of both RWST level channels: 1.0) = 3.4×10^{-9}/year.

Therefore, the change to the core damage frequency would not be risk significant.

43.5 References

1. Donald C. Cook, Units 1 & 2 Design Inspection (NRC Inspection Report No. 50-315, 316/97-201) November 26, 1997.

2. J. P: Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. *Cook Nuclear Plant Individual Plant Examination Revision 1*, October 1995.

45.0 LER No. 316/98-002

Event Description: PORV Inoperability Due to Failed Backup Air Supply

Date of Event: February 24, 1998

Plant: D.C. Cook, Unit 2

45.1 Summary of Issue

According to LER 315/98-002 (Ref. 1), in August 1992, the pressurizer power-operated relief valve (PORV) 2-NRV-152 was stroked using the backup air supply. The PORV failed to stroke within the required 6 seconds. The cause of the failure was determined to be a leaking check valve in the normal control air header. During the test, the leaking check valve allowed the backup air to leak into the normal control air header and prevented the PORV from receiving an adequate supply of pressurized air. The leaking check valve could have resulted in the depletion of the backup air supply in the event that the normal air supply was lost, thereby, challenging the ability of the affected PORV to operate.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW) and feed-and-bleed cooling capabilities, and the frequency of loss of offsite power.

45.2 Modeling and Affected Sequences

The pressurizer PORVs are used to control primary pressure and minimize challenges to the spring operated pressurizer safety relief valves during transients. During accident conditions, the PORVs can be used to bleed off primary coolant as part of feed-and-bleed cooling. A reduction in the availability of the PORVs has the greatest influence on the change in core damage frequency during this accident mitigation function. Therefore, the evaluation of sequences involving the feed-and-bleed cooling function is of interest.

The pressurizer has three air-operated PORVs. The normal control air supply is provided by the station compressed (control) air system. The backup air supply for each PORV is supplied by a dedicated air bottle, which is maintained by the nitrogen gas system. Two PORVs are required for successful feed-and-bleed cooling during sequences involving the loss of feedwater (main and auxiliary). The third PORV is assumed to be unavailable upon the loss of the normal control air system and the backup air supply. Three limiting event sequences are considered in this evaluation. The first involves a reactor trip due to a loss of main feedwater as the initiating event. The second sequence involves a loss of offsite power as the event initiator. Without manual recovery actions, the loss of offsite power will lead to the loss of the compressed (control) air system. The initiating event due to the loss of normal control air, which leads to the failure of PORV 2-NRV-152 (assuming that the backup air supply fails), is considered in the third sequence. The accident sequences of interest are:

Sequence 1- Reactor trip with loss of main feedwater

- Reactor trip occurs due to the loss of main feedwater or power conversion system;
- Auxiliary feedwater fails; and
- Feed-and-bleed cooling fails given the loss of control air.

Sequence 2 - Loss of offsite power

- Reactor trip occurs due to the loss of offsite power;
- Auxiliary feedwater fails; and
- Feed-and-bleed cooling fails.

Sequence 3 - Loss of control air

- Reactor trip occurs due to the loss of control air;
- Auxiliary feedwater fails; and
- Feed-and-bleed cooling fails.

45.3 Frequencies, Probabilities, and Assumptions

Sequence 1- Reactor trip with loss of main feedwater

- Reactor trip occurs due to the loss of main feedwater or power conversion system - *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the frequency of a reactor trip with loss of heat sink or the total loss of main feedwater is 0.205 per critical year (0.12+0.085). When adjusted by the criticality factor of 0.68 for Cook Unit 2 (Ref. 2, Table H-3) the initiating event frequency is 0.14 per reactor calendar year (0.205 x 0.68).
- Auxiliary feedwater fails - The AFW system failure probability from the Cook standardized plant analysis risk (SPAR) model is 1.1×10^{-4}. However, a number of other issues that can potentially affect AFW capability must be resolved in order to assess the AFW failure probability.
- Feed-and-bleed cooling fails given the loss of control air - The change in the feed-and-bleed failure probability (with and without the third, redundant PORV) due to the loss of backup air to the third PORV is the probability of interest. For the backup air supply to be significant, the normal control air

supply to the PORVs must fail during the 24-hour mission time following the reactor trip. From the individual plant examination (IPE) for D.C. Cook (Ref. 3), the probability of a random failure of the normal control air supply to the PORVs within the first 24 hours after a trip is 3.0×10^{-3} (Ref. 3, Section 3.2.1.6 and Table 3.3-5). Two modified Cook SPAR models were used to estimate feed-and-bleed failure probabilities for a two out of two and a two out of three success criteria for the PORVs.[1] For the two out of two success criteria model, it was assumed that the third PORV was unavailable due to the loss of backup air supply to that PORV. The failure probability of feed-and-bleed cooling based on a two out of three and two out of two success criteria are 1.0×10^{-2} and 2.3×10^{-2}, respectively.[2] Therefore, change in the feed-and-bleed failure probability given the loss of control air is $[3.0 \times 10^{-3}]\times[(2.3 \times 10^{-2})-(1.0 \times 10^{-2})] = 3.9 \times 10^{-5}$. However, a number of other issues that can potentially affect feed-and-bleed cooling capability must be resolved in order to assess this change in failure probability.

Sequence 2 - Loss of offsite power

- Reactor trip occurs due to the loss of offsite power - *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the loss of offsite power frequency is 0.046 per critical year. When adjusted by the criticality factor of 0.68 for Cook Unit 2 (Ref. 2, Table H-3), the initiating event frequency is 0.031 per reactor calendar year (0.046 x 0.68). However, other issues that can potentially affect the likelihood of the loss of offsite power must be resolved in order to assess the loss of offsite power frequency.

- Auxiliary feedwater fails - The AFW system failure probability from the Cook SPAR model is 1.1×10^{-4}. However, a number of other issues that can potentially affect AFW capability must be resolved in order to assess the AFW failure probability.

- Feed-and-bleed cooling fails - The sequence used to estimate this failure probability is identical to that used to estimate the feed-and-bleed failure probability in Sequence 1, above. The only difference in the calculation is the failure probability of the normal control air supply to the PORVs. During a loss of offsite power, the power supplies to the air compressors are stripped during load sequencing. Power must be manually restored along with the reopening of two valves. From the D.C. Cook IPE (Ref. 3, Section 3.2.1.6 and Table 3.3-5), the probability of failure to restore the normal air supply to the PORVs during a loss of offsite power is 7.4×10^{-2} for a 24-hour mission. Using the failure probabilities for bleed-and-feed cooling from the modified SPAR model calculated in Sequence 1, the change in the feed-and-bleed failure probability (with and without the third, redundant PORV) given

[1] The Cook ASP model assumes that all three PORVs are required for feed-and-bleed cooling. The success criteria from Cook IPE (Ref.3) requires a minimum of two PORVs.

[2] A review of the ASP fault tree model for feed-and-bleed cooling shows that the loss of the compressed (control) air system will have negligible impact on the failure probabilities of feed systems and the other PORVs.

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the failure to restore the control air supply is $[7.4 \times 10^{-2}] \times [(2.3 \times 10^{-2})-(1.0 \times 10^{-2})] = 9.6 \times 10^{-4}$. However, a number of other issues that can potentially affect feed-and-bleed cooling capability must be resolved in order to assess this change in failure probability.

<u>Sequence 3 - Loss of control air</u>

- A reactor trip occurs due to the loss of control air - *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995* (Ref. 2, Table 3.3) indicates that the initiating event frequency for the loss of control air is 9.6×10^{-3} per critical year. When adjusted by the criticality factor of 0.68 for Cook Unit 2 (Ref. 2, Table H-3), the initiating event frequency is 6.5×10^{-3} per reactor calendar year $[(9.6 \times 10^{-3}) \times (0.68)]$.

- Auxiliary feedwater fails -The AFW system failure probability from the Cook standardized plant analysis risk (SPAR) model is 1.1×10^{-4}. However, a number of other issues that can potentially affect AFW capability must be resolved in order to assess the AFW failure probability.

- Feed-and-bleed cooling fails - For conservatism, its is assumed that the normal control air supply to the PORVs is not restored. Therefore, using the results from the modified SPAR models that were calculated in Sequence 1, above, the change in the feed-and-bleed failure probability (with and without the third, redundant PORV) is $(2.3 \times 10^{-2})-(1.0 \times 10^{-2}) = 1.3 \times 10^{-2}$. However, a number of other issues that can potentially affect feed-and-bleed cooling capability must be resolved in order to assess this change in failure probability.

45.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequency associated with these sequences depend on the resolution of other issues affecting AFW and feed-and-bleed capabilities, and the loss of offsite power frequency. To provide perspective on these sequences the following information is provided.

If the resolution of other issues results in no significant changes to the AFW and feed-and-bleed cooling failure probabilities or the loss of offsite power frequency, the change in core damage frequency with the three sequences would be:

<u>Sequence 1- Reactor trip with loss of main feedwater</u>

(Frequency of reactor trip due to loss of main feedwater or power conversion system: 0.14/year) x
(Probability of AFW failure: 1.1×10^{-4}) x
(Change in feed-and-bleed cooling failure probability given the loss of control air: 3.9×10^{-5}) =
6.0×10^{-10}/year.

Sequence 2 - Loss of offsite power

(Frequency of loss of offsite power: 0.031/year) x
(Probability of AFW failure: 1.1×10^{-4}) x
(Change in feed-and-bleed cooling failure probability: 9.6×10^{-4}) = 3.3×10^{-9} /year.

Sequence 3 - Loss of control air

(Frequency of reactor trip due to due to the loss of control air: 6.5×10^{-3}/year) x.
(Probability of AFW failure: 1.1×10^{-4}) x
(Change in feed and bleed cooling failure probability: 1.3×10^{-2}) = 9.3×10^{-9}/year.

Therefore, the changes to the core damage frequency would not be risk significant.

45.5 References

1. LER 316/98-002, Rev. 1, "PORV Inoperability Results in a Condition Outside Design Basis," July 6, 1998.

2. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995*, NUREG/CR-5750, February 1999.

3. *Donald C. Cook Nuclear Units 1 and 2, Individual Plant Examination Revision 1*, October 1995.

54.0 LER No. 316/97-006

Event Description: Equipment in Containment Rendered Inoperable Because of Faulted Floodup Tubes

Date of Event: October 10, 1997

Plant: D.C. Cook, Unit 2

54.1 Summary of Issue

Damaged floodup tubes were discovered on both D.C. Cook units in March, 1997 (Ref. 1). Personnel at D.C. Cook, Unit 2, performed a more thorough inspection of the floodup tubes in October, 1997, following a shutdown for a refueling outage. This inspection identified three floodup tubes containing cables connected to safety related components with through wall holes. The holes in the tubes were caused by welding activities (Ref. 2). The concern is that the safety-related component cabling would be subject to wetting as the sump floods following a loss-of-coolant accident (LOCA). The cabling in the damaged floodup tubes is connected to the following instrumentation:

- Steam Generator 1 Narrow Range Level Transmitter (2-BLP-110) and Steam Generator 2 Narrow Range Level Transmitter (2-BLP-120),
- Reactor Vessel Level Indication System (RVLIS) Resistance Temperature Detectors (2-NTQ-130A, 2-NTQ-130B, 2-NTQ-130C), and
- High Range Radiation Monitor (2-VRA-2310).

The safety-related component cabling identified previously (Ref. 1) is connected to

- One of two Containment Recirculation/Hydrogen Skimmer Fans.

The change in core damage frequency associated with this issue is dependent upon resolution of the issues affecting auxiliary feedwater (AFW) and feed-and-bleed cooling capabilities.

54.2 Modeling and Affected Sequences

Because safety-related electrical penetrations are located below the predicted flooding level inside containment following a LOCA, safety-related cables are routed through stainless steel tubes, known as floodup tubes, to prevent the water in the containment from contacting the cables. This precaution is necessary because the electrical cables have not been environmentally qualified for submergence in water, and Kapton insulated wires, the type used in electrical penetrations, are known to be susceptible to degradation when exposed to alkaline solutions. All Kapton wires located below expected flood levels that are connected to environmentally qualified equipment are contained in floodup tubes. Limited

testing by the licensee indicated that the cable insulation would protect the cable function for at least 2 h. Therefore, the affected equipment should function immediately following an accident, but operation would be suspect beyond the immediate response. Hence, the dominant core damage sequences of interest involve a LOCA coupled with the failure of equipment that is required to function later in the sequence of events.

The containment high range area radiation monitor (2-VRA-2310) is required to be operable by technical specifications, but the monitor does not control any safety function. Therefore, the loss of one instrument will not affect the response to a LOCA.

The failure of a containment air recirculation/hydrogen skimmer fan would affect the peak pressure in containment following a LOCA. One fan is sufficient to ensure that the peak pressure remains below the design pressure of 12 psi. The loss of the second fan could allow the peak pressure to reach 17 psi. This pressure is well within the 36 psi ultimate capability of the D.C. Cook containment building. Furthermore, the loss of these fans would only impact containment leakage and not the probability of core damage. Hence, the loss of this fan will not compound any of the core damage sequences discussed in this analysis.

The sequences of interest because of the damaged floodup tubes are:

Sequence 1 – LOCA occurs with an anticipated transient without scram (ATWS)

- A LOCA of any size occurs; and
- The reactor fails to trip.

Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator

- A small LOCA occurs;
- The reactor trip is successful;
- Auxiliary feedwater (AFW) fails because the affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters); and
- Feed-and-bleed cooling fails because of a random equipment failure.

Sequence 3 – Small LOCA occurs with subsequent loss of AFW and RVLIS

- A small LOCA occurs;
- The reactor trip is successful;
- The AFW system fails because of a random equipment failure; and
- Feed-and-bleed cooling fails because operators are guided by errant RVLIS information. One RVLIS train fails because the wetted insulation on the resistance temperature detector cable fails. The redundant RVLIS train fails because of a random equipment failure.

Sequence 4 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator and RVLIS

- A small LOCA occurs;
- The reactor trip is successful;
- AFW fails because the water level indication in the affected steam generator becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters);
- Feed-and-bleed cooling fails because operators are guided by errant RVLIS information. One RVLIS train fails because the wetted insulation on the resistance temperature detector cable fails. The redundant RVLIS train fails because of a random equipment failure.

54.3 Frequencies, Probabilities, and Assumptions

Sequence 1 – LOCA occurs with an ATWS

This sequence is included because two inputs to the reactor protection system are affected by wetting. However, the licensee expects all cabling to operate normally in the short-term.

- A LOCA of any size occurs – Using the frequencies associated with large pipe break (5×10^{-6}), medium pipe break (4×10^{-5}), small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a LOCA of any size is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).
- The reactor fails to trip – *Reliability Study: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four)

steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs.

Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator

- Small LOCA occurs – Using the frequencies associated with small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a small LOCA is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).

- The reactor trip is successful – *Reliability Sudy: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four) steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs. Therefore, for calculational purposes, the reactor trip success probability can be assumed to be 1.0.

- AFW fails because the affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters) – It was pessimistically assumed that the occurrence of a LOCA would eventually fail the two afected water level transmitters with a probability of 1.0. The probability of ten level transmitters independently failing from random equipment failures is negligible. Adequate decay heat removal can be established from one steam generator with one operable level transmitter In addition, there is one wide range level transmitter per steam generator that would allow rudimentary control of the water level in a steam generator if necessary. The common-cause failure probability factor (alpha factor) for six component electronic systems is on the order of 1.0×10^{-3} (Ref. 4). Assuming this holds for a sixteen component system and assuming an individual level transmitter failure rate of 1.0×10^{-3} (Ref. 5), the common-cause failure probability for the steam generator water level transmitters is approximately 1.0×10^{-6}. The potential for the operator to make an error due to conflicting indications from different level indicators is not credible due to the following: (a) each steam generator is equipped with 4 level transmitters (3 narrow range and 1 wide range), (b) only two narrow range transmitters of these 16 fail and these two are associated with two different steam generators, and (c) the wetting will cause the level to go off-scale high or low rather than indicating

an inaccurate level which makes it obvious to the operator that the transmitter has failed. However, a number of other issues that can potentially affect AFW must be resolved in order to assess the overall AFW failure probability.

- Feed-and-bleed cooling fails because of a random failure – From the standardized plant analysis risk (SPAR) model for Cook, the overall failure probability of feed-and-bleed cooling is 2.9×10^{-2}. However, a number of other issues that can potentially affect feed-and bleed cooling must be resolved in order to assess the feed-and-bleed cooling failure probability.

Sequence 3 – Small LOCA occurs with subsequent loss of AFW and RVLIS

- Small LOCA occurs – Using the frequencies associated with small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a small LOCA is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).

- The reactor trip is successful – *Reliability Study: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four) steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs. Therefore, for calculational purposes, the reactor trip success probability can be assumed to be 1.0.

- The AFW system fails because of a random equipment failure – From the Cook SPAR model the nominal overall AFW system failure probability is 1.1×10^{-4}. This failure probability includes the probability of pumps, valves, and normal water supplies failing. However, a number of other issues that can potentially affect AFW must be resolved in order to assess the AFW failure probability.

- Feed-and-bleed cooling fails because operators are guided by errant RVLIS information. One RVLIS train fails because the wetted insulation on the resistance temperature detector cable fails. The redundant RVLIS train fails because of a random equipment failure – It was pessimistically assumed that the occurrence of a LOCA would eventually fail the three affected resistance temperature detectors with a probability of 1.0. These temperature detectors provide a reference temperature for one RVLIS channel; so information provided by this channel would be in error. The redundant RVLIS train fails because of a random equipment failure. A generic wiring failure probability of 1.0×10^{-5} (Ref. 5, Table 3.3-1, item 423) is assumed. This is representative of the failure mechanism of a resistance temperature detector. The potential for the operator to make an error due to two different indications from two RVLIS trains were considered and it was concluded to be incredible due to the following. When a RVLIS train fails due to wetting it will indicate off scale

high or off scale low. When one RVLIS train indicates a reasonable value that is realistic and varies appropriately and the second train goes high or low, the operators can easily distinguish the train that has failed. However, a number of other issues that can potentially affect feed-and-bleed cooling must be resolved in order to assess the feed-and-bleed failure probability.

<u>Sequence 4 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator and RVLIS</u>

- Small LOCA occurs – Using the frequencies associated with small pipe break (5×10^{-4}), stuck open power-operated relief valve (1×10^{-3}), stuck open code safety valve (5×10^{-3}), and reactor coolant pump seal LOCA (2.5×10^{-3}), the total frequency of a small LOCA is approximately 9×10^{-3}/critical year (Ref. 3, Table 3-1).

- The reactor trip is successful – *Reliability Study: Westinghouse Reactor Protection System, 1984-1995* (Ref. 6) indicates that the RPS failure probability (allowing credit for manual scram by the operator) is 5.5×10^{-6}. This probability of the reactor failing to trip is not expected to change because of the damaged floodup tubes. The only components affected by the damaged floodup tubes that input into the reactor protection system are the two steam generator water level transmitters. The two (of four) steam generators affected by the damaged floodup tubes still had two operable water level transmitters; trip logic only requires 2 of 3 level transmitters to be low to initiate a reactor trip. In addition, the affected transmitter channels were expected to operate normally in the near term following an accident. Furthermore, a LOCA would be detected by numerous other reactor protection inputs. Therefore, for calculational purposes, the reactor trip success probability can be assumed to be 1.0.

- AFW fails because the affected steam generator water level indication becomes unavailable after the wetted insulation on the water level transmitter cable fails (2 transmitters) and the ability to control the water level in the steam generator is lost because the steam generator water level transmitters unaffected by leaking floodup tubes fail from random equipment failures (10 transmitters) – It was pessimistically assumed that the occurrence of a LOCA would eventually fail the two affected water level transmitters with a probability of 1.0. The probability of ten level transmitters independently failing from random equipment failures is negligible. Adequate decay heat removal can be established from one steam generator with one operable level transmitter In addition, there is one wide range level transmitter per steam generator that would allow rudimentary control of the water level in a steam generator if necessary. The common-cause failure probability factor (alpha factor) for six component electronic systems is on the order of 1.0×10^{-3} (Ref. 4). Assuming this holds for a sixteen component system and assuming an individual level transmitter failure rate of 1.0×10^{-3} (Ref. 5), the common-cause failure probability for the steam generator water level transmitters is approximately 1.0×10^{-6}. The potential for the operator to make an error due to conflicting indications from different level indicators is not credible due to the following: (a) each steam generator is equipped with 4 level transmitters (3 narrow range and 1 wide range), (b) only two narrow range transmitters of these 16 fail and these two are associated with two different steam generators, and (c) the wetting will cause the level to go off-scale high or low rather than indicating an inaccurate level which makes it obvious to the operator that the transmitter has failed. However, a

number of other issues that can potentially affect AFW must be resolved in order to assess the overall AFW failure probability.

- Feed-and-bleed cooling fails because operators are guided by errant RVLIS information. One RVLIS train fails because the wetted insulation on the resistance temperature detector cable fails. The redundant RVLIS train fails because of a random equipment failure – It was pessimistically assumed that the occurrence of a LOCA would eventually fail the three affected resistance temperature detectors with a probability of 1.0. The redundant RVLIS train fails because of a random equipment failure. A generic wiring failure probability of 1.0×10^{-5} (Ref. 5, Table 3.3-1, item 423) is assumed. This is representative of the failure mechanism of a resistance temperature detector The potential for the operator to make an error due to two different indications from two RVLIS trains were considered and it was concluded to be incredible due to the following. When a RVLIS train fails due to wetting it will indicate off scale high or off scale low. When one RVLIS train indicates a reasonable value that is realistic and varies appropriately and the second train goes high or low, the operators can easily distinguish the train that has failed. However, a number of other issues that can potentially affect feed-and-bleed cooling must be resolved in order to assess the overall feed-and-bleed cooling failure probability.

54.4 Core Damage Frequency Calculation or the Bounding Calculation

The frequencies associated with these sequences depend on the resolution of other issues affecting AFW and feed-and-bleed cooling capability. To provide perspective on these sequences the following information is provided.

If the resolution of issues results in no significant changes to the AFW and feed-and-bleed cooling failure probabilities, the change in core damage frequency would be:

<u>Sequence 1 – LOCA occurs with an ATWS</u>

(Frequency of a LOCA of any size: 9.0×10^{-3} /critical year) x
(Criticality factor for Cook Unit 2--from Ref. 3, Table H-3: 0.68 critical year/reactor calendar year) x
(Probability of no reactor trip: 5.5×10^{-6}) = 3.4×10^{-8}/year.

<u>Sequence 2 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator</u>

(Frequency of a small LOCA: 9.0×10^{-3} /critical year) x
(Criticality factor for Cook Unit 2--from Ref. 3, Table H-3: 0.68 critical year/reactor calendar year) x
(Probability of reactor trip: 1.0) x
(Probability wetted level transmitters fail: 1.0) x
(Probability remaining level transmitters fail: 1.0×10^{-6}) x
(Probability of feed-and-bleed cooling failure: 2.9×10^{-2}) = 1.8×10^{-10}/year.

Sequence 3 – Small LOCA occurs with subsequent loss of AFW and RVLIS

(Frequency of a small LOCA: 9.0 x 10^{-3} /critical year) x
(Criticality factor for Cook Unit 2--from Ref. 3, Table H-3: 0.68 critical year/reactor calendar year) x
(Probability of reactor trip: 1.0) x
(Probability of normal AFW supply failure: 1.1 × 10^{-4}) x
(Probability wetted RVLIS train fails: 1.0) x
(Probability redundant RVLIS train fails: 1.0 × 10^{-5}) x
(Probability of feed-and-bleed cooling failure: 1.0) = 6.7 × 10^{-12} /year.

Sequence 4 – Small LOCA occurs with subsequent loss of ability to control the water level in the steam generator and RVLIS

(Frequency of a small LOCA: 9.0 x 10^{-3} /critical year) x
(Criticality factor for Cook Unit 2--from Ref. 3, Table H-3: 0.68 critical year/reactor calendar year) x
(Probability of reactor trip: 1.0) x
(Probability wetted level transmitters fail: 1.0) x
(Probability remaining level transmitters fail: 1.0 × 10^{-6}) x
(Probability wetted RVLIS train fails: 1.0) x
(Probability redundant RVLIS train fails: 1.0 × 10^{-5}) x
(Probability of feed-and-bleed cooling failure: 1.0) = 6.1 × 10^{-14} /year.

Therefore, the change to the core damage frequency would not be risk significant.

54.5 References

1. LER 315/97-006, Rev. 0, "Equipment in Containment Rendered Inoperable Due to Cracked Floodup Tubes," May 30, 1997.

2. LER 316/97-006, Rev. 0, "Equipment in Containment Rendered Inoperable Due to Faulted Floodup Tubes," October 10, 1997.

3. J. P. Poloski, et. al., *Rates of Initiating Events at U.S. Nuclear Power Plants 1987-1995*, NUREG/CR-5750, February 1999.

4. F. M. Marshall, et. al., *Common-Cause Failure Parameter Estimations*, NUREG/CR-5497, October 1998.

5. *Cook Nuclear Plant Individual Plant Examination Revision 1*, October 1995.

6. S.A. Eide, et. al., *Reliability Study: Westinghouse Reactor Protection System,: 1984-1995*, NUREG/CR-5500, Vol. 2, April 1999.