UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of:	)	
	)	Docket Nos. 50-348-CivP
ALABAMA POWER COMPANY	)	50-364-CivP
	)	
(Joseph M. Farley Nuclear	)	ASLBP No. 91-626-02-CivP
Plant, Units 1 and 2)	)	

SURREBUTTAL TESTIMONY OF ALABAMA POWER COMPANY

VOLUME I

Alabama Power Company

the southern electric system

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SURREBUTTAL TESTIMONY OF DAVID HUBER JONES,
BERNARD DOUGLAS MCKINNEY, JR. AND VINCENT S. NOONAN
ON BEHALF OF ALABAMA POWER COMPANY

I. INTRODUCTION

Q1. Please state your name and describe your current employment.

A: (Jones) My name is David Huber Jones. I am Manager of Engineering Support, Farley Nuclear Plant, for Southern Nuclear Operating Company, Inc.

(McKinney) My name is Bernard Douglas McKinney, Jr. I am employed by Southern Nuclear Operating Company, Inc., as the Manager of Nuclear Engineering and Licensing for Farley Nuclear Plant.

(Noonan) My name is Vincent S. Noonan. I am employed by HALLIBURTON NUS Environmental Corporation as General Manager of the Rocky Mountain Center (RMC) and Safety and Licensing Divisions.

Q2. Have you previously testified in this proceeding?

A: (Jones, McKinney, Noonan) Yes. Each of us have previously provided Direct Testimony in this proceeding on behalf of Alabama Power Company.[1]

Q3. What is the purpose of your testimony?

A: Our purpose is to provide Surrebuttal Testimony to that filed by James G. Luehman and Paul C. Shemanski on Behalf of the NRC Staff Concerning Enforcement. To do this, our testimony is generally organized so that it responds to the questions and answers of the Staff's witnesses in the order presented. For ease of reading, we have organized our Surrebuttal Testimony under the same four headings utilized by the Staff in their Rebuttal Testimony: December 1984 SER, Enforcement Matters, Mitigation and Escalation, and Inspections Conducted at Farley.

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[1]Unless otherwise indicated, the responses to each questions will be sponsored by Mr. Jones and Mr. McKinney. Mr. Noonan's responses will be separately identified.

II. DECEMBER 1984 SER

Q4. In his response to Q4, Mr. Shemanski contends that Alabama Power Company's understanding of the significance of the December 1984 SER is erroneous, is taken "out of context," and "simply is not reasonable given the wording of the entire SER and the information promulgated by the Commission at the time licensees were meeting with the NRC Staff to resolve environmental qualification issues." (Rebuttal Testimony, at pages 2-7). What is your perspective of Mr. Shemanski's testimony?

A: As an initial matter, we observe that the thrust of the Staff Rebuttal Testimony under this heading, and the one entitled "Enforcement Matters," is an attempt to shore up its evidence that Alabama Power Company "clearly knew or should have known" of the alleged EQ violations. There are other, less obvious issues raised, of course, but by discussing the meaning of the December 1984 SER, the meaning of various Information Notices, and, for the first time, contending that Alabama Power Company should have read EQ inspection reports from other utilities, the Staff is clearly focusing on the Modified Enforcement Policy and its mandate that, "[i]f the licensee does not meet the 'clearly knew or should have known' test, no enforcement action will be taken." Our Surrebuttal Testimony will refute the Staff's contention and fully demonstrate the basis for our conclusion that Alabama Power Company should not clearly have known of these violations.

As for Mr. Shemanski's testimony, it is our belief that the December 1984 SER, which was issued after more than five years of hard work by Alabama Power Company to comply with various EQ requirements, was a major milestone acknowledging Alabama Power Company's compliance with EQ regulations, as compliance was generally understood at that time. Because of the many times Alabama Power Company submitted documents, test reports and data to the NRC and its contractors, and the corresponding favorable NRC responses it received, it is also our belief that the December 1984 SER precludes a finding by the Board that Alabama Power Company "clearly knew or should have known" of the alleged EQ deficiencies in the Notice of Violation. We explained our EQ compliance efforts to the Staff in detail, particularly at a January 11, 1984, meeting. If deficiencies existed about which Alabama Power Company clearly should have known, then we believe that the Staff, with its knowledge about EQ, clearly should have told Alabama Power Company about them instead of communicating that its EQ program complied with 10 CFR 50.49 and that the Unit 2 EQ license condition had been met.

Q5. Please continue your discussion about Mr. Shemanski's testimony and the December 1984 SER.

First, it is undisputed that the December 1984 SER, and its associated transmittal letter, referred to the deficiencies identified in earlier Safety Evaluation Reports, the Franklin Research Center Technical Evaluation Reports, and the discussion held between the NRC Staff and Alabama Power Company on January 11, 1984, as documented in our letter dated February 29, 1984. Moreover, it is undisputed that additional letters dated March 14 and May 20, 1983, provided additional information to the Staff. Ultimately, the Staff concluded:

> Based on our reviews, we conclude that the Alabama Power Company Equipment Qualification Program is in compliance with the requirements of 10 CFR 50.49, that the proposed resolution for each of the environmental qualification deficiencies identified for Farley Units 1 and 2 is acceptable, and that the continued operation of Farley Units 1 and 2 will not present undue risk to the public health and safety.

(APCo Exhibit 21, at pages 1-2).

We understood that the word "program" as used in this SER referred to Alabama Power Company's efforts to identify, qualify, and document, its compliance with DOR Guidelines and NUREG-0588 (Category II).[2] The NRC Staff has provided testimony that reinforces this interpretation. In fact, at the hearing, Mr. Shemanski testified that an EQ program should

[2]Under 10 CFR 50.49(k), Alabama Power Company must qualify its equipment to these two standards.

identify and qualify equipment subject to EQ requirements, and document that qualification. (Tr. 390). For ease of reference, the relevant portion of the transcript is reproduced below:

> Q: I see a couple of sentences about the Staff's position that a licensee must establish a program for qualifying electrical equipment identified in 10 CFR 50.49(b).
>
> A: [Witness Shemanski] Yes.
>
> . . .
>
> Q: By program, do you mean to describe identification, qualification and documentation of Class I-E electrical equipment?
>
> A: [Witness Shemanski] I would extent [sic] that to the EQ Rule which talks about equipment important to safety.
>
> Q: I see.
>
> A: [Witness Shemanski] And that includes safety-related equipment, non-safety-related, and the Reg Guide 1.97.
>
> Q. Okay, so, equipment subject to EQ, <u>the program should identify it, qualify it and document the qualification?</u> (Emphasis added).
>
> A: [Witness Shemanski] <u>Yes, that's correct.</u> (Emphasis added).
>
> Q: <u>And that's what you mean when you talk about an EQ program?</u> (Emphasis added).
>
> A: [Witness Shemanski] <u>Yes.</u> (Emphasis added).

(Tr. 390). In their Direct Testimony, Messrs. Luehman, Potapovs and Walker describe the purpose of the inspections at Farley Nuclear Plant as "to review the program for environmental qualification of electrical equipment." (Staff Direct Testimony Concerning Enforcement, at page 13, A12).

It seems to us that, as used in these three important documents, the word "program" should retain its same meaning. If, for purposes of sworn testimony, an EQ program encompasses identification, qualification, and documentation of safety-related electrical equipment then, for purposes of an SER, it should be interpreted similarly. If, for purposes of an EQ inspection, the word "program" includes evaluating a licensee's EQ documentation then, for purposes of the December 1984 SER, the word "program" should be interpreted similarly.

Thus, it appears to us that we did not misinterpret or take out of context the meaning of the SER's conclusion that Alabama Power Company's program complied with the requirements of 10 CFR 50.49. We interpreted the SER to mean that our EQ "program," in which we identified, qualified, and documented our compliance with 10 CFR 50.49, had been reviewed and approved by the Staff.

In this Surrebuttal Testimony we have not restated all of the activities Alabama Power Company undertook to comply with EQ requirements from 1979-1985, but such efforts were extensive. They are discussed in our Direct Testimony (Jones, McKinney), at pages 17-25.

Q6. Will you also provide your perspective of why the SER, standing alone, precludes a finding that Alabama Power Company "clearly knew or should have known" of any EQ deficiencies?

A: (Jones, McKinney) On page 3 of the SER, under the Evaluation section, it says:

> The evaluation of the acceptability of the licensee's electric equipment environmental qualification program is based on the results of an audit review performed by the staff of: (1) the licensee's proposed resolutions of the environmental qualification deficiencies identified in the January 31, 1983 SER and January 14, 1983 FRC TER; (2) compliance with the requirements of 10 CFR 50.49; and (3) justification for continued operation (JCO) for those equipment items for which the environmental qualification is not yet completed.

(APCo Exhibit 21).

This statement clearly demonstrates that the Staff performed an audit review of Alabama Power Company's EQ program for purposes of determining compliance with the requirements of 10 CFR 50.49. As representatives of the licensee who received this SER, we can state that, prior to the deadline, we did not suspect that there were EQ issues or deficiencies about which

Alabama Power Company "clearly knew or should have known." Of course, Alabama Power Company knew that there would be an EQ inspection. Given the pattern of compliance efforts by Alabama Power Company, and favorable NRC responses in such important documents as SERs, however, we do not understand how a 1987 EQ inspection, ostensibly utilizing the state of knowledge existing in 1985, could ignore the conclusions of contemporaneous audit reviews and meetings described in the SER. Such conclusions were based on what was known by Alabama Power Company and the NRC Staff about the Farley EQ program and it is illogical to say now that Alabama Power Company "clearly knew or should have known" about any deficiencies. Indeed, had such EQ deficiencies been as patently obvious as the Staff now suggests, then we would expect the Staff to have said something to Alabama Power Company in our January 11, 1984 meeting or in a specific piece of correspondence. The Staff never did this, choosing instead to tell Alabama Power Company that based on the results of its audit review, its EQ program complied with 10 CFR 50.49.

Q7. Mr. Shemanski suggests that Alabama Power Company's interpretation of the SER is "not reasonable" because of the wording of the entire SER and the information promulgated by the Commission at the time licensees were meeting with the NRC Staff. (Rebuttal Testimony, at page 3). What is your response to this suggestion?

A: We believe that, read in its entirety, the SER supports our belief that no deficiencies in our EQ program, i.e., the identification, qualification, or documentation of qualification, existed before the deadline. Even if some documentation issues remained subject to inspection, the SER states plainly that, "Based on our discussions with the licensee and our review of its submittal, we find the licensee's approach for resolving the identified environmental qualification deficiencies acceptable." (APCo Exhibit 21, at page 5).

It is patently unfair for the Staff to tell us in 1984 that our approach to resolving deficiencies was acceptable and our program was in compliance with 10 CFR 50.49, and then in 1988, to conclude that a "programmatic breakdown" in EQ existed at Farley Nuclear Plant and that deficiencies existed that we clearly knew or should have known about. (Staff Exhibit 2, at pages 1-2). If it was so clear in 1984, then why did the Staff tell us? If it was so clear in 1984 and early-1985, then why did the Staff not say so, instead of leading us to believe that we had fulfilled our regulatory requirements? This is particularly true with respect to terminal blocks, since that was the only matter for which there was a "proposed resolution" outstanding. The resolution was discussed with the Staff in January 1984 and expressly accepted in the SERs.

(Noonan) I know for a fact that when I was on the Staff, it had nationwide knowledge about EQ compliance programs and anything Alabama Power Company "clearly knew or should have known" about would certainly have been known by the Staff. The Staff told Alabama Power Company its EQ program complied with 10 CFR 50.49, that its approach for resolving environmental qualification deficiencies was acceptable, after discussing the proposed resolutions "in detail" on a item-by-item basis with the licensee during the January 11, 1984, meeting. The Staff concluded that continued plant operation would not present undue risk to the public health and safety. If there were deficiencies that the Staff knew of, the Staff's practice was to tell licensees. We did not tell Alabama Power Company of any such "deficiencies" at the January 11, 1984 meeting or anytime prior to the deadline.

The fundamental work product of the NRC Staff that forms the basis for licensing atomic energy plants is a Safety Evaluation Report. In the context of EQ, the Safety Evaluation Reports were specific to the appropriate Farley unit, gave detailed discussion about the EQ compliance efforts of Alabama Power Company, and reached very specific conclusions. By contrast, Information Notices were mere correspondence that may have some applicability to some plants licensed by the NRC. These necessarily broad and wide-ranging documents did not supplant the specifics contained in a Safety Evaluation Report.

Q8. In his answer to Question 7, Mr. Shemanski contends that the NRC Staff never approved the Farley Master List. (Rebuttal Testimony, at page 10). He also contends that the 1981 SERs did not reflect "review and approval" by the NRC Staff of detailed environmental qualification documentation. (Id. at 10.) What is your response to this testimony?

A: The best response is found in the words of the 1981 SERs. (APCo Exhibit 14 - Unit 1, APCo Exhibit 15 - Unit 2). For Unit 1, the purpose of the SER was to identify equipment whose qualification program did not provide sufficient assurance that it would perform its intended function in a hostile environment. (APCo Exhibit 14, at page 2). To perform this task, the Staff conducted "an on-site inspection of selected Class 1E equipment and an examination of the licensee's report for completeness and acceptability." (APCo Exhibit 14, at page 2). The criteria described in the "DOR Guidelines and in NUREG-5888, in part, were used as a basis for the Staff evaluation of the adequacy of the licensee's qualification program." (APCo Exhibit 14, at page 2). The Staff issued a TER, which evaluated Alabama Power Company's response to Commission Memorandum and Order CLI-80-21 and IE Bulletin 79-01B. (APCo Exhibit 14, at page 2). The Staff also conducted an on-site verification inspection of selected safety-related electrical equipment. (APCo Exhibit 14, at page 2). The Staff developed a generic Master List of systems and equipment required to mitigate a loss of coolant accident (LOCA) and a high energy line break (HELB) basing such a list "upon a review of plant safety analyses and emergency procedures." (APCo Exhibit 14, at page 3). Alabama Power Company prepared a similar list and, "the list of safety-related systems provided by the licensee was reviewed against the Staff-developed Master List." (APCo Exhibit 14, at page 3). The Staff assessed 703 items of equipment identified by Alabama Power Company. (APCo Exhibit 14, at page 3). Then, in the SER, the Staff makes this statement:

> Based upon information in the licensee's submittal, the equipment location references, and in some cases subsequent conversations with the licensee, the staff has verified and determined that the systems included in the licensee's submittal are those required to achieve or support: (1) emergency reactor shutdown, (2) containment isolation, (3) reactor core cooling, (4) containment heat removal, (5) core residual heat removal, and (6) prevention of significant release of radioactive material to the environment. The staff therefore concludes that the systems identified by the licensee (listed in Appendix D) are acceptable, with the exception of those items deferred in Section 5 of this report.[5]

(APCo Exhibit 14, at page 3).

[5]For purposes of this enforcement hearing, Section 5 has no relevance.

The Staff also reviewed the service conditions of the affected equipment including temperature, pressure, and humidity conditions inside and outside containment, submergence, aging, and radiation. (APCo Exhibit 14, at pages 3-6). After doing this work, the Staff "determined that the licensee's listing of safety-related systems and associated electrical equipment whose ability to function in a harsh environment following an accident is required to mitigate a LOCA or HELB is complete and acceptable . . . ." (Emphasis added). (APCo Exhibit 14, at page 9).

From the licensee's perspective, it is very difficult to receive such a document and conclude, as Mr. Shemanski has done, that the NRC Staff did nothing to review or approve Alabama Power Company's Master List or equipment qualification documentation. The Staff may now be taking that position, but it appears to us to be glaringly at odds with the words they used in 1981.

Q9. Mr. Shemanski suggests that promulgation of 10 CFR 50.49, which did not occur until January 21, 1983, clarified and strengthened "the criteria for environmental qualification of electrical equipment important to safety." (Rebuttal Testimony, at page 11). Is this true in the case of Alabama Power Company?

A: No, it is not. Farley Nuclear Plant environmental qualification standards are described in the DOR Guidelines and NUREG-0588, Category II, and this is explicitly recognized in 10 CFR 50.49(k). It is our opinion that promulgation of 10 CFR 50.49 did not change the qualification standards applicable to Farley Nuclear Plant.

We note, also, that Mr. Shemanski agrees that the information provided by Alabama Power Company to Franklin (and which was later used to support the December 1984 SERs) was the "best available at the time." (Staff Rebuttal Testimony Concerning Enforcement, at page 12, A7). To us, this is clear evidence that the finding of the enforcement staff that Alabama Power Company "clearly knew or should have known" of other information is little more than retroactive application of 1987 knowledge. Said another way, if the information provided by Alabama Power Company to support the Staff's 1984 SERs was "the best available at the time," that necessarily precludes a finding that Alabama Power Company "clearly knew or should have known" of the kind of information that the NRC Staff now alleges it should have possessed.

Q10. What about the SER issued in March 1981 for Unit 2? Will you please comment on it?

A: Our conclusions regarding this SER are very similar to those regarding the one issued for Unit 1. Of course, Unit 2 was the subject of an operating license proceeding during this time frame and statements in the operating license hearing have been previously addressed by us in our Direct Testimony. The conclusion of the SER for Unit 2 was that Alabama Power Company's "listing of safety-related systems and associated electrical equipment whose ability to function in a harsh environment following an accident is required to mitigate a LOCA or HELB is <u>complete and acceptable</u> . . . ." (Emphasis added.) Even a cursory review of this SER reveals that extensive effort and review was undertaken by the Staff to reach this conclusion, both in the context of EQ requirements and a plant operating licensing proceeding.

Q11. In Question 8, Mr. Luehman and Mr. Shemanski contend that Generic Letter 84-24 "put APCo on notice of what was necessary for licensee certification of compliance with 10 CFR 50.49." Do you have a response to this contention?

A: Yes. We have previously pointed out that promulgation of 10 CFR 50.49 had no effect on the qualification standards applicable to Farley Nuclear Plant. Those standards were NUREG-0588 (Category II) and the DOR Guidelines. Generic Letter 84-24 identified certain Information Notices applicable to EQ. Thus, the issue is whether these subsequent

Information Notices can be used by the Staff to undermine its previous conclusions. To us, the answer is clearly no. We have previously testified about the specificity of the Staff's SER. We believe that specific correspondence on specific EQ issues overrides preceding "informational" correspondences.

Moreover, by letter dated January 7, 1983 (APCo Exhibit 112), Alabama Power Company wrote the NRC and requested, among other things, that the license condition 2.C(18)(a), (b) and (c) related to Unit 2's compliance with NUREG-0588, "be formally closed by the NRC." That license condition, shown as APCo Exhibit 83, required that all safety-related electrical equipment in Unit 2 be qualified in accordance with the provisions of NUREG-0588 and that complete and auditable records demonstrating such qualification be maintained.

By letter dated May 23, 1985 -- a few short months before the compliance deadline -- the NRC wrote Alabama Power Company regarding the "Evaluation and Status of License Conditions for Joseph M. Farley Unit 2." The transmittal letter said, "the enclosure to this letter indicates the <u>current evaluation and status of our review of your submittals relating to the identified license conditions</u> . . . ." (Emphasis supplied). (APCo Exhibit 84). The NRC concluded:

> The license condition required certain remedial actions or alternative actions no later than June 30, 1982. Commission

regulation 10 CFR 50.49 negated the June 30, 1982 completion date. By letter dated December 13, 1984, we have provided a safety evaluation which concludes that the EQ Program is in compliance with the requirements of 10 CFR 50.49.

Therefore, License Condition 2.C(18) has been met.

(APCo Exhibit 84, at page 1).

In our opinion, this affirmative statement from the NRC regarding the status of Alabama Power Company's equipment qualification efforts is not equivocal. It says plainly that the EQ license condition "has been met." It does not inform Alabama Power Company that there are EQ deficiencies about which it clearly knew or should have known.

The Information Notices on various items of electrical equipment are discussed in the context of the specific issues. These notices may, at most, indicate that certain items of equipment needed to be qualified. However, none provided notice, as the Staff now asserts, that our approach on the various issues was flawed. Further, none should receive greater weight and credibility than a specially prepared "Evaluation and Status of Certain License Conditions" by the NRC Staff. It would be inconsistent for the NRC Staff to tell Alabama Power Company, in the summer of 1985, that its EQ license condition is met, basing its statement on a current evaluation and review of EQ submittals, and then later contend that, during that same summer, Alabama Power Company "clearly knew or should have known" of multiple EQ deficiencies. These are mutually exclusive events.

Again, these Information Notices have previously been addressed in our Direct Testimony and Surrebuttal Testimony on the various technical issues allegedly raised by them. However, the important thing to keep in mind here is that none of these notices provide the recipients with a clear basis for a "clearly should have known" finding, as the enforcement staff is now suggesting. Some have nothing to do with the issues in controversy. They just happen to involve similar equipment, e.g., the alleged splice notice. (APCo Exhibits 4 and 41). Some are inconclusive, e.g., the T-drain notice. (Staff Exhibit 55). Another, IN 84-47 (Staff Exhibit 48), must be viewed in the context that the gist of that notice was discussed with the Staff in a January 11, 1984 meeting, and the Staff accepted Alabama Power Company's proposed resolution.

Q12. Mr. Luehman justifies the Staff's actions by noting that over 20 civil penalties were issued under the Modified Enforcement Policy and only Alabama Power Company has asserted that the December 13, 1984 SER "conveyed the NRC staff finding that Farley was in compliance with all the requirements of 10 CFR 50.49." What is your response to this?

A: It is irrelevant to us how other licensees interpreted their SERs. No attempt is made by either Mr. Luehman or Mr. Shemanski to correlate the issues raised in this enforcement hearing with the 20 civil penalties referenced in the testimony. We do know about the effort put forth by Alabama Power Company to comply with EQ; the many hours of work, the interaction with the NRC and its consultants, the audit reviews, TERs and SERs. To us, that is what counts in this enforcement proceeding, not what other utilities' may or may not have done.

III. ENFORCEMENT MATTERS

Q13. How do you respond to the testimony by Mr. Luehman answering Question 10 in his Rebuttal Testimony regarding undocumented engineering judgment and the necessity to document this judgment in a licensee's qualification file? (Rebuttal Testimony, at pages 17-18).

A: (Noonan) Mr. Luehman admits that the Staff "has in the past and continues to accept oral statements from licensees" regarding the qualification of a particular piece of equipment. (Staff Rebuttal Testimony Concerning Enforcement, at page 17, A10). He also admits that the December 1984 SER recognizes that a significant amount of documentation had already been reviewed by the NRC Staff and Franklin Research Center so that the primary objective of any subsequent file audit was to "verify" that the appropriate analyses and documentation exist in the file. (Staff Rebuttal Testimony Concerning Enforcement, at page 18, A10). The significance of this admission is that shortly before the deadline, Alabama Power Company had conveyed to the Staff, sometimes in writing and sometimes orally, its then-current state of knowledge regarding qualification of each item of Class 1E electrical equipment. The Staff had already undertaken "a number of pre-deadline inspections to monitor industry progress" (Staff Rebuttal Testimony Concerning Enforcement, at page 19, A10) and, thus, had superior knowledge about the issue in 1985. Our policy was that we would never have accepted statements or documents by Alabama Power Company regarding equipment qualification that were clearly erroneous.

Q14. Mr. Luehman identifies Bob LaGrange as a member of the inspection team that produced the Calvert Cliffs Inspection Report. (Staff Exhibit 63). He suggests that such a report illustrates the level of documentation the NRC Staff found necessary to comply with 10 CFR 50.49 implying, of course, that Alabama Power Company should have read that inspection report. (Rebuttal Testimony, at page 19). Do you have a response to this?

A: (Noonan) Mr. LaGrange was Section Leader of the Environmental Qualification Section, Equipment Qualification Branch, Division of Engineering, Office of Nuclear Reactor Regulation, U. S. Nuclear Regulatory Commission, subsequent to Mr. DiBenedetto. He remained in that position until the Equipment Qualification Branch was disbanded in 1985. During that time frame, Mr. LaGrange supervised the EQ reviews and evaluations performed by the NRC Staff and its consultants for all operating nuclear power plants and those under construction. He was involved with the NRC's EQ efforts for the entire six years the Equipment Qualification Branch existed. He then went to work with me at HALLIBURTON NUS as a senior executive consultant and provided consulting services regarding EQ to various nuclear utilities.

(Jones, McKinney) The Board should know that Mr. LaGrange executed a joint affidavit in which he addresses the issue of engineering judgment raised by Mr. Lehman. (Staff Exhibit 15). This affidavit provides his view, as he recalled it in 1988, regarding the level of documentation needed to meet 10 CFR 50.49. For ease of reference, the relevant part of this affidavit follows:[4]

> Q: In your opinion, what is the proper role of engineering judgment in complying with the EQ regulations as you helped develop them?
>
> A: Engineering judgment has long been recognized by the Staff as an area where significant regulatory and utility discretion is appropriate. Within many engineering disciplines, multiple reasonable conclusions, based on the same set of facts, are possible. As the regulator of the nuclear industry, the NRC has recognized that utility engineers can sometimes reach reasonable, albeit different, engineering conclusions even though presented with identical information. Therefore, for areas that require significant judgmental decisions, the Staff should be properly receptive to alternate views and hence, differing engineering judgments. The Staff has recognized this reality by developing its own internal "differing professional opinions" policy. In short, in our opinion, engineering judgment plays an

[4]To avoid any appearance of impropriety, Mr. Noonan's name has been removed from this affidavit, even though it is contained in a Staff exhibit.

important and necessary role in complying with EQ regulations.

Staff management has always been aware of the potential for judgment calls by licensees that differed from the Staff's preferred approach. While we were at the Staff, the test applied to licensee's compliance with EQ regulations was whether the licensee's technical position was reasonable. If it was, then the Staff may have still exercised its regulatory authority and required a licensee to adopt the Staff position that additional documentation was required, however, enforcement action regarding the differing view would not be, in our opinion, considered appropriate.

This same philosophy was anticipated in 1985 for 10CFR50.49 requirements and should accordingly be applied to Alabama Power Company. However, based on our current involvement in this Enforcement Action, it appears that the Staff has inexplicably retracted its prior acceptance of reasonable engineering judgment. We refer specifically to alleged violations of 10CFR50.49(j) where Alabama Power Company and the Staff have differing engineering opinions about whether a document properly demonstrates equipment qualifications. As we discuss the violations later in this affidavit, we will call attention to these differences of engineering judgment.

Q. While you were at the Staff, did you interpret 10CFR50.49 as requiring that all exercises of engineering judgment be documented in the licensee's files?

A. No. We are unaware of any regulatory requirement in 1985, or today, that requires a licensee to document its methodology for arriving at an engineering judgment (excluding, for example, a detailed analysis or systems evaluations). In the event a documented basis for the engineering judgment would be desired by the Staff, a licensee should be able to, at that time, document its engineering judgment without being penalized. Nothing more has been required in other regulatory areas and nothing more should be required for equipment qualification.

Q. Does the opinion you just expressed comport with the requirement of 10 CFR 50.49(j) which states that the licensee must provide qualification documentation in an "auditable form."

A. Yes. We note that 10CFR50.49(j) only requires that, "a record of the qualification, including documentation in paragraph (d) of this section, must be maintained in an auditable form for the entire period during which the covered item is installed in the nuclear power plant . . ." The list provided in 10CFR50.49(d) does not require or imply that documentation of engineering judgments must be maintained in written form or in the EQ file. As a practical matter, engineering judgments are frequently and continuously made during operation of a nuclear plant. It would therefore be impractical to document each "judgment". We, as former Staff EQ managers, never intended nor anticipated that the Staff now would require complete documentation of all engineering judgments in order to avoid imposition of a civil penalty. We obviously never communicated any such requirement to utilities, like Alabama Power Company, when we were on the Staff, and in our opinion it is inappropriate to conclude today that Alabama Power Company clearly knew or should have known of this requirement.

(Staff Exhibit 15, Affidavit, at pages 15-17).

Q15. Mr. Luehman testified that the NRC Staff carefully applied only pre-deadline knowledge in this case and further denies that the agenda from the August 1987 seminar at Sandia

National Laboratories has any relevance in this case. (Rebuttal Testimony, at pages 20-21). Do you have a response to this?

A: We simply cannot accept the implication that the remarkable similarity between the agenda at the Sandia Laboratories seminar in August 1987 and the violations found at Farley a few months later were coincidental. This is particularly true because the inspection team leader, Mr. Merriweather, admitted that, "The purpose of the Sandia seminar was to inform the inspectors, the EQ inspectors, of the latest and greatest of what was happening in the EQ inspections that have been going on since 1984." (Tr. 405).

It is not reasonable to suggest that the inspectors ignored this current state of knowledge while conducting the inspection. Nor do we agree that the NRC Staff "carefully" applied only pre-deadline knowledge in applying the Modified Enforcement Policy. The Modified Enforcement Policy had not been promulgated at the time of the Farley inspection. Of course, the EQ review panel met on this entire enforcement matter for less than two hours and no such evaluation was conducted by them.

(Jones) In addition, during the course of the inspection in September 1987, on numerous occasions I saw Mr. Merriweather refer to the Sandia seminar handouts or ask another inspection team member to recall the NRC position during the seminar when determining whether an identified deficiency needed to be pursued further. This is how I first learned of the seminar.

Q16. In Q/A 12, the suggestion is made that Alabama Power Company clearly knew or should have known of issues related to terminal blocks, GEMS, and lubrication because the Staff's interest in these issues had been documented in other inspection reports; for example, at Baltimore Gas & Electric's Calvert Cliffs Generating Station. It is also suggested that Alabama Power Company should have been on notice of these facts because a Bechtel employee was at Calvert Cl[illegible] during the inspection, and Bechtel was a primary EQ consultant to Alabama Power Company. (Rebuttal Testimony, at page 22). What is your response to this?

A: In our opinion, it is absolutely unfair to impute knowledge to a licensee, such as Alabama Power Company, on the basis of inspection reports from other utilities. In his deposition, Mr. Potapovs agreed with our position, at page 46:

> Q: [B]ut my specific question is, are you critical in any way of Alabama Power Company from what you know about its conduct in this matter for not looking at inspection reports in the public document room?
>
> . . .

> A: I'm not critical of Alabama Power Company for not having done that.

Along this same line, it is improper to impute knowledge of the Nuclear Utility Group on EQ to Alabama Power Company. Mr. Potapovs apparently agrees with this conclusion as well:

> Q: Can we say, though, that based on what you know you cannot give me your opinion that Alabama Power Company failed to exercise its best efforts because it did not join the Nuclear Utility Group on EQ? I'm not asking you to speculate or make something up, I'm just asking you to base your opinion on what you know now as you sit in that chair.
>
> A: Participating in the EQ group is not a requirement, and I cannot fault the utility for not doing it.

(Potapovs deposition, at page 47).

Finally, we believe that it is improper to suggest that the knowledge of Russ Bell, an employee of Bechtel Power Company, should be imputed to Alabama Power Company. We have determined that Russ Bell was at Baltimore Gas & Electric for approximately two and one-half years under circumstances in which he was a loaned employee who worked exclusively in Baltimore Gas & Electric's facility and was supervised by the EQ coordinator for the Calvert Cliffs facility. It is unfair for the NRC Staff to impute to Alabama Power Company, through Bechtel, alleged knowledge that a loaned employee may or may not have had, when that individual was working exclusively for

Baltimore Gas & Electric at its facilities and has very little, if any, actual contact with Bechtel during this time frame, much less any actual contact with other employees working on other projects within Bechtel. It is our opinion that if this information is so important then the NRC has the responsibility to notify the industry in a clear, unambiguous and understandable manner.

IV. MITIGATION/ESCALATION

Q17. Mr. Luehman, purporting to interpret Mr. Merriweather's sworn testimony, contends that Alabama Power Company did not exercise its best efforts to comply with EQ regulations by the deadline. (Rebuttal Testimony, at page 24). Please provide a response to this testimony.

A: Mr. Luehman's post-deadline perspective clashes with the affidavit of Mr. DiBenedetto and Mr. LaGrange[5] on this issue in 1988. For ease of reference, it is incorporated here as follows:

> Q. One of the mitigation factors which the Staff says it will consider in determining a proposed civil penalty under the Modified Policy is whether the licensee exercised its "best efforts to complete EQ within the deadline." Do you have an opinion whether Alabama Power Company exercised its best efforts to complete its EQ program by November 30, 1985?
>
> A. (Mr. LaGrange) Yes [I] do. In [my] opinion, the level of effort that Alabama Power Company devoted to the implementation of its EQ program was indicative of a licensee that exercised its best efforts to complete its EQ Program by November 30, 1985. As [I] have previously testified, [I was] instrumental in reviewing the EQ programs of virtually every nuclear utility in the United States during the 1980-84 time frame. In [my] dealings with Alabama Power Company, [I] found them to be responsive to any questions raised; they

[5]To avoid any appearance of impropriety, Mr. Noonan's name has been removed from this affidavit, even though it is contained in a Staff exhibit.

quickly provided the Staff with requested information and proceeded responsibly in their EQ efforts. This enabled the Staff to draft, review and issue Alabama Power Company's final SER in a timely manner. It is clear to [me] that Alabama Power Company's efforts to comply with environmental qualification in general met the best efforts of the other nuclear utilities in the country.

(Mr. DiBenedetto) I had several occasions to review and participate in the development and implementation of Alabama Power Company's EQ program. While at the Staff, I supervised the NTOL review of Unit 2 and reviewed the IEB-79-01B response of Unit 1. I also conducted similar reviews for virtually all other operating plants and NTOL's in the country. In my opinion, Alabama Power Company's EQ program was complete, responsive to the pertinent issues and was among the best of the EQ programs I evaluated. For example, in the Staff reviews prior to issuing the Unit 2 operating license, Alabama Power Company's EQ program was one of the few that was approved after only one visit. This meant that the Staff was not required to expend additional resources by re-inspecting this Unit.

Since becoming involved with Alabama Power Company in 1987, I have become aware of the efforts it undertook to comply with EQ after I left the Staff in 1981. In my opinion, the level of effort expended by Alabama Power Company thereafter increased, not diminished, and thus I believe that it maintained its best efforts to complete EQ within the deadline.

(Mr. DiBenedetto and Mr. LaGrange) One additional matter which we would all like to address is the statement in the Notice of Violation transmittal letter on page three that Alabama Power Company lacked "best efforts to complete environmental qualification of electrical equipment by the November 30, 1985 deadline". We were the designated management of the Staff during this time period with responsibility for evaluation of all EQ programs at NRC licensed utilities. We disagree with the NOV and base this disagreement on our personal knowledge of Alabama Power Company's responsiveness, desire

> and effort to excel in this area. Illustrative of this desire to excel are the corrective actions taken by Alabama Power Company after the EQ audit. They quickly and efficiently resolved any perceived problems in a conservative and prudent manner. Thus, in our opinion, Alabama Power Company should be afforded maximum mitigation for its best efforts to comply with the EQ deadline and, moreover, should not be subject to any penalty escalation.

(Staff Exhibit 15, Affidavit, at pages 19-21).

Two things are important about this affidavit: First, it is the affidavit signed by Mr. LaGrange, a witness whose credibility has now been accepted by the Staff. Second, the affidavit represents the joint opinions of two of the three NRC Staff individuals most knowledgeable about the efforts of licensees to comply with EQ prior to the compliance deadline. Nothing Mr. Luehman says in 1992 to justify his enforcement decisions can diminish this testimony.

Moreover, it is disingenuous for Mr. Luehman to fault Alabama Power Company for relying on outside expertise such as provided by Bechtel. It was typical in the industry then for utilities to seek advice from other consultants, and Alabama Power Company certainly was no different from any other utilities in this regard. For its own part, the NRC used Franklin Research Center as a major consultant and had Sandia design an EQ seminar.

What is really at work here is a clear recognition by the enforcement staff that the evidence strongly supports Alabama Power Company's position that it complied with the regulatory requirements of 10 CFR 50.49, as those requirements were understood prior to the deadline. The Staff cannot demonstrate that Alabama Power Company failed to engage in best efforts to comply with the EQ requirements, nor is there any credible proof that Alabama Power Company "clearly knew or should have known" of EQ deficiencies. The suggestion that such a conclusion can be supported by examining other utilities' inspection reports is not only unfair but completely different from anything expected by the NRC Staff. Even if such an approach was proper, there is no documented evidence that the enforcement staff performed such a review prior to imposing the $450,000 fine. (Response of Mr. Luehman to questions from Judge Carpenter. Tr. 306-316).

One additional matter, in their Direct Testimony the Staff says that it concluded that Alabama Power Company's efforts to comply with EQ "were not any more extensive than that of the average licensee." It seems unfair to use such a conclusion to escalate a civil penalty by 50% if, as it appears under the Staff's testimony, Alabama Power Company was consistent with the industry average.

Q18. Mr. Luehman suggested that Alabama Power Company still does not understand the NRC Staff's concern regarding changing out the V-type splices in the containment for fan motors. Specifically, he contends that Alabama Power Company was required to issue a Justification for Continued Operation (JCO) or immediately declare the fan motors inoperable. What is your response to this testimony?

A. We do not agree with Mr. Luehman. In Generic Letter 86-15, (Staff Exhibit 9, at page 1) it says:

> When a licensee discovers a potential deficiency in the environmental qualification of equipment (i.e., a licensee does not have an adequate basis to establish qualification), the licensee shall make a prompt determination of operability, shall take immediate steps to establish a plan with a reasonable schedule to correct the deficiency, and shall have written justification for continued operation. This justification does not require NRC review and approval.

Regarding these three requirements stated in the Generic Letter, Alabama Power Company made a prompt determination of operability and we have previously testified on that point. (See Direct Testimony of Love, Sundergill, Jones, Q/A 40-43, at pages 48-54.) The conclusions regarding operability of the splices, and the JCO, were documented in a letter dated September 30, 1987. (APCo Exhibit 108). In a meeting with the Staff held in Washington, D.C. on September 24, 1987, Alabama Power Company also explained this determination to the

Staff and the Staff consensus was that it would, "accept the Alabama Power Company judgment that splices are qualifiable at this time." (APCo Exhibit 94). This operability determination was later validated by Wyle, as documented in its test report. (APCo Exhibit 39).

As illustrated in Mr. Shipman's Direct Testimony (APCo Direct Testimony, Shipman, at pages 7-8, A9), Alabama Power Company also took immediate steps to establish a plan to correct the deficiency. As it turns out, this plan, which called for changing out the V-type splices in favor of Raychem splices, was implemented within eighteen days. Although Alabama Power Company had previously initiated a JCO, it was decided that the work to correct the deficiency could be completed prior to completion of the JCO and, accordingly, efforts on the JCO development were stopped. To us, Alabama Power Company went beyond the Generic Letter recommendation to, "take immediate steps to establish a plan with a reasonable schedule to correct the deficiency" by replacing promptly all fan motor splices with approved Raychem material. Moreover, it seems to us that it was appropriate to terminate action on the JCO since it obviously was no longer needed.

In any event, should Mr. Luehman continue to insist that a JCO should have been prepared, then we believe that the substance of the minute notes from the September 24, 1987 meeting (APCo

Exhibit 94) and the September 30, 1987 letter (APCo Exhibit 108) should certainly satisfy this concern. A specific JCO on the fan motors/room coolers would have been premised largely on our position that the splices would be operable in an accident environment, as articulated in APCo Exhibit 108.

V. INSPECTIONS CONDUCTED AT FARLEY

Q19. In response to Question 17, the Staff witness testified that, "For purposes of the Modified Enforcement Policy, the findings of the two inspections were considered together." He then goes on to say that the Wyle Test Report (APCo Exhibit 39), which applied to the V-type splices was "unacceptable." How do you respond to this testimony?

A: This testimony is inherently inconsistent with that provided by Mr. Merriweather and Mr. Paulk at the hearing in February. Mr. Luehman suggests that for purposes of the Modified Enforcement Policy, the findings of the two inspections would be considered together, yet Mr. Merriweather testified that he refused to consider the Wyle Test Report because it was not prepared during the inspection. (Tr. 383-384). It seems to us that if enforcement action is going to be taken on the basis of two inspections "considered together," then the opportunity under Section III of the Modified Enforcement Policy to provide additional information during the inspection should also last that long. The testing by Wyle was begun in August, 1987, and the report was available in October, 1987, well before the conclusion of the November 1987 inspection.

For enforcement purposes, the Staff wishes to combine the inspections and use the alleged violations in aggregate to impose a hefty civil penalty. Yet for mitigation purposes, or for demonstrating that the alleged violation was not sufficiently significant to justify civil penalty under Section III of the Modified Enforcement, the team leader refuses to even review the test report, saying that the inspection was concluded.

These two positions do not square. If the Staff views the September and November inspections as separate, it would be required to treat September as the "first round" inspection under the Modified Enforcement Policy. The November inspection deficiencies, if any, would be treated for enforcement purposes under Part 2, Appendix C, and a safety significant evaluation would then have to be conducted.

Q20. Does this conclude your testimony?

A. (Jones, McKinney, Noonan) Yes.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of:	)	
	)	Docket Nos. 50-348-CivP
ALABAMA POWER COMPANY	)	50-364-CivP
	)	
(Joseph M. Farley Nuclear	)	ASLBP No. 91-626-02-CivP
Plant, Units 1 and 2)	)	

SURREBUTTAL TESTIMONY OF ALABAMA POWER COMPANY

VOLUME II

Alabama Power Company

the southern electric system

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SURREBUTTAL TESTIMONY OF JESSE E. LOVE,
JAMES E. SUNDERGILL, DAVID H. JONES,
AND PHILIP A. DIBENEDETTO
ON BEHALF OF ALABAMA POWER COMPANY

I. INTRODUCTION

Q1. State your full name.

A. (Love) My name is Jesse E. Love. I am employed by Bechtel Corporation as a Project Engineer for the Farley Project.

(Sundergill) My name is James E. Sundergill. I am employed by Bechtel Corporation as the Engineering Supervisor of the Electrical and Control Systems Group of the Farley Project.

(Jones) My name is David Huber Jones. I am currently Manager of Engineering Support, Farley Nuclear Plant, for Southern Nuclear Operating Company, Inc.

(DiBenedetto) My name is Philip A. DiBenedetto. I am president of DiBenedetto Associates, Inc., which is an engineering and management services company that provides services to utility clients related to equipment qualification, quality assurance, and nuclear regulatory licensing. I am responsible for the technical and administrative management of the company, including participation in, and supervision of, the extensive environmental qualification (EQ) services that DiBenedetto Associates offers.

Q2. Have you previously testified in this proceeding?

A. (Love, Sundergill, Jones, DiBenedetto) Yes. We have previously testified on various technical issues raised by this enforcement proceeding.

Q3. What is the purpose of your present testimony?

A. (Love, Sundergill, Jones, DiBenedetto) Our present surrebuttal testimony is offered to address the rebuttal testimony of the various NRC Staff panels on the technical issues in this proceeding.

II. V-TYPE TAPE SPLICES

A. Introduction

Q4. What is the purpose of your testimony in this section?

A. (Love, Sundergill, Jones, DiBenedetto) The purpose of this section of our testimony is to respond to the Rebuttal Testimony of James G. Luehman, Norman Merriweather, Charles J. Paulk, Jr., and Harold Walker concerning V-type tape splices. Generally, this testimony is divided into several broad categories: the Okonite NQRN-3 test report, Wyle Test Report 17859-02P for CECo, the Arkansas Nuclear One (ANO) testing referenced by Mr. Paulk, and Wyle Test Report 17947-01 for Alabama Power Company. This testimony will discuss the pertinent part of these documents and their applicability to this enforcement proceeding.

B. Okonite Test Report NQRN-3

Q5. How do you address the Staff concerns given in the answer to Q5 about the alleged lack of documented qualification of Okonite tape and extrapolation of higher voltage tests described in Okonite report NQRN-3 (Staff Exhibit 21) to lower voltage applications at Farley?

A. (Love, Sundergill) In the test documented in Okonite report NQRN-3 (Staff Exhibit 21), the splice in question was in an in-line configuration with Okonite T-95 tape over the bolted connection and Okonite No. 35 tape over the T-95. In the Farley notes and details, this same configuration was approved for use at 5,000 volts and below. The basis for the engineering judgment for the acceptability of this application (for voltages at or below 5,000 volts) was that the No. 35 tape layer had shown no signs of significant degradation in the NQRN-3 test and it was the material which was directly exposed to the harsh environment. Since the environmental conditions are unchanged, it follows that there will be no degradation of the No. 35 over T-95 in other applications. This seems to us to be a perfectly obvious conclusion.

The T-95 tape is relied upon to provide the proper electrical insulation for the application. Since the NQRN-3 report demonstrated that T-95 wrapped with No. 35 will withstand the accident environment, it is only necessary to demonstrate that its voltage withstand capability is acceptable. To do this, only a simple volts/mil computation is needed. Based on a tape thickness of 20 mils and the published dielectric strength of 600 volts/mil for T-95, the total insulating capability of one layer is 12,000 volts without even counting the insulation capability of the No. 35 tape and ignoring the half over wrap instructions which would double the thickness of the T-95 portion of the splice. Thus, there is such an overwhelming margin that it is clear that the material used in the splices should not be a concern and that only the configuration of the splice should be an issue. This margin becomes even greater as the applied voltage decreases.

Moreover, there is no validity to the concern that testing an insulation system at a higher voltage cannot be extended to lower voltage systems. To demonstrate this, it is only necessary to review typical wiring practices in residential applications. (The principle applies to all other applications; the residential application is used due to its familiarity to everyone.) In residential wiring the typical type of wire which is used is a type called "Romex." This wire is rated for 600 volt service. That is, it is commercially tested to be able to withstand an electrical potential difference of 600 volts without any degradation to the insulation system. Of course residential circuits are typically 120 volt or 240 volt. Surely the entire electrical industry cannot be accused of incorrectly using this wire on a theory that the testing at 600 volts does not cover lower voltage applications. Mr. Paulk is obviously aware of this practice since he acknowledges in A19 of his Rebuttal Testimony the use of 1000 volt general purpose cable in 575 volt service.

Q6. What is your opinion on the applicability of the Okonite NQRN-3 report (Staff Exhibit 21) as qualification for submergence and instrument circuits?

A. (Love, Sundergill) Mr. Walker in A5 states that Okonite report NQRN-3 does not qualify the splice in question for submergence or for use in instrument circuits. It is unclear from Mr. Walker's testimony which is the splice in question: the general subject of the Rebuttal Testimony is V-splices, but the NQRN-3 report is for in-line splices. Regardless, Alabama Power Company has not claimed that either in-line or V-splice configurations are qualified for submergence (below flood level) and has not relied on NQRN-3 by itself for V-type splices in instrument circuits. Therefore, no matter which splice type Mr. Walker is referencing, we agree with his statement that NQRN-3 does not qualify splices for submergence or for instrument circuits. We still contend, however, that NQRN-3 qualifies the tape material for use at Farley Nuclear Plant and an analysis of the configuration in which it is employed is all that should be required to demonstrate qualification for configurations other than 5 KV in-line usage.

C. Wyle Test Report 17859-02P/V-Type Splice Operability

Q7. In A7, Mr. Paulk and Mr. Merriweather suggest that the "submergence test" of Wyle Test Report 17859-02P (APCo Exhibit 27)[1] is a valid application for Farley because the NEMA-12 box enclosure had a weep hole in the bottom and a level control system to prevent the test specimen from being submerged. Thus, the Staff witnesses imply that the failures identified in the test report resulted from V-type configurations, not submergence. Do you have a response to this?

A. (Love, Sundergill) As an initial matter, we point out that one reason Alabama Power Company engaged Wyle to test the V-type splice configurations found at the Farley Nuclear Plant was to confirm its engineering judgment that the failures observed in the CECo report did not apply to Farley Nuclear Plant. Nonetheless, the CECo test was a data point which supported our judgment -- upon identifying this potential concern -- that V-types splices would be operable under the accident environment conditions.

Turning to the test failures referred to by the Staff, there were a total of 20 specimens in the CECo test. Of these, 17 successfully passed the test. Two of the three failures were

[1]This may also be referred to occasionally as the CECo report.

caused by configurations unrelated to the splices themselves. In fact, Wyle stated (Report 17859-02P, pg. IX-I, Sect. 3.0 Results) (APCo Exhibit 27):

> Specimens Z11, Z12 and B4 were checked to find locations of a possible short circuit. On Specimens Z11 and Z12 the specimen shorted to the tray (or NEMA 12 enclosure) at a point close to where a tie wrap was attached to the cable to either hold the cable in the tray or hold a specimen tag to the cable (See Photographs IX-1 and IX-11). Thus, the point of failure was in the high temperature wire leads and not in the splice itself. The successful performance of Kerite splice specimens Z7 and Z13 (attached to different cable insulations) can be used to qualify the splice alone.

The remaining specimen which failed was identified as "B4". This specimen consisted of two Okonite AWG #14 wires lugged back-to-back, wrapped with Okonite T-95 tape, covered with No. 35 tape and configured with an open crotch. This was the only failure in the CECo test which was directly related to the splice itself. Wyle describes the failure as follows:

> Specimen B4 apparently arced at the crotch of the splice to the NEMA 12 enclosure. This specimen had visual evidence of chemical burns from the chemical spray which apparently concentrated on the bottom ledge of the enclosure. It is not known why this specimen failed the test and two other similar splices (specimens B5 and B6), in the same enclosure, passed.

(APCo Exhibit 27, pg. IX-I, Sect. 3.0 Results).

It is this concentration of chemical spray on the bottom ledge of the enclosure that gave us cause to feel that this condition would not be duplicated in the Farley configuration. It appears that this concentration of spray submerged at least a portion of the crotch of the splice. If this failure mechanism could have been confirmed, then the CECo report could have been used by itself for qualification at Farley. (The V-type splices were not subjected to submergence at Farley Nuclear Plant.) However, since the failure mechanism was not verifiable, plant-specific testing of the splices was performed to confirm our engineering judgment and analysis.

Q8. In A9, Mr. Paulk contends that the moisture intrusion pathway for a V-type tape splice is between the wires, "a straight shot to the connection." This is so, he contends, because T-95 tape "liquifies and runs when heated as stated in MLEA Letter 90-159, dated July 12, 1990 (Staff Ex. 67)." What is your response to this?

A. (Sundergill) Having now had the time to review the document quoted by Mr. Paulk as well as the associated documents which described the test in question, I am prepared to comment on Mr. Paulk's implied conclusion. Quite simply, Mr. Paulk is wrong.

Main Line Engineering Associates (MLEA) Letter 90-159 describes testing performed by ANO. Mr. Paulk did not explicitly state that the ANO results described in MLEA 90-159 invalidate the Farley testing in Wyle Test Report 17947-01. In his statements, he attempts to cast doubt on the validity and applicability of Wyle Test Report 17947-01. What Mr. Paulk has done in his testimony, however, is to provide only part of the details of the ANO testing. The ANO test does <u>not</u> support a conclusion that T-95 tape will "liquify and run" under Farley accident conditions.

The ANO test was an aging test, not a Loss of Coolant Accident (LOCA) test. It was a precursor to a LOCA test. As such, its purpose was to put the splice specimens in an end of life condition prior to LOCA testing as is required by IEEE 323-1974, NUREG-0588 Category I, 10 CFR 50.49, etc. The theory behind this testing is that set forth by Arrhenius: testing at a high temperature for a short time simulates natural aging at a lower temperature for a longer time. When accelerated aging tests are performed, it is economically desirable to test at as high a temperature as is practical to minimize the time in the test oven. In the testing performed for ANO, Nutherm International, the test lab, selected an aging temperature of 150°C. Somewhere between the witness points of 24 and 42 hours at a constant temperature of 150°C the T-95 tape and the Scotch #33 tape did display the characteristics Mr. Paulk mentioned. However, the significance of this result has not been discussed by Mr. Paulk. The test lab merely selected what turned out to be an improperly high aging temperature (150°C -- far in excess of qualification temperatures for Farley Nuclear Plant or ANO). Consequently the T-95 melted.

Accelerated aging is done to simulate age-related degradation; melting is a phase transformation which is not allowed by the Arrhenius method and, therefore, there is not an age-related phenomenon. The melting of T-95 tape has not been observed in any actual installation of which I am aware. When lower aging temperatures are used, such as in Wyle Test Report 17947-01, melting does not occur, the specimens are aged to their end of life condition, and the LOCA test can be initiated. In the 17947-01 test, specimens of splices insulated only with T-95, only with No. 35, with T-95 jacketed with No. 35, and T-95 jacketed with Scotch #33, were included. There were no anomalies with the specimens in this test. There is no significance to the ANO test cited by Mr. Paulk for Farley or for the industry; it is merely a case of a test being run at a temperature higher than the material could tolerate.

Q9. What is your opinion of Mr. Paulk's assessment of the engineering judgment used in respect to the splice configuration found at Farley Nuclear Plant?

A. (Love) I would define engineering judgment as an application of engineering experience, expertise, and knowledge, based on all available information. Historically, all judgments are not and need not be documented. Mr. Paulk apparently defines this term differently. As I understand his response to Q10, Mr. Paulk feels that an installation must be identical to that shown on a design drawing and there is no room for engineering judgment with respect to differences. In other words, Mr. Paulk rejects the concept of engineering judgment, for if the installation is identical to the design, there is no judgment required. I disagree with this approach. It leads to an impossibly high documentation standard.

D. Wyle Test Report 17947-01

Q10. Would you provide your response to the Staff's new "concerns" about the testing of V-type tape splices done for Farley Nuclear Plant and documented in Wyle Test Report 17947-01?

A. (Love, Sundergill, Jones) As an initial matter, we think it ironic that the NRC inspectors now express "concerns" regarding Wyle Test Report 17947-01 (APCo Exhibit 39), since during the EQ inspection these same individuals declined to examine this report. Such comments by these witnesses illustrate the new "concerns" of the inspectors as they retroactively attempt to discount qualification documents.

This report was available during the inspection. The current "concerns" of the inspectors should not be allowed as the basis for enforcement since the report was available for review and the inspectors opted not to review it.

Notwithstanding this initial matter, it is our opinion that Wyle Test Report 17947-01 is an acceptable qualification document used to verify our engineering judgment and conclusions derived from the review and evaluation of existing information for V-type splices used in EQ applications at Farley Nuclear Plant. (Our contemporaneous judgment made upon identifying the V-type termination issue was discussed in our Direct Testimony, at pages 48-54. Much of this rationale was documented in a letter to the NRC dated September 30, 1987 (APCo Exhibit 108) and was discussed with the Staff at a meeting on September 24, 1987.)

When Alabama Power Company decided to test representative samples of the splices, Bechtel dispatched two representatives to the Farley site to review approximately 80 samples of splices which had been removed from circuitry. These splices were destructively examined, that is, personnel cut them open and noted the exact configuration of the different type of splice materials. As the first few splices were examined, sketches were made of the splice construction. As subsequent splices were cut open they were compared to these sketches.

If the details were not comparable, a new sketch was drawn and a new splice category was created. In this way all of the splice samples were compared to each other and a total of 14 categories resulted. In some cases the initial sketch failed to bound a given sample which was very similar but, for example, may have had shorter taped legs or fewer wraps of tape. In these cases the original sketch would have been discarded and a new sketch drawn to show the more conservative configuration. Thus, the final 14 categories bounded all splice samples that were examined. Given the quantity of the samples examined, and the effort to ensure that the most conservative configuration was used, in our opinion, reasonable assurance existed that a representative sampling had been achieved.

During this process of determining representative samples, Wyle Labs was contacted and apprised of the intent to test the V-type tape splice configurations. The first recorded date of contact is August 21, 1987. The Test Plan (Wyle Number 17942-01, contained as an appendix to Test Report 17[illegible]7-01) is dated August 27, 1987. Thus, before the NRC's "reactive" inspection, the splices had been categorized and contacts were initiated with the test lab. Actual testing was started on September 1, 1987, and concluded on September 25, 1987, fully in accord with the test plan. Contrary to earlier Staff concerns, there was no premature termination of the test. The test went full term and produced the satisfactory, confirmatory conclusion that the splices were qualified for use at Farley Nuclear Plant.

This process of determining representative samples, and then testing them, responds to the concerns raised by Messrs. Paulk and Walker in their Rebuttal Testimony. For example, in A17, Mr. Paulk expresses concern that Alabama Power Company did not totally encapsulate the T-95 tape in any of its V-type splices. He further expressed concern that the plant electricians were confused about the proper configuration and material for the splices. In A24, Mr. Paulk repeated his concerns about an undetermined number of configurations and the various materials that were used. In A28, Mr. Walker also expressed concern about how closely the test specimens represented the Farley installations. These concerns are addressed by the method described above to obtain and test representative samples of splices. Included in these specimens were configurations with T-95 wrapped with No. 35, wrapped with Scotch #33 tape, and T-95 by itself with no outer wrapping. There were also specimens which were made up entirely of No. 35 tape. Regardless of any confusion on the part of the craft that may be postulated by Mr. Paulk, the methodology that was used in determining categories for the test covered as-found configurations at Farley Nuclear Plant. Further to this point, we know of no instance where a Staff inspector has claimed to have seen a splice configuration at Farley which was not covered by one of the categories tested.

Q11. In A20 of his Rebuttal Testimony, Mr. Paulk states that Mr. Jones was incorrect in saying that there were only about 250 V-type tape insulated connections (splices) at the Farley site. Mr. Paulk provides data suggesting a total of approximately 1020 such connections (splices), not including any instrumentation connections, in both units at Farley Nuclear Plant. Mr. Jones, do you have a response to these statements?

A. (Jones) Yes. Mr. Paulk states in his Rebuttal Testimony, "I believe Mr. Jones meant to say that there were approximately 250 components per unit affected." Mr. Paulk is correct that I was referring to "components" since that is how we tracked splices; however, our agreement ends there. First, Mr. Paulk has taken my statement out of context. My testimony on this point starts in the transcript on page 1010 at line 16 and goes through line 5 of page 1012 and is quoted here for convenience:

> Q. All right. Now, Mr. Jones, approximately how many V-type tape splices were discovered to exist at Farley? I don't think that's in your testimony.
>
> A. [Witness Jones] I don't have a number.

Q. Can you give us an order of magnitude? I think Mr. DiBenedetto indicates that there is going to be at least a thousand or more splices at a plant. Is that reasonable?

A. [Witness Jones] I would say it's not that magnitude. I would -- and I'm guessing, but I would say in the order of 250, maybe, was a ball park number of what we had in our plant.

Q. Okay.

A. [Witness Jones] I'm referring to V tape splices.

. . .

Q. I am referring now to Page 56 of your testimony, and this is question and answer 46. Since it's sponsored by all three of you, I suppose whoever feels most qualified to answer this question can do it.

Prior to testing, APCo found 82 V-type terminations at the Farley units. I understand that to mean that prior to the testing of the V splices which culminated in the October 1987 Wyle test report, that's all you had found up until that time. Is that correct?

A. [Witness Jones] That's correct.

Q. That's what that means.

A. [Witness Jones] That's right.

Q. Although there may have been another 100 or so out there?

A. [Witness Jones] That's right. We were developing the testing parallel to doing the replacement with Raychem.

(Tr. 1010-1012).

It is clearly seen from my testimony on this issue that: (1) At the time, I didn't have an exact number of V-type tape splices; (2) the number (250) was a "ball park number" -- an approximation; and (3) I was explaining Alabama Power Company's position on the 14 configurations related to the 82 configurations dissected.

Mr. Paulk, in his Rebuttal Testimony, seeks to cast doubt in this Board's mind regarding the applicability of Alabama Power Company's specific V-type tape splice testing to the splices installed in the plant. Mr. Paulk is attempting to accomplish this by questioning whether our testing of 14 V-type tape splice configurations envelop the "336 connections" for solenoid valves, "624 connections" for motor operated valves (MOVs) and "60 connections" for motors (not including any instrument connections). Since Mr. Paulk questioned my "ball park" number in his Rebuttal Testimony, I reinvestigated my basis. My reinvestigation reached the following conclusions:

(1) Mr. Paulk made a simple assumption. He assumed that all 84 solenoids, 104 MOVS, and 10 motors in the EQ scope in each unit had V-type tape splices. This simple assumption is simply not true.

(2) Based upon a review of maintenance records, there are a total of 298 components in both units which had V-type

splices. This total number of components includes solenoids, MOVs, motors, and instruments located inside containment, the main steam valve room, and outside containment excluding the main steam value room -- hence, Mr. Paulk is wrong in purporting that I must have been talking about 250 components per unit. Further, it is interesting to note that only 152 componants affected are located inside containment.

(3) Based on the quantity of splices required for each affected component, there was a grand total of approximately 718 V-type tape splices (connections) in Farley Nuclear Plant.

(4) As I mentioned earlier, we were tracking this issue by component -- hence, the 82 splices dissected represent 82 components -- 82 of the 298 affected (28% of the affected components).

(5) In the 82 components in which V-splices were found, there were a total of 236 V-splices. In each of these 82 components, the splices for the respective component were identical. Thus, the 82 samples are identical to their respective counterparts (33% of the 718 affected splices).

(6) Therefore, Alabama Power Company continues to have a high degree of confidence that the splices tested were representative of installed splices given that the 14 tested splices enveloped the 82 samples which in turn were identical to the 236 installed splices, coupled with our knowledge that one of the electricians who had installed such splices in Farley Nuclear Plant, based on skill-of-the-craft, supervised the preparation of the samples tested at Wyle.

Q12. How do you respond to Mr. Walker's concern about the propriety of utilizing Arrhenius techniques to extend accident testing expressed in A14, 15 and 16?

A. (Sundergill) Again, the NRC Staff has raised a new concern that was never expressed to Alabama Power Company during the EQ inspection in 1987. In fact, according to his testimony, Mr. Walker does not recall reviewing the Wyle Test Report until sometime in 1989. (Tr. 411). (The Staff's Direct Testimony, at page 15, shows that the Staff did not review the report until 1990.) Notwithstanding this new concern, Arrhenius techniques have been in use in the industry for many years. Test labs routinely use this principle to extend testing to encompass postulated accident durations of 30 days, 100 days, 180 days, even as long as one year. The basis for using this technique is no different than for using accelerated aging to verify qualified life of a component. That is, the technique is equally applicable for pre-LOCA testing as for post-LOCA transient testing.

Furthermore, various NRC inspectors have approved this technique over the years. In the particular instance of the Wyle test for Farley, Wyle Labs proposed the use of this technique. Wyle is a nationally recognized lab which has performed a major quantity of the qualification testing for the American nuclear industry. As a result of their preeminence in the field, their endorsement of this technique should not be taken lightly.

As additional verification of the acceptability of this technique and the longevity of its acceptance, refer to section 5.2.1 of the DOR Guidelines, Simulated Service Conditions and Test Duration, where it states,

> The time duration of the test should be at least as long as the period from the initiation of the accident until the temperature and pressure service conditions return to essentially the same levels that existed before the postulated accident. A shorter test duration may be acceptable if specific analyses are provided to demonstrate that the materials involved will not experience significant accelerated thermal aging during the period not tested.

Thus, for at least 12 years the NRC Staff has recognized that accident testing may be for a shorter duration than the postulated accident.

Another early document indicating NRC acceptance of this technique is contained in an NRC memorandum from William V. Johnston to Thomas M. Novak dated December 29, 1982. (APCo Exhibit 113). Attached to that memorandum is a document entitled, "Supplement to Safety Evaluation Report Office of Nuclear Reactor Regulation Equipment Qualification Branch Shoreham Nuclear Power Station Unit No. 1 Docket No. 50-322." On pages 3-5 of that supplement under section e, it states:

> Performance of the safety function for the accident duration: During LOCA testing, electrical operability was not demonstrated for the duration of the test, nor was adequate analysis provided to demonstrate operability for the 180 day accident duration. The applicant has now provided analysis to extend the test operability time to 180 days by equating temperature margins to time. We find this analysis to be acceptable.

Thus, at least nine years ago the NRC Staff was accepting licensees' analyses which extended accident testing to envelop plant-specific conditions.

Sandia document SAND86-0723C, written by Mark J. Jacobus, upheld this principle in 1986. In section III 2, it states in relevant part:

> A second method that is frequently used by utilities is post accident acceleration using the Arrhenius technique. The implicit assumption in using this technique is that the limiting degradation mechanism is thermal aging via a first order reaction. This method has generally been accepted by inspectors for 'reasonable' amounts of acceleration for the long-term steady-state conditions of the post accident environment. None of the qualification regulations deal specifically with post accident acceleration, but testing combined with analysis is considered by the regulation to be an acceptable qualification method.

This document was published in the time frame immediately prior to the V-splice testing which was done for the V-splices for Farley Nuclear Plant.

This acceptance of Arrhenius techniques is still valid at the present time. In the May 16, 1990 NRC letter from Gary M. Holahan to Samuel J. Collins (Staff Exhibit 26), the following statement was made in analyzing Wyle Test Report 17947-01 for Farley splices:

> Moreover, the duration of the LOCA simulation was only 45 hours. The licensee is apparently extended[sic] the 45-hour period to 33 days by use of the Arrhenius equation. There is reason for some concern in this area because the staff has always held the position that the transient portion of a temperature vs. time curve that is generated from a LOCA test should not be used in an Arrhenius calculation. Therefore, the only portion of the test curve that is considered available for use by the Arrhenius technique to extend the test to 33 days is the portion after 167 minutes when the temperature stabilized at 245°F and remained constant for the remainder of the test.

(Staff Exhibit 26, at page 2). (Note that in actuality the Wyle test stabilized at 240-245°F, 84 minutes into the test, not 167, but the principle expressed by Mr. Holahan is still valid.)

As additional indication of the present-day acceptance of this technique, refer to USNRC Region I inspection report 50-213/91-80, prepared by Mr. R. K. Mathew, Team Leader Electrical Section, Engineering Branch, DRS and approved by Mr. C. I. Anderson, Chief, Electrical Section, Engineering Branch, DRS. (APCo Exhibit 114). This report was for the electrical distribution system functional inspection conducted 1/22 - 2/22/91 at the Haddam Neck Plant. In section 3.2.2, Qualification of CAR Fan Motors, it states:

> The licensee used the Arrhenius Equation to extrapolate the post-accident operating time. This extrapolation included the peak containment temperature portion of the temperature-vs-time profile.
>
> Following the inspection of February 26, 1991, the licensee transmitted to the team their justification for applying the Arrhenius Equation to the peak containment portion of the temperature vs time profile, especially for the case of the CAR fan motors. The team agreed that the qualification of the CAR fan motors was established.

As a result of the above-cited examples, it appears that Mr. Walker's opinion on the use of Arrhenius techniques in extending test durations is not endorsed by the Staff in general.

Q13. How do you respond to the Staff questions concerning the acceptability of the activation energy used by Wyle in computing the equivalent degradation of the post-LOCA period of testing?

A. (Sundergill, DiBenedetto) The activation energy which was used by Wyle to determine the test duration was a value of 1.23 eV. This activation energy was determined by Wyle from information provided to them by Okonite. It is a standard value in the Wyle aging and materials library and to our knowledge has not been questioned in previous NRC reviews of Wyle and Wyle reports used at other utilities.

The calculation which Wyle performed to determine test duration assumed a straight-line decrease from the 240°F point of the calculated accident profile to the end point of 120°F. While this was a conservatism, the conservatism was not required because of others already in the calculation. For example, the calculated accident profile used conservative assumptions in its preparation. The test profile had a peak temperature in excess of 425°F, while the calculated peak for Farley is 378°F. Finally, the calculated duration of the

Farley accident is 30 days and the test was extended for 33 days. Thus, the conservatism that Wyle added is not needed.

Therefore, in addressing Mr. Walker's new concern in A14, the equivalent duration was recalculated using a step-wise decrease rather than a straight line decrease. The steps are at or above the required profile at all points; therefore, there is remaining margin in this technique since most of the points are still in excess of the calculated profile. Using this new profile and calculating the equivalent duration results in the 45 hour test being equivalent to an accident in excess of 40 days with an activation energy of 0.65eV. Thus, the No. 35 tape which has an activation energy of 0.65eV was exposed for a period of time in the test chamber much in excess of the calculated duration. The equivalent duration at 1.23 eV is even greater than 40 days and Mr. Walker's postulated 1.10 eV is also greater than 40 days. Therefore, regardless of which material is being addressed or what the postulated activation energy is, the results of this calculation show that the equivalent duration of the test is in excess of the requirements.

Notwithstanding the above argument, Mr. Walker's assertions are still invalid. He states in A14 that the T-95 tape is not sufficient for splicing without the No. 35 covering. However, there were specimens in the 17947-01 test (APCo Exhibit 39) that had no No. 35 covering. These specimens also successfully passed the test, proving that T-95 tape by itself is acceptable for splicing.

Q14. How do you respond to Mr. Walker's concerns about extrapolating the results of Test Report 17947-01 (APCo Exhibit 39) to encompass qualification for splices in instrument circuits?

A. (Sundergill) Mr. Walker also feels that the Wyle test 17947-01 cannot be used for qualification of instrument circuits. In A14 he states:

> In the Wyle test report No. 17947-01, only two specimens (Nos. 10.1A and 10.1B) that could potentially be used in an instrumentation circuit remained energized throughout the test. However, the test ran for 39.4 hours [it actually ran for 45 hours] and the requirement for Farley (in accordance with Mr. Sundergill's testimony, page 64, line 2) is 33 days.

Similar feelings are expressed by Mr. Walker in A15. Mr. Walker's objections to the use of Arrhenius techniques in extending test durations have been shown not to be endorsed by the Staff in general. Therefore, his sole expressed reason for not applying the 17947-01 test to instrument circuits does not appear to have a sound basis. It should be noted that in A16, Mr. Walker stated that:

> ...there are some other questions concerning grounding of the test set-up that should be addressed.

Mr. Walker does not further define these questions, so no response is possible other than the opinion of Bechtel, Alabama Power Company and Wyle that the test set-up was properly grounded.

In A28, Mr. Walker also adds to his list of concerns a new issue about the cable size used in the test for the specimens which verified qualification of splices for instrument circuits. Mr. Walker does not state why he feels that AWG No. 12 wire cannot be used for qualification of instrument circuits made with smaller gauge wire. The issue of extrapolating higher voltage testing to lower voltage applications does not appear to be at issue here. In the absence of specific reasons from Mr. Walker, it can only be surmised what his concerns are. The only such concern which readily springs to the surface would be a possible concern over the physical geometry of the configuration. If this is the case, such a concern can be dismissed by considering the splice from an end-on perspective. In this view the wires would be seen as circles with the tape wrapped around the outside of them. If the tape was taut and not self-fusing, there would be an air gap between the tape and the curvature of the wires between the two wires. The smaller the wire the smaller the air gap. The use of a larger gauge wire would produce a larger air gap and a consequent increased probability for moisture ingress. Thus, the use of a larger gauge wire in this application is more conservative and what is assumed to be Mr. Walker's concern is put to rest.

(DiBenedetto) Let me add that Mr. Walker's concern is irrelevant to the purpose of the Wyle test. In this regard, it is important to note that the intent of the Wyle test was to verify and confirm conclusions about the capability and qualification of the splice material and splicing technique. The results of the confirmatory test indicate that the splice material and wrapping (skill-of-the-craft) technique maintained an adequate mechanical boundary (i.e., no moisture intrusion). In this way, the electrical integrity of the circuit was maintained. Thus, the Wyle Test Report further demonstrated that the application of tape splices (using qualified materials and knowledgeable installers) is appropriate for use at Farley. On this basis, it is irrelevant and of no concern whether or not there are splices on 18 to 22 gauge cable at Farley.

Q15. Please address now Mr. Paulk's and Mr. Merriweather's stated concerns regarding whether the Wyle test addresses qualification for instrument circuits.

A. (Sundergill) Mr. Paulk feels that Wyle Test Report 17947-01 (APCo Exhibit 39) is not valid for splices in instrument circuits for several reasons. The first reason Mr. Paulk gives is that the test was not intended to encompass instrument circuits since, presumably, the pass/fail criterion was too broad. The original criterion was that no fuse blow and that there be no change in voltage more than ±25%. Circuits were monitored for leakage current and insulation resistance (IR) changes for information only. However, since none of the fuses blew and the voltage fluctuations were insignificant, the attention should be properly centered on the IR values and the leakage current values. Just because allowable fluctuations in these parameters were not set prior to testing does not mean that the monitored results are meaningless. Rather, it means that these results are even more meaningful because the pass/fail criterion was met. A review of these parameters shows that the splice specimens performed superbly in the test and verified our prior conclusion that the V-type tape splices tested were qualified for use at Farley Nuclear Plant. Regardless of the intent of the test, it is the results of the test which must be addressed. If the results show that the splices are adequate for use in instrumentation circuits, then it is acceptable to use them in that application. Therefore, Mr. Paulk's first reason is not valid.

Second, Mr. Paulk finds fault with the arrangement of the test circuitry since he feels there would be difficulty identifying any leakage from the splice because of the location of the grounds and because of the lack of verification of an adequate ground. The test specimens were arranged in the test so that they were forced against the raceway or condulets in which they were mounted. The fixtures on which the raceways and condulets were mounted were in turn tack welded to the test chamber to ensure a good path to ground. Therefore, I feel that, contrary to Mr. Paulk's opinion, there was an adequate ground established and that additional verification of it was not necessary.

Mr. Paulk's concern with the location of the ground is puzzling. The test circuitry was arranged to detect leakage to ground regardless of where it occurred in the test circuit: in the splice connection, in the Wyle splice to the specimen circuit, or in any of the wiring in the circuit. In fact, due to an installation error, a leakage current of 1.2 mA was imposed on the wire lead of one of the specimens. This current was detected by the test circuit proving its efficacy and resolving Mr. Paulk's second concern.

In A10, Mr. Merriweather explains the consequences of electrical shorts to ground. I quite agree with Mr. Merriweather's explanation and his concern that this is a failure which could be common mode if not prevented. I feel that the test that was performed by Wyle Labs for Farley (documented in test report 17947-01) (APCo Exhibit 39) demonstrates that there were no ground faults in the V-splice specimens even though the specimens were mechanically fastened to ground planes to eliminate the effect of electrical resistance of an air gap.

Q16. How do you address Mr. Paulk's concern with the size of fuses used in test 17947-01 (APCo Exhibit 39)?

A. (Sundergill) Mr. Paulk's concern with fuse sizing is perhaps an oversight on his part. He states in A15 that,

> ...the sizes of the fuses in the test circuits (i.e., 30 to 150 amps) were too large for instrument circuits.

Mr. Paulk is absolutely correct in this statement. As shown on pages VI-22 of 17947-01, 50A fuses were used in the circuits specimens 1, 2 and 3; these circuits, as shown on page VI-6, were energized at 27A. Specimens 7, 8 and 9 were fused at 30A (pg. VI-22) and energized at 20.2A (pg. VI-6). Specimens 4, 5 and 6 were fused at 150A (pg. VI-23) and energized at 130A. These specimens were intended to demonstrate the adequacy of V-type connections in power and control circuits. As such, it is not proper to extrapolate the results of these samples to instrument circuits. It is specimens 10, 11, 12, 13 and 14 which are relied on to demonstrate adequacy as instrument circuits. (Specimens 10.1A and 10.1B were continually energized during the test, so primary reliance is placed on extrapolating their results to instrument applications.) As shown on page VI-24 of Test Report 17947-01, these circuits were fused at 3A and as shown on VI-6 they were energized at 200mA. Therefore, Mr. Paulk is correct as far as he goes in his analysis but he apparently overlooked the circuits most appropriate for this issue.

In particular, specimens 10.1A, 10.1B, 11.1, 12.1, 13.1 and 14.1 were monitored for leakage current to ground. The test setup employed by Wyle was monitored to a resolution of 10 microamps. That is, any current greater than 10 microamps would have been detected by the setup. Therefore, a 0 reading by Wyle during the test could conceivably have been as much as 10 microamps. Since the most sensitive instrument circuits function in the 4 to 20 milliamp range, a leakage current of 10 microamps (0.01 milliamps) would introduce an error of 0.25% (0.01 / 4) at the low end of the scale. There would be even less error at the high end. Consequently, the testing documented in Wyle Test Report 17947-01 can be readily extrapolated to cover instrument applications and demonstrates the maximum error that could be postulated would still be insignificant.

As a sidelight to this issue, Mr. Jim Gleason, Director, Nuclear Engineering, for Wyle Labs, stated that on Nov. 21, 1989 he had a phone conversation with Mr. Paulk, Mr. Walker and Mr. Mark Jacobus of Sandia concerning the Wyle test documented in 17947-01. Mr. Gleason told the three gentlemen that he considered that it was valid to extrapolate the test to encompass instrument circuits. Mr. Gleason further stated that Mr. Jacobus agreed with him, but Mr. Paulk did not. No opinion from Mr. Walker was noted. Mr. Gleason's telephone conversation documenting this discussion is provided as APCo Exhibit 115.

Q17. What is your response to Mr. Merriweather's concern about the details of the terminations?

A. (Sundergill) Mr. Merriweather's concern for the termination details of an instrument splice does not have merit. Termination details such as solder vs. crimp connections, quantity of ground points or cable type are simply not at issue. Regardless of the type of mechanical connection or any of the other termination details, the pertinent issue is the means of maintaining the insulation integrity for the covering of the mechanical connection.

Q18. How do you respond to Mr. Paulk's allegation that the covers were not open during LOCA testing on samples 10.1A and 10.1B?

A. (Sundergill) In A13, Mr. Paulk revisits the issue of whether or not the covers of the condulets were open or were covering the condulet opening during the LOCA testing. (Tr. 1022-1023). Subsequent to the cross-examination, Mr. Rick Woodfin, who was the Alabama Power Company witness during the splice testing, confirmed that the specimens were tested as shown in the photographs on page VII-7 of test report 17947-01. (APCo Exhibit 39). These photographs clearly show the condulets with the covers open. Mr. George Langford, who was the Bechtel witness during the splice testing, also repeated to me his earlier statement that the condulets were open during the testing.

However, even had the covers been closed, there should be no concern. The covers are closed in the installation at Farley. The intent of having them open during the test was to introduce conservatism in the test. But if they had been closed they merely would have duplicated the as-installed condition. Moreover, as evidenced in photograph VII-5, there was evidence of significant rust inside the condulet. So whether or not a cover was in place, sufficient moisture entered the condulet to rust the fitting and consequently expose the splice to moisture. There were no failures reported.

Q19. How do you address Mr. Paulk's latest concerns about orientation of the splice samples during the 17947-01 (APCo Exhibit 39) testing?

A. (Sundergill) Mr. Paulk also is concerned that the open end of the V-type connections were facing downward in the motor limit switch configuration but were facing upward in the cable tray. The specimens that were facing downward were secured to the rear of the Limitorque limit switch compartment to try to establish as short a path to ground as possible; the specimens in the cable tray were facing upward so that spray would have the best chance of getting into the splice crotches. Both of the test configurations were oriented to be conservative, each in a different way. Both configurations successfully completed the testing. It is interesting to note that no matter what the orientation, Mr. Paulk appears to have a problem with it.

Q20. What is your opinion concerning the ability of the V-type tape splices to insulate the electrical joint if there was no issue of submergence?

A. (Sundergill) In A8 both Mr. Paulk and Mr. Merriweather express their feeling that even if the splices were not subject to submergence, the insulation on the splices would not have been sufficient to prevent grounding. This is apparently a case of the inspectors presenting their personal opinions. The simple fact of the matter is that the splices were tested and passed the test as documented in Wyle report 17947-01 (APCo Exhibit 39). There is no unsubstantiated opinion that can invalidate these results.

Mr. Paulk does mention a personal experience involving a failure due to moisture intrusion into the opening of what he considers a V-type configuration similar to those at Farley. However, for this experience to be considered applicable, Mr. Paulk would need to provide a similarity analysis or a detailed explanation of the exact circumstances surrounding his experience. Otherwise, there can be no conclusion drawn from Mr. Paulk's experience that would cast any doubt on the Farley splice installations.

Mr. Merriweather mentions concerns with the CECo test documented in Wyle report 17859-02P (APCo Exhibit 27). However, as discussed in our Direct Testimony (at pages 49-52), the CECo test did provide support for our operability determination and judgment regarding the V-type splices. Since Alabama Power Company's subsequent test was successful and since Alabama Power Company does not rely on the CECo test by itself for qualification of the splices, Mr. Merriweather's concerns are unfounded.

E. Clearly Should Have Known Matters

Q21. Mr. Luehman in his response to Q21 (at page 18) questions what records Alabama Power Company could have relied upon to conclude that the appropriate materials were used in the splices at Farley Nuclear Plant. How do you respond to his question?

A. (Love, Jones) First, it is interesting to note that in his answer, Mr. Luehman seems to be walking away from Circulars 78-08 and 80-10 as his basis for a "clearly should have known" finding. In our Direct Testimony (Q/A 59, at pages 71-74) we clearly explained why he had previously been attributing far too much to those circulars in the present context.

Nonetheless, Mr. Luehman in this answer goes on to question what installation records or QA records Alabama Power Company would have relied upon when Circular 80-10 was released to conclude that qualified materials were used in splices/terminations. Mr. Luehman is missing the point. Circular 80-10 in no way required or indicated a need to walkdown all terminations or splices, contrary to what Mr. Luehman in 1992 may claim. (See our Direct Testimony, at page 73). Rather, it dealt with a specific event regarding the use of the wrong insulating material in reconnecting certain leads at the H. B. Robinson Nuclear Plant. We did not have a material problem of this type at Farley Nuclear Plant. The EQ file specifically called out a qualified material (the Okonite material qualified in NQRN-3). The installation notes and details specifying this material were in place. Since Circular 80-10 was concerned with the use of the proper materials as opposed to the configuration of the tape splices or terminations, reliance on all of these documents would have been the appropriate response to the Circular.

Mr. Luehman, in his response to Q21, also goes on to restate the complaint that an installation and verification program would not have allowed V-type, rather than in-line, splices. We have addressed this at length in our Direct Testimony (see, e.g., pages 68-70). Mr. Luehman is simply overstating the importance of a V-type versus in-line configuration difference. This was simply not the sort of matter that was a focus prior to November 30, 1985. Mr. Luehman is again guilty of exercising an after-the-fact perspective.

F. Mr. DiBenedetto's Testimony

Q22. Mr. DiBenedetto, I want to turn now to the Staff's Rebuttal Testimony specifically addressing your Direct Testimony. (Rebuttal Testimony, at pages 19-23). First, do you agree with Mr. Paulk's assertion that in 1980, "tape insulated connections (splices) and terminal blocks were not considered to be very reliable because of the problems experienced at TMI?" (Rebuttal Testimony, Q/A 22 at page 19).

A. (DiBenedetto) No. Splices and splicing techniques were interface or connection methods endorsed by the NRC as early as 1975. I specifically recall an instance where the NRC Staff recommended that five utilities replace faulty Pin Type connectors with qualified splices. Splices and splicing techniques were considered to be state-of-the-art in the termination and connecting of electrical equipment.

As for Mr. Paulk's statement concerning Three Mile Island (TMI), it does not make any sense. It was to the Staff's amazement that equipment (e.g., main coolant pumps) at TMI continued to perform even after exposure to environments beyond those conceived or postulated to occur following a design basis event. Mr. Paulk's statements concerning TMI are not pertinent to this issue at Farley Nuclear Plant.

Concerns about splices and splicing techniques did not become evident until 1986 and later in 1987. Although Circulars 78-08 and 80-10 addressed some specific issues regarding connections and tape materials, they did not reflect widespread concern regarding splices. Initial splice concerns were relayed in Information Notice (IN) 86-53 (dated June 26, 1986), which addressed the amount of overlap and bend radius permitted for a qualified splice installation. The notice specifically addressed Raychem installation and use. Later concerns about splices arose as a result of the Calvert Cliffs inspection and subsequent NOV (1987).

Q23. How do you respond to the Staff's characterization of the Calvert Cliffs situation in A23 on page 20? They claim that the account of the situation in your Direct Testimony is inaccurate.

A. (DiBenedetto) Contrary to the assertions of Mr. Paulk and Mr. Merriweather, the Calvert Cliffs findings cannot be used to say that Alabama Power Company was on notice that tape splices were a concern that was not limited to power applications. Despite the Staff's characterization of my Direct Testimony, the fact remains that Baltimore Gas & Electric (BG&E) did not have any information on the tape used in their splices. Alabama Power Company, on the other hand, had fully tested and qualified its splice materials. This became evident when Alabama Power Company contacted BG&E (post-deadline) to determine whether the identified concerns related to the Calvert Cliffs installed configuration. The conclusion reached was that BG&E represented an isolated case that did not relate to or adversely impact splice configuration or qualification at Farley.

Q24. Mr. Sundergill addressed earlier (above) Mr. Walker's concern in A28 on page 22 regarding how closely the Wyle test specimens represented Farley installations. What about Mr. Walker's additional observation that vendors provide sufficient details to assure that a single piece of tested equipment is representative of other supplied equipment? (Rebuttal Testimony, A28 at page 23).

A. (DiBenedetto) Mr. Walker is correct in his assertion that when a vendor only tests one piece of equipment, supplemental information is provided to demonstrate its relationship to other equipment of a similar nature. However, since this was not the primary basis for the qualification of the tested splice, but only confirmation and verification testing, Mr. Walker's observation is not relevant. Furthermore, had failures or anomalies been observed, supplemental testing and/or analyses would have been presented to address all of the known applications of the V-type tape splices. No failure or anomalies were observed. Therefore, the testing fully supported the conclusions presented by Alabama Power Company.

III. 5-TO-1 PIGTAIL SPLICE (HYDROGEN RECOMBINER)

Q25. What is the purpose of this section of your Surrebuttal Testimony?

A. (Love, Sundergill, Jones, DiBenedetto) Our testimony responds to the Staff's 5-to-1 Rebuttal Testimony. Specifically, we disagree with the conclusions the Staff has reached regarding the alleged violations of environmental qualification requirements applicable to the 5-to-1 tape splices (terminations) at the Farley Nuclear Plant.

Q26. In general, why do you disagree with the Staff's conclusions concerning the environmental qualification of the Farley 5-to-1 tape splices?

A. (Love, Sundergill, Jones, DiBenedetto) We believe the Staff's conclusions are not supported by the facts. In addition, the Staff has raised several new issues -- four-and-a-half-years after the audit. Many of these new issues have been addressed and resolved by previous NRC inspectors. In support of our conclusions, we address each of the concerns and issues raised in the Staff's Rebuttal Testimony on this issue below.

Q27. Let's begin with the response to Q4 on page 2. Mr. Paulk asserts that none of the following reports would have been adequate to demonstrate the qualification of 5-to-1 splices: (1) NQRN-3 (Staff Exhibit 21); (2) WCAP-7709-L (Staff Exhibit 32); (3) Wyle Test Report 17859-02P (APCo Exhibit 27); or (4) Wyle Test Report 17947-01 (APCo Exhibit 39). How do you respond?

A. (Love, Sundergill, Jones) This assertion reflects a fundamental misunderstanding of our pre-filed Direct Testimony addressing this issue. For the sake of clarity, we reiterate that the reports, taken together, provide the data and logic supporting the conclusion that the 5-to-1 termination for the power cable on the Westinghouse Hydrogen Recombiner was qualified. In sum, these reports address the valid questions pertaining to splice configuration and material composition. Our contention is that the configuration in the Westinghouse qualification test documented in WCAP-7709-L was 5-to-1 and the material used was Scotch #70 electrical tape. Since the configuration for both the tested and installed terminations was 5-to-1, the only remaining issue then is tape material, and we contend that the tape at Farley was qualified. We address each of the reports identified by Mr. Paulk in greater detail below.

Q28. Turning, then, to the important questions of splice configuration and material composition, let's address each of these questions one at a time. In his response to Q4 at page

2, Mr. Paulk claims that the test "qualified the hydrogen recombiners with an unknown configuration using Scotch 70 tape." Please address whetner the splice configuration was "unknown" in WCAP-7709-L.

A. (Sundergill) In Westinghouse drawing 1366C51, originally dated April 5, 1972 (APCo Exhibit 116), the configuration of the splices is clearly shown as 5-to-1. This configuration makes sense because one power feed is being split to feed five banks of heaters. The Westinghouse test configuration, therefore, was not "unknown." In fact, it duplicates the configuration at Farley Nuclear Plant.

As noted on page 88 of my Direct Testimony, I must also repeat that I do not believe that configuration is truly germane to the issue of whether these terminations were qualified:

> I do not think it matters whether the splice was in a 4-to-2 configuration, a 3-to-3 configuration or the 5-to-1 configuration. What is important in this issue is that there was essentially a set of V-type tape splices. The number of Vs on one side of the center point versus the other is inconsequential. No matter what the configuration, the quantity of Vs remains the same. The order that they are in and their spatial orientation are inconsequential as well.

Q29. But in A5 at page 3, Mr. Walker contends that the equipment need not have been connected in a 5-to-1 configuration. Instead, he says that "an alternative connection possibility for the 5-to-1 termination is to rearrange it into three 2-to-1 splices and one termination." Would the configuration he suggests, or any other for that matter, have been superior from an EQ perspective?

A. (Sundergill) No. Even assuming that such a connection could have been made in the space allowed, the resulting configuration would result in the same type of EQ concerns at issue in this proceeding. Namely, as I explained in response to the previous question, any of the postulated configurations would result in a set of V-splices. The somewhat strange configuration suggested by Mr. Walker does not alleviate the need to consider the resulting V-splices. Again, however, it is important to realize that Mr. Walker's conjecture regarding configuration simply does not square with what we know about the Westinghouse test and the configuration depicted schematically in Westinghouse drawing 1366C51 (APCo Exhibit 116).

Q30. Then are you saying that the 5-to-1 issue is essentially another example of V-type tape splices?

A. (Sundergill) Yes. In the case of 5-to-1 splices, however, there is strong evidence that the Westinghouse testing was performed in the same configuration as the installed configuration at Farley. The evidence I am referring to includes: (1) Westinghouse drawing 1366C51, showing a 5-to-1 configuration; as well as (2) standard industry practice (skill-of-the-craft) on the part of the electricians preparing the 5-to-1 splices combined with supervision by the on-site Westinghouse engineer. This fact, combined with the fact that qualified tape materials were used at Farley Nuclear Plant, gives added assurance that these splices would perform their safety function.

Q31. According to Mr. Paulk, the V-type tape configuration is susceptible to failure due to moisture in-leakage. (Rebuttal Testimony, at page 2). How do you respond to this concern?

A. (Sundergill) I certainly believe that the concern is prudent, given that moisture in-leakage potentially can cause splice failure. However, if testing and analysis in accordance with standards and regulations demonstrate that a splice continues to function in the presence of moisture, then it reasonably can be concluded that moisture ingress is not an actual concern. Wyle Test 17947-01 has, in fact, demonstrated that moisture ingress to the point of causing electrical failure of the V-type tape splices did not occur. (APCo Exhibit 39).

Q32. Later in his testimony, A6 at page 5, Mr. Paulk again addresses the lack of splice configuration in WCAP-7709-L. In particular, he testifies that such level of detail was not "'far beyond' what was typical." Is this statement correct?

A. (Sundergill) The statement is completely without meaning because Mr. Paulk makes no reference whatsoever to the period of time for which he is drawing that conclusion. The NRC acceptance of WCAP-7709-L (Staff Exhibit 32) does not indicate any dissatisfaction with the lack of splice configuration details. In his December 1980 inspection, Mr. Gibbons did not identify any configuration problems. (APCo Exhibit 11). The January 1983 Franklin TERs expressed no concern about the equipment terminations, even though they clearly indicated a review of the power cable and the heater wire. (APCo Exhibit 16, at Bates 54533-45; APCo Exhibit 17, at Bates 54971-83). Since the 5-to-1 termination at issue here is the connection point between the two items expressly reviewed by Franklin, either Franklin reviewed the issue and did not deem it significant enough to document or did not believe the splice was an item requiring review. As much as the Staff believes in retrospect that this review was not as thorough as it should have been, the level of review that was performed at that time was, from my experience, typical. That level of review is what the December 1984 SER was based on and is what the Staff should be holding out as the state of knowledge as of the EQ deadline of November 1985.

Q33. Mr. Paulk also states that "the presence of the fiberglass braid on the wires [at Farley Nuclear Plant] aids the moisture in-leakage with a wicking effect." (Rebuttal Testimony, at page 2). Is this observation correct?

A. (Sundergill) Absolutely not. First, I note that this concern was initially relayed by Mr. Paulk during the hearings in February. (Tr. 490). It is not mentioned in the NOV, Order, or in the Staff's Direct Testimony filed in this proceeding. The issue was fully addressed in our Justification for Continued Operation (JCO) dated September 23, 1987. (Staff Exhibit 30). It is curious that Mr. Paulk has raised the issue at all, since it was not pursued by the inspectors during the November 1987 audit. In APCo Exhibit 117, inspector notes dated November 9, 1987, it is expressly stated that "non-wicking braid" is used in the Farley Hydrogen Recombiners. Thus, Mr. Paulk is re-visiting an issue which his fellow inspectors resolved favorably to Alabama Power Company over four years ago. However, I will address his concerns and show them to be groundless.

The installed cable leads from the heaters to the 5-to-1 splice were indeed covered with a braided jacket. Mr. Paulk either fails to mention, or is unaware, that these heater leads were supplied by Westinghouse with the Hydrogen Recombiners and are identical to the leads which were tested by Westinghouse in WCAP-7709-L. (Staff Exhibit 32). The latter report did not identify a problem with wicking during the Hydrogen Recombiner qualification testing. Therefore, it is reasonable to conclude that there was no wicking during testing.

A wicking phenomenon such as that of concern to Mr. Paulk could possibly be caused by a braided covering over the wire insulation acting as a wick to transport moisture under the splice material, establishing an electrical path. This effect has been experienced in other testing, regardless of whether the splice was in a V configuration or in an in-line configuration, or whether the splice material was electrical tape insulation or heat shrink material. However, this well-known effect is addressed in one of two ways: either the braid is cut back so that it does not extend under the splice material, or the braid is treated with varnish or similar substance to prevent the wicking effect. In the case of the heater leads for the Hydrogen Recombiners at Farley, Westinghouse provided heater lead wire saturated with a heat- and radiation-resistant varnish. Therefore, there could be no wicking effect resulting from these wires.

Q34. What about the material composition of the 5-to-1 splices? In their Rebuttal Testimony, the NRC Staff repeatedly asserts that Alabama Power Company failed to demonstrate the qualification of the T-95/No. 35 tape used to prepare the splice. Is that true?

A. (Sundergill) No. This tape material was qualified. Because 5-to-1 splices are a subset of the V-type tape issue, the evidence and testimony submitted in this proceeding concerning the latter is also applicable and relevant to resolution of the alleged EQ deficiencies involving the 5-to-1 splices at Farley. In particular, the material composition issue is addressed by Okonite Report NQRN-3 (Staff Exhibit 21) and by Wyle Test Report 17947-01 (APCo Exhibit 39), which tested the Okonite T-95/No. 35 tape in various V-splice combinations.

Okonite Test Report NQRN-3 qualified a 5Kv taped in-line splice using T-95/No. 35 tape material. Regardless of configuration, I believe this report demonstrates the qualification of the materials. The Staff has focused its attention on this report in its Rebuttal Testimony on this issue. However, Wyle Test Report 17947-01 also utilized Okonite T-95/No. 35 tape and concluded that this combination (among others) was qualified for use at Farley Nuclear Plant in a V-type configuration. Since, as stated, the 5-to-1 splice is a subset of V splices, the results of the 17947-01 test are applicable. It certainly responds to the conjecture and speculation we have heard about Okonite tape materials in this proceeding.

Q35. In response to Q5 at page 3, Mr. Walker concludes that "it is not reasonable to assume that the NQRN-3 test report, which qualified the T-95/No. 35 tape splice for the in-line configuration described in that report, also qualified the T-95/No.35 tape material for general use in all configurations." Have you advocated such all-encompassing use of the report?

A. (Sundergill) No issue is presented in this enforcement proceeding about "all configurations" which may use this qualified tape. We contend that for the configurations at Farley Nuclear Plant at issue here, the tape was qualified. Moreover, I certainly believe that NQRN-3, <u>in conjunction with analysis</u>, can demonstrate the qualifiability of configurations other than the specific in-line configuration described in the report. In fact, this was the exact technique used in the September 23, 1987, JCO for the Hydrogen Recombiner splices -- a JCO that has never been rejected by the NRC Staff. (Staff Exhibit 30).

Q36. Mr. Walker has identified what he believes to be several deficiencies in Alabama Power Company's reliance on the NQRN-3 (Staff Exhibit 21) test report. First, he states that, "NQRN-3 clearly does not qualify the T-95/No. 35 combination for submergence . . . ." (Rebuttal Testimony, at page 4). Is this concern relevant?

A. (Sundergill) No. The 5-to-1 Hydrogen Recombiner terminations at Farley Nuclear Plant are not subject to submergence under normal or accident conditions since they are installed above the design flood level.

Q37. He also notes that the NQRN-3 test report clearly does not qualify the T-95/No. 35 combination for instrumentation circuits because the 5Kv test did not include instrumentation circuits. (Rebuttal Testimony, at page 4). How do you respond?

A. (Sundergill) This is a statement which is totally irrelevant to the issue of 5-to-1 splices. These splices were not installed in instrument circuits -- they were installed in power circuits.

Q38. Likewise, Mr. Walker concludes that the in-line configuration tested in NQRN-3 does not address "many unaccounted-for variables found in the 5-to-1 configuration as installed on the hydrogen recombiner." (Rebuttal Testimony, at page 4). First among these, he lists the difference between the maximum test temperature (345°F) and those registered in the vicinity of the hydrogen recombiner (1100°F to 1400°F). Is this concern valid?

A. (Sundergill) No, it is not. Mr. Walker apparently is unfamiliar with the equipment at issue. The temperature range he makes reference to, 1100°F to 1400°F, is the air temperature near the surface of the Hydrogen Recombiner heaters. The electrical leads to the heaters are high temperature cables capable of withstanding that temperature range. The purpose of the 5-to-1 splice is to connect the high temperature leads to normal plant cable. That connection is achieved in a compartment removed from the heater compartment. One of the primary reasons for the separation is to ensure that ordinary cable does not experience the high temperatures of concern to Mr. Walker. Thus, the qualification temperature for the splices only needs to be comparable to that for the incoming power supply cable. The NQRN-3 temperature of 345°F is comparable and satisfies that requirement.

For further verification of the lower temperature in the termination compartment, see WCAP-7709-L (Staff Exhibit 32, at page 3-2, Bates 003392). This document states that the heater chamber has a pre-heater section which surrounds the heater section. Acting as a shroud, the pre-heater serves to help insulate the heaters and prevent losses from the Hydrogen Recombiner, as well as to heat incoming air to 250°F before it goes to the heaters. If the air immediately around the heater section is only around 250°F during heater operation, it is difficult to understand how the temperature would exceed 345°F in the termination compartment located outside of the pre-heater section.

Q39. In A5 at page 4, Mr. Walker goes on to question the effect of the water generated from the recombination of hydrogen and oxygen on the qualification of the 5-to-1 splice. How do you respond to this concern?

A. (Sundergill) Again, Mr. Walker has raised another new issue. As I will explain, it is of no concern -- even ignoring all of the qualification testing and analysis demonstrating qualification of the 5-to-1 splice to withstand the effects of chemical spray. The reason there is no concern is that the recombination of hydrogen and oxygen takes place in a chamber separate and removed from the location of the 5-to-1 splice. Due to this isolation, any generated moisture would not impact the 5-to-1 splice or adversely affect its environmental qualification.

It should be noted that immediately after raising this concern, Mr. Walker lists a series of questions that are somewhat difficult to understand. He questions whether the crotch of the 5-to-1 splice was properly covered "in this instance" and, if so, whether the material was capable of maintaining its integrity. In response, I must remind him of the termination configuration -- the taped 5-to-1 splice at Farley did not have tape wrapped through the crotch. It is exactly as portrayed in Appendix A to Staff Exhibit 30. As we have previously testified, we believe this configuration was qualified. Of course, Mr. Walker also pointedly ignores the inspection by Mr. Gibbons which examined this same interface and found no deficiencies. (APCo Exhibit 11).

Q40. Would you please address Mr. Walker's concern with the environmental qualification of Scotch #70 tape articulated in A5 at page 4? There he makes a general observation that "significantly more information than that provided in APCO Exhibit 46 is required to determine if Scotch #70 in [sic] environmentally qualified for any specific application."

A. (Sundergill) I will certainly try, although he has not made any indication of the type of information he is looking for or the nature of specific applications he has in mind. To begin with, this concern really does not apply to Farley because Scotch #70 was not used in the Farley 5-to-1 tape splices. Westinghouse, however, has claimed that Scotch #70 was the material used in the tested 5-to-1 splice documented in WCAP-7709-L. (*See* APCo Exhibit 46). Since the NRC has accepted that WCAP, it is difficult for me to understand Mr. Walker's concern with the qualification methodology or results. Thus, the only thing left to satisfy Mr. Walker is a verification of

Westinghouse's claim that the Scotch #70 was used in their test. Since Scotch #70 was not used at Farley, this is a matter for the Staff to pursue with Westinghouse.

Q41. Mr. Paulk has testified that "[e]ngineering judgment is nothing more than analysis of available data when the actual conditions do not meet the tested conditions." (Rebuttal Testimony, at page 5). Do you agree?

A. (Sundergill) No. Mr. Paulk's description is over-simplified. Engineering judgment consists of a lot more than analyzing data. It is based on and presumes past relevant experience, education, insight, and logic. It is the end-product of an engineer's ability to predict an outcome correctly and with confidence -- in the absence of complete, documented testing and analysis. It is the ability to take two or more disparate facts and draw a logical conclusion from them.

Q42. Mr. Paulk faults Mr. Sundergill for failing to discuss or provide engineering judgment on "how moisture intrusion would be prevented . . . ." (Rebuttal Testimony, at page 5). What is your response?

A. (Sundergill) Mr. Love and I discussed moisture intrusion and why it was not a problem in the 5-to-1 splice. I refer Mr.

Paulk to that testimony at pages 79-81 of our Direct Testimony, in response to Q67.

Q43. Mr. Paulk further testifies about the level of documentation necessary to support engineering judgment. (Rebuttal Testimony, A7 at pages 5-6). Do you agree with his assessment?

A. (Love, Sundergill, DiBenedetto) The appropriate standards for the level of documentation appear in the DOR Guidelines, NUREG-0588, and Supplement 2 to IE Bulletin 79-01B. Generally, the documentation must be in sufficient detail to permit evaluation of the adequacy of qualification. (For a fuller discussion of these standards, see Mr. Love's and Mr. Sundergill's Direct Testimony, at pages 29-31.) Mr. Paulk fails to recognize the fundamental premise that the person evaluating the documentation is qualified in the pertinent subject matter. In IEEE 323-1974 (APCo Exhibit 36), Section 6.5., Analysis, sub-section 6.5.1, General, it states, in part, that "the analysis shall be of a form that can be readily understood and verified by people qualified in the pertinent discipline of engineering or science." We believe that the information provided to the Staff at Farley Nuclear Plant in the fall of 1987 met the test of what a "qualified" person would need to know about EQ documentation.

(DiBenedetto) I also refer the Board to my affidavit attached to the Alabama Power Company response to the NOV. (Staff Exhibit 15). My testimony there addressed this issue.

Q44. In response to Q8 on page 7, Mr. Luehman concludes that it was not reasonable for Alabama Power Company to rely on Inspection Reports 50-348/80-38 and 50-364/80-49 (APCo Exhibit 11), or the January 1983 TERs (APCo Exhibits 16 and 17) and thus assume that the NRC had accepted the qualification of the 5-to-1 splice on the Hydrogen Recombiner at Farley. How do you respond?

A. (DiBenedetto) I disagree with Mr. Luehman's conclusion for several reasons. When the cited Inspection Reports were generated, it was the practice of the NRC EQ Staff to have I&E inspectors review, audit, and inspect various aspects of a licensee's EQ program. In reviewing the Inspection Reports at issue (APCo Exhibit 11), it is obvious that Mr. Gibbons indeed specifically reviewed the Hydrogen Recombiner 5-to-1 splices. He concluded there were no deficiencies. This is another example of how the enforcement staff has put aside existing documented findings and conclusions to pursue the civil penalty.

Similarly, the January 1983 TERs (APCo Exhibits 16 and 17) identified specific pieces of equipment and literature that were reviewed by the NRC Staff's consultant, Franklin Research Center. As a result, the Staff approved various pieces of equipment or identified deficiencies. It stands to reason that if Alabama Power Company, or any other licensee, had to undertake improvement efforts in response to identified deficiencies, it could also rely on documented Staff approval.

As such, it is reasonable for Alabama Power Company to rely on the Inspection Reports and the January 1983 TERs.

(Sundergill) I would like to add that Mr. Luehman is speculating when he states that the inspector examined nameplate data and that it was likely that he never looked at the splices since they were normally enclosed in a cabinet. As Mr. Jones testified in the hearing (Tr. 1048), Unit 2 was under construction at the time of the inspection and it would have been no problem to open the cabinet if it was closed. A cursory look at the splices would have revealed the 5-to-1 configuration and, since the No. 35 tape material is black and the Scotch #70 is sky blue gray, the same cursory inspection would have identified the difference between the two materials.

Contrary to Mr. Luehman's statement that there is no evidence that the splice documentation was reviewed, Inspection Reports 50-348/80-38 and 50-364/80-49 (APCo Exhibit 11) explicitly state that documentation was reviewed. Again, Mr. Luehman is speculating that the NRC inspector did not review the documents even though the reports specifically state that he did. In addition, Attachment 1 to the TER dated December 10, 1980 (APCo Exhibit 1?), clearly identifies the cable code for the power Unit 1 Hydrogen Recombiner supply cable which terminates in the 5-to-1 splice. The page containing this information is signed by "V. L. Brownlee" and dated November 6, 198?. Obviously, someone at the NRC reviewed some documentation to reach this conclusion. Of course, since Mr. Gibbons subsequently visited the plant to examine equipment for "overall interface integrity" it is not illogical to conclude that he verified the cable code with a visual inspection. Since the cable code is marked on the cable jacket and the cable could not have been seen entering the junction box, it is possible that the inspector looked inside the box to record this information.

Mr. Luehman also is mistaken when he states that in the Franklin TER there was only acceptance of the "power" cable and not the "in-plant" cable. Power cable and in-plant cable are one and the same. The Franklin TERs state that "power cable" and "heater connector wire" were reviewed as part of preparing the TER. (APCo Exhibit 16, at Bates 0054536; APCo Exhibit 17, at Bates 0054975). It is reasonable to conclude that if both the power and heater cables were reviewed, either the splices were also reviewed or Franklin did not consider them to be important.

(Jones) Let me finally call attention to the fact that the current enforcement staff's arguments require it to ignore, reject and denigrate the hard work and expertise of past NRC inspectors and consultants who were experienced in EQ matters. This highlights the retroactive nature of the enforcement staff's current positions. Those who had contemporaneous knowledge of Alabama Power Company's EQ compliance efforts prior to the deadline found no deviations (which could have been cited without a regulation) or noncompliances. It is only those who came later, after the deadline, who say that a civil penalty is justified.

Q45. Mr. DiBenedetto, in response to Q9, Mr. Paulk addresses your testimony. He contends that it was not reasonable for Alabama Power Company to assume that the Farley Hydrogen Recombiners were fully qualified because he does not believe that Alabama Power Company "looked at the electrical connections (splices)." Can you respond?

A. (DiBenedetto) Yes. Contrary to Mr. Paulk's conclusion, the documents referenced in my Direct Testimony at pages 80-82 support qualification. They were compiled over the years using information obtained from Westinghouse, Alabama Power

Company, and the NRC. The documents represent everything that was done to establish qualification of the Hydrogen Recombiners, including the power connections, prior to the deadline. This includes the review and evaluation of the Westinghouse Hydrogen Recombiner by the NRC, as well as the NRC approval of the generic Westinghouse EQ program and its topical report (WCAP-8587). As such, the documents provide tangible evidence of qualification based on the testing performed by Westinghouse and the use of qualified materials. Although the materials used at Farley were different than those used by Westinghouse, the materials used at Farley were qualified.

(Sundergill) In addition, I disagree with Mr. Paulk's unsubstantiated speculation that no one "looked at the electrical connections (splices)." Just the fact that the Farley splice configuration was the same as that tested by Westinghouse in WCAP-7709-L (Staff Exhibit 32) is evidence of their having been "looked at." Thus, Alabama Power Company certainly "looked at" the splices. In addition, there is every reason to believe that the NRC Staff also "looked at" the splices. As explained on page 91 of my Direct Testimony, Mr. T. D. Gibbons of the NRC inspected both Unit 2 recombiners against IE Bulletin 79-01B in December 1980. (APCo Exhibit 11). Two of the stated purposes of that inspection were to review proper installation and overall interface integrity.

The primary electrical interface for the Hydrogen Recombiners was the 5-to-1 splice.

Q46. In his response to Q10 on page 8, Mr. Luehman does not give much credence to the supervision provided by the Westinghouse on-site representative during installation of the Hydrogen Recombiner. Is this lack of confidence justified?

A. (Love, Jones) No, it is not. We testified from both personal knowledge and verification by plant personnel that a Westinghouse representative was on-site during installation of the Hydrogen Recombiners for Unit 1 and Unit 2. The practice then was for a Westinghouse representative to supervise the installation of Westinghouse-supplied equipment. We believe that such a practice provides further assurance that the 5-to-1 splices were properly installed to Westinghouse's satisfaction and were bounded by Westinghouse's Hydrogen Recombiner testing.

Mr. Luehman further questions the expertise of the Westinghouse observer. We can only respond that Westinghouse, one of the leading NSSS vendors, employs and is represented by individuals who are qualified for the jobs they are hired to perform. Thus, we are confident that Westinghouse provided Alabama Power Company with an individual possessing skills, education, and expertise suitable to supervise installation of the Farley Hydrogen Recombiners.

Finally, Mr. Luehman is mistaken when he implies that the Westinghouse engineer was responsible for the material used at Farley. The Westinghouse engineer would have been responsible for the configuration of the splice. Only materials approved for use at Farley would have been used in making the splice. Those materials were Okonite T-95/No. 35.

IV. CHICO A/RAYCHEM SEALS

A. Overview

Q47. The next issue concerns the Chico A/Raychem seals on NAMCO limit switches. Mr. Wilson of the NRC Staff has provided Rebuttal Testimony. Have you reviewed that testimony?

A. (Love, Sundergill, Jones, DiBenedetto) Yes.

Q48. In general, what is your response to that testimony?

A. (Love, Sundergill, Jones, DiBenedetto) We disagree completely. What follows highlights a few areas of disagreement:

(Love, Jones) (1) Alabama Power Company's position on the qualification of these seals has not changed since 1981. All of the qualification reports referred to in our Direct Testimony on this issue were available to Mr. Wilson and the NRC Staff during the 1987 inspections.

(Love, Sundergill, Jones) (2) The qualification approach we took for these seals is consistent with both DOR Guidelines and NUREG-0588, Category II (IEEE 323-1971) (the applicable standards for the Farley units). Mr. Wilson's assertions regarding our use of separate effects testing, taking "qualification credit for failed tests," and basing qualification on "design reviews or exercises," are either mischaracterizations of our qualification approach or are simply not correct or supported by the applicable requirements.

(3) We agree that this issue does not turn on "technicalities with respect to when an argument was made or whether documentation is sufficient" (Rebuttal Testimony, at page 9). This is a purely technical qualification dispute. It is simply our position that these seals were qualified, that documentation was sufficient by any reasonable standard (including that articulated by the Staff), and that Mr. Wilson's speculations (at the inspection and in this proceeding) regarding failure modes are not technically valid.

Let us also add that Mr. Wilson, in his Rebuttal Testimony, has added even more speculative failure modes for these seals to those previously articulated. These latest concerns also have no merit. However, they continue to illustrate how the issue has been treated by the Staff since the inspection. There is apparently an unending string of questions to be answered. We continue to believe that Mr. Wilson would be satisfied only by a LOCA test of the complete seal assembly. While we are sure such a test would validate our position, the fact is that such a test was not required prior to the EQ deadline, either technically or under the appropriate requirements since partial testing in conjunction with analysis is acceptable. We also note that if we had tested this seal to satisfy Mr. Wilson, the Staff still would not have accepted the test, likely calling it "after-the-fact" as they did on the V-type termination issue. Alabama Power Company chose instead to change out this equipment in 1987 to resolve the issue (using a NAMCO EC 210 connector first made available March 19, 1984).

Q49. Let's flesh out your responses to Mr. Wilson's Rebuttal Testimony in more detail. First, in his Rebuttal Testimony, Q/A 4 and 5 on pages 2-3, Mr. Wilson summarizes Alabama Power Company's position. What is your reaction?

A. (Love, Jones) Mr. Wilson characterizes our Direct Testimony as relying on three reports: (1) Raychem Report EDR 5033 (Wyle Test Report 58442-2), (Staff Exhibit 39) demonstrating qualification of the Raychem boot; (2) the 1981 Farley submergence test demonstrating the seal's ability to exclude moisture (Test Report 2BE-1049-3), (APCo Exhibit 61); and (3) the December 1981 testing at Farley to demonstrate that the Chico A resolved the pressure/temperature problem demonstrated by Raychem (Staff Exhibit 33). This is correct, although it neglects to mention the Southwest Research Institute (SWRI) radiation testing that was available for the Chico A compound (Staff Exhibit 40).

Nonetheless, we find it astounding that Mr. Wilson can state, as he does on page 3, that "[t]wo of the three test reports on which Alabama Power Company now bases qualification of the seal were not introduced into this issue until Alabama Power Company filed its direct testimony in January, 1992." As stated above, our position on this issue has not changed since 1981. We have always based qualification on the reports mentioned by Mr. Wilson. All three of the reports were available in plant document files for NAMCO limit switches at the time of the inspection. Mr. Wilson was informed, or should have been aware from the file, of the existence of these reports at that time.

In fact, Raychem Report EDR 5033 (Wyle Test Report 58442-2, Staff Exhibit 39) was specifically addressed by Mr. Wilson in Inspection Report 50-348, as referenced in Q/A 9 of his Direct Testimony (page 10). The Inspection Report then goes on to refer to all of the other reports we referenced in our Direct Testimony (Id. at 10-11). This simply is not consistent with Mr. Wilson's current testimony. In addition, at the follow-up EQ inspection conducted by NRC Region II inspectors at the Farley Nuclear Plant in March 1988, the submergence test (Test Report 2BE-1049-3, APCo Exhibit 61) was specifically discussed. We cannot speculate why Mr. Wilson now claims he was not aware of these reports or did not understand the basis for qualification. It certainly seems that he should have been clear on this before citing a violation.

B. <u>Compliance With Applicable Standards</u>

Q50. Turning to his specific arguments, Mr. Wilson first objects to the basic qualification approach taken with respect to these seals. In Q/A 6-8, at pages 4-7, he takes issue with, among other things, separate effects testing. What is your response?

A. (Love, Sundergill) The qualification approach used for these seals was completely consistent with both DOR Guidelines (applicable to Unit 1) and NUREG-0588 Category II, IEEE 323-1971 (applicable to Unit 2).

Separate effects testing involves multiple tests, each of which includes only some of the relevant harsh environment parameters. This approach, under DOR Guidelines, allows for tests that do not involve a combined temperature/pressure/steam/radiation/chemical spray test on one sample. Mr. Wilson asserts that our testing was inadequate because it did not include a combined test of temperature, pressure, and steam.

(*See also* Mr. Wilson's hearing testimony, Tr. 864.) However, Mr. Wilson is missing the point.

The Raychem test on the Raychem boot, essentially in the configuration that we utilized for the limit switch seal, was a combined temperature, pressure, and steam test. This was documented in EDR 5033, Wyle Test Report 58442-2 (Staff Exhibit 39), a report Mr. Wilson now maintains that he did not review until this proceeding. (Rebuttal Testimony, at pages 3-4). This test met DOR Guidelines. In this test, there was no exception taken to the minimum testing conditions (pressure, temperature, steam). To address Mr. Wilson's position, we also request that the Board review our testimony at Tr. 1081-1083.

As with all type testing, deviations between the tested sample and installed configuration are allowable if addressed by further testing or analysis. *See* DOR Guidelines, Section 5.2.2. Here, the only potentially relevant difference between the tested sample and the installed configuration was that the boot was installed over a pipe nipple rather than a cable. That difference was addressed in the subsequent test reports and is discussed further below.

Finally, to be clear, DOR Guidelines do not state that the minimum type tested conditions need to be in combination.

Section 5.1 simply says that these parameters should be tested, rather than qualified by analysis. IEEE 323-1971 (APCo Exhibit 37) sheds no meaningful light on this issue, but again, clearly allows for augmenting partial type tests by analysis (Paragraph 4.3). The issue, however, is irrelevant since there was a combined temperature/pressure/steam test performed for the Raychem boot.

Q51. But Mr. Wilson seems concerned, in his Rebuttal Testimony at page 6, that DOR Guidelines "do not endorse the concept of 'qualified materials' as advanced by the licensee." This seems to address the Raychem testing on the Raychem boot. Can you respond?

A. (Love, Sundergill) Mr. Wilson seems to be referring to Mr. Love's Direct Testimony, Q/A 126, on page 136, which states that for this seal, we utilized tested <u>materials</u> supplemented with analysis and partial testing. There was nothing wrong with our approach to qualifying this equipment. Perhaps it will help if we clarify what was meant in saying that we utilized tested materials.

Essentially, this seal had two major components: the Raychem boot and the Chico A backing. Both were tested for their relevant environmental parameters. Hence, the seal was made of qualified components and materials. However, with respect to the Raychem boot, we were not relying upon some "generic qualification of . . . materials," as implied by Mr. Wilson (Rebuttal Testimony, at page 6). None of the three tests on the boot which are relied upon for qualification (the Raychem test, the submergence test, and the test with Chico installed) were tests of random Raychem materials. They were all tests of a Raychem boot identical to that installed in the seal application, as required by DOR Guidelines Section 5.2.2.

The only deviation between the tested and installed Raychem boot, as previously noted, was that the Raychem pressure/temperature/steam test utilized a boot installed over a cable rather than a pipe nipple. The relevant difference between the two initial configurations was that the cable provided a backing to the Raychem boot. This backing was not present in the original configuration which failed the pressure test. Thus, when the Chico A material was added to provide the backing material, only the pressure portion of the testing needed to be re-done.

The subsequent tests utilized the boot over a pipe nipple (first for submergence testing and, second, for testing of the Chico backing). We believe, consistent with DOR Guidelines Section 5.2.2., that the difference between the installation over a cable, rather than a pipe nipple, was addressed by the subsequent testing and by the engineering judgment that the difference was irrelevant to seal performance. Some of the specific concerns Mr. Wilson has regarding the difference are discussed below and in previous testimony. We continue to believe that, based on any reasonable documentation standard, further documentation on these issues was unwarranted -- especially prior to November 30, 1985. An engineer versed in EQ could understand our logic and approach based on the documents in our files.

Also, note that Mr. Wilson, in his Rebuttal Testimony on page 6, highlights that DOR Guidelines, Section 5.2.6. states that type tests of seals "shall be representati[illegible] of the actual installation for the test to be considered conclusive." In our opinion, all of the tests relied upon were representative of the intended installation. With respect to actual installed configurations, we have addressed this at length in our Direct Testimony, Q/A 149, at pages 170-175. We believe there were adequate installation controls to assure that the tests remained representative. Moreover, even the NRC's November 1987 Inspection Report does not indicate any actual installed seals that deviated from the tested, qualified configurations. Mr. Wilson is merely speculating that there could have been such deviations, but he cannot state that there were deviations.

Q52. Mr. Wilson, on page 6 of his Rebuttal Testimony, also references DOR Guidelines Section 5.3.2. This states that the "effects of chemical sprays on the pressure integrity of any gaskets or seals present should be considered in the analysis." What is the significance of this reference?

A. (Love) Mr. Wilson never really explains himself on this point. However, we did precisely what Section 5.3.2 suggests.

As stated in our Direct Testimony, the effects of chemical sprays on pressure integrity were addressed in at least two different contexts. First, the original Raychem testing on the boot (EDR 5033) (Staff Exhibit 39) included not only a pressure/temperature/steam test, but also a chemical spray test. (<u>See</u> Rebuttal Testimony, at page 10, where Mr. Wilson acknowledges this fact.) This showed the integrity of not only the Raychem material, but also that of the Raychem boot configuration identical to that used at Farley for these seals.

Second, in performing the final December 1981 testing on the complete seal configuration (including the Chico backing), chemical spray was considered. However, as explained in my Direct Testimony, Q/A 138 at page 155, chemical spray testing was not necessary at that time since it was shown that there was no failure mode by which chemical spray could reach the

Chico compound. The pressure/temperature test showed that the Raychem boot, backed by Chico, was a positive leak-tight moisture exclusion seal which would prevent ingress of chemical spray.

I know that Mr. Wilson has raised subsequent concerns related to bonding of the Raychem boot to the pipe nipple based on chemical spray induced corrosion. However, as addressed in previous testimony (see, e.g., our Direct Testimony at pages 158-161), all of these concerns are simply unfounded. The very test report Mr. Wilson relies upon as a basis for pipe corrosion concerns (Wyle Test Report 58730) failed to validate the concern -- there were no documented Raychem boot failures due to corrosion. (See also Tr. 837-839, wherein Mr. Wilson fails to support his hypothesis.)

Q53. Mr. Wilson, on page 7 of his Rebuttal Testimony, also asserts that "DOR Guidelines do not allow qualification for failed tests." Did Alabama Power Company use this approach?

A. (Love, Sundergill) No. Our qualification approach was amply described in our Direct Testimony. Our approach was one of testing, supplemented by analysis as allowed by the DOR Guidelines and NUREG-0588. (See also 10 CFR 50.49(f)(2) and (4)).

The fact that we chose to organize our Direct Testimony in a chronological fashion is irrelevant to the merits of this issue (notwithstanding the inference of Q/A 14, on page 17 of the Rebuttal Testimony). The evolution of the seal design happens to be a useful means to explain the qualification approach taken and the justification for that approach.

Mr. Wilson, on page 7 of his Rebuttal Testimony, cites DOR Guidelines, Section 5.2.5., as follows:

> If a component fails at any time during the test . . . the test should be considered inconclusive with regard to demonstrating the ability of the component to function . . . .

This is a correct statement of the guideline. However, there were no failures in any of the tests credited for qualification of this equipment. The Raychem boot was successfully tested in the Raychem testing. Bechtel's submergence test on the seal configuration was successful. And the credited test specimen (test specimen 4, as discussed in my Direct Testimony) of the December 1981 testing of the complete Chico A/Raychem seal was a successful test. Contrary to Mr. Wilson's claim, we were not and are not using test failures as a basis for qualification.

In fact, the only failure of the Raychem boot relevant to this issue was the failure observed by Raychem, and recreated by Alabama Power Company, of the boot under pressure/temperature conditions <u>without</u> <u>Chico</u>. Obviously, this failure was relevant to our design evolution. We addressed it by adding the Chico backing. Since the assembly was then tested, there is absolutely no significance to Mr. Wilson's observation that "another failure mode may have been masked by the observed failure." (Rebuttal Testimony, at page 7).

Mr. Wilson, in fact, blatantly mischaracterizes our approach. He states (at page 7) that DOR Guidelines, Section 5.2.5., "prohibits the sort of argument that says, there were test failures, but we know what caused them and fixed it, <u>so there is no need to retest</u>" (emphasis added). With respect to the only failure ever observed (again, the Raychem boot breach), we suspected the cause, duplicated the failure to prove the cause, designed a fix, and <u>retested</u> after the fix under identical conditions to demonstrate no further failure, thus qualifying the final design.

There also is absolutely no significance to Mr. Wilson's observation that "another failure mode might have occurred if the test had run to completion." (Rebuttal Testimony, at page 7). All the credited qualification tests on this seal ran to completion. Mr. Wilson is simply in error regarding the facts and continues to attempt to confuse the issue.

Q54. A similar concern appears in Mr. Wilson's Rebuttal Testimony at page 11. He states that "failures invalidate every known LOCA test involving Raychem boots on metal pipe nipples." Is he correct?

A. (Love, Sundergill) No. Again, the tests we relied upon for qualification were not failures. Moreover, Mr. Wilson appears to be alluding here to the failures noted in the test report he has relied upon -- Wyle Test Report 58730. However, as stated previously, none of those failures were germane to our seal. None involved corrosion in the way Mr. Wilson implies (See our discussion in Q/A 6 above).

Q55. Mr. Wilson, in Q/A 14 on pages 17-18, also states that documentation of qualification is "not a design review process," implying that Alabama Power Company's approach was deficient. What is your response?

A. (Love) Again, I think Mr. Wilson is mischaracterizing our qualification approach. Our approach was a positive qualification approach, as previously described, consistent with applicable criteria and requirements. As also stated above, the fact that we chose to organize our Direct Testimony on this issue in a chronological fashion is irrelevant to the merits of the issue.

Mr. Wilson, in Q/A 14 at pages 17-18, states that, "[t]his proceeding does not address whether the seal design makes sense, or was developed in a logical manner, or has a reasonable chance of performing its harsh environment safety function." With all due respect to Mr. Wilson, these issues are exactly what this proceeding is about, in addition to the issue of "whether the licensee satisfied the environmental qualification requirements." After all, the matters dismissed so blithely by Mr. Wilson are exactly what engineering is all about. And the issue of whether or not EQ requirements were met cannot be addressed without first addressing these valid engineering considerations.

Q56. Mr. DiBenedetto, you were with the NRC Staff in the early years of the EQ regulatory work. Can you add any perspective on the issues raised by Mr. Wilson regarding test failures?

A. (DiBenedetto) Yes. When considering the Chico A/Raychem configuration, it is helpful to reflect on and revisit the early reviews performed by the NRC Staff on various industry equipment test reports. During the 1979 to 1981 time frame, one of the major and most common shortcomings of licensees' qualification reviews was the lack of technical justification provided when a tested specimen experienced or exhibited anomalous behavior during testing in a test credited for qualification. The anomalous behavior did not always result in failure of the equipment; however, the NRC Staff insisted (and rightfully so) that the utility verify or provide assurance that any test anomalies, observed or recorded, did not affect the intended operation, capability, or qualification of the equipment as installed in its specific location to perform its specific function.

In the situation here with the Chico A/Raychem seals, Alabama Power Company found that during testing, a pressure-related anomaly occurred which ruptured the Raychem boot seal. Alabama Power Company evaluated the failure mechanism of the tested configuration and engineered a solution. There were no other anomalies observed or experienced. This approach to addressing test anomalies was not only appropriate, but beyond what was the norm in the industry. Alabama Power Company took positive action to fix an identified deficiency while most utilities had to be prodded to address and evaluate test anomalies.

C. <u>Specific Technical Concerns</u>

Q57. Let's turn to Mr. Wilson's asserted technical concerns with the seals as articulated in the Rebuttal Testimony. Can you summarize these concerns as you understand them?

A. (Love, Sundergill, Jones) Focusing only on the Rebuttal Testimony, we have attempted to identify the technical concerns and speculations raised by Mr. Wilson. They are listed below:

(1) For the Farley seals, the Raychem boot was installed over a pipe nipple rather than over a cable as utilized in the Raychem testing (EDR 5033). (Staff Exhibit 39). (Rebuttal Testimony, at pages 8 and 10).

(2) There was insufficient surface preparation of the pipe nipple. Specific concerns include the absence of a cleaning procedure, the possible presence of burrs or sharp edges, and the possibility of chemical contaminants that might interfere with bonding between the pipe and the boot (Rebuttal Testimony, at pages 12-13).

(3) The submergence test was inadequate because it was not a temperature/pressure/steam test. (Rebuttal Testimony, at page 15).

(4) The 1981 Bechtel test with the Chico backing was inadequate in that: (a) it did not include steam or moisture; (b) it did not simulate the initial temperature rise of the specimen that would occur in a LOCA; and (c) tne test specimen

was built according to different instructions than the plant equipment. (Rebuttal Testimony, at page 16).

(5) Installation instructions did not control the minimum quantity of Chico mixture and there were no instructions directing the installer to perform a visual inspection. (Rebuttal Testimony, at page 8).

(6) The installation procedures were inadequate in that they did not specify the length of tygon tubing to be used and they failed to specify the position of the bottom of the tubing during cement insertion. (Rebuttal Testimony, at page 20).

(7) The installation instructions needed to specify heat shrinkage control for the Raychem boot more precisely than is necessary for a cable installation. Otherwise, Raychem material thinning and weakening could result. (Rebuttal Testimony, at page 12).

(8) The fact that the Chico cement is not compressed in the Farley seal could allow it to move, adversely affecting its performance. (Rebuttal Testimony, at pages 20-21).

(9) The Bechtel test plan for the December 1981 testing refers to different installation drawings and revisions than

those available during the inspection. (Rebuttal Testimony, at page 8).

(10) The compression adapter applied over the Raychem sleeve in the final seal lacked a model number or other descriptive information, contrary to DOR Guidelines. (Rebuttal Testimony, at page 8).

(11) The compression adapter, which connected conduit to the limit switch assembly, could cut the Raychem sleeve. The postulated failure mode is now one of torque on the sleeve due to "several feet of cable conduit." (Rebuttal Testimony, at pages 8-9).

Q58. To your knowledge, are any of these new concerns?

A. (Love, Sundergill, Jones) Several of them are new issues or new variations on old issues. For example, take the last item listed above. Mr. Wilson previously speculated that the compression adapter might cut the Raychem sleeve. However, the previous failure mode offered by Mr. Wilson was differential expansion of the various seal components. Since we have addressed that issue, he now speculates on cutting due to torque of the cable conduit.

Another new concern is Issue (7). Mr. Wilson has not previously asserted the possibility for Raychem material thinning and weakening due to lack of heat shrinkage control. We address this below.

Another new concern is Issue (8). To the best of our knowledge, this concern has not been previously articulated. Again, we believe this concern to be without merit as addressed below.

Issue (2) above was also a new issue when first raised in oral testimony. All of these examples aptly illustrate the debate between the parties on this issue. The focus seems to be ever-shifting. Even during the hearing, issues of prior minor (or unstated) concern then grew into major issues. An example of this is the alleged difference between adding Chico to the switches by pouring versus insertion by tygon tubing. (Tr. 873-74).

We attempt below to address all of the concerns and speculations of which we are now aware, which we did not have the opportunity to address in our Direct Testimony because they were not yet known to us. We do not believe that a violation has been proven -- or that a violation should be considered to exist based on speculation or imaginative "concerns."

In this light, we found Mr. Wilson's Rebuttal Testimony on page 18 to be misdirected. He states that satisfying EQ requirements turns "not on design reviews or exercises in speculating on what might happen if the accident situation occurs." We are not using and have never utilized speculation as a basis for qualification of these seals. The speculation on this issue has come from Mr. Wilson. He has speculated on concerns with these seals since the 1987 inspection, with no real engineering basis or documented support.

Q59. Let us turn now to the concerns Mr. Wilson has raised. Referring to your list above, Issue (1), based on the Rebuttal Testimony at pages 8 and 10, concerns the alleged difference between installation of a Raychem boot over a pipe versus a cable. Would you please respond?

A. (Love, Sundergill) We discussed the Raychem testing (EDR 5033) above. In our review, this testing -- including pressure, temperature, steam, radiation, and chemical spray -- satisfied DOR Guidelines, Section 5.2.2.

(Love) The differences between the Farley application and the cable application tested in EDR 5033 (Staff Exhibit 33) were: (1) the application over a galvanized steel pipe nipple; and (2) the cable fillers in a cable application provide a backing to the crotch of the breakout boot. I do not consider these to be significant differences and, in past testimony, have addressed these matters and Mr. Wilson's concerns. Let me now amplify my basis for this conclusion.

The Raychem boot kit utilized for this seal, and as tested, is selected for an application and procured from Raychem based on the outside diameter range of the cable or pipe nipple over which it is to be installed. In our application, the outside diameter use range of the boot was 0.78 - 1.2 inches. This is specified in the Raychem product control document and installation instructions provided with each kit. (APCo Exhibit 118). Whether the kit is installed over a cable or a pipe is not significant. The critical parameter is that the diameter of the pipe nipple or cable is within the specified use range of the boot kit. This assures that the shrinking process will achieve an effective seal, and that no unacceptable material thinning or stresses will exist after shrinking. Suffice it to say, we utilized an appropriate Raychem boot for the diameter of the pipe nipple on the limit switch.

With respect to shrinkage over a pipe rather than a cable, there is no real difference. Mr. Wilson's point in his Rebuttal Testimony seems to focus on the difference between application over plastic versus steel. (Rebuttal Testimony, at page 10.) However, we have addressed in our Direct

Testimony the issue of adhesion or bonding to a galvanized pipe. (_See_ Direct Testimony, at pages 159-160.) We have also addressed concerns regarding differences in expansion coefficients. (_See_ Direct Testimony, at pages 166-167.) The basic point here remains that an approximately 1-inch diameter pipe versus an approximately 1-inch diameter cable is not a significantly different application. This was also effectively demonstrated by the Bechtel submergence test (utilizing the Raychem boot over a pipe) and in the Alabama Power/Bechtel 1981 pressure/temperature testing.

With respect to the bonding issue, I would like to explain one other consideration. Mr. Wilson, on page 10 of his Rebuttal Testimony, references two Sandia tests (NUREG/CR-2812 and NUREG/CR-3361) that we relied upon, but then faults the reports because they "included no Raychem material or electrical application." Mr. Wilson seems to be confused and I believe the record should be clarified. These Sandia reports were never part of our basis for qualification of these seals. However, after Mr. Wilson raised a corrosion/bonding concern at the inspection, we did refer him to these reports for the limited proposition that there will not be extensive corrosion of a galvanized steel pipe in the postulated Farley design basis accident environment. These reports involved tests of galvanized material under accident conditions and supported that proposition. Therefore, these reports support our view that there will not be significant corrosion of the galvanized pipe on the NAMCO limit switch that would interfere with Raychem bonding.

Finally, with respect to the lack of cable filler in the pipe application, this difference was addressed by the addition of the Chico. (See Direct Testimony, at pages 144-145).

Q60. Issue (2) above, based on the Rebuttal Testimony at pages 12-13, concerns surface preparation of the pipe nipple and the absence of cleaning procedures. Please describe what was involved here.

A. (Love) As I testified at the hearing, there were no special procedures utilized for preparation of the pipe prior to applying the Raychem boot. (Tr. 1006; 1076-1078). I testified that Raychem provided installation instructions for nuclear cable breakout kits with each kit (Tr. 1077-1078), and these instructions were followed. The instructions did not involve any "special" sanding, filing or preparation of the nipple. (Tr. 1078).

Q61. Were these instructions sufficient to address chemical contaminants, burrs, or sharp edges?

A. (Love) Yes. To address Mr. Wilson's concerns for preparation of the pipe nipple, I will refer to the Raychem installation procedures. (APCo Exhibit 118). Notwithstanding that these standard instructions referred to applications over cable, they were followed for these limit switch seals and they provide for sufficient surface preparation. As shown on the first page of APCo Exhibit 118, a copy of the installation instructions was provided with each kit. The kit number is NCBK-04-04, and the instructions are designated as PII-57009. Preparation Step 3 is "Clean and Degrease." It states that, "[a]ll surfaces must be free of grease, oils or other contaminants brought into contact with Raychem products." This instruction would have applied to the pipe nipple and would have addressed any concern for grease or other chemical contaminants that might interfere with bonding.

(Love, Jones) We have also spoken with one of the lead electricians who installed these seals in the field. We asked about procedures for cleaning the nipple. He explained that the cleaning was performed with a solvent specifically to remove machine oils that might have been on the pipe threads. He also informed us that if there were any sharp edges or burrs, they would have been detected during the cleaning process. Although it was not required by procedure, he explained that the electricians would have smoothed down any such imperfections prior to installing the Raychem boot.

(Love) With respect to burrs and sharp edges, I will also note that properly machined pipe nipples (the threads) should not have these problems. The threads themselves were standard threads. In our testing, and in all of our handling of the material, we observed no problems due to tearing or cutting of the Raychem material -- including when exposed to thermal aging and to design basis thermal/pressure testing.

I also concur with an observation made by Judge Carpenter. (Tr. 852-54.) Given the heat shrinking process, application of the boot over the threads rather than an unthreaded pipe (or cable) is actually a more secure approach. The heat shrink Raychem material will form a thread mating with the pipe nipples. We historically considered, in designing this seal, whether to use unthreaded pipes or threaded pipes, and selected the latter for precisely this reason.

(Sundergill) I would also like to add a comment. In his oral testimony (Tr. 845, at line 3; Tr. 854), Mr. Wilson expressed concern that the threads of the nipple or any burrs that might exist could nick or cut the Raychem material. He stated that nicking of the material was a well-known mechanism which results in the material splitting at the nick. However, this failure mechanism has only been reported when the nick has been on the outside surface of the Raychem boot. It has never been reported as a result of an internal nick. From a mechanistic point of view, it is straight-forward to observe that an external nick will experience forces of stress that act to open up the nick. Such is not the case for an internal nick. Since such a failure has not been reported, Mr. Wilson is engaging in speculation once again.

Q62. Issue (3), raised by Mr. Wilson in his Rebuttal Testimony at page 15, concerns the submergence test. He states that it was not an adequate pressure/temperature/steam test. Please respond.

A. (Love) The submergence test, documented in Bechtel 2BE-1049-3 (APCo Exhibit 61), was not intended to be a pressure/temperature/steam test for containment application. I discussed this test and its purpose in Q/A 131-132 on pages 146-148 of our Direct Testimony.

Again, we are basing qualification of this equipment on a combination of four tests. Mr. Wilson seems to want each test to serve all purposes. The specific deficiencies referred to by Mr. Wilson on page 15 simply are not relevant to what was intended to be demonstrated in the submergence test. All of the issues he cites have been addressed by other test documentation. Specifically, Staff Exhibits 33, 39, and 40 addressed acceptability for containment applications.

Q63. Issue (4), from Mr. Wilson's Rebuttal Testimony at page 16, raises three concerns regarding the Chico backing in the seal. Have you addressed these matters before?

A. (Love) Yes, we have previously addressed all three of these points in our Direct Testimony, Q/A 139-149, at pages 156-175. The Rebuttal Testimony here simply restates old arguments in a new -- and still invalid -- way.

To summarize, the December 1981 Bechtel test (the Chico test) challenged here by Mr. Wilson did not need to include steam or moisture. The 1981 test was designed to address the specific pressure/temperature problem observed by Raychem and resolved by the addition of Chico to the design. The test bounded Farley pressure/temperature conditions as addressed in Direct Testimony, Q/A 136 at pages 150-152, and Figures 4 and 5.

Initial temperature rise of the specimen was also adequately simulated to bound the required design basis pressure/temperature profiles as shown in Figures 4 and 5 of the Direct Testimony. As we stated previously, we believe our temperature ramp was more severe than would be achieved in a commerc . test chamber. (Direct Testimony, at page 162-163). Mr. Wilson now suggests that LOCA steam conditions will heat the test specimen more rapidly than dry stagnant air. (See also Tr. 861). This is a new variation on the previous concern, and Mr. Wilson offers no thermodynamic heat transfer analysis to support the assertion. In any event, this restatement of the issue does not alter my previous conclusion that the December 1981 test adequately demonstrated that the temperature/pressure effect experienced in the early Raychem test failures would not exist for our Chico/Raychem version of the seal. (See Direct Testimony, Q/A 135-136, at pages 149-152.)

Finally, Mr. Wilson here alleges that the test specimen was built according to different instructions than the plant equipment. As I have addressed previously in my Direct Testimony, Q/A 149 at pages 170-175, adequate installation controls existed for these seals. The installation instructions, including the Raychem boot instructions, were fairly specific and were certainly adequate given the fairly simple nature of the task.

At the hearing, Mr. Wilson added a new twist to this last issue. He argued that in the test specimen subject to the December 1981 test, the Chico was added to the test specimen by "pouring it into the pipe nipple." (Tr. 873). He contrasted this with the tygon tube installation methodology used in the field, apparently maintaining that this difference was meaningful to qualification. (Tr. 874). In my Direct Testimony referenced above, I explained that there was nothing crude or imprecise about the tygon tube methodology for inserting Chico. Also, as I explained to Judge Carpenter (Tr. 989-990), the Chico prior to curing has good fluid characteristics for elim. nating voids. The slightly expar e curing process also lends itself to elimination o . s. Given these characteristics, I simply see no legitimacy in Mr. Wilson's distinction.

Finally, this issue is probably completely beside the point. Mr. Wilson relies on notes attached to the report for the 1981 test. As I acknowledged in hearing testimony, one of the quality control inspectors states in his notes that the Chico was "poured" into the test specimen. (Tr. 1004-1005). However, the report itself describes the fix for the seal as injection of Chico with a syringe, implying that the syringe was the installation method. (Staff Exhibit 33, at page 3). Also, as I testified, my recollection was -- and I was present at the 1981 tests -- that the test specimens were made by injecting the Chico by syringe.

(Love, Jones) Also, in our recent conversation with one of the lead electricians who helped make these seals, he stated that his recollection of the 1981 tests was that the Chico was added by injection. Regardless, however, in our judgment, for the reasons testified to previously, it is completely irrelevant for this application whether the Chico was injected or poured.

Q64. Let's move on to Issue (5) listed above. This again concerns installation instructions. Mr. Wilson's claim (Rebuttal Testimony, at page 8) is that the instructions did not control the minimum quantity of Chico mixture. Can you respond?

A. (Love) The installation procedure is APCo Exhibit 104. The procedure (step 5) calls for withdrawing "2-3 oz. (35-50 cc) of the liquid Chico mixture into the syringe." The procedure (step 7) then calls for "injecting 1½ oz. into the pipe nipple." This procedure is explicit and adequate.

Q65. As part of this concern, Mr. Wilson (Rebuttal Testimony, at page 8) complains that there is no instruction directing the installer to perform a visual inspection.

A. (Love) A visual inspection seems to me to be self-evident for this task. The installer must look at the switch and pipe nipple to inject the Chico. If the Chico were not adequately inserted, it would spill out into the switch housing. This would be obvious. In addition, the procedure (APCo Exhibit 104) includes a "Note" specifying that "it is important that no more than 1½ oz. of Chico is applied to each switch, and that no Chico finds its way to switch materials." To satisfy this Note, the electrician must be watching as he performs the operation.

(Love, Jones) Also note, the 1½ oz. specified in the procedure was based on the volume of the pipe nipple. The electricians in the field have verified for us that they would assure that adequate Chico was inserted by visually verifying that the Chico filled the nipple up to the level defined by the housing. Given all of this, we do not believe that an explicit "visual inspection" step needed to be in the procedure to assure proper preparation of the seal. This seems to be an allegation motivated by something other than a genuine, realistic technical concern.

Q66. Issue (6) above is taken from Mr. Wilson's Rebuttal Testimony at page 20. This issue again concerns the installation procedures, this time criticizing the lack of specification of the length of the tygon tubing and the failure to specify where the bottom of the tubing should be inserted in the pipe nipple. Please respond.

A. (Love, Jones) Step 6 of the procedure (APCo Exhibit 104, emphasis added) clearly states: "Through open side of the switch, carefully in[illegible] the free end of the tygon tubing into the pipe nipple at[illegible]ched to the switch <u>until it bottoms on the Raychem breakout seal</u>. Insure that the Chico mixture does not get in the switch internals." This seems fairly clear to us. Moreover, from discussions with the electricians, we have absolutely no reason to believe that the procedure was not followed.

The allegation of a lack of specificity regarding the length of tygon tubing is, in our opinion an example of incredible nit-picking and is without substance. Any reasonably skilled electrician would use a tygon tube of an appropriate length -- that is, long enough to complete the job in accordance with procedures (including the Note discussed above). The same can be said for where the bottom of the tube needs to be positioned.

In addition, the viscosity and pour characteristics of the uncured Chico which were discussed earlier would also address any concern in this area. Chico will flow to fill voids regardless of how deeply the tubing is inserted in the pipe nipple or the length of the tygon tube. (See also Tr. 989-990).

Q67. Issue (7), drawn from Mr. Wilson's Rebuttal Testimony at page 12, again focuses on installation instructions. The complaint here relates to the Raychem boot rather than the Chico. Please describe the issue as you understand it.

A. (Love) On page 12 of his Rebuttal Testimony, Mr. Wilson is concerned that heat shrinkage control needs to be specified in instructions. With no cited support, he argues that Raychem material thinning and weakening could otherwise result.

Q68. Do you agree?

A. (Love) No. As discussed earlier, the pipe nipple was within the usage (outside diameter) range for the Raychem breakout boot kit. The Raychem instructions (APCo Exhibit 118) supplied with the kit specify, in steps 1 through 5, the appropriate heat shrinkage method. These steps are adequate regardless of whether the boot is applied over a cable or pipe nipple (assuming an application inside the appropriate outside diameter usage range). We see no basis for Mr. Wilson's speculative claims, nor has he offered any.

Q69. Issue (8) above concerns compression of the Chico compound. Mr. Wilson argues (Rebuttal Testimony, at pages 20-21) that, unlike the SWRI tests on Chico, the Chico in the Farley application was not compressed. Do you understand this concern?

A. (Love) I understand that Mr. Wilson has articulated a concern. I do not agree that it has technical merit for the Farley application, as I have already testified. (<u>See</u> Tr.

1087-1088; Tr. 989-990). However, I will emphasize a few points here.

First, let me clarify that Q16 in the Rebuttal Testimony mischaracterizes my earlier testimony. At Tr. 1088, I did not state that the Crouse-Hinds explosion-proof fitting was not intended to compress the Chico. I stated that the specific intent of the plug was not to compress the Chico. I also stated that there will be some compression due to the plug in the application. However, this issue is irrelevant. I went on to testify that there is no significance to the compression. (Tr. 1089).

Compression of the Chico for the Farley application is not necessary for obtaining an adequate seal. As I explained to Judge Carpenter (Tr. 989-990), the viscosity of the uncured Chico and the fact that Chico is slightly expansive in nature will assure a bond. Furthermore, there is absolutely no observational or empirical evidence to support Mr. Wilson's speculation (Rebuttal Testimony, at page 21) that the Chico mass in the Farley seal will move.

Mr. Wilson's speculation is perhaps based on the fact that the expansion coefficient for steel differs from that for the Chico compound so that the steel could expand away from the Chico as temperatures increase. This phenomenon would be a function of the absolute value of the higher temperature as opposed to the rate of heating. That is, the effect would be greatest at the peak temperature regardless of how fast it took to achieve that peak. Since the Farley test was at peak temperatures and the Chico either did not move in that test or the movement was insufficient to affect the integrity of the Raychem material, Mr. Wilson's concerns have been shown to be groundless by virtue of testing.

Also, Mr. Wilson relies on the SWRI testing of the explosion-proof fittings for the idea that compression is necessary. However, the procedures used for installation of the Farley seal (APCo Exhibit 104), and the application itself, are completely different from those involved in the SWRI-tested fittings. First, at Farley, the switches were placed in the vertical position prior to adding Chico so gravity would allow the Chico to fill the cavity. When SWRI added Chico to the much larger explosion-proof fittings it tested, given the arrangement (which I will not belabor here), the fittings were essentially filled from the top and middle of the fitting through the plug opening. Compression from the plug was needed to ensure packing of the Chico against the internal cable dams at both ends of the fitting.

Second, the Farley cavity was quite small and crossed by four wires. The SWRI-tested fillings were much larger, and filled with many more, or much larger, cables. Given this arrangement, some compression was required to fill the cavity of the explosion-proof fittings. Mr. Wilson is comparing apples to oranges.

Q70. While we are on the subject of Chico, let me digress briefly to an issue first raised by Judge Carpenter at the hearing. He wondered about the moisture in the Chico that would be released during curing. (Tr. 1095-96). Mr. Wilson has now apparently adopted that issue as his own. (Rebuttal Testimony, Q/A 16, at page 20). Can you address this?

A. (Love) This is another good example of how this issue constantly changes. When Judge Carpenter asked the question, he acknowledged that it was not an issue here. (Tr. 1096). Now, Mr. Wilson somewhat obliquely refers to the issue, making the inference that this is an important issue that has never been addressed in testimony.

First, during the curing process, the majority of the water in the Chico compound will be transformed by hydration (the chemical process by which the compound solidifies) and remain in the final compound. The small amount of moisture that evaporates during curing is immaterial to the functioning of the switch. Also, after initial curing, as with concrete, exposure of the Chico to elevated temperatures postulated to occur in the Farley-specific Design Basis Events (DBEs) will actually result in additional hydration assuming that there remains any non-hydrated water in the compound.

Another issue raised by Judge Carpenter was whether moisture will be released by the compound at high (e.g., accident) temperatures. I have already testified that UL tests have been performed on explosion-proof fittings, giving no indication of breakdowns of the compound at high temperature. (Tr. 1095-97). However, even more directly, in our December 1981 testing, the Chico/Raychem seal was subjected to elevated temperatures. A physical examination of the sample after testing showed no evidence of compound breakdown (or release of moisture). The SWRI testing is another conclusive indication of this characteristic. The Chico there was tested to elevated design basis accident profiles and the reports indicate no significant breakdown of the compound.

In addition, we have reviewed the Material Safety Data Sheet for Chico compound filed with the U. S. Department of Labor. (APCo Exhibit 119). The data sheet specifies, for occupational safety reasons performance characteristics of the compound for the purpose of identifying when hazardous substances might be released. The data sheet shows that the melting point of Chico is 1300°C - 1450°C. These are, of course, temperatures much in excess of any postulated for Farley Nuclear Plant.

We do not believe, based upon the documented information, that the compound will release significant amounts of moisture at the elevated temperatures to be expected for the Farley-specific design basis accident. Even if, however, small amounts of moisture were, or could somehow be, released, it would be of no significance to performance of the switch. We have already testified as to the ruggedness of these types of switches and their ability to function in industrial environments without any special sealing. (Tr. 1049-95). Also, the NAMCO EA-180 limit switches are used at Farley in 125 volt DC and 120 volt AC control and indication circuitry. This circuitry is not sensitive to small amounts of leakage current and provides only an on/off conductive state, as opposed to an analog indication.

Q71. Issue (9) listed above, as raised in Mr. Wilson's Rebuttal Testimony, concerns the installation drawings and revisions referenced in the December 1981 Bechtel test plan. Are you familiar with this issue?

A. (Love) Yes. It is an old issue from the Direct Testimony. I addressed it at length in my prior testimony, specifically in answer to Q149 on pages 171-72. The installation drawings were living documents, and therefore the 1987 version reviewed by Mr. Wilson may not have matched that referenced in the 1981 test plan. However, the earlier revisions remained in plant files and were available for review. Also, as I have previously discussed, these instructions were at all times more than adequate to ensure that the seals were properly installed and that installed seals were bounded by the tested sample.

Q72. Mr. Wilson's Issue (10), as listed above, concerns the compression adapter over the Raychem keeper sleeve. Please address this issue.

A. (Love) The compression adapter is applied over a Raychem keeper sleeve and the pipe nipple to connect the flexible cable conduit. Mr. Wilson's assertion is that seal qualification was somehow incomplete because the compression adapter lacked a specific model number or other descriptive information. However, there is no substance to this claim.

I described the compression adapter on pages 140-41 of my Direct Testimony. The compression adapter is <u>not</u> part of the seal in that it is not intended to serve any sealing function. It serves only to attach the flexible conduit. The fact is that in the field, several different manufacturers' clamps were used on these limit switches to attach the flexible conduit. All were equivalent in design and served the purpose intended. The fact that one specific clamp was not called out simply is not relevant to qualification of the seal assembly.

Q73. Mr. Wilson has speculated that the compression adapter could cut the Raychem keeper sleeve. Are you aware of this?

A. (Love) Yes, I am, and I have addressed such a concern previously in my Direct Testimony at page 166. This is not a valid concern.

In his Rebuttal Testimony, Mr. Wilson seems to change, or supplement, his previous version of this concern by proposing a new cutting mode. He postulates cutting of the sleeve by the compression adapter due to the torque of the cable conduit. (Rebuttal Testimony, at page 9). However, the fact remains -- regardless of the postulated cutting mode -- that there is simply no evidence to support the concern. From all of our testing of this configuration, and in all of our observations of installed limit switches, I am aware of no evidence of cutting problems such as those posed by Mr. Wilson.

Moreover, the adapter clamps to the Raychem keeper sleeve, not to the Raychem boot. <u>See</u> Diagram 2 and the related discussion, pages 140-41 of my Direct Testimony on this issue.

The keeper sleeve is not the important component for seal integrity. The seal is provided by the Raychem boot. Therefore, a nick or a cut in the keeper sleeve would not present a qualification problem.

Finally, I would observe that there is no basis to assume that the cable and conduits will be moving around exerting excessive torque on the adapter. In general, I do not believe that these cables move, or are moved, during normal operation, and they are not such that they will move excessively during an accident.

Q74. Have you now addressed all of the concerns of which you presently are aware regarding these seals?

A. (Love) Yes, I have, either in my original testimony, oral testimony, or this Surrebuttal Testimony.

D. <u>Conclusions</u>

Q75. Overall, what is your conclusion regarding this issue?

A. (Love) First, in conclusion, I want to respond to an inference Mr. Wilson has raised at the hearing and in his testimony. He has implied that these seals would have failed catastrophically. I want to emphasize that I disagree very strongly. Based on all of my experience in electrical engineering and electrical design of equipment conduit and cable sealing systems, equipment qualification, and my work in developing and testing these seals, it is my strong position that they would not fail under the applicable design basis accident conditions.

Second, I want to address the paperwork aspect of qualification. I believe that at the time of the inspection, Alabama Power Company's files contained sufficient, auditable information documenting the basis for qualification of these seals. Obviously, many of Mr. Wilson's specific concerns were not addressed in the files. It is extremely difficult to even understand how one would or could predict Mr. Wilson's concerns in order to address or document responses in sufficient detail to satisfy Mr. Wilson. Mr. Wilson appears to be extremely capable in the area of technical, scientific, and theoretical speculation of hypothetical mechanisms for failure. However, he does not appear to be capable of making any engineering judgments as to the validity of his speculated failure mechanisms based upon the available documented information. For the reasons I have discussed, these speculative concerns lack technical merit.

However, even if these concerns were reasonably foreseeable, I do not believe they are of a type that can or needs to be specifically addressed in qualification documentation. Equipment qualification, at least as originally conceived and practiced, was a means of providing reasonable assurance based on known technical data and sound engineering judgment that equipment would operate when called upon. The focus was on hardware capabilities and the required functions. The basis for the reasonable assurance that equipment would operate does indeed need to be maintained in an auditable form. However, the documentation requirement simply should not be read to overshadow the original purpose of EQ. A reasonable engineer does not need documentation to the most microscopic level of detail. Documentation must be based on a real world, rather than a hypothetical, perspective. In my view, the documentation for these seals was adequate to meet applicable standards and was adequate to demonstrate to a knowledgeable engineer that the seals would function properly.

Q76. Mr. Sundergill, Mr. Jones, and Mr. DiBenedetto, do you agree with Mr. Love's conclusions?

A. (Sundergill, Jones, DiBenedetto) Yes, we do, on all points.

V. <u>TERMINAL BLOCKS</u>

A. <u>Overview</u>

Q77. The next issue is the terminal block issue. Have you reviewed the Staff's Rebuttal Testimony on this issue?

A. (Love, Jones, DiBenedetto) Yes, we have. The Staff's testimony does not change our previous conclusions. After summarizing our position, we would like to address matters raised in the Staff's Rebuttal Testimony in approximately the order presented by the Staff.

Q78. Beginning with the summary then, I observe that in Q/A 4 on pages 2-3 of his Rebuttal Testimony, Dr. Jacobus has restated his understanding of Alabama Power Company's position. Is his restatement complete and accurate?

A. (Love, Jones) It is correct in part, but it is not complete. To keep the record clear and focus this issue, our position includes the following elements:

(1) The terminal blocks at issue were qualified as of the November 30, 1985 EQ deadline, including for the instrument accuracy issue as it then existed. The terminal blocks had been tested to show that they could withstand the

accident conditions. Moreover, prior to the deadline, and as explained at a meeting with the NRC Staff in January 1984 (and as documented in correspondence of February 29, 1984 (APCo Exhibit 20)), Alabama Power Company had undertaken to use post-LOCA terminal block leakage current/IR data (the Wyle Test Report data) for determination of instrument loop accuracies. By including this inaccuracy data in the evaluation of the emergency response procedure (ERP) setpoint values prior to November 30, 1985, the terminal blocks were considered to be useable and qualified.

(2) The NRC Staff was aware of this pre-EQ deadline approach and sanctioned it in the December 1984 SER. Implicit in our position is the fact that by the time of the January 1984 meeting, the Sandia terminal block testing and the instrument accuracy concern as subsequently discussed in Information Notice 84-47 was well known to the NRC Staff. (See Mr. Shemanski's oral testimony, Tr. 679-80). At no time did the Staff express a problem with our approach.

(3) The issue of instrument loop accuracies (uncertainties) continued to evolve after the November 30, 1985 EQ deadline. In 1986 and 1987, in light of this evolution, Alabama Power Company sought to revise terminal block inaccuracy contributions to be used in loop accuracy calculations. Alabama Power Company utilized IR data from the

CONAX report for Connectron blocks (taken during the cooldown phase of the simulated LOCA testing). It was this post-deadline (1986 and 1987) treatment of terminal block contributions to the total loop accuracy which was reviewed during the November 1987 inspection and cited as a violation based upon the latest NRC approach to this issue at the time. This post-deadline approach was explained in APCo Exhibit 52. It was further documented in the November 24, 1987 JCO (APCo Exhibit 59) which was prepared, in response to the NRC Staff's concerns, for a November 25, 1987 meeting in Atlanta.

(4) IN 84-47 (Staff Exhibit 48), the Sandia testing and reports upon which it was based, NRC Regulatory Guide 1.89, Rev. 1 (June 1984), and 10 CFR 50.49 do not indicate that instrumentation terminal blocks are considered unqualified unless they can function at peak-LOCA conditions. It has been our consistent position -- apparently not recognized by the post-November 30, 1985 NRC Staff -- that instrument accuracies need not be maintained throughout peak LOCA conditions for qualification or for inclusion in loop accuracy calculations, because the instrument circuits at issue at Farley Nuclear Plant are not needed during these conditions. The instrument accuracy data utilized in our post-deadline approach to loop accuracies was adequately representative of the accident conditions for Farley Nuclear Plant at the times in which

these instruments would be needed to perform their safety functions.

(5) Existing test data for GE and States terminal blocks, including SAND83-1617, support the Alabama Power Company position that terminal blocks in instrumentation circuits would have been able to meet their performance (safety related) requirements when the instrument circuits were required to function for automatic or operator actions during design basis accidents.

(6) The Sandia terminal block test data presented in SAND83-1617, and referenced in NUREG/CR-3418 (August 1984) (Staff Exhibit 73) and NUREG/CR-3691 (September 1984) (Staff Exhibit 74), does not lead to the conclusion that the terminal block effects on instrument accuracies are significantly different from those used by Alabama Power Company for conditions representative of the Farley Nuclear Plant. In our post-deadline approach, we utilized an IR value of 1E7 ohms based on CONAX data. The Sandia data in fact supports this value for use in loop accuracy calculations as discussed below.

(7) Only a small number of the total Reg. Guide 1.97 variables are at issue. Reg. Guide 1.97 instruments provide post-accident monitoring information to the operator.

Therefore, by the NRC Staff's own measure of the significance of EQ issues, this is an issue with relatively low significance.

Q79. Now that you have summarized Alabama Power Company's position on this issue, please explain the focus of this Surrebuttal Testimony.

A. (Love, Jones) This testimony responds to the Staff's Rebuttal Testimony. The following basic points are made below.

First, Dr. Jacobus's discussion of the "progression of information" on this issue is misleading. We will clarify the pre-EQ deadline basis for qualification of terminal blocks, and then go on to discuss the 1987 post-deadline basis for qualification that was the focus of the inspection. We will also show how Dr. Jacobus's use of the temperature from the SCEW sheet is in error, and ignores the other pre-EQ deadline information available to him.

Second, we will respond to the Staff's assertions that there has been no evolution on this issue. In fact, there has been a clear evolution -- and neither Staff witness seems to even understand or acknowledge what was established with the NRC Staff on Farley instrument terminal blocks prior to November

30, 1985. In these first two sections, we will also address the Staff's latest "clearly should have known" arguments.

Third, we will explain again our approach -- post-EQ deadline -- to qualification of terminal blocks for instrument accuracy. We will show that the Sandia data relied upon by Dr. Jacobus actually supported our use of an IR value of 1E7 ohms. This IR value is appropriate for the instrumentation involved, given Farley-specific design basis accident conditions.

Fourth, we will rebut Dr. Jacobus's critique of our similarity evaluation supporting use of data from a Connectron terminal block. In fact, the Connectron block is dimensionally quite similar to the States and GE terminal blocks at issue. Nonetheless, the similarity analysis is now beside the point. The Sandia data confirms conclusively our 1987 approach from a performance perspective.

(DiBenedetto) Next, I will address the Rebuttal Testimony as it relates to my Direct Testimony on this issue.

(Love, Jones) Finally, we will provide some overall conclusions and perspectives on the issue.

B. Information Available on Qualification Environmental Conditions

Q80. In his Rebuttal Testimony, Q/A 5, at pages 3-6, Dr. Jacobus provides one explanation of "the progression of Alabama Power Company's information to you that forms the basis for their position." The point seems to address the temperature for which these terminal blocks should be qualified. Would you like to provide your views on this issue?

A. (Love, Jones) Yes. Dr. Jacobus attempts to describe the "progression of information" on the required qualification temperature for these terminal blocks. However, he has not accurately described what Alabama Power Company, in fact, did on this issue.

Dr. Jacobus references the peak temperatures of the SCEW sheets (Staff Exhibits 69 and 70) as the basis for qualification of the GE terminal blocks and the States terminal blocks. However, with the exception of the SCEW sheet, Dr. Jacobus does not describe or acknowledge any of the information which was available to the NRC Staff, and was previously accepted by the Staff, regarding the requirements for qualification of terminal blocks in instrument circuits. This information included the minutes of the January 1984 meeting with the NRC Staff (APCo Exhibit 20) accepted in the final NRC EQ SER (APCo Exhibit 21).

As testified to previously, the minutes of the January 1984 meeting explicitly state that "post-LOCA," not "peak-LOCA," terminal block leakage current (IR) data from the Alabama Power Company Wyle Test Report on States terminal blocks would be used for instrument accuracy purposes. Dr. Jacobus is illustrating that in November 1987 he was inspecting Farley EQ files based only on his current 1987 level of knowledge and understanding of this issue, without regard for the Farley-specific pre-deadline documented basis.

However, more importantly with regard to the SCEW sheet values, the Staff is now implying that these peak temperatures lead them to believe that the basis for terminal block performance in instrument loops was peak-LOCA temperatures. (See also Dr. Jacobus at Tr. 708-709, 739). Frankly, this is not a credible assertion. An EQ engineer knowledgeable in the derivation of the SCEW sheet and the history of terminal block qualification programs certainly should have known the meaning and significance of these numbers.

The SCEW sheet, as explained in our Direct Testimony, was prepared for each model of equipment and provided a summary level comparison of the peak-specified and peak-tested environmental parameters. These included temperature. The SCEW sheet was not intended to be the single document for explaining the performance qualification of terminal blocks in instrument loops. For the States terminal blocks and GE terminal blocks included with the GE electrical containment penetrations, the terminal blocks were tested to and did successfully withstand the required peak temperatures specified on the SCEW sheet. The ability of these terminal blocks to survive (withstand) the peak test temperatures and recover without significant degradation qualified the terminal blocks for the anticipated peak harsh environmental conditions at Farley. This has always been our claim as reflected on the SCEW sheets. However, Alabama Power Company has never claimed that the instrument circuit performance in terms of instrument loop uncertainty contributions should be based on peak conditions.

Q81. What is the significance of the withstand temperature for the terminal blocks as referenced in the SCEW sheets?

A. (Love) The fact that these terminal blocks will withstand peak-LOCA/High Energy Line Break (HELB) conditions, and recover, is important. It shows that the terminal blocks will survive the accident to the post-accident phase during which the associated instrument loops are needed to operate to provide information to the operators.

As we discussed before, and will discuss further below, IR values recover as temperature drops. The fact that a terminal block must withstand the harsh LOCA conditions does not mean that IR data for instrument accuracy needs to be based on these same peak-LOCA conditions. I believe Dr. Jacobus understands this distinction, but is simply extracting the SCEW sheet value out of context, to confuse the issue.

Q82. In his discussion of the "progression of information," Dr. Jacobus goes on to discuss (Rebuttal Testimony, at pages 4-5) some of the discussions on the peak qualification temperature issue during the November 1987 inspection and during the November 25, 1987 post-inspection meeting in Atlanta. Could you give your perspective on these interactions?

A. (Love, Jones) First, Dr. Jacobus discusses the documented questions and answers from the inspections. He refers particularly to Alabama Power Company's response to EQ Question No. 26. (Staff Exhibit 71). This references Alabama Power Company's EQ Action Items 018 and 067 (APCo Exhibit 52), which were post-EQ deadline activities addressing the contribution of terminal block leakage current to instrument loop uncertainty. They address the use of data for IR taken from the CONAX IPS-107 test graph. Dr. Jacobus claims that from this information he was still unable to determine that Alabama Power Company's approach was not based on peak LOCA conditions. In his testimony he states, "Interestingly, there is no mention in that document of the temperatures when the insulation resistances were measured, nor is there any argument that the blocks are not required at peak LOCA conditions." He next states, "The temperatures at which IR measures were performed is clearly not obvious from the plot that is cited from the CONAX report." (Rebuttal Testimony, at page 4).

These are all very odd statements. EQ Action Items 018 and 067 made explicit reference to the CONAX IPS-107 test graph from which the value of 1E7 ohms was extracted. (APCo Exhibit 53). Dr. Jacobus had access to and reviewed the CONAX report prior to the November 1987 meeting in Atlanta. All of the information needed to determine which DBE test temperatures corresponded to the IR data points contained on the graph can be easily determined from this information. In his Direct Testimony on this issue, at page 4, Dr. Jacobus clearly recognized (and faulted) the basis for qualification for instrument accuracy. He stated there that the "data that was taken from the CONAX report was taken at 150°F or less."

Therefore, it seems clear that it was known that the basis for our 1987 position on this issue (1E7 ohms) was taken below peak-LOCA conditions. Despite the smokescreen in the Rebuttal Testimony, the true issue is that Dr. Jacobus believes the value of 1E7 ohms to be too high, and that only lower IR values at peak-LOCA temperatures must be used. We addressed this point at length in our Direct Testimony on the issue, at pages 117-125, and will address it further below. We continue to believe that the IR value we utilized for the 1987 ERP calculations (1E7 ohms) was appropriate for the States and GE terminal blocks.

Q83. Do you agree with Dr. Jacobus when he states at the conclusion of his answer to Q5 (Rebuttal Testimony, at page 6) that "APCo still has not defined what temperature they feel the blocks need to be qualified to based on the circuit-by-circuit analysis that they claim to have used as a basis for qualification all along"?

A. (Love, Jones) No. As stated above, Alabama Power Company clearly defined in the January 1984 meeting with the NRC Staff, as documented in Alabama Power Company's February 29, 1984 letter (APCo Exhibit 20), that the leakage current (IR) data from the Wyle test report (APCo Exhibit 50) was recorded post-LOCA after the cooldown. These were the leakage current (IR) values on which the Westinghouse pre-EQ deadline circuit-by-circuit (or instrument loop) analysis for ERP setpoint values were based. Since the Staff never disagreed with the approach prior to the EQ deadline, we probably should not be here today. This accepted basis for terminal block accuracy should be the benchmark for EQ compliance as of the EQ deadline.

Nonetheless, since the Staff has made the 1987 post-EQ deadline instrument accuracies the issue, we will attempt to clarify below any remaining confusion with regard to the 1987 instrument loop uncertainty calculations and the basis for terminal block contributions used in these calculations. As will be clear from the discussion below, this issue is more involved than simply picking a peak LOCA test temperature and then concluding that the IR data corresponding to that temperature would result in unacceptable loop accuracies.

Q84. Dr. Jacobus discusses the relevant EQ requirements and standards at length in his Rebuttal Testimony, at pages 8-11, leading to a conclusion that -- for instrument accuracy purposes -- these blocks needed to be qualified for peak LOCA conditions. Do you concur?

A. (Love, Jones) No, and we believe Dr. Jacobus is omitting several very important references. While we agree that the applicable requirements for the qualification of the States and GE terminal blocks were the DOR Guidelines for Farley Unit 1 and NUREG-0588, Category II, for Farley Unit 2, we do not concur that these requirements indicated that values of leakage current or insulation resistance had to be taken during the peak of the design basis accident (DBA) qualification testing and used in calculating instrument loop accuracies. As stated in our previous testimony, and as agreed to by the NRC Staff in January 1984, and in the subsequent SER, using post-LOCA terminal block leakage currents for these calculations was acceptable to the Staff.

The pre-EQ deadline NRC Staff and Alabama Power Company understanding of instrumentation terminal block qualification can be stated as follows: If the terminal blocks could be shown to perform their required functions prior to reaching the worst-case peak LOCA temperatures, survive the worst-case peak LOCA temperatures, and recover function after cooldown, they were considered qualified. Inherent in this understanding was that no automatic or operator actions were required during the worst-case peak LOCA temperatures or prior to cooldown. Both the States and the GE terminal blocks used at Farley were demonstrated by design basis accident testing conducted in accordance with the requirements of the DOR Guidelines and NUREG-0588 to meet these qualification criteria for instrument circuits. If this were not the case, it is not conceivable that the Staff would have issued the December 1984 SER.

Q85. Was this approach ever documented?

A. (Love, Jones) Yes, as we have discussed previously, in the February 29, 1984 correspondence memorializing the January 1984 meeting. (APCo Exhibit 20). In Attachment 2, at page 6, our approach (accepted at the meeting and in the December 1984 SER) was described as follows (emphasis added):

> NRC Comment
>
> Address the current leakage of States Terminal Blocks and its effects on equipment within the scope of 10CFR50.49.
>
> APCO Response
>
> The environmental qualification test report for States Company Terminal Blocks, Wyle Laboratories Report 44354-1 provides the values of leakage currents. The States Terminal Blocks were LOCA tested with an applied voltage of 137.5 VDC which is the normal operation voltage of the terminal blocks. Instrumentation was attached to the terminal blocks at the conclusion of the LOCA test and leakage current values were recorded. The values of leakage current were recorded from terminal point-to-point and point-to-ground on the States Terminal Block. Also included were conductor-to-conductor and conductor-to-ground leakage current. These values were recorded for multiple combinations with an applied voltage of 137.5 VDC.
>
> The test leakage current values are being used in the development of the revised FNP Emergency Operating Procedures (EOPs) presently being prepared by Westinghouse/APCo.

Q86. Are there any clear regulatory requirements indicating that instrumentation must be demonstrated to maintain a specified (fixed) level of accuracy (or functional performance) at worst-case peak LOCA conditions in order to be considered qualified?

A. (Love, Jones) Neither the regulations nor the regulatory guidance requires or suggests that instrumentation terminal block functional performance must be demonstrated during an environmental service condition such as peak LOCA temperature if no safety function is required coincident with this condition. The regulatory guidance actually supports our conclusion that qualification of instrumentation terminal block functional performance can be based on the environmental service conditions which will be experienced when the terminal block safety function is required. (All of this presumes the capability to withstand or survive the complete time-dependent LOCA environmental conditions as discussed above, which is not an issue for these terminal blocks (<u>See</u> Dr. Jacobus's oral testimony, at Tr. 696).)

First, 10 CFR 50.49(e)(1) provides (emphasis added):

> (e) The electric equipment qualification program must include and be based on the following . . .
>
> (1) Temperature and pressure. The time-dependent temperature and pressure at the location of the electric equipment important to safety must be established for the most severe design basis accident <u>during or following which this equipment is required to remain functional</u>.

Under this regulation, an environmental profile is established for the entire event. However, functional qualification can be based on the time in the accident event when the equipment is required to function.

NRC Regulatory Guide 1.89, Rev. 1 (June 1984) is another important reference. (APCo Exhibit 35). Referring first to Section B, second full paragraph on page 1.89-2, the first sentence of this paragraph starts with the following statements:

> It is essential that safety-related electric equipment be qualified to demonstrate that it can perform its safety function under the environmental service conditions in which it will be required to function and for the length of time its function is required. . . .

The next paragraph states:

> The following are examples of considerations to be taken into account when determining the environment for which the equipment is to be qualified:

Consideration (3) states:

> [E]quipment required to initiate protective action would generally be required for a shorter period of time than instrumentation required to follow the course of an accident. . . .

Section C.1 states:

> Section 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," of 10CFR Part 50 requires that safety-related electric equipment (Class IE) as defined in paragraph 50.49(b)(1) be qualified to perform its intended safety functions.

This regulatory guidance supports our position that qualification of instrumentation terminal blocks can be based on the environmental conditions which will be experienced when the terminal block safety function is required. Here, as we discussed in our Direct Testimony, our position is that the affected Reg. Guide 1.97 instruments which included the terminal blocks at issue did not need to function at peak LOCA conditions.

Q87. In his Rebuttal Testimony, at page 11, Dr. Jacobus restates the Reg. Guide 1.97, Rev. 2, guidance. He concludes from the guidance that it is required to demonstrate "functioning through the peak LOCA conditions for the terminal blocks that are required after that time." Do you agree with his interpretation of this guidance?

A. (Love, Jones) No, we do not agree with his restatement of the guidance. Unlike Dr. Jacobus, we do not interpret the regulatory guidance as saying that an instrument which has no required function during peak LOCA conditions must <u>function through</u> the peak LOCA conditions. What is important is withstand and recovery capability. For the terminal blocks at issue, that capability has been shown.

Q88. Dr. Jacobus's Rebuttal Testimony (Q/A 8, at pages 11-12) again refers to IN 84-47 (Staff Exhibit 48) and NUREG/CR 3691 (Staff

Exhibit 74), which are based on the SAND83-1617 data. Dr. Jacobus argues that these documents provide the basis for why Alabama Power Company should have clearly known that terminal blocks in instrument circuits had to function at the peak temperatures of the worst-case design basis LOCA accident. Is this position clearly supported by these documents?

A. (Love, Jones) No. As testified to previously (see our Direct Testimony, Q/A 98, at pages 107-108), we followed the guidance provided in IN 84-47 (Staff Exhibit 48) during the pre-EQ deadline qualification of the terminal blocks. The relevant action statement of IN 84-47 was quoted in our Direct Testimony, at page 108. Consistent with that statement, from a pre-deadline perspective, we had taken steps to ensure that the terminal block performance would be addressed in emergency procedures. Since IN 84-47 followed closely after our meeting with the NRC Staff in January 1984, we had no basis to question our agreed-upon approach.

Moreover, a total reading of IN 84-47 will not yield any statement regarding the necessity to demonstrate function at the peak temperatures of worst-case design basis accidents. Also, it is a matter of fact that a complete reading of NUREG/CR-3691 (Staff Exhibit 74) and NUREG/CR-3418 (Staff Exhibit 73) (SAND83-1617) will not provide a clearly stated basis for the post-EQ deadline and present Staff's position on this issue.

Q89. In the Staff's Rebuttal Testimony (Q/A 9, at pages 12-14), the Staff is presenting additional arguments as to why Alabama Power Company "clearly should have known" from IN 84-47 and the Sandia reports that the Farley instrument terminal blocks were not qualified as of November 30, 1985. Do these additional arguments have any substantive basis?

A. (Love, Jones) Aside from the ridiculous implication on the bottom of page 13 that Mr. DiBenedetto is in some misquoted way agreeing that the instrument terminal blocks had to be used during peak conditions of the accident prior to November 30, 1985, the only other new information expounded seems to be a reference to Figure 8-3 on page 85 of NUREG/CR-3691. The Staff states that this figure demonstrates vividly the effects of terminal block leakage currents on an actual pressure transmitter circuit.

Alabama Power Company agrees with this observation. In fact, the figure shows vividly that as the temperature of the terminal block decreases with the simulated design basis accident temperature from its peak of 175°C to 161°C, and then to 95°C, the terminal block leakage current decreases and the transmitter signal level returns to its base value. This is also described in SAND83-1617 (Staff Exhibit 73) and depicts the terminal block test leakage current effect on transmitter response for the second of the three DBA test profiles (SAND83-1617, Figure 2, page 9) to which this terminal block was exposed. We would like to explicitly point out that the curve on Figure 8-3 shows when the cooldown from 161°C (321.8°F) to 95°C (203°F) is initiated, the transmitter signal current returns linearly to base level with time. This figure supports exactly our pre-EQ deadline position, as discussed in the January 1984 meeting and documented in Alabama Power Company's February 29, 1984 letter to the NRC. (APCo Exhibit 20). This position was that post-LOCA leakage currents (IR) could be used in the pre-November 30, 1985 Westinghouse EOP setpoint analysis.

It is also interesting that the Staff's Rebuttal Testimony now seems so dogmatic on the issue that peak LOCA conditions were essential (See, e.g., Q/A 9 at pages 12-14). This was not Dr. Jacobus's position in his Direct Testimony at page 5, where he recognized that peak LOCA data was not needed under certain conditions. In any event, it is certainly stretching the truth to now claim (almost 8 years after-the-fact) that IN 84-47 and the Sandia reports put Alabama Power Company somehow on notice of this issue.

The same can be said for IN 85-39 (Staff Exhibit 77) referenced in the Rebuttal Testimony, at page 14. That Notice has nothing to do with terminal blocks; rather, it related to resolving Franklin TER-identified problems. For terminal blocks in instrument circuits, we had a proposed resolution. The very purpose of the January 1984 meeting with the Staff was to discuss resolutions to Franklin open items. Our resolution on this issue was accepted.

C. <u>Evolving Requirements</u>

Q90. In the NRC Staff's Rebuttal Testimony, under the subheading "Evolving Requirements," at pages 16-27, the Staff has testified that there was no new post-EQ deadline knowledge applied by the NRC Staff in their findings or their assessment of a violation regarding this issue. Does Alabama Power Company concur with this testimony?

A. (Love, Jones) Absolutely not. The present NRC Staff continues to direct their arguments back to what a licensee should have been able to clearly determine from IN 84-47 when it was issued prior to November 30, 1985. The present Staff has applied their post-EQ deadline understanding of this document during and following the November 1987 Farley inspection, without any apparent attempt to review or consider the Farley-specific pre-EQ deadline NRC documentation, which provided the agreed-upon basis for NRC acceptance of the instrument terminal block qualification as of November 30, 1985. The present Staff then asserts that there is no evolving standard because IN 84-47 was issued in 1984 prior to the deadline. However, by refusing to view that document in context, they cannot do anything but apply an evolving standard.

Q91. Is there any evidence that the Staff witnesses were involved in the 1984 NRC Farley-specific reviews of this issue, or that they attempted to determine, or even cared to determine, the pre-deadline NRC documented basis for instrument terminal block qualification for Farley Nuclear Plant prior to conducting the November 1987 inspection?

A. (Jones, Love) None which is apparent to us. In fact, quite to the contrary. In Dr. Jacobus's deposition he responded to questioning related to Alabama Power Company's November 1988 response to the Notice of Violation on terminal blocks. He discusses, starting on page 133, line 9, Alabama Power Company's arguments related to pre-deadline matters. He states:

> A. . . . Then it [the NOV response] goes on to discuss things about what happened back in 1984, which I was not privy to, so I don't really have any comments. I wouldn't know what happened back in 1984.

> Q. As far as the SER and the meetings with NRC?
>
> A. That's correct.

Then, later in the deposition, starting on line 19 of page 134, Dr. Jacobus states:

> A. . . . Then at that point, it [again, the NOV response] goes on to say that GE terminal blocks any question [sic] is similar to the States terminal blocks, and somewhere they talked about the States terminal blocks. That's talked about up above about the 1984 meetings, the States terminal blocks, so they say that the GE blocks are similar to what the States blocks -- Alabama Power shouldn't clearly have known because of the SER, TER arguments.
>
> Q. And you already stated that you're unfamiliar with those arguments or at least you were not around at the time?
>
> A. I was not around at the time, and I have not been provided any copies of things that went on at that time.
>
> Q. Anything else in there that you care to comment on?
>
> A. Well, with regard the fact that the staff presumably prepared an SER that said that Alabama -- "that the Alabama Power Company equipment qualification program is in compliance with the requirements of 10 CFR 50.49, that the proposed resolution for each item of the environmental qualification deficiencies identified for Farley 1 and 2 is acceptable."
>
> Presumably the terminal blocks were one of those issues, one of these deficiencies identified. I don't know for certain that that's the case, and according to this, what the NRC then said is that their proposed resolution is

acceptable with the assumption that that proposed resolution will be implemented correctly, I assume. And so the question then becomes, was the proposed resolution implemented in an acceptable fashion, and I don't know the details of that.

Q. You don't know what the proposed resolution was. But based on your review of the files, what's your opinion on whether or not it was implemented?

A. I don't know what the proposed resolution is, but if I assume that the proposed resolution was to come up with an adequate qualification, then clearly it was not implemented.

From these statements of Dr. Jacobus, it is very obvious that no attempt was made by the present NRC Staff to determine what the Farley-specific agreed upon pre-EQ deadline basis for NRC compliance or resolution of this issue was. Instead, the witnesses categorically claim -- without really knowing -- that there has been no evolution.

Q92. Mr. Luehman, at pages 18-20 of the Rebuttal Testimony, also attempts to address the evolution argument. Would you care to respond to Mr. Luehman?

A. (Jones) Yes. Mr. Luehman is simply restating the position that IN 84-47 provides a basis for the Staff's "clearly should have known" finding. He also tries to show that terminal blocks were being inspected for qualification in the pre-deadline time frame. However, Mr. Luehman is again missing the point. He seems to think a "clearly should have known" finding can be based on indications that terminal blocks needed to be qualified prior to the deadline. That really is not in dispute. We knew the terminal blocks needed to be qualified for their application in instrument circuits and we had an accepted basis to do just that. Under the Modified Enforcement Policy, the real point is whether we "clearly knew or should have known of the lack of proper environmental qualification." (Staff Exhibit 4, Enclosure, at page 1) (emphasis added). We clearly did not know and clearly should not have known that our qualification approach was not sufficient for all the reasons we have discussed.

Q93. In Q/A 13 and the following series of questions and answers (Rebuttal Testimony, at pages 17-27), the Staff witnesses discuss actions taken by other licensees responding to concerns regarding the use of terminal blocks on instrumentation circuits. Does Alabama Power Company have a response?

A. (Love, Jones) Yes. We believe that the circumstances surrounding other plants' and other licensees' decisions to remove specific types of terminal blocks in specific instrument circuit applications, and to replace them with qualified splices, have no direct bearing or significance with regard to our compliance with 10 CFR 50.49 for Farley Nuclear Plant instrument applications as of November 30, 1985. The fact is, we addressed this matter prior to the deadline and reasonably believed that we had Staff approval.

All of the examples given by the Staff of inspections regarding other specific applications or interpretations of IN 84-47, and of actions taken by other licensees, certainly appear to have been a source of evolving knowledge to the current Staff. In fact, the Staff appears to have performed the inspection at Farley Nuclear Plant in November 1987 totally based on their knowledge and understanding of activities with other licensees, and failed to even consider that Alabama Power Company had -- before the November 30, 1985 deadline -- specifically established a 10 CFR 50.49 compliance basis for resolution of terminal block leakage currents in EQ instrument circuits. By 1987, the Staff was predisposed to question any use of terminal blocks in instrument circuits. This represents a clear evolution from the pre-deadline agreement for Farley and therefore is an inappropriate basis for enforcement.

Moreover, we addressed the new 1987 expectation adequately also, as addressed further below. Their pre-inspection 1987 approach, based on an IR value of 1E7 ohms, was and remains a valid technical approach to this issue.

Q94. Are there any additional comments you would like to make in response to the NRC Staff's Rebuttal Testimony on "Evolving Requirements?"

A. (Love) Yes. Specifically in reference to the second paragraph on page 21 in the answer to Q14, Dr. Jacobus states that:

> In terms of performing loop accuracy calculations involving contributions of calibration equipment and other secondary effects, I would agree that APCo probably began such calculations in the same time frame as the rest of the industry. However, that is not the issue in these proceedings. The issue is specifically for not properly considering the effects of terminal blocks on the accuracy of instrument circuits. The NRC Staff expected to see acceptance criteria established for the terminal blocks (based on their required function) and then a demonstration that the terminal blocks meet those specified functional performance requirements during accident conditions as is required by regulations.

Also, beginning in the last paragraph on page 25 in answer to Q18, Dr. Jacobus states:

> In response to IN 84-47, terminal blocks were either replaced or appropriately considered as part of the loop accuracy calculations by other utilities. At that point, most utilities began considering the effects of cables, electrical penetrations, and splices also. In the evolution of loop accuracy calculations after the EQ deadline, items such as process measurement accuracy, sensor calibration accuracy, sensor temperature effects, sensor drift, rack calibration accuracy, rack comparator setting accuracy, rack temperature effects, and rack drift began

> to be considered in the loop calculations. (Staff Exhibit 76). APCO has not been cited for failure to consider these effects. They have only been cited for failing to consider the effects of terminal blocks, the issue identified in IN 84-47.

These are very interesting statements from the standpoint of the evolving interpretations of requirements by the Staff. This testimony clearly underscores the vintage of the instrument loop accuracy calculations the inspectors were reviewing and questioning at Farley Nuclear Plant in November 1987. The Staff simply is not focusing on the pre-deadline context.

As I testified in our Direct Testimony (at pages 110-112), in the 1986 and 1987 time frame, the Farley-specific emergency response procedure (ERP) setpoint calculations were being revised to include the contributions of what Dr. Jacobus has called secondary effects. From his second quote above, I assume he is defining secondary effects to include the environmental effects of cable leakage currents which were added to the terminal block leakage currents (implied to be a primary effect, although not stated as such) to determine the overall instrument loop uncertainty during design basis events. Also, I assume that it is understood that the design basis event environmental effects on the instrument sensor itself are considered a primary contributor to overall instrument loop uncertainty during postulated design basis events.

It was the results of the contemporaneous 1987 total instrument loop uncertainty calculations that were being inspected and questioned in detail at the November inspection, including the contribution of instrument cabling. In fact, at the inspector's request, Alabama Power Company had the appropriate Westinghouse engineers who had performed the 1987 Farley uncertainty calculations make a special trip to Farley Nuclear Plant during the inspection and explain to the NRC inspectors their methodology for their ongoing evaluation. It must be emphasized that in the 1987 vintage calculations, cable and other so-called secondary contributions described above were included in the calculation of the overall loop uncertainly and ERP allowance values for the measured variable.

This inspection -- and the current testimony -- should again be contrasted with the pre-deadline context. Although not stated by Dr. Jacobus, Mr. Wilson, during the November 1987 EQ inspection, reviewed the 1987 RPS/ESFAS (reactor protection system/engineered safety feature actuation system) and ERP instrumentation total loop accuracy methodology for the treatment of instrument cable minimum IR criteria. He reviewed each specific instrument cable included in the 1987

Westinghouse analysis. No deficiencies were found in this portion of the November 1987 inspection.

Prior to November 30, 1985, the Farley ERP allowance values were primarily based on the environmental effects of the instrument sensor with specific consideration of the terminal block effects using the post-LOCA criteria for terminal blocks agreed to by the NRC Staff in the January 1984 meeting. Cable effects were considered to be negligible in this pre-EQ deadline analysis. (As we have testified previously, this was consistent with the general industry approach at that time to loop accuracy calculations.) Obviously, these pre-deadline ERP calculations were not what the inspectors reviewed in their November 1987 inspection as a basis for compliance to 10 CFR 50.49. Notwithstanding the Staff's claims, there was a clear evolution between the EQ deadline and the inspection.

Q95. Are issues regarding loop accuracy calculations (and terminal block contribution) still evolving?

A. (Love) Yes. NRC Information Notices are still being issued on the effects of leakage current on overall instrument loop accuracy during postulated harsh environmental conditions. Recently, the Staff issued IN 92-12, "Effects of Cable Leakage Currents on Instrument Settings and Indications," dated

February 10, 1992. (APCo Exhibit 120). It is interesting to note that on page 2 of 2, the second paragraph states:

> The NRC is aware that many licensees are revising instrument setpoints using the latest industry standards and are assessing the effects of leakage currents. However, since most licensees for operating plants may not have addressed these effects in their original design calculations, the problem described above for Surry may be generic.

It is also interesting to note that in the first paragraph of the Discussion, it states:

> Under conditions of high humidity and temperature associated with either a LOCA or HELB, the IR may decrease in components of the instrument loop such as cables, splices, connectors, terminal blocks, and containment penetrations. Consequently, leakage currents increase and measurement of process variables becomes more uncertain.

The third paragraph of the Discussion states:

> In June 1984, the NRC issued Information Notice (IN) 84-47, "Environmental Qualification Tests of Electrical Terminal Blocks." In this information notice, the staff identified the potential for errors caused by leakage currents at terminal blocks when these blocks are subjected to a harsh environment.

All of the statements above exemplify the evolving understanding of total instrument loop uncertainty determinations and of the significance of the harsh environment effects on the error contribution from each loop component after the EQ deadline. Certainly, in this context, trying to base compliance on 10 CFR 50.49 as of November 30, 1985, on the chronological issue date of IN 84-47 is ludicrous.

D. **<u>Required Qualification Temperature/ Value of IR Selected</u>**

Q96. In the Staff's Rebuttal Testimony section subtitled, "Required Qualification Temperature/Arguments that Blocks were Qualified/JCO," on pages 32-47 (Q/A 26-39), the Staff is continuing their argument as to why the Farley required terminal block qualification temperature is worst-case peak LOCA/HELB. The Staff also argues that Alabama Power Company has not demonstrated qualification at any temperatures other than peak LOCA/HELB. Is Alabama Power Company in agreement with these Staff positions?

A. (Love, Jones) No, we are definitely not in agreement. We have in our testimony above addressed our position on the applicable regulatory requirements. Also in our testimony above, we have addressed the historical basis upon which we contend regulatory compliance should have been assessed. The cited violation and the enforcement action on terminal blocks in instrument circuits could be refuted solely on these positions. However, we also feel very strongly that the 1987 findings are technically shallow and fail to recognize the pertinent performance characteristics of qualified terminal blocks under postulated design basis accident environments.

(Love) In the testimony to follow, I will expand further on the basis for our 1987 technical positions as provided in previous testimony and discussed at the hearing. This will address the Staff's arguments in the Rebuttal Testimony. I will show that even in a 1987 context, our approach -- as documented in APCo Exhibit 52 (the EQ Action Items 018 and 067) and in the November 24, 1987 JCO (APCo Exhibit 59) -- was a valid approach.

First, in my testimony I will address existing test data, including that contained in SAND83-1617, and provide in more detail our basis and conclusions regarding the significance of this data. Specifically, I will explain the meaning of this data to the insulation resistance versus temperature characteristics of terminal blocks during design basis accident environments.

Next, I will re-look at the temperature versus time profiles of the postulated Farley-specific worst-case design basis loss of coolant accident and main steam line break (MSLB) and illustrate the portions of the curves where automatic and manual operator safety-related actions were required. I will indicate specifically which instrument signals are required for the automatic and manual safety-related actions.

Then, having defined the design basis accident temperature ranges and the length of time the instrument terminal blocks would have been required to function, I will demonstrate -- by using the terminal block IR versus temperature characteristic data -- that the instrument terminal blocks would have been capable of performing their safety functions based on the 1987 vintage analysis (and the selected IR value of 1E7 ohms). Based on this, we can conclude that the terminal blocks were qualified in 1987, even against the Staff's 1987 perspective.

Q97. Let's turn first then to the existing test data. The NRC Staff has implied extensively that the Sandia testing documented by SAND83-1617 conclusively demonstrated that, during simulated design basis accident testing of terminal blocks, the IR versus temperature is not linear on a logarithmic scale. Do you agree?

A. (Love) No. SAND83-1617 (Staff Exhibit 73) provides the data that IN 84-47 was based upon. The terminal block testing involved subjecting the blocks to successive DBA profiles, which is, of course, not realistic. In fact, Sandia tested these blocks to near destruction, something that would not occur under the Farley-specific design basis conditions. This type of testing resulted in very conservative values of terminal block IRs for the first and second of the successive DBA tests, and IRs indicative of almost complete block degradation for the third successive DBA test.

In any event, reviewing the data for each simulated test DBA, considering the variable of time as well as temperature, I do not agree with the Staff's conclusion. During the initial increasing temperature ramp (heatup) and the decreasing temperature ramp (cooldown) of the first simulated DBA test temperature, the referenced Sandia testing does not indicate a non-linear relationship for the GE and States terminal blocks. I discussed this in oral testimony. (Tr. 1211-1222).

Q98. How does the SAND83-1617 data support your conclusion that Dr. Jacobus is in error regarding the linear relationship of IR vs. temperature?

A. (Love) This will require some explanation of the data. If you will bear with me, I will step carefully through the data and show how it supports my conclusion -- not Dr. Jacobus's.

In the Sandia testing, as documented in SAND83-1617, two phases of simulated DBA testing were conducted. The environmental temperature profile for the first phase testing

(Phase I) is shown on page 8 of the report and is entitled Figure 1, Phase I Environmental Temperature Profile. Page 9 of the report shows the environmental temperature profile for the second phase of testing and is entitled Figure 2, Phase II Environmental Temperature Profile. It is important to recognize that the Phase I test simulated two consecutive DBAs, and the Phase II test simulated three consecutive DBAs for the terminal blocks included in each phase of testing. I have marked these figures to indicate each simulated DBA on the profiles and for convenience have included them in this testimony as Figures 1 and 2.

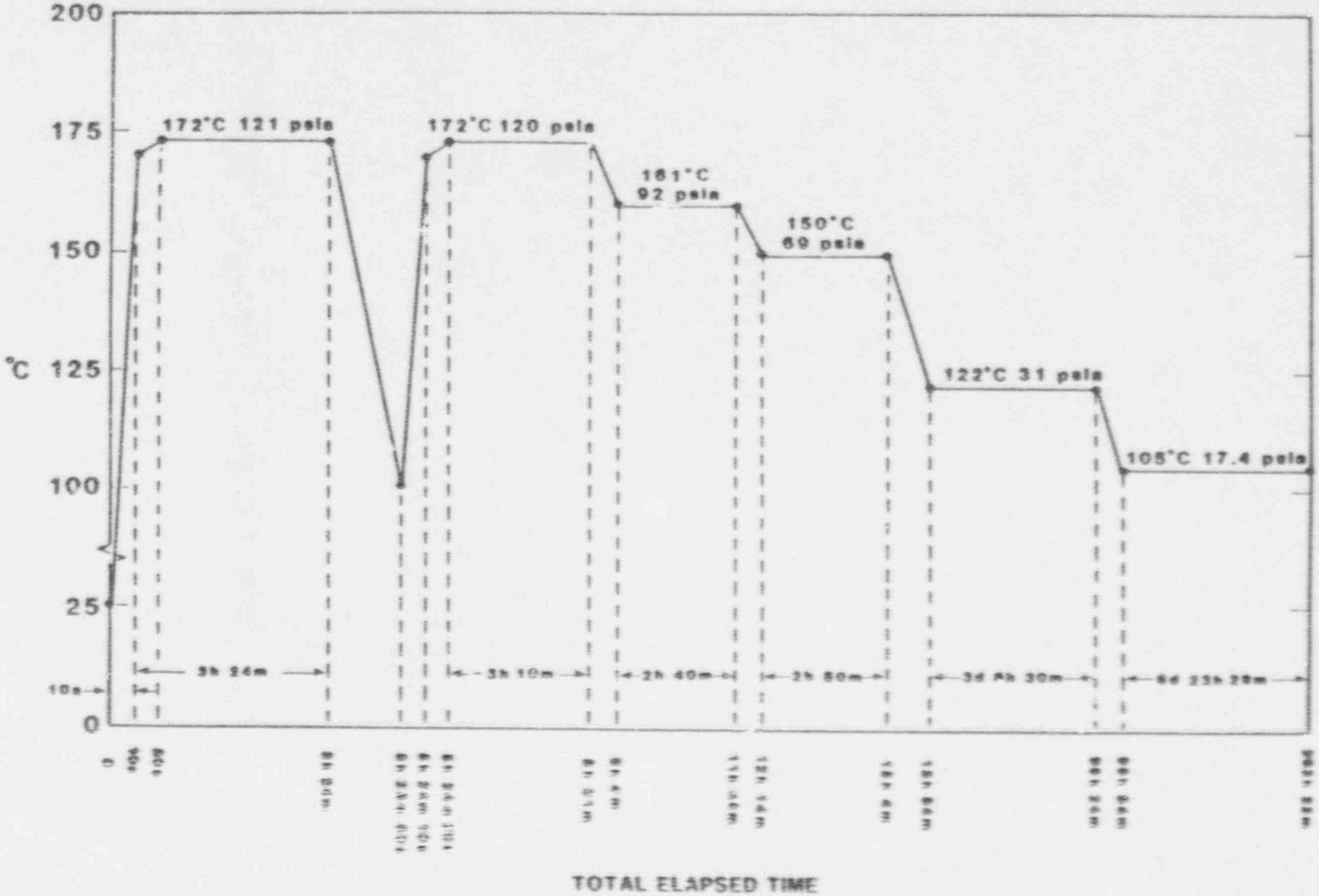


Figure 1

Phase I Environmental Temperature Profile

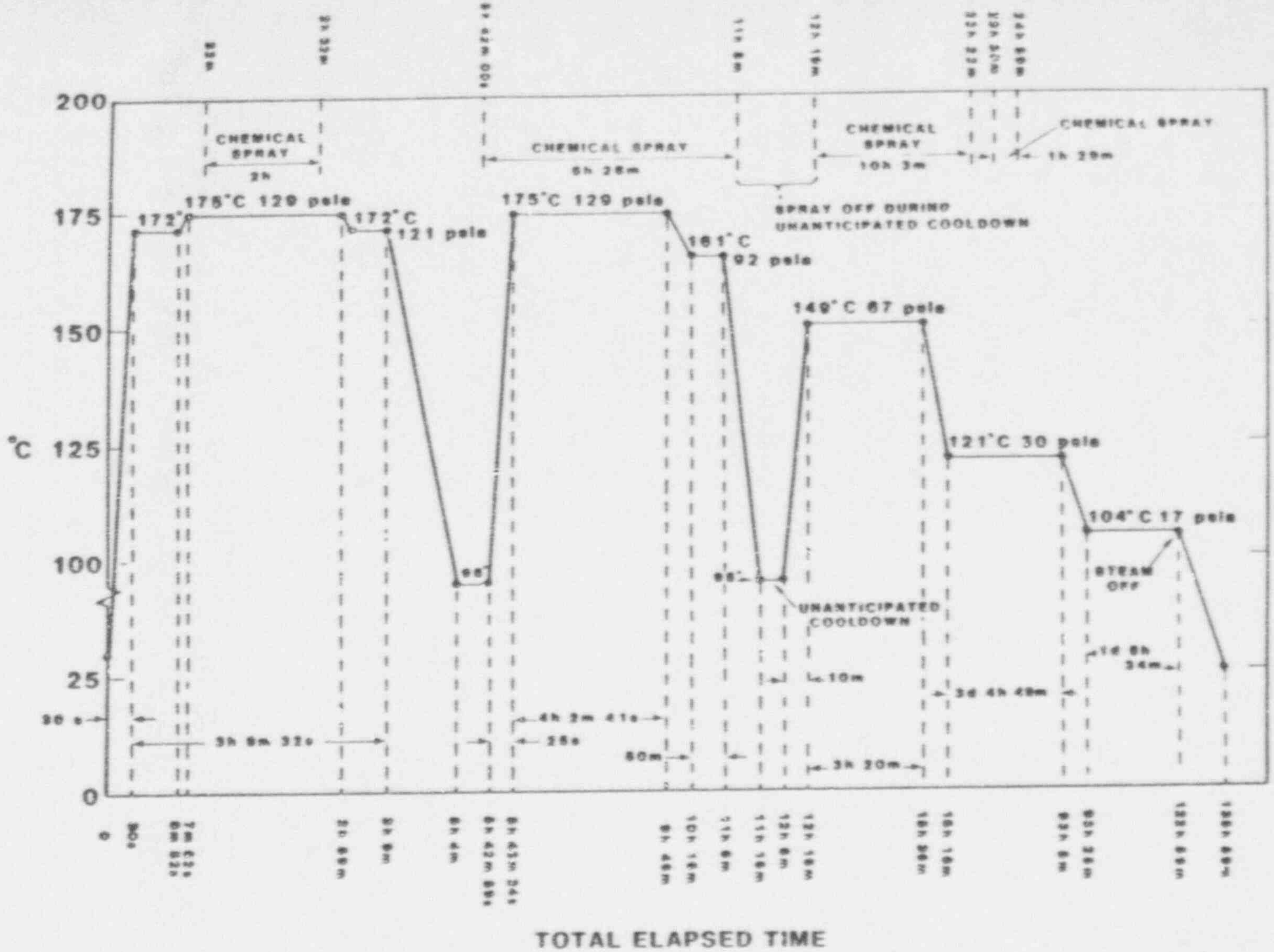


Figure 2

Phase II Environmental Temperature Profile

For the Phase I test, the first simulated DBA starts at time 0 and the temperature reaches 172°C (341.6°F) in 50 seconds. The peak temperature of the first simulated DBA was maintained at 172°C (341.6°F) for 3 hours and 24 minutes, after which the post-peak cooldown to 95°C (203°F) was initiated. After reaching 95°C (203°F), the second simulated DBA was initiated and the temperature reaches 172°C (341.6°F) in 90 seconds. The peak temperature was maintained on the second simulated DBA at 172°C (341.6°F) for 3 hours and 10 minutes, after which a series of stepped decreases in temperature were initiated with temperature plateaus between steps at 161°C (321.8°F), 150°C (302°F), 122°C (251.6°F), reaching the final plateau of 105°C (221°F). The temperature plateaus at 161°C (321.8°F) and at 150°C (302°F) were maintained for 2 hours, 40 minutes and 2 hours, 50 minutes, respectively, and the temperature plateaus at 122°C (251.6°F) and 105°C (221°F) were maintained for 3 days, 8 hours, 30 minutes and 6 days, 23 hours, 29 minutes, respectively.

In the Phase II test, the first simulated DBA starts at time 0 and the temperature reaches 172°C (341°F) in 30 seconds and was increased to 175°C (347°F) in 7 minutes, 52 seconds. The peak temperature of the first simulated DBA was maintained at 175°C (347°F) for almost 3 hours, after which it was reduced to 172°C (341.6°F). After maintaining the temperature at

172°C (341.6°F) for a short period of time, the post-peak cooldown to 95°C (203°F) was initiated. After reaching 95°C (203°F) and maintaining this temperature for approximately 30 minutes, the second simulated DBA was initiated and the temperature reached 175°C (347°F) in 25 seconds. The second simulated peak DBA temperature was maintained at 175°C (347°F) for 4 hours, 2 minutes and 41 seconds, after which it was reduced to 161° (321.8°F) where it was maintained for 50 minutes. From this temperature, the final cooldown to 95°C (203°F) was initiated. After maintaining a temperature of 95°C for less than an hour, the third simulated DBA was initiated and the peak temperature of 149°C (300.2°F) was reached in 10 minutes. The third simulated DBA peak temperature was maintained at 149°C (300.2°F) for 3 hours and 20 minutes, after which a cooldown to 121°C (250°F) was initiated. This temperature was maintained for 3 days, 4 hours and 49 minutes, followed by another cooldown to 104°C (219.2°F), where the temperature was maintained for 1 day, 5 hours and 34 minutes, prior to final cooldown.

In Staff Exhibits 50 and 51, the plots of IR vs. temperature, which are non-linear, indicated as CR-151 Complete Plot, EB-25 Complete Plot, and States ZWM Complete Plot, were apparently created by using IR data recorded during the Phase I and Phase II Sandia environmental test profiles <u>over the complete time duration of all consecutive simulated DBAs</u>. In other words, these Staff plots of Phase I and Phase II data were made without regard for when in time (First DBA, Second DBA, or Third DBA) the temperature related IR data was recorded. These plots simply represent the lowest value of IR at a corresponding test temperature regardless of when in the test temperature vs. time profile they were measured.

Since several consecutive DBAs were applied to the terminal blocks, they experienced the same temperatures more than once, as is evident from a review of Figure 1 and Figure 2 and the description of these profiles above. I believe that in order to understand properly the real meaning and significance of the data, the temperature related IR data for the terminal blocks should be reviewed in sequential test time (i.e., starting at time zero and reviewing the IR vs. temperature as it changes during each of the heatup, peak, and cooldown periods of the simulated temperature versus time profiles.) This review of the Sandia data results in a totally different perspective on the meaning of this data than that now presented by Dr. Jacobus. I want to also emphasize that I presented this perspective clearly to Dr. Jacobus in November 1987. He refused to acknowledge it at that time.

Q99. After reviewing the Sandia data as you have explained, what have you determined?

A. (Love) A review of the Sandia data from this perspective yields an insulation resistance vs. temperature characteristic that is linear on a semi-log plot for the GE and States terminal blocks for the temperatures critical to the Farley-specific functions.

In my oral testimony (Tr. 1211-1222), Page 210 (Figure A1-21) of SAND83-1617 was used to illustrate this perspective and the basis for our JCO presentation in Atlanta in which we concluded that the safety function of the instrumentation terminal blocks could and would be accomplished. Since Dr. Jacobus in his Rebuttal Testimony continues to "suggest" that the Sandia data contained in this report does not indicate a linear relationship, I will further expand on what this data indicates by referring to additional Sandia data as represented in SAND83-1617.

Q100. What is the additional Sandia data you are relying on as the basis for your conclusion?

A. (Love) The following are the pages from the Sandia report which I would like to introduce:

- PAGE 129, APPENDIX 1, Five-Number Summaries of Leakage Current and Insulation Resistance Data
- PAGE 142, FIGURE A1-1, Box and Whisker Plot of Insulation Resistance for TB 1, Phase I

- PAGE 136, TABLE A1-2a, Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks

- PAGE 137, TABLE A1-2b, Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks

- PAGE 146, FIGURE A1-5, Box and Whisker Plot of Insulation Resistance for TB-5, Phase I

- PAGE 138, TABLE A1-2c, Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks

- PAGE 139, TABLE A1-2d, Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks

- PAGE 147, FIGURE A1-6, Box and Whisker Plot of Insulation Resistance for TB-6, Phase I

- PAGE 210, FIGURE A1-21, Box and Whisker Plot of Insulation Resistance for TB-9, Phase II previously entered as (APCo Exhibit 111) and (Board Exhibit 1).

- PAGE 174, TABLE A1-5e, Five-Number Summaries of Insulation Resistance G, Phase II Terminal Blocks.

- PAGE 175, TABLE A1-5f, Five-Number Summaries of Insulation Resistance G, Phase II Terminal Blocks.

APPENDIX 1
Five-Number Summaries of Leakage Current and Insulation Resistance Data

Sections 4.3.3 and 4.4.2 discuss the presentation of the data in a five-number summary format. This appendix compiles the data in this format in both tabular and graphic form. The tabular arrangement for the data is:

median	
lower quartile	upper quartile
lower extreme	upper extreme

The graphic format is:

upper extreme

upper quartile

median

lower quartile

lower extreme

The graphical presentation is commonly referred to as a box and whisker plot for obvious reasons.

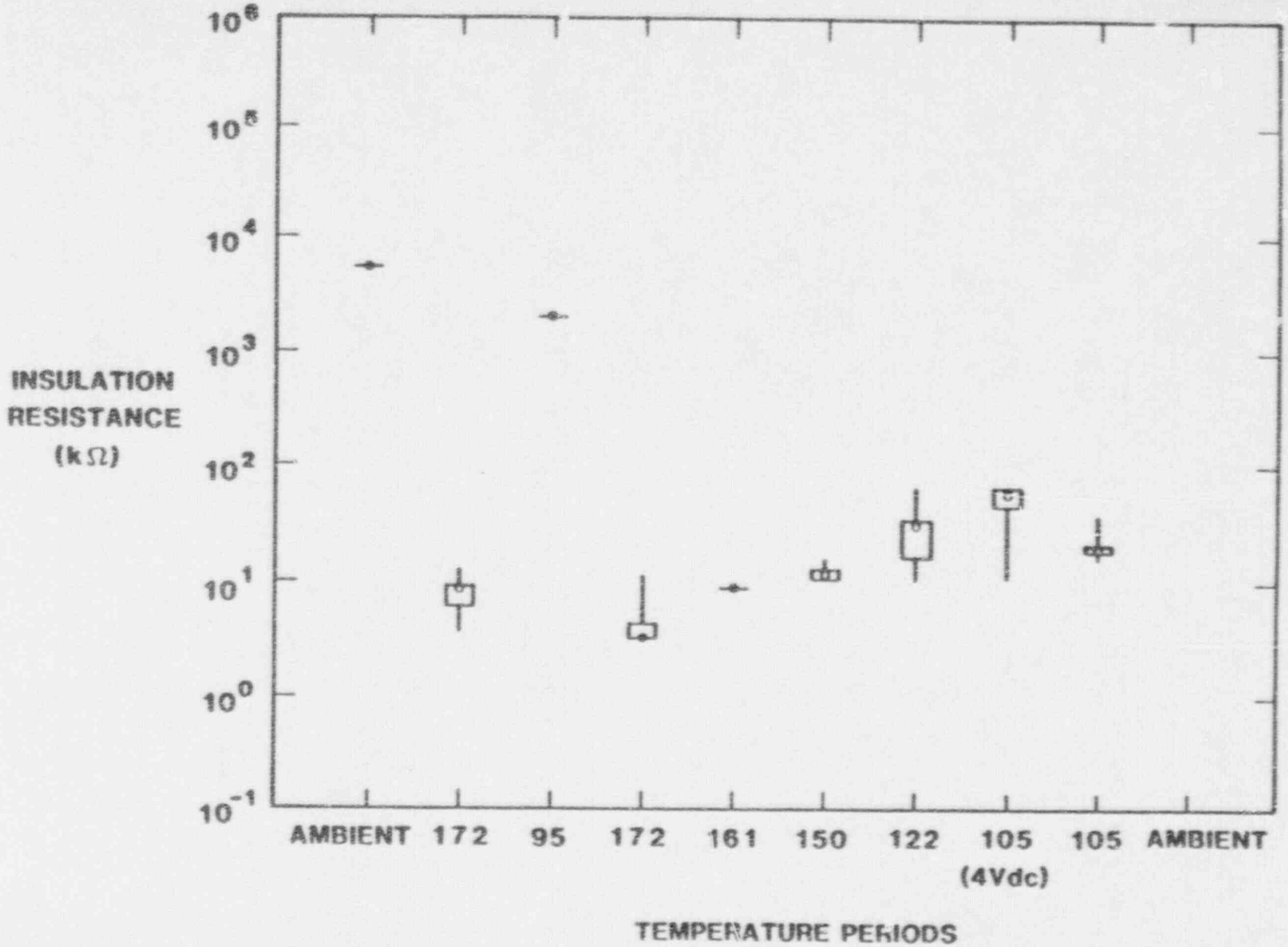


Figure A1-1

Box and Whisker Plot of Insulation Resistance for TB 1, Phase I

TABLE A1-2a

Five-Number Summaries of Insulation R[illegible], Phase I Terminal Blocks
(K[illegible]

TB	Ambient		Peak 1 172°C		[illegible]		Peak 2 172°C		161°C	
TB 1	5.40E+03		8.52E+00		[illegible]		3.32E+00		8.46E+00	
	5.39E+03	5.40E+03	6.07E+00	8.96E+00	1.98E+0[illegible]	[illegible]	3.20E+00	4.24E+00	8.41E+00	8.81E+00
	5.39E+03	5.40E+03	3.61E+00	1.22E+01	1.96E+03	[illegible]	2.97E+00	1.11E+01	8.01E+00	9.17E+00
TB 2	5.27E+03		6.14E+00		4.09E-02		3.41E-01		2.12E+00	
	5.27E+03	5.27E+03	5.65E+00	6.23E+00	4.09E+02	4.09E+02	3.05E-01	4.40E-01	1.45E+00	2.46E+00
	5.27E+03	5.27E+03	3.39E+00	2.11E+01	3.99E+02	4.09E+02	2.66E-01	2.54E+00	7.33E-01	3.04E+00
TB 3	4.92E+03		5.76E+00		2.30E+03		4.36E-01		2.48E-01	
	4.92E+03	4.92E+03	5.49E+00	6.01E+00	2.30E+03	2.30E+03	3.61E-01	5.26E-01	2.28E-01	2.84E-01
	4.92E+03	4.92E+03	3.55E+00	2.10E+01	2.28E+03	2.30E+03	2.95E-01	2.30E+00	2.02E-01	3.20E-01

TABLE A1-2b

Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks
(Kohms)

	150°C	122°C	105°C	105°C (4 Vdc)
TB 1	1.12E+01 1.02E+01 1.21E+01 9.74E+00 1.50E+01	2.91E+01 1.55E+01 3.27E+01 9.57E+00 6.34E+01	Sub 1: 5.80E+01 5.05E+01 6.47E+01 1.04E+01 6.50E+01 Sub 2: 4.50E+01 3.05E+01 5.23E+01 1.57E+01 5.94E+01 Overall: 5.41E+01 4.32E+01 6.22E+01 1.04E+01 6.50E+01	1.85E+01 1.81E+01 1.93E+01 1.49E+01 3.66E+01
TB 2	7.02E+00 6.12E+00 6.76E+00 2.03E+00 9.82E+00	1.51E+01 1.09E+01 2.08E+01 3.14E+00 7.10E+01	Sub 1: 1.58E+01 1.19E+01 1.87E+01 1.69E+00 1.88E+01 Sub 2: 1.43E+01 1.09E+01 1.56E+01 8.24E+00 1.63E+01 Overall: 1.47E+01 1.13E+01 1.74E+01 1.69E+00 1.88E+01	1.05E+01 1.01E+01 1.09E+01 7.55E+00 1.78E+01
TB 3	4.24E-01 3.64E-01 8.22E-01 2.40E-01 1.45E+00	9.87E+00 7.67E+00 1.26E+01 5.72E+00 2.65E+01	Sub 1: 1.32E+01 1.00E+01 1.49E+01 1.45E+00 1.50E+01 Sub 2: 1.07E+01 7.28E+00 1.31E+01 3.69E+00 1.45E+01 Overall: 1.28E+01 9.21E+00 1.46E+01 1.45E+00 1.50E+01	4.99E+00 4.80E+00 5.35E+00 3.17E+00 1.30E+01

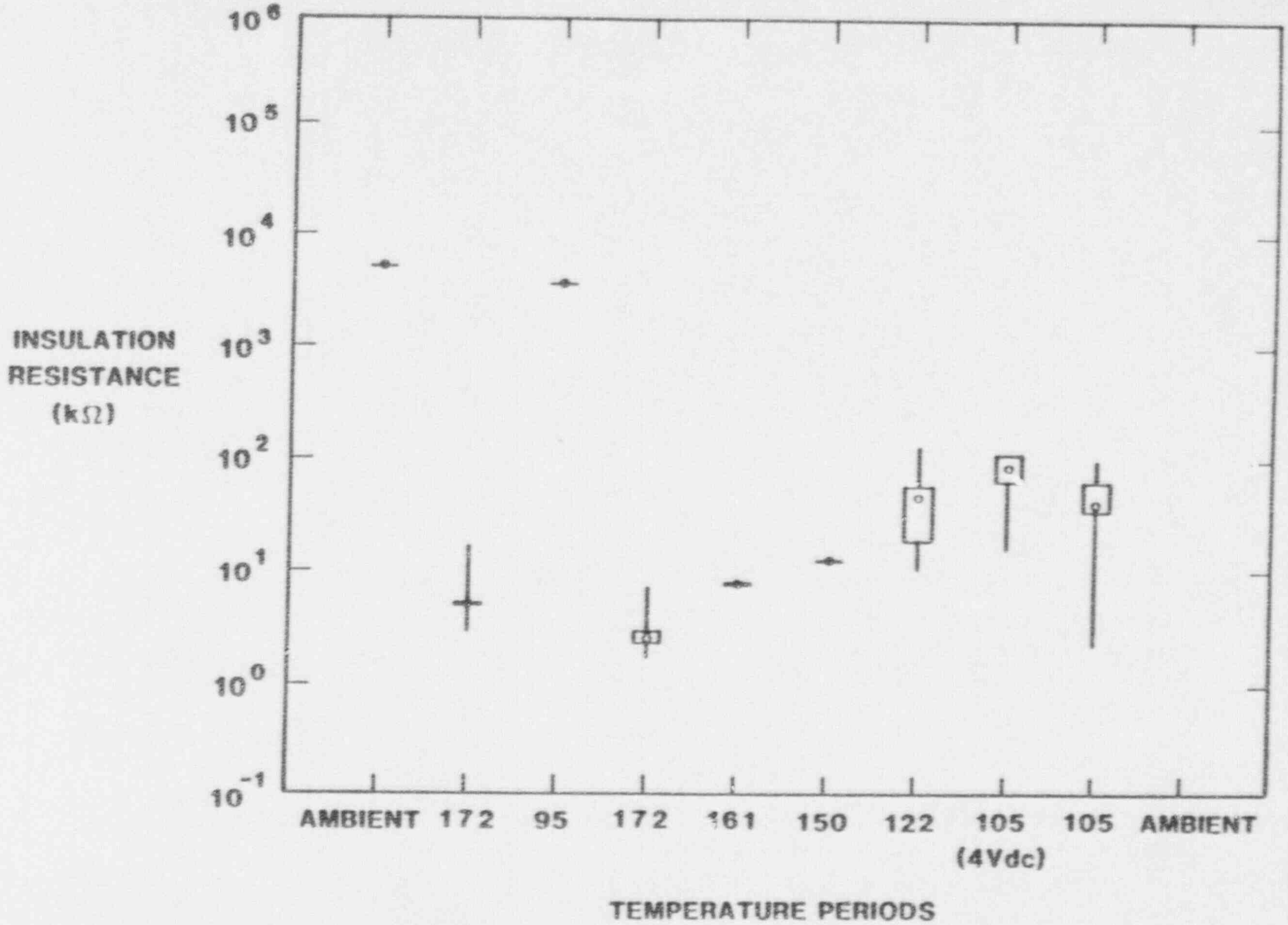


Figure A1-5

Box and Whisker Plot of Insulation Resistance for TB 5, Phase I

TABLE A1-2c

Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks
(Kohms)

	Ambient	Peak 1 172°C	95°C	Peak 2 172°C	161°C
TB 4	5.01E+03	5.05E+00	3.21E+03	2.41E+00	7.11E+00
	5.01E+03 5.01E+03	4.71E+00 5.09E+00	3.21E+03 3.21E+03	2.27E+00 2.80E+00	7.00E+00 7.37E+00
	5.01E+03 5.01E+03	2.68E+00 1.24E+01	3.20E+03 3.21E+03	1.63E+00 7.65E+00	6.54E+00 7.67E+00
TB 5	5.16E+03	5.28E+00	3.63E+03	2.55E+00	7.91E+00
	5.16E+03 5.16E+03	5.04E+00 5.33E+00	3.63E+03 3.63E+03	2.39E+00 2.98E+00	7.75E+00 8.17E+00
	5.16E+03 5.16E+03	3.12E+00 1.74E+01	3.61E+03 3.63E+03	1.67E+00 7.32E+00	7.46E+00 8.56E+00
TB 6	5.78E+03	1.14E+01	4.69E+03	8.20E+00	1.54E+01
	5.78E+03 5.78E+03	1.01E+01 1.16E+01	4.69E+03 4.69E+03	7.69E+00 8.62E+00	1.53E+01 1.57E+01
	5.78E+03 5.78E+03	9.06E+00 1.57E+01	4.58E+03 4.69E+03	6.63E+00 1.93E+01	1.52E+01 1.61E+01

TABLE A1-2d

Five-Number Summaries of Insulation Resistance, Phase I Terminal Blocks
(Kohms)

	150°C	122°C	105°C	105°C (4 Vdc)
TB 4	1.07E+01 1.05E+01 1.09E+01 9.94E+00 1.11E+01	3.10E+01 1.22E+01 4.39E+01 6.76E+00 9.30E+01	Sub 1: 6.69E+01 5.98E+01 7.28E+01 1.41E+01 7.29E+01 Sub 2: 1.14E+02 1.03E+02 1.17E+02 4.70E+01 1.23E+02 Overall: 7.00E+01 6.05E+01 1.17E+02 1.41E+01 1.23E+02	4.38E+01 4.34E+01 4.46E+01 3.46E+01 6.04E+01
TB 5	1.29E+01 1.27E+01 1.31E+01 1.25E+01 1.36E+01	4.67E+01 1.94E+01 5.90E+01 1.12E+01 1.30E+02	Sub 1: 1.03E+02 8.52E+01 1.17E+02 1.40E+01 1.17E+02 Sub 2: 6.32E+01 4.84E+01 6.83E+01 2.69E+01 7.88E+01 Overall: 8.85E+01 6.62E+01 1.13E+02 1.40E+01 1.17E+02	4.17E+01 3.64E+01 6.43E+01 2.21E+00 1.03E+02
TB 6	2.34E+01 2.19E+01 2.55E+01 2.11E+01 3.16E+01	1.25E+02 3.46E+01 3.51E+02 3.32E+01 4.82E+03	Sub 1: 2.89E+02 2.44E+02 3.33E+02 1.98E+01 3.36E+02 Sub 2: 2.78E+02 1.14E+02 3.03E+02 5.55E+01 3.79E+02 Overall: 2.79E+02 2.15E+02 3.25E+02 1.93E+01 3.79E+02	6.41E+01 6.06E+01 6.89E+01 2.52E+01 9.70E+01

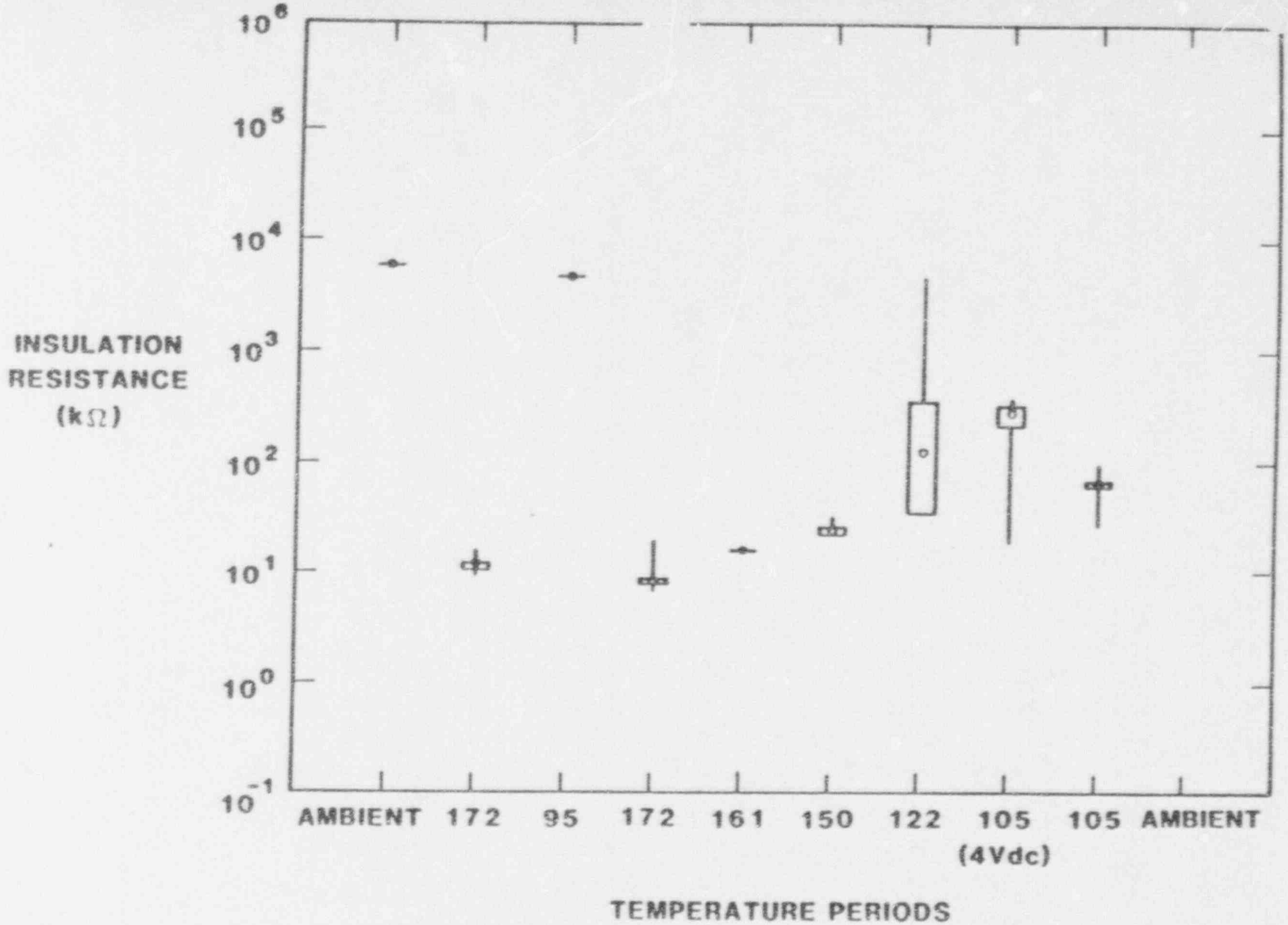


Figure A1-6

Box and Whisker Plot of Insulation Resistance for TB 6, Phase I

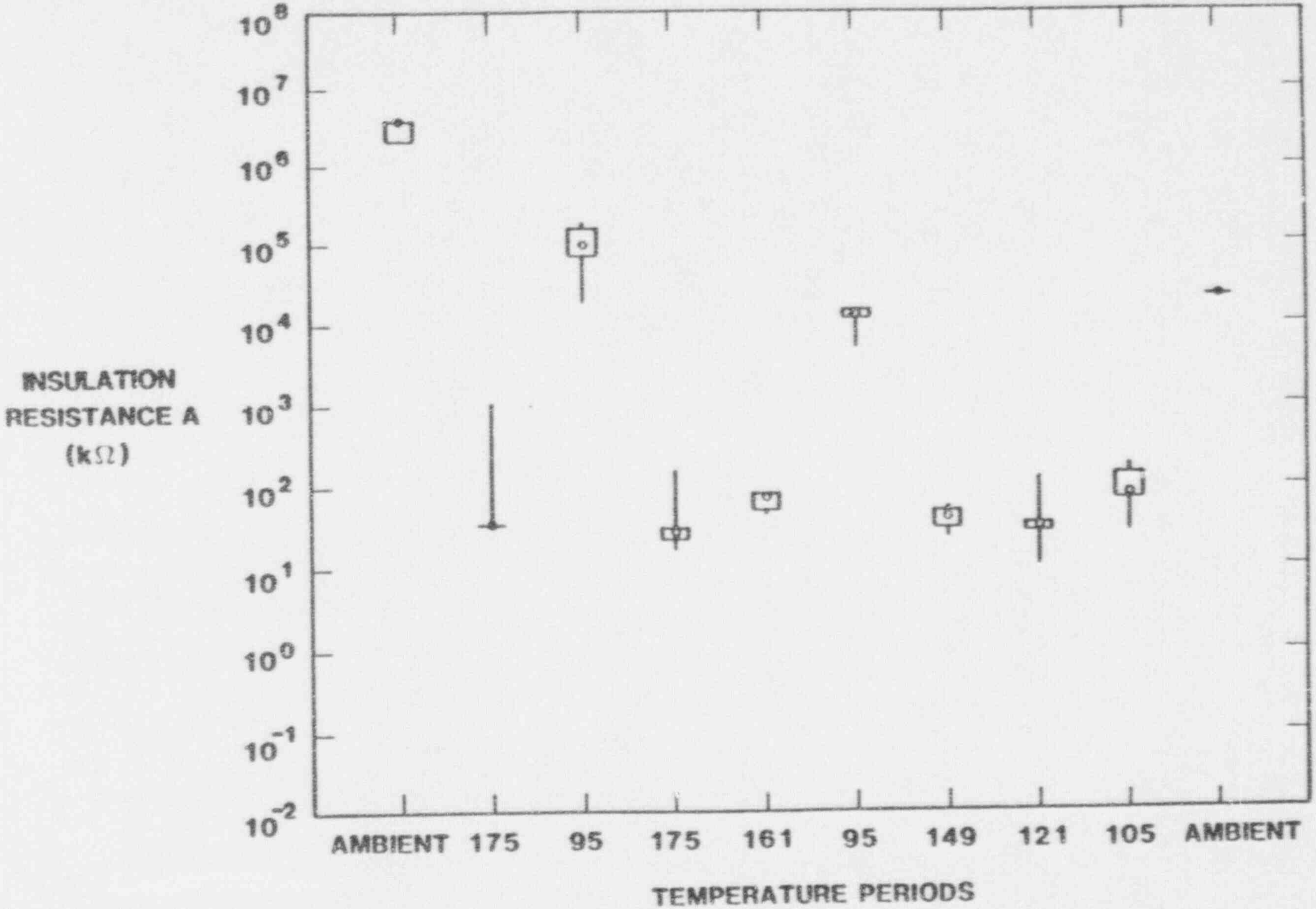


Figure A1-21

Box and Whisker Plot of Insulation Resistance A for TB 9, Phase II

TABLE A1-5e

Five-Number Summaries of Insulation Resistance G, Phase II Terminal Blocks
(Kohms)

TB	Ambient	Peak 1 175°C	95°C	Peak 2 175°C	161°C
7	7.66E+06 7.66E+06 1.15E+07 3.28E+06 1.15E+07	4.04E+01 3.48E+01 4.09E+01 1.28E+01 9.94E+02	8.98E+03 6.81E+03 1.50E+04 7.99E+02 1.84E+04	Sub 1: 1.08E+01 1.01E+01 1.27E+01 9.54E+00 2.01E+01 Sub 2: 1.30E+01 1.07E+01 1.34E+01 7.90E+00 1.58E+01 Overall: 1.33E+01 1.26E+01 1.38E+01 7.90E+00 2.01E+01	2.33E+01 2.15E+01 2.37E+01 1.82E+01 2.80E+01
8	2.30E+07 1.15E+07 2.30E+07 5.75E+06 2.30E+07	9.93E+01 1.17E+01 1.14E+02 2.34E+00 6.25E+02	5.76E+06 4.60E+06 5.76E+06 2.97E+03 1.15E+07	Sub 1: 8.52E+00 7.68E+00 8.93E+00 5.84E+00 1.99E+01 Sub 2: 2.02E+01 1.17E+01 2.70E+01 6.44E+00 3.42E+01 Overall: 1.23E+01 1.04E+01 1.28E+01 5.84E+00 3.42E+01	4.37E+01 4.33E+01 4.61E+01 4.26E+01 4.90E:01
9	2.30E+07 2.30E+07 2.30E+07 2.30E+07 2.30E+07	5.92E+01 5.66E+01 6.08E+01 5.58E+01 1.96E+03	2.23E+05 1.83E+05 3.83E+05 3.72E+04 4.89E+05	Sub 1: 2.40E+01 2.27E+01 2.58E+01 2.21E+01 2.26E+02 Sub 2: 4.00E+01 3.81E+01 4.15E+01 3.38E+01 4.46E+01 Overall: 3.67E+01 3.30E+01 3.81E+01 2.21E+01 2.26E+02	1.11E+02 9.28E+01 1.19E+02 9.28E+01 1.26E+02

TAB -5f

Five-Number Summaries of Insulation Resistance G, Phase II Terminal Blocks (Kohms)

	95°C	149°C	121°C	105°C	Ambient
TB 7	4.73E+02 4.56E+02 6.52E+02 4.42E+02 6.52E+02	1.57E+01 1.54E+01 3.61E+01 1.41E+01 1.77E+01	Sub 1: 1.56E+01 1.48E+01 1.76E+01 8.00E+00 4.72E+01 Sub 2: 3.73E+01 2.39E+01 4.14E+01 1.08E+01 5.23E+01 Overall: 1.53E+01 1.38E+01 2.10E+01 8.00E+00 5.23E+01	Sub 1: 1.58E+02 1.38E+02 1.80E+02 8.97E+01 1.97E+02 Sub 2: 6.52E+01 6.13E+01 6.77E+01 2.74E+01 7.20E+01 Sub 3: 4.73E+01 3.73E+01 4.73E+01 3.73E+01 4.73E+01 Overall: 6.40E+01 5.89E+01 6.77E+01 2.74E+01 1.97E+02	1.99E+02 1.95E+02 2.00E+02 1.93E+02 2.01E+02
TB 8	3.17E+04 1.99E+04 9.67E+04 1.69E+04 9.67E+04	3.52E+01 2.93E+01 4.59E+01 2.68E+01 4.88E+01	Sub 1: 2.21E+01 1.91E+01 2.48E+01 3.77E+00 3.09E+01 Sub 2: 2.34E+02 1.73E+02 3.05E+02 2.13E+01 3.50E+02 Overall: 2.18E+01 1.46E+01 7.61E+01 3.77E+00 3.50E+02	Sub 1: 2.34E+02 2.14E+02 2.73E+02 7.57E+01 2.73E+02 Sub 2: 7.65E+02 6.35E+02 8.16E+02 5.23E+02 8.31E+02 Sub 3: 1.18E+03 9.88E+02 1.40E+03 4.58E+02 1.49E+03 Sub 4: 8.33E+02 5.58E+02 8.33E+02 5.58E+02 8.33E+02 Overall: 8.60E+02 7.36E+02 1.09E+03 7.57E+01 1.49E+03	5.06E+05 4.46E+05 7.12E+05 3.35E+05 2.85E+06
TB 9	2.24E+04 2.21E+04 3.60E+04 1.54E+04 3.60E+04	5.95E+01 4.48E+01 6.38E+01 4.03E+01 9.97E+01	Sub 1: 1.97E+02 1.86E+02 2.18E+02 1.11E+02 3.17E+02 Sub 2: 1.63E+02 1.18E+02 1.58E+02 6.77E+01 2.27E+02 Overall: 1.37E+02 1.15E+02 1.71E+02 6.77E+01 3.17E+02	Sub 1: 1.45E+02 1.26E+02 1.65E+02 1.03E+02 1.82E+02 Sub 2: 3.98E+02 3.91E+02 4.99E+02 2.03E+02 5.20E+02 Sub 3: 8.78E+01 6.41E+01 8.78E+01 6.41E+01 8.78E+01 Overall: 1.72E+02 1.42E+02 3.81E+02 6.41E+01 5.20E+02	1.14E+05 1.12E+05 1.13E+05 1.09E+05 1.16E+05

(It should be noted that the data contained in the five-number summary tables is the same data which is being graphically depicted on the Box and Whisker plots as discussed in SAND83-1617, Sect. 4.3.3, page 40.)

A review of the data presented in these figures for the Phase I First DBA and Second DBA, and of the data for the Phase II First DBA and Second DBA, supports our conclusions reached on the linearity of the terminal block IR vs. temperature characteristic presented in the 1987 JCO. (APCo Exhibit 59). As testified to previously, the JCO used an IR vs. temperature characteristic plotted from Figure A1-21 based on the First DBA.

As the temperature axis on the SAND83-1617 Box and Whisker plots is following the environmental temperature profiles of each consecutive test DBA, and indicating the test temperature where the data was recorded, it is not to scale. I have re-plotted the IR vs. temperature data contained on these figures for the States and GE terminal blocks using the median, upper quartile, and lower quartile IR data for temperature as documented in the five-number summary tables for each applicable terminal block. Unlike the Sandia report, I also used a linear temperature scale on the temperature axis of each figure. (Plotting the SAND83-1617 data in this format was only performed to assist in the realization that the States and GE terminal block IR vs. temperature is not non-linear as Dr. Jacobus has in the past contended and is still suggesting.)

Figure IR-1, which I have included in this testimony for the States ZWM terminal block, was based on the Phase I First DBA and Second DBA data contained on Page 138, TABLE A1-2c, and Page 139, TABLE A1-2d, of SAND83-1617 -- for terminal block 6(TB6). Figure IR-1, Plot (A), is for IR vs. temperature of the First DBA cooldown from 172°C to 95°C, and uses the available IR data as documented at 172°C and 95°C. Plot (B) is for IR vs. temperature of the Second DBA cooldown and uses the available data as documented at 172°C, 161°C, 150°C, 122°C, and 105°C. Both Plot (A) and Plot (B) were made by drawing a line through the median data points.

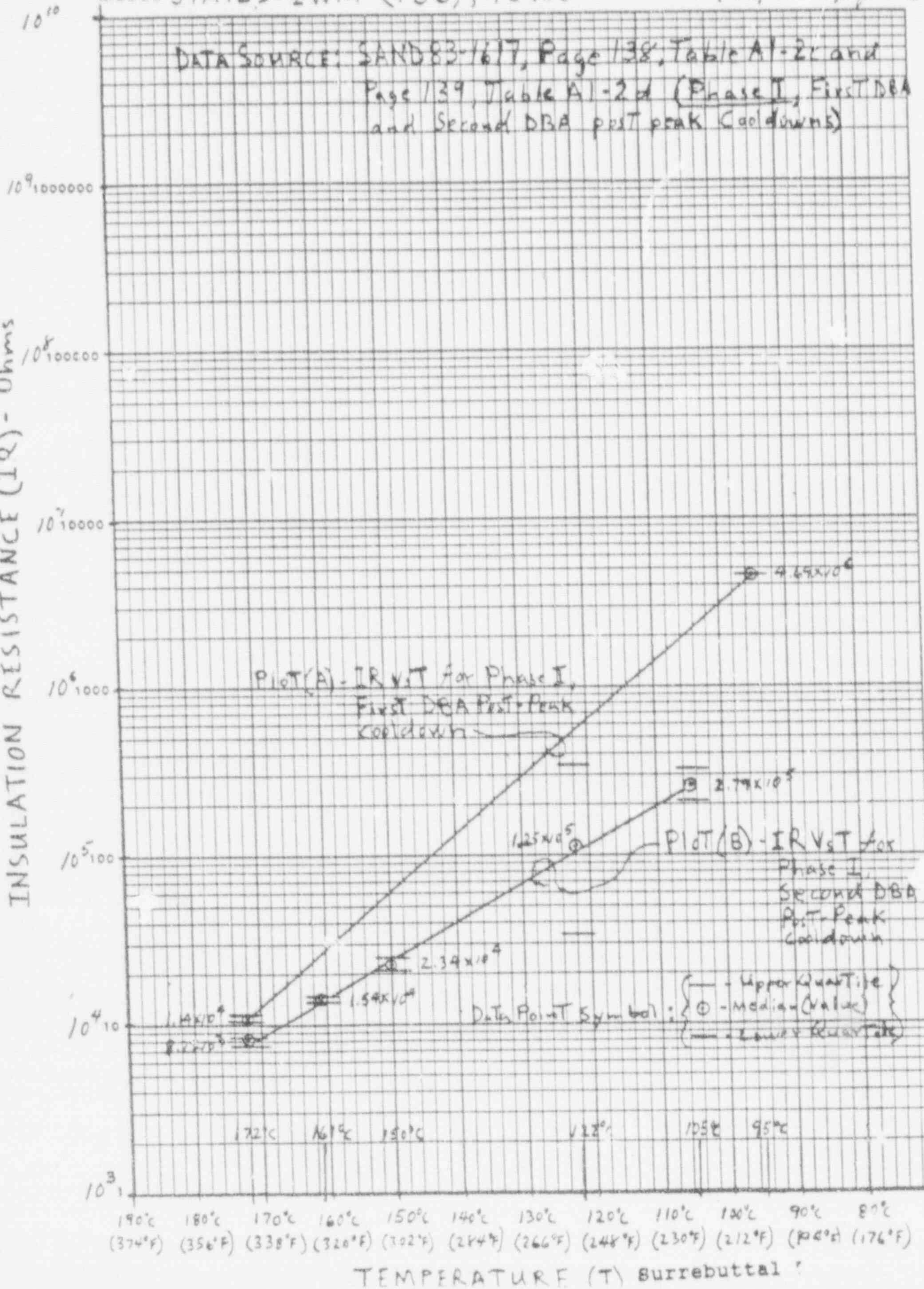
Figure IR-2, which I have included in this testimony for the GE CR-151B terminal blocks, was based on the Phase I First DBA and Second DBA data also contained on Page 138, TABLE A1-2c, and Page 139, TABLE A1-2d, of SAND83-1617 -- but for terminal block 5 (TB5). Plot (A) depicts the IR vs. temperature of the First DBA cooldown from 172°C to 95°C, and uses the available IR data as documented at 172°C and 95°C. Plot (B) depicts the IR vs. temperature of the Second DBA cooldown and uses the available data as documented at 172°C, 161°C, 150°C, 122°C and

105°C. Plot (A) and (B) were made by drawing a line through the median data points.

Figure IR-3, which I have included in this testimony is for the GE EB-25 terminal block, and contains four plots of IR vs. temperature. Plot (A) and Plot (B) are based on the Phase II (2) First DBA and Second DBA data contained on Page 174, TABLE A1-5e, and Page 175, TABLE A1-5f, of SAND83-1617 -- for terminal block 9(TB9). Plot (A) shows the IR vs. temperature of the Phase II First DBA cooldown from 175°C to 95°C using the documented IR data at 175°C and 95°C. Plot (B) shows the IR vs. temperature of the Phase II Second DBA cooldown and uses the available data as documented at 175°C, 161°C and 95°C. Plot (C) and Plot (D) are based on the Phase I First DBA and Second DBA data contained on Page 136, TABLE A1-2a, and Page 137, TABLE A1-2b, of SAND83-1617 for terminal block 1(TB1). Plot (C) shows the IR vs. temperature of the Phase I First DBA cooldown from 172°C to 95°C, and uses the available IR data as documented for these temperatures. Plot (D) shows the IR vs. temperature of the Phase I Second DBA cooldown and uses the available data as documented at 172°C, 161°C, 150°C, 122°C, and 105°C. Plots (A), (B), (C), and (D) were all made by drawing a line through the median data points.

FIGURE IR-1 - INSULATION RESISTANCE Versus TEMPERATURE

MODEL STATES-ZWM (TB6), 45VDC DATE 3/30/92 by: [illegible]



Surrebuttal

FIGURE IR-2 - INSULATION RESISTANCE Versus TEMPERATURE

MODEL G.E. - CR-151B (TB5), 45VDC DATE 3/30/92 by: [illegible]

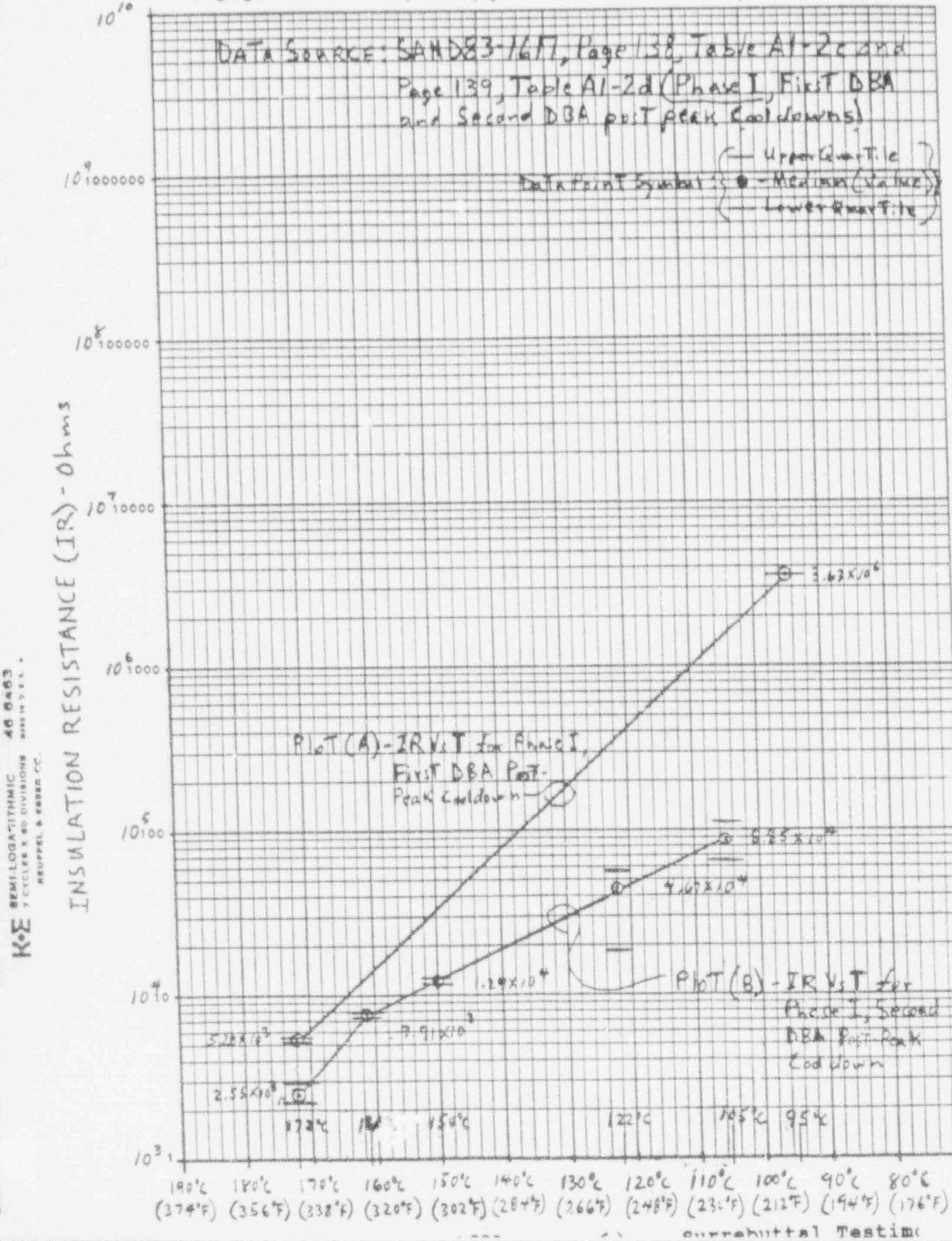
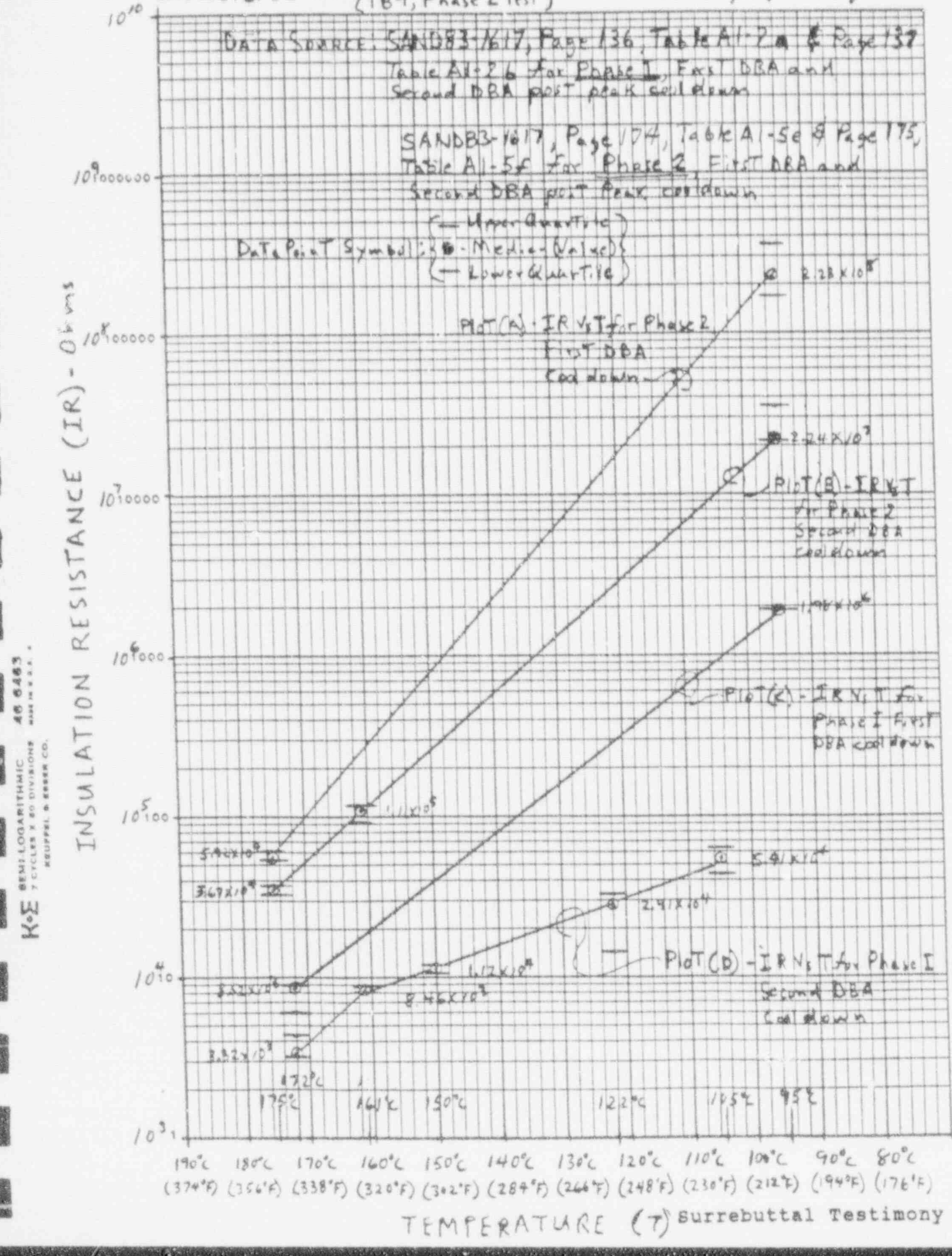


FIGURE · IR · 3 - INSULATION RESISTANCE Versus TEMPERATURE

MODEL G. E. EB-25 {TB1, Phase 1 Test / TB9, Phase 2 Test}, 45 VDC DATE 3/30/92 by: Jerry Calvert



Q101. Can you illustrate your conclusions based on this data?

A. (Love) Yes. A review of the IR vs. temperature plots contained in Figures IR-1, IR-2, and IR-3 clearly shows that the data documented in SAND83-1617 demonstrates a terminal block IR vs. temperature characteristic which is linear when plotted on a semi-log scale for the cooldown period of each simulated DBA. More significantly, it demonstrates this characteristic for each terminal block using multiple media data points available from the Sandia Phase I and Phase II Second DBAs. (The only area of non-linearity is for Phase I, Second DBA, GE terminal block tests, Plot (B) of Figures IR-2 and Plot (D) of Figure IR-3 -- between 172°C and 161°C.)

Q102. From this, what conclusions can we draw regarding Staff Exhibits 50 and 51 in which Dr. Jacobus has plotted IR vs. temperature?

A. (Love) The non-linear plots by Dr. Jacobus, because of the way they are based on the Sandia data, are not representative of the terminal block performance which was demonstrated in the Sandia testing. The Alabama Power Company plot for the GE EB25 block (based on the Sandia data) utilized in the November 24, 1987 JCO (APCo Exhibit 59) is actually a more representative curve.

Q103. The IR vs. temperature plot of the SAND83-1617 data is linear, as shown in Figures IR-1, IR-2, and IR-3, for the temperatures of concern. Is there any other information in SAND83-1617 which also indicates that IR is linear with respect to temperature?

A. (Love) Yes. In the temperature ranges of significance to the Farley instrumentation terminal blocks, Figure 26 on page 48 of SAND83-1617 (Staff Exhibit 73) shows a linear change in IR vs. temperature during the cooldown periods between temperature plateaus. Also, as discussed above, Figure 8-3 on page 85 of NUREG/CR-3691 (Staff Exhibit 74) indicates a linear response of the terminal block IR for the transmitter circuit during cooldown. These are yet further indications of how the Sandia data could not possibly support a position that our 1987 analysis was in error.

Q104. In NRC Staff Exhibits 50 and 51, Dr. Jacobus has also shown graphically a plot taken from a GE Test Report. He shows that IR of the terminal blocks at temperatures from 260°F - 340°F would be a constant value of 2E4 ohms. He reiterates this conclusion in his Rebuttal Testimony at page 35, drawing data from a November 6, 1973 GE Test Report. Would you care to comment on this?

A. (Love) Yes, I would. The November 6, 1973 GE Test Report was included in a 1987 similarity analysis demonstrating similarity between St .es ZWM and NT terminal blocks (not an issue here, as discussed in my Direct Testimony, Q/A 85, at page 97). The IR data in this report was not used as a qualification basis for terminal blocks in instrument circuits. It also was not the qualification report relied upon for overall qualification of GE CR-151B terminal blocks at Farley Nuclear Plant. (That qualification report was APCo Exhibit 58).

In this GE test referred to by Dr. Jacobus, the terminal blocks were subjected to elevated temperatures, 260°F - 340°F, for approximately ten days. The profile consisted of five temperature plateaus non-representative of the Farley DBA profile, and involved subjecting the terminal blocks to significantly elevated temperatures for long periods of time. This profile could have resulted (and apparently did result) in degradation of the test terminal blocks, reducing their IR vs. temperature capabilities. In any event, the results of this testing are not in agreement with the results indicated for the GE CR-151B terminal blocks as documented in SAND83-1617.

Q105. Putting the 1973 GE report aside, and returning to your earlier conclusions, what is the significance of the linear IR vs. temperature characteristic of the States and GE terminal blocks?

A. (Love) Characterization of the terminal blocks IR dependency on temperature during simulated DBAs permits the use of this characteristic in evaluating the ability of the terminal blocks to meet the required instrument circuit functions during plant specific postulated design basis events.

Q106. You mentioned above that the second step of your logic would be to re-look at the Farley-specific DBAs in order to show when the instrument loops were required to operate. Let's move on to this point. For starters, please explain the Farley-specific postulated design basis events which create the worst case environmental conditions, including temperature, inside the containment building?

A. (Love) As described in the FSAR, these worst case postulated design basis events (accidents) are large break LOCA and large break MSLB.

Q107. Does the containment temperature remain constant during a postulated large break LOCA or large break MSLB?

A. (Love) Definitely not. The temperature vs. time response of the containment to a large break LOCA has been shown in my

Direct Testimony (Figure 3). In the JCO presented in the November 1987 meeting with the Staff in Atlanta, the temperature vs. time response of the containment was depicted using a composite of the worst case LOCA/MSLB containment temperature curve. (APCo Exhibit 59, Attachment 2, Bates 0064097). For the sake of clarity and continuit- in this testimony, I have included another copy for the LOCA Containment Temperature Profile marked as Figure 3, and have also included a copy of the MSLB Containment Temperature Profile, Figure 4, which shows the temperature vs. time response of the containment to the postulated large break MSLB. I will refer to the significance of the markings I have made on these curves below.

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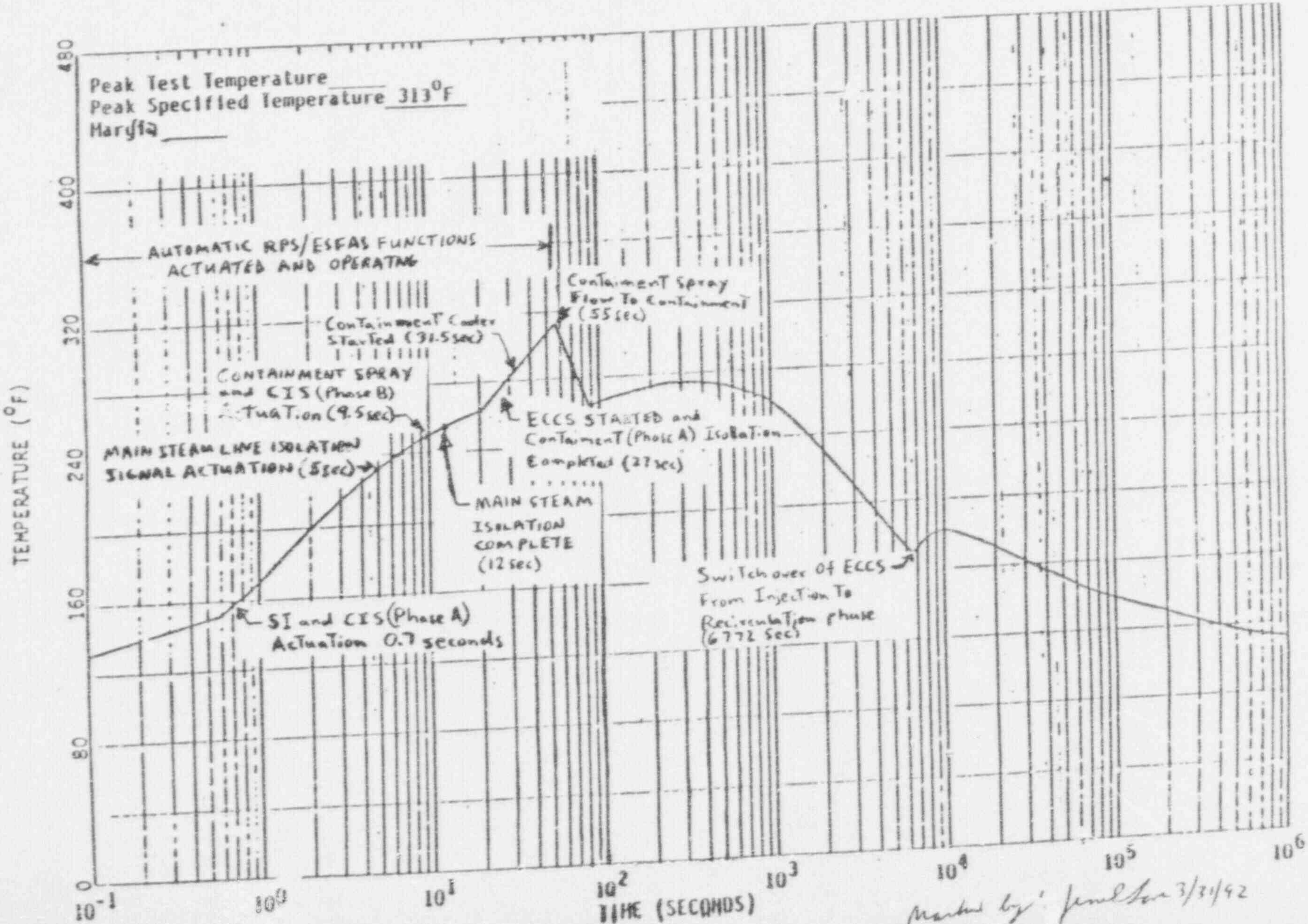
FIGURE 3

The specified curve is based on FSAR Curve, Figure 6.2-40

LOCA INSIDE
CONTAINMENT TEMPERATURE ENVELOPE



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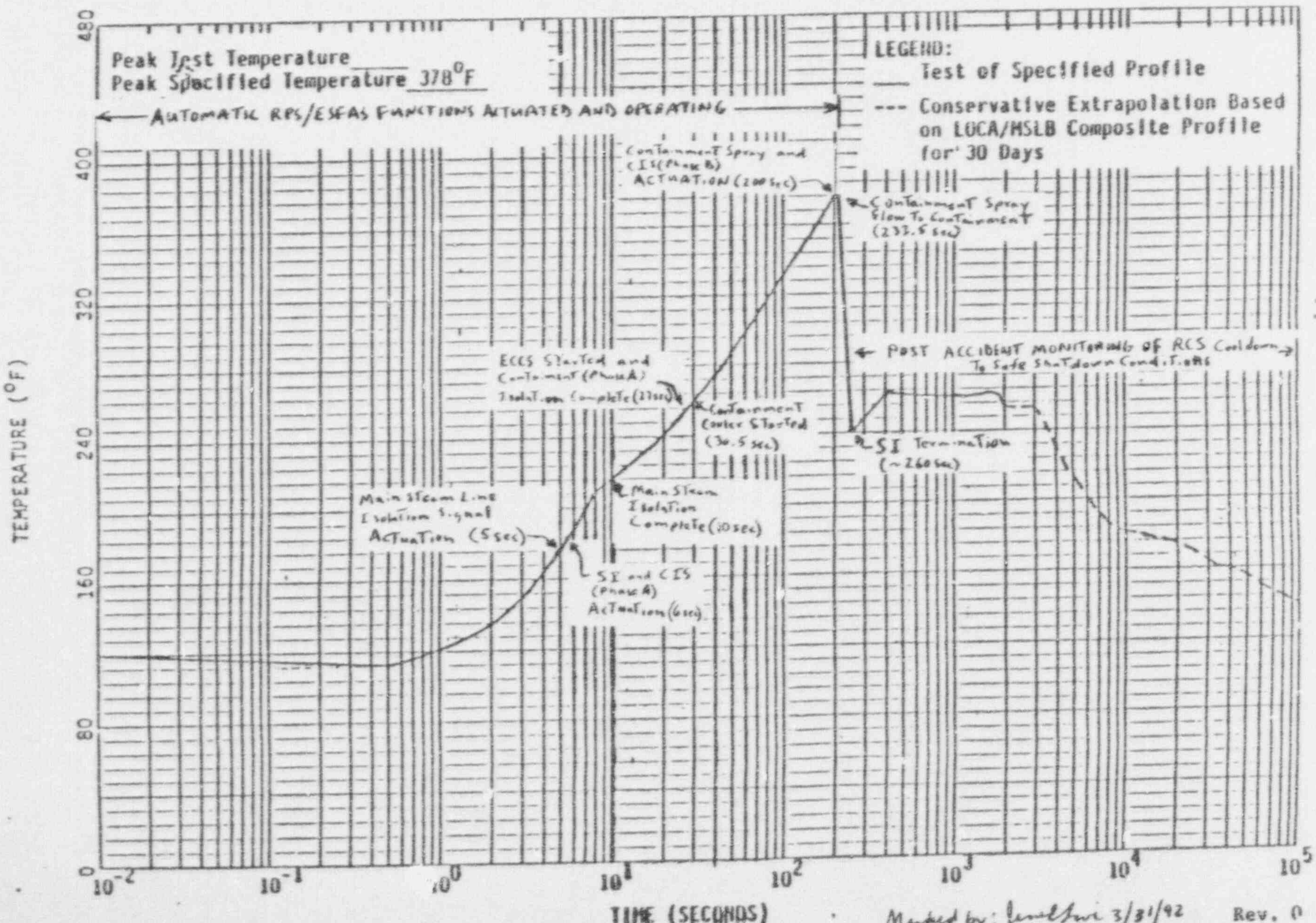
Surrebuttal Testimony Pg. 176

FIGURE 4

This curve is based on FSAR Curve, Figure 6.2-11

MSLB INSIDE CONTAINMENT
TEMPERATURE ENVELOPE



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Q108. What is the significance of the design basis large break LOCA and MSLB containment temperature vs. time response profiles with regard to the instrument loop accuracy effects of terminal blocks on overall instrument loop performance or function?

A. (Love) The documentation in the FSAR provides the bases for these profiles, including a description of the assumed automatic and manual actions required to mitigate the events and when in the events these actions are assumed to occur. The containment temperature response based on these assumptions is depicted by the large break LOCA and MSLB containment temperature profiles. The FSAR also provides a description of the instrumentation which provides the signals to initiate the assumed automatic actions and upon which the assumed manual operator actions are based.

Therefore, required instrumentation functions and the time during the event when the instrumentation functions are required have been established in the bases for the accident analyses. These considerations are not something we concocted after-the-fact -- they are reflected in the accident analyses. As stated above, the event temperature profile also reflects the containment temperature response in light of the mitigation actions being accomplished based on required instrumentation functions.

Having established the length of time or period of time during each event that the instrumentation function is required, and the corresponding temperatures for that time period from the event profile, the significance of the instrument loop accuracy effect of the terminal blocks on the required instrumentation function can be evaluated based on the IR vs. temperature characteristic of the terminal blocks over the required functional temperature range.

Q109. Can you be more specific with regard to the instrumentation loops required for mitigation of each of the applicable design basis events, and the length of time as well as the corresponding temperature range in each event when they are required to function?

A. (Love) Yes. I have already provided testimony (Direct Testimony, Q/A 110 at pages 120-21) for the large break LOCA, but I will expand upon my previous testimony regarding this event.

I have marked the copy of the LOCA Containment Temperature Profile included in this testimony as Figure 3, to show the portion of the profile where the automatic RPS/ESFAS instrumentation accident mitigation functions are accomplished. APCo Exhibit 52, at Bates 0063876-0063879, provides a list of the specific RPS/ESFAS instrument loops which contained States and GE terminal blocks. It should be noted that the containment wide range pressure instrumentation loops which initiate containment isolation (Phase B) and containment sprays for this event do not have any instrumentation cabling or terminal blocks inside the containment building.

As can be seen from the markings I have made on the profile, the automatic RPS/ESFAS actions take place in less than 55 seconds and before reaching the peak LOCA temperature of 313°F. No manual operator action is required until switchover of the ECCS and Containment Sprays from the RWST injection to the containment sump recirculation. I have also marked this point on the profile, which occurs at 6772 seconds when the containment temperature has dropped to approximately 170°F. The primary operator instrumentation relied upon for this manual action is RWST level which is located outside the containment. The wide range containment sump level instrumentation loops with terminal blocks located inside the containment provide diverse indication to the RWST level instrument loops.

Next, I will discuss the large break MSLB. For this postulated pipe break on the secondary side of the steam generators, the required RPS/ESFAS instrument loops located inside the containment have accomplished their automatic accident mitigation functions by 60 seconds from large break initiation. As can be seen from the markings I have made on the copy of the MSLB Containment Temperature Profile, Figure 4, this action is initiated before reaching 310°F and also before reaching the peak MSLB temperature of 378°F. For this postulated event, as with the large break LOCA, the containment wide range pressure loops initiate containment sprays and have no terminal blocks located inside the containment building. No manual operator action is required for this event until termination of safety injection which is executed at 250 seconds after break occurrence when the corresponding containment temperature has cooled down to 240°F. The in-containment instrumentation loops used for this manual action are RCS wide range pressure and pressurizer level.

After safety injection termination, a controlled RCS cooldown to safe shutdown will be initiated. It is during this portion of the event that post-accident monitoring instrumentation (primarily RCS sub-cooling, wide range RCS pressure, and narrow range steam generator water level) will be utilized. This portion of the event profile, Figure 4, starts at approximately 400 seconds after event initiation when the containment temperature is 260°F. During the rest of the cooldown, the containment temperature continues to decrease.

It should be noted that in the November 1987 JCO (APCo Exhibit 59), safety injection termination following a large secondary break MSLB was conservatively marked on the Composite LOCA/MSLB Containment Temperature Envelope, Attachment 2, Bates 0064097, at 296°F. However, as I have testified above, using the actual event specific MSLB profile, Figure 4, the safety injection termination is not required until containment temperature returns to 240°F.

Q110. Let's turn now to the third step of your logic outlined above. Referring now to the terminal block IR vs. temperature characteristic demonstrated by the SAND83-1617 data (Figure IR-3), what is the indicated terminal block IR which would exist when the manual operator actions are required for each design basis event?

A. (Love) For the large break LOCA discussed above, the required manual operator action is initiated when the containment temperature has cooled down to approximately 170°F. The corresponding IR value for this temperature taken from Plot (A) of Figure IR-3 would be greater than 2.23E8 ohms.

For the large break MSLB the required manual operator action is initiated when the containment temperature has cooled to 240'F. Again using Figure IR-3, the corresponding IR value for this temperature taken from Plot (A) would be 1.8E7 ohms.

During the post-accident monitoring phase of the MSLB accident recovery, the highest containment temperature is 260'F. Based on Figure IR-3, the corresponding IR value for this temperature is approximately 8.0E6 ohms.

Q11[illegible]. What is the significance of these terminal block IR values?

A. (Love) Contrary to the conclusions reached and presented by Dr. Jacobus during and following the 1987 EQ inspection, these values of IR, which were determined from the available SAND83-1617 documented test data, support the value of 1E7 ohms used in our 1987 Westinghouse setpoint calculations.

I want to be clear on another point. I do not believe this analysis of the SAND83-1617 data was necessary for qualification of our terminal blocks. I have gone through this data here simply to illustrate how Dr. Jacobus is in error in his testimony. The fact is, our 1987 approach, based on data from the CONAX report, yielded very similar IR data and was an equally valid approach to addressing terminal block instrument accuracy effects.

Q112. In the 1987 Alabama Power Company JCO (APCo Exhibit 59), what is the significance of the value of 5E5 ohms for the terminal block IR established by Westinghouse?

A. (Love) As discussed in the JCO, Attachment 2 (Bates 0064091), any IR value greater than 5E5 ohms would result in instrument inaccuracy that would allow the current ERP values to be used by the operator to take ERP actions. Thus, Westinghouse was saying that the ERPs, as they existed in 1987, would remain valid for instrument terminal block IRs greater than 5E5 ohms, and was establishing an absolute minimum value of IR for which the ERP setpoint values would remain unchanged.

Q113. How does this IR acceptance criteria relate to a temperature to be used for instrument accuracy qualification?

A. (Love) Using Figure IR-3, Plot (A), to find the corresponding temperature for an IR value of 5E5 ohms, the corresponding temperature would be 154°C (309.2°F). It can also be observed that for all temperatures lower than 309.2°F, the corresponding value of IR for the terminal blocks will be greater than 5E5 ohms.

It should be noted that in the JCO (APCo Exhibit 59) Figure 1 (Bates 0064083) and Attachment 2, Figure 1 (Bates 0064096), the endpoints of the IR vs. temperature curve were also based on the same terminal block test data presented as Plot (A) of Figure IR-3. For the JCO presentation, the IR value corresponding to the endpoint temperatures of 95°C was depicted as 1E8 ohms. On Figure 1 (Bates 0064083), the IR value for the endpoint temperature of 175°C was depicted as 3E4 ohms. On Attachment 2, Figure 1 (Bates 0064096), the IR value for the endpoint temperature of 175°C was depicted as 5E4 ohms. These endpoints were visually determined from SAND83-1617, Figure A1-21, page 210, and were conservatively less than the actual median data points for the same terminal block (TB9) as documented in SAND83-1617, Table A1-5e, page 174 and Table A1-5f, page 175, which are the basis for Figure IR-3, Plot (A). Therefore, in the JCO, the IR vs. temperature curves for the terminal block resulted in the determination of a limiting temperature of 296°F for the corresponding value of 5E5 ohms.

Q114. With the Westinghouse establishment of a minimum IR value of 5E5 ohms which would support the 1987 vintage ERP values, what should have been the 1987 basis for assessing the ability of the instrument terminal blocks to perform the required safety functions during the postulated design basis harsh environments?

A. (Love) The important criterion for qualification should have been demonstration of a value of IR greater than 5E5 ohms <u>at</u>

the containment temperature conditions when the instrument terminal blocks would be required to perform their safety functions. (Again, this assumes that the terminal block would be capable of surviving and recovering from the design basis event temperature conditions which would exist when no safety-related functions were required.) The NRC Staff has acknowledged in their Rebuttal Testimony (Q/A 17, at page 24) that the established performance specification for the qualification of instrument terminal blocks was 5E5 ohms.

Q115. In this light, were the GE and States terminal blocks at issue qualified during and following the November 1987 NRC Inspection?

A. (Love) Yes, because all containment temperatures at times when the instruments were required to operate were less than 309.2°F.

Q116. As you mentioned above, the NRC Staff has finally acknowledged that the 1987 performance specification for the instrument terminal blocks is 5E5 ohms. Nonetheless, what is the significance to the rest of the Staff's arguments that the GE and States terminal blocks were not qualified even at peak-LOCA/HELB temperatures?

A. (Love) As we have discussed, qualification at peak-LOCA/HELB is not required for instrument accuracy. Nonetheless, it is interesting to point out as an additional matter that the SAND83-1617 data indicates that the terminal block temperature corresponding to 5E5 ohms is 309.2°F. The peak LOCA temperature on Farley is above 309.2°F for only seconds, and the peak surface temperature of the terminal blocks during an MSLB (considering thermal lag) is less than 300°F. Therefore, the 5×10^5 performance specification would be met for these events.

Q117. In the Staff's Rebuttal Testimony, at pages 42-44, Q/A 35, the Staff is stating that there is no basis to conclude that the RPS/ESFAS instrument loop terminal blocks will perform their automatic actuation function prior to reaching temperatures which could affect their required function. Do you concur with these statements?

A. (Love) Absolutely not. As shown on the actual postulated Farley design basis containment accident temperature profiles, Figures 3 and 4, the automatic actuation signals using terminal blocks will occur well within 60 seconds of the event pipe break. For the MSLB, Figure 4, the only signal which is used for automatic actuation occurring after 60 seconds is based upon the containment wide range pressure instrument loops. However, these instrument circuits have no terminal blocks located inside the containment.

Dr. Jacobus states that thermal lag is not a valid concept for determining the qualified performance of terminal blocks based again on the SAND83-1617 moisture film effect. The only technical evidence which Dr. Jacobus offers to support his assertion is a reference to Figure 25, at page 45, of SAND83-1617. I am not sure that this curve, due to its time scale in 0.5 hour increments, shows anything relative to the first 60 seconds of the transient. However, on page 42 of SAND83-1617, first full paragraph, the concept of thermal lag as it relates to the test chamber terminal block is described and acknowledged. It appears that the correct figure showing the thermal lag in SAND83-1617 is Figure 28 on page 50 of the report, as described on page 42 -- not Figure 25 as referenced by Dr. Jacobus.

Q118. In the same Q/A of his Rebuttal Testimony, at page 43, Dr. Jacobus also challenges the idea of taking credit for thermal lag during pre-peak LOCA conditions based on his illustration of the instantaneous formation of a moisture film. What is your response?

A. (Love) Dr. Jacobus is implying, by his simplistic example of breathing moist air on a cold window, that a moisture film forming on a terminal block will result in a significant reduction in the block IR regardless of the temperature of the block. This is ridiculous and totally unsupportable by the results of SAND83-1617.

SAND83-1617 clearly indicates that the IR is temperature-dependent. Breathing on a cold terminal block may result in a moisture film on the block, but will not result in significant IR reduction. There is no data in SAND83-1617 which would indicate that a moisture film -- without the presence of significant temperature -- is a valid concern.

Q119. Again in the same Q/A, this time on page 44, Dr. Jacobus picks up on the figure of 5 minutes from Attachment 2 to the JCO (APCo Exhibit 59), a letter from Westinghouse. Has he drawn a proper conclusion?

A. (Love) No. The Staff refers to Attachment 2 to the JCO (APCo Exhibit 59) indicating that, 5 minutes into the event, the LOCA conditions have already passed the peak temperature. The reference to 5 minutes in the Westinghouse portion of the JCO is to the length of time required after event occurrence for small break LOCAs and small break MSLBs. As these small break events do not result in the worst-case design basis containment accident profile, including temperature, they are not the basis for qualification. Small break LOCAs and MSLBs result in less severe accident transients and will not yield the containment peak temperatures or profiles indicated by Figures 3 and 4.

E. Miscellaneous

Q120. To wrap up this aspect of the topic, I want to turn to a few additional miscellaneous aspects of the Staff's Rebuttal Testimony. First, in Q/A 28, at pages 36-27, Mr. Jacobus infers that we should have used the Phase I SAND83-1617 test data for the GE CR 151B and States ZWM terminal blocks in the JCO. Do you concur?

A. (Love) No. The basis for not using the Phase I data was explained in Attachment 1 of the JCO (APCo Exhibit 59, Bates 0064086-0064089), and was also verbally presented by me in great detail at the November 25, 1987 meeting in Atlanta. It was, and still is, our position that the SAND83-1617 Phase II First DBA test data for the GE EB-25 terminal blocks was correctly applied and justifies our 1987 approach to instrument terminal block functional qualification.

The Phase I testing yielded lower (or more conservative) IR results than the Phase II testing. However, this data was overly conservative and not realistic for the Farley-specific applications. Rather than repeating all of the reasons again, I will refer to Figures IR-1, IR-2, and IR-3 to provide additional clarification of my basis for using the Phase II DBA data.

On Figure IR-3, I have plotted both the Phase I and Phase II(2) IR vs. temperature curves for a GE EB-25 terminal block in this figure. Plots (C) and (D) depict the IR vs. temperature characteristic which results from the Phase I First DBA and Second DBA tests. Plots (A) and (B) show the results of the Phase II(2) First DBA and Second DBA tests. From these plots of the IR vs. temperature data for the same type terminal block (GE EB-25), it is obvious that the Phase I test produced much more conservative IR data than the Phase II(2) test. "More conservative" meaning lower values of IR vs. temperature.

The Phase II First DBA profile was used for the Alabama Power Company JCO (APCo Exhibit 59) since it was very conservative in relation to the Farley large break LOCA and MSLB profiles (Figure 3 and Figure 4). A review of the Phase I First DBA test plots for each type of terminal block -- on Figures IR-1, IR-2 and IR-3 -- shows that for temperatures less than 150°C, the States ZWM and CR-151B terminal blocks both exhibit a better IR vs. temperature characteristic than the GE EB-25 block ("better" meaning that IR recovers to a higher value as the temperature decreases). In fact, the States ZWM block exhibits a better IR vs. temperature characteristic than the GE EB-25 blocks over the complete test temperature cooldown from 175°C to 95°C. Therefore, it appeared reasonable in my engineering judgment to conclude that, if a States ZWM or GE CR-151B terminal block had been included in the Phase II testing, they would have also provided superior IR vs. temperature performance to that of the GE EB-25 terminal block which was tested during Phase II. It was this engineering judgment that resulted in the 1987 decision to use the GE EB-25 Phase II(2) First DBA IR vs. temperature characteristic profile for the Alabama Power Company JCO. (APCo Exhibit 59).

In the Staff's Rebuttal Testimony, Q29 and Q45, the Staff is questioning the meaning of my statement regarding the SAND83-1617 Phase II, Third DBA test data. The meaning of my statement is quite clear. By the time the GE EB-25 terminal block (TB9) had been exposed to the Third DBA, it, as well as the associated test conductors, were degraded to the point that they could no longer recover IR with decreasing temperatures. I did not plot the Third DBA IR vs. temperature plot, but a review of the test data on pages 174 and 175 of the SAND83-1617 report will verify this statement. A comparison of the Phase I First DBA and Second DBA, and the Phase II First DBA and Second DBA plots on Figures IR-1 through IR-3, will depict the degradation effects of successive DBA simulations on the tested blocks and test conductors. A complete review of the SAND83-1617 report (Staff Exhibit 73) will substantiate the conclusion I have expressed regarding the meaning and significance of the test data. (See Staff Exhibit 73, at pages 33, 52, 94, 112, and 237).

Based upon all of the above, the SAND83-1617 data for the GE EB-25 terminal block recorded during the Phase II First DBA supports the qualification of States ZWM and GE CR-151B terminal blocks for the Farley-specific design basis accident profiles.

Q121. The NRC Staff, in their Rebuttal Testimony (Q/A 26-27, at pages 32-24), has also expressed for the first time a list of new factors which they claim needed to be considered in the 1987 basis for instrument terminal block qualification. Are these factors relevant to the 1987 functional qualification of the instrument terminal blocks?

A: (Love) No, they are not. One example is the warnings on ERPs that Dr. Jacobus refers to in Q/A 27 on page 34. These factors -- including the warnings -- are only relevant if the terminal block would not have been able to meet the 1987 Westinghouse functional performance specification of 5E5 ohms. It has been, and continues to be, our contention that the instrument terminal blocks were capable of meeting (and in fact exceeding) this functional performance specification. Therefore, no changes to the 1987 ERP values were necessary. As is clear in the excerpt from the JCO (APCo Exhibit 59) cited by Dr. Jacobus on page 34, 5E5 ohms was the acceptance criterion. Our terminal block IRs were greater. The warnings and other considerations listed by Dr. Jacobus were not necessary or relevant.

Q122. Dr. Jacobus, in his Rebuttal Testimony (Q/A 43, at page 51, and Q/A 44, at page 52) provides his opinion of what you testified to regarding the single value of 2E4 ohms contained in the March 27, 1985 GE Test Report. (APCo Exhibit 58). Do you concur with his opinion?

A. (Love) The Staff is attempting to draw an inference that an IR value of 2E4 ohms means the GE terminal block is unqualified. In my oral testimony (Tr. 1123-1126), I concluded by saying that the single value of 2E4 ohms recorded in the GE Test Report (APCo Exhibit 58) was sufficient. "Sufficient" in this context meant that it was not an abnormal value of IR for the peak test temperature experienced. The IR value meant that the block was not damaged by the peak-te[illegible] temperature and, thus, could be expected to recover IR performance as the temperature decreases. This position is also supported by the SAND83-1617 test data for the GE terminal blocks. Therefore, depending upon plant-specific applications of the terminal block in instrumentation circuits, the terminal block could be qualified for post-peak conditions.

Q123. Dr. Jacobus, in his Rebuttal Testimony (Q/A 5, at page 6), is taking credit for clearly and conclusively demonstrating in the November 1987 meeting that IR was not related to temperature as indicated in the JCO. Do you agree?

A (Love, Jones) No. This simply does not reflect what occurred. In his Rebuttal Testimony, Dr. Jacobus also implies that this was the reason that Alabama Power Company planned to replace the instrument terminal blocks. (Please refer to Sections I, II and III of the JCO (APCo Exhibit 59)). As is clear therein, Alabama Power Company chose to replace the terminal blocks to remove the point of contention, because the Staff could not understand, or would not accept, our approach.

F. <u>Similarity Evaluation Arguments</u>

Q124. Another topic of the Rebuttal Testimony is the analysis of similarity between the Connectron NSS-3 block tested by CONAX and the States and GE terminal blocks at issue. (*See* Rebuttal Testimony, Q/A 20-25, at page 27-32.) Are you familiar with this similarity evaluation?

A. (Love) Yes. We developed a documented similarity evaluation of the terminal blocks to support our 1987 approach to the instrument accuracy issue. It was included in EQ Action Items 018 and 067. (APCo Exhibit 52). We discussed it in our Direct Testimony, pages 114-15.

Q125. One of the differences between the Connectron block and the GE/States blocks that you addressed in Direct Testimony was material differences between the blocks. Why did you address this?

A. (Love) Dr. Jacobus offers curious testimony on this point. He disavows knowledge of alleged material differences. However, we only addressed this point because the Staff raised it in their own Order imposing the civil penalty. (Staff Exhibit 3, Appendix A, at page 25). I gather from this that Dr. Jacobus never read or supported the Order.

In any event, material differences should not be important to Dr. Jacobus. The block material, according to Dr. Jacobus, is irrelevant to leakage currents due to the predominant effect of ionic conduction in the exterior moisture film (a theory and hypothesis he supports for terminal blocks). (Rebuttal Testimony, Q/A 22, page 29).

Q126. The major problem Dr. Jacobus seems to be standing by now regarding the similarity evaluation is the issue of spatial separation between the poles of the terminal blocks. Can you address his Rebuttal Testimony on this point?

A. (Love) Yes. Dr. Jacobus asserts that we "did not consider . . that the step design [of the Connectron NSS-3] effectively increases the distance between adjacent terminals." We certainly did consider this factor and concluded that it was not significant <u>for the blocks at issue</u>. (<u>See</u> Direct Testimony at page 115). The basis for my conclusion was that the spatial separation -- including both the horizontal and vertical separation -- is simply not very different for these terminal blocks.

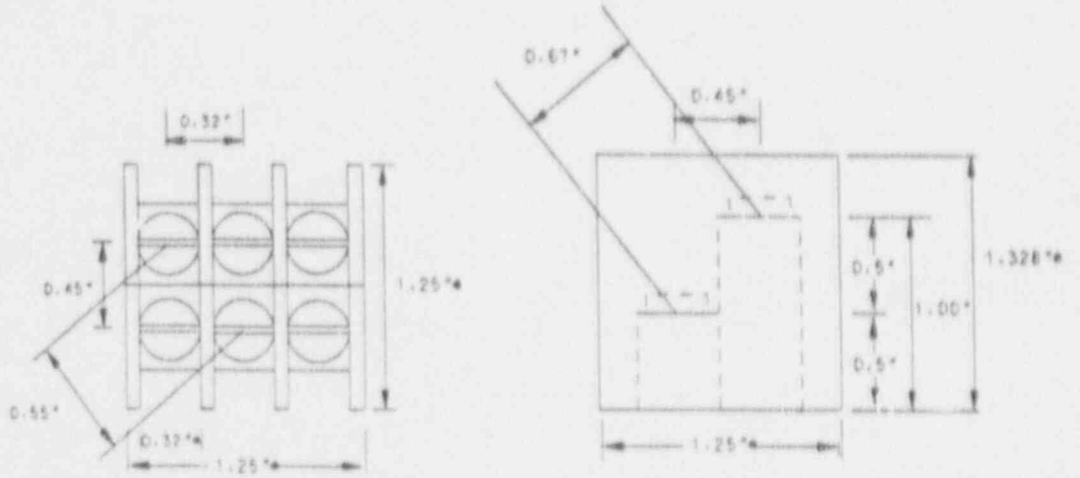
Dr. Jacobus uses an extreme example of a terminal block with a one foot vertical step between poles. While this is effective to illustrate a theoretical point, it has no bearing on our terminal blocks. The dimensions of the blocks at issue are significantly smaller than Dr. Jacobus's example, and all are effectively similar notwithstanding the step design of the Connectron NSS-3.

In the similarity analysis which I prepared to compare the Connectron NSS-3 terminal blocks to the other plant-specific terminal blocks, including States ZWM/NT and GE CR-151B blocks

(APCo Exhibit 52), I prepared a table, on page 3 of 4, showing the center-to-center pole spacing of each block and other relevanc physical factors. In this table for the Connectron block, I indicated the center-to-center spacing as 0.320 inches, which is the correct dimension from a plan view. Also included in the similarity analysis was Attachment 3, which provided electrical, dimensional, and physical information for the Connectron block. All of this information supported my conclusion that the three types of blocks at issue were similar.

To address Dr. Jacobus's testimony here, I will use dimensional information from the similarity analysis and explain why the step arrangement is of no significance. Figure 5 is a diagram which depicts the Connectron NSS-3 block in plan and end views. The spacings are shown, considering both horizontal and vertical dimensions. The vertical spacing of the steps is not one foot, but approximately 0.50 inches.

CONNECTRON INC. NSS3 TERMINAL BLOCK ASSEMBLY



PLAN VIEW

END VIEW

NOTES

1. * INDICATES DIMENSIONS AS GIVEN IN CONNECTRON, INC. CATALOGUE.
2. OTHER DIMENSIONS WERE DETERMINED BASED ON ENGINEERING JUDGEMENT AND THE FOLLOWING ASSUMPTIONS:
   - THE LOWER TERMINAL POLE STEP HEIGHT WAS DETERMINED TO BE APPROX. ½ THE HEIGHT OF THE UPPER TERMINAL POLE HEIGHT PER THE VENDOR PICTORIAL INFORMATION AND ATTACHED DRAWING.
   - THE POLE TO POLE DIMENSION OF 0.45" WAS BASED ON GIVEN DIMENSIONS AND THE DIMENSIONS OF A 6-32 ROUND HEAD SCREW (HEAD DIAMETER OF 0.25")

R.J. Puhl 3/6/92

DRAWN BY: S. L. HARSHBERGER CHECKED BY: R. J. PUHL

As shown on the figure, the separations between terminals, considering the step design, range from 0.50 to 0.67 inches. These spacings are comparable to the center-to-center spacings of States NT/ZWM and GE CR-151B terminal blocks (0.6250 inches for the States, and 0.5625 inches for the GE). Therefore, the terminal blocks are dimensionally similar.

As an engineering matter, this dimensional similarity is not a surprising matter. All of these terminal blocks are rated at 600 volts. The voltage of a terminal block will dictate the required physical spacings. The step design of the Connectron block was intended to create a smaller overall terminal block with the same voltage rating (and similar terminal-to-terminal spacings).

Q127. In the Staff's Rebuttal Testimony, on pages 30-32 (Q23 and Q24), additional new issues regarding similarity of GE, Connectron and States terminal blocks are raised. Are any of these new similarity issues relevant?

A. (Love) Dr. Jacobus, in his answer to Q23, is pointing out that the GE and Connectron blocks are molded as a single piece of insulating material, barriers and all. He is noting that in contrast, the States terminal block is a sectional block.

Next, he indicates that differences such as these were not addressed in the similarity analysis.

The Alabama Power Company similarity analysis to which he is referring (APCo Exhibit 52) did not repeat this analysis, which was already performed in SAND83-1617. The States terminal blocks (sectional blocks) were indicated on page 52 of SAND83-1617 to have exhibited among the highest measured terminal-to-terminal insulation resistances of any terminal blocks tested. This is also evident by reviewing my Figure IR-1 in comparison to Figure IR-2. Because this sectional block was shown by Sandia to be the best from a performance perspective, it is completely unnecessary to demonstrate similarity to molded blocks with lower IR vs. temperature characteristics.

In the answer to Staff Rebuttal Question 24, Dr. Jacobus again expounds on the danger of drawing similarity conclusions regarding terminal blocks which are to be operated near their performance limits and states that subtle differences between blocks can make a difference. Dr. Jacobus is being very vague about what should and needs to be evaluated for a similarity analysis. Nonetheless, I believe that performance is the final proof of similarity. The IR vs. temperature data contained in SAND83-1617 confirms similarity of performance for the GE and States terminal blocks. The data shows that their performance is very similar, with the States block being superior to the GE block. A review of the IR vs. temperature plots for the Phase I, First DBA and Second DBA as shown on Figures IR-1, IR-2, and IR-3 show this performance similarity. Also, for the specific design basis event temperatures where performance is important, similarity between the Conax terminal block IR (1E7 ohms) and the GE terminal block, IR was demonstrated in preceeding testimony.

G. Mr. DiBenedetto's Testimony

Q128. Mr. DiBenedetto, have you read the Rebuttal Testimony of Dr. Jacobus and Mr. Luehman with respect to the Staff's concerns on terminal blocks? What, if any, comments do you have?

A. (DiBenedetto) Yes, I have read the referenced testimony. I have many comments and opinions relating to the new testimony. However, rather than address the testimony point by point, I think it is more relevant and beneficial to describe the circumstances relating to the use of terminal blocks in the Farley Nuclear Plant instrument circuits and how qualification for the intended function is attained and concluded.

First, statements made by Dr. Jacobus allude to an assertion that Alabama Power Company never identified at what temperatures the blocks would operate. The Company's position that the blocks would perform their intended function prior to exposure to the design basis event simply indicates that their function is completed during their normal operating temperature environmental range (typically 80 - 140°F). The Reactor Protection System is designed to monitor critical parameters of reactor operation (i.e., pressurizer level, reactor water level, containment pressure, steam generator water level, etc.) all of which sense changes and are pre-set (safety limit setpoints, trip setpoints, pump actuation, valve closure, etc.) to perform a function when one or more of the setpoints are sensed. The circuitry and logic is redundant and complex and not an issue here. Upon sensing a rapidly changing parameter (e.g., loss of level, increase in containment pressure, increase in radiation, etc.), the logic system initiates a protective feature. The protective features range from containment isolation to activation of containment spray in the case of a LOCA. All of these actions occur within the first few seconds of the event, well before the peak environments are reached.

Once these actions have been accomplished, the terminal blocks are not required nor are the instruments. However, since the instruments and terminal blocks will experience exposure to the "harsh" or elevated environments, assurance must be provided that they will not fail in a manner detrimental to the safety of the plant. Terminal blocks have been tested more thar any other piece of electrical equipment. One fact that is evident and obvious from all the testimony proffered is that the terminal blocks did not exhibit any permanent damage. Additionally, the terminal blocks exhibited a recovery of electrical capability as environmental conditions subsided.

Q129. What is the import of these observations?

A. (DiBenedetto) These observations basically support the conclusion that during the short term (i.e., onset of the accident, first few seconds), the terminal blocks are not challenged. During the time period when the reactor protection features are performing their functions automatically (i.e., the injection phase of accident recovery where no operator action is required or permitted), the terminal blocks will experience and be exposed to accident environments and their electrical properties will be diminished. However, as previously stated, the terminal blocks as well as the instruments do not have any function to perform. They just must not fail. Ample terminal block testing demonstrated that they do not fail. (In fact, this was well documented in the report I provided to Dr. Jacobus during the November 1987 inspection.) The testing of the individual instruments demonstrates that they do not fail. Instrument testing has demonstrated that during the onset of the accident, the time they are required to function, their accuracy remained within the specified band of ±8%.

During long term cooling, defined as the operational period where coolant injection has been terminated and switched to coolant recirculation, post ident conditions require monitoring. This is a time in the accident scenario where containment temperatures and pressures return to near normal conditions. Observations of terminal block behavior during testing show that the blocks recover and very little leakage current is observed (e.g., insulation resistance values return to near normal). The instruments associated with these circuits have demonstrated, through testing, that they also perform as intended within specified accuracy limits (i.e., post-accident accuracy ±25%). Functioning during peak LOCA conditions is not required. The instruments and the terminal blocks must not fail and must be capable of functioning in the post-accident long term recovery period. These features have been demonstrated.

Q130. Do you have a perspective on Dr. Jacobus's use of a qualifying temperature drawn from the SCEW sheet?

A. (DiBenedetto) Yes. He is avoiding the real issue here. The SCEW sheet is not, contrary to statements by Dr. Jacobus, a basis for the qualification of the equipment. It merely presents the conditions that the equipment will experience and the conditions to which it was tested. Similarly, the report I prepared relating to the tested terminal blocks mentioned above was prepared not to show qualification, but instead to demonstrate that our views and conclusions on the survivability of the blocks were indeed supported.

Q131. IN 84-47 is reported by the Staff witnesses to have put utilities on notice relating to the concerns about using terminal blocks in instrument circuits, can you comment on this?

A. (DiBenedetto) Yes, IN 84-47 (Staff Exhibit 48) did indeed present the NRC's concerns relating to the use of terminal blocks in instrument circuits. It also suggested three steps that a concerned utility could take to rectify the situation if a significant problem with leakage current was determined to exist. The Staff is also correct in pointing out that most utilities replaced terminal blocks with splices as a result of reviewing IN 84-47 and performing their own evaluation. However, Alabama Power Company, in its evaluation, segmented their use of terminal blocks and determined, as stated above, that leakage current effects, at the time of the terminal block usage in the Farley-specific accident scenario, was not a concern. IR values were within acceptable criteria and were factored into the loop calculations for inclusion in ERPs.

H. Conclusions

Q132. Do you have any additional conclusions on this issue?

A. (Love, Jones) Yes. The NRC Staff is basing a "clearly should have known" finding on the issue extensively -- if not completely -- on IN 84-47. However, as discussed above, this completely ignores the 1985 basis for qualification of terminal blocks in instrument circuits at Farley Nuclear Plant. That basis was documented (APCo Exhibit 20) and accepted prior to the deadline -- in full awareness of the issues that were involved in IN 84-47. This is simply an evolutionary issue we should not be debating today in the EQ enforcement context.

As we have explained, the Staff's position today is taken in complete disregard for both the technical and regulatory context of this issue in 1984 and 1985. Dr. Jacobus and Mr. Luehman simply weren't there. Nobody else from the NRC Staff has even acknowledged reviewing the Sandia data post-deadline, much less pre-deadline.

From our perspective, Dr. Jacobus, an NRC contractor, staked out a singular position on the issue at the 1987 inspection. As a result, we developed the JCO in the short time after the inspection, before the November 25, 1987 meeting. However, he would not accept our position in the November 1987 meeting either, or at any subsequent time. NRC Staff management has never stepped in to allow an impartial, objective review of the issue, including at the November 1987 meeting. We believe our technical position would be validated by such a review. Moreover, the technical dispute that arose in 1987 was certainly not one we clearly could have known or anticipated prior to November 1985, and the data does not support a violation.

IN 84-47 was based upon the Sandia testing and summary reports discussed above. A thorough review of that data shows conclusively that our 1987 qualification basis was a valid basis. The Sandia data, therefore, does not support a violation -- much less a "clearly should have known" finding. Our review presented here conclusively demonstrates the lack of merit to the Staff's technical position. This cannot be dismissed as some "after-the-fact" analysis. What we have done here is explain again the position we took in 1987. Our pre-inspection analysis existed, was documented, and was valid -- as confirmed by the Sandia data adopted by the Staff.

VI. LIMITORQUE MOTOR OPERATORS: T-Drains

Q133. Mr. William Levis has prepared Rebuttal Testimony on behalf of the NRC Staff concerning T-drains in Limitorque motor operated valves (MOVs). Are you familiar with it?

A. (Sundergill, Jones, DiBenedetto) Yes.

Q134. What is the purpose of your Surrebuttal Testimony on this issue?

A. (Sundergill, Jones, DiBenedetto) Our testimony responds to the concerns and issues raised by the Staff in its Rebuttal Testimony regarding T-drains. We disagree with Mr. Levis' conclusions on this issue regarding violations of environmental qualification requirements. We believe, as before, that the MOVs at the Farley Nuclear Plant were qualified even if T-drains were not installed.

Q135. In general, why do you disagree with the Staff's conclusions concerning the environmental qualification of Limitorque MOVs at Farley without T-drains?

A. (Sundergill) The Staff's conclusions primarily are based on their assertion that Limitorque Test Report 600198 (Staff Exhibit 52), which tested actuators without T-drains for a seven day accident duration, cannot be extended to encompass the Farley accident duration. As more fully explained below, it is my opinion that this test can be extended to cover the Farley accident duration.

Q136. According to Mr. Levis, Test Report 600198 is not acceptable for MOVs with an operating requirement that exceeds seven days. (Rebuttal Testimony, at page 4). Is he correct?

A. (Sundergill) I do not believe that Mr. Levis is correct in his assessment. This disagreement is, in my opinion, the heart of the matter. If it is demonstrated that Test Report 600198 envelopes the Farley parameters, the three MOVs per unit in question were qualified. I contend that Test Report 600198 has sufficient temperature margin to demonstrate that it would cause the equivalent degradation to the actuators as would a lower temperature exposure for a longer period of time.

Q137. Let's begin with Test Reports 600456 (Staff Exhibit 53) and B0058. (Staff Exhibit 54). Mr. Sundergill, in your prior testimony, you state that "[i]nstallation of T-drains" is not evident in either report. (Direct Testimony, at pages 184-85). Mr. Levis disagrees with that statement. (Rebuttal Testimony, at page 3). How do you respond?

A. (Sundergill) My statement may have been imprecise but it was not wrong. I meant to explain that there was no indication in Test Report 600456 (Staff Exhibit 53) that T-drains were installed in that test, and that there was no indication in B0058 (Staff Exhibit 54) that T-drains were installed in the 600456 test. Even though B0058 is often referred to as a test report, it is a summary document providing overall guidance for the Limitorque test program. Test Report 600456 is the actual test in question, not B0058 - and Test Report 600456 includes no indication that T-drains were installed.

Mr. Levis is correct that there is a mention of T-drains in B0058. However, he is perhaps being equally imprecise in his language since he apparently reads more into the T-drain reference in paragraph 6.0 of B0058 than I do. That paragraph states:

> 6.0 DESIGN LIFE
>
> The inside containment and outside containment actuators are of the same basic design and construction with some differences in material to permit the actuator to withstand the more severe containment chamber DBE conditions. These differences consist of use of different phenolic insulating material for the switches, a special motor insulation system, Viton seals instead of Buna N, elimination of all external aluminum parts and the use of 'T' drains and grease relief valve to accommodate the extreme temperatures and pressures of containment DBE environments.

(Staff Exhibit 54, at page 30). Mr. Levis may believe that the simple listing of component differences implies that T-drains were included in the 600456 test, but I do not.

Mr. Levis further states on page 3 of his Rebuttal Testimony that the language in paragraph 6.0 of B0058 "specifically uses the term 'chamber,' which any reasonable engineer would take to mean the test chamber used in qualifying the MOVs." I believe that a reasonable engineer would not interpret that one word out of context. The phrase Limitorque used is "containment chamber," not simply "chamber." In my opinion, the phrase "containment chamber" refers to the containment of a nuclear power plant -- not an autoclave in some test lab. I also base my opinion on a review of the entire context of the statement by Limitorque. The referenced discussion centers on design differences between actuators used inside containment and those used outside containment. The differences exist because the inside containment actuators are exposed to more severe conditions than would be actuators installed outside containment. It is unreasonable to assume that Limitorque meant that it was building actuators strictly for test purposes or strictly for installation inside a test chamber.

Therefore, I reiterate that B0058 does not implicitly or explicitly state that testing was conducted with or without T-drains.

Q138. What about Test Report 600198? (Staff Exhibit 52). As Mr Levis recognizes on page 3 of his Rebuttal Te timony, it was conducted without the installation of T-drains. Did Test Report 600198 address all Limitorque MOVs at Farley?

A. (Sundergill) In my opinion it did, as explained in response to A162 on pages 183-85 of my Direct Testimony.

Q139. But in reaching your conclusion, aren't you relying on Arrhenius techniques to extrapolate the results of Test Report 600198 for a thirty day, post-LOCA period?

A. (Sundergill) Yes, in part, but also on engineering judgment. The Arrhenius methodology is a means of accelerating the chemical and physical reactions which are part of the aging process. By using this methodology, it can be shown that testing a piece of equipment for a short time at a high temperature is equivalent to it experiencing a lower temperature for a longer period of time. The question raised by Mr. Levis is based on his concern about extending the Arrhenius methodology to accelerate the effects of moisture degradation.

In the 600198 testing of the Limitorque actuators without T-drains, presumably moisture accumulated inside the motor housing. The report did not include any indication of whether or not moisture had accumulated in the motor housing during the test. If there was none, the need for a T-drain is precluded altogether. However, the presence of moisture was presumed in order to be conservative in the analysis.

Any moisture that was present in the motor housing during the test would have been at or about the temperature and pressure recorded for the actuator. The actuator was tested for the initial transient conditions which envelope the Farley LOCA profile for the first 24 hours. For the remaining six days of the test, the actuator was maintained at approximately 250°F and 15 PSIG. (_See_ APCo Exhibit 121, the pages showing the relevant test data for the 600198 testing; these pages from the test report were inadvertently missing from the full 600198 report admitted into evidence as Staff Exhibit 52.) By comparison, over the same period of time, the Farley LOCA profile is ramping down from approximately 140°F to approximately 120°F and the pressure is constant at approximately 5 PSIG. Therefore, the test conditions envelope the Farley profile for the first day and are significantly more severe than the postulated conditions for the next six days.

Based on my engineering judgment, moisture at 250°F and 15 PSIG for 6 days would have at least as significant an impact on the actuator components as would the same amount of moisture at 120°F for 32 days. The 32 days is based on the overall duration of 33 days minus the initial day which contained the transient and peak conditions. My judgment is further bolstered by noting that the electrical insulation used in the actuator exposed to the 600198 testing is not as good as that used at Farley. So, in summary, I believe that the 600198 testing at elevated levels using inferior electrical insulation is sufficient to encompass the postulated accident at Farley.

I note in passing that it is likely that this same reasoning has been employed by the Staff for Limitorque Test Report 600456. (Staff Exhibit 53). This report documents a 30-day accident test on a Limitorque actuator with T-drains installed. In paragraph 4.7.1 (page 26), it states that the "stator and rotor showed little evidence of corrosive build-up and no evidence of physical damage. The end bell was particularly clean with little evidence of water." Note that "little" evidence of water suggests that at least some evidence of water was present. Thus, for the period of the 30 day test, there was some moisture in the Limitorque actuator. Nevertheless, this test has been accepted by Staff for other plants with postulated accident durations in excess of 30 days. Thus, the Staff has tacitly acknowledged that moisture degradation effects may be extrapolated. If one test can be extrapolated, so can another.

(DiBenedetto) Let me add that extrapolation of data has routinely been used in aging studies to extend a test duration to encompass a required test duration (as discussed in the testimony on V-type splices). Additionally, EPRI NP-1558, "A Review of Equipment Aging Theory and Technology" (September 1990) -- an industry-accepted aging document -- suggests that extrapolation to extend life beyond that to which it was tested is permitted and justifiable provided that excess margin is available and the magnitude of extrapolation is reasonable. Reasonable, however, is not quantified. In my opinion, in the present context, the use of excess margin from the 7-day test is reasonable to extend the qualification by a factor of a little more than four times.

Q140. It is Mr. Levis' testimony that "certainly moisture is going to affect the performance of an electrical piece of equipment." (Tr. 595). Is this absolute assertion correct?

A. (Sundergill) No. There are certainly items of electrical equipment which are properly constructed to withstand the effects of moisture. Electrical cable is one example which immediately springs to mind. Another more immediate example is in the case of the Limitorque 600456 test where it states, in paragraph 4.7.1 (page 26), that there was "little" evidence of moisture intrusion. Even though the actuator had been sprayed with water during the test, and some (albeit "little") had gotten in, the performance of the actuator was not affected.

Q141. Before leaving the issue of moisture effects, Mr. Levis alleges that Mr. DiBenedetto's testimony is "misleading in that he states that he is unaware of any [MOV] failures without stating basis [sic] for his conclusion." Rebuttal Testimony, at page 2. How do you respond, Mr. DiBenedetto?

A. (DiBenedetto) Mr. Levis is referring to my Direct Testimony in response to Q160 which asked, in total, "[a]re you aware of any failures that can be attributed to moisture in the Limitorque?" I responded that "I am unaware of any failure reported in the industry where the Limitorque motor operator failed because of moisture intrusion." (Direct Testimony, at page 160). Quite frankly, I do not know what kind of basis Mr. Levis wants in support of my response. His own Rebuttal Testimony, page 2, supports my response and is similarly devoid of basis: "I am not aware of any test to either support use of Limitorque motor valve operators without T-drains in a long term post LOCA environment or that shows failures of Limitorques without T-drains in that environment."

Q142. On page 181 of your Direct Testimony, Mr. Sundergill, you testify that the T-drain issue "clearly evolved after the EQ deadline" of November 30, 1985. Mr. Levis disagrees, however, and purports that he is "aware of several sites where this configuration attribute was checked prior to the deadline." (Rebuttal Testimony, at page 5). How do you respond?

A. (Sundergill) In support of his disagreement with my statement, Mr. Levis identifies only one utility that, prior to the deadline, planned to verify the presence of T-drains. He also states that the unnamed company which previously employed him looked at them. The first fact is hardly an indication that the NRC Staff considered the absence of T-drains a violation. In fact, as we discuss below, prior to the deadline, the NRC was inconclusive on the issue. Also, I have no way of knowing what environmental conditions were involved in that plant application.

Mr. Levis' latter example is not even an NRC action. Again, I cannot speculate on the rationale underlying the company's position. I believe that Mr. Levis' examples serve only to bear out my contention -- the issue of T-drains evolved after the EQ deadline. The genesis of the issue may pre-date the deadline, but its evolution (e.g., the Staff taking a position on the issue) transpired after November 30, 1985.

Q143. Mr. Levis also rejects the statement on page 127 of Mr. DiBenedetto's Direct Testimony that "the fact that the T-drain issue was cited at 21 different utilities demonstrates that issue was not a concern of many reasonable and prudent engineers." (As paraphrased by Mr. Levis, Rebuttal Testimony, at page 5.) How do you respond?

A. (DiBenedetto) The 21 utilities I cite in my Direct Testimony represent approximately half of all operating nuclear units in the United States. This is most certainly indicative of what was known or clearly should have been known regarding this issue prior to the deadline. On this basis, and in accordance with the testimony of Mr. Luehman and Mr. Potapovs at the February hearing (Tr. 306-316), Alabama Power Company is not an outlier. One of the primary reasons why so many utilities were not concerned about the issue is because the NRC Staff, in IN 83-72 (Staff Exhibit 55), declined to identify the issue as a safety concern.

Q144. But Mr. Levis has testified that the industry was first notified of the T-drain issue in IN 83-72. (Tr. 606). Are you familiar with that document?

A. (Sundergill, Jones, DiBenedetto) Yes.

Q145. Could you please summarize the portion(s) of IN 83-72 relevant to T-drains?

A. (DiBenedetto) On page 126 of my Direct Testimony, I explained that, although IN 83-72 (Staff Exhibit 55) contained a brief discussion pertinent to T-drains, it did not conclude that a potential problem existed.

(Sundergill, Jones, DiBenedetto) IN 83-72 only stated that, at the time, it was unknown whether the existence of drain plugs or the orientation of the drain hole was essential to proper MOV operation or was in conformance with the qualification tests. Clearly, the NRC was unable to determine the impact, if any, on the operation or qualification of a motor operator without T-drains installed.

Q146. How did Alabama Power Company respond to IN 83-72?

A. (Jones) In response to the Notice, Alabama Power Company reviewed the qualification information provided by Limitorque, as well as its own maintenance practices, in order to determine whether the identified concern was applicable at Farley. During Alabama Power Company's January 11, 1984, meeting with the NRC Staff, we indicated that we would be reviewing IN 83-72 to determine its applicability at Farley, and concomitantly, whether any corrective action was necessary. (See APCo Exhibit 20, Attachment 2, at page 6).

This information notice again needs to be viewed in context. In response to Alabama Power Company's request, Limitorque had earlier, by letter dated October 13, 1980 (APCo Exhibit 122), documented qualification of the Farley MOVs to their qualification reports. Because Alabama Power Company had purchased the MOVs directly from Limitorque, and no modifications were performed by us, there was no reasonable assurance that the MOVs remained qualified after review of IN 83-72. Keep in mind that IN 83-72 -- as discussed in my Direct Testimony at page 197 -- addressed a concern regarding Limitorque MOVs not procured from Limitorque directly. Based on Limitorque's assurances of qualification, the lack of third-party involvement after original installation of the MOVs, and the fact that Alabama Power Company did not perform modifications without designer approval, Alabama Power Company had reasonable assurance that the Farley Limitorque MOVs were not impacted by IN 83-72.

Furthermore, as Mr. Sundergill has explained, we ultimately concluded that the Farley motor operators provided by Limitorque had been qualified to Limitorque Test Report 600198 (Staff Exhibit 52), which supported qualification of the actuators without T-drains.

Q147. Was IN 83-72 (Staff Exhibit 55) cited by the Staff in either the August 15, 1988, NOV (Staff Exhibit 2) or August 21, 1991, Order (Staff Exhibit 3) as a basis for the T-drain violation at issue?

A. (Sundergill, Jones) No, not explicitly. It was not discussed in the Staff's Direct Testimony on the T-drain issue or in the NOV. Although IN 83-72 is mentioned on page 12 of the Order, it is not expressly correlated to T-drains. The first direct correlation was provided by Mr. Levis in the hearing. (Tr. 606). This fact seems to belie the current argument that IN 83-72 provided such clear notification of a problem prior to the deadline. The Staff did not expressly rely on it before the oral testimony as a basis for a "clearly should have known" finding.

Q148. Based on your testimony regarding the content of IN 83-72, should Alabama Power Company clearly have known of the alleged T-drain EQ deficiencies at issue prior to November 30, 1985?

A. (Sundergill, Jones, DiBenedetto) We don't see how Alabama Power Company, prior to the EQ deadline, could have interpreted IN 83-72 to mean that there were EQ deficiencies at Farley Nuclear Plant due to the lack of T-drains in Limitorque Motor Operated Valves. (Keep in mind that the Modified Enforcement Policy test is whether Alabama Power

Company clearly should have known of <u>the lack of</u> qualification.) The issue did not seem important to Limitorque, in that they did not highlight it in their test reports. As we discussed in Direct Testimony, the industry position was that T-drains were not crucial to qualification.

Evidence was presented to the NRC inspectors at the time of the audit which verified that Test Report 600198 (Staff Exhibit 52) was applicable to Farley. Moreover, in late-1985 and early-1986, the Nuclear Utility Group on Equipment Qualification (NUGEQ) explored the T-drain issue as a generic industry matter. NUGEQ determined from Limitorque that Test Report 600198 involved MOVs without T-drains and Test Report 600456 (Staff Exhibit 53) involved MOVs with T-drains. Based on that information, NUGEQ concluded in an April 1986 report (APCo Exhibit 109, at page 7, footnote 3) that "[t]he omission of T-drains in other situations will not necessarily prevent proper actuator operation or violate environmental qualification." The report further stated that the lack of T-drains is acceptable provided "[t]he required environmental parameters are bounded by other reports (e.g., 600198 . . .) which did not utilize T-drains." (Id.) During the Farley inspection, Alabama Power Company provided proof to the NRC inspectors that Test Report 600198 bounds the accident conditions at Farley. (<u>See</u> Direct Testimony, at page 185).

Therefore, it is our professional opinion that the Limitorque MOVs installed at Farley were qualified as of November 30, 1985.

VII. GEMS LEVEL TRANSMITTERS

Q149. Having read the Staff's Rebuttal Testimony, will you please give the Board your perspective of the issues presented by this alleged EQ deficiency?

A. (Jones) In my judgment, the issues are whether the GEMS level transmitters were filled with silicon oil on November 30, 1985 and, if not, whether such a failure is an EQ problem or a maintenance one. Alabama Power Company has previously filed with the Board its report "on the level of silicone oil in the GEMS level transmitters on November 30, 1985." That letter says:

> Despite an extensive review of the GEMS Level Transmitters maintenance records, APCo has been unable to determine definitively the levels of the silicone oil in the transmitters on November 30, 1985. The GEMS installation manual, however, expressly identified the appropriate level of silicone oil for the eight transmitters. APCo believes that this installation manual was followed at the time of installation because had the appropriate level of silicone oil not been applied when the transmitters were originally installed, then APCo's quality assurance program or quality control program should have discovered any deficiencies No evidence of any such deficiency has been found. Between the date of installation and November 30, 1985, there are no records that would indicate that the level of oil had fallen below the appropriate levels, with one exception. APCo has discovered a May 16, 1985 Maintenance Work Request (MWR), which indicated that one of the eight transmitters did not have the appropriate level of oil. The MWR says that the transmitter was filled at that time to the appropriate level. Other than the one transmitter reference in the MWR, APCo cannot determine conclusively the level

of silicone oil in the transmitters at the deadline.

Regardless of when the transmitter lost the oil, it appears to be a maintenance problem, not an EQ one, for the reasons stated in the Direct Testimony.

(Sundergill) Let me add here that Mr. Levis provides a very general definition to the EQ program that simply is not contained in the applicable regulations: 10 CFR 50.49 or IEEE 323-1974. The requirements do not explicitly state anywhere within their contents that maintenance of equipment is part of an EQ program. While it is necessary to perform proper maintenance in order for the qualification of the equipment to remain valid, this necessity is not a regulatory requirement.

Q150. In the Staff's rebuttal testimony concerning GEMS level transmitters, it claims that Mr. Sundergill has "changed his testimony." (Rebuttal Testimony Concerning GEMS Level Transmitters, at page 3). It says that in Mr. Sundergill's written testimony he states that the low levels of silicone oil are attributable to "the four specific examples of installation deficiencies;" (Rebuttal Testimony Concerns Gems Level Transmitters, at page 2) however, at the enforcement hearing, he provided for the possibility of installation or maintenance deficiencies as being potential sources of the problem. Please respond to this.

A. (Sundergill) The full question and answer presented to me in the written Direct Testimony must be read and not taken out of context. The question, Q185 on page 202 of my Direct Testimony, states in relevant part: "With respect to the four suspect transmitters, you stated that the deficiency is more properly characterized as an installation/maintenance issue rather than an EQ issue." (Emphasis added.) This underlined portion of the question refers to my response to Q182 on page 201, in which I stated: "The first issue is an installation/maintenance issue; not an EQ issue." The Staff is not clear in its explanation of how I have "changed" my testimony. Nevertheless, Staff Counsel's questioning of me found in the hearing transcript on pages 1170-71 makes clear that I do not know whether the low level of silicone oil is due to a deficiency in the original application of the oil to the transmitters or to a deficiency in the subsequent maintenance of those four transmitters. My response is also clear that I recognize the possibility that either installation or maintenance could have caused the low levels of oil. As a result, any allegation that I have "changed" my testimony is not supported.

Q151. Based on the GEMS deficiency, the Staff draws some sweeping conclusions about the overall EQ program at Farley. In particular, Mr. Levis concludes that the "EQ program requirements were not understood or implemented at the craft level at the Farley plant." (Rebuttal Testimony, at page 4). How do you respond?

A. (Jones) This is both untrue and unfair. Bob Berryhill and I previously testified about the many hours, days, weeks, and months which many people, including highly competent, skilled craftsmen at Farley Nuclear Plant, devoted to complying with EQ requirements. To impugn the reputation of Alabama Power Company's craft labor on such thin and unrepresentative evidence as four transmitters found in 1987, in low-oil conditions, is over-reaching at best and, at worst, insulting. Besides, Alabama Power Company's training program and QA/QC program were NRC-approved. Moreover, the numerous, very favorable inspection reports, SERs, TERs, and other correspondence received by Alabama Power Company during this period belie the credibility of the Staff's current position on Alabama Power Company's EQ program.

Q152. Were the low oil levels in the GEMS safety significant?

A. (Sundergill) As explained in detail on page 203 of my direct written testimony, I do not believe that the low oil levels in the transmitters have any safety significance. The GEMS level transmitters provide only a redundant indication for transfer from the injection to the recirculation phase. Primary indication for this transfer is provided from the Reactor

Water Storage Tank level indication. The devices that provide the primary indication are Class 1E items of equipment and are located in a mild environment. Therefore, even under the postulation that the GEMS level transmitters would fail in a design basis accident, the primary indication system would be unaffected.

Q153. What is your conclusion on this issue?

A. (Jones, Sundergill) We continue to maintain that this issue does not represent a violation of 10 CFR 50.49. Even if it were, it is not a violation which Alabama Power Company clearly knew or should have known of prior to the EQ deadline.

VIII. PREMIUM RB GREASE

Q154. In the Rebuttal Testimony concerning Premium RB Grease in room cooler and containment fan motors, Mr. Paulk identifies Staff Exhibit 78, which is a Joy Manufacturing document entitled "Installation and Maintenance Manual: Series 800/1000/2000/3000 Axivane Fans Adjustable Pitch Direct Connected Single and Two-Stage Axial Flow Fans -- NP 408." Mr. Paulk claims that this document was "identical or similar" to the manual he reviewed during the 1987 inspection. Was NP 408 (Staff Exhibit 78) in the Farley Nuclear Plant files during the 1987 EQ inspection?

A: (Sundergill, Jones) No. Alabama Power Company had the Joy Installation and Maintenance Manual NP 403 (APCo Exhibit 99) at the time of the inspection, and not NP 408. Joy sent the NP 403 manual to Alabama Power Company in 1975 for Unit 1 and 1976 for Unit 2 when the fan motors were initially shipped. This NP 403 manual still remains in the Farley Nuclear Plant files today. As a result, NP 403 is the manual that was available for Mr. Paulk's review during the 1987 inspection.

Q155. On Page 3 of his Rebuttal Testimony, Mr. Paulk identifies a "warning" contained in Staff Exhibit 78, which he claims should have notified Alabama Power Company that Chevron SRI #2 was the only lubricant to be used in the fan motors. Could

Mr. Paulk have seen such a warning on a Joy manual at Farley Nuclear Plant?

A: (Sundergill, Jones) Absolutely not. Since Joy never sent to Alabama Power Company a copy of Staff Exhibit 78, there is no copy of the NP 408 manual in the Farley Nuclear Plant files. The Joy manual that is in the files, NP 403, does not contain any warning that only Chevron SRI #2 may be used. Therefore, Mr. Paulk's claim that he saw a Joy document at Farley Nuclear Plant that warned against the use of any grease except Chevron SRI #2 is simply in error.

Q156. On page 5 of his rebuttal testimony, Mr. Paulk states: "APCo Exhibit 99 does not mention nuclear or other special applications, which Staff Exhibit 78 does, therefore, APCo Exhibit 99 is not appropriate to use in analyzing qualification." How do you respond to this conclusion?

A: (Sundergill) This is the first time Mr. Paulk has asserted that APCo Exhibit 99 (Joy manual NP 403) is not intended to provide instructions for nuclear applications of the fan motors. Because of Mr. Paulk's statement, I telephoned Joy to determine the applicability of NP 403 to Alabama Power Company's nuclear application of the fan motors. Joy confirmed that NP 403 was meant to be used in a nuclear application and that it still applied to the motors used in

Farley Nuclear Plant notwithstanding the fact that a different manual (Staff Exhibit 78) had been prepared. Joy also confirmed that they had no record of NP 408 having been sent to Alabama Power Company. Furthermore, Joy confirmed that it knew in 1974, when it sold the fan motors to Alabama Power Company, that the motors would be used in a nuclear application. Joy's awareness that Alabama Power Company would use the fan motors in nuclear applications is also readily apparent from the Joy Nuclear Containment Axivane Fan Operator's Handbook, which was sent to Alabama Power Company in 1974 when the fan motors were initially sent. (APCo Exhibit 123) Enclosed with this Operator's Handbook is a copy of NP 403.

Q157. On page 10 of his Rebuttal Testimony, Mr. Paulk complains that Alabama Power Company provided no documentation to indicate that Premium RB grease had not been mixed with the Chevron SRI #2 grease in the fan motors. How do you respond to this statement?

A: (Sundergill, Jones) The first time mixing of greases in the Joy fan motors was raised as either an NRC Staff concern or a basis for the civil penalty was December 20, 1991, when Mr. Paulk raised it in his direct testimony.[2] Notwithstanding

[2]Mixing greases was raised with regard to Limitorque motor operators but the Staff has elected not to pursue enforcement action on this point.

this newly voiced concern, Alabama Power Company has experienced no incompatibility effects in the fan motors <u>in fifteen years of Premium RB usage at Farley Nuclear Plant</u>.

Furthermore, in 1987 Alabama Power Company submitted to the Staff a justification for continued operation regarding the use of Premium RB grease in the room cooler and containment cooler fan motors. Because neither compatibility nor mixing of greases was an issue at that time, Alabama Power Company did not include any such discussion in the JCO. Had the Staff in 1987 believed that mixing or compatibility were issues that needed to be addressed in order to continue plant operations, the Staff would have rejected the JCO. Instead, the Staff accepted the JCO as providing reasonable assurance that continued operation was justified. (Staff Exhibit 29).

Q158. The Staff also raises the issue of Alabama Power Company's failure to change out the grease "as required by the manufacturer." (Rebuttal Testimony Concerning Premium RB Grease, at page 9). Was there any such vendor "requirement" in 1977 when Alabama Power Company changed to Premium RB?

A: (Sundergill, Jones) No. In fact, the document identified by Mr. Paulk as "requiring" a specific procedure for changing out grease was not even developed until 1980 -- three years after Alabama Power Company changed to Premium RB grease in Unit 1.

Moreover, that document (Staff Exhibit 78 -- the Joy NP 408 manual) has never been sent to Alabama Power Company.

Additionally, we understand that the first time such a "requirement" appeared in the Reliance containment cooler fan motor instruction manual was in Reliance manual B-3628-10 (APCo Exhibit 101), which was not issued until January, 1989 -- four years after the EQ deadline and twelve years after Alabama Power Company changed to Premium RB grease. The Reliance manual B-3628-9 (APCo Exhibit 100), which Alabama Power Company had in the Farley Nuclear Plant file in November 1987, contains *no* change out "requirements." Further, Mr. Paulk's contention that a change out procedure is "required" by the vendor is simply wrong. The change out procedure in the Reliance manual B-3628-10 is presented merely as a "note" and not as a "requirement" for maintaining qualification. This "note" reads in part: "Mixing lubricants is not recommended due to possible incompatibility. . . . Care must be taken to look for signs of lubricant incompatibility, such as extreme soupiness visible from the grease relief area." (APCo Exhibit 101, Section IV, Routine Maintenance). Notwithstanding that this "note" did not appear in the Reliance containment cooler fan motor maintenance manual until four years after the EQ deadline, to our knowledge, in the fifteen years of Premium RB grease usage on these fan motors at Farley Nuclear Plant, no such "extreme soupiness" has ever been seen, nor have any signs of incompatibility been observed.

IX. CONCLUSION

Q159. Does this conclude your testimony.

A. (Love, Sundergill, Jones, DiBenedetto) Yes. We hope so. To be candid, since this inspection fir began in 1987, we have noticed that the NRC Staff is rarely satisfied with any answer we give them. Each concern raised by them, and answered by us, begets yet another concern. There seems to be no end in sight. After five years, we are still addressing new concerns, new issues and new retroactive applications of current knowledge. We hope we are done. We genuinely do not know.

MAR 24 '92 11:04 SOUTHERN NUCLR/FARLEY PROJECT

APCo Exhibit 112

071324

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Alabama Power
the southern electric system

January 7, 1983

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R: 6572
5-13-87

Docket No. 50-364

Director, Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Mr. S. A. Varga

Joseph M. Farley Nuclear Plant - Unit 2
Closure of Completed License Conditions

Gentlemen:

The operating license for the Joseph M. Farley Nuclear Plant - Unit 2 contains several license conditions that have been completed by Alabama Power Company but have not been previously identified to the NRC as being complete. Many of these license conditions have resulted in commitments for additional action beyond the requirements of the license. Attached is a description of nine license conditions that are complete and the subsequent commitments made to address any remaining outstanding issues such as NUREG-0737. Since the nine license conditions are complete, Alabama Power Company respectfully requests that they be formally closed by the NRC. This letter supercedes our letter of October 19, 1982 relating to these conditions.

Yours very truly,

F. L. Clayton, Jr.

F. L. Clayton, Jr.

FLCJr/GGY:lsh-D34
Attachment
cc: Mr. R. A. Thomas
Mr. G. F. Trowbridge
Mr. J. P. O'Reilly
Mr. E. A. Reeves
Mr. W. H. Bradford

071325

ATTACHMENT

(1) License Condi..on 2.C.(18)(a), (b) and (c)

Requirement: The licensee shall take the following remedial actions, or alternative actions, acceptable to the NRC, with regard to the environmental qualification requirements for Class 1E equipment:

(a) Complete and auditable records shall be available and maintained at a central location which describes the environmental qualification method used for all safety-related electrical equipment in sufficient detail to document the degree of compliance with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," dated December 1979. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified to document complete compliance no later than June 30, 1982.

(b) Within 90 days of receipt of the equipment qualification safety evaluation (Appendix B to SER Supplement 6, NUREG-0117), the licensee shall either (i) provide missing documentation identified in Sections 3.0, 4.2 and 4.3 of the equipment qualification safety evaluation which will demonstrate compliance of the applicable equipment with NUREG-0588, or (ii) commit to corrective actions which will result in documentation of compliance of applicable equipment with NUREG-0588 no later than June 30, 1982.

(c) No later than June 30, 1982, all safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of NUREG-0588.

Response: Alabama Power Company has made several submittals documenting the environmental qualification of applicable equipment in accordance with NUREG-0588. The completion date of June 30, 1982 for having all applicable equipment qualified has been superseded by 10 CFR 50.49 which suspends the completion date requirement. All current action on this issue is being taken in accordance with 10 CFR 50.49 and NUREG-0588. Alabama Power Company has completed all applicable requirements of this license condition and requests that it be formally closed by the NRC.

ATTACHMENT

071326

(2) <u>License Condition 2.C.(20)</u>

Requirement: Prior to April 30, 1981, the licensee shall provide a schedule to the NRC for bringing the facility into compliance with Revision 2 of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," dated December 1980.

Response: Alabama Power Company letter dated March 30, 1981 documented compliance with license condition 2.C.(20) by forwarding a schedule to meet the requirements of Revision 2 of Regulatory Guide 1.97. Subsequently, Alabama Power Company letter dated November 16, 1982 stated that the previously transmitted schedule was being withdrawn based on a mutual agreement between the NRC and Alabama Power Company. The recently issued NRC Generic Letter 82-33 establishes the latest guidance for demonstrating compliance with Regulatory Guide 1.97 such that all current action on this issue is being taken in accordance with the Generic Letter. Alabama Power Company has completed all applicable requirements of this license condition and requests that it be formally closed by the NRC.

ATTACHMENT

071327

(3) License Condition 2.C.(21)(a)

Requirement: The licensee shall complete each of the following conditions to the satisfaction of the NRC by the times indicated. Each of the following conditions references the appropriate item in Section 22.5, "Dated Requirements" in SER Supplement 5, NUREG-0117:

(a) Guidance for the Evaluation and Development of Procedures for Transients and Accidents (I.C.1)

Prior to startup following the first refueling after January 1, 1982, complete the upgrading of emergency procedures and associated operator training.

Response: Alabama Power Company has made several submittals relating to license condition 2.C.(21)(a) and has referenced the Westinghouse Owners Group transmittal of November 30, 1981 which contains the latest available guidelines for emergency operating procedures. The actions taken by Alabama Power Company in association with the Westinghouse Owners Group satisfy the applicable requirements of license condition 2.C.(21)(a). Subsequent action by the NRC (i.e., issuance of Generic Letter 82-33) establishes revised guidance on upgrading emergency operating procedures such that all current action on this issue is being taken in accordance with the Generic Letter. Alabama Power Company has completed all applicable requirements of license condition 2.C.(21)(a) and requests that it be formally closed by the NRC.

ATTACHMENT

071328

(4) License Condition 2.C.(21)(b)

Requirement: (b) Reactor Coolant System Vents (II.B.1)

Submit a design description and operating procedures for reactor coolant system vents prior to July 1, 1981 and complete installation prior to July 1, 1982.

Response: Alabama Power Company letters dated June 26, 1981 and December 22, 1981 document completion of all installation work associated with the reactor system vents. Operating procedures were submitted as part of the Westinghouse Owners Group letter dated November 30, 1981. Final implementation of the reactor coolant system vent operating procedures will not be accomplished until NRC approval is given for the design of the installed system. Alabama Power Company has completed all requirements of license condition 2.C.(21)(b) and requests that it be formally closed by the NRC.

ATTACHMENT

071329

(5) License Condition 2.C.(21)(g)(1), (2) and (3)

Requirement: (g) Inadequate Core Cooling Instruments (II.F.2)

For the proposed reactor vessel water level instrument,

(1) Provide detailed design information identified in Section 22.5 of SER Supplement 5, Requirement A, Parts (1)(a), (3), (4), (7), (8) and (9) prior to July 1, 1981.

(2) Provide results of tests on Farley Unit 1 for consideration in this facility prior to July 1, 1981.

(3) Provide planned program to complete development, including any additional test data needed to determine feasibility, prior to January 1, 1982.

Response: Alabama Power Company letter dated June 29, 1981 documented compliance with license conditions 2.C.(21)(g)(1), (2), and (3). Subsequently, Alabama Power Company letter dated August 3, 1982 stated that the previously transmitted program plan was being terminated based on a mutual agreement between the NRC and Alabama Power Company. The recently issued NRC Generic Letter 82-28 establishes the latest guidance on this subject such that all current action is being taken in accordance with the Generic Letter. Alabama Power Company has completed all requirements of these license conditions and requests that they be formally closed by the NRC.

071330

ATTACHMENT

(6) License Condition 2.C.(21)(h)(1)

Requirement: (h) Commission Orders on Babcock & Wilcox Plants, Subsequently Applied to all PWR Plants (II.K.2.)

Prior to January 1, 1982,

(1) Submit a detailed analysis of the thermal mechanical conditions in the reactor vessel during recovery from small break LOCAs with an extended loss of all feedwater (II.K.2.13).

Request: Alabama Power Company letters of January 14, 1981 and December 22, 1981 documented the fact that license condition 2.C.(21)(h)(1) would be addressed as part of a Westinghouse Owners Group generic effort. The required analysis was submitted to the NRC by the Westinghouse Owners Group in a letter dated December 30, 1981. All subsequent action on this issue was agreed to by Alabama Power Company and the Westinghouse Owners Group in response to NUREG-0737, Item II.K.2.13. Alabama Power Company has completed all requirements of this license condition and requests that it be formally closed by the NRC.

ATTACHMENT **071331**

(7) License Condition 2.C.(21)(h)(2)

Requirement: (h) Commission Orders on Babcock & Wilcox Plants, Subsequently Applied to all PWR Plants (II.K.2)

Prior to January 1, 1982,

(2) Provide an analysis of the potential for voiding in the reactor coolant system during anticipated transients (II.K.2.17).

Response: Alabama Power Company letter dated December 22, 1981 documented compliance with license condition 2.C.(21)(h)(2) by referencing submittal of the required analysis attached to an April 20, 1981 letter from the Westinghouse Owners Group. Alabama Power Company has completed all requirements of this license condition and requests that it be formally closed by the NRC.

071332

ATTACHMENT

(8) <u>License Condition 2.C.(21)(i)(2)(i) and (ii)</u>

Requirement: (i) Final Recommendations of B&O Task Force (II.K.3)

(2) With respect to tripping of reactor coolant pumps (RCPs) (II.K.3.5):

(i) Submit to the NRC for approval either (1) an evaluation which shows that sufficient time is available to the operator to manually trip the RCPs in the event of a small break LOCA, or (2) a description of design modifications required to provide for an automatic pump trip. This submittal is required within three months after NRC determination of acceptability of the small break LOCA model based on comparisons with LOFT test L3-6.

(ii) If required based on (i) above, complete plant modifications to provide for automatic tripping of reactor coolant pumps within 11 months after NRC determination of model acceptability, provided there is an appropriate outage during that time interval to complete installation or during the first such scheduled outage occurring thereafter.

Request: Alabama Power Company letter dated December 22, 1981 documented compliance with license conditions 2.C.(21)(i)(2)(i) and (ii) by referencing submittal of the Westinghouse Owners Group evaluation in letters dated March 3, March 23, and June 15, 1981. The conclusion was that automatic tripping of the RCPs is not required. Alabama Power Company has completed all applicable requirements of these license conditions and requests that they be formally closed by the NRC.

ATTACHMENT

071333

(9) License Condition 2.C(21)(i)(4)(i) and (ii)

Requirement: (i) Final Recommendations of B&O Task Force (II.K.3)

(4) With respect to a revised small break LOCA model,

(i) Prior to January 1, 1982, submit to the NRC a revised model to account for recent experimental data (II.K.3.30).

(ii) Submit to the NRC the results of plant-specific calculations using the NRC-approved revised model prior to January 1, 1983.

Response: Alabama Power Company letter of December 22, 1981 documented compliance with license conditions 2.C.(21)(i)(4)(i) and (ii) by referencing the NRC approved small break LOCA model used in the licensing process for the Farley Nuclear Plant. Subsequently, NRC letter dated March 2, 1982 requested confirmation of a commitment by Alabama Power Company to participate in the Westinghouse Owners Group effort to address NUREG-0737, Item II.K.3.30 generically. This commitment was confirmed in Alabama Power Company letters of March 26, 1982, June 4, 1982 and January 7, 1983. All current action on this issue is being taken in accordance with the January 7, 1983 Alabama Power Company letter on NUREG-0737, Item II.K.3.30. Alabama Power Company has completed all requirements of license conditions 2.C.(21)(i)(4)(i) and (ii) and requests that they be formally closed by the NRC.

03-26-1992 10:53 202 371 5953

APCo Exhibit 113

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

071316

DEC 2 9 1982

MEMORANDUM FOR: Thomas M. Novak, Assistant Director for Licensing
Division of Licensing

FROM: William V. Johnston, Assistant Director
Materials & Qualifications Engineering
Division of Engineering

SUBJECT: SUPPLEMENT TO SAFETY EVALUATION REPORT FOR SHOREHAM NUCLEAR POWER STATION UNIT 1

Plant Name: Shoreham Nuclear Power Station Unit 1
Docket No: 50-322
Licensing Stage: OL
Licensing Branch & Project Manager: LB#2, R. Caruso

In a memorandum dated November 23, 1982, we furnished a Safety Evaluation Report for the Shoreham Nuclear Power Station environmental qualification program for safety-related equipment. Two items were identified as outstanding: justification for interim operation with equipment lacking complete qualification documentation and qualification of the GE 200 Series electrical penetrations. The applicant has recently provided additional information for these items which we have evaluated in the attached report. Several areas remain outstanding, as defined in the SER, and must be adequately addressed by the applicant before our review can be completed.

for William V. Johnston, Assistant Director
Materials & Qualifications Engineering
Division of Engineering

Enclosure: As stated

cc: V. Noonan
A. Schwencer
R. LaGrange
G. Bagchi
R. Caruso
E. Weinkam
EQ Section
M. Yost, EG&G
T. Humphrey, EG&G
R. Burgun, EG&G
E. Rossi
J. Ridgely
J. Kn[illegible]
M. Fields
J. Kennedy

Contact: J. Kennedy
x28207

071317

SUPPLEMENT TO SAFETY EVALUATION REPORT
OFFICE OF NUCLEAR REACTOR REGULATION
EQUIPMENT QUALIFICATION BRANCH
SHOREHAM NUCLEAR POWER STATION UNIT NO. 1
DOCKET NO. 50-322

3.11 Environmental Qualification of Safety-Related Equipment

In our previous Safety Evaluation Report, we identified two areas as outstanding which would require further review: justifications for interim operation with equipment which is not fully qualified, and the qualification of the GE 200 Series penetrations. The applicant has recently provided additional information addressing these areas which we have evaluated below.

1. Justifications for Interim Operation

The Commission Memorandum and Order of May 23, 1980 (CLI-80-21) acknowledged that some equipment may not meet all of the detailed documentation requirements in NUREG-0588 and directed that existing qualification documentation be analyzed to determine if interim operation with this equipment is justified. Subsequent to this Memorandum and Order, the staff developed guidelines to be used in evaluating equipment whose full qualification could not be established prior to plant operation. These guidelines require, where appropriate, consideration of:

a. Accomplishing the safety function by some designated alternative equipment if the principal equipment has not been demonstrated to be fully qualified.

b. The validity of partial test data in support of the original qualification.

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c. Limited use of administrative controls over equipment that has not been demonstrated to be fully qualified.

d. Completion of the safety function prior to exposure to the accident environment resulting from a design basis event and ensuring that the subsequent failure of the equipment does not degrade any safety function or mislead the operator.

e. No significant degradation of any safety function or misleading information to the operator as a result of failure of equipment under the accident environment resulting from a design basis event.

In letters dated November 3, 1982 (SNRC-768), and November 19, 1982 (SNRC-797), the applicant provided these justifications. We have performed an audit review of approximately 20% of the equipment types in the Shoreham environmental qualification program to determine if the applicant's approach meets the guidelines provided, is technically correct, and supports the conclusion that interim operation is justified. Because these justifications are interdisciplinary in nature, a coordinated review among seven review branches was performed. We have identified the following items which need to be addressed by the applicant before our review can be completed:

a. Some mechanical equipment has been justified for an undefined period of interim operation. The applicant should confirm that full qualification of these items will be achieved by the end of the first refueling outage.

b. In Item 2 on page H-2 in SNRC-768, the applicant states that temporary wiring modifications may be made to preclude failure of equipment with incomplete qualification documentation. It is our understanding that the temporary wiring modifications will consist only of bypassing safety grade instrumentation in such a way that the associated safety equipment operates at full capacity and that the applicant has determined that operation at full capacity will not result in any safety

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problems. It is our position that Item 2 on page H-2 be augmented or other written confirmation be provided by the applicant to include this information on the Shoreham docket.

c. For motor control center 1R24*MCC1124, the justification states that the fuel pool circulating pump is not required to operate following a LOCA or pipe break outside containment. This statement needs to be clarified. In addition, the period of interim operation must be defined.

d. Single line diagrams must be provided for MCC's 1R24*MCC112X, 1121, 1127, 1129, 112A, 112C, 1124, and 1R23*SWG 112.

e. The justification for Okonite splicing tape should be expanded in part (c) to more clearly indicate the function of the additional moisture barrier.

f. For the Anaconda Flex Conduit, Type EF (PVC jacket), the applicant has indicated that this material has a continuous temperature rating of 175°F and can withstand a peak accident temperature of 194°F. However, the manufacturer's rating for this conduit is 140°F continuous and 180°F intermittent. We therefore do not agree that this item is justified based on the information supplied by the applicant to date. Additional back-up information must be furnished to show that interim operation is justified.

g. Based on our findings in Item f, we believe additional review is required by the applicant for equipment justified based on handbook temperature ratings for materials. The applicant's selection of ratings may not always have been conservative. Additional justification (such as the manufacturer's rating for the specific material) is required and revisions to the justifications for interim operation factoring in the results of this review should be submitted.

We will issue a supplement to this report after the additional information requested in the above items has been furnished.

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2. GE 200 Series Electrical Penetrations

In our audit trip report date' 'une 30, 1982 we identified a number of unresolved items related to t qualification of the GE 200 Series electrical penetrations. In letters dated September 9, 1982 (SNRC-767), November 26, 1982 (SNRC-801), and December 14, 1982 (SNRC-809), the applicant has responded to these open items. Our evaluation of the applicant's responses follows.

a. Dose reduction calculation: In a letter dated November 26, 1982 ('NRC-801), the applicant provided a calculation to reduce the postulated radiation dose to these penetrations. We have reviewed this calculation and find it to be acceptable. Qualification for radiation exposure was based on a test dose equal to the calculated dose. A discrepancy in calculated dose rates has been satisfactorily addressed by the applicant in discussions with the staff but should also be clarified on the docket.

b. Qualification for pipe breaks outside containment: In a letter dated September 9, 1982 (SNRC-767) the applicant adequately demonstrated that qualification for LOCA conditions envelopes the environmental conditions associated with pipe breaks in the secondary containment.

c. Secondary side radiation dose: The applicant has provided additional information in SNRC-767 to show that the epoxy seals had received the required radiation dose of 5×10^7 rads during qualification testing. We find this additional information to be acceptable.

d. Surveillance - We had previously requested the applicant to describe the surveillance program for the electrical penetrations. These penetrations are good candidates for surveillance since a) their function is important, and failure would impact other equipment, b) the amount of accelerated aging data is less than normal, c) operating experience with an earlier operating design has been

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adverse, d) no operating plant in the U.S. utilizes the new design, and c) maintenance cannot be performed on the organic insulating materials.

The applicant has described a program for monitoring the pressure integrity during the installed life of the penetrations. The program defined for the 100 Series will also be used for the 200 Series penetrations. We find this approach acceptable for monitoring pressure integrity.

The applicant has also described a surveillance program for monitoring the electrical integrity of the penetrations. This program consists of insulation resistance measurements on spare conductors during each refueling outage. However, a minimum acceptable value has not been identified below which corrective action or further investigation should occur. The applicant maintains that a rapidly decreasing series of resistance measurements implies that degradation may have taken place. We believe that significant aging over the life of the plant may also occur by slow deterioration of insulating materials. The applicant should therefore specify and justify a value for insulation resistance below which corrective action will occur.

In addition, the monitoring of spare conductors is not acceptable since the application of voltage and current may significantly increase age degradation. Operating experience at Millstone 2 indicated that only energized conductors were subject to deterioration for the failure mechanism at that plant.

We will require surveillance as described above for incorporation into a plant surveillance procedure. The staff will verify that a procedure is developed in accordance with the applicant's commitments.

e. Performance of the safety function for the accident duration: During LOCA testing, electrical operability was not demonstrated for the duration of the test, nor was adequate analysis provided to demonstrate operability for the 180 day accident duration. The applicant has now provided analysis to extend the test operability time to

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180 days by equating temperature margins to time. We find this analysis to be acceptable. The radiation test performed was equivalent to a 180 day accident.

f. Operability during LOCA: We requested that the applicant compare the test values for voltage and current versus those for installed penetrations. These data were provided and are acceptable.

g. Similarity: The 200 Series penetration design is composed of various conductor sizes for different voltage and current ratings. During LOCA qualification testing, only a few of the various configurations were tested with the simultaneous application of voltage and current (tests with voltage and current applied separately were conducted on other penetrations but are not considered since they do not represent actual operation or the limiting condition). We therefore requested the applicant to demonstrate that the test results obtained with the simultaneous application of voltage and current are applicable to all penetration configurations. The applicant has provided information concerning conductor spacing, voltage and current ratings, dielectric strengths, and I^2R heating effects to show similarity of the various 200 Series penetrations. This approach is acceptable with the exception of I^2R heating effects. Although the summary section of this latest submittal states that the penetration module tested with simultaneous application of voltage and current also represents the highest I^2R heating, Appendix B to the submittal indicates otherwise. The I^2R heating reported is only about 3-4% of other penetration configurations. The applicant has clarified this discrepancy in discussions with the staff but should revise the information currently on the docket. This area will remain an open item until additional information is provided.

Based on our review of the above information we find the following items relating to the qualification of 200 Series penetrations to remain outstanding:

- Surveillance testing for monitoring insulation degradation (specification of a minimum acceptable value and commitment to surveillance of normally energized conductors)

- I^2R heating and its effect on LOCA qualification for all penetration modules.

- Clarification of calculated dose rates for 200 Series penetrations.

APCo Exhibit 114

071334

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406

MAY 03 1991

NOTED MAY 14 1991 M.J.W.

Docket No. 50-213

RECEIVED

MAY 14 1991

SENIOR VICE PRESIDENT
Nuclear Engineering & Operations

Connecticut Yankee Atomic Power Company
ATTN: Mr. E. J. Mroczka
Senior Vice President - Nuclear
Engineering and Operations
P. O. Box 270
Hartford, Connecticut 06141

Gentlemen:

Subject: Electrical Distribution System Functional Inspection (EDSFI) of Haddam Neck, Inspection Report No. 50-213/91-80

This letter transmits the report of the EDSFI team inspection conducted by Mr. Roy K. Mathew and other NRC personnel, from January 22 to February 22, 1991, at the Haddam Neck Plant in Haddam, Connecticut. Mr. Mathew discussed the team's findings with your staff on February 22, 1991, at the conclusion of the inspection.

Areas examined during this inspection are discussed in the enclosed inspection report. Within these areas, the inspection consisted of selective examinations of electrical distribution system's design calculations, relevant procedures and representative records, installed equipment, interviews with personnel, and observations by the inspectors. The team concluded that the electrical distribution system at Haddam Neck is capable of performing its intended function and the engineering organizations provide adequate engineering support for the safe operation of the plant. A number of strengths, observations and unresolved items as detailed in the enclosed report, were also identified.

Based upon the results of this inspection, it appears that three of your activities appeared to be in violation of NRC requirements, as set forth in the Notice of Violation, enclosed herewith as Appendix A. The violations have been categorized by severity level in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (Enforcement Policy). You are required to respond to this Notice of Violation (NOV) and, in preparing your response, you should follow the instructions in Appendix A.

MAY 0 3 1991

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We are concerned about s me of the team's findings. Specifically, the lack of adequate control of Emergency Diesel Generator (EDG) loading and surveillance testing program to envelop worst case design basis accident loads, lack of adequate licensing documents indicating EDG short term ratings and resulting in this information not being reflected in Emergency Operating Procedures (EOP) nor given to control room operators, several examples which indicate that a more thorough technical review and attention to detail could be improved to assure that applicable regulatory requirements are met and comprehensive design outputs are generated, and potential for overloading of EDG with the existing protective relay settings.

We request that you notify us, in writing, within thirty days, of actions taken or planned, in order to enhance the functionality of the electrical distribution system and confirm the commitment dates provided by you during the inspection. The sections of the report which address the specific findings are identified in the table titled, "Summary of Inspection Findings."

Your cooperation with us in this matter is appreciated.

Sincerely,

Jacque P. Durr for
Marvin W. Hodges, Director
Division of Reactor Safety

Enclosure: NRC Inspection Report No. 50-213/91-80

071336

cc w/encl:
W. D. Romberg, Vice President, Nuclear Operations
J. P. Stetz, Nuclear Station Director
G. H. Bouchard, Nuclear Unit Director
R. M. Kacich, Manager, Generation Facilities Licensing
D. O. Nordquist, Director of Quality Services
Gerald Garfield, Esquire
K. Abraham, PAO (2) All Inspection Reports
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of Connecticut

APPENDIX A
NOTICE OF VIOLATION

071337

Connecticut Yankee Atomic Power Company
Haddam Neck Plant

Docket No. 50-213
License No. DPR-61

As a result of the inspection conducted on January 22 through February 22, 1991 and in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (Enforcement Policy) (1990), the following violations were identified:

1. The Connecticut Yankee Atomic Power Company Technical Specification, Section 6.8.1 states that written procedures shall be established, implemented, and maintained covering the requirements and recommendations of Section 5.3 of ANSI N18.7-1976.

   ANSI N18.7-1976, Section 5.3.10, "Test and Inspection Procedures," states, in part, that test and inspection procedures shall contain a description of objectives and acceptance criteria that will be used to evaluate the results.

   Northeast Utilities Quality Assurance Program (NUQAP) Topical Report Section 11.0, "Test Control," implements the above by requiring that tests be accomplished in accordance with approved test procedures which incorporate the requirements and acceptance criteria in applicable design documents.

   Contrary to the above, on February 5, 1991, final voltage acceptance criteria of 105 Vdc at the battery terminals for the Class 1E battery service tests specified in procedure SUR 5.5-38, "BT-1A, 1B, and 1C Battery Service Test," Rev. 1 was inadequate in that they did not conform to design document PA 91-LOE-1171-GE, "Connecticut Yankee Existing Batteries 1A, 1B and 1C Adequacy Determination Requirement," (a minimum voltage of 108 Vdc and 111 Vdc are needed at battery A and B terminals, respectively, to ensure the minimum voltage of 105 Vdc required for closing solenoid operated 4160 V circuit breaker).

   This is a Severity Level IV Violation (Supplement I).

2. 10 CFR 50, Appendix B, Criterion III, requires, in part, that measures be established to assure that applicable regulatory requirements and design basis are correctly translated into procedures and instructions.

   Northeast Utilities Quality Assurance Program (NUQAP) Topical Report Section 3.0, "Design Control," implements the above requirement by providing that design control measures be established to assure that applicable design requirements, such as design bases and regulatory requirements, are translated into procedures and instructions.

Contrary to the above, on February 5, 1991, the established relay trip setpoints (105.3 volts and 114.8 volts on 120 V basis) for the level 2 and 3 degraded voltage protection given in Calibration Procedure PMP-9.8-22 were inadequate in that instrument drift was not considered for the selection of setpoint to meet the technical specification allowable limits (≥104.7 volts and 114.3 volts). Consideration of instrument drift is required to ensure that the instrument operates within the allowable values throughout the calibration period as specified in the technical specifications and as recommended by the manufacturer.

This is a Severity Level IV Violation (Supplement I).

3. 10 CFR 50.49, Paragraph f, requires electric equipment important to safety be qualified by type-test, analysis or a combination of both. 10 CFR 50.49, Paragraph g, requires the qualification be accomplished before November 30, 1985.

Contrary to the above, on February 18, 1991, the high pressure safety injection pump motors were not qualified in that they had not been type-tested nor analyzed to 114% of the rated horse-power at which they are required to operate following a postulated accident.

This is a Severity Level IV Violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Connecticut Yankee Atomic Power Company is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, Region I, and, if applicable, a copy to the NRC Resident Inspector, within thirty days of the date of the letter which transmitted this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include, for each violation: (1) the reason for the Violation, or, if contested, the basis for disputing the violation; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps which will be taken to avoid further violations; and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked, or why such other action, as may be proper, should not be taken. Where good cause is shown, consideration will be given to extending this response time. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-213/91-80

Docket No. 50-213

License No. DPR-61

Licensee: Connecticut Yankee Atomic Power Company
P.O. Box 270
Hartford, Connecticut 06141

Facility Name: Haddam Neck Plant

Inspection Conducted: January 22 - February 22, 1991

Inspection Team:
R. Mathew, Team Leader, RI
L. Cheung, Assistant Team Leader, RI
J. Lara, Reactor Engineer, RI
C. Woodard, Reactor Engineer, RI
W. Raymond, Sr. Resident Inspector, Millstone

NRC Consultants:
M. Goel, Mechanical Engineer, AECL
A. Josefowicz, Electrical Engineer, AECL
N. Rivera, Electrical Engineer, Parameter Inc.

Prepared By: Roy K. Mathew 4-11-91
R. K. Mathew, Team Leader, Electrical Section, Engineering Branch, DRS — Date

Approved By: C J Anderson 4/17/91
C. J. Anderson, Chief, Electrical Section, Engineering Branch, DRS — Date

Inspection Summary: Inspection on January 22 through February 22, 1991, Report No. 50-213/91-80

Areas Inspected: Announced team inspection by regional and contract personnel to review the functionality of the electrical distribution system.

Results: Details can be found in the Executive Summary.

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EXECUTIVE SUMMARY

During the period between January 22 and February 22, 1991, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at the Haddam Neck Plant. The inspection was performed to determine if the electrical distribution system (EDS) was capable of performing its intended safety functions as designed, installed, and configured. The team also assessed the licensee's engineering and technical support of EDS activities. For these purposes, the team performed plant walkdowns and technical reviews of studies, calculations and design drawings pertaining to the EDS, and conducted interviews of corporate and plant personnel.

Based upon the sample of design drawings, studies and calculations reviewed and equipment inspected, the team's conclusions were that the electrical distribution system at Haddam Neck is capable of performing its intended function. In addition, the team concluded that the engineering and technical support staff, both at Haddam Neck and at the corporate offices in Berlin, Connecticut provide adequate support for the safe operation of the plant. The inspection also identified three violations and one non-cited violation, unresolved items, various strengths, and observations as discussed in the paragraphs below.

The quality of engineering and technical support, as evidenced by the proper and timely disposition of NCRs, LERs and root cause investigation program, was one of the notable strengths identified by the team. The licensee has a commendable self assessment program to improve safe operation of the plant by reducing the core melt frequency through their risk reduction task force. The Connecticut Yankee Atomic Power Company (CYAPCO) Engineering personnel were knowledgeable, and the personnel that interacted with the inspection team was well prepared, technically competent and very familiar with the EDS. The team also noted that there is a good program for completing design modifications and administrative procedures reviewed were of good quality. Preventive maintenance of electrical distribution system equipment was found to be good. Communications between engineering and other site organizations was considered adequate. The team found adequate staffing and training in the engineering groups, and a good program for controlling temporary modifications.

The team found the procedures to operate the EDS to be generally of good quality and would assure EDS operability under normal, abnormal and accident conditions. Control room operators were knowledgeable of the EDS and its associated procedures. However, a deficiency involving EDG loading under certain limiting conditions highlighted a weakness in the EOP review process. Engineering support to operating activities is generally good with an effective interface evident in many areas. However, some deficiencies were noted in this area. The team observed several examples which indicate the thoroughness of technical reviews and attention to detail could be improved. This is needed to assure applicable regulatory requirements are met and design bases documents are referenced to assure comprehensive design outputs are generated. Three violations of 10 CFR Part 50 requirements were identified; the first relates to inadequate set points for degraded bus undervoltage relays to meet the design requirements; the second relates to inadequate acceptance criteria and load profile for the 125 Vdc battery service test; the third relates to inadequate environmental qualification of HPSI motors. One non-cited violation was identified regarding the lack of design control for the EDG loading.

The team expressed concern that the licensee had not firmly established the worst case EDG loading. The review indicated that the present EDG loading (3033 kW) calculated during this inspection for the worst case design basis accident condition (large break LOCA coincident with loss of off site power and the failure of "A" EDG unit) exceeded the continuous and 2000 hour rating (2600 kW and 2850 kW respectively) of the EDG. Although this loading is within the 30 minute (3050 kW) rating of the machine as stated by the manufacturer, the licensing documents do not reflect this additional rating and its qualification has not been established. Furthermore, the present Technical Specification (TS) surveillance tests do not envelop this condition and the power factor rating of the EDG and the power factor of the loads have not been considered.

A number of issues identified in the mechanical area with regard to inadequate design and calculation reviews indicated the need for establishing a thorough design review for the EDG and associated equipment. For example: the review of power demands for major loads indicated that the EDG automatic load will be increased by 27 kW and the manual load by 5 kW from the loading calculations; no test data or documentation was available to demonstrate that the EDG could start at the present air bank low pressure alarm setpoint of 165 psig; no calculation exists to determine the EDG room ventilation exhaust system capacity and also, the screen house ventilation system calculations were not revised to reflect actual loading condition.

The team made several observations which the licensee agreed to review further in order to resolve the issues. These include: potential for overloading the EDGs with the existing protective relay settings; lack of adequate coordination of supply breakers and feeder breakers for the 125 Vdc system for a worst case fault; some buses were exposed to continuous overvoltage due to lack of load flow studies performed to determine the actual voltage condition of the plant; appropriate design requirements for the EDG were not adequately translated into EOPs and the operators were not trained to acknowledge the expected higher EDG loading; no quality controlled calculation exists for 120 Vac protective coordination; the fault level could exceed the 125 Vdc system interrupting rating of breakers if short circuit contribution from the battery charger exceeds the current limiting of 125% of full load rating; feeder breakers for MCC5 are not monitored for their required operating positions, and some UFSAR information and a few drawings need to be updated as a result of this inspection.

A summary of the team's findings is contained in the attached table. The table also identifies the sections of the report which address the specific issues.

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SUMMARY OF INSPECTION FINDINGS

		Section	Tracking Number 50-213
A.	Violations		
1.	Inadequate acceptance criteria for battery service test	4.2.2	91-80-06
2.	Inadequate environmental qualifica for HPSI Motor	3.2.1	91-80-04
3.	Inadequate degraded bus relay settings	4.3.1	91-80-07
B.	Non-Cited Violation		
1.	Inadequate technical review of EOPs to establish EDG loading	2.4.1	91-80-01
C.	Unresolved Items		
1.	EDG loading and surveillance testing*	2.4.1	91-80-02
2.	EDG air bank low pressure setpoint*	3.3.2	91-80-05
3.	Calculations for EDG room and screenhouse ventilation*	3.4.1	91-80-03

Licensee commitment date:

* January 1992

071345

Observations

D.	Observations	Section	Commitment dates for resolution
1.	[illegible] flow study and updating [illegible]DS calculations	2.6	January 1993
2.	120 Vac coordination calculation	2.9	January 1993
[illegible]	[illegible]tion of feeder breakers [illegible]y breakers for DC system	2.10	Ja[illegible]ary 1992
[illegible]	[illegible] battery charger [illegible]ircuit contribution	2.10.2	January 1992
5.	[illegible]ve actions to address prog[illegible] weakness in the EOP review process	5.2.1	May 1991 August 1991
6.	Revision of AOP to ensure safety related loads are not inadvertently started	5.6	January 1992
7.	Include MCC5 feed breakers in the surveillance program	5.6	January 1992
8.	Review EDG protective OC/UV relay protection	5.6	January 1992
9.	Operator aids,training and procedure update	5.6	July 1991

1.0 INTRODUCTION

During recent inspections, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants in the country, the functionality of safety related systems had been compromised by design modifications affecting the electrical distribution system (EDS). The observed design deficiencies were attributed, in part, to improper engineering and technical support. Examples of these deficiencies included: unmonitored and uncontrolled load growth on safety related buses; inadequate review of design modifications; inadequate design calculations; improper testing of electrical equipment; and use of unqualified commercial grade equipment in safety related applications.

In view of the above, the objectives of this inspection were to assess: (1) the capability of the electrical distribution system's power sources and equipment to adequately support the operation of Haddam Neck's safety related components and (2) the performance of the licensee's engineering and technical support in this area.

To achieve the first objective, the team reviewed calculations and design documents paying particular attention to those attributes which ensure that quality power is delivered to those systems and components that are relied upon to remain functional during and following a design basis event. The review covered portions of onsite and offsite power sources and included the 115 kV offsite power grid, station auxiliary transformers, 4.16 kV Class 1E and non Class 1E system, emergency diesel generators, 480 V Class 1E unit substations and motor control centers, station batteries, battery chargers, inverters, 125 Vdc Class 1E buses, and the 120 Vac Class 1E vital distribution system.

The team verified the adequacy of the emergency onsite and offsite power sources for the EDS equipment by reviewing regulation of power to essential loads, protection for calculated fault currents, circuit independence, and coordination of protective devices. The team also assessed the adequacy of those mechanical systems which interface with and support the EDS. These included the air start, lube oil, and cooling systems for the emergency diesel generator and the cooling and heating systems for the electrical distribution equipment.

A physical examination of the EDS equipment verified its configuration and ratings and included original installations as well as equipment installed through modifications. In addition, the team reviewed maintenance, calibration and surveillance activities for selected EDS components.

The team's assessment of capabilities and performance of the licensee's engineering and technical support included organization and key staff, self assessment program and technical training, temporary and permanent plant modifications, operating procedures for EDS, root cause analysis and corrective action programs and engineering support in design and operations and their interface.

In addition to the above, the team verified general conformance with General Design Criteria (GDC) 17 and 18, Systematic Evaluation Program (NUREG 0826), and appropriate criteria of Appendix B to 10 CFR Part 50. The team also reviewed the plant's Technical Specifications, the Final Safety Analysis Report and appropriate safety evaluation reports to ensure that technical requirements and licensee's commitments were being met.

The details of specific areas reviewed, the team's findings and the applicable conclusions are described in Sections 2 through 5 of this report. The sections of the report which address the specific findings are identified in a table titled, "Summary of Inspection Findings."

2.0 ELECTRICAL SYSTEMS

The team reviewed, on sample basis, several features and components of the Class 1E distribution system. Particular attention was given to a selected sample "vertical slice" load path through the Class 1E EDS. The scope of the review included verifying the adequacy of the following attributes: 1) design, fault analysis, voltage drop study, and protection coordination studies of the Class 1E dc, vital 120 Vac, and Class 1E ac systems; 2) EDS equipment ratings, such as switchgear and transformer ratings, transformers basic insulation levels (BIL), short circuit ratings, 125 Vdc battery sizing ground fault protection, motor overload protection, and EDGs loading, sequencing, shedding and protection schemes; 3) the steady-state and the transient load profiles on train "B" of the EDS under normal and abnormal operating conditions; 4) cables sizing and voltage drops during motor running and starting; 5) electrical containment penetrations, sizing and protection; and 6) offsite power capabilities and degraded bus protection.

The team also reviewed procedures and guidelines governing the EDS design calculations, design control and plant modifications, and EDS single line diagrams and wiring schematics. A simplified single line diagram of Haddam Neck Plant is shown on Attachment 4.

2.1 Offsite Power, Grid Stability and Bus Alignments

The plant's safety related buses are energized from two 115 kV offsite lines through non-safety related buses. Two 115 kV lines are tied at the 115 kV switchyard so that the plant safety related buses can be energized from either of the two lines. CONVEX (the offsite distribution control authority) retains jurisdictional control of the switchyard up to and including the low voltage side circuit breakers (CB) of the station service transformers (SSTs). The safety related buses have no access to either the main generator output system or the 345 kV network.

The team reviewed logs of the 115 kV network voltage levels for years 1985 to 1991, and observed that the grid operating voltage level has been changed to a new higher level in the second half of 1990 (from an average of 112 kV to 117 kV). This change was reflected in the licensee's degraded voltage setpoint study. The team concluded that the 115 kV network was very stable and had access to sufficient power to permit successful operation of the plant safety related loads.

2.1.1 Bus Alignments During Start-up, Normal, Abnormal and Shutdown Operation

The output of the turbine generator (19 kV) is stepped up through the main transformer to 345 kV and power flows into the ring bus in the 345 kV switchyard to the Connecticut Valley Electric Exchange (CONVEX) power grid.

Normal station power is provided by the three station service transformers. Station service transformer 309 steps down the 19 kV output from the turbine generator to 4160 V to feed non-safety 4160 V buses 1-1A and 1-1B which feed the RCP motors. Station service transformers 12R-21S and 12R-22S step down the 115 kV offsite power from the switchyard to 4160 V and feed non-safety buses 1-2 and 1-3 respectively, with tie breakers connected to 4160 V emergency buses 8 and 9. The emergency buses 8 and 9 are backed-up by emergency diesel generators to supply vital plant auxiliaries if normal ac power is lost.

During start-up operation all station loads are energized from the 115 kV system. Bus 1-2 supplies power to buses 1-1B and 8, and bus 1-3 supplies buses 1-1A and 9. After a successful start-up, the operator manually initiates transfer of buses 1-1A and 1-1B to the main generator. The other buses are aligned in the same way as during start-up mode. During abnormal operation, as long as the 115 kV network is available, buses 8 and 9 are supplied from buses 1-2 and 1-3 respectively. On total loss of offsite power to the safety related buses 8 and 9 (as detected by the Degraded Grid Voltage undervoltage relays), the buses are automatically isolated from 1-2 and 1-3 respectively, selected loads of the buses 8 an 9 are tripped, and the EDGs started. A tie-breaker (12R-1T-2) in the 115 kV switchyard allows buses 1-2 and 1-3 to remain energized following a loss of one of the 115 kV lines. A tie-breaker (2T3) between these buses allows the two buses to remain energized following a failure of one of the SSTs.

For shutdown operation,the buses are aligned the same as during start-up operation. Prior to tripping of the main turbine-generator the operator manually initiates transfer of buses 1-1A and 1-1B from the main generator to buses 1-2 and 1-3 respectively. Manual transfer is performed one bus at a time.

The team did not identify any unacceptable conditions during this review.

2.1.2 Bus Transfer Schemes

The team reviewed bus transfer schemes to assure that transfers occur without any damage to the connected load and maintain the independency and redundancy of the EDS. All transfers are "open circuit" type with a built in time delay of 1 second. The team observed that all of the transfer schemes and tie-breakers associated with the safety related 4.16 kV buses used two circuit breakers (CBs). Each of these CBs had its control circuit energized from a different train of dc power, thus ensuring isolation of safety related buses from the non-safety related buses when required.

The team reviewed the transfer scheme for motor control center (MCC) 5. The MCC5 could be fed from either bus 5 or 6. One bus was always manually selected as the "preferred" source. The automatic transfer scheme is based on drop-out and pick-up functions of Agastat timing relays. The scheme always re-transfers to the preferred source, even when this source is established shortly after the safety related loads become energized from the alternate source. For example, ECCS valves could start to operate from the alternate source, then be interrupted for no more than 0.225 seconds with any tolerance associated with operation of the timing relays and attempt to be re-started again, this time from the preferred source. The team observed that this case has not been analyzed. The licensee explained that the characteristics of the small motors involved in this transfer were such that the residual voltage was of such a small magnitude that it did not represent any danger to those motors during this re-transfer. The team also observed that the method of operation of this transfer scheme was such that a fault would be energized from one source and then transferred to the other before both transfer breakers would trip and lock-out. The team noted that this issue was reviewed by the NRC during the licensing process and found acceptable. The team had no further questions regarding this issue.

In summary,the team observed that the alignment of buses, and the transfer schemes assured availability of power to the safety related loads, from either the offsite network (preferred) or the EDGs (backup), during all modes of plant operation.

2.2 4160 Vac/480 Vac Class 1E Systems

There are six 4.16 kV primary buses in the plant. Two of these buses (1-1A and 1-1B) are dedicated to supply RCP pump-motors, two buses (1-2 and 1-3) supply all other loads in the plant, and two Class 1E buses (8 and 9) supply the safety related loads.

Class 1E bus 8 can be energized from the offsite network through bus 1-2 or from its dedicated EDG 2A. Class 1E bus 9 can be energized from the offsite network through bus 1-3 or from its dedicated EDG 2B.

There are five 480 V buses; buses 4 and 5 are energized from bus 8, and buses 6, 7, and 11 are energized from bus 9. Each 480 V bus feeds a number of MCCs. MCC 5 can be fed from either bus 5 or bus 6 through an automatic transfer scheme.

2.2.1 Ground Fault Detection System

The original design had an ungrounded 4.16 kV delta-connected distribution system. This was later changed to a high-resistance grounded system, partly to control voltage surges in the system. The NRC review included:

1. Verification of capabilities of the standby generators to start the loads with a ground fault present in the system.

2. Performance of the ground fault detection, and capability of the fault energy dissipation system.

The team observed that in the cases when two 4.16 kV buses (buses 1-1A and 1-2 or 1-1B and 1-3) were connected together, the occurrence of an unrestricted ground fault affecting the connected buses would result in a total energy dissipation equal to 52 kW (an average value based on the nominal voltage condition at the time of fault). The resultant temperature profile of the switchgear room has not been analyzed. The licensee stated that procedures for locating a ground fault (ANN 4.9-15A), and for loss of cooling in the switchgear room would provide the operator with a sufficient action plan to ensure an orderly shutdown of the plant following this event.

The team concluded that performance of the ground fault detection and fault energy dissipation systems were found compatible with the EDS arrangement, and the predicted fault condition.

2.2.2 Voltage Surge Protection

The team observed that there were no voltage surge arresters installed on the transformers' secondaries on the 4.16 kV or 480 V buses. The licensee stated that lightning arresters located on the primary side of the station service transformers (SSTs), the high-resistance grounded distribution system, and an extensive grounding grid, ensures an acceptable attenuation of the voltage surges initiated within the outdoor 115 kV switchyard. The team observed that there were no lightning arresters on the low voltage side of the SSTs as described in modification No. PDCR-CY-89-100. The licensee agreed to revise the PDCR to address this discrepancy.

The team concluded that the Class 1E EDS was designed to reduce the possibility of voltage stress exceeding the insulation levels of equipment and circuits.

2.3 Electrical Distribution System Loading

The ratings of the SSTs and Class 1E 4160/480 V distribution transformers were compared with their loading, both normal and abnormal, such as plant start-up, and loss of one of the 115 kV lines. The limiting condition for rating of the SSTs was found to be "one SST out of service." At this point the load on the remaining SST (with a continuous rating of 17.3 MVA) would be between 18.9 MVA and the limit of the 4 kV side circuit breaker (CB) rating (3000 Amp or 21.6 MVA). The team noted that procedure EOP 3.1-10 limited this mode of operation to 1 hour. There is no long term degradation of the SST as within 1 hour the transformer's temperature would not exceed the maximum allowable limit.

The team found the rating of the transformers to be compatible with the loading conditions.

2.4 Emergency Diesel Generator (EDG)

This inspection was performed in order to evaluate the capability of the EDG system to provide the maximum power to support the loads required during plant accident conditions under the most severe operational conditions for the EDG units.

2.4.1 EDG Loading

According to the FSAR, the system consists of two 2850 kW, 0.8 power factor EDG units which are designed to be of sufficient capacity and capability to start and carry all vital loads required under postulated accident conditions. Both the technical specifications and periodic surveillance procedures require that each EDG be demonstrated operable by monthly testing between 2750 and 2850 KW. According to a letter from the manufacturer(General Motors) the EDG units are each rated as follows:

- Continuous 2600 kW
- 2000 Hour 2850 kW
- 7 Day 2950 kW *
- 30 Minutes 3050 kW *

* These ratings could not be verified in plant licensing documents.

During the 1989-1990 refueling outage an operations/engineering review of Emergency Operating Procedure (EOP) E-0, the licensee discovered that the EDG loading can exceed the maximum load (2850 KW) to which the unit is surveillance tested. As a consequence, a "one time" surveillance test was conducted during July 1990 at 2950 kW, 0.8 power factor to demonstrate the capability to carry EDG "B" calculated maximum load of 2915 kW. On August 2, 1990 an engineering evaluation of EOP ES 1-3, "Transfer to Sump Recirculation" showed that restarting a HPSI pump would result in load shedding of an RHR pump due to the low starting voltages and the low voltage tripping scheme on the respective 480 volt buses. As a consequence the setpoints were lowered for the 480 volt buses that power the RHR pumps to alleviate this condition. Investigation by the licensee revealed that this condition had existed since an EOP revision in 1986. The licensee addressed this deficiency and provided a detailed root cause analysis in LER 90-11 which was made in accordance with 10CFR 50.73 reporting procedures. The root cause analysis concluded that there were procedural deficiencies which permitted changes in EOP's without adequate technical review and safety evaluation review. This is further discussed in section 5.2.

The team concluded that this deficiency represents a violation of 10CFR 50, Appendix B, Criterion III "Design Control." The violation normally would be classified as a Severity Level IV violation. However, the violation is not being cited because the criteria specified in 10CFR 2, Appendix C, Section V of the Enforcement Policy was satisfied. Specifically, this is a Severity Level IV violation, which was identified and reported by the licensee, and appropriate corrective actions are being implemented to prevent recurrence. Therefore, this constitutes a non-cited violation (50-213/91-80-01).

During this inspection, further licensee engineering review disclosed that the worst case accident loading of the EDG's now exceeds the previously identified (July 1990) maximum loading of 2915 kW. According to load calculation PA-90-LOE-1167-GE dated February 20, 1991, the worst case loading occurs during a large break LOCA coincident with loss of offsite power and the failure of the "A" EDG. This calculation shows that the "B" EDG loading increases to 3033 kW (within the 30 minute 3050 kW EDG rating) for approximately 8 minutes before load reductions are made which decreases this loading to less than the 2600 kW continuous rating of the EDG for the duration of the accident.

In order to gain confidence in the licensee's load calculations, the team reviewed licensee calculations and independently calculated some major loads. The team reviewed the load calculations of MCC-5 and MCC-12 as documented in NUSCO CAL# PA 78-741-01-GE entitled, "Connecticut Yankee Diesel Generator Automatic Loading Analysis." In these calculations, the licensee introduced a parameter known as "demand factor." The licensee defined the demand factor as the ratio of the measured load (during a 24 hour period) to the total load of the bus. The team was concerned that the use of the demand factor in the calculation was not appropriate and the demand factor was not based on conservative assumptions. The licensee could not provide proper justification for its application. Subsequently, the licensee revised their calculations which were documented in NUSCO CAL# PA 90-LOE-1167-GE dated February 20, 1991. The team's review of the new calculation did not identify any unacceptable conditions.

Since severe voltage and frequency drops could result in the inability to start and accelerate loads and loss of running loads, a review was made of worst case load starting transients. The review of the diesel generator load calculation shows that when the HPSI pump starts following a postulated accident in conjunction with loss of offsite power, the transient voltage of diesel generator 2B drops to about 52% of rated and recovers to approximately 90% of rated within two seconds. The HPSI pump requires approximately 12 seconds to attain rated speed. (The team noted that these conditions do not meet the guidelines stipulated in R.G.

1.9). The frequency variations were found to be less than 3% of rated. The licensee substantuated the ability of the HPSI pump to start and operate under these conditions (with test data from "full flow to run out" tests conducted during 1980 and from the routine sequence/manual loading tests of starting and operating under bypass flow conditions). Further substantuation was provided by analysis of the manufacturer's pump motors torque/speed curves under conditions of low voltage. The team was concerned that this substantial voltage drop may cause some seal-in relay to drop out in the 480V power circuit, and disable the running motors. The licensee provided relay test data which show that the drop out voltage is below 52% of the rated voltage. The licensee also reviewed their 480 V wiring diagrams and determined that no seal-in relays are used in the 480 V motor starting circuits.

As a consequence of exceeding the loads for which there is demonstrated EDG capability to power loads in excess of 2915 KW, the licensee took actions to provide the team with assurance that the EDG's could power the worst case accident loads. Included were an EDG load rating letter from the manufacturer, documentation of inadvertent operation for several minutes at 3300 KW (governor speed control failure), and the periodic outage maintenance conducted with the assistance of the EDG manufacturer's personnel to assure that capability is not degraded.

The team noted that the present T.S surveillance tests do not envelope the maximum loading conditions and the critical parameters are not recorded for trending. Also, the power factor rating of the diesel generators is not considered for the surveillance tests.
The team considered the following issues as unresolved pending completion of the following licensee actions: (Unresolved Item number 50-213/ 91-80-02)

a. Firmly establish the maximum EDG loading.
b. Confirm the EDG 30 minute qualification rating and update the licensing documents.
c. Evaluate the adequacy of the existing TS surveillance requirements considering the above items and the adequacy of existing testing at unity power factor (KVAR loading requirements).

2.4.2 <u>EDG Generator Excitation and Control Power</u>

The EDG generator field excitation current is proportional to both generator load and power factor. The team confirmed from manufacturer's data and by calculations the exciter's capability to support the large low power factor accident loads. Since the generator field excitation current can exceed 100 amperes, the team also confirmed by inspection that the 100 ampere field circuit breaker had been replaced with a 125 ampere breaker during the 1990 outage. The team concluded that the EDG generator excitation system was adequate to support the required EDG performance

The team observed that the design of the 125 volt dc control power system for the EDG requires the power to pump fuel from the underskid EDG day tank, open the air start solenoids to start the engine, flash the generator field, power the electronic portion of the Woodward governor, and to close the EDG output circuit breaker. Neither the design nor the procedures provide for starting and operating the EDG unit when 125 Vdc control power is not available. However, the design is such that loss of dc control power will not cause an operating EDG to shut down. Speed control is maintained by the mechanical back up portion of the Woodward governor. Generator voltage control/regulation is not dependent upon the dc control power.

2.4.3 Load Sequencing and Shedding on Class 1E Bus

The team reviewed the EDG load shedding and load sequencing on Class 1E buses by a selective review of the shedding and sequencing system designs, by a review of periodic calibrations, a review of periodic surveillance tests, and by a review of licensee analysis of the maximum errors in the system. No deficiencies were observed in these areas. A detailed review of the maximum projected errors in the system revealed only one area for potential sequencing overlap. This overlap was in the initial small connected motor control center loads and the starting of the HPSI pump. The 0.5 second maximum time overlap was satisfactorily demonstrated by licensee analyses to produce no adverse affects either on the EDG loading or in the safety systems capability. The team considered the load sequencing system adequate to perform its safety functions.

Conclusion

The team concluded that inadequacies in the licensee's technical review of emergency operating procedures led to an unreviewed/unanalyzed safety concern in the EDG units capability to power the emergency loads as required by these procedures. This deficiency was licensee identified, reported, and corrective actions are being implemented. This was classified as a non cited violation. An unresolved item was identified which requires further licensee actions including EDG loading,qualification testing, establishing adequate surveillance testing to envelop the worst case loading and revising the TS and procedures as required to reflect the changes.

2.5 AC System Short Circuit Study

The team noted that the results of the short circuit study were available as an attachment to coordination studies PA82-050-43GE and PA82-050-65?GE. The licensee explained that full analysis will be completed together with the load flow study (see Section 2.6). This will enable both analysis to utilize a common data base describing the components of EDS.

The team noted that there was no formal comparison of the results vs. rating of the equipment. The initial review of the available information by the team indicated that the cases of the maximum bus loading (as present during the start-up mode) and the highest system voltage were not analyzed. Subsequently, the licensee performed new analysis with the worst case and the results indicated that the fault levels increased between 6% and 20% (depending on the bus).

These new results had no impact on the protection coordination study, in that study the maximum fault level was based on an "infinite" bus on the primary side of transformers supplying a bus in question.

The momentary and interrupting ratings of the 4.16 kV and the 480 V circuit breakers on safety related buses were found to be acceptable as compared with the new fault levels.

2.6 AC System Voltage Regulation Study

The team observed that there were voltage drop calculations for some individual loads. Also, there was a set of calculations related to degraded grid voltage setpoints but there was no load flow study for the plant.

The team observed that as compared with the available logs from control room (CR), a number of calculations (e.g. PA82-050-40GE) used very conservative assumptions for bus loadings.

The team observed that the calculations did not address in detail the voltage profile on each safety related bus. The voltage drop calculations for steady state used only the full load amps, although the majority of motor drives were both rated and operated at a service factor of 1.15. Even though, for the cases reviewed by the team, the resultant difference in the steady state voltage drop was found to be within an acceptable range, the future load flow study should include the actual conditions.

The team observed that some of the transformer loading conditions were not analyzed in the dynamic mode. For example, during start-up mode, starting of the second RCP per bus caused a substantial voltage drop on the 4 kV bus such that the level 3 degraded grid voltage alarm was observed in the control room. This however, did not downgrade the performance of the EDS during this mode of operation.

The review of voltage regulation also included assessment of the overvoltage detection system. The settings for the overvoltage detection was found to be compatible with the range of operating voltage of the equipment. No overvoltage condition was observed on the 4 kV buses.

Following the recent upward change in the operating voltage of the 115 kV grid, the taps on most of the in-plant distribution transformers have been changed to retain the old settings of the degraded grid voltage detection system. The team observed that as a result of the change, the 480 V distribution system was subjected to a continuous overvoltage. As noticed during walkdowns, voltage on 480 V buses 4, 5, 6, and 7 was in excess of 485 Volts, and over 515 Volts on bus 11. The team observed that the overvoltage alarms in the control room were annunciated. These voltages were much higher than those dictated by the fact that majority of the motors were rated only 440 Volts ± 10%. The licensee reviewed this and concluded that there was no immediate impact on the performance and/or life of the safety related loads.

The licensee indicated that they were in the process of reviewing a computerized load flow study program. When accepted , the program would be used to conduct the complete study to verify not only the voltage profiles in the system during steady state but also during transients. The program would also permit the refining of degraded grid voltage setpoints. The licensee is committed to perform this study by January 1993.

The team also reviewed calculations PA80-200-25-GE, PA89-LOE-00574-GE and PA83-117-0493-GE to determine the adequacy of voltage at the component level. The most critical voltage drop calculations are related to motor operated valve feeders and have the objective of ensuring adequate torque capacity to operate safety related valves. The NUSCO procedure for performance of these calculations has not been formalized. For example, MOV voltage drop calculation PA86-006-0574-GE has the objective of determining the minimum voltage at the MOV motor terminals to ensure that the motor operator can produce sufficient torque. The calculation does not identify the torque capacity and line current at the delivered terminal voltage of 391 Vac. These values were extracted from motor performance curves corresponding to a terminal voltage of 460 Vac and incorrectly used as constants applicable to the lower terminal voltage level. In response to the above , the licensee provided a corrected provisional calculation which demonstrated adequate terminal voltage and torque relationship. The licensee stated that the voltage drop study for all MOVs will be reviewed further to address the NRC Generic Letter 89-10 and action is being taken to establish an MOV voltage drop calculation procedure. This response was considered satisfactory. The team had no further questions regarding this issue.

2.7 AC System Protection and Coordination

The team reviewed calculations PA82-050-0659GE and PA82-050-0043GE to verify adequate selection and settings of protective devices for 4160 Vac and 480 Vac systems. Calculations for bus supply overcurrent protection with motor feeder surge coordination for the 4160 Vac system did not consider the initial bus load currents. The plant does not have a formal load flow study for the medium voltage system, however, standard practice would have included bus load analyses to account for initial loading conditions. The licensee responded to this by performing a supplementary calculation which included initial loading considerations

All motor starting characteristics shown in the calculations are assumed or calculated rather than based on as-built operation experience or test records. In response to this, the licensee presented operational instrument traces which showed that the assumed motor starting characteristics are conservative.

The team noted that the reactor coolant pump (RCP) starting characteristics were incorrectly factored into the coordination for station service buses 1-1A and 1-1B. The RCP's are always started from preferred busses 1-2 and 1-3. The licensee performed a supplementary calculation with corrections which showed that satisfactory coordination does exist. The licensee has also committed to regenerate system calculations by use of a computer based systems analysis program by January 1993.

The team noted that initial bus load current values used for the 480 Vac system were assumed rather than calculated or measured under as-built operating conditions. In response to this, the licensee provided instrument reading records that showed the actual maximum loading of the sampled buses are well within feeder capacities.

The team observed that due to a faster response of the level 1 degraded grid voltage relay than the overcurrent protection of the bus feeder (8T2 or 9T3), it was possible to start an EDG and connect it to a faulted bus. This is further discussed in detail in section 5.6

In summary, the licensee responses to the questions raised by the team showed that AC system coordination is adequate except for the miscoordination of buses 8 and 9 overcurrent vs undervoltage protection relays during a bolted bus fault.

2.8 Electrical Penetration Sizing and Protection

The team reviewed calculations PA82-050-0659GE and PA82-0043GE to evaluate the adequacy of containment electrical penetrations. The containment electrical penetrations were replaced during the 1980 plant outage as an upgrade conforming to the penetration qualification requirements of IEEE Std. 317-1976. The coordination of penetration protection was shown in the two calculations listed above. The team noted that only medium voltage feeder penetrations are for the RCP's. These are shown to be adequately protected by primary (feeder) and backup (bus supply) protective devices. The 480 Vac feeder penetrations for the containment air recirculation (CAR) fans 3 and 4 are also shown to have adequate primary and back up protection. However, CAR fans 1 and 2 have adequate primary protection but no back up protection. The team noted that secondary protection provided by the bus supply breaker is not effective in the lower overcurrent range (less than 3000 amperes). The protective device performance was deemed as an existing condition not covered by current criteria. However, penetration thermal withstand capability could be exceeded under existing backup protective conditions. Following the inspection, the licensee provided the information to the team which indicated previous review by the NRC. The team observed that the electrical penetrations of reactor containment were reviewed by the NRC as SEP Topic VIII-4. The review indicated that a single circuit breaker to protect a penetration serving a (Class 1E circuit or non-safety) circuit containing only components that are qualified to Class 1E requirements is acceptable provided that each component of such circuit is qualified to the accident environment. The team agreed that the CAR fan primary breaker protection and EQ requirements meet this criteria.

2.9 <u>120 Vac Class 1E System</u>

Division A for the 120 Vac system consists of two inverters, A and B, each supplying a 120 Vac distribution panel. Each inverter is capable of supplying the entire division load through a manual bus transfer arrangement. These inverters are powered by 125 Vdc battery bus A. Division B consists of two new inverter/static switch combinations designated C and D and supplied from 125 Vdc battery bus B. Each inverter is capable of supplying the entire train load through a manual bus transfer arrangement. Additionally, each static switch can automatically transfer the vital load to a constant voltage transformer in the event of inverter source failure. These transformers are energized from 480 Vac, MCC 12. The inverters and constant voltage transformers limit short circuit currents to less than 200 percent of rated load capacity.

To asses the adequacy of 120 Vac system, the team reviewed calculations PA80-208-229 GE,PA83-117-00976GE, PA83-113-00984GE, and calculation (no number assigned) for low voltage system coordination studies. The team noted that division B of the Class 1E 120 Vac vital and semivital system was recently modified by PDCR 903. The load analysis performed by calculation PA80-208-229 GE was found in agreement with instrument measurements of inverter loading performed by work orders. The team noted that a quality controlled and approved protective coordination calculation for this system does not exist. The coordination study listed above was performed to satisfy Appendix R requirements . However, the team noted that there were no discernible technical inadequacies. The licensee committed to perform a quality controlled calculation by January 1993.

2.10 <u>125 Vdc Class 1E System</u>

The 125 Vdc system was reviewed to verify its capability to support a safe plant shutdown. The team's review included: battery sizing, voltage drop and overvoltage control, short circuit protection, and coordination.

The 125 Vdc system consists of two Class 1E battery Divisions A and B, each normally supplied by a separate battery charger, and a third non-class 1E battery, battery charger, and switchboard designated as Bus C.

This system was recently modified by PDCR's 903 and 995. The purpose of the changes included in PDCR 903 was to satisfy the requirements of 10 CFR 50, Appendix R. That is, to maintain sufficient separation of redundant systems such that a single fire will not prevent safe shutdown of the plant. To achieve this, Division B has a new battery and 125 Vdc switchgear located in a new switchgear room. In addition, non-class 1E system loads were reassigned to non-safety related Bus C which remained in the old switchgear room. PDCR 995 replaced Division A circuit breakers with new Westinghouse molded case circuit breakers types "JD" and "FD" as a maintenance upgrade. The old Westinghouse breakers were out of calibration and there were no direct replacements available.

2.10.1 DC System Voltage Drop and Overvoltage Control

Calculations PA91-LOE-1171GE and 18961-E-13 were reviewed to evaluate these areas. Evaluation of voltage drop at the terminals of safety related equipment is needed to verify Class 1E circuit capability to start and operate assigned loads. Calculation PA91-LOE-1171GE evaluated the most limiting component voltage drops and established battery discharge limits to ensure proper component operation. The team noted that the overvoltage conditions possible during battery equalizing are prevented by administrative procedures.

2.10.2 125 Vdc Class 1E System Short Circuit and Coordination

Calculation PA80-241-0106GE was reviewed to determine the adequacy of this area. The team noted that the battery short circuit contribution level estimated in the above calculation was based on IEEE 946 criteria which is less conservative than the reported manufacturer tested level at an initial electrolyte temperature of 77°F. However, the final results of the calculation were given for a temperature of 104°F corresponding to maximum design ambient air temperature instead of maximum expected initial electrolyte temperature. During the inspection, the licensee recalculated battery short circuit contributions in consideration of battery manufacturer test data and using 95°F as worst case electrolyte temperature based on maintenance records. The same calculation states that the battery charger short circuit contribution is limited to 125 percent of rated full load current. Considering that the battery charger control elements are Silicone Controlled Rectifiers, such current limiting control would not be effective until the first zero crossing of the AC supply current waveform is reached. This may take more than half a cycle (8 ms.) depending on the AC supply circuit time constant (X/R ratio). This is of concern because small frame molded-case feeder circuit breakers will attempt to interrupt bolted fault currents in less than 9 milliseconds. Thus, the higher initial battery charger short circuit contribution, combined with the battery contribution, could exceed the molded case circuit breaker interrupting duty ratings.

The licensee initiated a manufacturer inquiry on battery charger short circuit performance. Preliminary response from one manufacturer (Elgar) estimated an initial contribution of 500 percent of rated load current. The licensee committed to correct the calculation by use of definitive battery charger short circuit capability following the expected manufacturer response to the above inquiry by January 1992.

The team noted that the licensee's recalculation of the short circuit level by use of the above considerations resulted in a fault level exceeding 10,000 amperes at the load side of small frame molded case circuit breakers, thus exceeding their UL certified interrupting duty ratings.

Manufacturer catalog information on circuit breakers types GE THED indicates an interrupting rating of 20,000 amperes which is not UL listed. Bus A switchboard was fitted with Westinghouse JD and FD breakers by PDCR 995 as discussed above. The manufacturer provided a statement relating anticipated interrupting duty to similar breakers types HFD and HJD which were tested at 22,000 amperes interrupting duty. Follow-up discussion with the manufacturer indicated that the contact assemblies and arc chutes of the two breaker types (JD/HJD) are substantially the same and should perform identically. The licensee submitted this as evidence that the breakers can handle the anticipated interrupting duties.

The team observed that the same calculation does not consider the most limiting conditions affecting the adequacy of coordination between load feeder circuit breakers and the bus supply breakers. For example, a bolted fault at the load terminals of the 100 ampere feeder breaker (Ckt. IV1D) for inverter C will also cause instantaneous tripping of battery breaker 72BT1B supplying Bus B.

An explanation was given by the licensee for acceptability of coordination under worst case fault predicated on Appendix R considerations and personnel safety advantages. This explanation does not address the Class 1E system design basis which is intended to preclude bus failures as a result of cascading events by having satisfactory coordination between bus supply and feeder breakers. The licensee also stated that the design and installation features of the 125 Vdc Class 1E system and precautionary maintenance procedures greatly reduce the probability of a bolted fault and no common mode failure mechanism exists due to this condition.

In summary, the subject calculation needs to be corrected and expanded to cover the issues related to accurate estimation of short circuit duties and satisfactory coordination of feeder and bus supply circuit breakers. The licensee is committed to resolve this issue by January 1992.

2.10.3 Class 1E Battery and Charger Sizing

Calculations PA91-LOE-1171GE, PA82-076-31-GE, PA91-LOE-1173GE and PA80-208-229 GE were reviewed to assess this area. The battery sizing calculation PA91-LOE-1171GE was performed in accordance with IEEE Std. 485-1985. DC system load data used in the calculation was based on actual instrument readings taken in the plant by authorized work orders and by component load estimates. The instrument readings taken for inverters C and D compared favorably with the load estimates of calculation PA80-208-229-GE on inverter loading. Calculation PA82-076-31-GE was performed in accordance with IEEE Std. 946-1985 to verify the adequate size of battery chargers. The team concluded that the battery and battery charger have adequate capacities and they are adequately sized.

2.11 Conclusions

Based on the team's review of the EDS design, the team identified no operability problems, and concluded that generally the Haddam Neck electrical distribution system is capable of performing its intended safety function. However, the team identified some areas of concern which needed further evaluation by the licensee. Specifically, there appears to be a lack of adequate control of the Emergency Diesel Generator (EDG) loading and surveillance testing program to envelop worst case design basis accident loads, lack of adequate licensing documents indicating EDG short term ratings and resulting in this information not being reflected in Emergency Operating Procedures (EOP) nor given to control room operators. Further, several examples indicate that a more thorough technical review and attention to detail would assure that applicable regulatory requirements are met and comprehensive design outputs are generated. Also, there is a potential for overloading of the EDG with the existing protective relay settings, and a lack of adequate coordination of supply breakers and feeder breakers for the 125 Vdc system for a worst case fault.

With the exception of specific findings, observations and unresolved issues identified in the report, the EDS components were adequately sized and configured. However, margins for the EDGs loading under worst case design bases requirements were found to be minimal and are a concern to the NRC. In addition, the team observed that: 1) there was no load list available for all of the "global" calculations, such as EDG loading/sizing, fault analysis, and degraded grid voltage setpoints; 2) some of the operating conditions (such as start-up bus configuration) had not been included in the protection coordination, voltage drop, and fault analysis; 3) as a consequence of not having performed load flow studies, some buses were exposed to continuous overvoltage; and 4) the electrical distribution system identification for divisions A and B buses and loads for all voltage levels was not consistent.

3.0 MECHANICAL SYSTEMS

To determine the functional ability of mechanical systems to support the EDGs during postulated design basis accidents, the team reviewed sample documentation and conducted a walkdown of the fuel oil storage and transfer, lubricating oil, starting air, and diesel heating and cooling equipment. The team reviewed equipment associated with the heating, ventilation and air conditioning (HVAC) of the diesel generator building, service water screenhouse, switchgear buildings, battery rooms, control room, and selected EDG and HVAC design modifications. The team also reviewed the power demands for major loads (selected pumps) for input into design basis calculations and environmental qualification of certain major loads.

3.1 Power Demands for Major Loads

The team reviewed the power demands for the major pump motors powered by the EDGs following a loss of offsite power during LOCA conditions. The team noted that the diesel loads for the LPSI and HPSI pumps were based on amperage data taken during the May 22, 1990 LPSI/HPSI full flow test and not on the manufacturer's pump curves. The licensee also did not allow for instrument error in BHP calculations.

The team noted that the peak LPSI pump loading occurs at runout condition and peak HPSI pump loading occurs prior to runout. The LPSI pump BHP based on the manufacturer's pump curve for the flow of 6000 gpm near runout condition was 1139 and the motor power demand was 900 kW. The EDG automatic loading calculation PA78-741-01-GE Revision 3, dated 1-20-91, Attachment 3 assumed the LPSI pump BHP as 1107 and the motor power demand 874 kW. The HPSI pump BHP based on the manufacturer's pump curve was 1425 and the motor power demand was 1115 kW. The EDG loading calculation assumed 1423 BHP for the HPSI pump and 1114 kW for the motor power demand. Based on the teams's findings, the licensee agreed to revise the EDG automatic loading calculations to correct these loads.

The licensee further determined that 33 seconds after the LOCA, the HPSI pump would attain full speed and, with the reactor coolant system (RCS) depressurized, would be near runout flow. Calculation 90-102-763GM, Revision 0, dated February 14, 1991, was performed to provide a best estimate HPSI pump flow during steady state. The licensee calculated the corresponding HPSI pump power demand to be 1093 kW. The licensee will revise the EDG steady state loading calculation to reflect this HPSI load.

The team noted that, according to UFSAR, Page 6.3-4, the developed head of 500 ft at the maximum flow of approximately 2750 gpm was not consistent with the manufacturer's pump curve. The licensee reviewed the pump curve as well as the test results from the May 22, 1990, HPSI pump full flow test and determined that the correct pump head should be 1125 ft. The licensee is committed to correct this in next UFSAR update.

In summary, as a result of the team's finding, the EDG automatic and steady state loads will be increased by about 27 kW and 5 kW, respectively, from the existing loading calculations. The team noted that at the end of the inspection, the manual loading calculation PA-90-LOE-1167-GE was updated to reflect the increased loads.

3.2 Environmental Qualification of Certain Pump and Fan Motors

During the inspection, the team noticed that the HPSI pump motors and the Containment Air Recirculation (CAR) fan motors are required to operate at higher than the rated horse power. The team reviewed the environmental qualification (EQ) files of these motors to ascertain whether they are qualified for the additional load. The results are as follows:

3.2.1 Qualification of HPSI Pump Motors

The HPSI pump motors are required to operate at 114% of the rated horsepower based on the power demands following a LOCA condition. The test report in the CY EQ file indicated that these motors were tested at 100% of the rated horsepower. At the time of this inspection, there was no engineering analysis in the EQ file to demonstrate that the motors were qualified to 114% of the rated horsepower. This constitutes a violation of 10CFR 50.49, paragraphs f and g, which require that electric equipment important to safety be qualified by type-test, analysis or a combination of both, and that the qualification be established before November 30, 1985 (50-213/91-80-04).

Before the conclusion of this inspection, the licensee was able to generate an analysis showing that the HPSI motors can be qualified to 114% of the rated horsepower because of the relatively low temperature (140°F) and non-steam environment.

3.2.2 Qualification of CAR Fan Motors

The CAR fan motors at Haddam Neck are required to operate at 106% of the rated horsepower based on the power demands following a LOCA condition. The test report in the CY EQ file indicated that the CAR fan motor was tested at a load sufficient to envelope the Haddam Neck operation requirement. However, the team identified some deficiencies in qualifying the post-accident operating time of the CAR fan motors as follows.

The SCEW sheet in the CY EQ file of the CAR fan motors indicated that the CAR fans are required to operate 180 days following a postulated LOCA. Westinghouse test report WCAP 7829 showed that the CAR fan motors were tested to a total post LOCA operating time of approximately 180 hours. The licensee used the Arrhenius Equation to extrapolate the post-accident operating time. This extrapolation included the peak containment temperature portion of the temperature-vs-time profile. At the time of the inspection, the licensee could not provide sufficient evidence to show that the Arrhenius Equation can be conservatively applied to the containment accident environment which consists of chemical spray and high pressure steam. During the inspection, the licensee was able to refine their calculations to exclude the peak containment temperature portion of the temperature-vs.-time profile. The results of these calculations indicate that, for the post-accident operating time, the fan motors can be qualified.

Following the inspection on February 26, 1991, the licensee transmitted to the team their justification for applying the Arrhenius Equation to the peak containment portion of the temperature vs time profile, especially for the case of the CAR fan motors. The team agreed that the qualification of the CAR fan motors was established.

3.3 Diesel Generator and Auxiliary Systems

3.3.1 Fuel Oil Storage and Transfer System

According to procedure SUR 5.1-10, the above ground fuel oil tank has a minimum level of 10.5 ft. However, to provide 7 days of fuel for the EDG in accordance with R.G. 1.137, a minimum level of 13 ft is required. The licensee stated that Connecticut Yankee is not committed to a 7 day fuel oil supply requirement. The licensee further indicated that it is uneconomical to deliver fuel oil until tank level drops to 10.5 ft or 11 ft because the vendor charges for a full truck of 7000 gallons. The team noted that the licensee meets the TS requirements for fuel oil storage. During the walkdown, the team noted that the vent piping and flame arresters for fuel oil storage and day tanks were located outside the EDG building. There was no analysis to assess the effect of tornado wind and missile impacting of the vent lines. The licensee agreed to address this by considering the diesel fuel oil vent piping in the final analysis of tornado winds and missiles at the Haddam Neck Plant as part of the Integrated Safety Assessment Program (ISAP). The team had no further questions regarding this issue.

3.3.2 Air Start System

According to UFSAR, Section 8, page 8.3-20, the air compressor starts when pressure in the air receivers drops to approximately 175 psig. However, procedure PMP 9.2-101, "EG2A Instrument Calibrations", Table 6.12-10, states that this pressure is 190 psig. The licensee stated that the UFSAR would be revised to indicate that the air compressors would start at approximately 190 psig.

The team noted that, according to procedure PMP 9.2-101, Revision 4, Table 6.12-8 and Table 6.12-9, the required setpoint for the EDG low starting air pressure alarm is 165 psig. However, no test was conducted to determine whether the EDG would be capable of starting and ready to accept its loads within 10 seconds with 165 psig starting air pressure available. The licensee agreed to verify the adequacy of the low pressure alarm setpoint by conducting a test during the next outage or providing adequate justification for the EDG's ability to start at air bank low pressure limit by January 1992. This item is unresolved. (50-213/91-80-05)

The team also noted that the P&ID for Air Start System D-26020 sheet 2, "Diesel Generator Starting Air System A" did not show the as-built condition of a snubber upstream of valve DA-V-41A. The licensee has assigned drawing change request DCR-S-157-91 to revise this drawing.

3.3.3 EDG Cooling

The team reviewed the EDG trending data from May 22 to December 27, 1990. The EDG trending program is utilized to measure engine jacket water temperature (in and out), engine oil cooler outlet temperature, engine oil crankcase outlet temperature, service water supply temperature, EDG heat exchanger (inlet and outlet) service water pressures and are used to verify the EDG cooling function. The team noted that these parameters must be maintained within a normal range as defined in procedure SUR 5.1-17B. However, if a measurement is obtained which is outside the specified range, an engineering investigation would be initiated. The team did not find any unacceptable conditions.

3.3.4 Diesel Generator Governor

Since the EDG power output can be limited either by the Woodward governor power limit adjustments or by governor linkage adjustments, the team confirmed by a review of licensee governor calibration/adjustment procedures, surveillance procedures and by inspections that the licensee has not imposed undue limitations on the power output.

3.3.5 EDG Turbocharger

According to the EDG manufacturer, the EDG turbocharger does not become fully operational until approximately 3 minutes after loading is initiated. Therefore, the team confirmed that the accident loads were within the non/partial turbocharged engine's capability during this time period from information provided by the EDG manufacturer.

3.4 Heating, Ventilation and Air Conditioning Systems

3.4.1 EDG Building and Service Water Screenhouse

Two diesel room steam heaters were replaced with electric heaters in 1979 in accordance with plant design change request (PDCR) 328. The licensee's plant change review indicated that the heater supports were not seismically qualified. The team noted that the heater size was small and the licensee's analysis indicated that it would not damage the diesel or the diesel controls if the supports failed.

During the inspection, the team noted that there was no calculation performed by the licensee to demonstrate that the EDG performance would not be affected if the room heaters were failed during winter. The licensee prepared calculation No. 90-102-106-GF, Revision 0, dated February 12, 1991, which showed that with a loss of heaters in both EDG rooms during winter the room temperature would fall to approximately 47°F. The licensee determined that with this temperature, neither the performance of EDG nor other safety related equipment contained in the building would be degraded. The licensee further stated that according to their discussion with the EDG manufacturer, the most limiting concern with the low ambient temperature is the maintenance of 85°F for the lube oil. An immersion

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heater in the jacket water system maintains the lube oil temperature in the 125°F to 155°F range. In addition, the licensee stated that the operator verifies the EDG room conditions every 8 hour shift. If the lube oil temperature falls below 115°F, an alarm is annunciated in the EDG cubical.

The team noted that there were no calculations to determine cooling ventilation requirements for the EDG, instrumentation and control panels in the EDG building. The team also reviewed screenhouse ventilation calculation CY-SW-M-0122, dated December 18, 1963, and determined that the calculation did not reflect the present loads. The licensee agreed to perform new calculation for EDG room and revise the existing calculation for screenhouse ventilation by January 15, 1992. This item is unresolved (50-213/91-80-03).

3.4.2 Switchgear and Battery Rooms

The team noted that there was no heater in the "A" battery room to maintain its temperature. The licensee stated that the operator verifies the temperature every 8 hour shift in accordance with procedure SUR 5.1-0. If the temperature falls below 60°F, appropriate action would be taken to maintain the room temperature. The team had no further question at this time.

3.4.3 Control Room

The team reviewed calculation 80-241-511GM, dated August 26, 1986, which showed that following a fire resulting in the loss of control room and computer room ventilation, the temperature would be 102°F. The licensee provided a copy of Appendix R final report on the control room ventilation system which stated that this temperature would not pose a threat to either personnel or equipment required for safe shutdown. Furthermore, the remote control panels in the EDG building permit the isolation of the control room circuits and restore control of safe shutdown loads.

In summary, there was no concern regarding the operability of the HVAC systems. However, the licensee must complete the calculations to determine the cooling ventilation requirements for the EDG rooms and update screenhouse ventilation calculations factoring the existing loads.

3.5 Service Water System

The service water system supplies cooling water to the EDG heat exchangers and other plant loads. The system has four, two stage, vertical centrifugal pumps. Each pump has a capacity of 6000 gpm at 150 ft head. The normal flow requirement is provided by three pumps. The fourth pump is on standby.

A safety system functional inspection (SSFI) was performed on the service water system by the licensee and the final report issued in June 1990. The SSFI team identified a number of observations. The licensee indicated that all of the observations related to the safety of the service water system have been resolved. The service water system seismic analysis is being reevaluated as part of the SEP and unresolved safety issue A-46.

The service water system experienced waterhammer and consequent pump discharge strainer cover failure in the past due to the slamming of check valve disc on its seat by reverse flow following pump stoppage. To minimize waterhammer, the licensee replaced these check valve with double disc fast closing check valves. The licensee stated that during installation testing by tripping a pump, the new check valve produce no discernable noise or vibration. Therefore, the check valve waterhammer appears to be eliminated.

There was no analysis performed to address a possible water column separation due to pump stop and resulting waterhammer loads when the pump starts. The licensee indicated that they would be reviewing the potential for waterhammer as part of the effort required for completing Item 4 of NRC Generic Letter 89-13 by the end of the next refueling outage.

The team reviewed isometric drawings 16103-20231-SH-164C and -164D and noted that the note "not field verified" did not clearly identify the concrete encased piping whose dimensions cannot be field verified. The licensee will be revising the drawings to clearly indicate which dimensions cannot be verified and the reason.

In summary, the licensee's service water system design review must address all the possible design inadequacies to assure its intended function. However, the team had no concerns regarding the operability of this equipment.

3.6 Conclusions

The team concluded that the appropriate technical staff was knowledgeable of the mechanical systems affecting the EDG. Sufficient information was available to review and assess the operability of these mechanical systems. As a result, the team considered this a strength in regard to engineering and technical support.

A number of issues were identified in the mechanical area with regard to inadequate design and calculation reviews which indicated the need for establishing a thorough design review of EDG and associated equipment. However, the team had no concerns regarding the operability of this equipment.

4.0 EDS EQUIPMENT

The scope of this inspection element was to assess the effectiveness of the controls established to ensure that the design bases for the electrical system is maintained. This effort was accomplished thorough the verification of the as-built configuration of electrical equipment as specified in electrical single-line diagrams, modifications packages, and site procedures. In addition, the maintenance and test programs developed for electrical system components were also reviewed to determine the technical adequacy.

4.1 Equipment Walkdowns

The team inspected various areas of the plant to verify the as-built configuration of the installed equipment. Areas inspected included the diesel generator, switchgear, battery, and electrical panel rooms. Transformer, protective relay and pump motor nameplate data were also recorded. This information was collected to verify the completeness and accuracy of system calculations. The collected information was also compared to applicable design drawings. The inspected equipment was found to be installed in accordance with design drawings with two exceptions:

* Drawing 16103-3004, Sh. 3, (MCC-5) position 2FFL (AC Distribution Cabinet) indicated a 30 A circuit breaker while a 100 A was actually installed. The installed 100 A breaker was determined to be correct. The licensee indicated that the drawing would be revised to reflect the as-built configuration.

* Drawing 83117-31093, Sh. 7A, indicated three (3) 200-5 current transformers (CTs) while other protective device controlled documents (ACP 1.0-52) stated that the CTs are 300-5. Tests performed confirmed that 300-5 CTs were installed. The licensee indicated that the drawing would be revised.

The team also verified the installed fuse sizes and types in several control circuits. The installed fuses were the same as that specified in wiring diagrams. However, the team could not verify that the correct type was installed since the licensee does not have this data available. The correct type is desired since it establishes the operating time-current characteristics for the fuse. The licensee indicated that whenever blown fuses are identified, replacement is on a like-for-like basis. If one is not available, engineering is contacted to provide guidance for acceptable replacements. The team did not identify any non conforming condition during the review.

In summary, walkdown inspections indicated that adequate measures are in place to effectively control system configuration. Equipment inspected was found to be well kept with surrounding areas clear of safety hazards.

4.2 Equipment Maintenance and Testing

The team reviewed various maintenance and testing procedures for such equipment as the diesel generator, switchgear, circuit breakers, batteries and battery chargers, inverters, and protective relays. Licensee personnel were interviewed to ascertain their understanding of the testing programs. The team also reviewed the controls to establish instrument setpoints during the calibration and testing process. Team observations are described below.

4.2.1 Diesel Generator Testing

The team reviewed licensee periodic surveillance/test loadings of the EDG units. The tests are performed in accordance with approved procedures which demonstrate the 2700 to 2800 KW capability required by the technical specifications. Outage surveillance/tests demonstrate the capability to automatically sequence and manually apply accident loads. No discrepancies were observed in either the licensee's compliance with the procedures or in meeting technical specification requirements. However, an observation was made that the monthly surveillance/test procedure mandated that the load tests be conducted at 1.0 (unity) power factor.

Several recently completed routine, monthly and outage surveillance/test/maintenance procedures for the EDG units were reviewed to assess their adequacy in addressing the requirements needed to demonstrate/assure EDG system capabilities to perform. In addition to review, a team member witnessed the performance of and walked down a portion of SUR 5.1-17B during the routine monthly surveillance/operation/testing of the "B" EDG unit on February 7, 1990.

There were no adverse findings in either the EDG test procedures review or in the witness/walkdown of the operational surveillance test of the "B" EDG. However, the team noted that the existing surveillance tests do not envelop the worst case loading of the EDGs and power factor rating of the machine. This was discussed in Section 2.4.1

4.2.2 Class 1E Batteries

The Haddam Neck Technical Specification (TS) Surveillance Requirement 4.8.2.1 requires that both 125 Vdc batteries be subjected to service and performance discharge tests. The service test is performed to verify that the capacity is adequate to supply all of the actual or simulated emergency loads for the design duty cycle. The performance discharge test is used to detect signs of degradation. Additional maintenance monitoring requirements are specified in the TS.

The team reviewed the surveillance procedures as shown in attachment 2 to ascertain whether they incorporated the TS requirements and to determine the technical adequacy. Review of the service and performance test procedures along with battery sizing calculations, UFSAR, SEP evaluations and applicable TS sections revealed several discrepancies in the load duty cycle, service test time duration, and battery terminal final voltage acceptance criteria. These discrepancies are enumerated below.

(1) The Haddam Neck UFSAR Table 8.3-2, "Battery Duty Cycle," tabulates the A and B battery load duty cycles. It furth specifies the duty cycle time duration as 2 and 3 hours for batteries A and B, respectively. (The 3 hour duration differs from Item 2 and 3 below.)

(2) The Haddam Neck Systematic Evaluation Program (SEP) Topic VIII-3.A evaluation stated the NRC recommendation that the licensee modify the TS to include a service test to verify that the batteries are capable of maintaining emergency loads for 2 hours. The licensee incorporated this recommendation upon conversion to the present Standard Technical Specifications by requiring an 18 month service test.

(3) NUSCO Calculation #PA91-LOE-1171-GE, "Connecticut Yankee Existing Batteries 1A, 1B, and 1C Adequacy Determination," Rev. 0 determined the adequacy of the existing batteries by utilizing the minimum allowable battery voltage from the worst case of voltage drop to the connected dc loads. The calculation established battery load duty cycles of 2 hours for each battery. The calculation also documented that a minimum voltage of 105 Vdc is required at solenoid-operated 4160 V circuit breaker. The following minimum voltages are required at the battery terminal:

Battery A	108 Vdc
Battery B	111 Vdc

These values contradict the acceptance criteria of 105 Vdc specified in item (4) below.

(4) Review of the service test surveillance procedure (SUR 5.5-38) indicated that the licensee was performing a service test for each A and B battery for a time duration of 3 hours. (The 3 hour duration differs from items 2 and 3 above). The acceptance criteria specified in the procedure was that the battery terminal voltage should not drop below 105 Vdc after the 3 hour test instead of the required minimum battery terminal voltage (108 Vdc and 111 Vdc for A and B batteries, respectively, as shown on NUSCO Calculation PA91-LOE-1171-GE).

The team evaluated the above discrepancies and concluded that the service test presently performed did not adequately demonstrate the capability of the battery to carry design loads as required. The licensee concurred that the battery service test should be performed for a two hour duty cycle as documented in the SEP evaluation. The team determined that the service test did not incorporate the appropriate battery final voltage acceptance criteria in that the batteries A and B require 108 Vdc and 111 Vdc, respectively, at the terminals instead of 105 Vdc to adequately power all design loads. Failure to incorporate the required minimum acceptable voltage into the service test procedures to verify that all loads can be powered is a violation of Technical Specification, Section 6.8.1 (50-213/91-80-06).

Subsequent evaluation by the licensee indicated that the battery had sufficient capacity to power required safety loads.

Other Electrical Equipment

The team reviewed test procedures for other Class 1E electrical equipment. This review included battery chargers, circuit breakers, inverters, and alarm relays. The procedures reviewed were determined to be technically adequate with applicable acceptance criteria.

The team noted that the licensee performs periodic preventive maintenance testing of electrical equipment. This includes hi-potential testing of all 4.16 kV pump motors every refueling outage. The results are reviewed to detect signs of degradation. Doble tests and gas and oil analysis are also performed on the Class 1E 4160/480 V transformers. The licensee also inspects the EDG generator every refueling outage and megger tests the EDG power cable feed to the switchgear. The team concluded that the preventive maintenance tests performed on the safety related electrical equipment was a strength in that predictive maintenance activities contribute to identifying signs of equipment degradation.

In summary, the team identified an inadequate test procedure for the Class 1E 'A' battery service tests. The maintenance and test procedures for other electrical equipment such as motor control centers, circuit breakers and battery chargers were found to be acceptable and technically adequate. Test and calibration records for selected devices indicated that they were operating within the applicable acceptance range. The preventive maintenance program for electrical equipment was noted to be a strength.

4.3 Protective Device Setpoint Control and Calibration

The team reviewed the licensee's program for controlling protective device setpoints. In addition, instrument calibration procedures and records were also reviewed to determine whether the contents of procedures and test results were acceptable. The control of instrument setpoints provides assurance that equipment will operate at predetermined levels.

4.3.1 Setpoint Control

The licensee maintains a Master Setpoint List (MSL) to maintain station setpoint data. An individual setpoint is assigned a Setpoint Quality Classification (SQC) to identify its relative importance as well as the level of review required for changes to associated setpoint data. Instrument setpoints maintained in the MSL include pressure switches and circuit breaker overcurrent settings. Instrument setpoints are also controlled via procedure ACP 1.0-52, "Connecticut Yankee Relay Calibration Program". The procedure specifies schedules for the instrument calibration of protective relays utilized in electrical protection schemes at CY and provides a vehicle to control the associated setpoints. Changes to setpoints in either of the above databases are accomplished and controlled in accordance with procedure ACP 1.2-3.3, "Setpoint Change Request".

The licensee has developed specification SP-EE-299, "Control of Nuclear Plant EC&I Design Basis," to define the requirements for the preparation, review, approval, revision and control of the nuclear, electrical, instrumentation and control (EC&I) system design bases. It defines the process to ensure that setpoint changes are properly reviewed. This specification is expected to be incorporated into a Nuclear Engineering and Operations procedure by the end of 1991.

The team reviewed calibration procedures and results for several overcurrent and undervoltage relays. The procedures were determined to be technically adequate. Instruments which are specified in the TS which are found to be out of calibration are evaluated in accordance with procedure ACP 1.2-12.2, "Instrument Calibration Review (ICR)". Surveillance procedure results which are found to be outside the acceptance criteria are documented on ICR forms. These forms are reviewed by the Shift Supervisor and the Duty Officer to determine the reportability of the failure. Based on the instrument performance and history, corrective actions such as replacement or trending are initiated.

The Haddam Neck TS Section 3/4.3.2 Engineered Safety Feature Actuation System Instrumentation establishes the Limiting Condition For Operation (LCO) with respect to instrumentation channels including the emergency bus undervoltage (UV) protection relays. It requires that, with an interlock trip setpoint less than the allowable value, the channel must be declared inoperable and appropriate action statements must be applied. These channels must be demonstrated operable by performing channel calibrations at least once per 18 months. The 4160 V degraded grid (Levels 2 and 3) undervoltage trip setpoints as listed in TS Table 3.3-3 are:

Emergency Bus UV		Trip Setpoint	Allowable Value
a.	4.16 kV Bus UV Level 2	≥3684 volts with a 9 second time delay	≥3664 volts with an 8 to 10 second time delay
b.	4.16 kV Bus UV Level 3	≥4019 volts with a 9 second time delay	≥3999 volts with an 8 to 10 second time delay

To set the individual relay dropout setpoints, the above trip setpoints must be translated to the 120 V relay operating voltage. Review of the relay setpoints indicted that the licensee considered only the PT ratio of the transformer (4200/120) in establishing the setpoint. No consideration was given to instrument tolerances, calibration errors, or instrument drift. Therefore, the licensee set the relay dropout value at exactly the TS minimum value. The above trip setpoints and allowable values are set at the following voltage values:

	Trip Setpoint	Allowable Value
4.16 kV Bus UV Level 2	105.3 volts	104.7 volts
4.16 kV Bus UV Level 3	114.8 volts	114.3 volts

While setting the relay dropout value at the TS minimum trip value meets the TS requirement, it must also be set at a value such that there is reasonable assurance that the relay dropout setting will not drift lower than the TS allowable value prior to the next calibration period. Review of previous Bus 9 calibration records (Calibration Procedure PMP9.8.22) for the above relays indicated that there is evidence of drift in varying degrees. Two relays indicated that the as-found trip values were below the TS allowable values (these as-found values were prior to their incorporation into the Standard TS). These conditions are as follows:

	8/87 As-Left	10/89 As-Found
Level 2 (27K-1-9)	105.3 V	103.21 V
Level 3 (27R-1-9)	114.8V	112.43 V

The above as-found values are below the TS allowable values. Based on this experienced drift, the team concluded that it is possible that the relays could presently be below the TS allowable values since drift was not considered in the setting of the dropout setpoints. The licensee initiated a Reportability Evaluation Form (REF 91-03) to determine the reportability/operability of the condition since the UV relays could presently be below the TS allowable values. Failure to incorporate the instrument drift in the relay settings (to ensure that the established relay setpoints for degraded voltage protection operates within the TS allowable values throughout the calibration period) is a violation of 10 CFR 50, Appendix B, Criterion III (50-213/91-80-07).

At the conclusion of the inspection the licensee stated that upon a required plant shutdown the subject relays would be tested to determine any drift. Subsequent to the inspection, the licensee calibrated the above relays and found them outside the Technical Specification allowable value. The licensee stated that the relays and its potential transformers were replaced to correct the problem.

4.4 Conclusions

The team concluded that in two cases, the licensee failed to perform a thorough technical review of design requirements to establish acceptability. As a result, two violations were identified pertaining to inadequate testing and design control.

5.0 ENGINEERING AND TECHNICAL SUPPORT

The team assessed the capability and performance of the licensee's organization to provide engineering and technical support by examining the interfaces between the technical disciplines internal to the engineering organization and the interfaces between the engineering organization and the technical support groups responsible for the operation.

The team also reviewed the licensee's plant modification programs (including major, minor and temporary), training, QA audits, root-cause analysis and corrective action programs, self assessment programs and EDS operating procedures. In addition, the team reviewed a sample of licensee event reports (LERs), plant information reports (PIRs) and nonconformance reports (NCRs).

5.1 Organization and Key Staff

The engineering and technical support for the Haddam Neck Station are provided by the Corporate Generation Engineering group in Berlin, Connecticut, and the Station Engineering at the site. The Corporate Generation Engineering group is headed by the director, Generation Engineering and Design Department. This department handles all engineering and design activities (including plant modifications) for Haddam Neck and Millstone plants. The corporate support for the electrical distribution system area is provided by the electrical engineering group, which is headed by the system manager of Generation Electrical Engineering. The Station Engineering is responsible for providing site engineering support to plant operation, maintenance and design support, and coordination of technical function inputs.

Throughout the inspection, the corporate and site engineering personnel provided timely and thorough responses to the team members. The team observed that both the corporate and site engineering and technical support personnel were knowledgeable and very familiar with the electrical distribution system. The team concluded that the licensee has provided adequate engineering and technical support to Haddam Neck's electrical distribution system operation.

5.2 Root Cause Analysis and Corrective Action

Nonconformance reports, licensee event reports, audits and special investigative reports were reviewed to determine the effectiveness of the licensee's root cause analysis and corrective action program. The NUSCO program for completing formal root cause analyses is described in procedure ADM 1.1-177, "Root Cause Determination". Problems and discrepancies are also documented and investigated in accordance with plant procedure ACP 1.2-16.1," Plant Information Reports". Licensee event reports and nonconformance reports reviewed are listed in Attachment 2.

The NCRs reviewed by the team indicated that the corrective actions were appropriate to address the problems noted in the NCRs. The team's review of LERs found good root cause assessment of the events and corrective actions that would prevent recurrence. Corrective actions were generally broad in scope to address the root and contributing causes. The root cause investigation process is thorough and self-critical to identify weaknesses. This was found to be especially true in the root cause analysis for LER 90-11 titled, "Potential for Loss of Sump Recirculation Due to Bus Undervoltage." The licensee completed an independent root cause investigation to determine causes for the EDG problems described in LER 90-11. The team reviewed the background information and root cause analysis for the above LER. They are discussed in detail in Section 5.2.1.

5.2.1 EDG Loading and Bus Undervoltage

Reviews by plant operations and the training personnel in June 1990 noted that Emergency Operating Procedure (EOP) E-0, "Reactor Trip and Safety Injection," was not reviewed by the Generation Electrical Engineering (GEE) group. Subsequently, the GEE completed a review to evaluate the EDG loading during the conduct of E-0. This resulted in the determination that EDG loading could exceed the 2000 hour rating of 2800 kW to 2915 kW. A test of the B EDG to the 7 day rating of 2950 KW was satisfactorily completed on July 13, 1990. Licensee evaluations completed under reportability evaluation REF 90-40 determined the load deficiency was not safety significant and the diesel was determined operable.

Upon completion of the review of EOP E-0, the remaining EOPs were reviewed for impact on EDG loading. The licensee found that EOPs ES-1.3 and ES-1.4 also impacted EDG operation under worst case conditions and that the loading profile in ES-1.3 was bounding. Further engineering reviews identified that the CAR fan loads used in the worst case loading calculation were not conservative. The revised brake horsepower values for the fans increased the EDG loading, but not over the 30 minute rating. The licensee concluded this increase was not a problem since the EDG remained within its rating and testing to the maximum load levels was not required.

During an engineering evaluation of EOP ES-1.3, "Transfer to Sump Recirculation," the licensee determined on August 2, 1990, that the restarting of a high pressure safety injection pump in step 7 of the EOP could result in load shedding of a residual heat removal (RHR) pump due to a bus undervoltage condition. After completion of procedure step 3.i in the EOP, the low pressure safety injection pump would be shut down and a second service water and an RHR pump would be restarted. The EDG load at that point would be greater than 2385 kW when the HPSI pump is restarted in step 7, the load on the EDG exceeds the full load rating of 2850 kW and an unacceptable 480V bus voltage profile occurs (bus voltage less than 70% for 8 seconds). The licensee concluded that this could result in tripping of the RHR pump by the 480 V bus undervoltage protection scheme. Since the RHR pump is supplying the suction of the HPSI pump, the HPSI pump could be damaged due to inadequate net positive suction head.

Corrective actions included the immediate actions documented in LER 90-11 to preclude a trip of the RHR pump on bus undervoltage. Subsequent licensee evaluations verified that EDG manual loading as a result of EOPs E-0, ES-1.3, and ES-1.4 are within the rating of the generator. Actions were taken to train plant operators regarding the load limits, including coverage of the topic with three operating shift as part of the operator requalification program in the Fall of 1990. The remaining shifts will be covered as part of the requalification program. Coverage of the topic on the simulator was also in progress in 1991. The sequence in ES-1.3 is routinely performed during simulator drills of accident mitigation during the switchover to sump recirculation.

The NUSCO root cause investigation reviewed the history of the EOP ES-1.3 and the modifications made to the HPSI system in order to use long term sump recirculation. EOP ES-1.3 was revised as a result of PDCR 854 "Long Term ECCS Modifications" installed in 1987. The root cause of the procedure/load inadequacy was a deficiency in the technical and safety review process for then existing EOP 3.1-4 "Loss of Coolant" dated April 21, 1986. The diesel loading criteria was not reviewed in the development of Revision 29 to that procedure and this error was subsequently perpetuated when ES-1.3 and ES-1.4 were written to supersede EOP 3.1-4, as part of the licensee's conversion to the Westinghouse Emergency Response Guideline (ERG) format. While EOPs ES-1.3 and ES-1.4 received an integrated safety evaluation by NUSCO engineering (safety analysis group), the procedures did not receive a complete review by various NUSCO discipline engineering groups (e.g., electrical, mechanical, etc.). In addition to the specific root cause, the licensee identified a contributing cause to be a weakness in the review process for EOP changes and in the review of procedures during the PDCR process.

The team noted that, as of January 1991, and except as noted above, the EOPs had not been submitted for additional review by NUSCo discipline engineering. Instead, the licensee stated that a major revision of the Emergency Response Guidelines (ERGs) network was currently in progress and that new EOPs will be developed from the revisions, as required. Additionally, the licensee stated interim corrective actions are in place to assure procedure changes receive a full review. The licensee stated that newly revised EOPs, inclusive of

EOPs ES 1.3 and ES 1.4, will be submitted for discipline and integrated review as part of the package. The licensee stated the final package of revised procedures will be reviewed and approved by May 1991. This action and schedule is acceptable.

In summary, the team noted a good licensee program to investigate deficiencies, identify root causes and to complete appropriate corrective actions in a timely manner. Licensee actions to address the EOP review weakness and to prevent recurrence are appropriate. The licensee's investigation of this matter recognized the potential implications for the EOP review process at Millstone as well.

5.3 Self Assessment Program and Technical Training

The team reviewed the licensee's self assessment programs to assure that problem areas are identified and corrected before they affect the safe operation of the plant. The licensee's self assessment programs consist of various engineering and plant activities, including Risk Reduction Task Force, Safety System Functional Inspections (SSFI), QA audits and surveillance, and independent safety evaluation group review.

The Risk Reduction Task Force was formed in 1985 to evaluate the safe operation of the plant in the Probabilistic Risk Assessment (PRA) standpoint of view. The task force identified about 10 recommended modifications to be implemented to reduce the core melt frequency from 10^{-3}/yr to about 10^{-4}/yr. Some of the recommended modifications (e.g., the new switchgear building and semi-vital bus system modification) had been completed, while others were being planned or implemented. According to the licensee, the current core melt frequency is about $4x10^{-4}$/yr.

The licensee conducted an SSFI of the service water system in early 1990. The inspection identified about 70 observations to be resolved by the plant. The final report of this inspection was issued in June 1990. In January 1991, a findings amendment was issued, identifying that only five minor observations remain to be resolved.

The team reviewed the risk reduction evaluation reports,the SSFI reports and QA audits and found them to be complete and thorough. The team concluded that the licensee's self-assessment efforts are commendable in that the licensee aggressively pursued reducing the core melt frequency.

The licensee's training program was reviewed to evaluate the adequacy of training given to the corporate and plant engineering support personnel. The licensee's training program for this purpose is described in Nuclear Training Manual NTM-3.202 entitled, "Technical Staff and Manager Training Program Implementing Procedure," dated May 10, 1990. It describes the training requirements for all technical and managerial personnel. The training is usually conducted at the training center located at the Millstone site. The training center offers a variety of technical courses including reactor theory, thermodynamics, mechanical and electrical systems and components, instrumentation and controls, safety evaluations, root cause analysis, etc. The team discussed the program with the training supervisor and reviewed the training procedures. The training supervisor was very knowledgeable of training requirements and activities. The team concluded that the licensee has an adequate training program for their engineering and technical support personnel.

5.4 Equipment Modifications

The team reviewed the program for plant design changes and modifications to ascertain that they were processed by both site and corporate engineering groups in accordance with a well defined program and were performed in conformance with established procedures and regulatory requirements.

Design changes are classified as either minor (PDCR short form), or major (PDCR long form). Minor changes are processed with the plant in a lead role for overall design and review responsibility, with corporate engineering in a support role for drawing control and special reviews. Major design changes are processed with the corporate group having lead for overall design, design review and discipline specialty support, with the plant in a support role for procedure changes, testing and turnover. Temporary modifications and setpoint changes are also controlled by procedures and receive engineering review for technical adequacy and safety impact.

A sampling of work orders for the EDS completed in the 1989 - 1990 period were reviewed to assure maintenance activities did not result in design changes. No unintended design changes were identified.

Plant modifications reviewed are identified in Attachment 2, and include a variety of temporary and permanent changes to the electrical distribution system. The plant changes selected for review were those that either modified or affected the EDS. The team walked down portions of modification packages in the field to verify conformance with design requirements.

The modifications reviewed were well organized, complete and documented in accordance with applicable procedures. All changes were evaluated for plant safety impact under 10 CFR 50.59. The safety evaluations were considered to be exceptionally well done. Material and equipment were suitable for the application, design inputs were incorporated, and as-installed equipment was found to be in conformance with the purchase order and engineering specifications. The modifications received independent review, and multi-discipline review was evident. The modifications were supported with calculations that were completed in accordance with applicable procedures and post modification tests were completed. The team found the testing to be appropriate for the scope and nature of the design changes. Design drawings were updated and training on the plant modifications was completed.

In summary, the team found modifications were processed by both site and corporate engineering groups in accordance with a well defined program. The team verified that modifications were performed in conformance with established procedures and regulatory requirements. The program for completing design modifications was well implemented and the modification packages reviewed were of good quality.

5.5 Temporary Modification Program

Temporary modifications are performed by the station engineering at the plant site. Procedure NOD 3.04 entitled, "Jumper, Lifted Lead, and Bypass Control," Revision 2, was used to control Haddam Neck's temporary modification activities. The procedure requires each temporary modification to be reviewed by the shift supervisors and a duty- officer-qualified person, who will perform a technical and safety assessment to identify possible adverse effects on plant safety. In some conditions, the temporary modification requires PORC approval within 14 days following installation. All temporary modifications are logged in the control room. A temporary modification requires PORC review if it is not restored within three months, and requires the review of the Vice President of Nuclear Operation if it is not restored within six months.

The team reviewed a selected sample of 10 temporary modification packages. These packages were found to be properly signed, assessed and approved by appropriate personnel. The team also reviewed the temporary log in the control room and found that the open temporary modifications are minimal.

The team concluded that the licensee has a good program for controlling temporary modifications.

5.6 EDS Operations Procedures

Normal, abnormal and emergency operating procedures were reviewed to assure that administrative controls and instructions were adequate to assure operability of the electrical distribution system during all plant operating and accident conditions. The list of procedures reviewed is provided in Attachment 2.

The procedures were reviewed by performing a walkdown in the control room and in the plant with licensee operators as necessary to assure the instructions were accurate as written and personnel were familiar with the equipment operated. The walkdown also verified the procedures could be accomplished using the installed equipment, instrumentation, and controls. The procedures were reviewed for clarity to assure they provided sufficient guidance so as to minimize operator confusion.

The procedures contained a sufficient level of detail to assure the procedure objectives could be satisfactorily accomplished. The operators were familiar with the procedures and plant equipment. The operators were able to perform the required actions. Controls and indications referenced in the procedure were readily identified and readable. The inspector noted good agreement between procedure instructions and labeling in the control room as well as the plant. Labeling of plant equipment was noted to be good in general, with tags that are large and easy to read. Tools and personnel safety equipment needed to operate 480V and 4160V switchgear was readily available in the switchgear rooms.

The team identified all loads that the operator is directed by procedure to start manually and verified they were accounted for in the load study for the emergency generator (EDG). No inadequacies were identified.

The team noted that the only EDG indications available to the operators on the front of the main control board is amperage when connected to Buses 8 and 9. Other EDG controls and indications are available to the operator on a back panel in the main control room. The team discussed with licensee personnel the desirability of having EDG load indication more readily availability to the operator to assure overload conditions are avoided. The licensee stated the need to relocate certain EDG controls had been identified as a control room human factors deficiency as part of the licensee reviews for ISAP Topic 1.19.9. This topic is scheduled to be implemented in Cycle 17, or in March 1993. The inspector had no further comments on this item.

Some discrepancies of low safety significance were identified. The issues were directed to licensee personnel for review.

(1) Step 4.3.2a.1 of Procedure AOP 3.2-25 was not clear as written on the sequence for placing standby equipment in trip pull-out (TPO) to prevent auto starting when energizing the bus with the EDG. The licensee stated that the procedure would be revised by January 15, 1992, to ensure that safety related loads are not restarted inadvertently in the process of transferring the emergency buses from offsite power to the EDGs. Licensee followup actions were acceptable.

(2) Procedure SUR 5.1-153 provides for a periodic verification that the AC and DC distribution systems, including MCC-5 are properly aligned. The team noted that the MCC-5 tie breaker 8FD is administratively controlled by the licensee by using a lock and by incorporation in the surveillance procedure. However, tie breakers 2FD and 13FD are neither locked in position nor surveilled periodically for proper positioning. The concern was that a standby mispositioned tie breaker would not be discovered until called upon to automatically supply MCC-5.

The licensee stated that the breakers are used for maintenance only and are not operated during plant operations. The licensee revised Procedure SUR 5.1-153 by temporary procedure change (TPC) 91-65 on February 7, 1991, to include both breakers in the checklist to verify that they are closed. The licensee committed to further evaluate the possibility of including these breakers on the locked valve checklist. The licensee committed to resolve this issue by January 15, 1992.

(3) Alarm response procedures ANN 4.18-11 and 4.19-11 direct operator actions in the event of an overcurrent condition on the associated EDG Bus 8 and 9, respectively. The alarm is actuated when an overcurrent condition greater than 960 amps is sensed. The EDG OC trip is bypassed during an emergency condition. When the alarm occurs, the operator is directed to acknowledge the alarm, manually reduce load on the EDG, and to notify maintenance personnel to investigate operation of the overcurrent relay. No inadequacies were noted in the procedure as written.

The coordination between overcurrent (OC) and undervoltage (UV) relays on Buses 8 and 9 was reviewed. This review noted that the present protective relay settings will allow the EDG to operate on a faulted bus and that this condition is not annunciated in the control room. The team noted that a three phase bolted fault on the emergency bus would result in the UV relay causing initiation of the loss of normal power (LNP) logic to strip the bus and load the associated EDG, prior to actuation of the OC relays on the incoming 9T3 and 8T2 supply breaker. The EDG output breaker would close in on the faulted bus. Further, because the EDG OC relays are set at 960 amps, which is greater than the maximum EDG rating of 850 amps, the diesel would attempt to carry a faulted bus and no overcurrent alarm would be generated. The team noted that neither alarm response procedures ANN 4.18-11 and 4.19-11 nor other operating procedures provide the operator guidance to recognize and respond to this situation.

The licensee noted the concern and stated that, based on operator training and available indications, it is expected the operator would take actions to respond to the event commensurate with plant conditions and the severity of the overcurrent. For the worst case condition, the operator would stop the EDG and place its breaker in TPO. The licensee stated, however, that consideration would be given to develop a means to make the operator aware of a possible abnormal condition on one emergency bus when only one diesel starts automatically. This would involve use of existing equipment and/or installation of additional equipment, and the development of a procedure to help the operator diagnose and respond to the situation. The licensee is committed to resolve this issue by January 15, 1992.

(4) A deficiency involving EDG loading under certain limiting conditions highlighted a weakness in the EOP review process. This issue is discussed further in Section 5.2.1, along with licensee corrective actions. The adequacy of the current procedures was reviewed.

The manual EDG loading sequence specified by the EOPs (ES-1.3 and 1.4) would result in loading the generator above its listed full load rating of 2850 kW. The EOPs (procedure EDC-0.0, Station Blackout), normal surveillance procedures, and operator training specify that 2850 kW is the maximum full power load for the EDGs. Procedure ECA-0.0 cautions the operator to not exceed 2850 kW when placing loads on the emergency bus. During a discussion of the EOP ES-1.3 sequence with a senior reactor operator, the team noted that 2850 kW was deemed to be a hard limit and that the operator would depart from the procedure as necessary to eliminate loads in order to continue with the ES-1.3 sequence.

The licensee had not added guidance to the EOPs to stipulate either the EDG expected load when following the EOP ES-1.3, or the allowable load above 2850 kW for the EDGs. The team noted that no guidance was readily available to the operator to identify what the EDG design limits and overload ratings. The team noted it would be appropriate to inform the operators that it is acceptable to load the diesels to its 30 minute or 7 day limits in accordance with the EOPs since that is the intended design condition. The apparent need for better operator guidance on maximum allowable EDG loading was discussed with the licensee.

The licensee responded on February 19, 1991, that short and long term actions would be taken to address this concern. As an immediate action, a Night Orders would be issued to provide operators with information regarding EDG load limits. The team reviewed a memorandum from the Operations Manager (ODM 91-025, dated February 22, 1991) to shift personnel that described the diesel load limits and discussed the acceptability of operating the EDGs to the 30 minute and 7 day limits in accordance with the EOPs.

Additionally, the licensee stated that two operator aids in the form of bakelite signs would be posted in the control room to address this issue. The operator aids are controlled per administrative procedure ADM 1.1-212 and the operators will be trained on use of the aids. One sign will be posted near the kW meters on the EDG control panel and will list the EDG 30 minute, 7 day and 2000 hour load limits. A second sign will be posted near the EDG amp meter on the main control board section G and will provide a matrix giving a load to be started versus the maximum load allowed on the EDG. The load data for the matrix will be developed from testing to be completed in June 1991. The licensee stated this action will be completed by July 19, 1991. For the long term, reference to 2850 kW will be deleted from the ERGs during the next major revision to further reduce the possibility for confusion. The team had no further questions regarding this issue.

In conclusion, the team's review found the procedures to operate the EDS to be generally good and would assure EDS operability under normal, abnormal and accident conditions. Operators were knowledgeable of the electrical distribution system and the associated procedures. A deficiency involving EDG loading under certain limiting conditions highlighted a weakness in the EOP review process. The licensee program for implementing normal and emergency procedures is otherwise generally good.

5.7 Engineering Support/Interface

The team reviewed the involvement and effectiveness of the engineering staff to support design functions, operations, maintenance and other organizations at the site.

Engineering and technical support is provided by the onsite engineering group; by engineering support within the plant operations, I&C and maintenance departments; and, by the corporate engineering groups. There is extensive engineering involvement with plant activities, including design functions, drawing control, testing, procedure changes, maintenance, temporary and permanent modifications, procurement, setpoint changes, and deficiency resolution. The control of engineering support activities is formalized in procedures to direct the assignment, administer, prioritize and track engineering functions. The team noted generally sound and effective engineering support of plant activities.

The team found the engineering staff was knowledgeable and competent. The licensee was able to provide the required design documents within a short time, although there was some difficulty in accessing some of the original documentation. The team noted that the licensee's self-initiated design basis reconstitution program will reestablish design basis files for the selected systems. The team found the engineering staff to be very knowledgeable of the electrical distribution system. The design engineers prepared two detailed design calculations within a short time, indicating good familiarity with the areas of responsibility. The team observed good support was provided to the station during this inspection.

The team did observe three examples where a lack of thorough review of the design bases resulted in failure to properly establish design outputs or conformance with regulatory commitments and they were discussed in Sections 2.4, 4.2, and 4.3 of this report.

In summary, while engineering support to operating activities is generally good with an effective interface evident in many areas and projects, the team noted some deficiencies in this area. The team observed several examples which indicate the thoroughness of technical reviews and attention to detail could be improved. This is needed to assure applicable regulatory requirements are met and comprehensive design outputs are generated.

5.8 Conclusions

The team observed that both the corporate, site engineering and technical support personnel were knowledgeable and very familiar with the electrical distribution system. The team found adequate staffing and training in the engineering groups, and an adequate program for temporary modifications. Engineering's interface with other organizations was considered to be good. There is a good program for completing design modifications and the engineering modification packages reviewed were of good quality.

The team's review found the procedures to operate the EDS to be generally good and would assure EDS operability under normal, abnormal and accident conditions. Operators were knowledgeable of the electrical distribution system and the associated procedures. A deficiency involving EDG loading under certain limiting conditions highlighted a weakness in the EOP review process. The licensee's program for implementing normal and emergency procedures is otherwise generally good.

The licensee has a commendable self assessment program. The licensee aggressively pursued reducing the core melt frequency through their risk reduction task force.

Engineering support to operating activities is generally good with an effective interface evident in many areas of projects. The team observed several isolated examples which indicate the thoroughness of technical reviews and attention to detail could be improved. This is needed to assure applicable regulatory requirements are met and comprehensive design outputs are generated.

The team noted a good licensee program to investigate deficiencies, identify root causes and to complete appropriate corrective actions in a timely manner. Licensee actions to address the EOP review weakness and to prevent recurrence were appropriate.

6.0 UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items or violations. Unresolved items identified during this inspection are discussed in detail, paragraphs 2.4.1, 3.3.2 and 3.4.1

7.0 EXIT MEETING

The inspector met with licensee corporate personnel and licensee representatives (denoted in Attachment 1) at the conclusion of the inspection on February 22, 1991. The inspector summarized the scope of the inspection and the inspection findings.

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ATTACHMENT 1

PERSONS CONTACTED

CYAPCO Personnel

* E. Annino	Licensing Analyst, NUSCO
* W. Batron	Staff Assistant, CY
* W. Becker	Supervisor, GEE, NUSCO
* G. Bouchard	Unit Director, CY
* R. Brown	Staff Assistant, CY
* J. Chiloyan	Electrical Engineer, NUSCO
J. Chiarella	I&C Engineer, CY
S. Cohen	Engineer, NNECO Unit 1
* E. Debarba	Vice President, GE&C, NUSCO
B. Depatie	Engineer, EQ, NUSCO
* H. Epstein	Consultant
J. Evola	Maintenance Engineer,CY
R. Ewing	Electrical Engineer, NUSCO
G. Flannery	Sr. Civil Engineer, NUSCO
S. Frolov	System Engineer, NUSCO
B. Heidecker	Supervisor, Operator Training
* P. Hesler	Electrical Engineer, CY
* G. Johnson	Director, GE&D, NUSCO
* W. Kadlec	Supervisor, CY Generation Test, NUSCO
L. Lebron	Electrical Engineer, CY
P. Mason	Sr. Mechanical Engineer, NUSCO
R. McBeth	Operator Training Instructor, CY
* B. Mckenna	Electrical Engineer, CY
E. Montalvo	Operations Assistant, CY
T. Nericcio	Public Information, CY
* G. Noordennen	Supervisor, Nuclear Licensing, NUSCO
* G. Pitman	Manager, GEE, NUSCO
* G. Polleto	Technical Manager, ABB IMPELL
B. Quinlan	Mechanical Engineer, NUSCO
A. Roby	System Manager,GEE, NUSCO
* G. Silberquit	Engineer, GEE, NUSCO
* J. Stetz	Station Director, CY
J. Summer	Engineering Supervisor, Millstone Unit 1
* G. Townsend	Electrical engineer, NUSCO
* B. Tuthill	Supervisor, EQ, NUSCO

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* G. Tylinski	Supervisor, Electrical Engineering, CY
* D. Vail	Supervisor, GEE, NUSCO
C. Warner	Engineer, HVAC, NUSCO
S. Weyland	System Engineer, NUSCO
* M. Whitelaw	Special Programs, NUSCO
B. Young	Electrical Engineer, NUSCO

U.S. Nuclear Regulatory Commission (USNRC)

J. Linville	Branch Chief, Project Branch No.1
* J. Durr	Branch Chief, Engineering Branch
* S. Athavail	Electrical Engineer, Head Quarters
* J. Shedlosky	Sr. Resident Inspector
* A. Asars	Resident Inspector

NRC Guests

Andrey Glukhov	GPAN, Soviet Union
Victor Koltunov	GPAN, Soviet Union
Anatoly Demjanenko	GPAN, Soviet Union
Nickolas Berhoff	Interpreter, State Department

* denotes those present at the exit meeting held on February 22, 1991.

ATTACHMENT 2

LIST OF ITEMS REVIEWED

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The following is a partial list of licensee documents used as references during the inspection.

Temporary Modifications

90-005, Temporary Charging System Jumper
87-048, EOF Diesel Heater
89-30, Battery Bus Voltmeter Fuse Holder
90-17, DG Fuel Oil Pump Control Switch
88-008, Reverse Power Relay 32-14
87-078, MCC 6-6 and 6-7

PDCRs

PDCR 866, New 4160 Volt Bus 9 Circuit Breaker Cubicle
PDCR 342, Emergency Power to Pressurizer Heaters
PDCR 910, Appendix R and Auxiliary Cable Terminations
PDCR 89-140, RHR Pump Motor Terminations
PDCR 854, Long Term ECCs Modifications
PDCR 636, EDG Electrical Trip and Lockout Feature
PDCR 90-000, EDG Excitation Breaker Replacement
PDCR-865, New Switchgear Building.
PDCR-867, Replacement for Station Service Transformers 484, 485, 496, and 497.
PDCR-906, New Equipment - Old Switchgear Room - MCC 13-4.
PDCR-910, Appendix R Switchgear Modifications.
PDCR-CY-89-100, HPSI Motor Surge Capacitors.
PDCR-328, Diesel Room Heaters.
PDCR-83, EDG Air start system piping modification.
PDCR 90-127, EDG Fuel Pump Control Switch Upgrade

Calculations

PA-90-LOE-1167-GE, - Diesel Generator Manual Loading Analysis
PA76-633-40GE, - Degraded Voltage Setpoints
PA83-117-993GE, - Voltage Drop for Service Water Pump Cables, C.A.R Fan Power Cables, and from Offsite Transformers to Selected Load Center Transformers.
PA82-050-659GE, - 4160 V Coordination, Buses 1-1A, 1-1B, 1-2, 1-3, 8 & 9.
PA82-050-43GE - 480 V Coordination, Buses 4, 5, 6, 7, 10 & 11.
PA88-042-945GE - C.A.R Fan Repowering.
PA79-172-804GE - MCC-7 Load Study.
PA80-105-112GE - MCC-6 Load Study.
PA79-184-234GE - MCC Loading MCC 4-1, Bus 4-4.
18691-E-006 - New Switchgear Building - Cable Sizing Calculation

18691-E-004 - Voltage Drop to Loads Supplied by 480 V Bus 11.
18691-E-003 - Connecticut Yankee New Switchgear Building - Short Circuit Level on 480 V Buses.
18691-E-017 - Connected Load Calculation for MCC 12-11, 480 V Bus 11 & New Class 1E Loads At MCC 12-11 & Bus 11.
18691-E-005 - Connecticut Yankee New Switchgear Building - Ampacity of Cables in Ductbank.
PA91-LOE-1171GE - CY Existing Batteries 1A,1B, & 1C Adequacy.
PA82-076-31GE - CY Bat. Replacement, Battery Charger Sizing Check.
PA91-LOE-1173GE - CY Battery Charger Sizing Check.
PA80-208-229GE - CY Vital Bus Inverter Loading.
PA80-241-106GE - CY 125 VDC Short Circuit & CB Settings, Busses A, B, & BX.
PA80-208-229GE - CY Vital Bus Inverter Loading.
PA83-117-976GE-120 VAC Feeder Coordination, CY Swgr. Bldg.
PA80-200-25GE- Voltage Drop From MCC to MOV.
PA89-LOE-574GE - CY MOV Voltage Drop.

Nonconformance Reports (NCRs)

NCRs 88-65, 89-113, 89-182, 90-22, 90-142, 90-160, and 88-177

Licensee Event Reports (LERs)

LERs 89-09, 89-14, 90-08, 90-11, 90-23, 90-32, and 90-01

Documents

SUR 5.5-16, "BT-1A,B,C Weekly Station Battery Checks",Rev. 12
SUR 5.5-17, "BT-1A, 1B, 1C Quarterly Station Battery Checks", Rev. 11
SUR 5.5-37, "Station Battery Cell Inspection, Intercell Resistance Test and Rack Inspection"
SUR 5.5-38, "BT-1A, 1B and 1C Battery Service Test", Rev. 1
SUR 5.5-39,"BT-1A,1B and 1C Battery Performance Test",Rev. 1
SUR 5.1-17A(B) - Emergency Diesel Generator EG-2A(2B) Manual Starting and Loading Test, Revision 3, dated June 22, 1990 (June 19, 1990). Surveillance completed 10/16/90.
PMP 9.5-21 - Testing of Emergency Diesel Generator Redundant Systems, Revision 19, dated May 25, 1989. SUR 5.2-24 - Safeguards Equipment Timer Test, Revision 10, dated June 3, 1990. Surveillance test completed 11/11/90.
SUR 5.1-18 - Test of Emergency Diesel Generator EG-2A with Partial Loss of A-C Coincident with Core Cooling Activation, Revision 17, dated July 23, 1987. Test completed February 29, 1988.
NUSCo Independent Root Cause Investigation - Emergency Diesel Generator Overload and Potential Loss of Sump Recirculation, dated January 31, 1991
Safety Evaluation 1SE/CY 87-062, Rev 1, ECCS Modifications - 1987

071289

ATTACHMENT 3

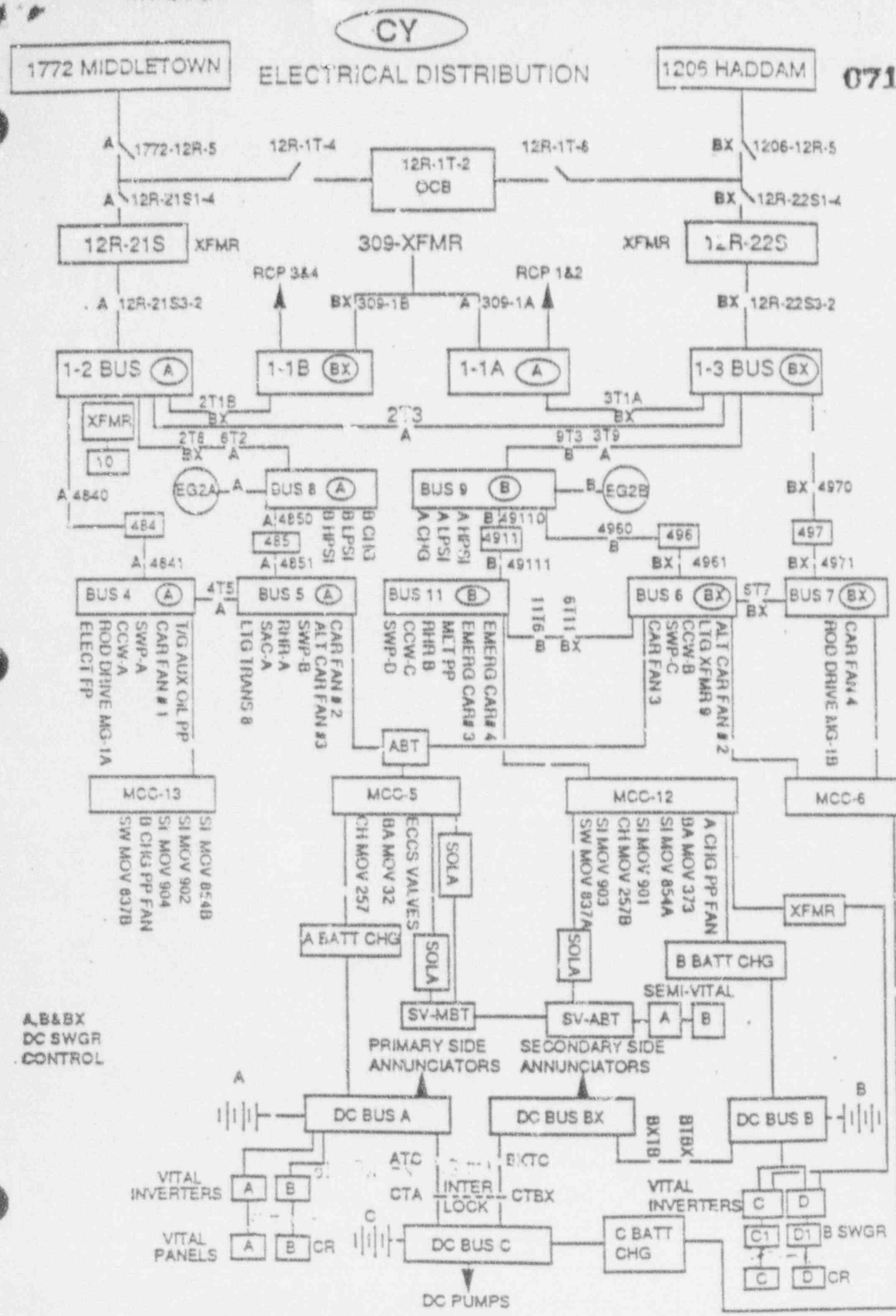
ABBREVIATIONS

A or Amp	Amperes.
AC or ac	Alternating Current.
ANSI	American National Standards Institute.
ASME	American Society of Mechanical Engineers.
BHP or bhp	Brake Horsepower.
BIL	Basic Insulation Level
CAR	Containment Air Recirculation
CB	Circuit Breaker.
CFR	Code of Federal Regulations.
CONVEX	Connecticut Valley Electric Exchange.
CR	Control Room.
CT	Current Transformer
CVT	Constant Voltage Transformer.
DBA	Design Basis Accident.
DC or dc	Direct Current.
DEMA	Diesel Engine Manufacturers Association.
ECCS	Emergency Core Cooling System.
EDG	Emergency Diesel Generator.
EDS	Electrical Distribution System.
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
FLA	Full Load Amps.
FSAR	Final Safety Analysis Report.
FTOL	Full Term Operating License.
GDC	General Design Criteria.
GE	General Electric.
GPM or gpm	Gallons per Minute.
HV	High Voltage.
HVAC	Heating Ventilation and Air Conditioning.
IEEE	Institute of Electrical and Electronics Engineers.
ISAP	Integrated Safety Assessment Program
kV	kilovolts.
kVA	kilovolt-amperes.
kW	kilowatts.
LC	Load Center.
LOCA	Loss of Coolant Accident.
LV	Low Voltage.
MCC	Motor Control Center.
MOV	Motor Operated Valve.
MS or ms	Milliseconds.
MVA	Mega Volt-Amperes.
NEC	National Electrical Code.

071390

NEMA	National Electrical Manufacturers Association.
NUSCO	North Eastern Utilities Service Company.
PDCR	Plant Design Change Request
PR	Protective Relay(s).
PSI or psi	Pounds per Square Inch.
PT	Potential Transformer
RCP	Reactor Coolant Pump.
RG	USNRC Regulatory Guide.
SCR	Silicone Controlled Rectifier.
SEP	Systematic Evaluation Program.
SF	Service Factor.
SST	Station Service Transformer(s).
STD or Std	Standard.
TS	Technical Specification.
UL	Underwriters Laboratories.
UPS	Uninterruptible Power Supply.
USFAR	Updated Final Safety Analysis Report
USNRC	United States Nuclear Regulatory Commission.
V	volt(s).
VAC or Vac	volts alternating current.
VDC or Vdc	volts direct current.

ATTACHMENT 4 - HADDAM NECK ELECTRICAL DISTRIBUTION SYSTEM



071391

APCo Exhibit 115

071314

CONTACT REPORT

11-21-89

Mark Jacobus, Sandia
Chuck Pulk, NRC, Region IV, Arlington
Harold Walker, NRC, Rockville

Jim Gleason, Wyle

RE: J/N 17110

Subject: Okonite Tape Splices

I told them that the purpose of the call was twofold:

First- I had received word that there was concern from the NRC, that there were some problems with the Wyle Report No. 17947-01. If problems do exist, this may be a 10CFR part 21 situation and I needed to know this.

Second- There appears to be some concern over the use of this report to show qualification of the subject splices at LP&L. I would like to know what the problems are.

On the first issue, they agreed that they had uncovered no errors in the report and thus there was not a part 21 problem.

On the second issue, the following problems exist:

1. The test was done originally for power and control circuits and Chuck doesn't think the results can be extrapolated to instrument circuits.

2. The low side of the splices won't show leakage and therefore it's not a valid test.

3. Leakage current was zero, thus raising a flag on the integrity and accuracy of the measuring circuit.

4. LP&L did not produce a specific test on splices in an instrument circuit or completely address which transmitters are affected and the accuracy needed.

Discussion:

I explained that three sets of two splices each, a high side splice and a low side splice were tested. It was agreed that most leakage would occur from the high side splice, assuming both splices were good. It was agreed that the high side splice (137.5 VDC) enveloped an instrument circuit of 30 VDC, typical. The low side was representative of a low side DC. Since three high side splices were in the test and

071315

only one high side splice is required for qualification, These splices constitute a valid extrapolation for an instrument circuit. (Chuck disagreed with Mark and myself on this point, invoking problem # 1, in-spite of the evidence to the contrary).

The leakage current of zero is not itself in question, rather Mark want's supporting evidence such as IR's during the test and/or a through explanation of Wyle's QA on the circuit and the accuracy or threshold of the circuit. He would like to know how much leakage may be in the circuit. LP&L needs this so that they can resolve problem #4.

In future tests Wyle should consider actual Transmitter circuits, and confirmation of circuit accuracy with leakage current and IR measurements during the test.

On a separate issue, Harold thanked me for some information of equipment sealing which I had sent him a few months ago.

Action: J. Henley : Pleasa resove test circuit accuracy problems and meet with LP&L on 11-29-89 during there audit of Wyle.

cc: S. Hyten, W. Holbrook, J. Henley, C. Poplin, E. Smith, F. Johnson, Vernon Coy (LP&L)

OVERSIZE DOCUMENT PAGE PULLED

SEE APERTURE CARDS

NUMBER OF OVERSIZE PAGES FILMED ON APERTURE CARDS 1

9204140239 -01

APERTURE CARD/HARD COPY AVAILABLE FROM

RECORDS AND REPORTS MANAGEMENT BRANCH

EXHIBIT
Licensee #55

0102379

(482)

APCo Exhibit 117

Farley 11/9/87

p 1 of 2

Conlon - Potapovs 11/9/87 am

- CAL requires evaluating Unit 1 Op re Unit 2 findings - no due date
- Conf call this pm with RII, project, mgmt, licensing (Merriweather, Walker, Paul Lewis, Alexander - ~6:30)

Steve Alexander feedback from walkdown

- Gems xmtrs put in 30d LCO - silicone oil for TBs submerged
- GE 100 + W EPAs - JB KO's and TBs (called 11/18. wrote JCO)
  - backfitted Conax modules had Kapton ins.
  - Q - are the inst ckts there TBs on ML?
- Ltgs in Cont - no T drains, Generally OK.
- H_2 recombiner - new Raychem splices over non-wicking braid
- Numerous in-cont JBs with States sliding link TBs incl ML xmtr ckts - top ent., conduit, no RTV seal (per test), no blowout plugs or btm weephole
  - Spared wires loosely taped - licensee will verify that they're disconnected - ASCO + Namco boxes in steam room (large top vents, roof)
- Wide range RCS PT-402 - wire ins cut thru btwn Rosmt seal and taped V-splices to expose both conductors - spar
- ASCO + Namco below 115 ft submergence level - no seal - claimed early safety fcn (? for cold leg accum valve + Dings brake)
- ~~Ltg with external Namco (in cont)~~
- ASCOs - almost all had new Raychems - no ESA or alternative (no conduit btm drain, JB weephole, etc) / Namcos had Chico sealant with Raychem boot and pipe nipple)
  Straight thru 4 cond plus 5 flat-fort. Good.

0102380

Farley 11/9/87 am p2

- Loose flex conduit fittings - several cases - some conduit too short to reach
- ASCOs - many loose coil housings
- Victoreen HRRM detector leads feed to ~6" cube JB whose output isn't sealed
- JBs with TBs - narrow + wide RTDs (Rout 178 KF and KS) - no weepholes
- Files kind of informal - some SCEW sheets lacked required Op Time. Bechtel + W doing

Stay at Sheraton
Fly Delta
Eat at Conestoga

Raychem

PRODUCT CONTROL DOCUMENT

NCBK-04-04

APCo Exhibit 118

USAGE: NUCLEAR CABLE BREAKOUT KIT

Cable Jacket O.D.: 0.78" - 1.2"

Insulated Conductor O.D.: 0.19" - 0.34"

CONTENTS:

Item	Qty.	U/M	Description	Key
1.	1	pc.	502A823-52/144 Conductor Sealing Breakout	E
2.	1	pc.	WCSF-650-6-U Outer Sleeve	√
3.	1	ea.	Installation Instructions PII-57009	-
4.	1	ea.	Product Control Document PCD-57014	-

QUALIFICATION REPORTS:

EDR-2001: Heat Aging Study of WCSF Compound

EDR-5009: Flammability Testing of Heat Shrinkable Field Splicing System for Class IE Electric Cables Type WCSF-N

WYLE 58442-2: Environmental Qualification Test Report of Raychem Nuclear Cable Breakout and End Sealing Kits

071310

Raychem NCBK

INSTALLATION INSTRUCTIONS FOR NUCLEAR CABLE BREAKOUT KITS

GENERAL

1. Use a clean burning propane torch or an electric hot air heater for the installation of NCBK kits.

   ORDER:

   PROPANE TORCHES: Rayc Model FH-2609 Clean Burning Torch
   Raychem Model FH-2616 Mini Torch

   HOT AIR HEATERS: Raychem Model CV-5000 Thermogun Model 750 (115V)
   Raychem Model CV-2116 Heavy Duty Leister (115V)
   Raychem Model CV-2117 Heavy Duty Leister (230V)

2. Adjust to ch flame to an approximate 8" length with a 3" - 5" yellow portion at a regulator pressure of 5 PSIG. Use the yellow portion of the flame with a paintbrush motion. KEE THE FLAME MOVING.

3. SHRINK BREAKOUTS beginning at the junction of the legs and body. After the legs are recovered, shrink the body.

4. Begin shrinking tubing components at the c ter of the tube. Heat uniformly circumferentially. When recovered, ve first towards one end, then to the other.

5. Parts are "fully recovered" when the outer surface is smooth and has a glossy appearance. Coated parts will have a visible flow of adhesive.

PREPARATION:

1. CONFIRM KIT SELECTION. Check dimensions of Cable and wire against kit label.

2. REMOVE ALL NON-QUALIFIED OR BRAIDED JACKETING MATERIAL from the Jacket Cutback. RAYCHEM products are designed to seal to smooth, non-woven surfaces. All non-qualified or braided jacketing material should be removed from the Jacket Cutback for a distance of one inch longer than the length of the Breakout body.

3. CLEAN AND DEGRE cable jacket and w insu ation with a solvent (such as 1,1,1 trich oethane) which is appr by the cable manufacturer. All surfaces must be free of greass, oils or other contaminants prior to being brought into contact with RAYCHEM products.

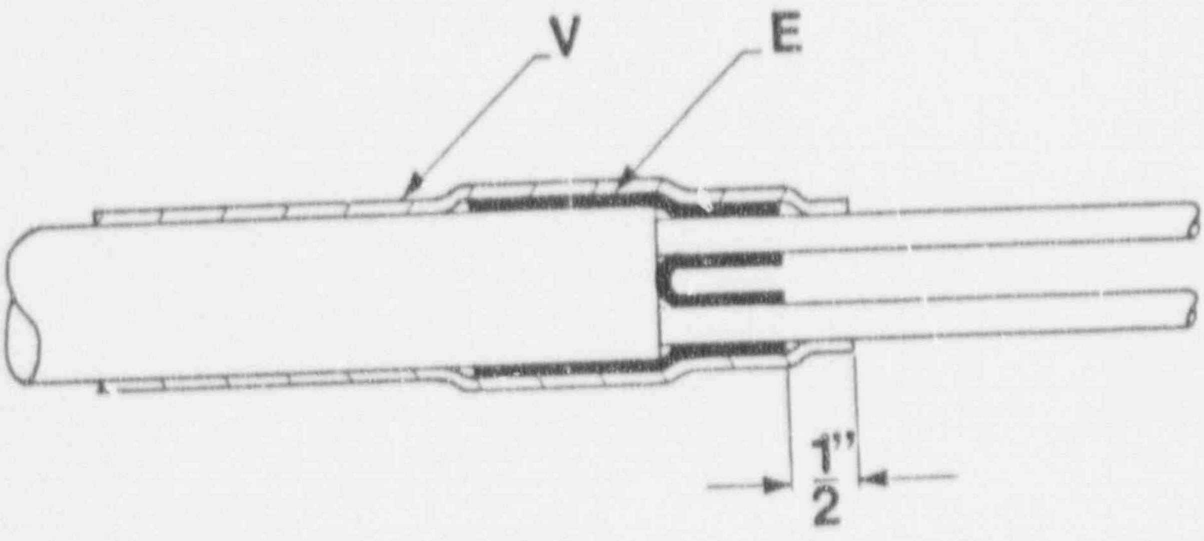
   ORDER: Cable Preparation Kit, Raychem No. CPK-01-00 (contains 6 solvent wipes and 1 abrasive cloth).

INSTALLATION:

1. THREAD ONE INSULATED CONDUCTOR through each leg of the Cable Breakout, Part E. Ensure the large open end of the Breakout faces toward the Jacket Cutback. Slide the Breakout along the individual wires and over the cable as far as it will go. SHRINK IN PLACE.

2. POSITION THE OUTER SLEEVE, Part V, over the Cable Breakout such that there is approximately 1/2" extending past the legs of the Breakout. SHRINK IN PLACE.

DO NOT FLEX UNTIL COMFORTABLE TO TOUCH



APCo Exhibit 119

071212

Material Safety Data Sheet
May be used to comply with OSHA's Hazard Communication Standard, 29 CFR 1910.1200. Standard must be consulted for specific requirements.

U.S. Department of Labor
Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

IDENTITY (As Used on Label and List)
CHICO® A Sealing Compound

Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that

Section I

HMIS Hazard Rati
Health: 0 Minimal
Flammability: 0 Min
Reactivity: 0 Minim

Manufacturer's Name
Crouse-Hinds ECM Div. Cooper Industries

Emergency Telephone Number
315/477-7000

Address (Number, Street, City, State, and ZIP Code)
Wolf & 7th North Sts.
P.O. Box 4999
Syracuse, NY 13221

Telephone Number for information
315/477-7000

Date Prepared 10/86,3/87, 6/87,9/87,2/88,2/89 12/90, 1/91

Signature of Preparer (optional)

Section II — Hazardous Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other Limits Recommended	% (option
Aluminum Oxide CAS1344-28-1	15mg/m^3 Total	10mg/m^3 Total		25%
Calcium Oxide CAS1305-78-8	15mg/m^3 Total	10mg/m^3 Total		24%
Ferric Oxide CAS1309-37-1	15mg/m^3 Total	10mg/m^3 Total		8%
Ferrous Oxide CAS1345-25-1	15mg/m^3 Total	10mg/m^3 Total		3%
Silicon Dioxide CAS7631-86-9	15mg/m^3 Total	10mg/m^3 Total		3%
Titanium Dioxide CAS13463-67-7	15mg/m^3 Total	10mg/m^3 Total		2%
(All of the above components are combined as common names calcium aluminates, calcium alumino ferrites, calcium alumino silicates, and calcium titanate)				
Plaster of Paris CAS7778-18-9	10mg/m^3	5mg/m^3 (respirable)		34%
Portland Cement CAS65997-15-1	10mg/m^3	5mg/m^3 (Respirable)		1%

All substances in Chico A Sealing Compound appear on the Toxic Substance Control Act In

Section III — Physical/Chemical Characteristics

Boiling Point	N/A	Specific Gravity (H_2O = 1)	3
Vapor Pressure (mm Hg.)	N/A	Melting Point	1300°-14
Vapor Density (AIR = 1)	N/A	Evaporation Rate (Butyl Acetate = 1)	N/A

Solubility in Water
Negligible to 0.2%

Appearance and Odor
Light gray, odorless powder

Section IV — Fire and Explosion Hazard Data

Flash Point (Method Used)	Flammable Limits	LEL	UEL
NONE	N/A		

Extinguishing Media
Not combustible

Special Fire Fighting Procedures
None

Unusual Fire and Explosion Hazards
None

071313

Section V — Reactivity Data

Stability	Unstable		Conditions to Avoid None
	Stable	X	

Incompatibility (Materials to Avoid)
None

Hazardous Decomposition or Byproducts
Above 1450°C - SO_2 & CaO

Hazardous Polymerization	May Occur		Conditions to Avoid
	Will Not Occur	X	

Section VI — Health Hazard Data

Route(s) of Entry:	Inhalation?	Skin?	Ingestion?
	X	X	X

Health Hazards (Acute and Chronic)

Acute: See below

Chronic: None known

Carcinogenicity	NTP?	IARC Monographs?	OSHA Regulated?

Signs and Symptoms of Exposure
Over exposure may cause irritation of eyes and skin. May develop sufficient heat to cause burns to a large skin mass if kept in contact while hardening takes place. Inhalation: dust is considered a nuisance dust with a TLV of 10 mg/m3 total, or 5 mg/m3 respirable.

Emergency and First Aid Procedures
Sealing compound hardends when wetted and if ingested results in obstruction (hardenin[illegible] time is 22-28 minutes) see physician. In case of eye contact, flood immediately for 1[illegible] minutes with water. Remove from skin by washing, if irritation continues, see physici[illegible]

Section VII — Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled
Vacuum where possible, or sweep up. Avoid creating excessive dust. Material will har[illegible] in presence of water and may plug drains.

Waste Disposal Method
Best convenient method in accordance with Local, State, and Federal regulations.

Precautions to Be Taken in Handling and Storing
Store under dry conditions. Dew point conditions or other wet conditions during stora[illegible] will harden sealing compound.

Other Precautions
None

Section VIII — Control Measures

Respiratory Protection (Specify Type)
NIOSH approved nuisance dust repirator if above TLV (in very dusty conditions)

Ventilation	Local Exhaust: Yes if above TLV	Special
	Mechanical (General)	Other: Outdoor conditions

Protective Gloves	Eye Protection
Wear gloves if dust or slurry is irritating	Dust goggles if dust is annoying

Other Protective Clothing or Equipment
Not required

Jesse: 071392
FYI from RWS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

APCo Exhibit 120

February 10, 1992

NRC INFORMATION NOTICE 92-12: EFFECTS OF CABLE LEAKAGE CURRENTS ON INSTRUMENT SETTINGS AND INDICATIONS

Addressees

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to a safety problem that could result from inaccuracies introduced into safety-related instrument loops because of increased leakage currents from instrument cables when subjected to a harsh environment. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

On May 15, 1989, while reviewing instrument loop accuracies, test technicians of the Virginia Electric and Power Company (VEPCO), the licensee for the Surry Power Station, determined that during a harsh environmental condition, the leakage currents in cables could prevent performance of safety functions (Licensee Event Report 50-280/89-20). These potential failures would be caused by reduction in the cables' insulation resistance (IR) in the harsh environment. Such a harsh environment could be produced inside containment by a loss of coolant accident (LOCA) or by a high energy line break (HELB) event. The instrument cables installed at the Surry plant were environmentally qualified, but the previous safety system calculations for the accuracy of the instrument loops and for trip setpoints did not account for the additional uncertainties that could be introduced by the reduced IR values.

In particular, the licensee noted that this phenomenon could potentially mask the reactor trip signal for steam generator low level and the safety injection signal for pressurizer low pressure and, thus, prevent the required protective actions. Furthermore, the licensee also noted that the pressurizer level and reactor coolant system wide range pressure instrument systems could be adversely affected by leakage currents.

The licensee reviewed all safety-related instrument loops and replaced, where appropriate, affected cables in both units with new cables having a higher IR value. The licensee reviewed setpoint calculations and verified the margins taking into consideration errors caused by cable leakage currents. The licensee also reviewed the loop accuracy calculations for indication loops and revised affected emergency operating procedures to address errors in indications caused by leakage currents.

The NRC is aware that many licensees are revising instrument setpoints using the latest industry standards and are assessing the effects of leakage currents. However, since most licensees for operating plants may not have addressed these effects in their original design calculations, the problem described above for Surry may be generic.

Discussion

Under conditions of high humidity and temperature associated with either a LOCA or a HELB, the IR may decrease in components of the instrument loop such as cables, splices, connectors, terminal blocks, and containment penetrations. Consequently, leakage currents increase and measurement of process variables becomes more uncertain. In a normal environment, however, leakage currents are small enough to be essentially calibrated out of consideration.

The instruments of a safety-related system provide monitoring and control to ensure the system will perform its intended safety function. The decreased IR of the instrument loop components may disable such monitoring and control.

In June 1984, the NRC issued Information Notice (IN) 84-47, "Environmental Qualification Tests of Electrical Termination Blocks." In this information notice, the staff identified the potential for errors caused by leakage currents at terminal blocks when these blocks are subjected to a harsh environment.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

Technical contacts: S. V. Athavale, NRR
(301) 504-2974

Jerry L. Mauck, NRR
(301) 504-3248

Attachment: List of Recently Issued NRC Information Notices

APCo Exhibit 121

APPENDIX II.

Performance Test Data of Limitorque Valve Operator

Table 1, Collected Data.

Table 2, Average and Peak Values.

311-C2232-01

Date Nov. 1, 1965
J. F. Witcher

ENVIRONMENT TEST CYCLE

TEST LEVEL NO. V DESIGNATED STEAM PRESS. 15 PSIG SATURATION TEMP. 250 °F

Time Level Reached: 1524 Hours

Time from Previous Level: 7 Minutes

Chamber Press: 15 psig Temp.: 25~~0~~ °F

Test Unit: Temp. 250 °F Press. 16.2 Psig

5.2%

First Test Cycle of Motor at this Level: Time: 1528 Hours

This level maintained continuously through Nov 7, 1965

Boric Acid Spray

Flow Rate None. Temp. ______ °F PH ______

Nov 7, 1965

Second Test Cycle of Motor at this Level: Time: 1528 Hours

End of Level No. Final Test Nov 7, 1965

Time: 1528 Hour

Chamber Temp. 247 °F Press. 14.7 Psig.

Unit Temp. 247 °F Press. 14.5 Psig

058415

LIMITORQUE CORPORATION

5114 Woodall Road • P. O. Box 11318 • Lynchburg, Virginia 24506
Telephone—804-528-4400 • Telex—82-9448

APCo Exhibit 122

October 13, 1980

NUREG 0588 DOCUMENTATION

Bechtel Power Corporation
15740 Shady Grove Road
Gaithersburg, MD 20760

Attention: Mr. A.A. Vizzi - Project Engineer

Gentlemen:

Reference: Qualification Information
Joseph M. Farley Nuclear Plant
Bechtel Job 7597-20
Alabama Power Co. P/O 66420
Limitorque O/N 3F1782

Regarding your request for qualification information, at the time Limitorque received the orders for some of the units supplied, no accepted IEEE qualification standard existed and therefore the units were not manufactured in accordance with any specific qualification requirement.

1. A review of our records show that our Qualification Report 600456 can be applied to the actuators supplied on the following orders.

Limitorque O/N	Actuator S/N	MOV No.
UNIT 1		
360278A	162456-58	3232A-C
*364499A	167055	3131
365513A	164582-84	3350A-C
376540A	195174-75	3536
378148A	195176-79	3528C, 3835A, and 3660
379035A	209324-25	3530
380365A	202202-03	3528B
381730A	206701-712	3528A, 3835B, and 3318B
387496A	222192-93	3822A-B
390553A	232405-08	3528D

10/28 15:36 2282327 #02

A.A. Vizzi - Project Engineer
ober 13, 1980

0058416

Limitorque O/N	Actuator S/N	MOV No.
UNIT 2		
*358999A	192802-09	3441A-D
360282A	162619-21	3233A-C
*364499A	167055	3131
365512A	164579-81	3350A-C
376540A	195174-75	3536
378148B	196730	3528D
379035A	209324-25	3530
380365A	202302-03	3660 - C.2.4
381730A	206701-12	3528A-C, 3835A-B, and 3318B
387495A	221630-31	3872A-B C.1.4
*3C5243A	284499	3046

* - Our records indicate the actuators supplied on these orders include motors with thermal contacts. We have not conducted any environmental tests on actuators including motors with thermal contacts and would recommend that they be removed from the control circuitry.

2. Our records indicate that our Qualification Report 80003 can apply to the actuators supplied on the following orders.

UNIT 1		
**357806B	151262-65	8112
358990B	169292-95	3441A-D
UNIT 2		
**357806B	151262-65	8112

** - Our records indicate that two of the actuators supplied on this order were converted to containment units (Qualification Report 600456), however, our records do not indicate the serial number of the units so revised.

3. Our records further indicate that our Qualification Report #600198 plus addendum 1 can be applied to the actuators supplied on the following orders. Report 600376A can be used to support the capability of the actuators only (not including motor) to withstand irradiation only. It would be necessary for you to provide us with the motor ID numbers to permit us to attempt to expand this statement to include the motor.

0058417

	Limitorque O/N	Actuator S/N	MOV No.
UNIT 1			
	357806AB	153642-47	8808A-C c.2.9
UNIT 2			
	357806AB	153642-47	8808A-C

4. Our records also indicate that our Report #C3271 can be applied to the actuators supplied on our O/N 358995B (S/N 175414) MOV 3046.

Very truly yours,

LIMITORQUE CORPORATION

J.B. Drab

J.B. Drab
Special Projects Engineer

wcd

214494 071250 5

APCo Exhibit 123

JOY

NUCLEAR CONTAINMENT AXIVANE FAN

OPERATORS HANDBOOK

CUSTOMER ORDER NO'S. 25-1351-1 & 25-1351-2

ALABAMA POWER COMPANY

FARLEY NUCLEAR PLANT #1

COLUMBIA (HOUSTON COUNTY), ALABAMA 36301

JOY MANUFACTURING COMPANY ORDERS NPX-63330 & NPX-63330A
FAN SERIAL NO'S. GF-17241 THRU GF-17250

JOY MANUFACTURING CO.
GENERAL PRODUCTS DIVISION
NEW PHILADELPHIA, OHIO

Revision 0

071251

ALABAMA POWER COMPANY

JOSEPH M. FARLEY NUCLEAR PLANT #1

COLUMBIA (HOUSTON COUNTY), ALABAMA 36301

871252

U-214494 Sheet 1

ENVIRONMENTALLY QUALIFIED COMPONENTS LIST

EQUIPMENT	COMPONENT TPNS	MODEL	DESCRIPTION
Q2E12H001A-A	Q2E12M001A-A	M/YE	Ctmt Cooler 2A
Q2E12H001B-A	Q2E12M001B-A	M/YE	Ctmt Cooler 2B
Q2E12H001C-B	Q2E12M001C-B	M/YE	Ctmt Cooler 2C
Q2E12H001D-B	Q2E12M001D-B	M/YE	Ctmt Cooler 2D

For further information on environmentally qualified components, see the Unit 2 E.Q. Masterlist, U-416798 (latest revision).

For replacement/maintenance schedule of environmentally qualified components, See U-416800 (latest revision) "Component, Maintenance and Replacement Schedule."

Environmentally Qualified Splices are required for field cable to motor lead terminations.

FOR INSERTION INTO MANUAL
U214494 UPDATING TO SHEET 1 A

REV. AO

TABLE OF CONTENTS

GENERAL DESCRIPTION

The fan units are …anufactured by JOY Manufacturing Company, New Philadelphia, Ohio 44663.

The general fan design consists of one (1) multi-bladed rotor assembly mounted directly on the motor shaft. The motor is supported by a bulkhead in an inner fairing and by motor cable conduit tubes.

Motor grease leads are extended to the outside of the fan casing with grease fittings attached. See attached motor manufacturer's instruction manual for motor maintenance and lubrication recommendations.

The fan rotor is of the adjustable pitch type which provides a method of changing the blade pitch when the fan is not in motion. This is accomplished by removing the Nose (Fan Rotor) and loosening the nut under each blade. After the blade setting has been made, each nut must be r tightened and the nose reinstalled.

Inspect fan for cause if excessive vibration is encountered. Rebalance fan if the cause of unbalance cannot be located. Observe fan closely for several weeks after restarting.

ORDERING SPARE PARTS

The following information should be given when ordering spare parts to insure prompt and efficient service:

1) Give serial number of the fan. This number can be found on the fan nameplate attached to the outside of the fan casing.

2) Give part number and name of part. Part numbers can be found on drawings and bills of material, furnished with this manual.

JOY MANUFACTURI[illegible]G COMPANY

071256

NAL 2-20-74

CUSTOMER'S ORDER NO.	DATE	REQ. NO.	MKT.	DATE	AT REC. POINT
25-1351 -2*	1-19-73		3	2-20-73	

CONTRACT	BRANCH	SHIP PT	STATE	IND.	TAX	AREA	DATE	AT SHIP POINT
100%	97	08	01	96	203	2	2-20-74	NPX-63330A

PAGE 2 OF 2

01533
SOLD TO

AMERICAN AIR FILTER
215 CENTRAL AVE.
LOUISVILLE, KY. 40208

GF-17241 THRU
GF-17245

INVOICE NO.

INVOICE DATE

DATE SHIPPED

SHIPPED VIA

3264
SHIP TO

ALABAMA POWER COMPANY
C/O W.A. LINDSTROM
C/O DANIEL CONST. CO.
JOSEPH M. FARLEY NUCLEAR PLANT #1
COLUMBIA (HOUSTON COUNTY), ALABAMA 36301*

MARKS
25-1351-2
AND AS NOTED

REQ ROUTING

FOB NPO
B/W/SURF/ALLOWED

FROM NEW PHILADELPHIA, O

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
	5			500722-103 SERIES 2000 JOY FAN MODEL			
				54-26-1170/870 NUCLEAR			
				CONTAINMENT-(VERTICAL MOUNTING)			
				1. 505543-87**STEEL ROTOR (A/P)			
				1. 600287-4 MOTOR 125/125 HP, 1200/900 RPM,			
				550/3/60AC, 2SP-2WDG, FRAME 5008, RELIANCE ELEC.			
				1. 600279-1 VIBRASWITCH			
				1. 74262 NAMEPLATE (STN'L ST.) STAMP DUTY ETC.			
				NOTE: STENCIL FAN WEIGHT ON FAN IN 3" LETTERS			
				AFTER PAINTING			
	5			505549-2509 INLET BELL (STEEL)			
				NOTE: STENCIL INLET BELL WEIGHT ON BELL IN 3"			
				LETTERS AFTER PAINTING.			
	5			505550-1871 INLET BELL FLAT STEEL SCREEN(1"MESH)			
	5			3386635-99 DISCHARGE CONE			
**CHANGE 1-22-75				NOTE: STENCIL CONE WEIGHT ON CONE IN 3" LETTERS			

HANGE 3-5-74

(CONTINUED)

071257

JOY JOY "ANUFACTURIN COMPANY

SOLD TO: AMERICAN AIR FILTER

PAGE NO. 2 GF-17241 THRU GF-17245

OUR ORDER NO | AT REC. POINT | AT SHIP POINT NPX-63330A

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				AFTER PAINTING.			
				FAN ARRANGEMENT PER DWG. #FF-13361 FF-13907			
	5			1388852-15 FABREEKA RING			
	5			700109-405 ERECTION HDW. (REF DWG. FF-13361) &FF-13907			
				PAINT SPECS: SURFACE PREPARATION PER FF-12144			
				700150-321 CARBOZINC #11 PRIMER			
				(BASE GREEN) (1COAT - 3 MILS DRY)			
				700150-322 PHENOLINE #305 FINISH			
				(CREAM #808) (1 COAT - 4 MILS DRY)			
				*BLADE SETTINGS:			
				FACT. 24½°, #1.5 SETTING. MIN #6-2° MAX #1-27°			
				TIP DIA. 53.80 IN. CAUTION EMBLEM 190458-1			
				SPECIAL REQUIREMENT SHEET ATTACHED.			
	1			AMCA PERFORMANCE & SOUND			
	6 COPIES & 2 SEPIAS			TEST (WITNESS-NOTIFY AAF - 2 WKS PRIOR			
				TO TEST.) PERFORMANCE & SOUND			
				TEST REPORT REQ'D - 2 SEPIAS & 6 COPIES			
				TEST ON ONE UNIT ONLY			
	1			SEISMIC ANALYSIS			
				2 SEPIAS - 6 COPIES			
	21			INSTRUCTION MANUALS			
				DATA REQUIRED ON MOTORS			
				1 SEPIA & 4 PRINTS-MOTOR OUTLINE DRAWINGS			
				1 SEPIA & 4 PRINTS-MOTOR DATA SHEETS			
				1 SEPIA & 4 PRINTS-MOTOR TEST DATA ANSIC-50.20-7			
				PRIOR TO DELIVERY CERTIFIED TYPICAL TEST			

(CONTINUED)

JOY

JOY MANUFACTURING COMPANY

071258

SOLD TO AMERICAN AIR FILTER

PAGE NO. 3 GF-17241 THRU GF-17245

OUR ORDER NO.	AT REC. POINT	AT SHIP POINT
		NPX-63330

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY SINCE ORDERED	PART NUMBER / DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				DATA IS ACCEPTABLE			
				1 SEPIA & 4 PRINTS-SPEED TORQUE CURVE @ RATED VOLTAGE SUPERIMPOSED ON FAN TORQUE CURVE-PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-SPEED VS TIME FOR ACCELERATION OF SPECIFIED LOAD-PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-CURRENT VS SPEED-PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-SPEED VS POWER FACTOR-PRIOR TO DELIVERY.			
				NOTE. ALL CURVES AT 100% AND 75% RATED VOLTAGE.			
				1 SEPIA & 4 PRINTS-CERTIFICATION OF SEISMIC QUALIFICATION OF MOTOR PER APPENDIX 1.0 PARA 2.0 (6) OF MOTOR SPEC.			
				SPECIAL REQUIREMENTS (QUALITY CONTROL)			
				MATERIAL CERTIFICATION			
				CERT. OF CONFORMANCE (BECHTEL FORM)			
				CERT. OF COMPLIANCE			
				MILL TEST REPORTS			
				BALANCE TEST REPORT			
				LIQUID PENETRANT TEST REPORT (ROTOR-AFTER WHIRL TEST)			
				INSPECTION CHECK LIST			
				WHIRL TEST REPORT			
				MOTOR SUPPLIER CERT. OF COMPLIANCE			
				NOTE: 4 COPIES OF EACH TO BE SHIPPED WITH EACH FAN			

(CONTINUED)

JOY "ANUFACTURIN~ COMPANY 071259

SOLD TO AMERICAN AIR FILTER

PAGE NO. 4 GF-17241 THRU GF-17245

OUR ORDER NO.	AT REC. POINT	AT SHIP POINT
		NPX-63330

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				1 COPY OF EACH TO CENTRAL FILE			
				1 COPY OF EACH TO MKT. DEPT. (S. HARRIS)			
				NOTE: SPECIAL MARKING (METAL TAGS TO BE STAMPED WITH FOLLOWING MARKING & SECURELY ATTACHED TO FAN)			
				SERIAL NOS. — MARKING — @UNIT			
				GF-17241 — Q1E12-H001A-A — @1			
				GF-17242 — Q1E12-H001B-A — @1			
				GF-17243 — Q1E12-H001C-B — @1			
				GF-17244 — Q1E12-H001D-B — @1			
				GF-17245 — **Q1E12C001 — @1			
				REQ DEL: 5 EA. 8-14-73 DEL PROM: END OF 8-74			

HANGE 11-4-74
*CHANGE 8-15-74
*SPEC. REQM'T SHEET ATTACHED (CHANGE 3-5-74)

071260

JOY MANUFACTURI G COMPANY

FINAL 2-15-74

CUSTOMER'S ORDER NO.	DATE	REQ. NO.	MKT.	DATE	AT REC. POINT
25-1351-1	11-19-73		3	2-20-73	

CONTRACT	BRANCH	SHIP PT.	STATE	IND.	TAX	AREA	DATE	AT SHIP POINT
100%	97	08	01	96	203	2	2-15-74	NPX-63330

PAGE 1 OF 2

01533 SOLD TO
AMERICAN AIR FILTER
215 CENTRAL AVE.
LOUISVILLE, KY. 40208

GF-17246 THRU
17250

INVOICE NO.

INVOICE DATE

DATE SHIPPED

SHIPPED VIA

3264 SHIP TO
ALABAMA POWER COMPANY
C/O W.A. LINDSTROM
C/O DANIEL CONST. CO.
JOSEPH M. FARLEY NUCLEAR PLANT #1
COLUMBIA (HOUSTON COUNTY), ALABAMA

REQ ROUTING
FOB NPO
B/W/SURF/ALLOWED

MARKS 25-1351-1
AND AS NOTED

FROM NEW PHILADELPHIA, O

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
	5			500722-103 SERIES 2000 JOY FAN MODEL			
				54-26-1170/870 NUCLEAR			
				CONTAINMENT-(VERTICAL MOUNTING)			
				1. 505543-87* STEEL ROTOR (A/P)			
				1. 600287-A MOTOR, 125/125 HP, 1200/900 RPM,			
				550/3/50 AC, 2SP-2WDG, FRAME 5008, RELIANCE ELEC.			
				1. 600279-1 VIBRASWITCH			
				1. 74262 NAMEPLATE (STNL ST.) STAMP DUTY ETC.			
				NOTE: STENCIL FAN WEIGHT ON FAN IN 3" LETTERS			
				AFTER PAINTING			
	5			505549-2509 INLET BELL (STEEL)			
				NOTE: STENCIL INLET BELL WEIGHT ON BELL IN 3"			
				LETTERS AFTER PAINTING.			
	5			505550-1871 INLET BELL FLAT STEEL SCREEN (1" MESH)			
	5			3386635-99 DISCHARGE CONE			
*CHANGE 1-22-75				NOTE: STENCIL CONE WEIGHT ON CONE IN 3" LETTERS			
				AFTER PAINTING			

071261

JOY MANUFACTURING COMPANY

SOLD TO AMERICAN AIR FILTER

PAGE NO. 2 GF-17246 THRU 17250

OUR ORDER NO.	AT REC. POINT	AT SHIP POINT
		NPX-63330

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER / DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				FAN ARRANGEMENT PER DWG. #FF-13361			
				FF-13907			
	5			1388852-15 FABREEKA RING			
	5			700109-405 ERECTION HDW. (REF DWG.FF-13361) & FF-13907			
				PAINT SPECS: SURFACE PREPARATION PER FF-12144			
				700150-321 CARBOZINC #11 PRIMER BASE GREEN)			
				(1 COAT - 3 MILS DRY)			
				700150-322 PHENOLINE #305 FINISH (CREAM #808)			
				(1 COAT-4 MILS DRY)			
				*BLADE SETTINGS: MIN #6-2°			
				FACT. 24½°, #1.5 SETTING. MAX #1-27°			
				TIP DIA. 53.80 IN. CAUTION EMBLEM 190458-11			
				SPECIAL REQUIREMENT SHEET ATTACHED.			
	1			AMCA PERFORMANCE & SOUND			
				6 COPIES TEST (WITNESS-NOTIFY AAF-2 WKS PRIOR			
		2 SEPIA		TO TEST.) PERFORMANCE & SOUND			
				TEST REPORT REQ'D - 2 SEPIAS & 6 COPIES			
				TEST ON ONE UNIT ONLY			
	1			SEISMIC ANALYSIS			
				2 SEPIAS - 6 COPIES			
	21			INSTRUCTION MANUALS			
				DATA REQUIRED ON MOTORS			
				1 SEPIA & 4 PRINTS-MOTOR OUTLINE DRAWINGS			
				1 SEPIA & 4 PRINTS-MOTOR DATA SHEETS			
				1 SEPIA & 4 PRINTS-MOTOR TEST DATA ANSIC-50.20-7			
				PRIOR TO DELIVERY CERTIFIED TYPICAL TEST			

(CONT.)

071262

JOY MANUFACTURING COMPANY

SOLD TO AMERICAN AIR FILTER

PAGE NO. 3 GF-17246 THRU 17250

OUR ORDER NO.	AT REC. POINT	AT SHIP POINT
		NPX-63330

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER / DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				DATA IS ACCEPTABLE.			
				1 SEPIA & 4 PRINTS-SPEED TORQUE CURVE @ RATED VOLTAGE SUPERIMPOSED ON FAN TORQUE CURVE-PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-SPEED VS TIME FOR ACCELERATION OF SPECIFIED LOAD - PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-CURRENT VS SPEED-PRIOR TO DELIVERY.			
				1 SEPIA & 4 PRINTS-SPEED VS POWER FACTOR-PRIOR TO DELIVERY.			
				NOTE: ALL CURVES AT 100% AND 75% RATED VOLTAGE.			
				1 SEPIA & 4 PRINTS-CERTIFICATION OF SEISMIC QUALIFICATION OF MOTOR PER APPENDIX 1.0 PARA. 2.0 (6) OF MOTOR SPEC.			
				SPECIAL REQUIREMENTS (QUALITY CONTROL)			
				MATERIAL CERTIFICATION			
				CERT. OF CONFORMANCE (BECHTEL FORM)			
				CERT. OF COMPLIANCE			
				MILL TEST REPORTS			
				BALANCE TEST REPORT			
				LIQUID PENETRANT TEST REPORT (ROTOR AFTER WHIRL TEST)			
				INSPECTION CHECK LIST			
				WHIRL TEST REPORT			
				MOTOR SUPPLIER CERT. OF COMPLIANCE			
				NOTE: 4 COPIES OF EACH TO BE SHIPPED WITH EACH FAN 1 COPY OF EACH TO CENTRAL FILE			

(CONT.)

071263

JOY MANUFACTURING COMPANY

D
J AMERICAN AIR FILTER

PAGE NO. 4 GF-17241 THRU GF-17245

OUR ORDER NO.	AT REC. POINT	AT SHIP POINT
		NPX-63330

ITEM NO.	ORIGINAL QUANTITY ORDERED	QUANTITY SHIPPED	QUANTITY BACK ORDERED	PART NUMBER / DESCRIPTION	SALES CODE	UNIT PRICE	AMOUNT
				1 COPY OF EACH TO CENTRAL FILE			
				1 COPY OF EACH TO MKT. DEPT. (S. HARRIS)			
				NOTE: SPECIAL MARKING (METAL TAGS TO BE STAMPED WITH FOLLOWING MARKING & SECURELY ATTACHED TO FAN)			
				SERIAL NOS. — MARKING — @UNIT			
				GF-17241 — Q1E12-H001A-A — @1			
				GF-17242 — Q1E12-H001B-A — @1			
				GF-17243 — Q1E12-H001C-B — @1			
				GF-17244 — Q1E12-H001D-B — @1			
				GF-17245 — **Q1E12C001 — @1			
				REQ DEL: 5 EA. 8-14-73 DEL PROM: END OF 8-74			

*CHANGE 11-4-74
**CHANGE 8-15-74
*SPEC. REQM'T SHEET ATTACHED (CHANGE 3-5-74)

071264

REPORT NO. X-463

DATE February 11, 1975

JOY MANUFACTURING CO.

NEW PHILADELPHIA, OHIO

WITNESS TEST REPORT

ON

JOY SERIES 2000 AXIVANE FAN

FAN MODEL: 54-26-1170/870
FAN UNIT NO.: 500722-103
FAN SERIAL NOS.: GF-17246 THROUGH GF-17250
JOY PURCHASE ORDER NO.: NPX-63330 & NPX-63330A

SOLD TO: AMERICAN AIR FILTER
215 CENTRAL AVENUE
LOUISVILLE, KENTUCKY 40208

INSTALLATION: JOSEPH M. FARLEY NUCLEAR PLANT #1
COLUMBIA (HOUSTON COUNTY), ALABAMA

PREPARED BY T.E. Frank/ T. E. Frank

CHECKED BY R.M. Jordan/ R Jordan

APPROVED BY T.A. Bissett/ T A Bissett

REVISIONS

DATE	PAGES AFFECTED	REMARKS

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO 44663

DATE: February 11, 1975
PAGE 1 OF 14
REPORT NO. X-463

TEST CERTIFICATION SUMMARY

PURCHASER: American Air Filter
215 Central Avenue
Louisville, Kentucky 40208

MFGRS. ORDER NO. WPX-63330 & WPX-63330A
PURCHASE ORDER NO. 25-1351-1

DESCRIPTION OF FAN:

TYPE Axial UNIT 500722-103 MODEL 54-26-1170/870
CFM 76763 PRESSURE 4.57" P_t DENSITY 0.075#/Cu.Ft.
SERIAL NO. GF-17246 through GF-17250*

DESCRIPTION OF MOTOR:

MFGR. Reliance PART NO. 600287-4 TYPE TEAO FRAME 5008
SERIAL NO. HP 125/125 RPM 1200/900 VOLTAGE 550
AMP 132/138 PHASE 3 CYCLE 60 RISE Spcl.
JOY PART NO. 600287-4 SERVICE FACTOR 1.0

TIME AND PLACE OF TESTING:

Joy Manufacturing Co. Test Laboratory, New Philadelphia, Ohio
Monday through Friday, February 3 through February 7, 1975

WITNESSES: Mr. W. T. Fox, Bechtel Corp.

* Fan S/N GF-17250 was not tested at this time. The performance curve (page 12) and sound levels will be added to this report upon completion of testing.

SEE NEXT PAGE FOR TESTS CONDUCTED, RESULTS, AND SUMMARY.

071266

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO 44663

DATE February 11, 1975

PAGE 2 OF 14

REPORT NO. X-463

TEST CERTIFICATION SUMMARY

TESTS CONDUCTED: TEST RESULTS:

Performance tests were conducted per AMCA Bulletin 210-67, Figure 1.1. Test results are given on pages 3 through 12 for normal operation. Curve No. C-6294, page 13, shows fan operation at leak test and refueling conditions. C-6295, page 14, shows the fan operation at accident condition.

Sound power tests were also conducted. The results are given below.

SOUND POWER LEVEL - DB re 10^{-12} WATTS

FAN SERIAL NO.	STATIC PRESSURE INCHES W.G.	OCTAVE BAND 1	2	3	4	5	6	7	8
GF-17241	3.24	99	103	106	107	105	100	94	89
GF-17242	3.15	98	106	109	107	106	102	94	90
GF-17243	3.02	101	103	107	108	108	103	96	90
GF-17244	3.20	99	103	109	109	106	101	94	89
GF-17245	3.21	100	103	106	107	106	102	96	92
GF-17246	3.03	100	101	108	108	107	102	96	90
GF-17247	3.10	99	103	105	108	107	103	96	90
GF-17248	3.22	100	102	106	107	103	99	95	89
GF-17249	3.06	101	102	106	109	107	103	96	92
GF-17250									

DATE OF CERTIFICATION

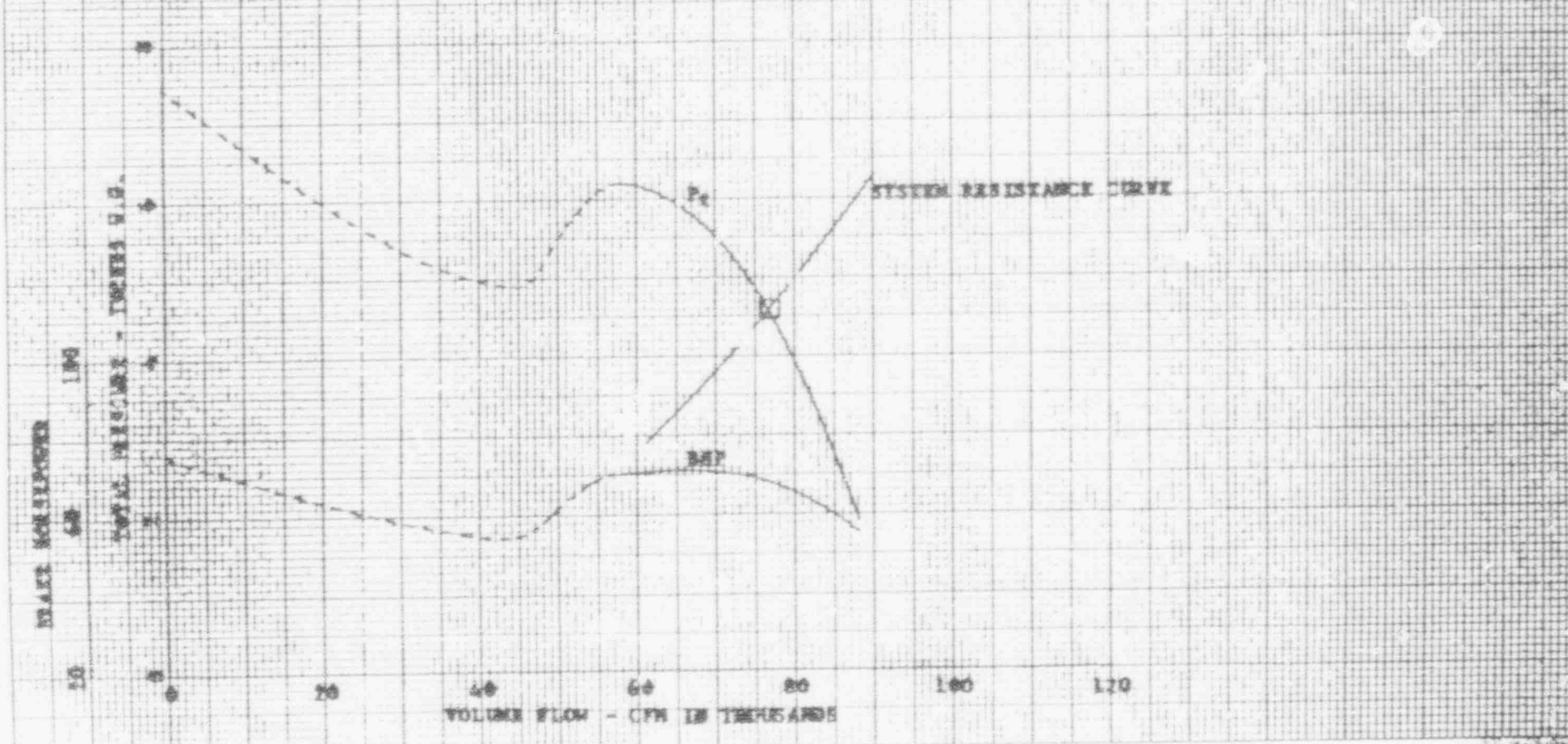
K·E 10 X 10 TO ½ INCH 46 1323
7 X 10 INCHES
KEUFFEL & ESSER CO.

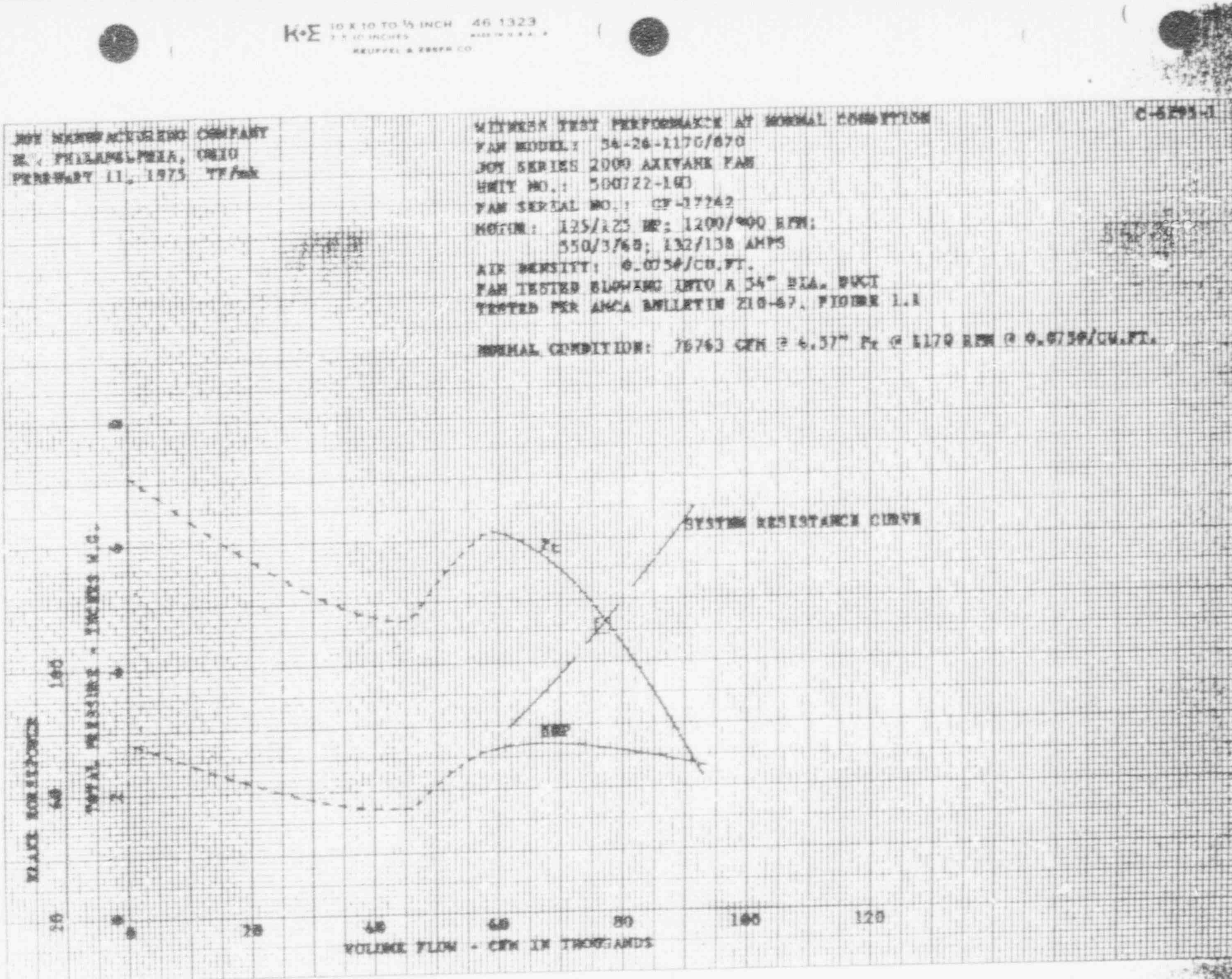
JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/mk

C-6293

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/879
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: GF-17261
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1

NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.075#/CU.FT.




K·E 10 X 10 TO ½ INCH 46 1323
KEUFFEL & ESSER CO.
C-6295-1
JOY MANUFACTURING COMPANY
N. PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/mk
WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 34-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-10D
FAN SERIAL NO.: CF-17742
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 34" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1
NORMAL CONDITION: 76763 CFM @ 6.37" Pt @ 1170 RPM @ 0.075#/CU.FT.
SYSTEM RESISTANCE CURVE
Pt
BHP
BRAKE HORSEPOWER
TOTAL PRESSURE - INCHES W.G.
VOLUME FLOW - CFM IN THOUSANDS
0
20
40
60
80
100
120
2
4
6
8
20
60
100

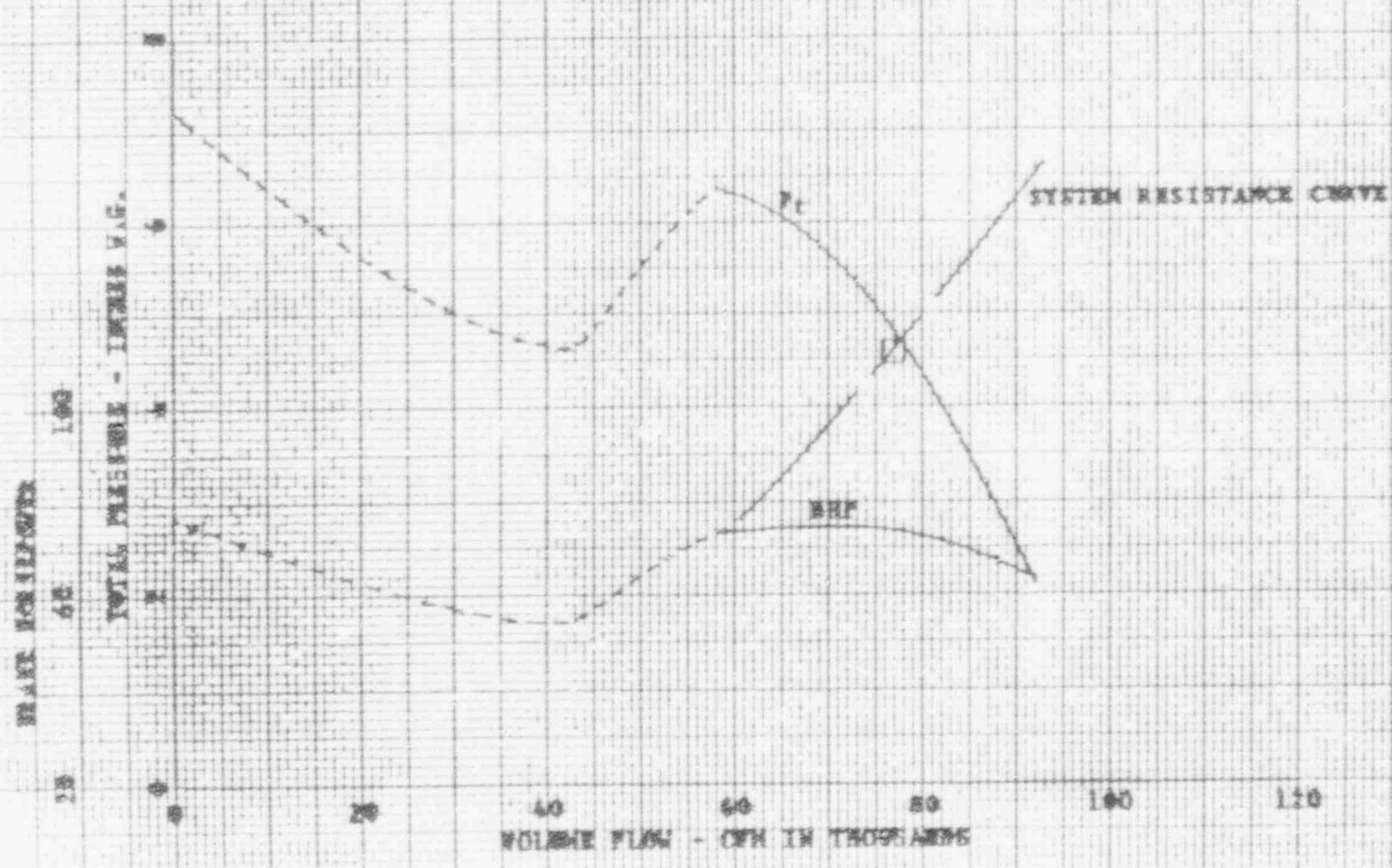
K+E 10 X 10 TO ½ INCH 46 1323
KEUFFEL & ESSER CO.

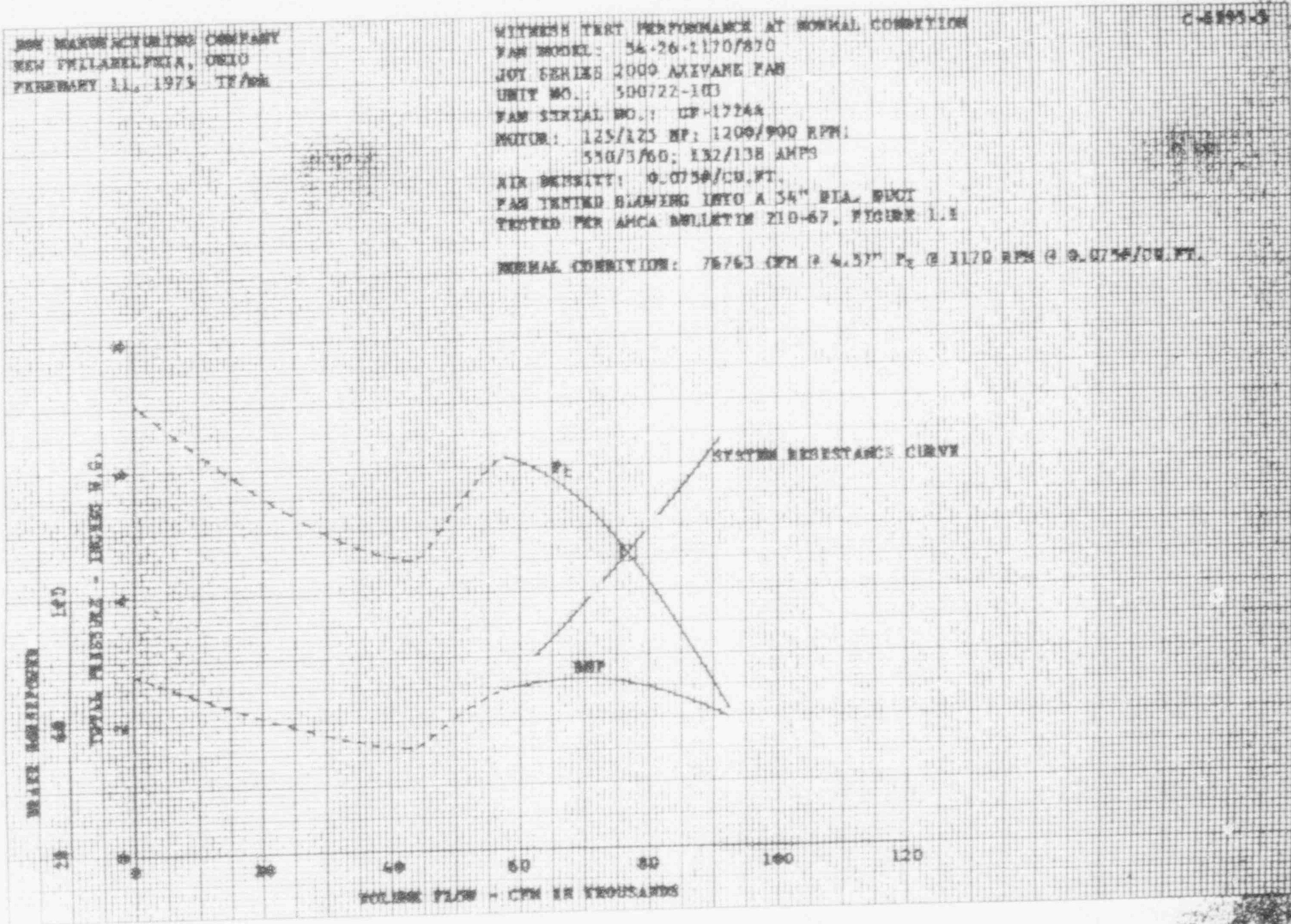
C-6293-2

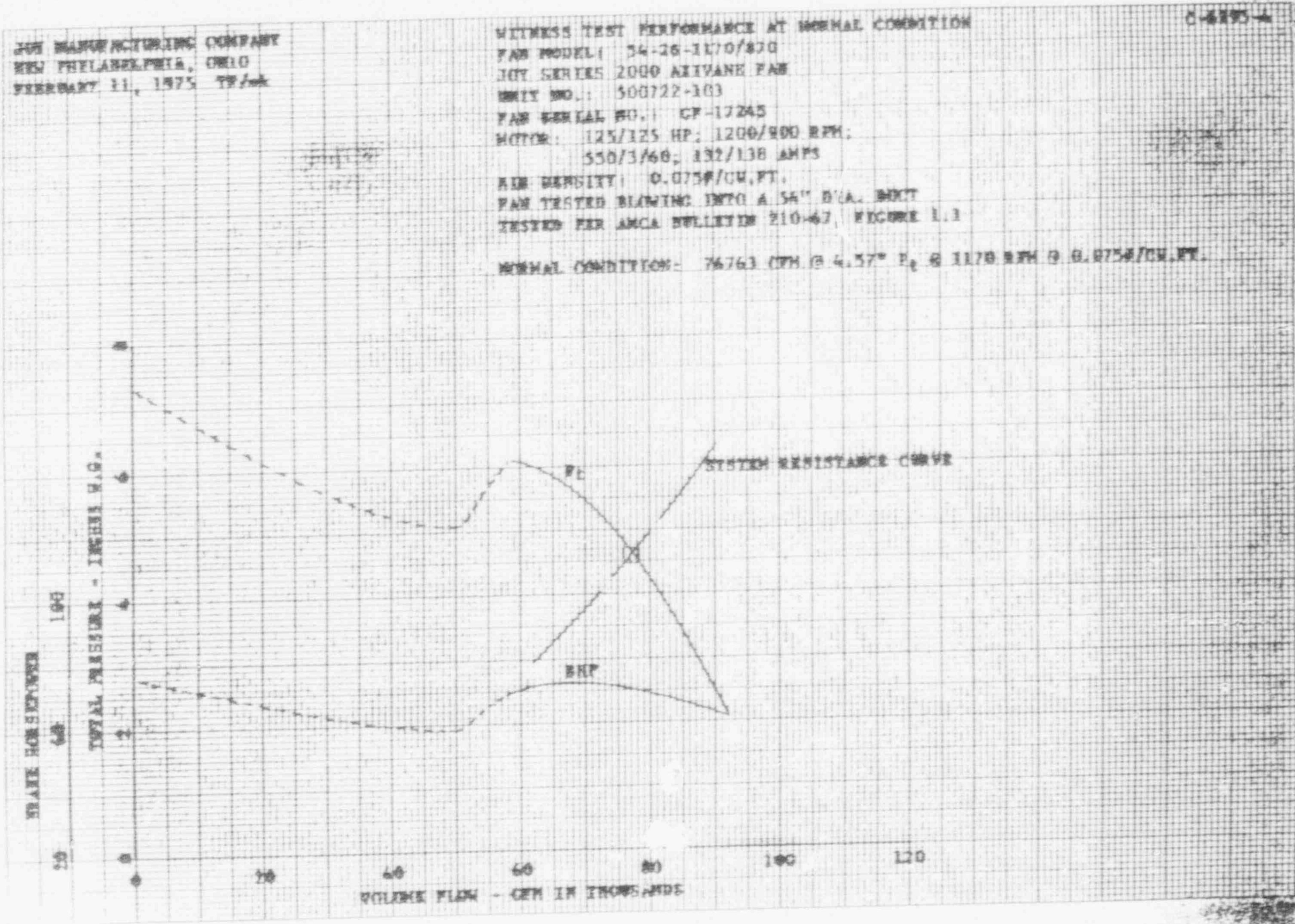
JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TP/mk

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 34-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: CF-17243
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.073#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1

NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.073#/CU.FT.




JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/bk
WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 300722-103
FAN SERIAL NO.: CF-17244
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.0750/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1
NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.0750/CU.FT.
C-6895-3
SYSTEM RESISTANCE CURVE
P_t
BHP
TOTAL PRESSURE - INCHES W.G.
BRAKE HORSEPOWER
120
40
0
20
40
60
80
100
120
VOLUME FLOW - CFM IN THOUSANDS


JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/mk
C-6395-A
WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 300722-103
FAN SERIAL NO.: CF-17245
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1
NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.075#/CU.FT.
SYSTEM RESISTANCE CURVE
P_t
BHP
BRAKE HORSEPOWER
TOTAL PRESSURE - INCHES W.G.
VOLUME FLOW - CFM IN THOUSANDS
8
6
4
2
0
100
60
20
0
20
40
60
80
100
120

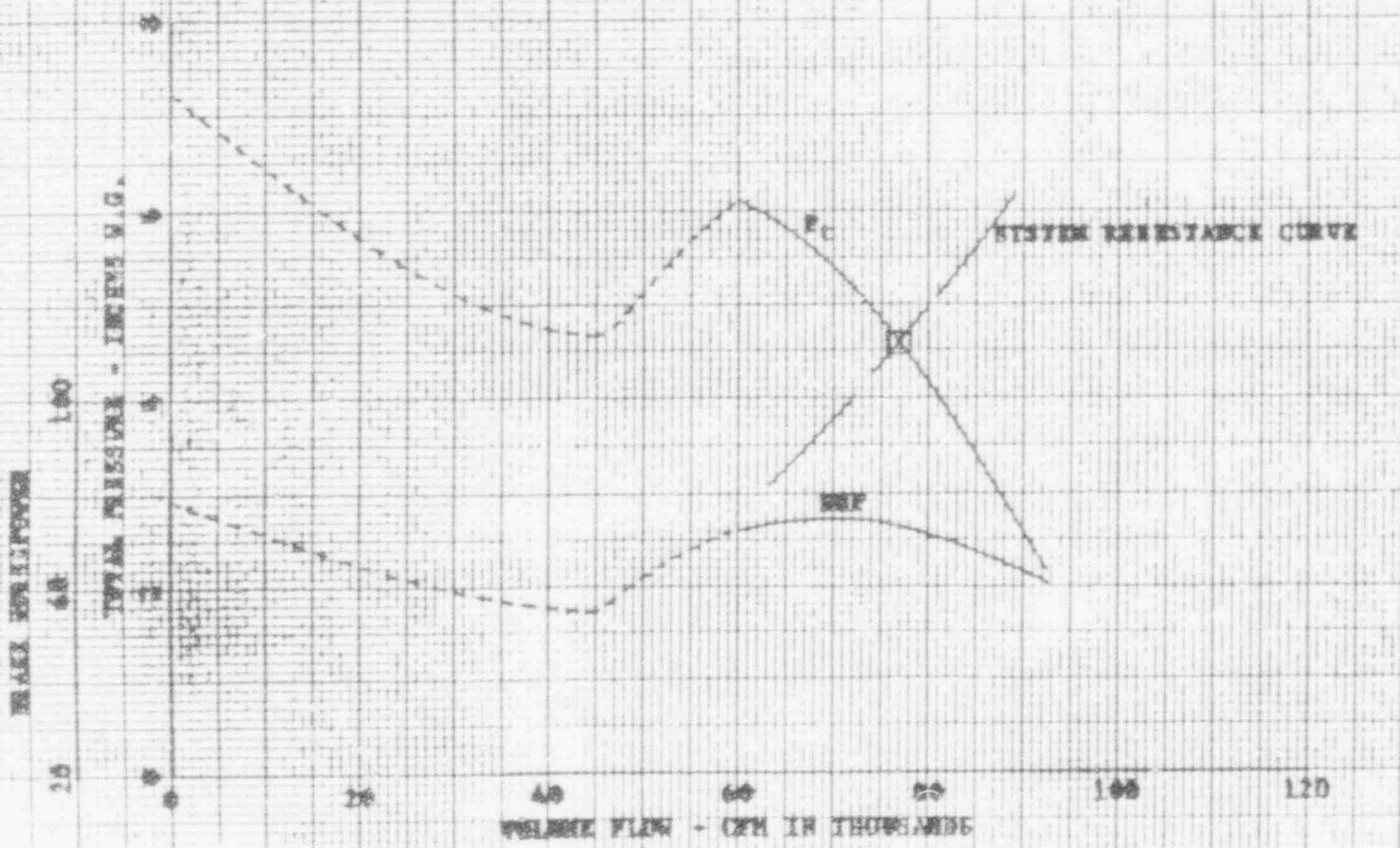
K•E 10 X 10 TO ½ INCH 46 1323
KEUFFEL & ESSER CO.

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/mk

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: GF-17266
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1

NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.075#/CU.FT.

C-5398-3



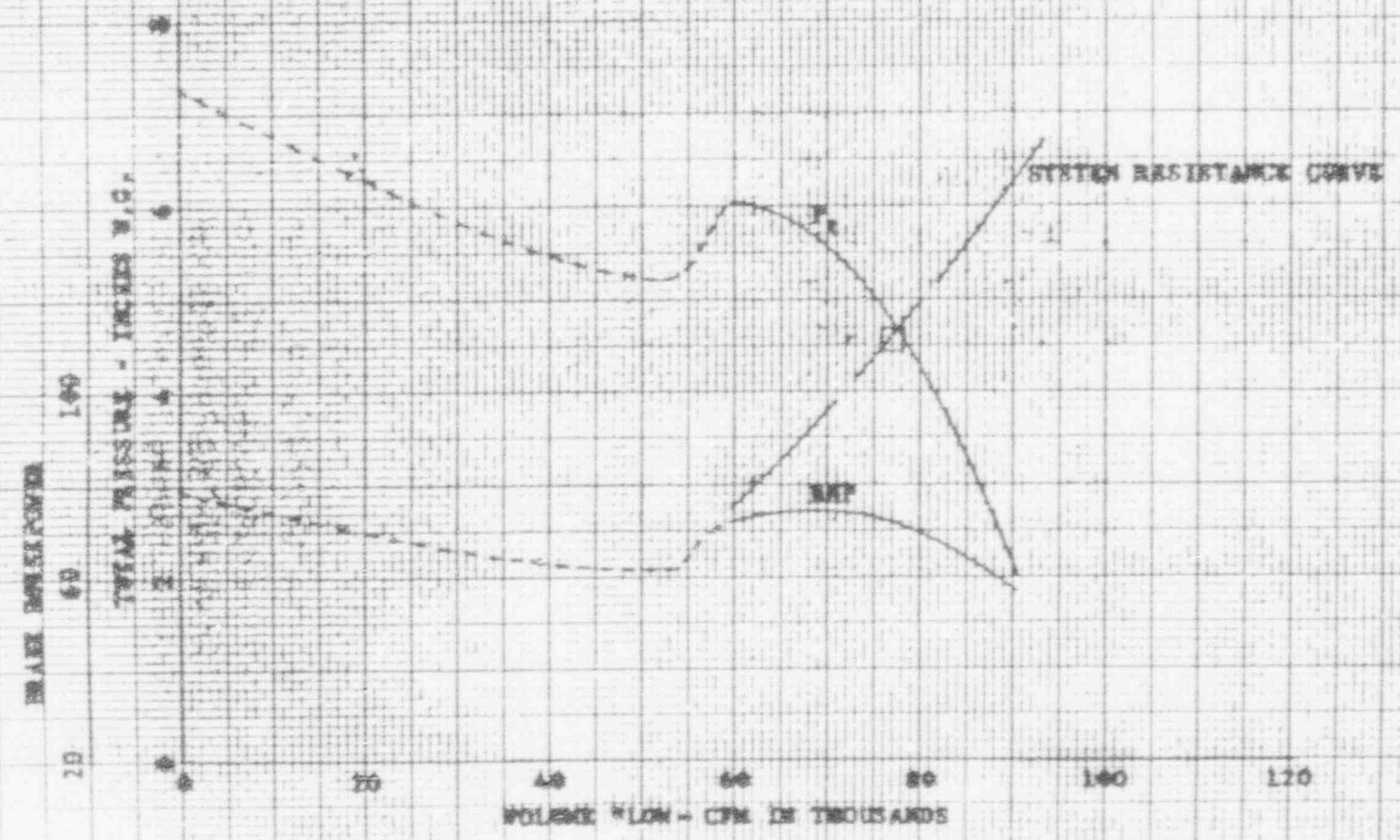
K+E 10 X 10 TO ½ INCH 46 1323
KEUFFEL & ESSER CO.

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TP/mk

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: GF-17287
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1

C-4295-A

NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1170 RPM @ 0.075#/CU.FT.

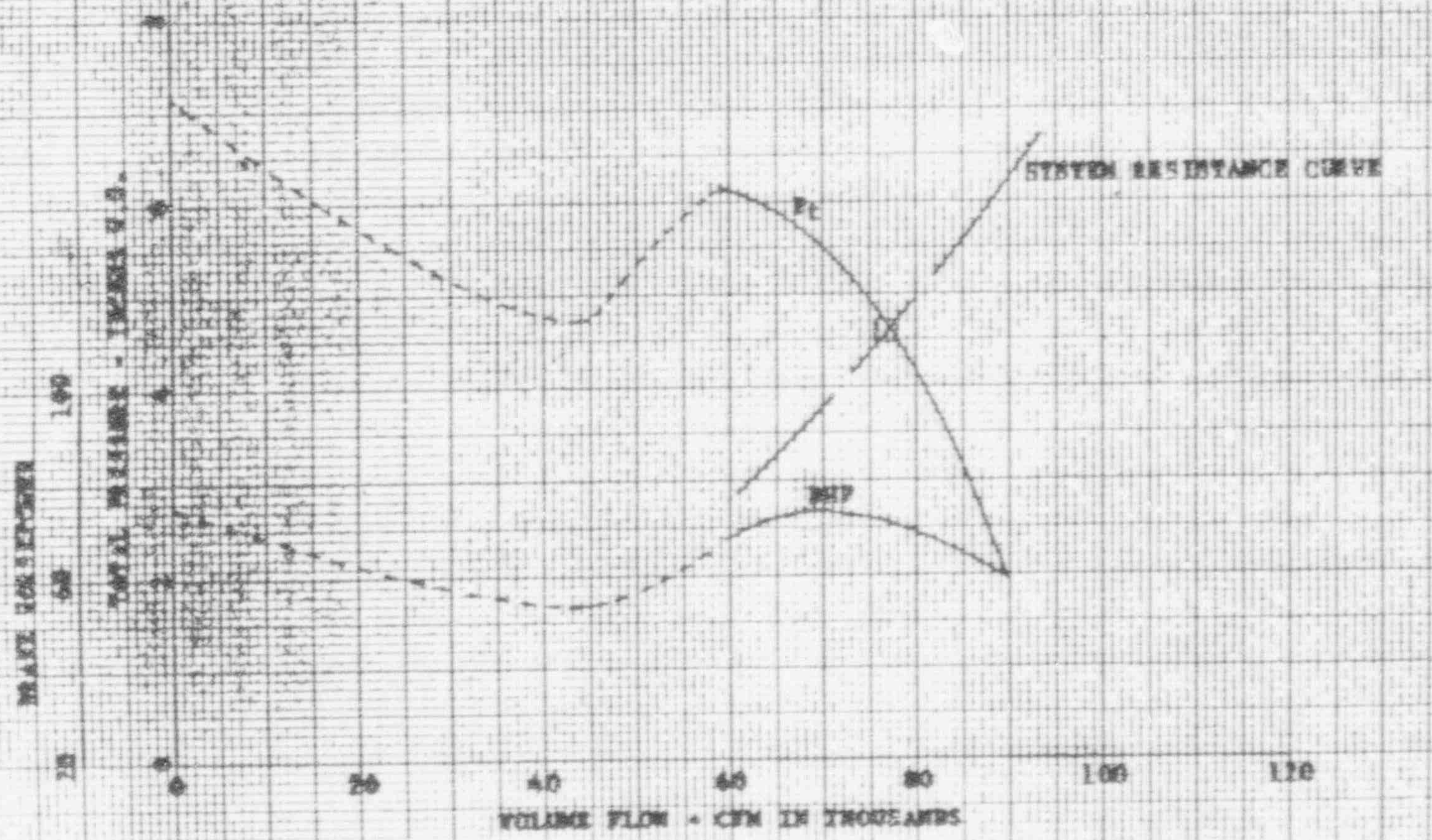


071273

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TP/mk

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: CF-17248
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.8

NORMAL CONDITION: 75763 CFM @ 4.57" P_t @ 1170 RPM @ 0.075#/CU.FT.



071274

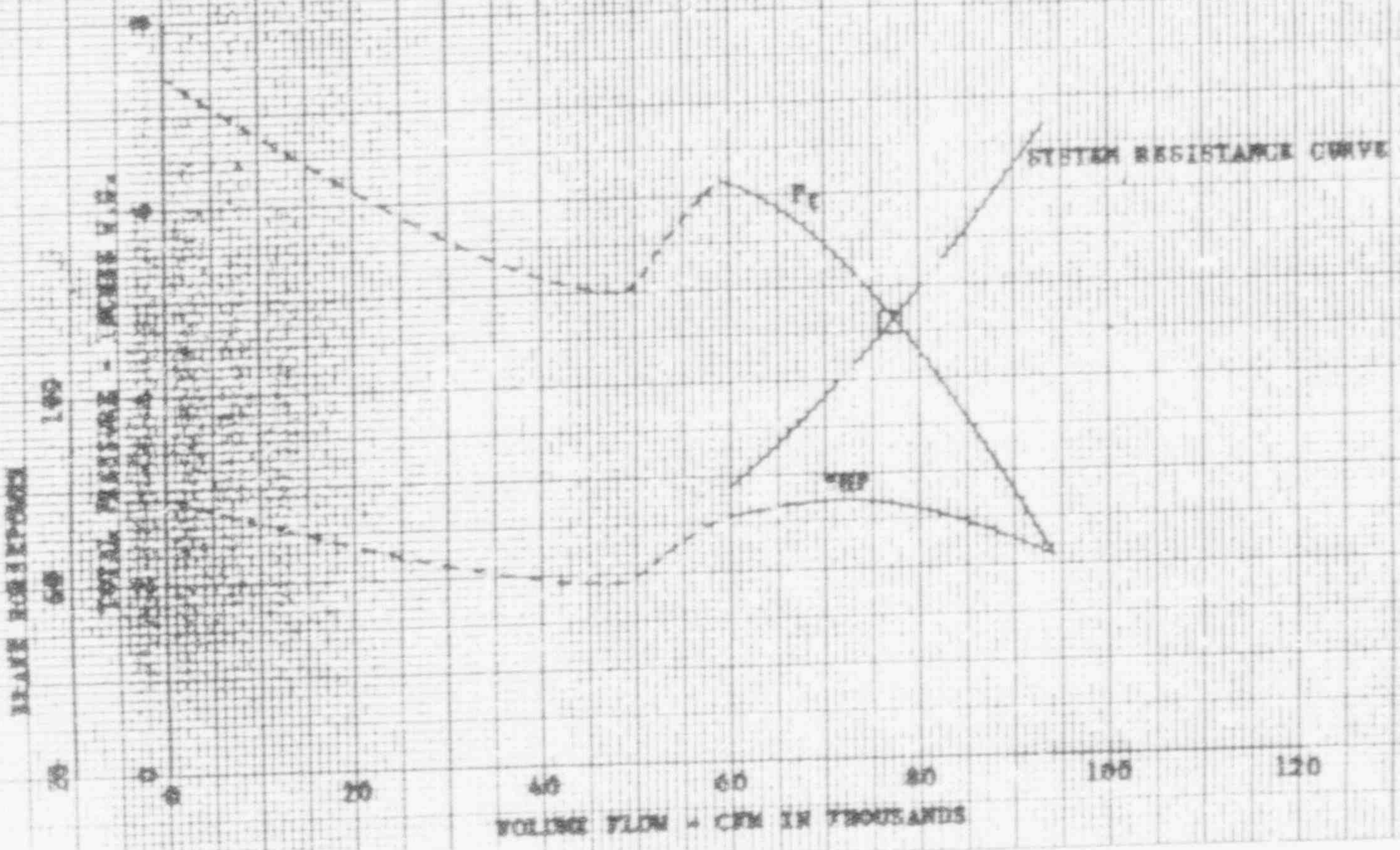
K+E 10 X 10 TO ½ INCH 46 1323
7 X 10 INCHES
KEUFFEL & ESSER CO.

C-4295-4

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TF/mk

WITNESS TEST PERFORMANCE AT NORMAL CONDITION
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500/22-163
FAN SERIAL NO.: UF-17249
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: 0.075#/CU.FT.
FAN TESTED BLOWING INTO A 54" DIA. DUCT
TESTED PER AMCA BULLETIN 210-67, FIGURE 1.1

NORMAL CONDITION: 76763 CFM @ 4.57" P_t @ 1178 RPM @ 0.075#/CU.FT.



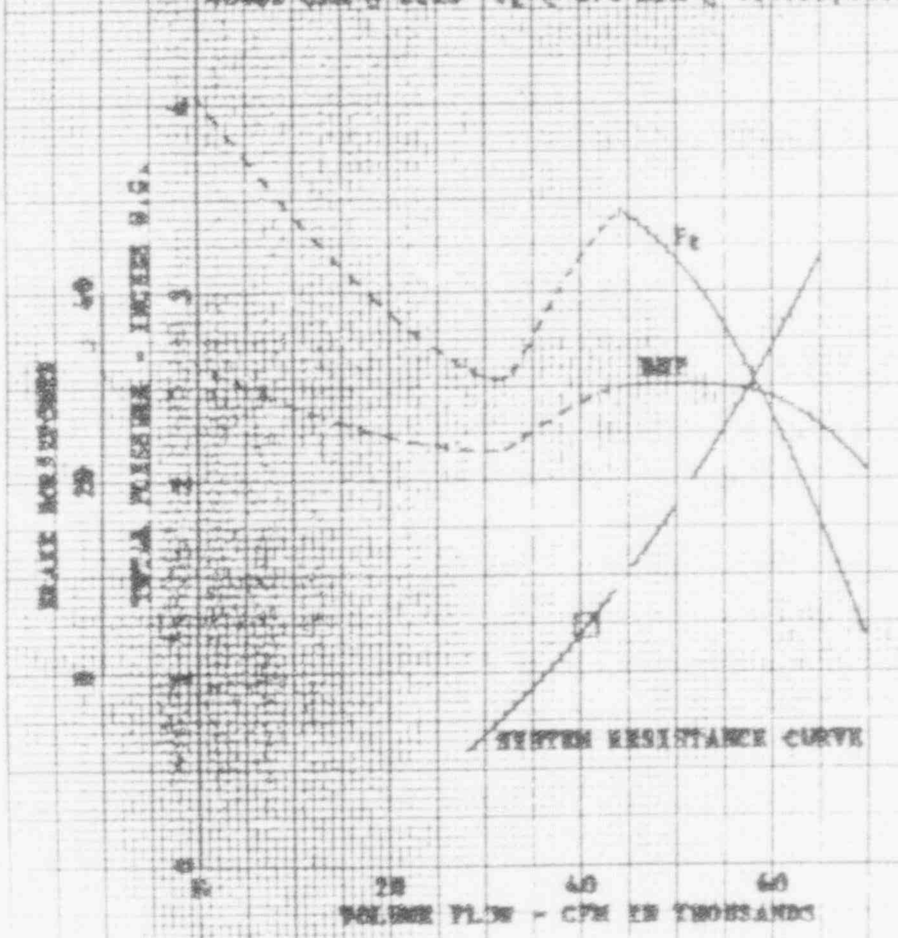
071275

JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1976 TF/mk

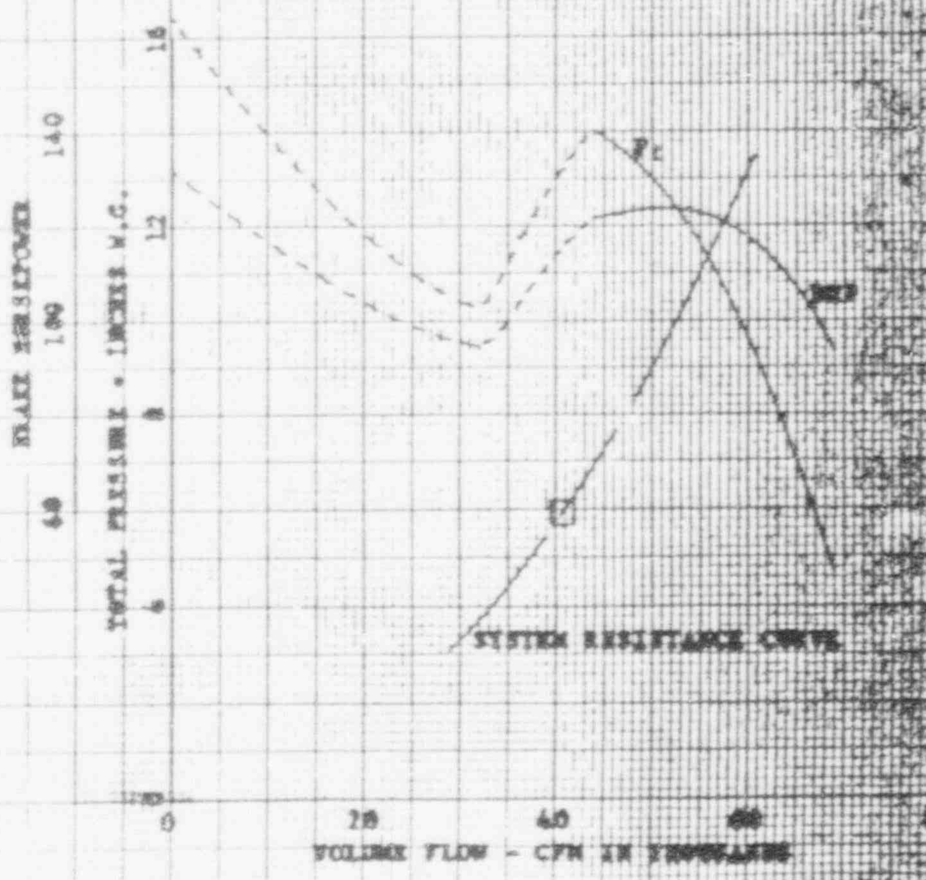
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: GF-17244
MOTOR: 125/125 HP; 1200/900 RPM;
550/3/60; 132/138 AMPS
AIR DENSITY: STATED BELOW
FAN BLOWING INTO A 54" DIA. DUCT

C-4206

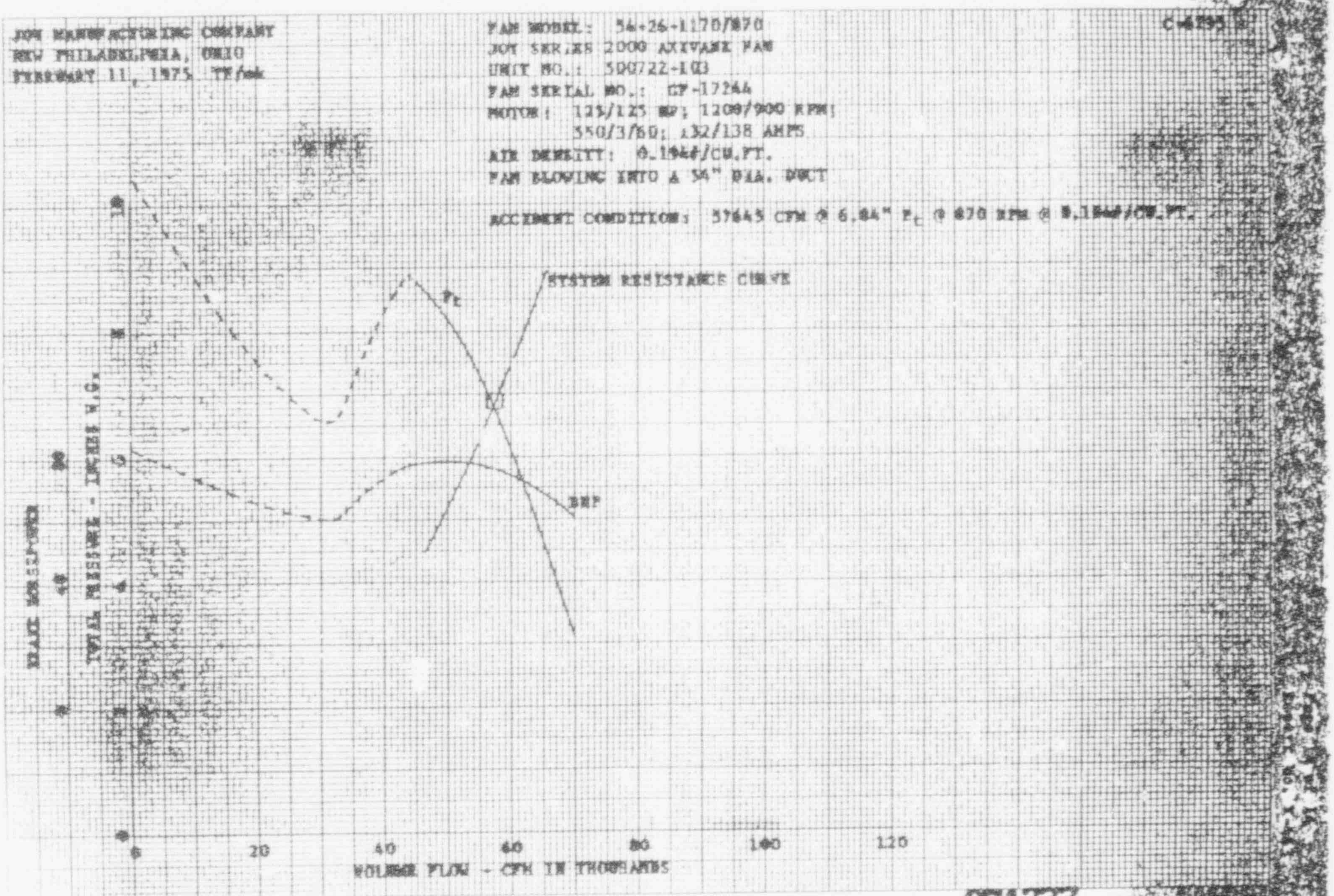
[illegible] CONDITION (TESTED):
40469 CFM @ 1.23" P_t @ 870 RPM @ 0.075#/CU.FT.



LEAK TEST CONDITION:
40596 CFM @ 5.83" P_t @ 870 RPM @ 0.366#/CU.FT.



071276


JOY MANUFACTURING COMPANY
NEW PHILADELPHIA, OHIO
FEBRUARY 11, 1975 TE/mk
FAN MODEL: 54-26-1170/870
JOY SERIES 2000 AXIVANE FAN
UNIT NO.: 500722-103
FAN SERIAL NO.: GP-17244
MOTOR: 125/125 HP; 1200/900 RPM;
350/3/60; 132/138 AMPS
AIR DENSITY: 0.1944/CU.FT.
FAN BLOWING INTO A 54" DIA. DUCT
ACCIDENT CONDITION: 37645 CFM @ 6.84" Pt @ 870 RPM @ 0.1944/CU.FT.
SYSTEM RESISTANCE CURVE
Pt
BHP
BRAKE HORSEPOWER
TOTAL PRESSURE - INCHES W.G.
VOLUME FLOW - CFM IN THOUSANDS
0
20
40
60
80
100
120

071277

Same drawing as in U258759

07128

DWG. No. FCC-13361

071279

DWG. No. FF-13907

See U258759

071280

DWG. No. 500722-103

JOY MANUFACTURING CO.

BILL OF MATERIAL

DRAWING NO. 071791

500722-103 (4)
FF-13361 (3)
FF-14027 (3)

BILL OF MAT. NO. 500722-103

SHEET NO. 1 OF 3

NAME Joy Axivane Fan
Model 54-26 1/2-1170/870

ORDER NO. T.O.K.

ISSUED	H.A.B.		NBT148		1-16-74	
NBU651						
NBU697						

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
	1	505543-~~86~~ -87	Rotor Assembly		
	2	505549-1639	Breather Drain		
	1	505549-2717	Casing Assembly		
	1	505549-2720	Motor Support		
	1	600279-1	Vibra-Switch		
	1	600287-4	Motor FRM. 5008		
	1	1383393-76	Motor Support Disc		
	1	1388113-2	Nose		
	1	1387348-2	Washer		
	1	1387348-5	Washer		
	1	1388789	Flange Adapter		
	1	1388790	Flange Adapter		
	4	900258-13	#6 x 1/4" Rd. Hd. Drive Screw		
	12	900026-390	1/4-20 x 5/8 Hex Hd. Capscrew Dr. Hd.		
			(Stainless Steel)		
	4	900037-21	1/4-20 x 1 1/4 Hex Hd. Capscrew		
	4	900037-395	1/4-20 x 3/8 Hex Hd. Capscrew		
	10	900037-24	1/2-13 x 1 1/4 Hex Hd. Capscrew		
	~~16~~ 8	900026-35	5/8-11 x 1 1/2 Hex Hd. Capscrew Dr. Hd.		
			(Stainless Steel)		
	A/R	76857-7	Safety Wire (Stainless Steel)		
	8	900026-95	5/8-11 x 2 Hex Hd. [illegible]		

JOY MANUFACTURING CO

BILL OF MATERIAL

071282

BILL OF MAT. NO. 500722-10

SHEET NO. 2 OF 3

ORDER NO.

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
	12	900303-1	1/4 Spring Lockwasher (Stain. Stl.)		
	8	900305-1	1/4 Spring Lockwasher		
	10	900305-4	1/2 Spring Lockwasher		
	16	900303-5	5/8 Spring Lockwasher (Stain. Stl.)		
	4	901285-2	1/4" Pipe Coupling		
	1	901285-8	1 1/2" Pipe Coupling		
	1	902469-359	1 1/2" x 14 1/2" Pipe Nipple		
	1	902469-1533	3" x 16 1/2" Pipe Nipple		
		GREASE INLET FITTINGS - MOTOR			
	2	901261-1	1/8" Grease Fittings		
	2	901160-1	1/4" x 1/8" Pipe Bushing		
	2	907235-54	Adapter - 5/16 O.D. Flare Tube To		
			1/4" Female Pipe		
	A/R	901509-788	5/16 O.D. Stain. Stl. Tubing		
			(Trim To Lg.)		
	4	907465-5	Tube Nut - 37° Flare - 5/16" O.D. Tube		
	4	907475-5	Tube Sleeve - 37°Flare - 5/16" O.D. Tube		
	1	907235-52	Adapter - 5/16 O.D. Flare Tube To		
			1/8" Female Pipe		
	1	907256-52	90 Elbow 5/16 O.D. Flare Tube To 1/8"		
			Female Pipe		
		GREASE OUTLET FITTINGS - MOTOR			
	2	903103-1	1/8" Grease Relief Fitting - 1 to 5 PSI		
	2	903160-1	1/4 x 1/8 Pipe Bushing		

FORM 8015A-1

JOY MANUFACTURING CO.

BILL OF MATERIAL

071283

BILL OF MAT. NO. 500722-103

SHEET NO. 3 OF 3

ORDER NO.

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
	3	907235-54	Adapter 5/16" O.D. Flare Tube to 1/4" Female Pipe		
	A/R	901509-788	5/16" O.D. Stain. Stl. Tubing (Trim to Lg.)		
	4	907465-5	Tube Nut - 37° Flare 5/16" O.D. Tube		
	4	907475-5	Tube Sleeve - 37° Flare 5/16" O.D. Tube		
	1	907256-54	90° Elbow 5/16" O.D. Flare Tube To 1/4" Female Pipe		
	1	74262	Name Plate		
	1	700185-405	Parts For Motor Power Lead Isolator Ass'y		

RELIANCE ELECTRIC COMPANY

24701 Euclid Avenue, Cleveland, Ohio 44117

REPORT OF ROUTINE TESTS

Induction Motor

Purchaser

JOY MANUFACTURING CO.

Date of Test —

Manufacturer's Order No. X-328261

Purchaser's Order No. UV-2064

NAMEPLATE DATA

Hp	Service Factor	Rpm	Phase	Hertz	Volts	Amperes
[illegible]	1.0	1190/890	3	60	550/550	132/133

Type	Frame	Temp Rise by Method Indicated	Ambient Temp and Insulation Class	Time Rating	Design Letter	Code Letter for Locked Kva/Hp
H	DC500P	Spcl.	Spcl. H	Spcl. 60 [illegible]	Spcl.	H

TEST CHARACTERISTICS

Serial Number	No Load					Locked Rotor ~~(Single Phase)~~ (Three Phase)					Wound Rotor Open Circuit Volt.	High potential Test Voltage
	Volts	Hertz	Rpm	Amperes		Volts	Hertz	Amperes				
A1	550	60	1199	61		275	60	414			-	2000
A1	550	60	899	79		275	60	354			-	2000
A2	550	60	1199	60		275	60	413			-	2000
A2	550	60	899	79		275	60	346			-	2000
A3	550	60	1199	61		300	60	460			-	2000
A3	550	60	899	69		[illegible]	60	334			-	2000
A4	550	60	1199	61		275	60	433			-	2000
A4	550	60	899	70		275	60	342			-	2000
A5	550	60	1199	61		275	60	448			-	2000
[illegible]	550	60	899	69		275	60	366			-	2000

Notes - for 1 min.

Data on test from these motor.
(this or duplicate)

Approved by [signature] (Engineer) Date 12-5-74

RE 1293VV Printed in U.S.A.

071285

RELIANCE ELECTRIC COMPANY

24701 Euclid Avenue, Cleveland, Ohio 44117

REPORT OF ROUTINE TESTS

Induction Motor

Purchaser

JOY MANUFACTURING CO.

Date of Test ....

Manufacturer's Order No. X-328261

Purchaser's Order No. NV-2904

NAMEPLATE DATA

Hp	Service Factor	Rpm	Phase	Hertz	Volts	Amperes
125/125	1.0	1190/890	3	60	550/550	132/138

Type	Frame	Temp Rise by Method Indicated	Ambient Temp and Insulation Class	Time Rating	Design Letter	Code Letter for Locked Kva/Hp
H	DC5008	Spcl.	Spcl. H	Cont. / 60 Min.	Spcl.	H

TEST CHARACTERISTICS

Serial Number	No Load					Locked Rotor ~~(Single Phase)~~ (Three Phase)					Wound Rotor Open Circuit Volt.	High potential Test Voltage
	Volts	Hertz	Rpm	Amperes		Volts	Hertz	Amperes				
A6	550	60	1199	61		275	60	422			-	2000 @
A6	550	60	899	70		275	60	349			-	2000 @
A7	550	60	1139	61		275	60	420			-	2000 @
A7	550	60	899	80		275	60	338			-	2000 @
A8	550	60	1199	61		300	60	466			-	2000 @
A8	550	60	899	68		300	60	387			-	2000 @

Notes: * - for 1 min.

Data on test from these motor.
(this or duplicate)

Approved by George N. Bandrek (Engineer) Date 12-5-74

RE 1293VV2 In U.S.A.

071286

RELIANCE ELECTRIC COMPANY

24701 Euclid Avenue, Cleveland, Ohio 44117

JAN 24 1975

Pg. 3 of 3

REPORT OF ROUTINE TESTS

Induction Motor

Purchaser

JOY MANUFACTURING CO.

Date of Test 12-6-74

Manufacturer's Order No X-328261

Purchaser's Order No. NV-2964

NAMEPLATE DATA

Hp	Service Factor	Rpm	Phase	Hertz	Volts	Amperes
125/125	1.0	1190/890	3	60	550/550	132/138

Type	Frame	Temp Rise by Method Indicated	Ambient Temp and Insulation Class	Time Rating	Design Letter	Code Letter for Locked Kva/Hp
M	DC5008	Spcl.	Spcl. H	Cont. / 60 Min.	Spcl.	H

TEST CHARACTERISTICS

Serial Number	No Load					Locked Rotor (~~Single Phase~~) (Three Phase)					Wound Rotor Open Circuit Volt.	High-potential Test Voltage
	Volts	Hertz	Rpm	Amperes		Volts	Hertz	Amperes				
A9	550	60	1199	61		300	60	463			-	2000 @
A9	550	60	899	70		300	60	388			-	2000 @

Notes: V - for 1 min.

Data on test from these motors (this or duplicate)

Approved by George Brandrick (Engineer) Date 1-21-75

RE 1293VV2 Printed in U.S.A.

SK-50800-216 Test

071287

RELIANCE ELECTRIC COMPANY

24701 Euclid Avenue, Cleveland, Ohio 44117

REPORT OF ROUTINE TESTS

Induction Motor

Purchaser

JOY MANUFACTURING CO.

Date of Test 4-1-74

Manufacturer's Order No. XF-329600

Purchaser's Order No. NV-2964

NAMEPLATE DATA

Hp	Service Factor	Rpm	Phase	Hertz	Volts	Amperes
125/125	1.0	1190/890	3	60	550	132/138

Type	Frame	Temp Rise by Method Indicated	Ambient Temp and Insulation Class	Time Rating	Design Letter	Code Letter for Locked Kva/Hp
M	DC5008	Spcl.	Spcl. H	Cont.	Spcl.	H

TEST CHARACTERISTICS

Serial Number	No Load					Locked Rotor (Single Phase) (Three Phase)					Wound Rotor Open Circuit Volt.	High potential Test Voltage
	Volts	Hertz	Rpm	Amperes		Volts	Hertz	Amperes				
A1	550	60	1199	61		300	60	449			-	2000 @
A1	550	60	899	70		300	60	377			-	2000 @

Notes: @ for 1 min.

Data on test from this motor.
(this or duplicate)

Approved by G. Braidich (Engineer) Date 11-6-74

G. Braidich

RE 1293VV2 Printed in U.S.A.

DWG

071288

Duty Master

Axivane Fan Motor - Vertical Mount.

Dimension Sheet

89372-10

071289

RELIANCE ELECTRIC COMPANY

General Offices
24701 Euclid Ave.
Cleveland 17, Ohio

SK-50800-216 Test
Joy BM No. 600267-4
Joy P.O. No. NV-2964
Sheet 1 of 5

PERFORMANCE DATA SHEET

INDUCTION MOTOR

NAMEPLATE DATA

FRAME	HP	TYPE / FORM	PHASE / HERTZ	RPM	VOLTS	AMPERES	DUTY	TEMP. RISE °C	DESIGN LETTER	CODE LETTER	ENCL.
D5008	125/125	M/YF	3/60	1190/890	550	132/138	Cont./60 Min.	Amp. Spcl.	-	H	TEAO

DESIGN DATA

E/S	ROTOR	DESIGN NUMBER	TEST ON SALES ORDER	TEST DATE	STATOR RESISTANCE AT 25°C (BETWEEN LINES OHMS)
525330	67817-7RD	27169	A6	8-31-74	.118/.0885

PERFORMANCE

LOAD	HP	AMPERES	RPM	% POWER FACTOR	% EFFICIENCY	KW INPUT
NO LOAD	0	61/70	1199/899	-	-	3.6/3.2
1/4	31.3	69/77	1198/898	39/36	91/89	26/26
2/4	62.5	84/92	1197/897	62/57	93/93	50/50
3/4	93.7	106/114	1196/896	73/67	94/95	74/73
4/4	125	132/138	1195/894	80/77	93/93	99/100
5/4	156	149/170	1193/892	87/79	93/92	124/127

SPEED TORQUE

	RPM	TORQUE % FULL LOAD	TORQUE LB. FT.	AMPERES
LOCKED ROTOR	0	175/166	790/1009	936/779
PULL UP	-	-	-	-
BREAKDOWN	1165/868	348/273	1899/2003	525/442
FULL LOAD	1195/894	———	546/735	132/138

ALL DATA ON 550 VOLTAGE CONNECTION. AMPERES AT OTHER NAMEPLATE VOLTAGES WILL VARY INVERSELY WITH THE VOLTAGE.

REMARKS:

APPROVED BY Lloyd N Frank DATE 12-9-74

RELIANCE ELECTRIC AND ENGINEERING COMPANY

071290

General Offices • 24701 Euclid Ave., Cleveland 17, Ohio • U. S. A.

REPORT OF TEST

Induction Motor

Purchaser

JOY MANUFACTURING CO.

Date of Test 8-31-74

Purchaser's Order No. NV-2964

Nameplate Rating

Hp Output	Syn. Speed Rpm	Full-Load Speed—Rpm	Phase	Cycles	Volts	Amperes Full Load	Type	Frame Number
125/125	1200/900	1190/890	3	60	550/550	132/138	M	DC5008

Temperature Rise

Conditions of Test				Temperature Rise—Deg C					
				Stator		Rotor			
Hours Run	Line Volts	Line Amperes	Cooling Air Deg C	Core By Thermometer Method	Windings (Cross Out One) By Resistance Method By Thermometer Method	Core by Thermometer Method	Windings (Cross Out One) By Resistance Method By Thermometer Method	Commutator Bars	Collector Rings
-	-	-	-	-	-	-	-	-	-

Characteristics Test

Slip—Per Cent	Amperes Running Light	Secondary Volts at Standstill	Secondary Amperes per Ring at Full Load	Resistance at 25 C (between lines) Ohms
.42 / .67	61 / 70	-	-	.118/.0885

Torque and Starting Current

Break-Down Torque Lbs at 1 ft radius	Locked-Rotor Torque Lbs at 1 ft radius with 50 % volts applied	Starting Current Amperes (locked rotor) with 50 % volts applied
1899/2003	152/194	347/347

Dielectric Tests

Volts A-c for 60 Sec.	
Stator	Rotor
2000 V.	—

Efficiencies and Power Factor

Efficiency, Per Cent			Power Factor, Per Cent		
Full Load	¾ Load	½ Load	Full Load	¾ Load	½ Load
93.5/92.8	94.0/93.5	93.2/93.1	73.0/76.7	62.2/67.1	39.0/57.1

Notes:

Data from test on .... this .... motor.
(this or duplicate)

Approved by George N. Tindall ..... Date Dec. 6, 1974
(Designing Engineer)

RE 1232A Printed in U.S.A.

071291

RELIANCE ELECTRIC COMPANY
CLEVELAND, OHIO U.S.A.

DRAWING NUMBER
SK-50800-216
Test
Pg. 2 of 5

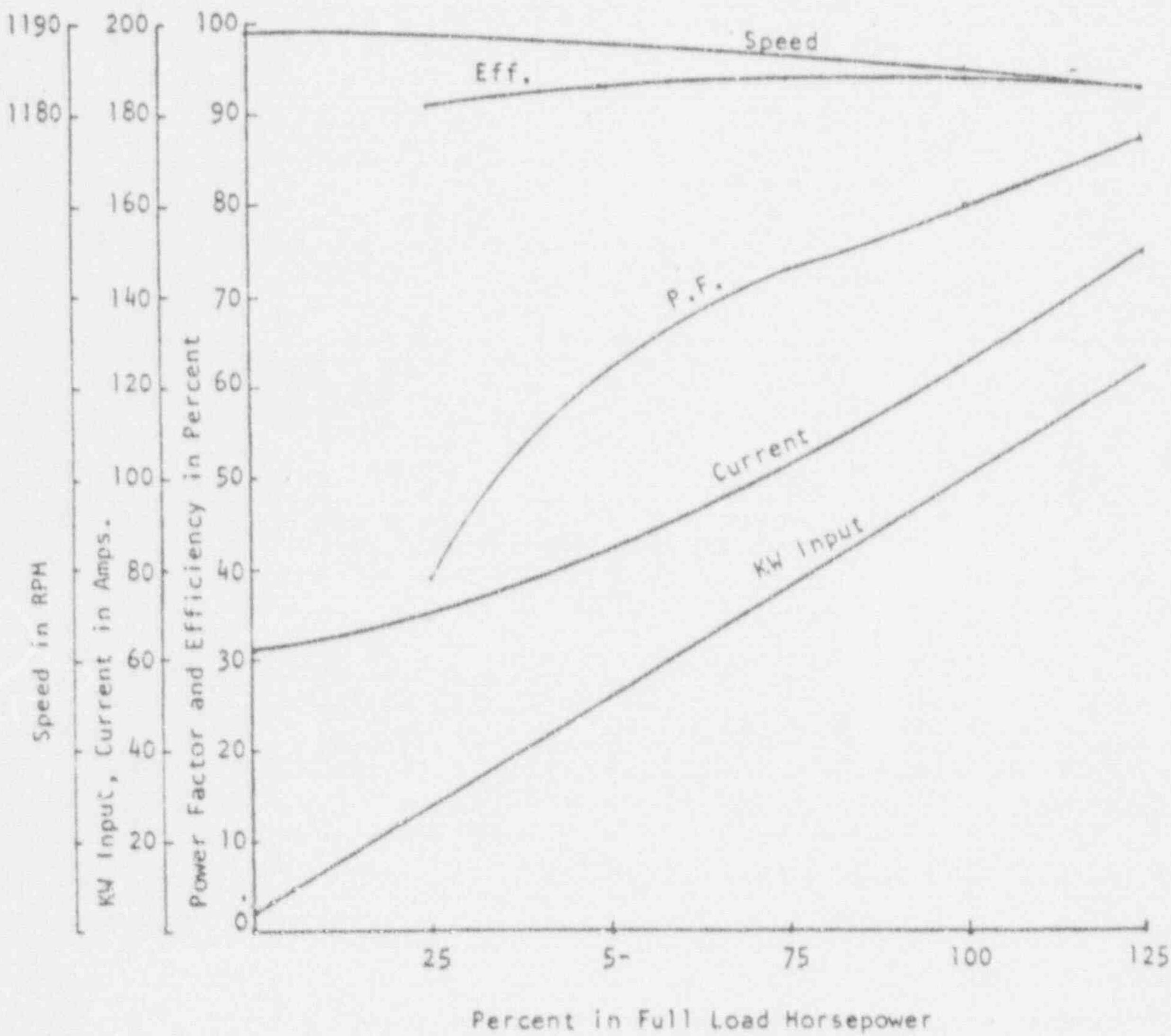
A-C MOTOR PERFORMANCE CURVES

SPECIFICATION DATA:

NAMEPLATE DATA:

E/S	525330	FRAME	D5008	H.P.	125/125	CYCLES	60
ROTOR	67817-7RD	DUTY	Cont/60 Min.	RPM	1190/890	CODE	H
TEST S.O.	X-328261-A6	PHASE	3	VOLTS	550/550	TEMP. RISE	Spcl.
TEST DATE	8-31-74	TYPE/FORM	M/YF	AMPS	132/138	NEMA DESIGN	-
RES. AT 25 C	.118/0885					ENCLOSURE	TEAO

HIGH SPEED



RE 1572V PRINTED IN U.S.A.

ELECTRIC COMPANY
CLEVELAND, OHIO, U.S.A.

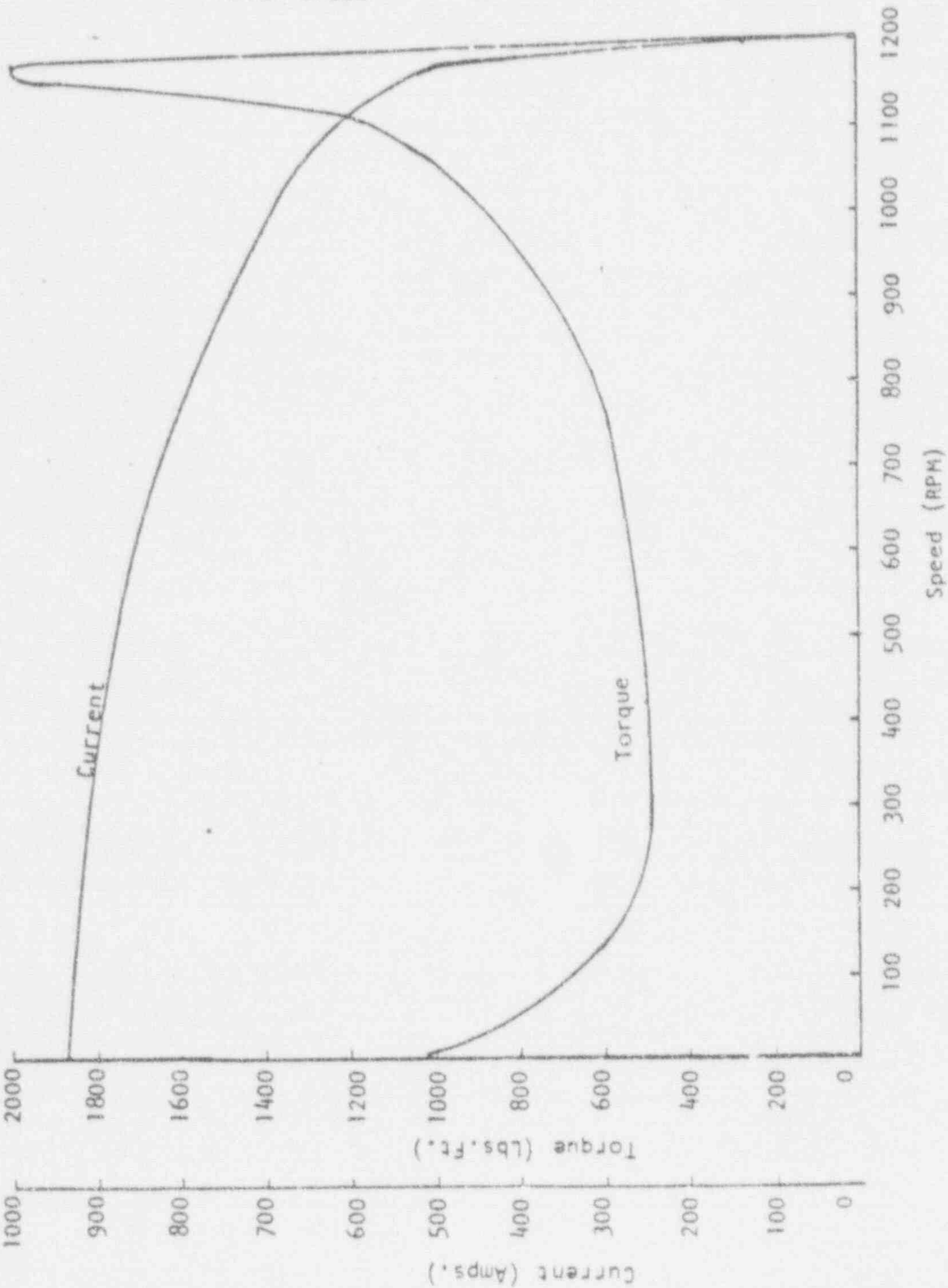
071292
DRAWING NUMBER
SK-50800-216
Test
Pg. 3 of 5

A-C MOTOR PERFORMANCE CURVES

SPECIFICATION DATA: | NAMEPLATE DATA:

E/S	525330	FRAME	D5008	H.P.	125/125	CYCLES	60
ROTOR	67817-7RD	DUTY	Cont/60 Min.	RPM	1190/890	CODE	H
TEST S.O.	X-328261-A6	PHASE	3	VOLTS	550/550	TEMP. RISE	Spcl.
TEST DATE	8-31-74	TYPE/FORM	M/YF	AMPS	132/138	NEMA DESIGN	-
RES. AT 25 C	.118/.0885					ENCLOSURE	TEAO

HIGH SPEED



RE 1572V PRINTED IN U.S.A.

ELECTRIC COMPANY
CLEVELAND, OHIO, U.S.A.

071293

DRAWING NUMBER
SK-50800-216
Test
Pg. 4 of 5

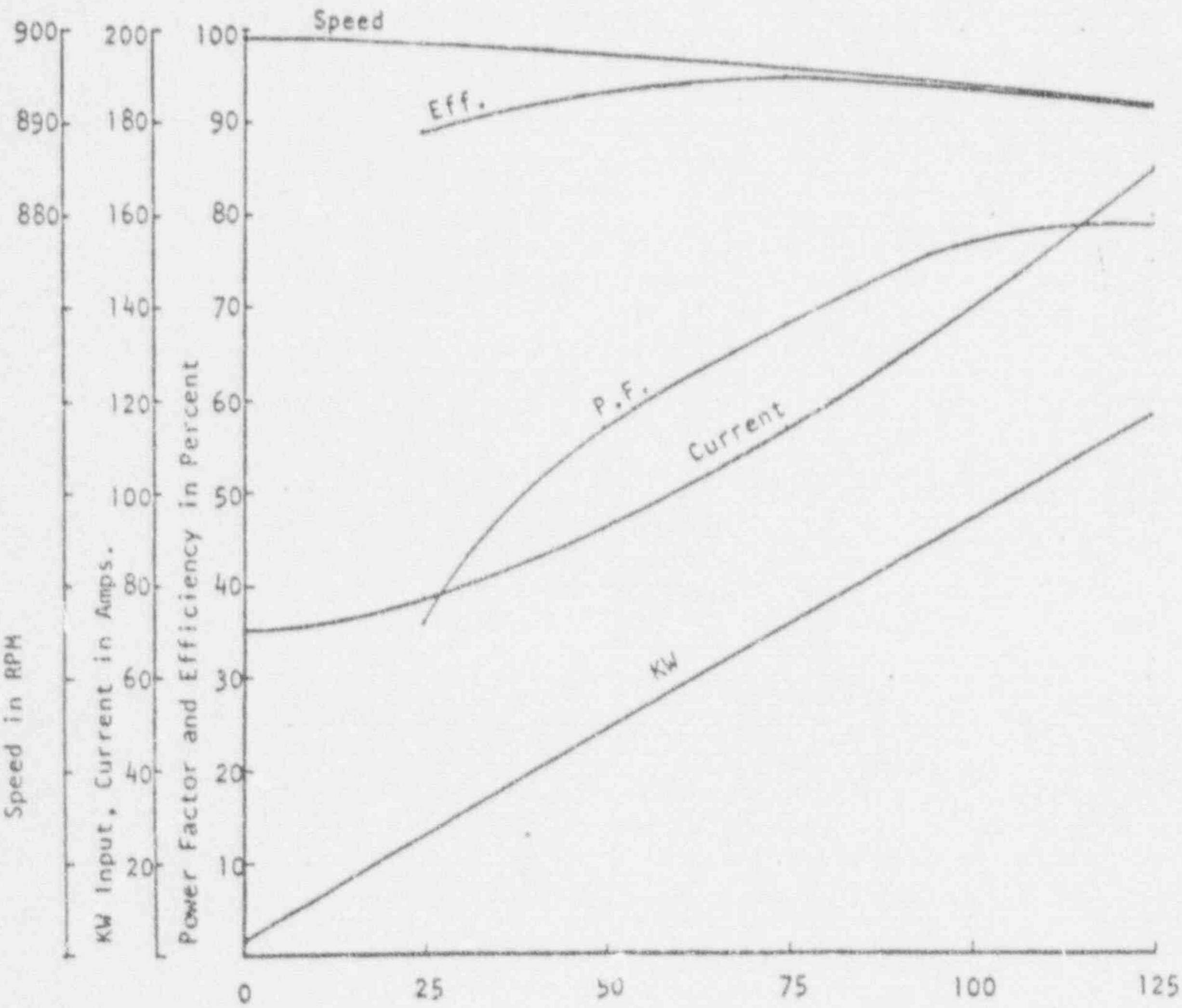
A-C MOTOR PERFORMANCE CURVES

SPECIFICATION DATA:

NAMEPLATE DATA:

E/S	525330	FRAME	D5008	H.P.	125/125	CYCLES	60
ROTOR	67817-7RD	DUTY	Cont/60 Min.	RPM	1190/1890	CODE	H
TEST S.O.	X-328261-A6	PHASE	3	VOLTS	550/550	TEMP. RISE	Spcl.
TEST DATE	8-31-74	TYPE/FORM	M/YF	AMPS	132/138	NEMA DESIGN	-
RES. AT 25C	.118/.0885					ENCLOSURE	TEAO

LOW SPEED



Percent Full Load Horsepower

9E 1572V PRINTED IN U.S.A.

071294

ELECTRIC COMPANY

CLEVELAND, OHIO, U.S.A.

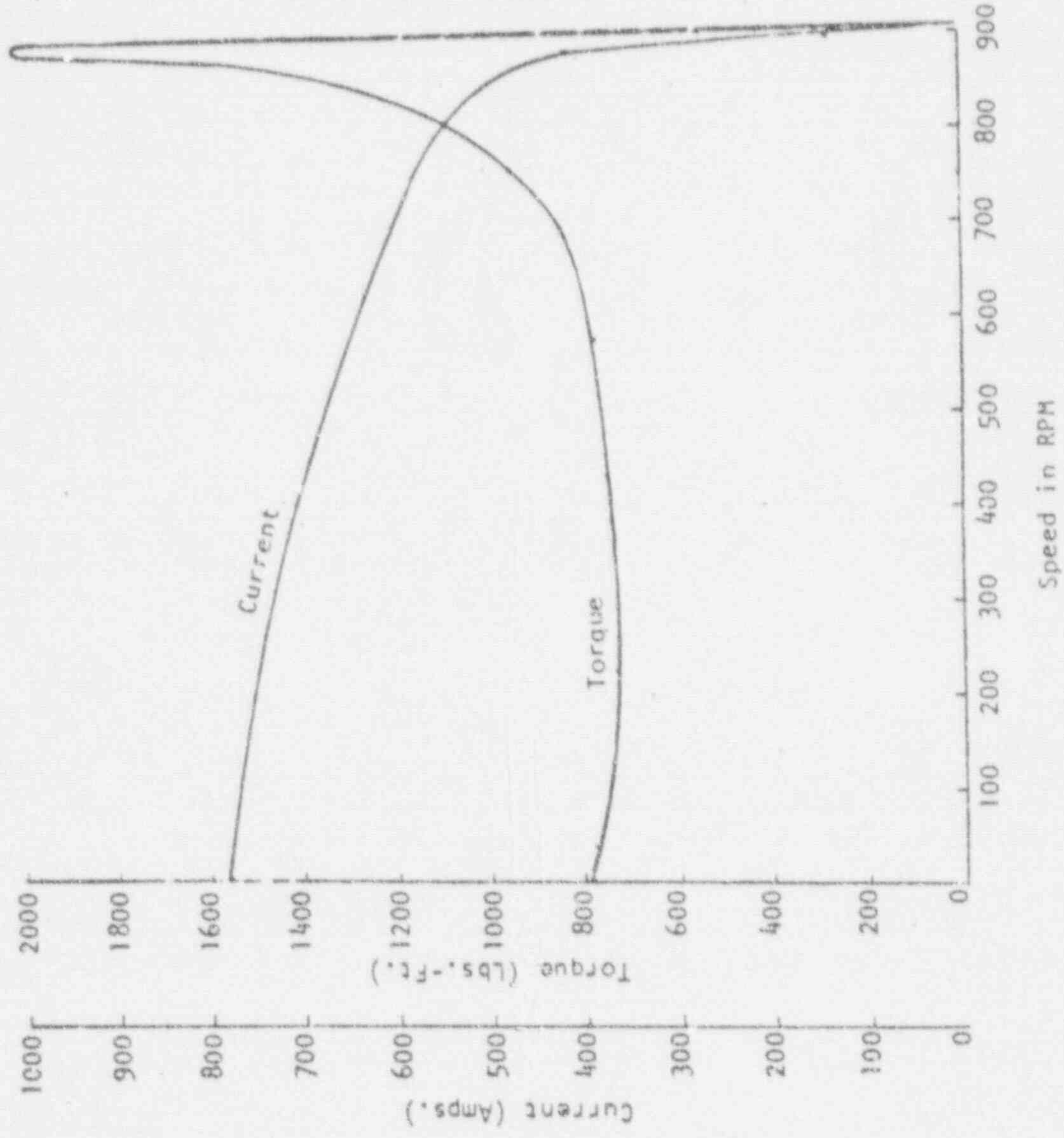
DRAWING NUMBER
SK-50800-216
Test
Pg. 5 of 5

A-C MOTOR PERFORMANCE CURVES

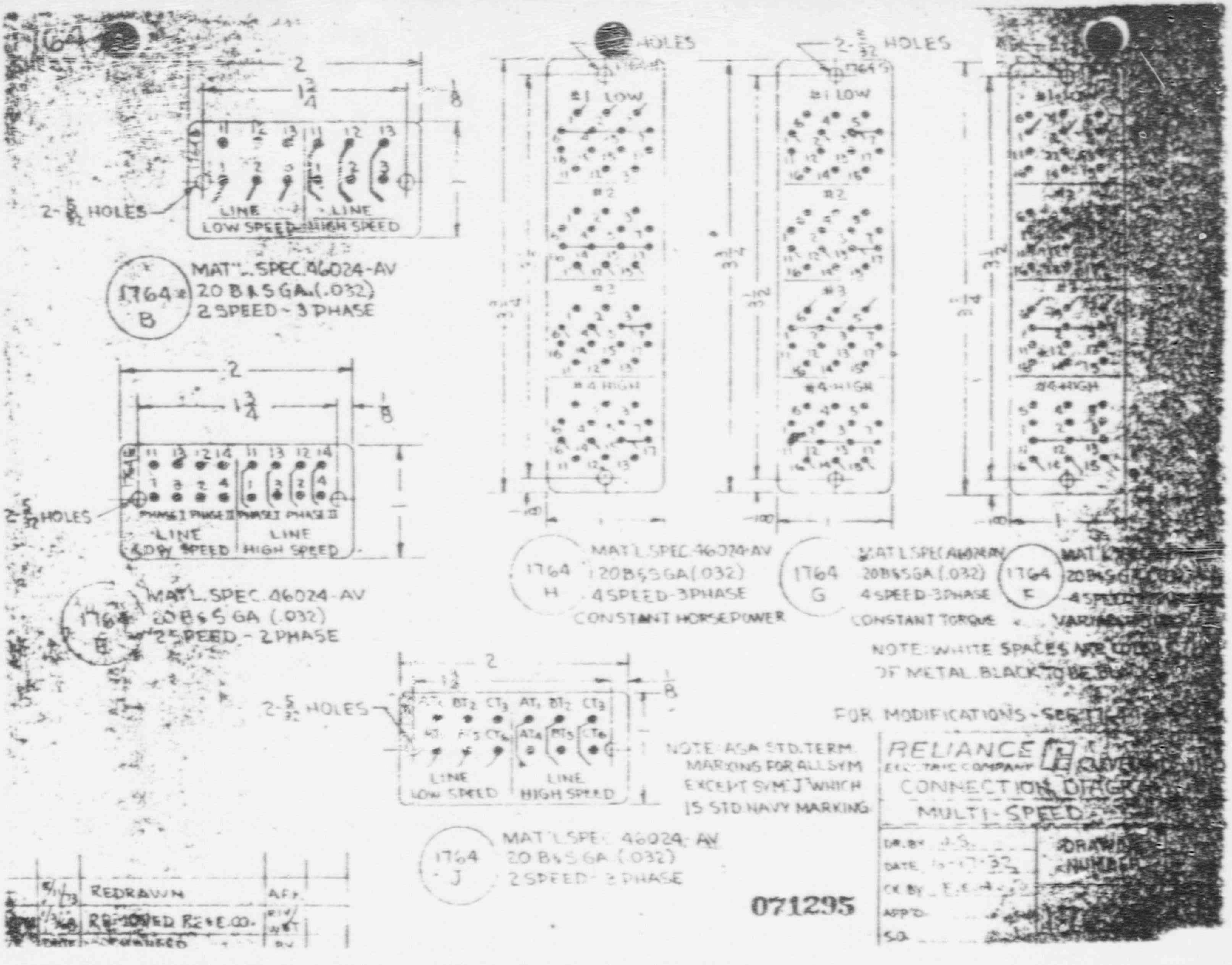
SPECIFICATION DATA: NAMEPLATE DATA:

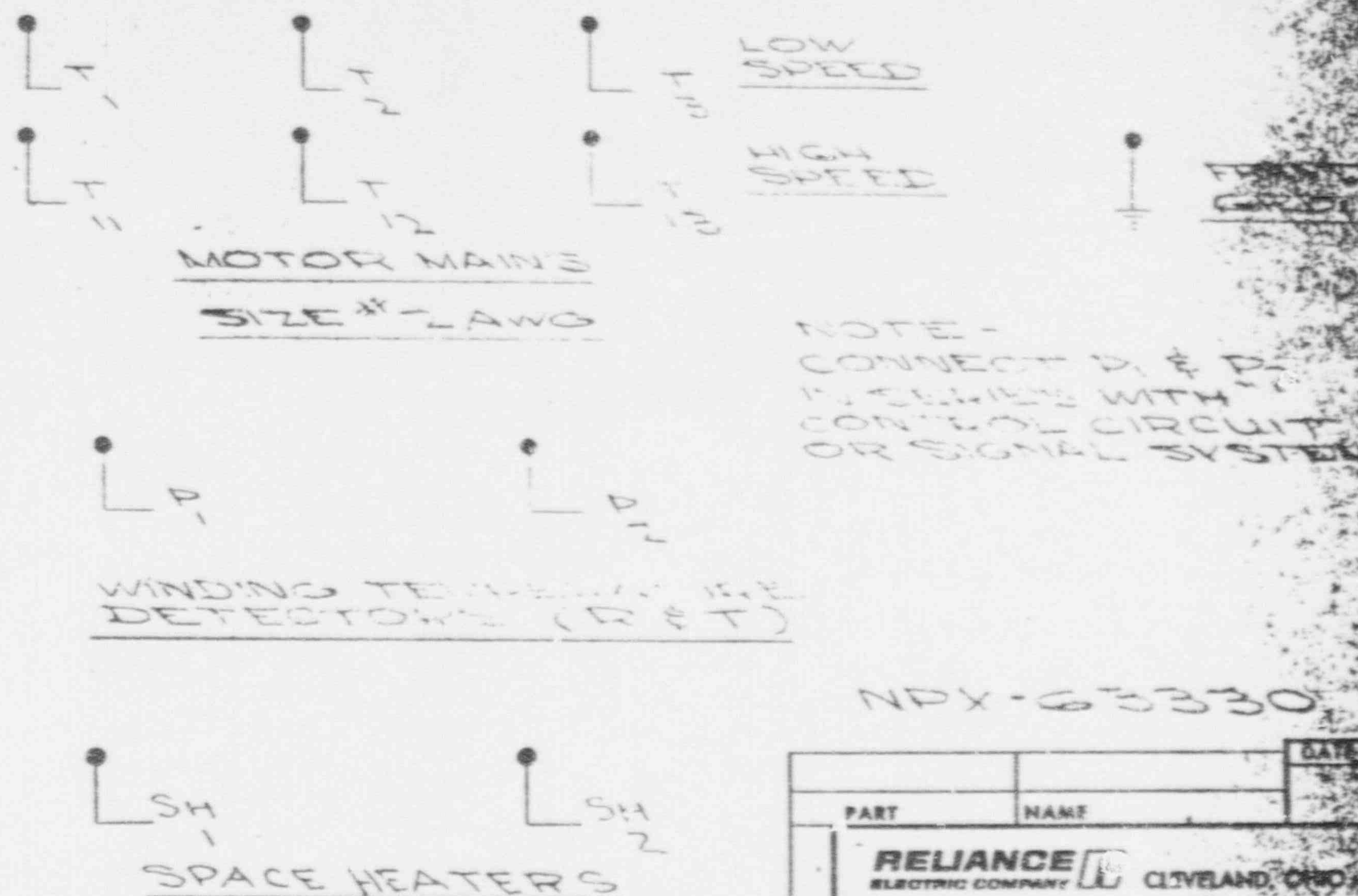
E/S	525330	FRAME	D5008	H.P.	125/125	CYCLES	60
ROTOR	67817-7RD	DUTY	Cont/60 Min.	RPM	1190/890	CODE	H
TEST S.O.	X-328261-A6	PHASE	3	VOLTS	550/550	TEMP. RISE	Spcl.
TEST DATE	8-31-74	TYPE/FORM	M/YF	AMPS	132/138	NEMA DESIGN	-
RES. AT 25 C	.118/.0885					ENCLOSURE	TEAO

LOW SPEED



RE 1572V PRINTED IN U.S.A.


2-5/32 HOLES
LINE LOW SPEED
LINE HIGH SPEED
1764 B
MAT'L SPEC. 46024-AV
20 B&S GA. (.032)
2 SPEED - 3 PHASE
PHASE I PHASE II PHASE I PHASE II
1764 E
MAT'L SPEC. 46024-AV
20 B&S GA (.032)
2 SPEED - 2 PHASE
#1 LOW
#2
#3
#4 HIGH
1764 H
MAT'L SPEC. 46024-AV
20 B&S GA (.032)
4 SPEED-3 PHASE
CONSTANT HORSEPOWER
1764 G
20 B&S GA (.032)
4 SPEED-3 PHASE
CONSTANT TORQUE
1764 F
NOTE: WHITE SPACES
OF METAL. BLACK TO BE
FOR MODIFICATIONS - SEE
AT1 BT2 CT3 AT1 BT2 CT3
AT4 BT5 CT6 AT4 BT5 CT6
NOTE: ASA STD. TERM. MARKINGS FOR ALL SYM EXCEPT SYM "J" WHICH IS STD NAVY MARKING
1764 J
MAT'L SPEC. 46024-AV
20 B&S GA (.032)
2 SPEED - 3 PHASE
RELIANCE
ELECTRIC COMPANY
CONNECTION DIAG
MULTI-SPEED
DR. BY
DATE
CK BY
APP'D
S.O.
DRAWING NUMBER
REDRAWN
AFF.
REMOVED R. E. & E. CO.
DATE
BY
071295



NPX-63330

071296

PART	NAME	DATE

RELIANCE ELECTRIC COMPANY CLEVELAND, OHIO

CONNECTION DIAGRAM
JOY NUCLEAR FAN MOTOR

DR.	DATE 5-28-73	S.O.	
B/M	ENG'R.	SHEET	
CK. LEC	DUP.	60026	
APP. /	TR.		

See U258759 071297

Duty Master-
Axivane Fan Motor - Vert. Mounting

U213442
Farley

89372-10

071298

JOY MANUFACTURING CO.

BILL OF MATERIAL

DRAWING NO. FF-12642 SK31170

BILL OF MAT. NO. 600287-4

SHEET NO. 1 OF 5

NAME Electric Motor (Containment)

ORDER NO. Customer Specs Notes 13 & 14

ISSUED	DFC		NBR932		4-17-73	
NBS2?	NBT278					
NBS342	NBT337					
NBS868	NBT648					

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
H.P.:			~~XXXXXXX~~ 125/125 ~~XXXXXX~~ N/P Rated - Max. HP At Emergency Mode Conditions		
Volts, Phase, Hertz.:			550/3/60 Capable of Low Voltage Start-Up. See Notes.		
Amps:			Rated ________ S.F. (AOM) ________		
Speed:			1200/900 RPM. NEMA Design B (6.5 X F.L.C.)		
Winding:			Two Speed - Two Winding - Constant HP - Braced For Reverse Starting		
Frame:		A2	500B Vendor Drwg. No. 89372-10 ~~XXXXXXXXXXXXXXX~~		
Bearings:		416821-1 (A3	Type - A-F Regreasable. Life - B-10, 100,000 Hours		
Lubrication:			Type - Chevron BRB#2 Temp. - -30° to +150°C.		
Fitting:			Grease - 1/8" Pipe Plug		
			Relief - 1/4" Pipe Plug		
Enclosure:			TEAO - Watertight		
Mounting:			Footless Double C-Face Horizontal ____ Vertical Yes - Shaft Down		
Conduit Box:			Main Location 9 O'clock Type - C.I. One Size Oversize		
			Accessory Location: 3 O'Clock. Type - C.I. Std.		
Accessories:			Type - Winding Temp. Detectors - R. & T. Type - Space Heaters - 208/1/60 Location - Inside Of Winding Coils. (R. & T.) Location - In End Bracket (Heaters).		
Duty:			Fan (Air-Over-Motor) Continuous.		
Ambient:			Per FF-12642	NEW DESCRIPTION INTO MANUAL PERTAINING TO SUFFIX C	
Insulation:			Class BN Life - 40 Years Per FF-12642		
Leads:			Mains - 36" Marked Terminals - Yes - In Box		
			Accessories - 36" Marked Terminals - Yes - In Bag		
Shaft Extension:			Per SK-31170 (Tapered)		
Condenstate Drains:			Type - Removable Plugs Location - End Bells & Frame		

JOY MANUFACTURING CO.

BILL OF MATERIAL

071299
BILL OF MAT. NO

SHEET NO. 2 OF 5

ORDER NO. 600287-4

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
Application:			Nuclear Containment Fan Motor		
Manufacturer:			Reliance Electric Co.		
		NOTES: 1.	Bearing Loads -		
			A. Fan Rotor Wt. 520 Lbs. (Cast Steel)		
			B. Fan Rotor Inertia (WR^2) 800 Lbs./$Ft.^2$		
			C. Aerodynamic Thrust 305 Lbs. (Vertical)		
			D. Max. Thrust (Vertical) 825 Lbs. (Running)		
		2.	Painting -		
			Interior - Per FF-12642		
			Exterior - 1. Cleaned Per SSPC - SP - 6 - 63		
			2. Prime - Carbozinc #11 - 3/2 MILS.		
			3. Finish By Joy. Carboline - Phenoline #305		
			4 MILS Dry - Cream #808		
		3.	Note: No Thermocouples Required. Per FF-12642 -		
			See Accessories, Page 1.		
		4.	Name Plates -		
			A. Motor - NEMA Standard MG1 - 10.39 - 1968		
			With AFBMA Bearings. Numbers On Plate. Rotation		
			To Phase Sequence.		
			B. Connection Diagram - One On Motor And One Loose For		
			Fan Mounting To Show Connections For Hookup From Stator		
			(Mains) And All Accessories. Copy To Engineering (Repro.)		

JOY MANUFACTURING CO. **BILL OF MATERIAL** **071300** BILL OF MAT. NO

SHEET NO. 3 OF 5 ORDER NO. 600287-4

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
		5.	Grounding -		
			Frame Ground Lead To Be Connected Inside Of Motor Frame And Brought Out With Mains To C-Box With Grd. Post Thru Side Of Box For Customer's No. 2/0 Awg. Ground Connector.		
		6.	Motor Standards Certification (Repros.)		
			~~Per Reliance Nuclear Motor Program Spec.~~		
			~~Per Reliance Nuclear Motor Program Spec.~~		
			C. NEMA MG1-1967		
			D. ANSI - C50. 20-7, Forms A1 & A2		
		7.	Job Specifications, Forms And Certifications - (Repros.)		
			A. Quality Assurance Per ~~Spec.~~ Reliance Q.A. Program for Nuclear Motors. Spec. No. RSP-2-0095-01-661-0.		
			~~Reliance Nuclear Motors Spec.~~		
			C. Vibration Test Documented (Max. 2 MILS)		
			D. Motor Data To Joy For Sisemic Design Analysis.		
			E. Technical Requirements Per Specs. ~~[illegible]~~		
			As Follows -		
			1. E-3 Forms		
			2. Motor Data Sheet Forms (2 Pages)		
			3. Bechtel Forms G-321-C Drawing & Data Requirements.		
			F. Motor Curves (Repros.)		
			Chart On One Diagram, At 70%, 90% And 100% Voltage -		

JOY MANUFACTURING CO.

BILL OF MATERIAL

BILL OF MAT. NO 600287-4

SHEET NO. 4 OF 5

ORDER NO.

QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
			1. Speed - Torque With Fan Load Imposed On It.		
			2. Current - Safetime (Thermal)		
			3. Speed - Current		
			4. Speed - Time (Load Acceleration)		
			5. Speed - Power Factor		
			6. Motor Rating Curve Showing HP - Air Velocity		
			0 to 3600 Feet/Minute - Class B Insulation.		
		8.	Drawing Requirements - (Repros.)		
			Furnish Motor Outline & Cross Section With		
			Accessories Complete Shaft Outline-Dimensions		
			And Overall Conduit Box's With Complete		
			Dimensions. Conduit Boxes To Have Terminal		
			Blocks Mounted Inside Per Bechtel Drwgs.		
			E-20 & E-21. Show On Motor Drwg.		
		9.	Hardware - To Be Corrosion Resistant		
		10.	Motor Balance - .002 Double Amplitude (Max.)		
		11.	Motor Sealing - Per TP-12642		
		12.	Breathers - Per TP-12642 Notes 6 & 13.		
		13.	Except as Noted Herein: Motor To Meet All Requirements Of Customer Job		
			Specifications No. SS-1102.14 Latest Revisions		

JOY MANUFACTURING CO. BILL OF MATERIAL 071302 BILL OF MAT. NO.

600287-4

SHEET NO. 5 OF 5 ORDER NO.

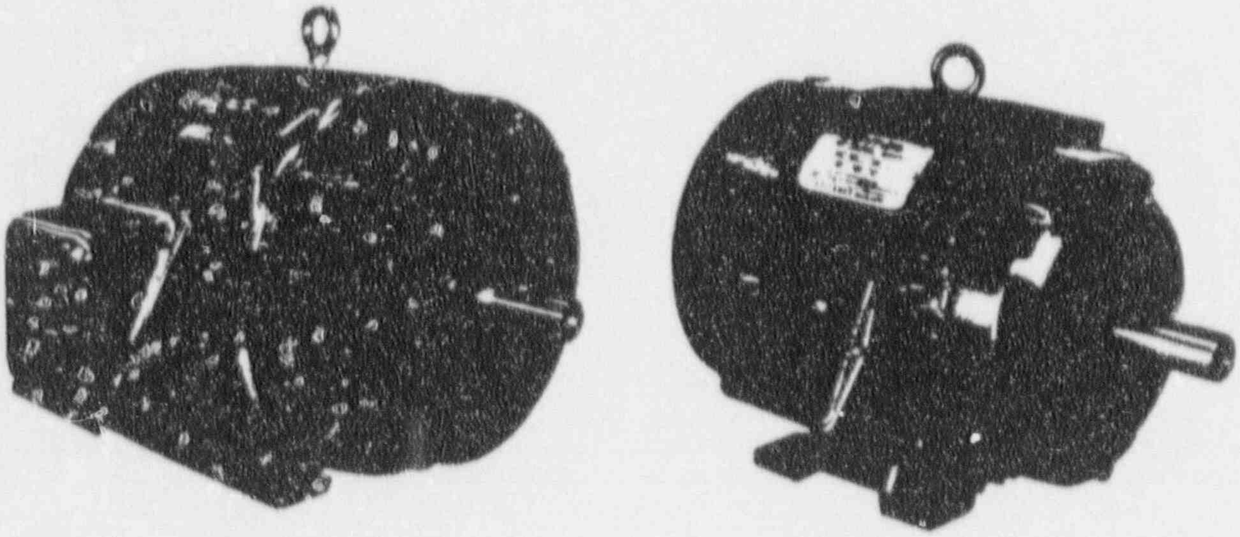
QUANTITY PER ORDER	QUANTITY PER UNIT	PART NUMBER	NAME OF PART	COST PER PIECE	TOTAL AMOUNT
			With All Related Sub Specifications Per Joseph M.		
			Farley Nuclear Plant, Alabama Power Co. By		
			Bechtel Corp. No. 7597-03-M12.		
		14.	NOTE - (Rel.) Specify On Sales Order - Reliance		
			Electric To Set Up In Chart Form All Required		
			Drawings, Forms & Certifications With Indicated Dates		
			Of Submission To Joy. This Has To Be Submitted		
			On A Weekly Basis For Varification And Documentation		
			Per Contract Requirements.		

APRIL, 1972 INSTRUCTION MANUAL B-3620-5

INSTALLATION, OPERATION AND CARE OF

RELIANCE

STANDARD INTEGRAL HORSEPOWER INDUCTION MOTORS



IMPORTANT: it is important that these instructions be studied by the men installing and operating this equipment. Read thoroughly before starting. Keep these instructions for future reference.

RELIANCE ELECTRIC COMPANY

RECEIVING AND HANDLING

ACCEPTANCE

Thoroughly inspect this equipment before accepting shipment from the transportation company. If any of the goods called for in the bill of lading or express receipt are damaged or the quantity is short, do not accept them until the freight or express agent makes an appropriate notation on your freight bill or express receipt. If any concealed loss or damage is discovered later, notify your freight or express agent at once and request him to make an inspection. We will be very happy to assist you in collecting claims for loss or damage in shipment; however, this willingness on our part does not remove the transportation company's responsibility in reimbursing you for collection of claims or replacement of material. Claims for loss or damage in shipment must not be deducted from the Reliance invoice, nor should payment of the Reliance invoice be withheld awaiting adjustment of such claims, as the carrier guarantees safe delivery.

If considerable damage has been incurred and the situation is urgent, contact the nearest Reliance District Office for assistance. Please keep a written record of all communications.

STORAGE

Equipment which is not going to be used immediately, should not be unpacked until ready for use. If this equipment is to be stored for any period of time prior to installation, the area storage should be clean and dry, protected from low temperature, rapid or extreme changes in humidity, oil, dirt, and similar adverse conditions. Equipment storage should be inspected periodically and the shaft rotated approximately every six months.

UNPACKING

After unpacking and inspection to see that all parts are in good condition, turn the shaft by hand to be sure there are no obstructions to free rotation. Equipment which has been in storage for sometime should be tested and relubricated prior to being put into service. Refer to "Test for General Condition" and "Lubrication" for procedure to be performed after extended storage.

Equipment with roller bearings is shipped with a shaft block at the opposite pulley end. In removing the shaft block, be sure to replace the bolts which are used to hold the shaft block in place during shipment.

WARRANTY

The Reliance Electric Company warrants workmanship and materials on this motor for a period of one year from date of shipment from the Reliance factory. In every case concerning warranty, contact the nearest Reliance Sales Office or authorized Reliance Service Shop.

INSTALLATION

INSPECTION

After the motor in unpacked, examine the nameplate data to see that it agrees with the power circuit to which it is to be connected. The motor is guaranteed to operate successfully with frequency not more than 5% and voltage not more than 10% above or below the nameplate data, or combined variation of voltage and frequency of not more than 10% above or below nameplate data. Efficiency, power factor and current may vary from nameplate data.

LOCATION

The motor should be installed in a location compatible with the motor enclosure and specified ambient.

LIFTING MEANS

When a lifting means is provided for handling the motor or generator, it should not be used to lift the motor or generator plus additional equipment such as gears, pumps, compressors, or other driven equipment. In the case of assemblies on a common base, any lifting means provided on the motor or generator should not be used to lift the assembly and base but, rather, the assembly should be lifted by a sling around the base or by other lifting means provided on the base. In all cases, care should be taken to assure lifting in the direction intended in the design of the lifting means. Likewise, precautions should be taken to prevent hazardous overloads due to deceleration, acceleration or shock force.

MOUNTING

Mount the motor on a foundation sufficiently rigid to prevent excessive vibration. Ball-bearing motors may be mounted with the feet at any angle. After carefully aligning the motor with the driven unit, bolt securely in place.

DRIVE

The pulley, sprocket, or gear used in the drive should be located on the shaft as close to the shaft shoulder as possible. Heat to install. Driving a unit on the shaft will damage the bearings.

Belt Drive: Align the pulleys so that the belt will run true; tighten the belt just enough to prevent slippage, any tighter will cause premature bearing failure. If possible, the lower side of the belt should be the driving side.

INSTALLATION (Cont'd)

ROTATION

To reverse the direction of rotation, disconnect from power source and interchange any two of the three line leads for three phase motors, for two phase four wire, interchange the line leads on any one phase. For two phase three wire, interchange phase one and phase two line leads.

TEMPERATURE RISE

Under normal operating conditions, with the motor applied in accordance with the nameplate rating, the temperature rise will not exceed the proper limits. Always use a thermometer to determine the heating of a motor. The hand is not reliable in determining whether or not the motor is too hot.

TEST FOR GENERAL CONDITION

If the motor has been in storage for an extensive period or has been subjected to adverse moisture conditions, it is best to check the insulation resistance of the stator winding with a megohmeter.

If the resistance is lower than one megohm the windings should be dried in one of the two following ways:

1. Bake in oven at temperatures not exceeding 90°C. until insulation resistance becomes constant.

2. With rotor locked, apply low voltage and gradually increase current through windings until temperature measured with thermometer reaches 194°F. Do not exceed this temperature.

INITIAL LUBRICATION

"Reliance motors are shipped from the factory with the bearings properly packed with grease and ready to operate. Where the unit has been subjected to extended storage (6 months or more) the bearings should be relubricated prior to starting."

OPERATION

Due to the inherent characteristics of insulating materials, abnormally high temperatures shorten the operating life of electrical apparatus. The total temperature, not the temperature rise, should be the measure of safe operation. The class of insulation determines the maximum safe operating temperature. Aging of insulation occurs at an accelerated rate at abnormally high temperatures. A general rule for gauging the effect of excessive heat is that for each 10°C. rise in temperature above the maximum limit for the insulation, the life of the insulation is halved.

Unbalanced voltage or single-phase operation of polyphase machines may cause excessive heating and ultimate failure. It requires only a slight unbalance of voltage applied to a polyphase motor to cause large unbalance currents and resultant overheating.

Periodic checks of phase voltage, frequency and power consumption of a motor while in operation are recommended; such checks assure the correctness of frequency and voltage applied to the motor and yield an indication of the load offered by the apparatus which the motor drives. Comparisons of this data with previous no-load and full-load power demands will give an indication of the performance of the complete machine. Any serious deviations should be investigated and corrected.

Stator troubles can usually be traced to one of the following causes:

Worn bearings	Operating single phase
Moisture	Poor insulation
Overloading	Oil and dirt

Dust and dirt are usually contributing factors. Some forms of dust are highly conductive and contribute materially to insulation breakdown. The effect of dust on the motor temperature through restriction of ventilation is a principal reason for keeping the windings clean.

Squirrel-cage rotors are rugged and, in general, give little trouble. The first sympton of a defective rotor is lack of torque. This may cause a slowing down in speed accompanied by a growling noise or perhaps failure to start the load.

This is caused by an open or high resistance joint in the rotor bar circuit. Such a condition can generally be detected by looking for evidence of localized heating.

MAINTENANCE

The fundamental principle of electrical maintenance is KEEP THE APPARATUS CLEAN AND DRY. This requires periodic inspection of the motor, the frequency depending upon the type of motor and the service.

LUBRICATION (Cont'd)

RELUBRICATION PERIOD

For relubrication period, follow instruction plate on motor. If no plate is provided, relubricate per the following table:

HP at 1800 RPM or Less	Standard Conditions	Severe Conditions	Extreme Conditions
1/8 - 7 1/2	3 years	1 year	6 months
10 - 40	1 - 2 years	6 mo. - 1 yr.	3 months
50 - 150	1 year	6 months	3 months
200 & Up	9 mo. - 1 yr.	6 months	3 months
All Motors Over 1800 RPM	6 months	3 months	3 months

Standard Conditions: Eight hours per day, normal or light loading, clean 100°F. maximum ambient.

Severe Conditions: Twenty-four hour per day operation, or shock loading, vibration, or dirt or dust 100-150°F, ambient.

Extreme Conditions: Heavy shock or vibration, dirt or dust.

For units with roller bearings divide above times by 3.

For motors operating in ambients between 0°F. and 120°F., use the following lubricants or their equal.

Standard Oil Co. of California - Chevron BRB 2 **
Standard Oil Co. of Indiana - Stanobar No. 2
Standard Oil Co. of New Jersey - Andok C* and B
Master Lubricants Co. - Lubriko M-6, M-21, and M-32
New York and New Jersey Lubricant Co. - F-925, S-58 and S-58-M
Gulf Refining Co. - Precision No. 2 and No. 3
The Texas Co. - Starfak H, M, and No. 2
Sinclair Refining Co. - A. F. No. 2
Tidewater Associated Oil Co. - Tycol Armitage 0
Union Oil Co. of California - Strona Ht - 1
Shell Oil Co. - Alvania No. 2
Socony Mobil Oil Co. - Mobilux Grease No. 2

* Not recommended for roller bearings.
** Standard lubricant supplied on new units.

For operation in other ambient temperatures, refer to motor tag 162214 or nearest Reliance Sales Office.

SLEEVE BEARINGS (FRAMES D-5000)

Motors with sleeve bearings are shipped from the factory without oil. Fill the reservoirs to the center of the oil level gauge (minimum) to 3/8 above center (maximum) with a good grade of turbine oil as recommended for electric motor and generator use by a reputable oil manufacturer.

THESE OILS MAY BE USED

Mobil DTE Light or Heavy Medium
Texaco Regal A or PC

Use Oil of the viscosity range indicated in the following table:

Speed Range RMP	Recommended Viscosity Range SSU @ 100°F
1500 and below	250-350
1800 and over	100-200

Watch oil rings when first starting to see that they revolve.

Change oil every six months or more often under severe operation conditions.

CONSTANT LEVEL OILER

When supplied, refer to instructions accompanying the constant level oiler.

GENERAL

For special motors for use by United States Government including special specifications, master plans, etc., refer to the applicable master plans and specifications involved.

E.O. NBG272 DATE 5-12-72 | REVISIONS NET424 2-28-74 | 071307

FF1330

PATTERN No.

FAN STORAGE INSTRUCTIONS

1) Fans must be stored in a storage area which is dry, protected from low temperature, rapid and extreme changes in humidity. The storage area must also be free from any vibration.

2) For extended storage and negotiated extended warranty, the following instructions must be followed:

When fans are in storage longer than six (6) months, the rotors are to be rotated manually at least every six (6) months. Additional grease is to be added at this time to purge some of the grease in the bearing grease cavity. This is done to ensure that the bearings are always coated with lubricant.

If motors are equipped with space heaters, they are to be made operable.

Motor windings are to be megged at time of storage and at time of removal from storage. The resistance reading must not have dropped more than 50% of the initial reading. If the drop is below 50%, then the fan motor must be dried electrically or mechanically.

3) At time of removal from storage, fan motor bearings are to be purged to make sure that an ample supply of fresh grease is in each bearing grease cavity.

SIMILAR TO

UNLESS OTHERWISE NOTED: ALL DIMENSIONS IN INCHES; MACHINING DIMENSIONS LIMITED TO FRACTIONAL ± 1/64, DECIMAL ± .005, ANGULAR ± 1/2°; STRUCTURAL DIMENSIONS LIMITED TO ± 1/16. DO NOT SCALE THIS DRAWING.

MATERIAL | HEAT TREAT | CARB. | HARDEN | QUENCH | DRAW | HARDNESS

FINISH SYMBOLS

SYM	MICRO INCHES	DESCRIPTION	SYM	MICRO INCHES	DESCRIPTION
A	4	PRECISION POLISH	G	250	ROUGH MACH.
B	8	FINE POLISH	H	500	HEAVY ROUGH
C	16	COMMON POLISH	K	1000	EX. HEAVY ROUGH
D	32	GRIND OR EQUAL			
E	63	SMOOTH MACH.			
F	125	COMMON MACH.			

JOY MANUFACTURING CO.
PLANT LOCATION AS INDICATED BELOW

BUFFALO, N. Y. | NEW PHILADELPHIA, O.
CLAREMONT, N. H.
FRANKLIN, PA.
GALT, ONTARIO, CAN.
GREENOCK, SCOTLAND
MICHIGAN CITY, IND.

FAN STORAGE INSTRUCTIONS

GR. BY | TR. BY | CK. BY | APPD. BY
DATE | DATE | DATE | DATE
SUPERSEDES
SUPERSEDED BY
REPLACES
REPLACED BY
SCALE | CLASS

FF1330

071308

Installatn & Maintenance Manual

(Same as in U258759)

Bulletin No.
NP-403