NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

IN THE MATTER OF:

230th GENERAL MEETING

Place - Washington, D. C.

Date - Thursday, 14 June 1979 Pages 1 - 261

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

Thursday, 14 June 1979

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

230th GENERAL MEETING

Room 1046
1717 H Street, N. W.
Washington, D. C.

Thursday, 14 June 1979

The 230th General Meeting of the Advisory Committee on Reactor Safeguards was convened, pursuant to notice, at 8:30 a.m.

PRESENT:

DR. MAX W. CARBON, Chairman
DR. MILTON S. PLESSET, Vice Chairman
MR. MYER BENDER, Member
MR. JESSE EBERSOLE, Member
MR. HAROLD ETHERINGTON, Member
PROF. WILLIAM KERR, Member
DR. STEPHEN LAWROSKI, Member
DR. J. CARSON MARK, Member
MR. WILLIAM M. MATHIS, Member
DR. DADE W. MOELLER, Member
MR. JEREMIAH J. RAY, Member
DR. CHESTER P. SIESS, Member

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P R O C E E D I N G S

(8:30 a.m.)

DR. CARBON: The meeting will now come to order.

This is the 230th meeting of the Advisory Committee on Reactor Safeguards. During this meeting the Committee will further consider the implications of the accident at Three Mile Island Unit 2, the responses of the various nuclear vendors to the questions posed in NRC Inspection & Enforcement Bulletin 79-05, 05A, 05B, 06, 06A, 06B and 08, and the NRC staff evaluation of those responses, the report of the investigation and evaluation of stress corrosion cracking in piping in light water reactor plants, NUREG-0531, dated February 1979, recent plant operating experience in seismic design of piping systems, application of increased power rating to the Millstone Nuclear Power Station Unit 2.

The Committee will also hear reports from its Subcommittees on Regulatory Activities, Reliability and Probabilistic Assessment, and Operations at Fort St. Vrain. We'll also discuss various other topics, as well as future schedule.

The specific items for today's discussion are a report by the ACRS Chairman on various matters relating to Committee procedures and operation, reports by Subcommittees on Three Mile Island Unit 2 and on the applications of the Three Mile Island 2 accident, NRC staff reports on current status of Three Mile Island 2, responses to NRC I&E bulletins, NRC orders, ACRS recommendations and lessons learned from TMI-2, NRC staff reports on the investigation and evaluation of stress corrosion cracking in piping in light water reactor plants, NUREG 0531, recent operating experiences with seismic design analyses, a proposal to increase rated power of Millstone Nuclear Power Station Unit 2; and to hear reports from various ACRS Subcommittees and members.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act and the Government in the Sunshine Act. Mr. Raymond Fraley is the designated federal employee for this portion of the meeting.

A transcript of the meeting is being kept and it's requested that each speaker first identify himself or herself and speak with sufficient clarity and volume that he or she can be readily heard.

We have not received any written statements or requests for permission to make oral statements from members of the public with regard to this meeting.

The first item on today's agenda is the Chairman's report.

(Chairman's Report given.)

(Brief recess.)

DR. CARBON: Let's continue with the meeting, and for a report on the ACRS Subcommittee on Three Mile Island, I'll call on Mr. Etherington.

MR. ETHERINGTON: The meeting was held in Middletown on the afternoon of June the 6th and the morning and early afternoon of June the 7th. There were 8 Committee members present, three consultants and two ACRS staff members. Mr. Vollmer of the NRC staff described the current plant status.

The plant is operating on natural circulation through the A steam generators leading to the condensor, 348 psig and 160 degrees. The B loop is isolated. The maximum core thermocouple reading was 282 degrees Fahrenheit. The containment is about atmospheric pressure, 102 degrees F. The water in the containment is somewhere over 500,000 gallons, 7-1/2 feet above the top of the sump.

The radioactivity is 10^{-3} microcuries per cc of iodine, 10^{-1} microcuries per cc of noble gases.

The plant modification and standby systems are essentially as described by Mr. Arnold in a report which the Committee received called "Plant Cooldown and Temperature Modification," dated May 1979. The modifications included a backup coolant system for the B steam generator, consisting of a closed pressurized intermediate loop. This was being tested at the time and it is nearly operational now.

The standby RHR system is in storage, but can be installed within 24 hours if it should ever be needed.

Consideration is also being given to pressurizing the reactor coolant system by head tank outside the containment.

Additional electric power supplies have been installed. New air filtering systems have been installed, and a system called EpiCore for water cleanup.

The NRC support to Three Mile Island consists of 14 licensing professionals, half at the site; also, 15 I&E personnel on the site, giving 24-hour-a-day coverage.

Mr. Vollmer said that all plants now have direct phones to a duty officer in the I&E regional office and 24-hour-a-day coverage; and each regional office has a dedicated line to Bethesda.

Mr. Michelson pointed out that the plans and drawings available in Bethesda are likely to be inadequate and unreliable.

Mr. Arnold and other public utilities and Metropolitan Edison representatives discussed the accident chronology. The chronology has been given in a Met Ed document which the Committee received, "Preliminary Annotated Sequence of Events," dated May 10th. This will be updated from time to time. I think that is the third edition.

This document is based on records and interviews with operators. And the Committee did not follow the chronology step by step, as we're more or less familiar with it. But significant sequences were discussed.

Mr. Keaton discussed the reactor coolant system and steam generator transients during the period of forced circulation --I missed a page, excuse me -- and presented curves that showed generally good correlation pressures and levels, and those computed by their RETRAN code.

The operators on duty responded to questions by the Subcommittee and the consultants. The responses were straightforward and conformed generally to the chronology as we had understood it.

Emphasis on the importance of keeping the core covered led to the over-reliance on the pressurizer level as an indication that the core was in fact covered.

The B&W resident representative, after his arrival, was a party to discussions of actions to be taken, and there was no agreement between him and Met Ed concerning subsequent actions.

PROF. KERR: I'm sorry. You said?

MR. ETHERINGTON: There was no disagreement. There were incomplete agreements.

Some miscellaneous topics related to the sequences of events was discussed in response to interested individual members and consultants. Data on the in-core thermocouples were presented.

Station organization, the Met Ed central organization and the technical support organization from General Public

Utilities were described, with organization charts. A summary of these are in our black ring binder.

The review committees, procedure preparation and the training program were also discussed.

After the accident, it was recognized that education and training improvements were necessary in the areas of thermodynamics, the extension of postulated failure simulation to the ultimate consequences, and on shift training drills; also, that the procedure formats needed to be improved.

Incidentally, during the visit of some members of the Committee, the staff and consultants to the B&W simulator to Lynchburg, Mr. Kosiba made the important distinction between educational and training. I believe it was his opinion that the necessary education could be acquired by about six months of study in selected subjects above the high school level.

However, I may be misinterpreting his formal opinion. So if that opinion is important to the Committee, they might ask him directly this afternoon.

DR. CARBON: Would you mind repeating that?

MR. ETHERINGTON: His opinion was that the education in university-type subjects could be accomplished in sufficient depth for the purpose of training operators in about six months. This would include the thermodynamics, heat transfer and things like that. That's apart from the training in knowing where everything is in the plant and actual control of the reactor.

The emergency plan was described, including the emergency organization drills, training, communications emergency equipment and off-site assessment. Emergency classifications include local, site and general emergency, and required actions are defined for each class of emergency. The emergency plan chronology was described in the TMI accident. A site emergency was declared at 6:55 a.m. That's about three hours after the loss of feedwater. And the general emergency was declared half an hour later, at 7:24 a.m.

The Committee had been notified that there was to have been a written statement by a member of the public, but this statement was not received and there were no oral statements made at the meeting.

Many of the Subcommittee members left before the meeting was adjourned, and Dr. Carbon took over chairmanship of the meeting to cover a few remaining topics and to advise Three Mile Island on topics that would be most likely to be of interest to the full Committee.

Mr. Muller's memo, which I don't know whether you have it here -- it's been distributed somewhere -- lists 30 items that were considered as possibly of interest to the full Committee. This is a rather long list. It's more than two pages. And I don't think there would be much point in reading it, Mr. Chairman. Or shall I read it?

DR. CARBON: I don't think there's any point in reading it.

MR. ETHERINGTON: Right.

The Subcommittee members, consultants and staff visited the Three Mile Island plant in two separate parties. The visits were made to the control rooms and turbine buildings of both Units 1 and 2 and the auxiliary building of Unit 1.

That concludes my report, Mr. Chairman. But I would like to mention that Mr. Fraley had made a suggestion that the Subcommittee hold a press conference at the end of the meeting. I elected not to do this without the Committee approval, because it might set a precedent and there might be a disadvantage as well as advantage to this procedure.

It may be, Mr. Chairman, that this will be worth discussing at some stage during this meeting as a matter of policy, whether we should or should not hold press conferences. As Chairman of this particular meeting, it could have saved me from being shoved up in a corner by a pug-ugly brute of a reporter and bulldozed into saying things which I didn't mean.

DR. SIESS: It might have been a real cute girl, though.

MR. ETHERINGTON: It could have been, yes.

(Laughter.)

MR. ETHERINGTON: All right.

(Laughter.)

DR. SIESS: You still know the difference, don't you?

MR. FRALEY: I would like to say that my suggestion was based on a press conference that we held in Japan, which was a very orderly, very nicely organized, very well-done, versus the kind of grabbing and pushing that usually goes on following our meetings.

I thought a scheduled press conference might avoid that.

MR. ETHERINGTON: I think it's well worth discussing. I just didn't want to start it unilaterally.

DR. CARBON: Let's come back to that later in the meeting.

That finished your report, then?

MR. ETHERINGTON: Yes.

PROF. KERR: Harold, would you repeat the activity? you gave it and I missed it. You gave noble gases. If you have difficulty finding it, I'll just get it from you later.

DR. MOELLER: It was very near the beginning.

MR. ETHERINGTON: It's 10^{-3} microcuries per cc of the iodine and 10^{-1} noble gases.

PROF. KERR: Thank you.

DR. MOELLER: I had several items to be clarified in terms of the meeting, and if it's appropriate, I'd like to ask them now.

You mentioned that the B&W representative -- that there was no disagreement with his recommendations of what the plant operators did.

MR. ETHERINGTON: Of course, he got there when they were in real trouble.

DR. MOELLER: Now, according to the draft minutes which we have, he arrived there about 7:00 a.m.

MR. ETHERINGTON: That's right.

DR. MOELLER: So from that point on, he was pretty much in contact.

MR. ETHERINGTON: It was stated that there was no agreement, that the actions were taken more or less on a confidence basis, I think. Obviously there were some wrong actions taken after that time, too.

DR. MOELLER: My second question: At the bottom of page 6 of the draft minutes, it says that in Dr. Mattson's report, if you classified the errors as human, equipment malfunction and design deficiency, and if you had eliminated any one of the three errors, the accident, it says, may not have been less severe.

I gather that they're saying, even if we could have eliminated human error, the accident still would have been equally as severe?

MR. ETHERINGTON: That's clearly not right.

DR. MOELLER: I didn't understand the minutes.

MR. ETHERINGTON: Can you put your finger on that?

DR. MOELLER: I'm looking at the memo of June 12th from Peter Tam.

MR. ETHERINGTON: That's another meeting.

DR. MOELLER: Oh, that's another meeting.

PROF. KERR: That's the one Dave Okrent chaired.

DR. MOELLER: Okay, this is a different meeting. Well, thank you. Maybe that's why you're not familiar with it.

MR. ETHERINGTON: I'm afraid I'm stuck with it anyway.

(Laughter.)

DR. MOELLER: Maybe we could have that clarified later.

One last question. Noting again the wrong meeting, the May the 31st-June the 1st Subcommittee meeting, but nonetheless still on the subject of TMI, Dr. Kerr had raised some questions at that meeting regarding the r eal cause or the real initiator of the accident, namely the problems with the condensate demineralizer.

Did you get into that at all?

MR. ETHERINGTON: Yes, but to what degree? Clearly that initiated the accident. If it hadn't happened, the plant would be running today, of course.

DR. MOELLER: Yes. And I understand that they had

had problems many times previously and that the technician that worked with the system had problems.

MR. ETHERINGTON: There is a fairly long history of that kind of problem.

DR. MOELLER: And is the NRC addressing this problem? Are there any reports on it?

MR. ETHERINGTON: There are the I&E bulletins that have gone out addressed to all plants.

DR. MOELLER: Right. But unless I have missed it, I don't recall seeing any large amount of attention being directed to this and how to correct it or improve it. Have I missed something? And I don't understand it. It seems to me that if this initiated the accident and, as Dr. Kerr has pointed out, we need more reliability in these systems, in these condensate demineralizer systems, I guess my question is: Did the Subcommittee address this? Is the NRC addressing it?

MR. BENDER: We had talked about this some. The problem turned out to be something along the following lines. They have had trouble with the resin backing up into the line, which they've attempted to clear by blowing air into the line.

It turned out in this particular case that during that operation, somehow or other, they got water backup into the air line, and this in turn caused some reaction that

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affected some of the valves that they were depending upon for the relief system, as I understood it, and they think that might have been a contributor to the accident.

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That was theory, and not proved. That's one of the things we have to look at.

DR. LAWROSKI: That's exactly the way they put it, too. That they think that that may have been it, but they have yet to ascertain.

MR. ETHERINGTON: That could well have been the initiator in this case. There have been many similar cases of main feedwater failure due to the rather tricky controls, and this must be regarded as a more or less anticipated transient, coupled with the relief valve staying open, and of course subsequent incorrect actions, gives us the Three Mile Island accident.

In its directions to plants, the staff is requiring them to set the relief valve at a higher setting, so that it will not open; and the other ac   ns in the I&E question.

DR. MOELLER: Right. I understand all of that. But I haven't seen an I&E all-points bulletin that says when operating the condensate demineralizers, take the following precautions.

MR. ETHERINGTON: This is a unique case.

DR. MOELLER: Maybe there has been -- I haven't seen three or four consultants or NRC staff members working diligently on this problem, and I guess I just don't understand.

DR. CARBON: I think part of the reason is that, as Harold has said, the system at Three Mile Island 2 I think is unique, not like other systems.

MR. ETHERINGTON: Not so much the system, but th incident.

MR. BENDER: I think we're focusing on the wrong part of it. Whether the demineralizer caused problems or not is not the issue. There is a question of whether there is some interactive effect in using the control air system for things other than control.

The staff is conscious of that, and has indicated they're looking into that matter.

DR. CARBON: Dade, did you have other questions?

DR. MOELLER: No, thank you.

MR. RAY: Harold, you mentioned that there's a history in this plant, and among B&W plants, for similar troubles. Has this plant in the past had a similar occurrence that caused reactor scram?

MR. ETHERINGTON: I believe so. I'm not sure.

MR. RAY: So whatever you're doing, the control systems worked. If this is true, the control systems worked satisfactorily in the past.

MR. ETHERINGTON: Yes, the control systems worked satisfactorily in general.

MR. RAY: Apparently it's been practice to use the air tube to clean the filter? Is this unique to this incident?

MR. ETHERINGTON: I think it's quite common to use air for flushing down spent resins.

MR. FRALEY: I don't think you normally use control air, though. You use service air.

MR. ETHERINGTON: You sometimes have separation of the air systems.

MR. RAY: So the uniqueness might be that, on this one occasion, they used control air rather than service air?

MR. BENDER: They have only one air system, as I understand it. It has a lot of capacity, and normally you wouldn't expect that it would back up and cause any difficulties.

The fact of the matter is, in this case it got some water in the system in some way.

MR. RAY: So when they've done this in the past, it had a successful scram, an effective scram, a safe scram; apparently the water was not involved.

MR. ETHERINGTON: You don't expect a scram when you're flushing down the resin. It's just that the line got plugged. Then we had the backup and the postulated backup and the water in the air system.

MR. RAY: Did I understand from you, Steve and Mike, that the NRC is vigorously pursuing this thing?

MR. BENDER: Well, "vigor," I would not be willing to testify on, but they're aware of the question.

MR. RAY: Well, we've all focused on the results o f the accident, and there's no real focus-- and I think this is Dade's point -- has been indicated on the basic cause -- and it isn't necessarily deficiencies in the reactor or its controls -- as to what they were doing, or the manner in which they were doing it, something involved there.

And I've heard no emphasis -- I'm with Dade. I heard no emphasis on a real effort to establish why, and all the r::ctors that are operating around the system could be exposed and subject to the same fallibility.

MR. BENDER: Without wanting to take issue with your position, there must be hundreds of things that go on in the non-nuclear part of the plant that could have interactive effects.

MR. RAY: Sure.

MR. BENDER: And a focus on this one, just because it was an initiator, would be overemphasizing it.

DR. CARBON: Carl?

MR. MICHELSON: If I could change the subject, let me go back to one of the things that Mr. Etherington mentioned that I think is important.

When we had our meeting, I asked the NRC people what information do they use during, say, the first 24 hours of an event when they're sitting in Bethesda trying to determine what has happened.

And of course they basically said that they were using the FSARs as the basis for their determination. This then brings up the very important question about the accuracy and up-to-dateness of these documents, and how often should they be revised for an operating plant?

Should they be revised as soon as a significant change occurs? I think this is an important subject, and Mr. Etherington touched upon it, but it may be something that the committee would possibly want to make a recommendation on.

MR. BENDER: Again, at the risk of using up a little bit more time, Mr. Chairman, having looked at the FSARs recently, I have to say that if that's what the staff was relying upon as base information, it's not very useful. Even if it were accurate, it's not useful, because it doesn't have enough of the kind of information that's needed in it. And one of these days we will have to look at what they really have available to them for accident assessment purposes.

DR. CARBON: Walt?

DR. LIPINSKI: I would like to go back to the discussion of the initiating transient. When we toured the plant, the question came up: What was different about this particular case of flushing the resins? Normally they run one pump at 80 psi. So this does not cause the water to back up. On this occasion, they put on a second pump, so they had 160 psi. And they have a built-in valve with an intermediate position that allows the air/water systems to be interconnected. And it was held in that position longer than normal.

There was a check valve at the air line that stuck open, and this is really what caused that water to back up -- the fact that the check valve did stick open when they had water pressure exceeding the air pressure.

Now the other thing as to what this transient did, it was not just to initiate the trip in the sequence where these valves closed, there was a water hammer. The water hammer sprung a leak downstream, and it also ripped the air lines loose that were allowing them to control the hot water level.

During the course of the transient, the hot well filled up on them. At one point, they were forced to do an atmospheric dump until they restored the air line, and regained control of the hot well. Had steam generator A ruptured in addition to B, they would have had radioactivity going out that atmospheric relief.

DR. CARBON: Are there questions?

MR. BENDER: Neither A nor B steam generator ruptured. They just thought maybe one of them had.

DR. LIPINSKI: No, they verified at the meeting that they do have radioactivity from steam generator B on the secondary side, and primary to secondary leaks occurred. Maybe the term "rupture" is the wrong term.

PROF. KERR: Is that now clear? Because that's the first report I had had. There definitely was leakage from primary and secondary through the steam generator tubes?

DR. LIPINSKI: This is what they reported, that they had radioactivity on the secondary side of steam generator B.

PROF. KERR: There's a difference to having radioactivity on the secondary side -- I mean, there could be. Did they have it? And it's because of leakage?

DR. LIPINSKI: Because of leakage.

DR. CARBON: Further questions of Harold?

MR. BENDER: The last point was not established. We don't know -- we don't know whether either of the steam generators are leaking significantly or not, and I don't think we want to put too much emphasis on that point at this time. The fact that there is radioactivity on the secondary side is known, but we don't know how it got there, yet.

MR. ETHERINGTON: I don't remember the answer, Mike. There was discussion of pressure buildup on the secondary side with the system isolated. I don't know whether they said there was pressure buildup, or whether there wasn't. Not helpful.

DR. MATHIS: Well, we specifically asked the question, if the leakage in steam generator B had been verified. They said, "yes, verified."

Now that's the only information I have.

MR. BENDER: What I'm concerned about is that the nature of the verification is so vague and subject to so much operator interpretation that you really can't tell what was going on.

The pressures jumped up and down several times, for several reasons, in that system. Some of it had to do with the cooling of steam, and those things have not all been shaken out, yet.

MR. ETHERINGTON: I don't think there's any suspicion that it's anything like a tube rupture. I think if it's a leak, it's a small leak.

DR. CARBON: If that takes care of that topic, let's move on to Item 1.3, then, which is the report of the ACRS subcommittee on the implications of the Three Mile Island 2 accident.

This subcommittee meeting was chaired by Dave Okrent, who could not be here today, and we've asked Harold if he would present part of the report, and Chet if he would present the other part. I don't know that there's a difference in order, here, but since the part on research came first, perhaps it's reasonable for you, Chet, to give your report.

DR. SIESS: I think it would be the other way around, since research can be separated from the other letter, and Harold can go on into the parts that sort of overlap with the other TMI 2.

DR. CARBON: If that's all right with Harold, would you go ahead?

MR. ETHERINGTON: There were eight committee members at the meeting. We had four consultants also at the meeting.

The subcommittee met with the NRC staff on the morning of May the 31st, and with B&W in the afternoon of May the 31st and the morning of June the 1st.

The staff reviewed proposals for augmented research resulting from the Three Mile Island accident. The proposed additional budget items -- and those will be discussed by Dr. Siess.

The NRR and RES staff also discussed proposed studies of hydrogen problems, including hydrogen generation and removal, detonation of hydrogen/oxygen mixtured inside the reactor vessel, presentation of combustion data in simplified form, and a possible program of selected experiments.

The question was raised concerning the possibility of hydrogen embrittlement of the Three Mile Island primary system components, and I believe the staff plans to look into this.

The staff reviewed the status of boiling water reactors in addition to the Three Mile Island accident, and the I&E Bulletin 79-08. This bulletin requires licensees of BWRs to review and record the following items: (1) the applicability of the Three Mile Island incidents to their specific plants; (2) containment isolation; (3) consequences of loss of main feedwater; (4) level indication systems; and (5) operating and training procedures; (6) valve positioning indication; (7) the possibility of inadvertent release of radioactive fluids; (8) maintenance and test procedures; (9) procedures for notifying NRC of unexpected conditions; (10) procedures for dealing with abnormal hydrogen generation; (11) appropriate changes in tech specs.

Responses have been received from most of the licensees, and many procedures and design changes have been proposed by the licensees.

The applicability of NUREG-0560 to BWRs has been reviewed by the staff. Responses to ACRS recommendations have been requested of GE and of all BWR licensees. The NRC plans to issue a generic BWR report similar to NUREG-0560 in July, and to take subsequent actions as may be appropriate.

Dr. Mattson discussed lessons learned from the Three Mile Island, briefly, including the combination of human error, equipment malfunction, and design deficiencies.

It was proposed to the subcommittee that this was of sufficient importance to the entire committee that detailed discussions was deferred at that time, and Dr. Mattson will speak at greater length on this subject to the committee this afternoon.

For B&W, Mr. McMillan introduced his associates. Mr. Tayor stated that, after the accident, B&W's attention was mainly directed at Three Mile Island, but has subsequently shifted to support of the operations of B&W plants in development of design changes and retraining of operators.

Mr. Taylor gave the chronology of the B&W participation during the first day. The committee may want to hear a brief resume, and I believe B&W will answer a question that Dr. Carbon asked concerning the loss of communication between Lynchburg and the B&W site representative on the first day, from 7:45 a.m. to 6:00 p.m.

Mr. Elliott discussed the educational background of operations, and described a typical operator training program and use of the B&W simulator for operator training.

This also is a topic in which the committee has shown considerable interest and may wish to hear from Mr. Elliott.

Mr. Kosiba discussed operating experiences, listed PORV and bent-valve failures that have occurred, and described how such operating information is acquired by B&W and used to improve procedures and designs.

Mr. Roy also addressed this subject. I think this is the topic that Dade Moeller was interested in, and perhaps Mr. Kosiba can give us a resume of the failures that have occurred.

Mr. Englund demonstrated a device newly installed on the B&W simulator to read out the margins of saturation from pressure and temperature input.

Mr. Labelle compared the computer analysis with the course of events at the Three Mile Island accident. The B&W CRAFT-2 code is used for analysis of causes during forced circulation with the CADS code being used duiing the subcooled period of about six minutes.

The computer output showed, over a period of forced circulation, system pressure, hot leg temperature, and level, all in generally good agreement with the values observed during the Three Mile Island accident.

Curves were presented showing recovery from the loss of main feedwater under both design conditions and

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abnormal conditions. The subcommittee indicated that the Full Committee would probably want to hear this presentation in an abbreviated form.

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Mr. Womack discussed actions taken to reduce the probability of accidents such as the Three Mile Island accident. Mr. Dunn discussed small-break phenomenology and operating guidelines. The subcommittee indicated that the full committee might want to hear these presentations in an abbreviated form. Mr. Jones provided additional information on small-break analysis and LOCA evaluation models. Mr. Karas discussed B&W lowered and raised loop designs and presented data on natural circulation demonstrated at B&W plants, both in tests or in loss-of-off-site power during operation.

In response to a request by the NRC staff, B&W has provided, dated May 12, an analysis entitled "Small break in the pressurizer PORV with no auxiliary feedwater and single failure of the ECCS with realistic decay heat." It was concluded that their system had survived this extreme condition indefinitely with no feedwater supplied at all. However, during the early stages of heat removal by boiling, the relief valve safety valve would have to pass water equal in volume to the steam generation.

B&W has undertaken to verify that the valves have sufficient capacity to pass the large quantity of water without significantly overpressurizing the system. We expect that they will give us a response to that in this afternoon's meeting.

The agenda included a list of items A through M. These were items suggested by individual members who are listed

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in the meeting agenda and were responded to by Mr. Mattson. Again, I could read this list, but it's a long list, and they were responses to individual items of interest.

Mr. Roy summarized the B&W responses to ACRS recommendations. First, additional analyses have been made and reported on small breaks and natural circulation. Two, they have recommended to customers use of wide-range hot-leg temperature indicators, installation of the new B&W indicator to show the margin of saturation, and improved display of key operating data. Three, they are offering a supplementary traning program. Four, they are reviewing the matters of reactor vessel level indication, reactor coolant system venting, and expanded safety research.

This concludes my part of the report, Mr. Chairman.

DR. CARBON: Are there questions of Harold?

(No response.)

DR. CARBON: Or comments?

MR. ETHERINGTON: You might ask whether our consultants have anything.

(No response.)

DR. CARBON: Let's then go to the portion on research. Chet.

DR. SIESS: Mr. Chairman, I have to apologize because I had hoped to have something much better organized. But, as you know, I have been ill, and although the illness was physical, it impaired my mental abilities more than usual.

At the meeting that Harold has reported on, the research staff brought to us a list of identified research needs that related to TMI-2 and the proposal that they initiate much of this research in fiscal year '80. We have got to realize that FY '80 begins October 1, I guess it is, 1979. So, we're talking about something being initiated within the next few months. And the FY '80 research budget is now at $169 million. I think that's the authorization.

The longer list that the staff has come up with amounts to about $29 million. Carson has already mentioned earlier, talking about the fuel research, something like $5 million other. THey divided their TMI-2 research needs

They divided their TMI-2 research needs into six categories. I don't find the categories all that helpful. But just to give you a quick rundown:

Transient small-LOCA events, $13-1/2, roughly. $9-1/2 million of that for tests. $3.9 million for analysis. Enhanced operator capability, plant response under accident conditions: the first, $3-1/2 million; the next $5 million. Post-mortem examination and plant recovery of $2.7 million; improved risk assessment, $2.4 million; and improved reactor safety, $2.2 million. A total of about $29 million.

The staff also gave us a copy at that meeting of a draft communication to the Commission that they expected to transmit in late June or early July, requesting an FY '80 budget supplement, and conducted additional research related to TMI-2.

When we thought that we would be meeting with the Commission at this meeting, there was the additional thought that perhaps we could make some comment to the Commission on the scope and the need for an FY '80 budget supplement for research related to TMI-2. Dave Okrent and I had hoped to come up with some sort of draft, which unfortunately we have not, but it may not be necessary since we are not meeting with the Commission.

The proposal to the Commission suggests various ways in which this additional -- I am sorry -- in which this $29 million in research might be financed. One obvious way, of course, is an additional budget allocation, to go back to the Congress and ask for a supplemental budget for either the entire amount or part of it.

Another way, of course, is some combination of additional budget plus reallocation. And then, I guess, at the other extreme is to do it entirely within the current budget, entirely by reallocation.

I don't believe any of these could be done without some congressional approval. Obviously, they can't be done without Commission approval.

One of the first thoughts that comes to mind is whether this $29 million is reasonable. Carson raised the question very well in connection with the fuel behavior. If we divert $5 million out of $23 million to TMI-2, should we add $5 million and call the $23 million sancrosanct, and the same question can be asked here.

In the staff's draft proposal to the Commission, they suggest several alternatives. One is simply to do some reallocation. They've proposed to reorient current programs to the maximum extent possible and fund the remaining work by terminating lower-priority programs. And to give you some idea of the thinking, to do this, the lower-priority programs, they would terminate and replace by TMI-2-oriented programs would be the breeder, advanced converter, safeguards, and most of the fuel cycle environmental research programs. Essentially, they would cut all of those programs to about zero. They'd take out all advanced reactor research, $4.6 million out of $7.6 million on environmental and fuel cycle, everything on safeguards.

They would pick up $23 million that way, and currently, the other $6 million they would take care of by some reallocation of priorities. So, by not changing the budget at all, they can do most of this research in the cost of dropping certain areas and complete areas. It's a very clear-cut type of option.

Their second alternative was to reorient the current programs to the maximum extent practicable and request new budget authority for the remaining work. That, in effect, simply says: Ask for $29 million more.

There is some reorientation, but it's on the order of $2 million here and there.

They had another alternative, which was reorient current programs to the maximum extent possible -- the operative word there is "possible," rather than "practicable" -- including the termination of LWR research programs focused on large-break loss-of-coolant accidents. That would presumably require no additional money, but it says "terminate the large-break loss-of-coolant accidents."

A fourth alternative was to reorient current programs to the maximum extent practicable and to request EPRI, DOE, and the industry to fund the remainder of the research needed. They sort of dismissed that one without giving it, really, as much consideration as I think it deserves.

If you would like to guess which alternative they prefer, I will give you a couple of seconds, but it's clearly Alternative 2, which was to ask for $29 million more. I don't think the staff has any expectations of getting $29 million more. Somebody, in an unguarded moment, thought they might get 10 or 12, but I didn't see it fitted into one of these alternatives.

I don't think there is any question that under the Three Mile Island 2 incident has indicated quite clearly that we need, at the very minimum, some redirections in our reactor safety research, or maybe our safety research in general, since it's more than reactor safety research. I use the word "redi-rections" advisedly. I am not sure how much it means that we need completely new research. I would hate to think that everything we have been doing has been so wrong and that a lot of things need to be dropped and completely new things started. I think most of the research has been more or less of the right kind, but it's gotten off in some directions. It's very clear not only research has, but some of the regulatory thinking.

They haven't divided this up the way I would like to see it divided. I think I would like to see the needed research divided into maybe three categories that I could think of off the top of my head.

One could be those that related to TMI-2 recovery. The immediate future safety of that installation. The cleanup and decontamination, all the things that are involved in getting that plant to where people can get into it and nobody gets hurt.

There is another area, which would include research that's needed to understand, to further reduce the probability of TMI-2-type accidents, defined rather narrowly. I don't know how narrowly.

Then, the third is the much broader one, and that's the lessons learned. What redirections do we need. What did we learn about the way that we were going that we shouldn't have been going, if we ought to change some directions.

On the first one, the TMI-2 recovery, it's a type of thing they did mention that could be handled by industry through DOE. They think they've got to have a hand in it. I don't see why not. But this is the sort of thing that has to do with recovery, decontamination, and so forth. I would think it wouldn't be too difficult to get the industry and the DOE to fund even more than they have in mind here. In fact, I am sure industry is already funding more than they have in mind here, just thinking of the Dresden 1 decontamination situation. How much money is going into that, as compared to what they're talking about here.

On the category of lessons learned, I just find it difficult to see how anything we've learned says keep on doing everything we're doing but just do more. To me, one of the lessons we've learned is that we have been devoting too much attention, and probably attention of the wrong kind, to large LOCAs and PWRs. We've been spending hundreds of millions of dollars to develop and validate codes, but we haven't been using the codes to predict the sort of things that will happen that confuse people. We've been using the codes to license plants, go through evaluation models, correct for four-degree changes in plant temperature, this little bit and that.

So, on the lessons learned side, it seems to me the indication is that there should be a major redirection in

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research, rather than piling a lot of new stuff on. So, this sort of leads me to believe that the $29 million additional appropriation would be a little hard to justify. You might throw out two or three million and say let industry do it, we'll spend a few hundred thousand keeping an eye on them or asking questions, although the research budget doesn't cover asking questions -- that's NRRs.

The reorientation of light water reactor research from large LOCA to small LOCA, BWR to PWR, if necessary and so forth, should be done to a considerable extent by this reorientation, as they call it, of current programs and reallocation of funds.

Now, I don't know what we can agree on, but I personally would have difficulty trying to support $29 million of completely new money beginning in October '80. On the other hand, I don't think they can do a good program with no additional money without just cutting some other programs to the bone.

There is some advantage in the approach of saying no more money, because there's going to be a lot sharper thinking about what they're going to do, and they can also think about what they don't want to do.

I won't say this is a laundry list. This was at least cut by half from all the ideas that came out of all the research offices. But it's not honed quite as fine as it could be if somebody said, "Look, you're not going to get any more

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money, and you just decide what you can do and what you have to do and what you're going to leave out." So, I am being just a little hard-nosed there, but I don't want to give the impression that they can just put down anything anybody could think of and say, "Let's ask for this, let's go ask for the money." They're only asking for about half of that, and probably expect to only get about half of that.

We had a presentation from Dr. Budnitz on this. I would say that the breakdown was the six items I gave. It's not quite broken down in parallel with NRR's approach to TMI-2, you know, with the three task forces.

I think we should try to find some time during the meeting, if we can, to discuss this further, to see what time schedule we need to offer some advice to the Commission. It could go in with our July letter on the FY '81 budget. This is an FY '80 item. But no matter which way they go, if they stick with what they've got and ask for reallocation authority, they've got to go to Congress. If they're moving money around, I think, within the NRC, they ought to go to the Congress for some amount. If they want $29 million, they obviously have to go through Congress.

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I think there's a need. I'm not satisfied that it's been all that well thought out, or at least, if it has been that well thought at, it's been that well explained to me. There were seven or eight other people at that meeting that heard the story. I hope any of them, if they have a different impression of it, will speak up now.

Carson? Steve, you were there?

DR. LAWROSKI: I don't have any comment.

MR. RAY: I was there and I support your viewpoint, Chet.

DR. SIESS: I don't want to get accused again of telling them to cut out.

MR. BENDER: Why not?

DR. SIESS: Because I didn't say it. It may not mean that I don't think it.

But in the transient small LOCA events, the $13.4 million, the biggest single item is to upgrade semi-scale to study PWR transients. Now, I may be naive, but I just don't see how semi-scale is a suitable mechanical experimental device to validate codes for the PWR transients that we've been hearing about and Carl Michelson's been talking about.

Can semi-scale reproduce the burping and slurping?

DR. PLESSET: Chet, you're not naive.

DR. SIESS: Now, accelerate the small break tests in

LOFT I think has merit. We've got an excellent small break test at TMI-2, not very well instrumented. The idea is, they plan to make small break tests on LOFT, but they'll get to them a lot earlier. They'll get to them in FY '80, presumably, instead of FY '81 or '82.

Now that's a million bucks, not very much. I think they had about a million dollars in there somewhere to validate -- or I forget how the words went. There was a LOFT-type instrumentation to measure water level in PWRs. You know, we got into a number of these subjects. But it needs some thought, gentlemen.

DR. CARBON: Does that complete your report?

DR. SIESS: That completes my report, Mr. Chairman.

DR. CARBON: Are there added comments or questions?

DR. MARK: I don't really have anything to add on this. Chet has just mentioned some money to validate the instruments to measure water levels in PWRs. We received a very interesting package from TVA, sent by Carl. They don't suggest spending a million dollars to validate water level. They just say they're going to do it. I don't know if we want to hear any more about that here.

I wonder, however, in what respect is money needed to validate a measurement of water level? Why not just say, people will measure water level?

DR. SIESS: Let me elaborate a minute. I think the instruments they were talking about -- what is it, gamma density? Correct me. I just know the words.

PROF. KERR: Gamma densitometers.

DR. SIESS: Gamma densitometers. And they say that they don't really have any idea over what range they're valid, over what range they should be good, and so forth. And they've got an item, one million dollars, to test proposed instruments.

This may be essential. It may be desirable. I'm not sure that it's essential for the NRC to do it. The NRC needs to define the conditions under which these instruments have to operate and to have some acceptance criteria. But I'm not sure it's NRC's job to prove that they work. Maybe it's industry's or whatever.

I'm not, again, sure what "confirmatory" means.

DR. PLESSET: Well, I would like to add a comment. I think Chet indicated some skepticism about semi-scale for small breaks. I would go farther. I have a general skepticism about semi-scale for any kind of break. I think one can only justify semi-scale as trying to help validate codes. And even there, it's not terribly useful.

Also, about LOFT for small break tests, I'm not terribly enthusiastic about that either. I don't know how useful it's going to be. I'm not even sure it's better than nothing.

I think that this whole excitement about small breaks has been somewhat exaggerated. In some ways they're a lot easier to handle than large breaks, and we don't need to get excited about using massive codes or validating massive codes. I think one can just get carried away, as we have been up to this point, I think, with this big code program. We may talk later on about a very, very elaborate, expensive program which involves TRAC. Some people aren't very enthusiastic about TRAC at all.

DR. SIESS: Let me make another comment, Mr. Chairman. I should have read this in the beginning to put it in perspective. But in our Interim Report No. 3 on the Three Mile Island 2 incident, the Committee included in one of the items a comment that there was need for additional research brought out by the TMI-2 accident. But we did think that the staff should seek a supplementary appropriation for research for FY '80.

However, we thought that there should be more emphasis on exploratory research than on confirmatory research and that there should be an attempt to develop the ability to simulate -- I am not sure what the word was, but transients and anomalous transients.

Now, I'm not all that sure about what we meant by all of those words. But some of them are Dave's. I wish Dave were here. Is he going to be here tomorrow?

DR. CARBON: Yes.

DR. SIESS: On the exploratory. But we've been using codes to predict the course of an accident, assuming that things worked in certain ways. I don't think we've been using the codes except post hoc to look at the things that can go wrong and how that might confuse people. This is, I think, one of the lessons from Three Mile Island.

If we had gone through a number of anomalous accident situations, not assuming single failures, assuming double failures, not assuming this, assuming the guy closes the valve, opens it, closes it, does all sorts of odd things, we might have found out that you get into some very peculiar situations where even the codes get confused. I don't know.

Now, this to me is exploratory. I don't know that you can explore everything. There is no way you can think of everything under the sky that somebody might do wrong. And we recognized this. We tried to bound it.

But we've been too satisfied with the bounding solutions and saying, well, that covers everything, when it doesn't cover the mistakes that could be produced by staying within the bounded solutions.

So I think we've already said some words in a letter to the Commission, and we've already made, I think, some kind of a commitment to support an additional research appropriation for FY '80. We've said some words about it should be different research, though, and I think that means that we don't want to just see small LOCA research done with the same blinders on that we've had for large LOCA research. You can use your own definition of what the blinders are. I've got mine.

MR. MICHELSON: Could I comment on one thing? I did want to comment on Dr. Mark's observation, to make sure that we understand each other. When it comes to the question of level indication, there are a number of uncertainties concerning how accurately it can be measured under certain conditions, particularly if there is high void fraction of the water. So it is advantageous to perform some amount of research to confirm perhaps the best way of doing this and what kind of correction one might make and how to use temperature correction, and so forth.

That I think I assumed, in part at least, perhaps what NRC was trying to look at.

PROF. KERR: I don't think that's the case, Carl.

MR. MICHELSON: Maybe I'm just hoping that's tne case.

They were, of course, pushing a particular type of device. And I don't think that should be discouraged, either. Right now we looked over 11 different kinds of ways of doing the job. We ultimately came back to the delta P stuff, with possible corrections for density and temperature. But it's far from perfect. But maybe we don't need a perfect measure of level, either. We just need an indication.

DR. SIESS: But you're going to get a perfect measure if the NRC does it through a research project at one of the national labs. That's exactly what bothers me.

MR. BENDER: What Carl is stating is a point which I think needs more than a little emphasis. There are several ways of measuring level. One of the things that the Committee recommended -- and I'm not sure I understood the whole meaning of this letter -- was an unambiguous measurement of level. One of the ways in which you avoid ambiguity --

PROF. KERR: Excuse me, Mr. Bender. The wording, I believe, was "an unambiguous indication," not "measure."

MR BENDER: Thank you. I think "indication" was the right term.

One of the w ys in which you accomplish that is by having more than one dev [illegible] ing able to see whether there's water there.

DR. SIESS: That's no way to get unambiguous.

(Laughter.)

MR. BENDER: When they disagree, you're in trouble. But when they agree, you find yourself really comfortable. It [illegible] ce to have two out of three, and that's sort of what we've done in the instrumentation business.

But two types of measurement have some value. And I don't know whether I'd support a million dollars more for research. Don't misunderstand me. But I don't think that we need to take too much issue with the idea that pressure measurements are not the only thing to do.

PROF. KERR: While the concern about the NRC research, or at least on my part, is not that they, if I understood the point, that they would try to confirm general ways of handling the level, but they would like to explore further development of the characteristics of a particular device. That's, in effect, instrument development, not the kind of confirmatory research on methodology. And there are some of us, I think, who feel that development of instruments ought to be fairly low on the priority list of NRC research.

DR. SIESS: I think we've indicated, too, in a letter that we thought that the industry should come up with some proposals, they should do some thinking about it, there should be more people thinking about ways to do this, and somebody might come up with a good answer. Somebody might come up with the best answer. Somebody might even come up with the perfect answer.

PROF. KERR: Someone might even come up with a workable answer.

DR. CARBON: With that point, I wonder if we could move ahead. We're running behind schedule. Let's go, then, to Item No. 2, the meeting with the staff.

I believe, Mr. Vollmer, you're going to lead off on the current status of TMI-2.

MR. VOLLMER: Okay, Mr. Chairman. Before I start, I'd like to clarify a couple of items or further discuss a couple of items that were mentioned in the Subcommittee report. The activity that was described as being 10^{-1} microcuries per cc of noble gas and about 10^{-3} of iodine, it should be clear that that is containment atmosphere.

MR. ETHERINGTON: Yes.

MR. VOLLMER: I thought, Dr. Kerr, Mr. Bender's question asked for coolant or something like that.

PROF. KERR: I did.

MR. VOLLMER: Well, the coolant activity is about 200 microcuries per milliliter cesium 137, which is now the dominant isotope. And as I recall, the iodine is of the order of 100 and, of course, decaying with an 8-day half-life.

The water in the containment sump we estimate, again the dominant isotope being cesium 137, we estimate that to be on the order of 50 microcuries per milliliter of cesium 137. There are barium and a mixture of other isotopes in both of these waters.

We haven't had a measure of the water in the containment sump as yet, but we suspect it has the same general mixture as the primary water, which does include barium. And incidentally, there's another. We've had one measurement of strontium activity in the primary water, which appears to be on the order of 500 microcuries per milliliter. And we're taking a close look at that, mainly for our cleanup programming, but certainly from a dosage or activity point of view.

DR. KERR: Did you say about 5?

MR. VOLLMER: 500, yes.

It's a difficult measurement to make, particularly in the presence of the other isotopes in the primary water. But we're trying to confirm that and we should have a better measurement. They may have it now.

DR. LAWROSKI: Higher than the cesium 137?

MR. VOLLMER: That is the indication we have, yes. We make it tentative, because, again, it's a difficult measurement, and that hasn't been confirmed as yet.

PROF. KERR: This is a measurement made on a small sample, I presume?

MR. VOLLMER: Yes.

PROF. KERR: And one cannot chemically separate the strontium from the cesium?

MR. VOLLMER: I think prior to this we haven't been looking very hard for the strontium and the tritium, for example. We have been looking for the higher activities. And it's true, the measurement can be made. What I'm suggesting is that one measurement that was made would indicate about 500 microcuries. And we'll get confirmation on that.

DR. MARK: You've mentioned several numbers -- 100,

200. 500 sounds to me like the biggest one you've mentioned, as if there were five times as much strontium as iodine, for example, in curies.

Are these all beta emitters? Why is it such a difficult measurement?

MR. VOLLMER: Well, the strontium is primarily a beta emitter. The cesium is a high .6 MEB gamma. So the iodine -- they aren't difficult measurements if you go ahead and look for them. But if you try to measure, for example, strontium in the residues of cesium, it's not an easy measurement.

PROF. KERR: I think he's saying you can't do it with a hand-held Geiger counter.

DR. MARK: I guess I would believe that. But it doesn't sound --

MR. VOLLMER: The measurements are being made on spectrographic equipment and so on.

DR. MARK: Cesium you read a gamma. For the strontium you read a beta. Iodine is also a beta, I guess.

MR. VOLLMER: Gamma. They all have betas associated with them.

DR. MARK: It seems to me that it might be separable.

DR. LAWROSKI: The units are the same, microcuries per ml?

MR. VOLLMER: That's right.

DR. LAWROSKI: Does strontium seem like a legitimate number, considering --

MR. VOLLMER: It appears that the strontium is high compared to what you would expect based on the other isotopes. That's why I said to consider it a tentative measurement until it's been confirmed. And indeed, they may ask the applicant tomorrow -- they may by that time have a measurement. I haven't been up there in several days, so I'm not sure.

DR. LAWROSKI: That would be a sorry affair with. strontium rather than ionic.

MR. VOLLMER: Mr. Michelson mentioned the accuracy of information at Bethesda. I'd like to say to the Committee that we found, even at the site, even in the licensee's own TMIDs, a lack of accurate information, particularly on auxiliary systems and things of that nature. So I think it is indeed a problem, which we're trying to cope with, to have available drawings that accurately display particularly the smaller connecting lines, drain lines and small valves and sample lines. It gets to be difficult and in many cases impossible without going in and actually looking.

Also isometrics. It's often important when you get into a situation where you don't have a great deal of your equipment available. Isometrics' actual locations, vertical locations in lines and valves and things get to be a very important thing. This type of information is not generally given too much accord in the review process, certainly, and

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therefore it's just not generally available.

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(Slide.)

Getting onto topics that I want to briefly discuss, the core is in natural circulation, steaming on the A steam generator. At this temperature the A steam generator, of course, has a negative pressure of about 10 pounds to permit the steaming process. It's open through a turbine by-pass valve to the main condenser, and the vacuum is being drawn by mechanical vacuum pumps.

So, the current mode really depends on holding the vacuum on the steam generator and condenser with mechanical vacuum pumps. The temperatures, hot leg and cold leg, have been very, very slowly decreasing pretty much in accord with what you would expect. With the slow decrease in the thermal level from the core, the delta T in the core has been of the order of nine, 10, 11 degress for some time. The maximum in-core thermocouple has been decreasing pretty much monotonically.

We have noticed that the effects of pressure, even when it was much hotter, the effects of pressure were not significant on this particular -- on the higher in-core thermocouple, which would indicate that they're not being blanketed by steam and perhaps not even by gas, but there is some sort of an insulation being provided perhaps by the current configuration of the core that's keeping these thermocouples from seeing the coolant. They certainly appear to be, as best the instrumentation people can determine to be valid measurements.

The reactor pressure is about 325 pounds. This is a balance between several things: One, because of the water level in the reactor building, one of the containment valves of the decay heat removal systems was threatened, so that valve was opened, and downstream of that valve is a relief valve which is set at about 375 pounds. So, it's important to keep the reactor pressure under that level in case we have to open or in case the stream isolation valves leak or something like that, you wouldn't have a path from the primary system back to the containment.

On the upper side -- or on the lower side, I guess, it's difficult to get much lower than 300 pounds or so, because even though we're in solid operation, you need to keep the pressurizer as your hot point in the system; you need to keep the heaters dry. And it's pretty difficult to physically get any lower than this without going into RHR operation.

Reactor building pressure has been, throughout the course of the accident, negative. It's now just bordering around zero. Of course, it's relative to atmospheric pressure, so when you have a low front in, it gets positive; when you have a high front in, it gets negative.

The reactor building is being kept cool by coolers which are supplied by river water, and even if the building were to get pressurized to a pound or two with the current activity level in the building, there would be a not measurable and pretty insignificant releases and doses off-site, based on the actual measured leakage level over the period of months when it was negative.

PROF. KERR: Mr. Vollmer, do you have a rough estimate of the volume of containment occupied by that atmosphere whose activity you describe? I just want to do some arithmetic on total activity, if I can.

MR. VOLLMER: Roughly, two million cubic feet would be the volume. The water doesn't take up that too much. The measurement is representative in the sense that the building fans have been on continuously so that the building should be fairly uniform.

However, in drawing a long sample, I couldn't guarantee that certain things were not plated out.

PROF. KERR: I do not expect to get great accuracy from my calculations. I was just curious.

MR. VOLLMER: Okay. The reactor building water level is about at the seven-foot level, the primary system leakage in solid operation and knowing what the sources of makeup are, are pretty well determined to be of the order of half a gpm, maybe a little bit higher, which would indicate 700 to 1000 gallons a day leakage.

At this water level, a foot increase is equivalent to about 70,000 or 80,000 gallons. So, if the primary system leakage is the only source -- and we believe it is substantially the only source, because all secondary sources have been isolated -- then the water level should rise appreciably.

DR. LAWROSKI: Do you have phs for those liquids whose activity levels you quoted?

MR. VOLLMER: Not offhand.

DR. LAWROSKI: If we could get them --

MR. VOLLMER: We have ph measurements on the primary system water. We've been watching that ph, as a matter of fact, fairly closely.

DR. LAWROSKI: Other than the primary coolant, they're pretty alkaline; aren't they?

MR. VOLLMER: The primary coolant, in my recollection, was 7.9 at the last measurement, and we got a measurement of something like 7.3, which was pretty far out from what it had been.

They're going to take a remeasurement to see if they haven't had any ph.

The boron, I might mention, in the primary coolant, we're holding that at about 3000 gpm, and of course, the source is a makeup and so on; it's fairly easy to do that.

Lastly, the environmental releases. Since the accident, the water releases have been less than Appendix I. The total release from the site has been something like a quarter of a curie, and I think the allowable from the site is about 10 curies a quarter. So that's considerably under the Appendix I design objective values.

The gas release currently is also less than Appendix I. At the filtration system discharge point, the iodine activity is on the order of 10-12 microcuries per cc, which is one percent of an unrestricted NPC for iodine; so that's fairly low.

(Slide.)

Briefly, the modifications to the reactor systems. The B steam generator was modified by taking a line from the steam line itself prior to the turbine inlet valve and running that through a closed heat exchanger demineralizer pump and back into the feedwater line for B, giving you the capability of loop circulation in B.

That system, as Mr. Etherington indicated, is essentially complete, and I think this week they will start cleaning up the water in the B steam generator. It has been running a few microcuries per cc. Let's see, about one microcurie per cc, by my recollection, on the cesium. And even though the steam generator was running pretty much since the accident initiation, when they isolated it, they brought it down to a low pressure, so that the pressure differential across the primary to secondary and the B steam generator has been significant all throughout the cooldown and recovery phase so far. But the activity in the B steam generator has not increased. So, whatever leaks did occur have been very well healed.

Okay. Also, the decay heat removal system. There is a two-loop decay heat removal system in the auxiliary building. These have been both upgraded by the addition of instrumentation and TV monitoring to monitor for leaks. They have been tested, and all leaks that were visible have been corrected, and so we think they're reasonably high-integrity decay heat removal system, although that would not be the primary backup if the current mode of cooling were lost. We would still go to the B steam generator solid operation because that keeps the activity in the containment, rather than bringing it out to the aux building, primarily; and also, the B steam generator is set up so that the pressure differential primary to secondary would give you leakage from the secondary to the primary. The higher pressure would be in the secondary, so any leakage would be in-leakage.

An alternate heat decay removal system has been built and is in storage, and basically, to put that into service and you have to bring it up to the aux building and connect it to a pipe gallery. There have been pipes put in, penetrating the auxiliary building below the ground level. These have been installed. They have not been hooked up yet to the current decay heat removal system. So, that system would not be operable as yet. But by around the 20th of the month or so, they should be in a position to hook those pipes up to the current decay heat removal system to provide a third backup, if you will, for that particular capability.

The pressure volume control is a passive system with borated water and a nitrogen pressure head which will be hooked into the primary again, to provide positive control over the pressure and any loss of primary fluid in case all instrumentation is lost in the containment building itself, and you really don't know where you are in terms of the pressurizer level.

Lastly, a couple of 2-1/2 megawatt diesels have been installed and hooked up so that there is capability of complete cooling with B steam generator using only on-site power as well as decay heat removal system using only on-site power. Rad waste system upgrade consisted of putting four large filter trains, any three of which can handle all of the filtration, all of the exhaust from the fuel-handling end of the auxiliary building. These are in series and downstream of the original filtration systems.

The original filtrations systems have had their charcoal filters replaced. Basically, you have two separate charcoal filtration systems in series, providing filtration of the air before its release.

EPICOR-II is a filtration demineralization system which is capable of handling activities on the order of 30 to 50 microcuries per cc per millimeter of cesium line 37. It's heavily shielded and remotely operated and controlled facility. And that would be used to clean up first the auxiliary building water.

That particular activity is being held up for two reasons: One, they're in the process of training operators and shaking down equipment for the use of EPICOR-II itself, since the filters will be of fairly high hundredths of bar levels when they're taken out, 2500 are, when the filters are removed before they're put in a cast. So it has to be done remotely and a lot of training is being done to accommodate that.

Secondly, the use of the system is being held because of a suit that was filed by the City of Lancaster. There was an injunction against the NRC asking us not to allow any water to be discharged from the facility.

The Commission, on May 25, put out a statement directing the staff to keep any high-level water or intermediate-level water -- the high level being containment primary system; the intermediate being auxiliary system -- keeping any of that water from being cleaned up and discharged into the Susequehanna until appropriate environmental assessments can be made.

We have completed an assessment for the use of EPICOR, and hope to be able to proceed to operate that. When it's ready to operate, we still would not be able to discharge the water, no matter how clean it was, because that would be the subject of another environmental assessment. That one has to include the various options for disposing of the water, which would include, of course, putting it in the river, putting it in railroad cars and taking it away somewhere else, putting it in somebody else's river, or evaporating it, or putting it back into the system itself.

That has not really -- the disposition of the water has not yet been determined.

PROF. KERR: You would have to do an environmental assessment to evaporate it?

MR. VOLLMER: Yes.

PROF. KERR: No matter at what rate?

MR. VOLLMER: Whatever we do with that water, it's considered a special brand of water. It's being treated, in all senses, as something special. And whatever is done with it will be the subject of an assessment, an evaluation of alternatives.

Okay. Lastly, there has been a tank farm, which is 100,000 gallons worth of tankage, has been installed in the spent fuel pool in Unit 2, and this was just a contingency volume. It's heavily shielded and well instrumented. A contingency volume for the possible need for pumping out containment water on any other source of water that couldn't be handled in the auxiliary building.

The auxiliary building has about 250,000 gallons of tankage, most of which is full. And if we get to use EPICOR-II, that particular activity, which ranges from the order of one microcurie of cesium up to about 30 or so, when that water is processed, then we'll have about 460,000 gallons of tankage, and we can start working on the containment building water.

So far, we have not used any of the Unit 1 tankage. For contaminated water all the Unit 1 water is cleaned up, and the tankage is available for an emergency.

(Slide.)

Lastly, I would like to spend about a minute on future plans. What's going on now is completion and testing of those modifications that are not yet in operation at this point in time. And generally, our criteria have been very stringent in terms of any types of leakage, and high on instrumentation, to make sure that in any of these modifications that are operated, we know exactly what's going on, because the level of public interest has been pretty high, particularly anything dealing with waste cleanup and waste discharge.

The cleanup of the auxiliary building water, we hope, then will proceed perhaps about the middle of July, and the cleanup of containment in primary water, we have not received the plans from the utility. I understand they have selected a contractor who is looking at the best ways of managing both the containment and the primary water.

Containment entry and cleanup will be the subject of a meeting up at the site tomorrow, and we'll get an idea of what their plans there are. They do have a contractor working on that and have had for some time.

I think, as a matter of interest, the containment at the personnel entryway, I think, is enterable now, with self-contained air and appropriate probes in front of you. I think it's likely that the highest activity level in the containment comes from the water in the basement, which has various streaming paths around the building. So, you know, some of the building is well protected by concrete; some of the areas of the building are not well protected from that water.

They're doing a couple of things. They're trying to measure the activity of the water in the bottom of the containment. They found an electrical penetration which penetrates containment. It goes in 10 inches inside containment and is considered to be about two feet above the water level, and they're drilling holes on the auxiliary building side and the turbine building side. This is from the turbine building side of that penetration. They're going to put probes in that should be able to measure directional and spectral radiation levels. So we might get an idea of what levels are in the water.

Also, they've been making measurements outside the equipment air lock, which is about, if I recall, a half an inch or so of steel. They're trying to make spectral measurements outside of that so they can tell what the levels are inside and what likely activity is.

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That's coupled with the measurements of the containment atmosphere activity. It should give us a pretty good handle of what we're liable to see when the containment is entered. I have no idea wh-t their plans are, however, as far as timing goes on containment entry.

DR. LAWROSKI: Do you have long life Krypton?

MR. VOLLMER: Yes, sir, the Krypton 83 is at about ten to the minus one microcurie. That's the one that's hanging in there. The other noble gases are either gone or going away fast. The iodine is going away fast. So, that will hang in there. And, of course, the cesium strontium, if they are indeed in that high a level the water of the containment building will not go away very fast. Barium also.

That concludes my talk.

DR. LAWROSKI: Could we, Mr. Chairman, ask if a tabulation of some of those measurements could be given to us?

MR. VOLLMER: The transcript is being made and will be available in 24 hours in the Public Document Room.

DR. LAWROSKI: I'd like to get one though that is free of sometimes errors in the transcript.

MR. VOLLMER: Well, Mr. Chairman, I'd be glad to get one for the staff members, but the latest measurements of primary system water and containment atmosphere, and I'll identify all the isotopes for them. I just didn't have them with me and don't recall them offhand.

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DR. CARBON: Fine, thank you.

Other questions?

DR. MOELLER: I gather up to this point that the legal aspects of the release of the water have not hampered recovery operations.

MR. VOLLMER: No, they haven't, yet there have been some problems with getting rid of sanitary wastes. We ended up putting it in some of our railroad cars that were put aside for other purposes. Basically, we are putting about 150,000 gallons of normal, what are considered industrial wastes, primarily turbine building leakage water and things of that nature is being put through into the river everyday. Most of this water is of such a low activity it doesn't need processing and is just a normal discharge.

The Commission's statement made it clear that this type of water and processing would continue as would the use of Epicor-I, which was a system the same as Epicor-II, basically the concept, but designed to handle a much lower activity level. But the use of that system could also continued.

So, it's some amounts of waste or some amounts of water that have been contaminated by the accident has indeed been processed, but the levels are very low.

DR. CARBON: Thank you, Dick.

Let's move on to the next topic. Denny, are you up for it?

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(Slide.)

DR. ROSS: I am going to discuss the status of the various bulletins and orders and some related material that we're doing generically that may lead to further regulatory requirements that may not be either precisely a bulletin or an order, but would have the same effect as far as the regulated industry is concerned.

Looking first at the status of the orders that have been issued (Slide) these apply to B&W plants. I'll pick up the right-hand side of the chart as soon as we get through going through the left-hand side.

There have been five utilities that have received orders from the Commission. The first of these for which our short term action has been completed pertains to the Duke Power Oconee units. We had some discussion with the Committee before. What we have done is we have lifted the short-term aspects of the order effective May 18th. This permitted operation of all three Oconee units. The third unit, Oconee 3, is due to start up, I think, like today or tomorrow; certainly this weekend. It was down for a reload.

We did have a requirement that has not yet been done in a short term. Some cold tests had to be done on the auxiliary feed water system when the third unit got back up and that was available, for a hot steaming test of the auxiliary feed water.

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Two items of interest: I'd like to point out some long-term modifications were ordered, and the schedule for those long-term modifications should be submitted next week. I have a little more detail on it, but a feed water transient occurred last Monday which tested some of the features that were implemented in the short-term order, and I'll discuss that in more detail later on.

For the other clients we processed Arkansas and released Arkansas unit 1. We released an SER approving it for restart. However, that was on May 31st. A couple of days later some difficulties appeared during a rise to power. The plant was at hot shut down doing some Section 11 leak tests on the main feed water check valves. Some steps were taken that defeated or would have defeated initiation of auxiliary feed water had it been called on. These defeat steps were not documented in the procedure.

Our resident inspector observed that the auxiliary feed water system was in a nonprocedural covered bypass condition. As a result, a new order was issued by inspection and enforcement on Saturday, June 2nd ordering the plant to return to cold shut down until some additional procedures had developed and additional training had been given to any Arkansas Power and Light staff.

I have a little more information on this also. This plant is currently in a cold shut down condition until

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additional procedures can be developed and verified by inspection and enforcement.

Rancho Seco received its shut down order, confirmatory order on May 7th. We're in the final stages of reviewing that plant for return to power. This slide indicates it could be lifted as early as the 16th. That date no longer seems feasible. Next week sometime is a more likely date.

The Commission has some petitions that it's considering for hearing petitions requested by Friends of the Earth in California. They have requested a hearing prior to start-up. The Commission is considering these, and I am not aware of the outcome as of now. I don't know what the Commission plans to do.

Davis Besse in terms of our review, pursuant to the short term portion of the order is about at the same stage as Rancho Seco. We are in the final stages of review and I would expect this to be complete next week, also.

Crystal River 3 is a little bit farther behind than Rancho Seco and Davis Besse. It is in the final stages of review, but a few days behind. Maybe we'll make the end of next week, maybe not.

We had a meeting last Monday with the management of a GPU and a Met Ed with respect to the restart of Unit 1. The utility believes it would be ready around mid-August and have laid out some of their proposals for the changes to be

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made in the plant prior to restart. The only agreement we have at this point is that we're going to have a technical meeting at the site in about two weeks to discuss some of the features. This plant is not covered by the same type of confirmatory orders as the other plants. We expect that it will be within two or three weeks.

That's a real quick treatment of 6 B&W plants.

Yes, sir?

DR. PLESSET: Could you tell me, there was a question this morning about the water purification and the resin handling systems. Are they pretty much the same in all these plants?

DR. ROSS: I don't know. I believe tomorrow's agenda B&W might answer that. I would suspect that the once through steam generator would require an equivalent level of condensing polishing, but the types of air compressors and the interconnections, I would suspect are very strongly AE related. Unit 1 had a different AE than Unit 2.

DR. LIPINSKI: Mr. Chairman, I have a comment.

DR. CARBON: Mr. Lipinski?

DR. LIPINSKI: I have a comment on Three Mile Island Unit 1. On March 27th they issued a licensing event report concerning the enclosure of the steam valve to the auxiliary feed water system. Itek expects the head to write it up. But they showed us this valve and of course in the discussion

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it turned out that the electric driven pumps are not automatically started. Consequently, had Unit 1 gone to power, and suffered a loss of feed water transient they would have had the same initiator as Unit 2.

DR. ROSS: Well, when we look at -- I have some details on each feed system. But when we look at Arkansas 1 it has a steam turbine and an electric pump. The electric pump is not now connected to the vital bus. So, if you have a feedwater event that happens to be either associated with or accompanied by a loss of off-site power, it would not be automatically started either. The same, it applies to the Rancho Seco motor driven pump. It's operable from the on-site power, but it's not automatic. And the long term provisions of the order is going to upgrade.

Is this your question that it's not operable automatically from onsite power?

DR. LIPINSKI: The point was, where they had done some repair work on the steam driven pump walked away and left this valve closed. Had they gone into operation, it would have been in the same condition as Unit 2. The system was disabled, but they uncovered it before they did go into operation. As a result they're down because of Unit 2. But again, it was an operator error after maintenance when they walked away from the system and left it disabled.

DR. ROSS: Okay. I think if you look at the style of the confirmatory orders Paragraph A uniformly deals with the needed improvements to the auxiliary feed water system. Perhaps that is one of the things that we'll focus on when we discuss the confirmatory order with GPU and Met Ed. At first blush, it sounds like a good one to focus on.

(Slide.)

I need to -- I guess I need to ask the Committee to what extent, how much time -- we hope to be through with both this and lessons learned by 1:00. In your handout I have quite a few slides. I think some of them are self-explanatory, and it looks like I'm getting into too much detail. You can say -- you can call a halt, and I'll go onto the next one.

DR. CARBON: Okay the way you're going, when do you expect to be done?

DR. ROSS: I think I'd be through by 12:15.

DR. CARBON: Including our questions, probably?

DR. ROSS: Yes, sir.

DR. MOELLER: Mr. Chairman, a quick question following up Mr. Lipinski's remarks. It doesn't have to be answered here, but the thought occurred to me, could you have a system where it automatically, when an auxiliary emergency feed water pump cut on, it would open the same switch or another switch would open the valve even if it were inadvertently closed? Have you considered or rejected that?

DR. ROSS: Some systems have that, and if you look

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one slide further into your presentation (slide) at the Oconee system.

When the Oconee system (this slide) shows unit 3 only, because it shows the new electric feed water pumps, but even with Units 1 and 2, which have only turbine driven pumps, you have one pump and it currently pumps through a valve which when you get an emergency feed water need, this valve automatically comes open to the 60 percent level. Other plants do this also. And then you take control if you get into a faster cool down to throttle level.

DR. MOELLER: Thank you.

(Slide.)

DR. ROSS: This is more detail on what went wrong at Arkansas. What I would like to do -- the second slide in the presentation shows the existing Arkansas feed water system; (Slide.) main and auxiliaries. The points of interest are that you have an electric emergency feed water pump. Arkansas uses the term E for emergency. They have a separate start-up pump. They use A for auxiliary. A little bit of terminology.

You have a turbine driven emergency feed water, and an electric emergency feed water pump. These pumps pump through here either through an integrated control system valve or a bypass valve into the steam generator, and likewise to the other steam generator. The test in progress had shut down and aroused our concern was that the main feed water tray check valve

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is not shown on here, but it's number 7, feed water 7. They wanted to do a Section 11 integrity test in which they wanted the steam generator hot so that there would be a driving pressure to keep the check valve closed. During this test it was not desirable to have any emergency feed water running. So, the turbine emission steam valves that admit steam to the turbine driven pump were both pulled to lock, which means that they were disabled.

There were two valves, each steam generator drives this. So, those two valves were disabled, the start switch for the electric pump was disabled, and the switches that would allow these valves to come up and admit feed water were disabled. So, there were five switches in the defeat position. The unit was not at power. It's in hot shut down. Nevertheless, the procedure for doing this integrity test did not call that these switches either be defeated or restored. During his morning tour, the I&D inspector noticed these valves in what appeared to him to be the wrong position. No procedure. So, the concern escalated. We had discussions, and before the day was out, we had a licensee commitement and a confirmatory order to go back to cold shut down.

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(Slide.)

Until, according to the terms of the order, these three steps were done: Reevaluate how you develop the approved procedures; look at your existing procedures to make sure that safety is covered even though it might not be a safety-related procedure; and to make sure the operators don't develop an ad hoc procedure and do some things that are not called out.

This is an inspection and enforcement action, and I think there are about three. However, the licensee is in Bethesda today meeting on some other matters. I am not exactly sure when that order will be lifted.

DR. LAWROSKI: This thing that your resident inspector found, was that an ad hoc procedure?

DR. ROSS: What he does?

DR. LAWROSKI: No. What he found.

DR. ROSS: There existed a feedwater check valve integrity test. It was a regular procedure. It just didn't call out these steps. This is not the first time it had been done. When the operators went to do it this time, they said, "Well, we can't do it without turning off the signals. It would start a feedwater." They had to turn off main feedwater, and that would have started emergency feedwater. They didn't want that to happen.

DR. LAWROSKI: So that part was ad hoc, then.

DR. ROSS: Yes. It was. The integrity was not, but

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this bypassing was.

DR. CARBON: Walt.

DR. LIPINSKI: On the subject of procedures, in the case of TMI-2 their procedure called for their systems to be totally defeated in order to perform their test.

In discussing this with them, they initially had a procedure -- their very first one on those systems -- that was different, that did not call for all of the feedwater systems to be defeated in order to conduct the test. It was later in time that they wrote the new procedure and this new procedure resulted in them calling for all the systems to be blocked. Are you looking at that aspect?

DR. ROSS: Yes, sir, we definitely are. We're looking at it in the short term, from two viewpoints. I believe that most of our procedures that we're looking at now are being revised so that they do not have to defeat both trains. But even if one train is out, we are requiring that during tests and maintenance an operator be at the valves in question that have to be repositioned for tests and maintenance, with continuous communication to the control room, that if a system is needed, he does his action; if he loses communication, he restores the system, anyway.

DR. LIPINSKI: The other thing is that these particular valves at TMI-2 were not on their shift or daily checklist. They got left out from surveillance.

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DR. ROSS: We are looking at that. We are looking at the procedures; for example, at Davis-Besse, there's a requirement that each shift, that the switches that would disable these valves be checked to make sure they're in an operable position. We're also requiring that after test and maintenance that double inspection be required, that the people who restore it complete the procedure and a subsequent independent check verifies it.

The long-term aspects have to do with Reg Guide 147, which would enunciate this system if it's in the by-pass inoperable condition. That's a decision yet to be made: To what extent should this Reg Guide be backfit to operating plants.

Okay. The next five slides are feedwater diagrams for the five B&W plants. I didn't propose to discuss these. They're available if we have to come back to pick up any particular point.

Let me turn now to the available --

MR. MICHELSON: Before we get away from this, maybe you can answer for me a basic generic question on the design of these auxiliary feedwater systems.

Since you are reevaluating them, could you tell me what your position will be concerning the requirement that the auxiliary feedwater feed only grid steam generators?

DR. ROSS: Feed only what?

MR. MICHELSON: You must be sure the auxiliary feedwater does not feed a broken steam generator, for instance, because of containment overpressure problems.

DR. ROSS: In the short term, we are not doing anything automatic. We are requiring in the short term that each steam generator have independent flow measurement capability. If you are delivering excess flow or if there were a pressure imbalance because of a broken line, it would be detectable. But in the short term, what we're going through with the order would not take care of that point.

MR. MICHELSON: Okay. Well, really, the question gets down to: Are you going to assume single failure in the process of requiring that you do not feed a broken steam generator?

DR. ROSS: That point has not been specifically covered in what we've done to date.

MR. MICHELSON: Are you looking at the containment then to see if that's an acceptable position?

DR. ROSS: I understand your question, because you talked to Tom Novak and he and I had discussed it. I just don't have an answer for you right now. I think we'll have to study it.

Okay. I want to discuss the Oconee Unit 1 feedwater transient of June 11. Now, in your handout --

PROF. KERR: Is Mr. Michelson's point that one should not have to depend on operator action or that even with operator intervention one would be in trouble?

MR. MICHELSON: The problem is real simple. If you have a broken steam generator which is pressurizing the containment, and if you continue to input water in that broken steam generator, it just continues to pressurize containment until you do something.

PROF. KERR: I understand that, I think.

Your question was whether they were going to depend on operator intervention to trust all that, or whether it should be done automatically.

MR. MICHELSON: Two aspects: First of all, depending upon operator intervention; and secondly, what happens if there is a single failure and the equivalent of the operator needs to be used to intervene.

PROF. KERR: Okay, I understand your question. Thank you.

(Slide.)

DR. ROSS: There are about 10 or 12 slides of relatively poor quality, showing the process conditions for Oconee. Let me describe the first two pages on Oconee have some detailed sequence.

What happened was that there was a failure in the turbine-cooled circuit; the intercept valves between the high- and low-pressure turbine stages failed due to an electrical malfunction on our controlled circuit card. This led to a cascading of events: steam extractor valves tripped; feeder drain system tripped; condensate burster pumps tripped; and then the main feedwater pump tripped. And that's what caught the reactor.

This was the new control-grade secondary side reactor trip.

It also started automatically all three emergency steam-driven feedwater pumps, one for each unit. The feedwater control valves came into the open position. The only thing the operator did after a minute or so was to throttle back on the aux feedwater to maintain level of the steam generators.

In general, all systems operated as designed. The primary system pressure went up to about 2260 or so. Had this been in the previous configuration, the PORV certainly would have lifted. Reactor pressure would have gone up somewhat higher.

It's a little hard to read.

PROF. KERR: I am sorry. What did you say? "Would certainly have lifted?"?

DR. ROSS: Would have lifted, certainly.

PROF. KERR: Thank you.

DR. ROSS: In the middle of your slides, you can pick out the one which I thought was interesting; the pressurizer level --

(Slide.)

-- Went down about 70 or so inches. The -- there are some peculiar units. This is 72 inches, and it was running about 200 inches or so. Each of these is, I believe, five minutes on the abscissa, the time index. You see a rather sharp drop when you get the reactor trip.

The event is shown -- the dotted line with the steps is the timing of the reactor trip. So I wasn't going to go into this in any more detail unless there are some questions.

DR. MOELLER: You did say if the changes had not been made, this could have been much more --

DR. ROSS: Yes. If the changes had not been made, if this had been two months ago, then the PORV would have lifted for this event.

DR. MARK: Well, is that bad?

DR. ROSS: I am sorry?

DR. MARK: Is that bad? It's supposed to.

DR. ROSS: In and of itself, probably not. There is enough data to suggest the likelihood that it would stick open was one out of 50. So, it's the beginning of the sequence. It's one of the ingredients that was a precursor to TMI.

DR. SIESS: Even if the probability is one out of 50 that it would stick open, do you think the probability is now as high as it was that it would stay stuck, stay open?

DR. ROSS: No, sir, because of operator intervention. Its probability of sticking open hasn't changed, but the probability of the flow path remaining open is markedly less. I think the operator would be much more alert to the shut valve.

DR. SIESS: Even without physical changes in the plant?

DR. ROSS: That's right.

I want to turn now to the work that we're doing on Westinghouse and Combustion.

(Slide.)

The work is about the same in terms of scope. Now, what we envision as the work product -- at least this is our present thinking -- for dealing with the other LWRs, both PWRs and BWRs is neither a bulletin nor an order. We are presently thinking about writing letters to each utility not otherwise covered by an order, at varying times in the next six weeks or so, with some new short-term requirements. These are the operating utilities that I am speaking of.

In order to get a precise basis for the things that we want done differently, we are developing a generic report which is not truly generic because there are specific auxiliary feedwater chapters and sections in it. The report would look something like NUREG-0560 did for the B&W case.

This is an abbreviated table of contents. We are fairly well along in this report. We expect to complete the report for Westinghouse and CE in the month of July.

DR. LAWROSKI: So, if we had a Michelson transient --

DR. ROSS: It's specifically listed. We asked, in quotes, the PWR people to respond in writing in detail to his concerns.

Okay. In order to get started -- in other words, for us to have the information for us to develop this generic report -- we sent out some information requests to the operating plants.

(Slide.)

They're in two broad categories. The report deals primarily with small-break LOCA and with auxiliary feedwater and with possible changes in operator guidelines and procedures that might go along with those two events. So, we asked each operating plant to give us updated information on the auxiliary feedwater system and its role in various transients and accidents.

DR. SIESS: Is this the May 4 letter?

DR. ROSS: I don't remember the date, but it sounds right.

We also asked some generalized information on analysis, which I will have more detail on. We fleshed out these four points on analysis. This is very cryptic. It says: more information, more analysis on small-break LOCA and feedwater transients. We have greater definition now on these analysis events.

PROF. KERR: Denny, I assume that somewhere in this process one is putting some emphasis on increasing the reliability of the main feedwater, because you certainly need auxiliary feedwater in many cases in which nothing did go wrong, but main feedwater, it seems to me, a lot of cases in which it's been called on, very simply because the main feedwater system is unreliable.

DR. ROSS: That's true, Prof. Kerr. That's not in our scope of work. We're not doing anything short term with operating plants on that line. That's not to say it isn't needed, but it's just that it's not in our scope.

PROF. KERR: What determines your scope?

DR. ROSS: Well, we were trying to get --

PROF. KERR: I would assume that you were trying to make reactor plants more reliable; therefore, you pick the thing that is most important. It seems to me that that here is concentrating on the auxiliary feedwater system. Or am I missing something?

DR. ROSS: I understand the question. The arrival rate of feedwater transients certainly would be an input into some-kind of a risk calculation. If the auxiliary feedwater system never works, then its reliability is irrelevant. I don't even know if -- in lessons learned, Bob, are you doing anything on the reliability of the main feedwater system?

MR. TEDESCO: That's probably part of the long-term regulatory effort. We wrote that out in NUREG-0560, limiting areas we should consider. You're probably not going to reduce to zero the frequency of transients.

PROF. KERR: I didn't know if anybody was suggesting reducing it to zero. But it seems to me that you possibly could reduce the sum.

One gets the impression from LER that the control systems are somewhat primitive, particularly --

DR. ROSS: Pardon me. We did something for B&W. We did start something.

PROF. KERR: I am not talking about B&W.

DR. ROSS: That's the only one.

PROF. KERR: You're not thinking about LERs the same way I am.

DR. ROSS: We put a time on the order requiring failure modes and effects study on the integrated control system, which has been an initiator of some feedwater transients.

MR. TEDESCO: Denny, we are including that in the letter for all plants in the long term.

DR. ROSS: The next few slides are some tentative conclusions on these studies. Like I said, we're pretty far along. I am not sure whether in the final disposition whether each of these recommendations would stand and whether it will indeed stand on the short-term list, or the next page, which is the long-term list. These are all for teh auxiliary feedwater system. Since the analysis work is not complete, we don't have any recommendations and conclusions that I can share with you today in that area.

(Slide.)

And these are applicable for the Westinghouse-Combustion class. We have done nothing along this line yet for the BWR.

There are seven short-term generic recommendations on the auxiliary feedwater system. I don't think I need read through the slide. The thrust is to increase the reliability and availability of the feedwater train.

Probably No. 7 might be the one that would be of the most interest, because some plants -- eight or 10 -- still have manual initiation of aux feed. That's one of the recommendations that I think might be a target for going from short to long term.

DR. CARBON: Excuse me. I haven't found that chart yet. What does 7 say?

DR. ROSS: The auxiliary feedwater system should be automatically initiated (control-grade circuitry) but retain the manual start as backup.

PROF. KERR: Is there some reason for having it manual? Why is it manual in some plants?

DR. ROSS: Why was it done manually in the first place?

PROF. KERR: Yes.

DR. ROSS: My understanding -- and I have to qualify it that way -- is that at the time, which is -- what -- 10 or 12 years ago, it was thought that there was ample time, like 20, 30 minutes, to start them up, and operator action was suitable for this purpose. But there is enough inventory above the U tube that by the time it boils down the operator will have done his job.

PROF. KERR: The consensus now is that much time is not available, or that the operator will have so many other things to do that it should be automatic?

DR. ROSS: I think it would be more the latter than the former. The time hasn't changed. There is as much time as there ever was. But it's also more in the area where the concept of single failures and single operator error may not be what we want to regulate in the future. And to depend on the operator to do something may not be the best way to go.

PROF. KERR: It seems to me as is you have concluded --

DR. ROSS: Excuse me?

PROF. KERR: It sounds to me that you have concluded that it is not the way, not that it may not be the way. You made it automatic.

DR. ROSS: I think it will be made automatic. It's just a question of time.

PROF. KERR: I am simply trying to understand why you concluded that the automatic is safer and more reliable than manual.

DR. SIESS: What is the status of those generic requirements?

DR. ROSS: They are items being discussed internally within NRR. You see, our report is about half drafted, and they're on draft pieces of paper within the staff's --

DR. SIESS: Possible staff positions.

DR. ROSS: That's right. This is one thing I wanted to cover when we got through, when I got through, was the potential for full or subcommittee interaction on all of these recommendations.

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We have shared these viewpoints with the combustion and Westinghouse operating utilities. They have seen these recommendations and undoubtedly have an opinion.

Yes, sir?

MR. MICHELSON: Before you leave that slide, would you comment on the question of at what point in time it might not be suitable to say, isolate a break and that sort of thing as a part of the generic problem of providing operational instructions.

PROFESSOR KERR: Would you permit me to continue to pursue the question that I was here --

What is the process that one goes through to determine that automatic actuation is safer than manual? Have you not some sort of formal procedure?

DR. ROSS: Well, what we have done -- I can't describe it to you because I haven't reviewed it yet myself. We are preparing a reliability calculation. I don't know. I hate to put Saul on the spot, but Saul's people are doing some unreliability calculations on each of these auxiliary feed water system types and I think there's about 20 types, and we're using that as an input in deciding this system is not reliable and it needs to be made more reliable.

PROFESSOR KERR: I was specifically referring --

MR. LEVINE: A number of plants are going to be visited by people for a probablistic analysis staff along with

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human factor consultants to look at the specific arrangements of some of these manually started systems to determine what the manual start might contribute to unreliability of the system. And then when that work is completed in the next month or so, then we'll have a better basis for making a decision.

PROFESSOR KERR: So, the decision hasn't yet been made.

DR. ROSS: No.

PROFESSOR KERR: Okay.

DR. ROSS: Now, I was with Dr. Lipinski or Michelson?

MR. MICHELSON: Do you want me to repeat it again? The question is very simply to what extent are you considering break isolation actions in analyzing the operator response to small breaks?

DR. ROSS: Are you talking about an isolatable reactor primary coolant system break?

MR. MICHELSON: I mean a small break that might possibly be isolatable in which case is it all right to go ahead and do it?

DR. ROSS: This is one thing that is going to be covered during our generic negotiations. It came up in particular, because if you had a small break like in the let down line, or if it was an inadvertent opening of the PORV, those two locations that are isolatable that you could get

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that system down, turn on the high pressure injection or the charging pump could go up to full flow.

Another question is, when should you terminate that injection. And the concern is either relifting a safety valve or release valve or else the pressure vessel integrity. And I'm not sure we have the best criteria for terminating HPI, but at any rate we are looking at it on that basis.

DR. CARBON: Wait?

DR. LIPINSKI: During the B&W presentation when they described their design of the pressurizer, under the conditions of volume shrinkage in the pressurizer they allowed the heaters to be exposed. Under shrink condition the heater power would be on calling for the systems to pressurize. They used pressurizer level to interlock power control signals to those heaters. Similarly, when the level comes back up, this interlock is supposed to work to turn the heater power back on. On the way down it may not turn the power off when it's supposed to. On the way up it may not restore the power to control those heaters. The reliability of this level control system I have questions as to how effective it is. Are you considering looking at this aspect of it?

DR. ROSS: I don't know if we're considering that specific thing. We did ask each plant to verify the extent to which the heaters were operable from on-site power. I believe most of them do have a bank or so operable, not at the seven or

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eight megawatt level, certainly, but at some control level. But I don't think we have that level of detail that you're talking about.

DR. LIPINSKI: This level system is a very low reliability, and these transients have to be analyzed without the availability of feeder power for failure to cut it off when they are supposed to.

DR. ROSS: I think all we can do -- your comments will be in the transcript and we'll consider it as we go through the other two plants. I don't have an answer now.

(Slide.)

Some possible long-term recommendations again on the feed water that have to do with safety grade initiation. There's been some concern expressed about the motive power. Should both feed water pumps be of the same motive power? Should one be steam and one be electric? Of interest along this line is a transient, feed water transient at Davis Besse which uses two steam-driven pumps and had a complete loss of feed water. The steam generators dried out.

The steam was being diverted to one of the steam turbines, but the turbine was only running at about two-thirds of the speed. It wasn't pumping the water, but it was using steam up. The operator noticed that the steam pressure was going down and the steam generator -- the level was dry, so we took manual action to raise the speed from roughly 2:00 up to

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3500, and then the pump developed enough pressure to have feed water.

Had this sequence continued, I guess there's a possibility of having a dry steam generator at zero pressure. I am not sure how likely it is, but the potential was there. Had electric been available as a diverse motive power, then the operator would have had more flexibility.

This certainly is a long-term consideration.

It's mentioned here as Point No. 3. Now, whether we take the ultimate viewpoint and say that you should have at least one steam turbine, I don't know. I think we will have to consider in the long term the diverse motive power for auxiliary feed water systems. I think this is another area where Saul Levine's risk assessement or probablistic studies on feed water will help a lot.

DR. SIESS: Denny, your Item 3, what you said didn't quite sound like what it says on the chart.

DR. ROSS: I pointed out that the chart is concerned with diversity from AC power. But an equal concern would be diversity from steam. The same argument goes both ways.

DR. SIESS: What do you mean by AC power? Diesels or dedicated AC power.

DR. ROSS: It could be that or it could be a steam turbine.

DR. SIESS: But when you say eliminate AC dependency,

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I would read that as meaning that it normally would run under diesels, but you don't want to be dependent on the diesels. But there are auxiliary feed water pumps that run on dedicated diesels.

DR. ROSS: I would think that that would be acceptable also.

DR. SIESS: What is the rule on this?

DR. ROSS: I don't know, do you Bob?

MR. TEDESCO: On that point the action has been that you would have one train in the auxiliary feed water system that's got to rely on AC power. That means the water-driven pumps, whether by a diesel or a steam-driven pump and on the valves would not have to rely on AC.

DR. SIESS: By AC you mean onsite or offsite AC?

MR. TEDESCO: Yes, sir. Diverse systems.

DR. SIESS: And this would go farther than say one motor driven pump not dependent on AC, and one steam-driven pump not dependent on AC.

MR. TEDESCO: That would be an acceptable arrangement. Not only the pumps, though, also the admissions valve and so on.

DR. SIESS: Have any studies been made of the reliability of turbine driven pumps? It seems to me for awhile we were seeing an awful low liability on the B&W HPSI.

DR. ROSS: We asked two different B&W people that use steam-driven turbines what their experience was. From both sources we independently got a .1 unreliability; failure to start on demand of these turbines that we were looking at.

Saul?

MR. LEVINE: I'd just like to add that in looking at the transient involving loss of main feed and then relying on aux feed you have a situation in which both feed water trains -- you get involved in a very serious situation after half an hour to an hour, and you would like not to get into that situation. So, you would like to have an aux feed system that's highly reliable. Even if you could improve the reliability of a main feed water system somewhat, you're unlikely to achieve more than an order of magnitude. It might be difficult to achieve even that. So, you need an auxiliary feed water system of high reliability.

And in the Surry plant, which was looked at in WASH-1400, there were in fact both electric-driven pumps from either onsite or offsite power and the steam-driven pump. And you need that kind of a system to get a high reliability system.

DR. ROSS: Professor Carbon, in the interest of time I think I'd like to pass the next four slides, especially if we are going to have some subsequent subcommittee discussions on these generic topics. I think they speak for themselves (slide), but I did want to emphasize operator training.

We do expect to conclude -- we heard earlier this

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morning on anaomalous transients, additional scenarios need to be developed on anomalous transients. They need to be simulated on computer codes, and ultimately on the reactor training simulators, and the operators need additional training on how to cope with the unexpected.

DR. KERR: Mr. Ross, a number of us have been tossing around the term anomalous transient. I am not sure that I know what an anomalous transient is. How is the term used?

DR. ROSS: To me it would obviously be one that is not analyzed in Chapter 15.

DR. KERR: I'll accept that as the working definition.

DR. ROSS: That's a bare start. I think it would be one that would come from multiple equipment failures. For example, a total loss of auxiliary feed water for 20 minutes for a U tube boiler where it degraded long enough from whatever mechanism to produce some voiding in the core, that's anomalous. Now that you've got these voids, or as the joke goes, now you have this battleship on the prairie and how are you going to sink it?

In some instances it would be a nonmechanistic approach to an unusual primary cooling system.

Roger has got his hand up.

DR. MATTSON: Roger Mattson from the staff.

Bill, I think there's a terminology evolving, but I'm not quite sure that we've frozen on it yet, but I think maybe we're using it too loosely. The Tedesco report picked up off normal transients and accidents as a new terminology and anything using something similar to that. I think we see from the lessons learned perspective, and maybe we can talk about that a little later on when we get up and try to give our summary of where we're at.

A need to increase understanding and increase capabilities, expertise, training, what have you in the nonprescriptive design basis event kind of analysis. We think that people understand fairly well how Chapter 15 transients or Chapter 15 acciden: would progress given the traditional regulatory based sort of a single failure. And we at the moment see no compelling reason to change the design basis as the regulations stated.

But we do see a need for training operators, for increasing staff understanding, for increasing technical support understanding and utilities of these off-design bases or off-normal transients and accidents simply because your design for a transient of moderate frequency and you had a single failure doesn't mean that you want your understanding to stop there. There can be multiple failures. There can be anomalous things. And recognizing that you can't anticipate every possible sequence of events, we're heading in a direction of increasing the capability of operating crews and of diagnostic instrumentation or what have you to put the operator in a

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more productive position being capable of intervening productively in the course of an accident by increasing his understanding of what to expect, what to do, how to think, what instrumentation to look for in the event of an off-normal situation, meaning off-normal compared to the design basis analysis.

DR. CARBON: Chet?

DR. SIESS: Mr. Chairman, could I offer a definition of an anomalous transient for the Committee's consideration?

An anomalous transient is one you have not analyzed.

DR. MATTSON: No, because we may want to analyze some anomalous transient.

DR. SIESS: After you've analyzed it it is no longer going to be anomalous.

DR. MATTSON: It would be anomalous perhaps through the design, Chet.

DR. SIESS: Ah.

DR. MATTSON: You can't put one of these things into a simulator unless you analyze it.

DR. SIESS: So, when we make a distinction between design and safe operation of the plant, and you don't have to design the plant for everything in order to operate it safely.

DR. ROSS: Professor Siess, let me follow up on that, if I may.

DR. SIESS: Think about the definition.

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DR. MATTSON: I think we need to, you're right.

DR. ROSS: Let me follow up a little, because we're still trying to decide where to go from General Electric BWR's.

We've considered two things: One is to go through a sort of mechanistic way where we would degrade by multiple failure and multiple operator error various systems that produced as yet unanalyzed transients. These, of course, could be analyzed and these could be simulated and the operators could be trained on it. And in order to walk down that road a bit, we've got for audit purposes some procedures, and we're going through them to see where we want to go in that respect.

We did consider the alternative was to just tell the operator you have moderate core damage, a significant portion of your clad has melted and disintegrated, and a moderate amount of your fission pellets have been released. What are you going to do?

We didn't tell him how he got there; he's there. That would be a true anomalous transient.

DR. SIESS: You can't possibly think of everything, I mean you can't possibly make every combination and permutation and mistake and anomaly. But if you think of enough of them you'll probably envelope a set of conditions that you could then give information to the operator about and you don't have to design for them. You may envelope them, but you may find that there are three dozen things you can

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think of that will all get you into the same general situation that you could keep out of.

Whether the operator would at least know what he was getting into --

DR. CARBON: Time is running out on us. I think we'd better move ahead.

(Slide.)

DR. ROSS: I said that we were going to have a little more detail on the analysis. This slide and the next one are more detail on the analysis that we want Combustion and Westinghouse to do. First, they want to develop some methods for analyzing small breaks. They found that the very small breaks at TMI, the existing analysis methods weren't quite good enough, (slide), especially when we had voiding or noncondensibles postulated between the vessel steam and the steam generator.

Once the methods have been developed, we are going to do some applications of analysis for various classes of plants.

MR. BENDER: I am sorry, Denny, but I am just confused as to what that analysis is supposed to tell us.

When you start doing analysis that includes voiding of noncondensibles, what are you driving at?

DR. ROSS: We're looking at four ways to maintain the heat transport path from the core to the steam generator,

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even though you don't have a single phase liquid doing the work.

MR. BENDER: Is that presumably after core oxidation has occurred or before?

DR. ROSS: In this instance, before. Although, if you postulate arbitrary amounts of noncondensibles it could have come after. But all the analysis that I have talked about on the short-term work is for an otherwise intact core in terms of heat transfer.

DR. BENDER: I was bothered about the term noncondensible. I am still bothered about it, because if the source is not for noncondensibles that come from reaction with the fuel -- I don't know where it comes from.

DR. ROSS: We've done kind of a mass balance. There's some stored in the water. It comes out at saturation. Not a whole lot.

There's some in the gas, not very much.

MR. LEVINE: There's nitrogen gas in the accumulators.

MR. BENDER: It can be all kinds of things, but sometimes I wonder about whether analysis means anything when you've got to invent the mechanism by which it gets there.

DR. ROSS: I understand. Hopefully, these analyses don't mean anything. However, there's a subcommittee meeting with Professor Plesset next week where we'll spend more detail

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on these subjects.

MR. BENDER: He's a great enthusiast for those kind of analyses.

(Slide.)

DR. ROSS: In order to get the analysis done I mentioned that we've been working with an owner's group of Westinghouse and CE have agreed to an owner's group. We are working mostly on the generic analyses and the procedures that would be furnished from the analysis to the utilities; either the guidelines or the diagnostic.

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Our schedule for Westinghouse should be completed at the end of the month, and Combustion, I think, we'll know in a few days.

On the subject of bulletin response, last month you had a chart which utility had done what with respect to what bulletin. There is an update of these in here. In the interest of time I guess I will pass those up. Let me go to the last two slides to just bring us to where we are on the boiling water reactors.

(Slide.)

The BWRs have been, prioritywise, at the end of our line. We're beginning now to assign people to work on them. Of course, bids have gone out. We've got most of the responses in, and we're looking at them. We've only recently started to work on the generic review. We're trying to decide what transients that we discussed should be considered. We have a meeting set with the operating BWR utilities late this month. We hope that that results in an owners group where we can do the analysis work as needed in July and complete it as shown here in August.

(Slide.)

Some of the things we were thinking about reviewing. Notice the ACRS is up to the top of the list now in terms of recommendations, and additional transients and small breaks. These -- I cannot define these at this time, but we're still

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trying to work on them ourselves.

Some of the other matters: more guidance to the operators. We're hoping to pick up the Oyster Creek event and see what significance it had. And some 0560 matters applicable to BWRs. As I said, we're going to meet on the 28th of this month. We hope to get an owners group started down the line there.

This is all of my presentation. I did have, I guess, a question as to how the committee wants to interact, if it wants to interact, on any of these meetings. I am not expecting an answer now, but I think if you want to have subcommittee meetings or further discussions, please let us know.

DR. CARBON: Fine.

Are there questions of Denny?

DR. SIESS: Mr. Chairman, it just occurred to me that we've got a TMI-2 subcommittee that I think is the appropriate interaction with the owners group on TMI recovery. Of course, we've got our implications subcommittee, which is the appropriate interaction with the lessons-learned. How are we handling the interaction with Denny's group? Since the staff has a very logical organization, it seems to me we've sort of got a middle ground. I think we might consider it.

DR. CARBON: Appropriate maybe to discuss that further Saturday.

Thank you, Denny.

Do you want to break before? Let's take a 10-minute break and make it as short as we can.

(Brief recess.)

DR. CARBON: Let's go ahead with the meeting.

Roger.

DR. MATTSON: I want to spend just a couple minutes giving you for the first time formally as a committee a description of who the lessons-learned people are, how we're organized. I won't spend a lot of time at it because there are more substantive things to talk about.

Following the remarks that I want to make, Jim Milhoan from the task force wants to spend some time on operations. Then Bob Tedesco is prepared to go into design and analysis to the extent you have time to listen and want to discuss it.

The task force has 21 people: two managers, myself and Bob Tedesco. Warren Minners, whom you know, and my technical assistant, with the general reactor systems background. Dick Ireland, whom you know, with a fast reactor systems, single failure kind of background, senior technical staffer. Chuck Long from the plant systems area, with a background in one system generator reviews, system generator reviews. Bob Telford from the division of operating reactors, with kind of a generalist background with reactor systems capability. John Olshinksi from the reactor systems branch. Jose Calvo from the power systems branch. John Vogelwied from the core performance branch. Bill Milstead from the containment systems branch. Harley Silver from the division of project management. Jim Conrad from the division of project management. Bill Stoddard from eff'ent treatment systems branch. Gary Krug from the radiological assessment branch. Gary Hollahan from the analysis branch. Leo Beltrochhi from instrumentation and control systems. Jerry Holman from the operator licensing branch. Larry Chandler, a lawyer. Jim Milhoan from the office of standards development; they're specialists in operation standards. Bob Kudland from the office of research, with a strong background in reactor systems and operating reactor licensing before he went to research. Terry Harpster from the office of inspection and enforcement; he's from the field office and was very much involved in Three Mile Island. Lake Barrett, whose effluent treatment radiological assessement accident analysis background, from the division of operating reactors.

We've organized the lessons-learned work into three groups. The first group is a design and analysis group, with the obvious systems experts from among those that I read. The second group is an operations group with the operator licensing, operations, and standards, and some man-machine instrumentation and controls reactor systems expertise within that group itself. The reason being that we think one of the fundamental lessons we learned is that there is a disconnect, an uncoupling between people who, day in and day out, worry about operations, operations procedures, operator training, and the people, on the other hand, who, day in and day out, worry about design analysis and review of design and analysis; said disconnect occurring not only in the industry as we understand it today to varying degrees, depending upon the utility, and certainly within the NRC, where traditionally up until this time procedures have not been thoroughly combed in an engineering analysis sense, they've been reviewed for their existence by the office of inspection and enforcement, but not with an independent adequacy viewpoint, more to a bookkeeping audit.

They are not reviewed at all in the licensing process, so we've started with our basic organization to try to come at that problem and to come up with novel ways to couple these important parts of reactor safety.

So, we have the two technical groups: design and analysis groups, and operations, then, a project group which Harley Silver, Jim Conrad, Dick Ireland and, to a certain extent, Warren Minners, and the lawyer participate in.

There the primary reason is so that we can keep track of the various parties to the lessons learned from Three Mile Island. One party, of course, is the ACRS. So, for example, Jim Conrad is the project manager to keep on top of coordinating the response to the ACRS letters, including your recommendations on lessons learned, and for arranging our business with you.

Harley Silver, on the other hand, is the man who will have to coordinate the short-term lessons learned from the standpoint of communicating with pending OLs and pending CPs. That is those license applicants who are caught up at the moment in the process of our trying to learn lessons learned and to set for them some additional licensing requirements before either completing the construction permit process or completing the OL process.

There is some urgency with getting on with that, as you can well understand. The Salem 2 unit, the North Anna 2 unit are both in operational status, as I understand it, today, yet they have no operating license. There are some four or five other plants due to come to that important milestone within the remainder of this calendar year, and we need to set down in some systematic and disciplined way the requirements that we wish to place upon those people before allowing them to receive their OL, to finish the CP.

I had hoped today to be able to give you a status report on all of your recommendations. I must apoligize that it's not here. The man who is pulling it together, Jim Conrad, has been ill the last several days, and because there are a limited number of people on the task force, we were not able to complete that status report.

Let me summarize it by saying that we have taken your

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recommendations, distributed them within the staff to the various offices that we feel will play a role in responding to your recommendations: the office of research, the office of standards development, and NRR.

We have sought to assign responsibility for each of your recommendations. We are momentarily going to provide you a written status, and I think it will be early next week, which will say what's going on so far on each recommendation, when do we expect to finish it, who's doing it, and, to the extent that we can at this point, what direction we're headed in.

Suffice it to say the urgent recommendations, the ones you said you wanted to move on quickly, we're prepared to discuss today as we move forward to talking with you about our short-term recommendations from the lessons learned task force.

Before doing that, let me tell you of our approach to lessons learned in order to try to develop an operational philosophy on how to proceed with the work of the task force.

We had basically two choices: We could have started in the beginning a couple of weeks ago and said: What are the broad policy fundamental issues that flow from Three Mile Island, and then assigned ourselves to going about developing analyses and evaluations of those policy issues. Or we could have taken an approach that said: What are all the details; what are the prescriptive details; what are the broad recommendations that have come from everywhere in the country on what we should be learning from Three Mile Island.

Thus, we felt a need to continue to consider short-term actions; that is, those things that are necessary to do now because of their safety implications. We chose to start with the piecemeal approach; that is, to try to get our arms around all the suggestions of which we have been made aware for lessons learned from Three Mile Island. And that means those from the ACRS, those from the staff itself, the recommendations from private citizens or public interest groups, the recommendations that have come from other industries as people with advice to offer have felt free to offer it, recommendations coming from congressional committees, residential commissions, whatever.

We set about cataloging, prioritizing, understanding, and keeping track of all those recommendations. We haven't counted them yet. Let me guess: There may be a thousand of them.

We then have been, in the last week, about the process of putting those recommendations into two categories -- well, really, three categories: The first category is short term -- things that we think are necessary to accomplish right away because they are either easy to do and they significantly improve the safety of operating plants; or because maybe they're not so easy to do but they're a hole that maybe we see now but we didn't see before that we think is urgent to get out and fill.

A second category is a category of things that require more fundamental decisions, more evaluation of the basics of regulation and the basics of operation of nuclear power plants.

Before we feel comfortable with laying on band-aids or gadgets or gimmicks, either in an operations sense or in a design sense, one of the reasons we want to put things into those fundamental-issue categories is because we recognize our finite resources to solve some of these problems. We have finite resources. You have them. The industry has them. There are only so many nuclear engineers in this country.

There also is, I sense in meeting with industry representatives -- and I have met with many of them in the last few weeks -- a tremendous enthusiasm for correcting the fundamental problems that Three Mile Island has called to our attention. And I want to foster that enthusiasm to address those fundamental issues and to address them quickly and to make productive change. And I don't want to nitpick the industry to death at the risk of losing enthusiasm and resources for addressing the more fundamental issues.

So, we've been about the process of separating the short term from the long term.

We've also tried to put those suggestions that don't make any sense at all into a fourth category -- and now I have got them mixed up -- into the last category, the category of things that, for one reason or another, are not worth doing either short term or long term. I am trying to keep track of the people who recommended them and making sure that they have a response appropriate to the recommendation.

DR. MARK: That must be quite a stunt.

DR. MATTSON: Yes.

Let me give you a feel for how we see actions coming on the short-term recommendations.

DR. CARBON: Excuse me. Before you get into that, will you be, somewhere during your discussion, pointing out what these fundamental issues are that industry has this tremendous enthusiasm for?

DR. MATTSON: Yes. You had Dr. Ross describe a number of areas in which short-term actions are being taken by his task force implementing bulletins and orders and reaching decisions on whether other orders or other bulletins are necessary in the immediate reaction to the Three Mile Island accident -- diverse things: aux feedwater reliability, analysis, ECCS performance, containment isolation. The list is long, and I won't repeat all of it.

We have come to the short-term decisions from a different perspective than Dr. Ross' group. He comes to it from implementing day in and day out with individual licensees and owners groups those things identified in April and May as important, and then those additional related things that, as you try to address the important short term, you find out that there is another important short term. And he's generated a list and described it to you.

We have come to a list for the short term from the perspective of looking at all the recommendations -- our own and those of others -- and said: From among that set which we think is all and it grows day by day, what do we think of the short term, what do we think of the things that are important to do now?

Those two lists need to be meshed.

(Slide.)

And maybe this gives you a graphical explanation of how. Bulletins and orders, lessons learned, recommendations from the ACRS, Three Mile Island review, ourself, NUREG-0560, I&E bulletins, Commission questions and directions. Those are common inputs to both Ross and my people.

Then lessons learned has some other inputs: other things from the Commission, things from the Congress, things from the presidential investigation, and things from the general public.

Short-term phase 1 are the bulletins and orders, the knee-jerk reaction, if you will, the things done early in April and May, saying these are things we ought to go in with. Ross is processing them now with Westinghouse, Combustion, and GE and B&W.

Short-term phase 2, some of those grow up in this organization all by themselves. But we're defining them from

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a broader perspective that I told you. What we hope to do yet this week is to freeze the short-term requirements that we see from Three Mile Island; that is, in a collegial decision process involving Ross' group and my group, we will feed back all the short-term actions not already being addressed in bulletins and orders, recycle them back through the bulletins and orders group, lay them on as requirements to operating plants, and that laying on could take a variety of forms: It could be further bulletins; it could be letters; it could be show-cause orders; it could be immediately effective ruling -- all apropos to the short term. And the particular kind of action being chosen on the basis of its relationship to our current regulations, of course.

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So, that goal of freezing the short-term requirement now is the sort of thing that we're working on most earnestly. The task force is in fact meeting at this point, working on the final description of what the short-term recommendations are. And, as you could expect, the urgent recommendations of the ACRS are contained, if not already addressed by the bulletins and orders scope of work. They're in a short-term phase, too.

Now, the other product of the short-term actions will either feed them into the Division of Project Management, the Division of Systems Safety for communication. To the pending OLs and the pending CPs, we would hope to do that on or about July 1, and that's a couple of weeks from now. The chances of making that are pretty good.

So, fundamental issues, policy issues, things that need to be decided in the long term are what we intend to turn our attention to as a task force. Early next week, certainly by the week after we should be devoting 100 percent of our time to the long-term issues. We'll continue to follow in a coordination sense the things that Dr. Ross is doing to implement the short-term, but we don't expect to be much involved with them.

Mr. Siess recommended that you might want to find a mechanism for following Dr. Ross' things yourself. I think that that may be a good suggestion, given what I am telling you now.

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The long-term fundamental issues: Well, I don't know that I'm prepared to go into a long list of them, but let me give you some ideas.

We all know that we want to do something different in the reactor operations areas. We want to do something different with training, we want to do something different with staffing, we want to do something different with qualifications, education. I think we want to do it not only with the reactor operator, we want to do it with auxiliary operators and technicians. We want to do it with station management. And I think we want to do it all the way up to the vice-president level.

Before you can make piecemeal decisions on what you want to do with this or that element of an operations organization, it appears to us that you have to answer some fundamental questions.

For example: Before you can decide finally what you want an operator to be capable of doing, you have to be able to state with some clarity what you think the role of the operator is. That may seem simple, but there is a school of thought that says you ought to change the machine and things ought to be more automatic. There ought to be better diagnostic tools; there ought to be better instruments. That says you want to make the machine better.

There's this other school of thought that says you want to make the operator better. Well, how much better operator depends on how much better machine, or the extent to which you can back fit existing machines.

So, until you understand the interrelationship between these two things that we want to improve them in the long term, I think we have to step back and address some pretty hard questions about what is the role of the operator, what is the role of his technical advisors, what is the role of his support staff? Should they be onsite? What should their training and qualifications be? What should their communications capabilities be? We could bandaid those things. We could take the best of the currently existing ideas that have been suggested in three months, lay them on and walk away from Three Mile Island.

We don't propose to do that. We propose to take on these tougher issues for the next two to three months, think of them from the broader perspective and towards the end of the task force's tenure, which was ordained to be six months, almost a month at this task already, to state which particular recommendations should flow from these broader fundamental considerations.

We will want to be back in touch with you as we go about that process. I suspect we will want to be back in touch not generally on what lessons learned is doing, but specifically in the area of operations, what do we think we

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want to do over the long term. We're going to tell you in a few minutes what we want to do over a short term in the operations area.

Emergency preparedness by the licensee within the plant is certainly something that the task force has some opinions on and of some thoughts to further develop. There again, the role of the licensee depends upon what you decide the role of some other people are. There's a debate about the role of NRC. If that changes fundamentally in broader considerations than the lessons learned considerations, then the role of the operator that we'll be speaking to, might also change.

Degraded core cooling is a further fundamental consideration. We've talked about the reliability to do what is necessary for decay heat removal system. It would be fairly easy for us today to issue a request for information, even a directive, that says to the operating plants, here's what we want to know and what we want you to do with decay heat removal systems; to either tell us about their capability or increase their capability.

Well, the reason you might want to do that for Three Mile Island is that there was debris, there was contamination, there was leakage, there were questions about the performance of the decay heat removal system because the degraded core cooling event that people want answers to. But if you go to

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that kind of question now, you are really going to have to set some criteria against which to compare your answers. What are those criteria to be?

Well, if they're from a degraded core cooling perspective, then you've got other questions you have to worry about before you can choose those criteria. For example, we have a hydrogen design basis for recombiners and for containment, and what have you. A hydrogen design basis has been a subject of interest and work for some years, and acceptable ways of dealing with that hydrogen design basis are stated in the regulations.

Should that hydrogen design basis change? It's certainly exceeded the Three Mile Island accident which says that degraded core cooling happened. How long are we going to approach degraded core cooling in its broadest ramnifications?

Well, we'll go back to Atlas for a minute. You can prevent it or you can mitigate it or you can do a little of both.

What should the design basis be for degraded core cooling? Do a better job of preventing it by increasing the capability of operators and operating staff to constructively intervene in the course of an off-normal transient? Or in PWR containments to deal with the rapid evolution of significant quantities of hydrogen. Those are fundamentally different approaches.

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Over the long term we may show them both to be necessary or we may show only one of them to be necessary before proceeding down one of those particular paths with precedent setting your term requirements. We've chosen to go to the fundamental issues and hold back for a few more months and give them time to be thought about and analyzed, evaluated, proed and conned, alternatives developed and further discussion to occur with people like you, before making those decisions.

W-'l, that's some understanding of the way we're approaching the problem.

I know you had two questions that Dr. Carbon asked me, two specific questions that maybe I can cover before I turn it over to Jim and to Bob.

Reg Guide 1.97 the Committee had a question as to why it had not been implemented on Three Mile Island. You may recall that Reg. Guide 1.97 instrumentation for following the course of an accident has been an acrimonious subject for some years on which you've stated your opinions several times. And the staff that issued the guide, it must be a year or more now, and the industry had said that it's not possible to implement that guide the way it's written. It has things that are not prescribed or are beyond the state of the art or are unnecessary or whatever. And the implementation of 1.97 had been stalled, I think you're aware, and an approach to its implementation, a unique approach, had been generated which was to take some lead plants and to work together with those lead plants to discover the pitfalls of 1.97 to try to be specific about what was or what was not beyond the state of the art, and what was not well enough specified in the guides.

Three Mile Island was not one of those lead plants. You may or may not be aware, but the review of Three Mile Island was complete from most of the technical standpoint two or more years ago, and the debate over 1.97 has been going on in the interim. I don't remember any specific cases or the lead plants, except one: Diablo Canyon was a lead plant for 1.97 implementation.

Does anybody on the staff remember what another one was?

DR. LAWROSKI: LaSalle was another.

DR. MATTSON: LaSalle, maybe, I don't remember.

DR. CARBON: Let me, Roger, expand the question a little bit before you finish up on it.

It covers not only 1.97, but in our letter before of October, 1976, on our review of TMI-2, it stated the Committee recommends that prior to commercial power operation of Three Mile Island Unit 2, additional means for evaluating the clause and likely course of various accidents including those of very low probability should be in hand in order to provide improved bases for timely decisions concerning possible off-site emergency measures. The Committee wishes to be kept

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informed. That's a quotation from our OL letter in 1976.

And in our meeting with the Metropolitan Edison GPU people on June 7th they said they never paid any attention to this or 1.97, nor had the staff ever urged them to do anything in this direction.

DR. MATTSON: That certainly puts a different perspective on the question. Whether there is a piece of paper back to you saying that we intended to do something different, I don't know. We'll find that out. It may be that the staff, in its discussions with you about the difficulties of implementing 1.97 may have presumed and by oversight that it was mutually understood that that requirement would not be met. I can't say at this point. Those two possibilities occurred to me and we'll have to find out better what the answer to your question is.

MR. BENDER: I don't think you should limit your evaluation of that question to Three Mile Island. There are a number of other places where this same point is valid.

DR. MATTSON: Does the Committee recollect about what time you began putting that in letters? Was Three Mile Island the first?

MR. BENDER: Take a look at the Hartsville letter, for example.

DR. MATTSON: Hartsville? But that would have been a CP letter. But this one sounds like an OL letter.

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Well, the first OL letter would have been the first one that went into operation.

MR. BENDER: We've pointed this out a number of times that the time to do things is at the CP stage and not at the OL stage. These are already well past the opportunity point when you get to the OL.

DR. MATTSON: Again I'll say I think it's been general knowledge shared with you that 1.97's implementation had stalled out and was not proceeding for reasons I have summarized.

Clearly, one of the lessons learned from Three Mile Island is that stalling cannot be permitted to continue. One of the long-term actions of the task force will be to get started a rather short-term revision and republication of 1.97.

MR. BENDER: Just to expand on the point one step further, one of the reasons why it stalled was emphasis on perhaps the wrong things, and I think you need to go back and see whether you're implementing the things that were important as determined by the accident at Three Mile Island.

DR. MATTSON: I think I agree with your statement. This may be jumping too quick, but I think we were stressing the things that were important at the expense of getting some of the important things done. That is to be corrected rather quickly. We won't correct that by July 1, but I would suspect it's something that could move quickly in the course of the s-10

summer evɔn.

We're taking steps to encourage the A&S Committee that was developing this guide to work with us to find a way to get it revised and acceptable and done quickly. It may mean that some mangement involvement and some involvement of some other people than were involved in the acrimonious dispute down through the years take place in order to move it quickly. I made a commitment yesterday to some people that I personally know myself. I will see whether I can do anything.

You had another question, Dr. Carbon, about qualifications and training in the preparation of operating staff. I think it's better for you to hear Jim Milhoan's prepared remarks on the package that we think would be possible to accomplish in a short term, to upgrade the capability, and a couple of other functions of the operating staff. That will inevitably as it does every time Jim talks about it, lead you to a discussion about the kinds of things we have in mind for the long-term. That is directly appropriate to that question.

If there aren't any others, I am going to sit down and let Jim talk about operations.

DR. CARBON: Fine, thank you.

(Slide.)

MR. MILHOAN: I'd like to speak to the activities of the lessons learned operations subgroup.

As Roger told you, the make-up of the Committee, I'd like to review the operations subgroup of the lessons learned committee.

We have five individuals under standards development. We have Terry Harpster our Region 3 inspector; Jerry Holman, Operator Licensing Branch; Tom Telford and Leo Beltroggi, Instrumentation and Control Section.

In the area of operations subgroup, we're looking at the following major activities: plant procedures; personnel, meaning the selection, training and initial qualifications and requalification of the utility personnel; the conduct of operation; technical specifications; the carrying out of the direct operations of the plant; the man machine interface the area of human engineering; preoperation and start-up testing; and incidentally, spots from the operators' viewpoint. And we are also dealing with the area of reactor operating experience.

In our subgroup as we were looking at these many suggestions we came on one concept which is not new to anyone, but which a number of suggestions for the short-term fall into this area of command and control.

(Slide.)

In other words, give the authority to the on-shift supervisor who has responsibility for direct operation of the plant. Make sure he knows he has that authority. Give him the tools to carry out the authority. Give him the environment in which to carry out his responsibilities, and also make sure that

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he knows and can carry out the responsibilities of his position.

In this regard there are a number of areas that I will address which will be nothing new, and which we'll probably be asking the plants to review and revise as necessary certain procedures in the area of command and control. And then I will discuss one aspect of the incident response, which will be new.

In the area of command and control, we would like to ensure that they review and revise as necessary their procedure which specifies authority and responsibility for safe operations to ensure that they have a person on-shift specified, that he has the authority and duty for safe operations of the plant. This would be in the case -- I am going to use the term shift supervisor throughout my discussion.

PROFESSOR KERR: The nomenclature being used suggests perhaps unconsciously a quasi-military organization; is that deliberate?

MR. MILHOAN: It is deliberate in a certain aspect. From the point of view that in off-normal conditions in the control room in normal operations there has to be a line of authority. There cannot be a debating society, and yes, it is certainly intended in that line. The connotation is there.

As I said, we want this specified in the shift supervisor. Now, the shift supervisor may not always be in the control room during plant operations. When he's not in the control room, we want to be sure that there's a lead control

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room operator designated, and his duties and responsibilities are also specified. We want to ensure that there is a line, a succession, to shift supervisor.

In the case of off-normal conditions the persons are specified who have the authority to relieve the shift supervisor when they come on the plant. We also want to ensure that there is training which specifically relates to the shift supervisor's responsibilities and which he will know that he has these responsibilities to exercise.

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In this regard, we would desire a policy statement issued at the highest corporate level, which emphasizes the responsiblity for the safe operation of the plant and which emphasizes that that is the primary responsibility of the shift supervisor over production of power. And we want to ensure that that's laid out at the highest corporate level.

In the area of shift and relief turnover, we would desire that the shift and relief turnover procedure be revised as necessary to ensure there is a written checklist for shift and relief turnover. It would be signed by the oncoming and outgoing watches, which would contain a number of essential elements. And in the short term, it would contain elements such as critical plant parameters and the limits of those critical plant parameters;

The fact that the oncoming watch section would include a verification of the control room console to ensure the availability of systems for the operation of the plant, and it would also include a separate entry in which we would be required to specify on the shift and relief turnover checklist those systems and components that are in a degraded mode of operation permitted by the technical specifications, and the length of time that they have been in degraded mode of operation. We'd like to ensure that that's on the checklist.

I spoke about providing the environment in which to conduct the operations of the plant. This is the area of the control room. We would like to ensure that we have minimum staffing in the control room so that the shift supervisor or the person directly responsible for the operations of the plant in time of an off-normal condition does not have to become directly involved in control room console operation. In other words, he should not be flipping the switches; he should be standing back taking an overview of the plant. So, we should have enough operators in the control room to ensure this is the case.

In this regard, standardized technical specifications for a single-unit plant require one senior reactor operator and two control room operators and two auxiliary operators -- operators outside the control room. However, there is a provision which allows or permits reduction of this staffing for a period of two hours so that you could wind up with a situation where you would only have, let's say, the senior reactor operator and one reactor operator in the control room. We want to correct that provision.

PROF. KERR: How did you conclude that the safest situation would be one in which the person responsible not be manipulating controls? I ask this because I heard a lot of discussion with airline pilots as models recently, and there the senior person in charge not only manipulates controls but perhaps does most of the manipulating, especially in an emergency situation.

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I don't mean that is a great model, but it seems in contrast to what you are saying.

MR. MILHOAN: We are looking -- this is partially from Navy experience, partially from reviewing the event -- but we do not want that senior reactor operator to be so engrossed in one operation that he is not aware of the other operations going on. We want him to stand back and look at the situation and be able to analyze the situation. We think it would be best -- that he could best do this if he does not perform any direct manipulation.

PROF. KERR: I am trying to find out how you reached that conclusion.

MR. MILHOAN: I don't think there was any one thing that made us reach that conclusion.

PROF. KERR: I am simply citing one example that's been used in other contexts, which seems somewhat contrary to the conclusion you have reached.

DR. MATTSON: There is basic geometrical differences. The command pilot in an airplane has everything within his reach. The command pilot in a reactor control room --

PROF. KERR: No, he doesn't, Roger. I am sorry. Even in a 727.

DR. MATTSON: He doesn't need to see to take those actions.

PROF. KERR: He doesn't. But he does need to control --

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DR. MATTSON: Well, we have considered an alternative to this, and it's a concept that tries to come to grips with infinite possibilities, permutations and combinations of events, and says something like the following: It says the control room has got all kinds of indicators, alarms, and controls and buttons and switches, and the way those things can combine and be used in a given event is infinite. It's an infinite set of stuff they're moving about.

However, there is a finite set of things important to core cooling and, say, primary coolant pressure boundary detection. These are two very fundamental first-line defense in depth, if you will. And it may be possible to identify the scope of responsibility for someone we've called a "safety monitor," and to provide redesign of control rooms to put those, that finite set of indicators and diagnostic equipment or core cooling and primary coolant pressure boundary protection, for example, directly in the hands or under the purview of this safety monitoring function.

That's one of the things that we're considering for the long term. It might be that that safety monitor is one of the two reactor operators or a third reactor operator, or it might be that that safety monitor function should fall directly to the senior reactor operator, shift supervisor kind of person, that these short-term recommendations reach.

We have chosen to reserve on that alternative until we think through some of those possibilities, because one of the things that we're also going to recommend adding to the crew in the short term is what some people have called a "technical adviser," a person with engineering and system qualifications who is also capable of operations things.

These short-term recommendations go more to the recognition, formalization, of the role of the shift supervisor, the senior reactor operator, as the man responsible for decision-making, the person who must have the overview, who must know how the primary system and the secondary system are being controlled and protecting the core.

And it's felt that if you put him at one console or another or flipping switches, he, simply by line of sight or by concentration of activities, will not have this overview, won't have the freedom, the time, the perspective, to make these decisions that we feel are his responsibility to make.

PROF. KERR: All these considerations are important. I am not disagreeing with them. I am trying to understand whether you have reached this conclusion by looking at a lot of models or whether the lessons-learned group knew that something was wrong and that this is a possible change.

I have heard a number of things this morning which cause me some concern. For example, I heard the statement that the principal responsibility of this man -- in fact, his first responsibility -- and that this should be clear from corporate management -- was safety and not power production. And I am hearing a philosophy which seems to say that we're going to separate responsibility for safety; there's going to be somebody responsible for safety in the plant and maybe another group responsible for production.

It seems to me that one of the things --

DR. MATTSON: That's not our interpretation.

PROF. KERR: I may have misinterpreted it.

It seems to me one of the things that one might learn from Three Mile Island is that one needs to consider the plant as a whole. I don't know what it means, for example, to say to a utility, "You consider only safety and not power production," because one of the principal reasons you build a reactor is to help produce power. And you've got to somehow integrate those considerations into a more meaningful whole.

It seems to me the more you separate considerations of safety and reliability, the more likely it is that you may fail to achieve both.

DR. MATTSON: The word was not "separate;" it was "emphasis." Primary emphasis on safety; secondary emphasis on power.

MR. MILHOAN: That was certainly the intent of my remarks.

PROF. KERR: But the implication is that there are other people who put primary emphasis on production and secondary emphasis on safety. I guess --

DR. MATTSON: Two pieces of information -- there are several -- but two pieces of information that sort of make me think this is an important consideration: First, the direct experience at Three Mile Island, where the shift supervisor did not stay in an overview capacity, did not stay back looking at the general things that were going on in the plant, concentrating on what they were doing. Instead, he found himself at the second area, flipping switches, taking action with the secondary system, while the core was uncovered. That's one piece of direct information from Three Mile Island.

Another kind of information, I think, is that it's not unheard of for a reactor operator to be put on report for taking an action on reactor coolant pumps during a transient to shut those pumps down, because their seals might go out. Management puts them on report for not thinking about the seals first.

That gives us an uncomfortable feeling that the role of those kinds of data -- it gives us an uncomfortable feeling that the role of that senior man in the control room is not specified, not formalized, not respected by people above him -- maybe by even some of the people themselves. And we want to see that corrected soon.

There are a lot of other things that we want to think about, by way of training that person, educating that person, supporting that person, giving him better instrumentation, or further specifying his duties, that we're not able to do. That one problem, we're uncomfortable with going much further. We'd like to make sure it's articulated well so he understands it and so do the supervisors.

PROF. KERR: I will stop after this. We see the same problem, and I don't know what the solution is, but it concerns me if all the solutions come out of Washington. It seems to me one of the significant remarks that Denton was quoted to have made -- I am not sure if he really made it -- is that he learned that he probably had a better feel for going on once he got to the plant than he did from a remote location.

I think, in the long run, if the people responsible for running the plant can't run it safely, it can't be run safely. I don't believe the ACRS and the NRC can operate reactors safely. It seems to me that we're moving into a situation in which more and more an attempt is being made to specify in a lot of detail the way in which plants, for example, are to be operated.

This is in response, I think, to an observation that perhaps they have not been operated properly in the past. But I am concerned that a solution has to be found which involves what looks to me like a reality, that ultimately the people who operate the plant have to operate it; it can't be operated remotely, and if it can't be operated safely by some local initiative, I would guess that it can't be operated safely.

MR. LEVINE: I agree with what you're saying. And maybe from my perspective I can say what I saw missing at Three Mile Island: that is, leaving the situation as it was and a situation, the responsibility of the operators and the senior operators and all that, was largely unchanged. What was missing there was a more knowledgeable person who could understand the system of interactions better. And that would have helped a great deal.

A person like that could do many other things besides just that. That is, when there were no accidents, which would be most of the time, he could help the operator to do those kinds of things that would prevent accidents and to help mitigate accidents if they were to occur, and then during the course of an accident could, in fact, be in charge.

He would have to be a very well educated person, and he would belong to the utility; he wouldn't be from Washington. That would be a strictly local kind of thing. It might become an NRC requirement or something. But that's the kind of thing I would propose.

DR. CARBON: Chet?

DR. SIESS: My concern is a little bit different than Bill's. I think you're asking the right questions.

What bothers me is it seems to me you're looking for the answers in a vacuum. I don't believe the situation is unique to operating a nuclear plant. I don't want to belabor the parallel, if any, with flight safety, but there are other process systems and similar things where people have been looking for years in response to man-machine interaction and operator response. I know the aviation psychologists have done a great deal of work, and I am sure they must have been asking questions and finding some answers as to who thinks and who pushes buttons and who thinks before he pushes buttons and who pushes buttons before he thinks, how much education do you have to have, how much knowledge do you have to have, how much information do you have to have.

Are you looking outside of our own little field to see what basically people have done in these areas?

DR. MATTSON: Yes. And we're going to do more. We've talked to FAA, we've talked to the airlines, we've talked to the Navy -- both the nuclear Navy and the non-nuclear Navy. We're writing reports for the Commission. We will come to you summarizing the kinds of things we're finding.

We met with the electric utility industry under the auspices of the Atomic Industrial Forum and the Edison Electric Institute. We have their feedback on some of these suggestions at this point. We have their suggestions, the things they're considering.

Our feeling is that most people who have sat down and considered the body of information -- and I point out that the EEI people and the EPRI people also enjoy the experience with conventional power plants and how things are done there -- it comes down to a fundamental set of things that take a little longer to analyze and a fundamental set of things that are fairly generally recognized as things that could be done now to significantly improve the present situation. And the command and control function, the recognition of responsibility, and the beginning now to support that command and control function is one such issue.

We met yesterday to hear the Atomic Industrial Forum's steering group of senior vice presidents of both utilities and vendors and architect engineers describe what their early thoughts are on things that ought to be done, long term, short term, in the operations area. There are many encouraging signs, from what they are saying. Their short-term ideas are almost an overlay of what Jim is describing to you here today.

We went into some detail, giving them the same kind of presentation that Jim is giving you, and there was a lot of head-nodding. This, plus starting from looking at FAA and the Navy and other people who have these kinds of operations problems, admittedly there is more we need to do. I don't think we factored in the psychologists, for example, that we could factor in; we haven't factored in the crisis management specialists that we need to factor in. We haven't factored in the training specialists.

There are people in this land wh for other reasons, are better at these things than we are, and we need to talk to them. So, all of us are going to be talking to some of these people in the context of the research program, lessons learned, and in that short life we can talk to all that we can afford to talk to, and that kind of thing is being factored in.

But it doesn't remove from us the responsibility to say are there things that could and should be done within the next week or two to get something moving, to increase the operational capability of these plants. We think there are, and that's what we're trying to describe, is a set of these things.

Now, many of the comments you're making are addressed by other elements of the set that Jim is trying to describe. I don't want to squelch conversation, but if he could just get the set out, maybe you'd see how it fits together in the package.

DR. SIESS: I was getting a lot of comfort until you got down to the end. Any action you take in the absence of really good, basic underlying knowledge has about a 50 percent chance of being wrong, of making things worse rather than better. I don't know whose fault that is.

DR. CARBON: I think we're going to have to chop this off.

Mike, did you have a question?

MR. BENDER: I just wanted to make one comment. I am still concerned about dealing with TMI-2 in isolation. We've had a number of other events that parallel it: the Browns Ferry, Oyster Creek, Davis-Besse. It seems to me that when you start looking at operator response, it would be worthwhile to include all those other near-accidents that didn't happen as well as the one that did, when you make your assessment of the operator needs.

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DR. MATTSON: That's the intent.

MR. MILHOAN: That would be true in the long term.

So, let me finish the last two items on this list of conduct of operation.

We talked about emphasizing the responsibilities of the shift supervisor. We should also provide a response capability of a person or group of persons with technical engineering knowledge in plant systems. In this area we would be talking about revising, as necessary, the recall procedure of the plants to ensure that that engineering capability is there to respond during the back shifts to request from the on-shift personnel, on a very short-time basis to provide the shift supervisor with the technical advice availability; and in the area of environment, providing a control room in which to exercise his responsibility for operation of the plant, we propose looking at the procedure and develop a procedure, if necessary, to specify control room access -- who has responsibility for limiting access to the control room in an off-normal and also during normal operation. And this should be specified in detail and the control room operators given definitive direction in this area.

The last area I would like to talk to --

(Slide.)

-- Is a prospect of a rather comprehensive change in the plant itself, in which we could begin some actions now to provide the control room as a place for direct operation of the plant and provide a separate center on-site -- and I have labeled it "on-site incident response center" -- in which you would have the capability of remote readouts of critical plant parameters in which the plant supervisory personnel would go to in the event of off-normal situations in which they could look at the trend analysis of the plant. You would reduce the control room access in this regard.

You would also have a center for communications off-site, rather than directly into that control room, where you introduce a certain level of confusion into the control room. You also have communication with an off-site response center.

One example, the TMI control room at various times had to be cleared of personnel. At one time we had 83 people in the control room. The operators couldn't get to the panels.

We want to look at reducing that control room crowd, if I may say.

DR. CARBON: Is that so? We were told very specifically at Three Mile Island by the station manager that at no time was there any circumstance where people were up close to the control board.

MR. MILHOAN: Is Terry Harpster here? He can speak to that.

MR. HARPSTER: I think we did have a problem several days into the transient, where we had to clear the control room several times.

DR. CARBON: Several days into the transient?

MR. HARPSTER: Three days into it, and on several subsequent days, of both NRC and utility personnel. The operators were having difficulty getting to their instrumentation.

DR. CARBON: For the record, my comment referred to the first few hours.

MR. MILHOAN: I see.

DR. MATTSON: The I&E scenario would tend to refute that. Terry recalled for me the other day an experience where he had to ask the 83 people to leave the control room when it reached a point that the operator couldn't reach the buttons. The I&E scenario says that in the first day there was a time when there were reported to be 50 people in the control room at 7:00 or 8:00 in the morning. And I think we had indication that there were an awful lot of people in the control room. Several shifts, no clearly defined line of authority while those things were happening.

We think we'd like to move to correct that situation.

MR. MILHOAN: I was told by one of the TMI operators they had four external phones in the control room. In the immediate response to the accident when he was there, he was, let's say, distracted by the phones themselves, by people coming in and asking him for plant status information. And his comment was: I could give the people the plant status information, but

I could also destroy the plant in doing it.

So, that's one of the areas leading to the on-site response center with the remote readout capability.

Yes?

DR. SIESS: On that diagram, you have a control room, an on-site incident response center, and an off-site response center. In which of those three will the responsibility and the authority to act reside?

MR. MILHOAN: For the authority and responsibility for direct operations of the plant -- by that, I mean, changing plant status -- it would reside in the control room through the shift supervisor, whoever may relieve the shift supervisor, such as the operations superintendent.

DR. SIESS: He has the authority and the responsibility to make the decisions?

MR. MILHOAN: For changing the plant status.

DR. SIESS: Once you change the plant status.

MR. MILHOAN: Yes.

Now, in this center, you would have plant management personnel looking and providing advice to the control room from looking at trends and also from carrying out responsibilities for, let's say, implementation of emergencies.

DR. SIESS: Since they are his superiors, how do you assure that they provide only advice and not orders? And if they can provide orders, the off-site can provide orders. ANd

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now we've got that dilution of responsibility, dilution of authority.

MR. MILHOAN: In establishing the line of succession for, let's say, command in the control room, you could establish that. In other words, if the plant management personnel were qualified reactor operators, they would have the authority to go in and relieve the shift supervisor and assume direct operations.

DR. SIESS: They would have to go in and relieve him?

MR. MILHOAN: That's correct.

DR. SIESS: As long as he's in the control room, he can do what he wants without getting authorization from them?

MR. MILHOAN: We've got information exchange. You sound like we're doing everything in a vacuum.

DR. SIESS: You're formalizing it. I just wanted to see whether the formalization is going to be to a dilution.

MR. MILHOAN: In my opinion, it would not lead to a dilution. If you have the formal channel of communication --

MR. BENDER: This thing is still in the formative stage, so there is no sense spending too much time debating it at this stage.

DR. SIESS: When there is a peril with a military organization, you don't get any dilution of authority; it only goes one way.

MR. MATHIS: This kind of system is used in a lot of organizations, and the off-site defense center is the final command, if you want to boil it down to that.

DR. CARBON: Go right ahead.

MR. MILHOAN: The last area of the chart we term the "plant operations support center." This is an area in which the operations support personnel could report to and be available to assist the control room in plant operations, such as equipment changing, valve lineups outside of the control room, rather than all being in the control room area. The control room would know where that area was and could establish communications and have that resource available.

That is the end of what I would like to go into this morning.

MR. ETHERINGTON: Are these centers rooms dedicated to the purpose, or are they ordinarily used for offices or something else?

MR. MILHOAN: In this particular one, we would have to provide some design changes, habitability requirements, communications requirements, for that particular room. It would be a design change.

MR. ETHERINGTON: Would that room normally be used for something else?

MR. MILHOAN: We would have to consider that. We would have to look at the use of that room in other situations.

DR. CARBON: I have one short question: For the shift supervisor, the person who is really responsible, what are the current minimum educational and training requirements for someone for that position?

MR. MILHOAN: I can give them to you briefly. But our operator licensing branch -- Jerry Holman, I think, could probably give you a better rundown of those capabilities.

MR. HOLMAN: I was hoping I could lay my hands on it real quickly in our licensing guide.

Basically, the educational requirement is high school education or equivalent.

DR. CARBON: This is for the shift supervisor who would be in charge of an accident?

MR. HOLMAN: That's right. Four years of qualified experience, responsible qualified experience, two years of which may be accomplished by education. In other words, we could look for experience, or we would swap a couple of years of it for education.

DR. CARBON: And by "responsible education," this might be serving as an operator?

MR. HOLMAN: Coming from a fossil plant in a similar position or serving as an operator, this type of thing.

DR. CARBON: Coming from a fossil plant.

MR. HOLMAN: Responsible qualified experience.

He also, of course, would have to get his minimal nuclear experience, plus the minimum time at his plant.

DR. CARBON: Go ahead with your summary. Or was that it?

MR. HOLMAN: That's essentially it.

DR. CARBON: Let me see if I understand this clearly. He has to have a high school education and four years of experience, responsible experience, which could have been in a fossil plant.

MR. HOLMAN: It could have been on a submarine.

DR. CARBON: How much nuclear experience, in your words, does he have to have?

MR. HOLMAN: This is what I was going to look at. It's a year minimum, and I think it's two, but I would have to look again.

DR. CARBON: A year or two is what? An operator?

MR. HOLMAN: Well, it could be as an operator; it could also be involved with startup; it could be involved in essentially construction of a plant.

DR. CARBON: He might never have operated a plant or been in charge?

MR. HOLMAN: It's quite possible.

DR. CARBON: How about the amount of fundamental training that he might have in the physical understanding of what reactor physics is all about, and shielding?

PROF. KERR: I hope you didn't say reactor physics.

DR. CARBON: I did. I will retract it. Core physics.

MR. HOLMAN: If he is in a situation where he has not had previous experience, his training program is approximately two years' duration. It starts with A, for atom, and essentially works up from there. 12-week fundamentals course. Three to four months of observational simulator training course. His plant specifics. The design, six weeks of specific design features of his plant. And about a year of on-site training as the plant is getting ready to fuel, in which he is not only involved in their formal training program, but also involved in startup activities, precritical checkouts of systems, procedure-writing, this type of thing. And a final refresher course back on the simulator, at which point we would come in then and license him -- examine him; excuse me. Okay.

DR. CARBON: Thank you.

MR. MILHOAN: I think we did one statistical survey, and the senior reactor operators -- I think about 80 percent; I believe that was the number -- had education above the high school level.

MR. HOLMAN: Yes.

DR. CARBON: Are there other questions?

(No response.)

DR. CARBON: Fine. Thank you, then.

I guess we're at the point of adjourning for lunch.

MR. TEDESCO: Mr. Chairman, excuse me. We were prepared to give you a summary of some of the other things along the line of design analysis.

DR. CARBON: I am sorry. Go right ahead.

MR. TEDESCO: I would just like to point out that through the discussion that we held before between Dr. Mattson and Denny Ross, I think many of the items were covered. I am at the point now where I am compiling a short-term list. It really is nothing new to what you have heard already, but I can run through it, if you want.

I want to indicate, at the point where we are still talking among ourselves and we're talking to Ross' people and trying to come up with at least a list of short-term actions, so all I would be able to give you an overview and a summary, if you want it.

DR. CARBON: Gentlemen, what's your pleasure?

MR. BENDER: Why don't we just let him give us the list?

PROF. KERR: Speaking of ingestion ...

DR. CARBON: Give us the list.

MR. TEDESCO: You realize that we have maybe a half to three-quarters of an inch thick of material that we're dealing with -- several hundred or a thousand areas of input. We're at the point now of culling through these items, and it's been going on now for several days. The list I will go through now is not final, but it might give you some insight into the thinking that's going on.

DR. CARBON: Could you just simply give us the list and let us read it?

MR. TEDESCO: It's written by hand.

PROF. KERR: I am sure your handwriting is legible.

(Laughter.)

DR. CARBON: You can give us copies of that.

PROF. KERR: 50 percent of this committee can read.

DR. CARBON: Does that then cover everything?

MR. TEDESCO: At this point, yes.

DR. CARBON: Fine.

Well, this then finishes the session before lunch. Let's break and reconvene at 2:45.

(Whereupon, at 1:45 p.m., the meeting was recessed for lunch, to reconvene at 2:45 p.m., this same day.)

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AFTERNOON SESSION

(2:45 p.m.)

DR. CARBON: Let's go ahead and begin with you, Jim.

MR. HAZELTON: I am Warren Hazelton from the Division of Operating Reactors. I am going to present a short version of the activities of the Pipe Crack Study Group, and the report, and also discuss, to a limited extent, what the staff actions are regarding the report and how we plan to implement the recommendations.

The man who probably really should be giving this is Larry Shao, and he's hiding in the audience there. He is the Chairman of the Pipe Crack Study Group. Somehow or other he talked me into doing this.

(Slide.)

Just as a little bit of background, prior to 1975 the pipe crack study group did investigate and evaluate the significance of cracks found in austenitic stainless steel piping systems of BWRs. They put out a report that's NUREG-75/067. In this case, cracks were found primarily in small-diameter piping -- that is, 10-inch diameter and under.

During 1978, Intergranular stress corrosion cracking was reported for the first time in large diameter piping. That is, on the order of 2 feet in diameter, in a

German BWR. This discovery, together with reported questions in Germany concerning the interpretation of ultrasonic inspections, led to the activation of a new Pipe Crack Study Group.

(Slide.)

So on September 14th, 1978, this new Pipe Crack Study Group was organized under the Chairmanship of Larry Shao. The Vice Chairman was Spence Bush. The effort was to be a crash effort. The study was completed on January 21st, and a report was published in February 1979.

(Slide.)

The purpose of this Pipe Crack Study Group was to investigate and evaluate the cracks found in the larger diameter pipes, and some cracks found in furnace sensitized safe-ends, primarily also in Germany.

The recommendations on current NRC programs and the foreign concerns regarding the capability of ultrasonic examination methods; and then we were asked also to investigate the cracking in the inconel safe-ends at the Duane Arnold operating facility.

Also, to reevaluate the potential for stress corrosion cracking in pressurized water reactors.

(Slide.)

The members of the study group were, of course, Larry Shao, the Chairman; Spence Bush, the Vice Chairman;

Hazelton Gamble; Charles Seyfrit; Al Taboada; Muscara; there were some other major contributors, Mr. Woodruff Burns; John Weeks from Brookhaven; Rodabaugh from Battelle-Columbus; and Ray Klecker from NRR.

(Slide.)

In addition, the Pipe Crack Study Group had a good number of consultants that went to varying areas of expertise. These people helped the study group a great deal.

(Slide.)

Basically, the factors that were investigated and evaluated by the Pipe Crack Study Group included the BWR cracking experience and corrective actions; the PWR cracking experience and corrective actions; the metallurgy associated with the pipe cracking; reactor coolant chemistry; pipe configuration and stress levels; the Duane Arnold safe-end cracking; methods of detecting cracks; the significance of cracks; and recent developments relevant to control and detection of intergranular stress corrosion cracking.

(Slide.)

The Pipe Crack Study Group held many meetings, and also had meetings with outside groups, particularly General Electric, with EPRI, with Iowa Power and Light, of course regarding Duane Arnold. We had representatives from the Federal Republic of Germany and met with them, and we sent representatives to Japan to investigate what was going on there.

(Slide.)

One of the real initiating events for the Pipe Crack Study Group was the German experience. I'd like to cover this very briefly. The intergranular stress corrosion cracking was observed in the Gundremmingen Power Plant, which is a dual-cycle boiling water reactor, and it was found in the primary piping connecting the steam generators to the reactor vessel.

The situation was that after a transient occurred at the plant, they wanted to do some further investigation to see whether any damage had occurred to any of the piping, and particularly they were concerned with the sensitized safe-ends on the reactor vessel and the steam generators.

So they did some ultrasonic examinations there. There were some questions regarding whether or not they really saw cracks, but they decided that, in any event, they were going to cut the affected parts out and replace them at that outage.

After cutting them out, they found that, in addition to cracking in the sensitized safe end, they also saw cracking on the other side of the pipe-to-safe-end weld. That is, in the pipe itself.

This was the cause for concern by the NRC, because this was large diameter piping, larger than any that we had heard about stress corrosion cracking previously.

The other important thing, I think I mentioned, was the fact that the Germans were not pleased with how well they could detect these cracks by the standard method of ultrasonic inspections, and there was a major program that they carried out on that, and this was one of the more important things that we had discussed with the Germans.

You notice that the cracks that were found were extremely shallow, on the order of 5 millimeters deep, starting from the inside, and the cracks that we were concerned about -- that is, those in the pipe -- always seemed to start at the very root of the weld, progress in the pipe material, until it intersected the weld; because the weld is at an angle, of course.

They all stopped either before they got to the weld, or after they had penetrated the weld just a very slight amount, to where they would get into the region with a reasonable amount of delta ferride.

The general feeling is that these were not very significant cracks. Almost all of them were less than 10 percent of the wall thickness.

(Slide.)

The situation regarding the Japanese experience is more pertinent, because they have more BWRs of essentially the same type that we have.

They had found pipe cracks in recirculation bypass lines, and also in recirculation riser lines, which was something new -- different than our experience. As we have, they found cracks in the core spray lines and some of the emergency shutdown cooling lines and reactor cleanup lines.

PROF. KERR: What is the significance of the parenthetical "(2-14 inch diameter)"?

MR. HAZELTON: The size of the pipe.

PROF. KERR: Thank you.

MR. HAZELTON: Some of their recirculation risers are up to 14 inches in diameter, as I remember, but it may be one of those others. I can't remember which of the 14-inch ones. Most of them were 4- to 12-inch diameter.

They didn't have furnace-sensitized safe-ends. They found a very large percentage of their cracks by ultrasonic examination, which was a very comforting thing. We were happy to find that ultrasonic seems to work pretty well there.

They have a major program to prevent cracking, and they are taking some steps that are among those that are being taken today in some plants in this country, and we can go into that a little later when we get there.

They are also looking at improvement of water chemistry, primarily de-aeration, and some other methods that I'll go into later.

(Slide.)

Basically, the Pipe Crack Study Group was asked to take a look and see whether there's anything new about pipe cracks, or whether the basic conclusions from the original Pipe Crack Study Group were still valid. And the group came to the conclusion that this is still valid; that the causes for the intergranular stress corrosion cracking for the piping in the BWRs are caused by critical combinations of very high stress levels, and comparatively light sensitization of the heat affected zones of welds caused by the welding, and the corrosive environment, particularly the oxygen level normally found in the coolant of a boiling water reactor.

(Slide.)

So the Pipe Crack Study Group didn't come to any fundamentally different conclusions. The Pipe Crack Study Group was also asked to evaluate, or to answer a series of questions, rather specific questions. These were as follows:

First, the significance of the cracks discovered in large diameter pipes is relative to the conclusions and recommendations set forth in the referenced report. That's the earlier Pipe Crack Study Group report, and its implementation document -- that's NUREG-3/13. And the response of the Pipe Crack Study Group can be summarized that: Yes, intergranular stress corrosion cracking could occur in large diameter stainless steel piping, but it was felt it will be less frequent in large diameter piping than in the smaller piping, and it is unlikely that significant intergranular stress corrosion cracking in piping would go undetected.

Another important point was: It is unlikely that the cracking will become unstable. That is, they felt that it is most likely that you'll have a leak occur before you have a major break in the pipe.

I might add that this is the experience up to date. It is felt that even if we had a major break, ECCS will provide adequate protection.

We also concluded that the recommendations in NUREG-3/13 are adequate.

(Slide.)

Question two pertained to resolution of concerns raised over the ability to use ultrasonic techniques to detect cracks in austentitic stainless steel. As you recall, I said the Germans were not pleased with how well they could detect these cracks. You remember, their cracks were extremely small; whereas, the cracks in Japan were found quite readily by ultrasonics.

The conclusions reached by the study group are that improved ultrasonic testing equipment may be needed to detect very tight or branched intergranular stress corrosion cracking. Many cracks will not be properly identified as "cracks" using the present code evaluation standards.

We believe that most cracks will be detected with frequent in-service inspections using equipment that's especially suited to detect intergranular stress corrosion cracks, and improved evaluation methods when the cracks are deeper than 10 percent of the wall thickness and extend at least several inches in circumferential length.

(Slide.)

Question three was the significance of cracks found in large diameter sensitized safe-ends, and recommendations regarding the current NRC program dealing with the matter.

The conclusions were that intergranular stress corrosion cracking may occur in a limited number of furnace-sensitized safe-ends remaining in the United States BWRs, but it is expected to be less frequent than in the core spray or recirculation bypass line. If it exists, it is unlikely that unstable crack growth will develop; and again, that the ECCS will provide adequate protection.

I might poi-... that there are very few large sensitized safe-ends in any pipes in the United States left today. Most of these have been replaced.

(Slide.)

The next question was the potential for stress corrosion cracking in PWRs.

The group concluded that in the primary systems of pressurized water reactors, the potential for stress corrosion cracking is extremely low, because oxygen is limited to very low levels with the overpressure of hydrogen. In other piping systems, however, they are not immune to stress corrosion cracking. Incidents have occurred in weld-heat affected zones, as well as in sensitized base metal. High oxygen levels can be expected, particularly in lines that are usually left open, a drain chlorides and chemical additives have been noted, and NRC has initiated proper action for control.

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(Slide.)

The fifth question concerned the significance of the cracking in the inconel safe-ends that was experienced at Duane Arnold, and to develop any recommendations regarding NRC actions taken or to be taken.

I believe we're going to cover some points of Duane Arnold later in the meeting today, but the Pipe Crack Study Group concluded that the intergranular stress corrosion cracking in the Duane Arnold safe-ends was caused by a combination of high stress, nonfavorable chemical environmental conditions, and the thermal sleeve to safe-end attachment welds. That's primarily because there was a very tight capillary-type crevice there in the location of very high residual stresses, and inconel 600 is known to be particularly subject to crevice stress corrosion cracking.

The other point is that inconel 600 is not particularly susceptible to cracking in the absence of a crevice, but thermal sleeve attachments with crevices should therefore be avoided.

Where this type of attachment cannot be removed or changed, an in-service inspection program should be adopted.

The recommendation was made that all weld attachment geometries that do not form crevices, but are welded to or form a part of the primary pressure boundary, should be inspected by an inspection program.

I might just mention the fact that this is related to the fact that in the Duane Arnold case, the area that cracked, the weld area that's cracked, was not considered to be a pressure boundary weld, because it was just essentially a fillet weld on the inner surface of the pipe, and therefore it was not therefore subject to the "in-service inspection program."

So the study group recommended that the look at areas like this.

(Slide.)

Going back now to the major conclusions of the Pipe Crack Study Group, the conclusions and recommendations reported in the earlier Pipe Crack Study Group report, and the implementing document, NUREG-0313 are valid.

The piping design code does not consider environmentally influenced phenomena such as intergranular stress corrosion cracking. The treatment of both operating and residual stresses is not appropriate for predicting intergranular stress corrosion cracking, and therefore will have to take steps beyond the normal piping design to stay away from this type of cracking.

Techniques have been identified to reduce the potential for intergranular stress corrosion cracking in type 304 stainless steel welds. That is, using the same material that is susceptible to stress corrosion cracking.

There are approaches that can be used to reduce the potential. First of course is the obvious metallurgical solution, to give it a heat solution treatment -- meaning that the material will not be sensitized, and therefore won't be subject to the problem.

Another approach is to put a corrosion resistant cladding on the inside of the pipe at the weld area in which this cladding, which will be essentially a weld deposit, is

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not subject to the intergranular stress corrosion cracking, and therefore the material exposed to the reactor coolant will not crack.

Another approach is called "heat sink welding." This is a procedure that uses a heat sink to reduce the effect of the welding heat in reducing the sensitization. That is, the route pass will be made, and then the pipe will be filled with water, or the water will be sprayed on the inside while the remaining weld passes are made. Thus, significantly reducing the heat input.

Another one sort of related to that is to use tighter welding specifications. This will certainly reduce the potential, but is a lot less certain. You can have rather tigh- specifications, but it's not followed; or if you have to do repairs, it would not be too certain.

Another thing that has been found is that severe grinding on the inside of the pipe at the weld area seems to accelerate the cracking. So it's been found that limiting the amount of grinding, or limiting grinding altogether, would be a help.

(Slide.)

Going on with the major conclusions, the suscepti.ility or nonsusceptibility of say welded type 304 stainless steel can be determined by the electro chemical potentio kinetic reactivation technique. It's a new method that's a sophisticated method of determining whether or not the material is sensitized. It's quick and easy to use. It's been developed by General Electric under contract with our Research Division.

One of the methods that was developed primarily in Japan was to improve the residual stress pattern on the inside of pipe welds where the high residual stresses contribute a great deal to the susceptibility to cracking, by using a method wherein you heat the outside of the piping by induction heating quickly, and then cool it off, and this, because of the high thermal gradients that they put in here, changes the residual stress pattern so that you have compressive stress on the inside, and of course tensile stresses on the outside.

But you do end up with beneficial compressive residual stresses on the inside of pipes, and this approach is considered very useable by the Japanese, and they have been using it.

It's being investigated very carefully in this country.

Another important point is that the control of oxygen in the primary coolants is apparently very desirable. There's been a lot of work going on on this. We can touch on that a little bit later.

DR. LAWROSKI: Is that practical in the BWR?

MR. HAZELTON: We think that it can be practicable in some cases, yes. It has been used to some extent, if only to de-aerate, to begin with. I don't know how much time I should spend on that, but there has been a great deal of work going on on that, and we have not concluded that it's the whole answer.

The general feeling is that it would be helpful, but that's about as far as we can say now.

MR. ETHERINGTON: Where is this control effective?

MR. HAZELTON: I'm sorry?

MR. ETHERINGTON: Where is the oxygen control accomplished?

MR. HAZELTON: Primarily by de-aeration of the water to begin with, before it's heated up.

MR. ETHERINGTON: But the condenser gives pretty good de-aeration, doesn't it?

MR. HAZELTON: That's correct. One of the postulates is that the major problem may occur during startup of the plant after the plant has been down, and the bulk water has been aerated, then in going up to temperature into power it takes awhile for the oxygen level to get down to normal operating levels.

Some people have postulated that some of the major problems that had occurred during that time period, therefore, it has been suggested that de-aeration before startup may be useful.

MR. ETHERINGTON: I see, you mean once only, not continuous?

MR. HAZELTON: That's right. There are more sophisticated methods being looked at for on-line during power operation.

MR. ETHERINGTON: On-line you shouldn't have much trouble.

MR. HAZELTON: There's still a lot of controversy in this area. Staff is following it pretty closely.

One of the more important subjects here has been of course the ability to bind cracks by ultrasonic examination. And as I said before, the study group concluded that the present code methods are not adequate and we'll have to use some better methods. That's an ongoing program, but I'll talk about that a little later.

But it also concluded that methods that are being used now that are somewhat improved over the old methods will detect and evaluate cracks of significant size reliably.

Another major conclusion was that the General Electric Stress Rule, or Stress Rule Index, is a potentially useful tool in identifying those welds that are likely to be most susceptible to intergranular stress corrosion cracking, and therefore would permit in-service inspection to be focused on those welds and thereby reduce the probability that they'll have problems about detection.

The GE Stress Rule is an approach to determine the total stress in the weld joint, including the residual stresses, the applied stresses, and it seems to work very well.

(Slide.)

MR. ETHERINGTON: Is that some kind of a formula?

MR. HAZELTON: We can discuss that in detail later, if you want.

Some of the recommendations of the Pipe Crack Study Group include the future use of regular grades of type 304 and 316 stainless. That is, normal carbon grades should be avoided. And if these materials are used, steps should be taken to ensure that intergranular stress corrosion cracking cannot occur.

Some of the steps that I talked about, such as corrosion resistant cladding. The presence of oxygen should be minimized in BWRs.

Then specific procedures should be incorporated into the ASME Code to improve the ultrasonic detection and evaluation methods. And advanced nondestructive detection and evaluation methods now being developed should be actively pursued in investigations to determine the effect of actual BWR operating stress and thermal loading on intergranular stress corrosion cracking should be expanded.

Another significant recommendation is that, based on the Japanese experiences, augmented in-service inspection should be developed for recirculation riser piping in this country.

Okay, that's a very quick rundown of the Pipe Crack Study Group activities and report.

Now of course is the question: What are we going to do about it?

So now the staff has actions that are going on, and that will be augmented.

(Slide.)

I just want to touch briefly on this to put some of the Pipe Crack Study Group recommendations in perspective.

Task Action Plan A-42 has been initiated. The title is "Pipe Cracks in BWRs." And although the Task Action Plan has not formally been written yet, it's in the process of being written.

It appears that it will consist primarily of two major efforts. The first will be a revision or updating of NUREG-0313. That is, the staff implementation of the Study Group's recommendations. Then it will also hopefully prepare a set of recommended follow-on efforts.

(Slide.)

In the area of revision of the NUREG-0313, we see the following major tasks:

First, to redefine, if necessary, those materials and processes where control for intergranular stress corrosion cracking that are considered acceptable by the staff. These might vary somewhat, depending on whether we're talking about a new plant, or a plant under construction, or whether it's an operating plant.

We will have to consider, for example, whether this material that General Electric has developed and tested rather extensively that they call "Nuclear Grade 316" will be an acceptable material.

Nuclear Grade 316 has very low carbon, and it is strengthened with nitrogen to counteract the effect of the low carbon. And the tests have looked very good so far.

So the improvement in materials and processes that has been going on over the last three or four years will have to be evaluated by the staff, and we will have to determine which ones we will consider acceptable.

Then we'll have to redefine the required augmented in-service inspection in light of the latest information. This is sort of divided in three parts.

One, sometimes called "target lines." These are small lines that are normally stagnant, are just flowing part of the time, and are under extremely high stresses, such as the recirculation bypass lines, the core spray lines, and the control rod drive return lines.

Then in addition to those, NUREG-0313 speaks of other "service sensitive lines." That is, other lines that have experienced intergranular stress corrosion cracking. In this case, we're talking about residual heat removal lines, isolated condenser lines, reactor coolant cleanup lines, and as well as recirculation risers.

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We'll have to define this and define the augmented in-service inspection required.

Another task in the revision of NUREG-313 will be to reconsider the leak detection and leakage limits that have been specified in NUREG-313 in light of past experiences. Are these adequate? Should and can they be tightened up? And then we'd have to also recommend positive implementation methods. That is, in addition to stating what the staff position on these items is, we will have to determine how we're going to implement these positions.

Possible ways are through regulatory guides or through bulletins or, if necessary, I guess even through orders.

(Slide.)

We expect that the work under Task Action Plan A-42 will recommend certain staff follow-on efforts, and at the moment we see these as rather important ones. Again, one of the most important is to, in some manner, codify effective ultrasonic inspection methods. To that end, we have work in progress. The Office of Standards Development has been working on a regulatory guide and the Division of Systems Safety people and the engineering branch there has been doing some work preparing proposed code revisions that will consist of much more effective ultrasonic methods.

Another thing is to review all the information we have, evaluate it, and, as we see fit, implement water chemistry improvements. And these are, as we see, one of the most significant ones is whether we should require or how should we promote de-aeration, as I discussed before.

Another question that the staff still has is whether in all cases we'll have leak before a break. The work that the pipe crack study group did on this seemed to indicate that that was the case.

Professor Parris did a rather sophisticated study of this using his modulus concept and it looks pretty good. But we're not sure that what he did included all possible editions that we need to be concerned about. So the staff is evaluating this.

Another item that appears to be important is to determine whether the leak detection capability that we now have is adequate. Some of these are sort of inter-related, as you can see.

Then one of the more important things is to develop and implement a focused, augmented inspection program. That is, we just can't go out there and insist that all welds be inspected in every refueling outage. There just are not that many people. It just cannot be done.

Therefore, we want to come up with a program where we will have a realistic chance of inspecting those welds that are most likely to be cracked. And we have to take into

IMAGE EVALUATION TEST TARGET (MT-3)

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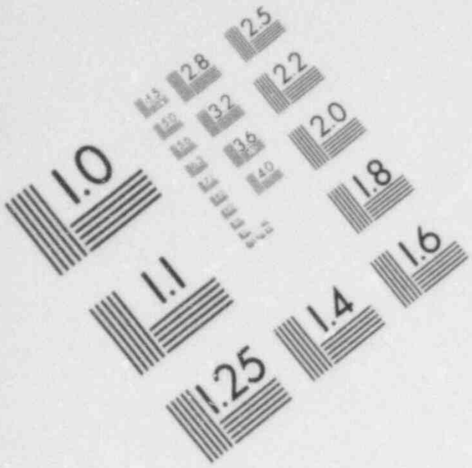

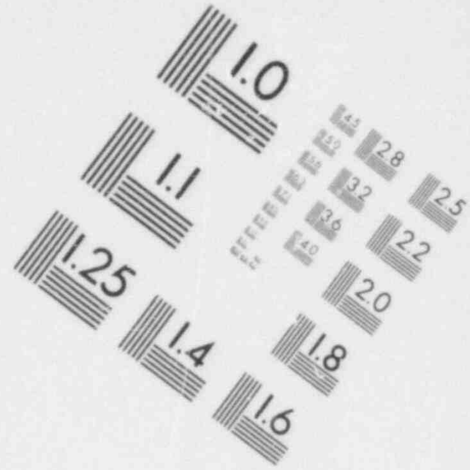

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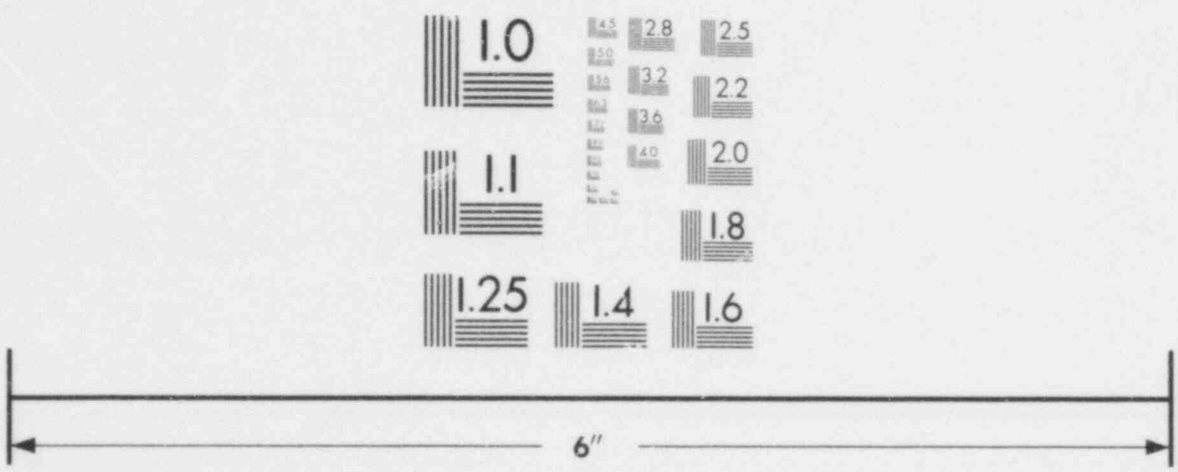

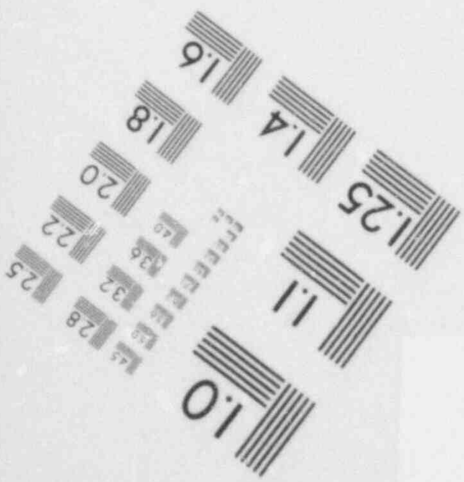

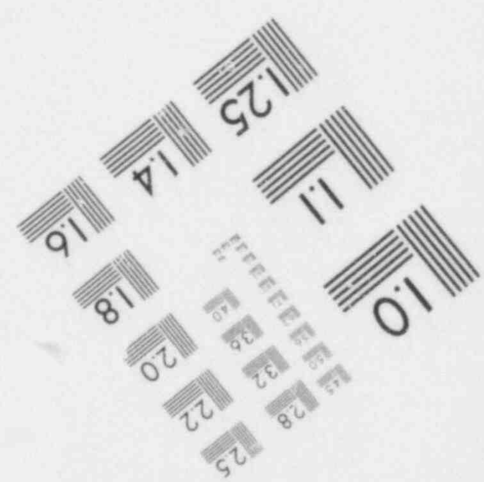

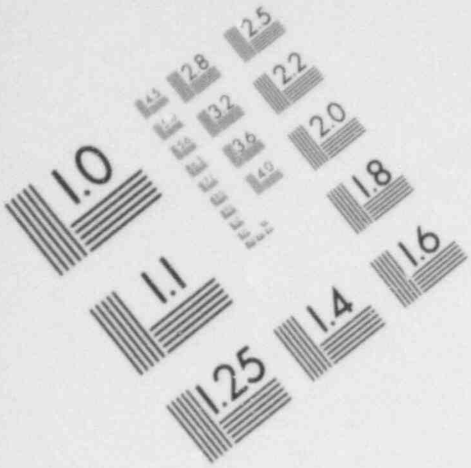

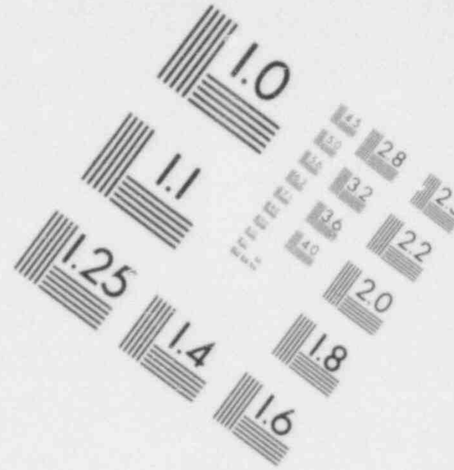

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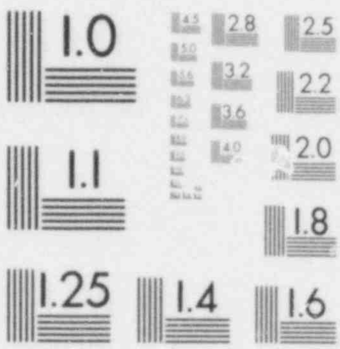

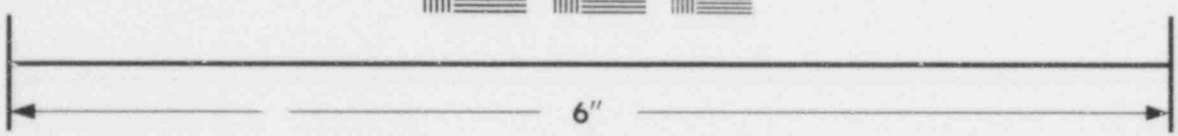

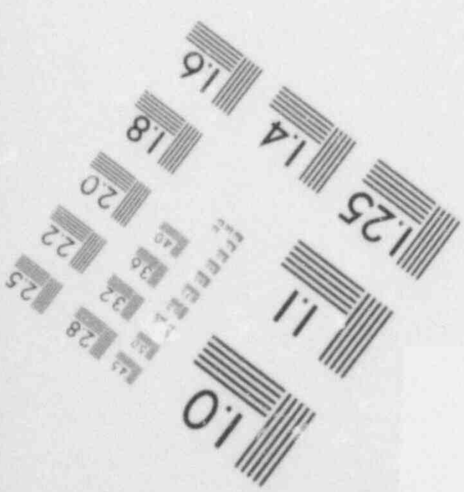

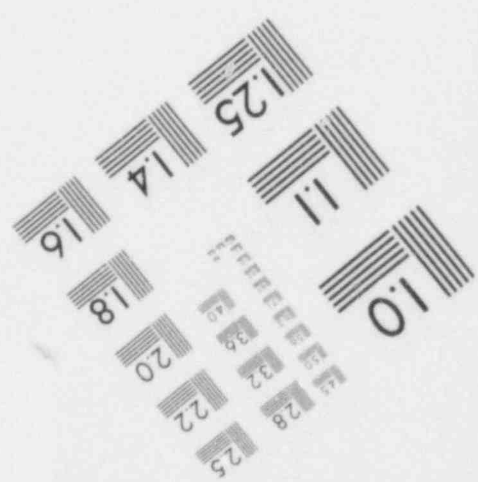

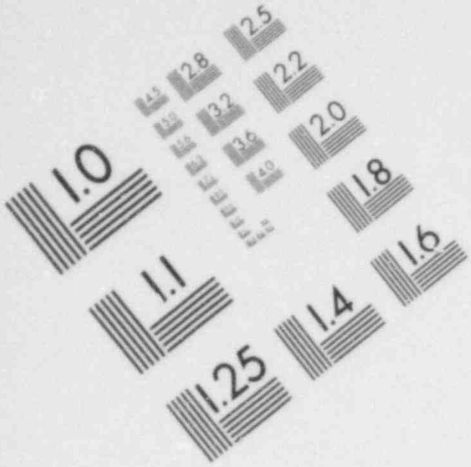

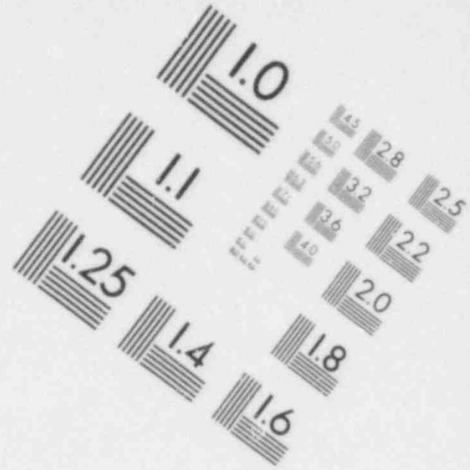

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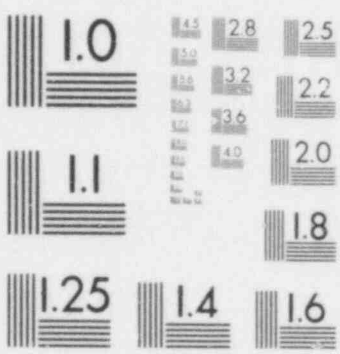

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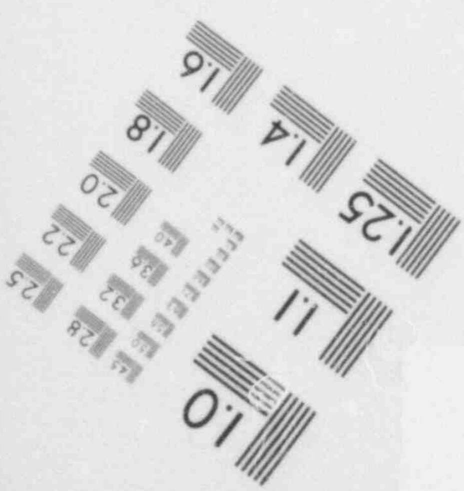

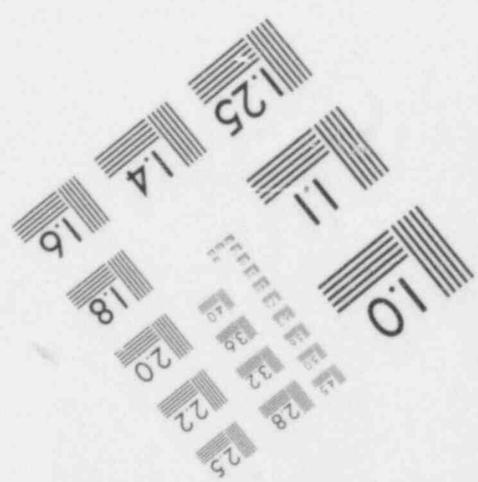

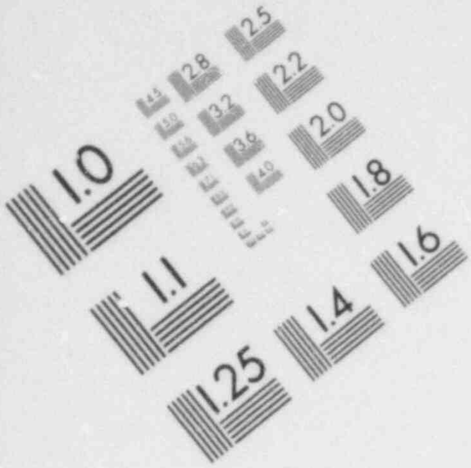

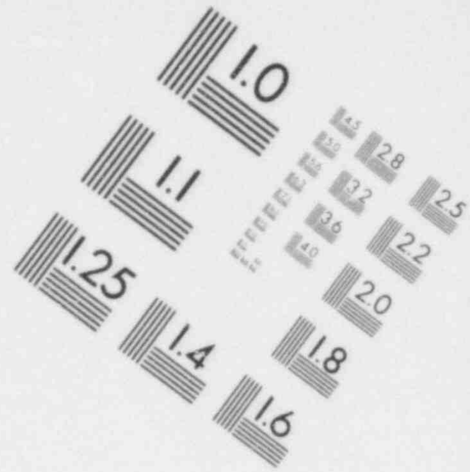

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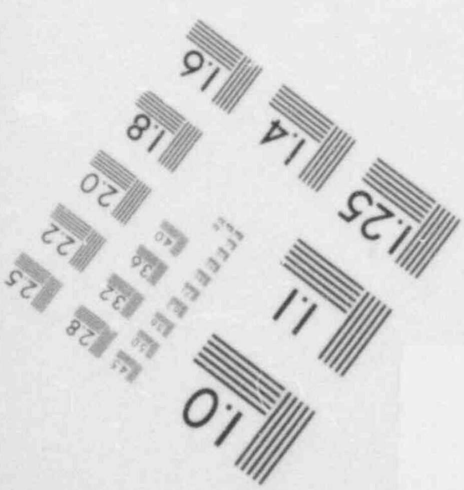

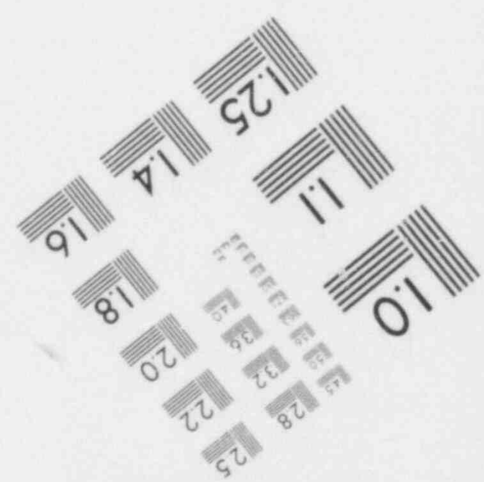

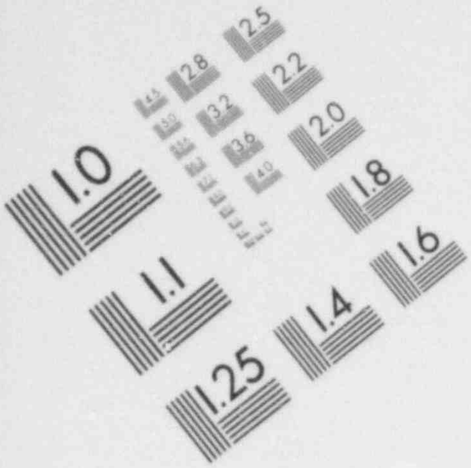

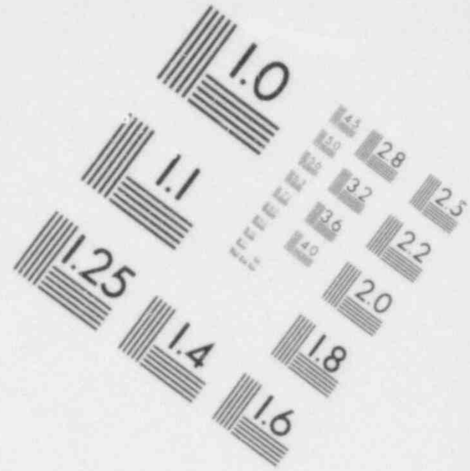

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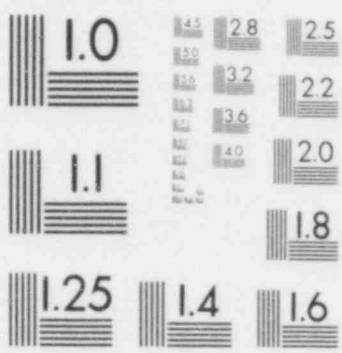

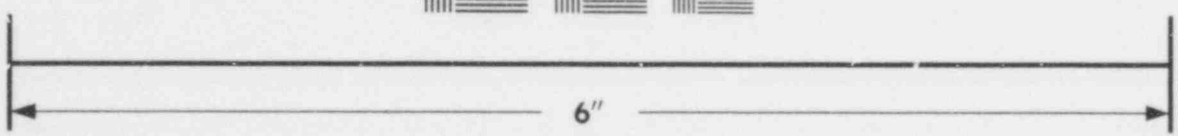

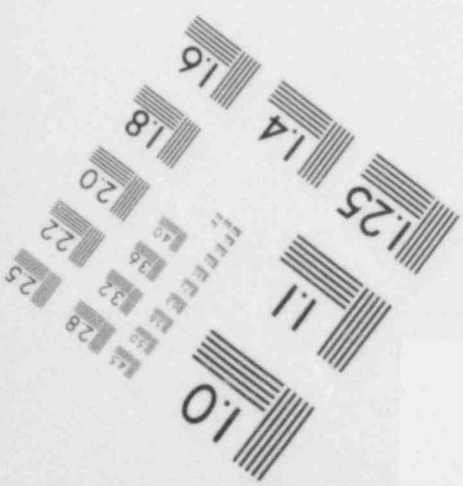

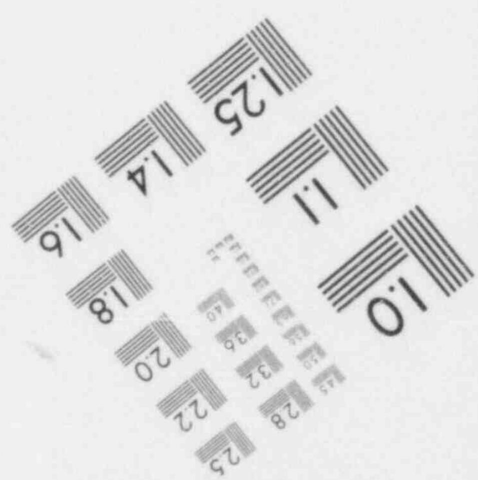

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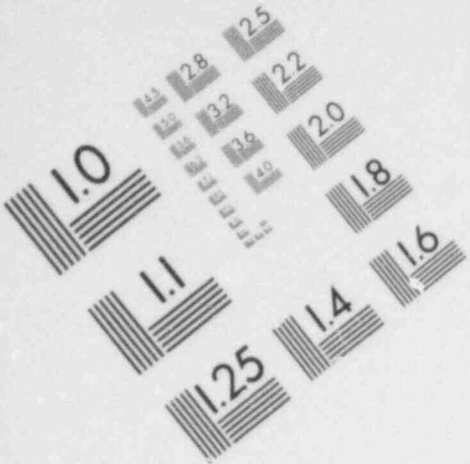

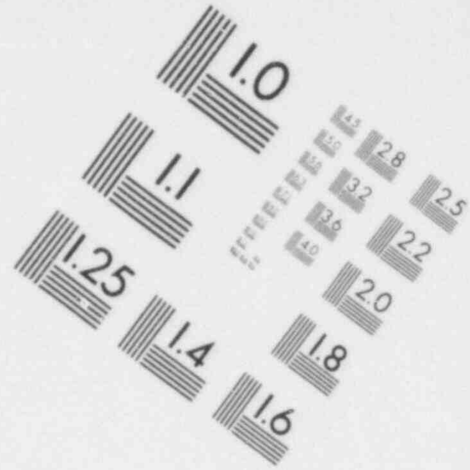

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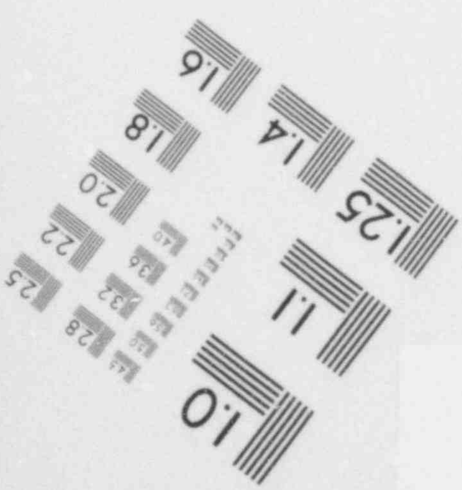

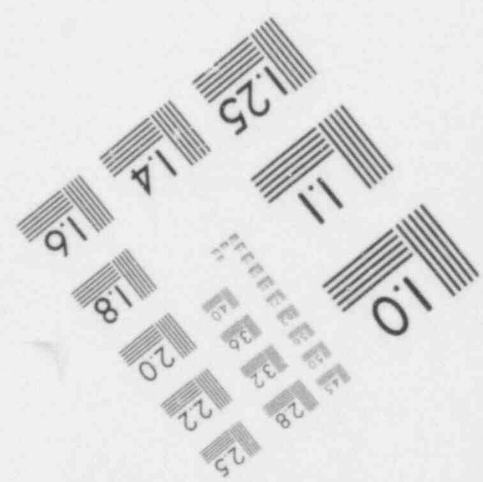

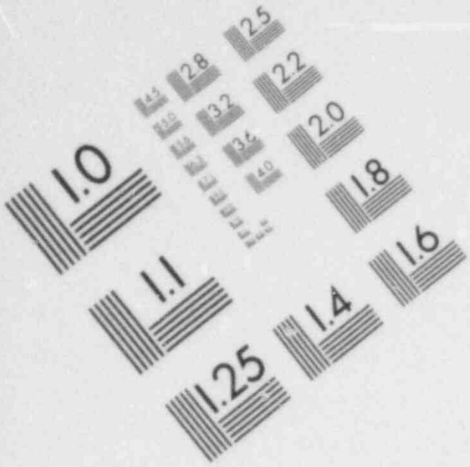

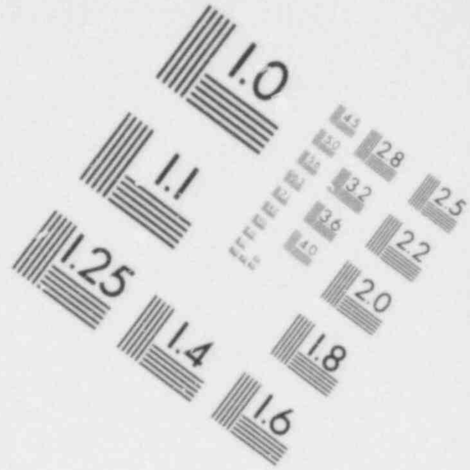

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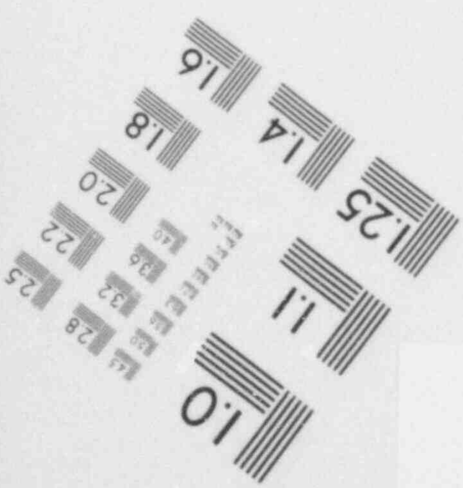

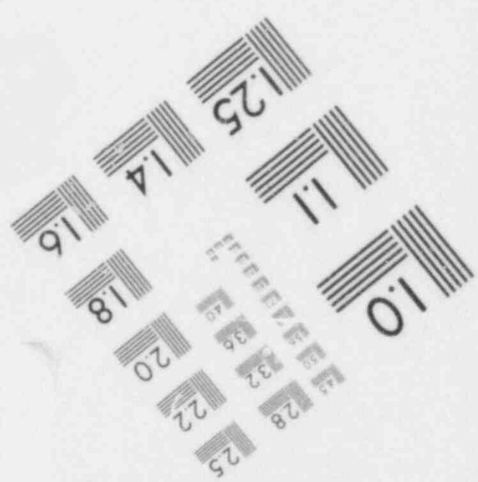

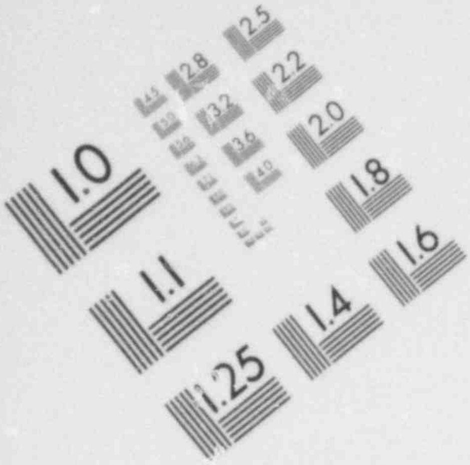

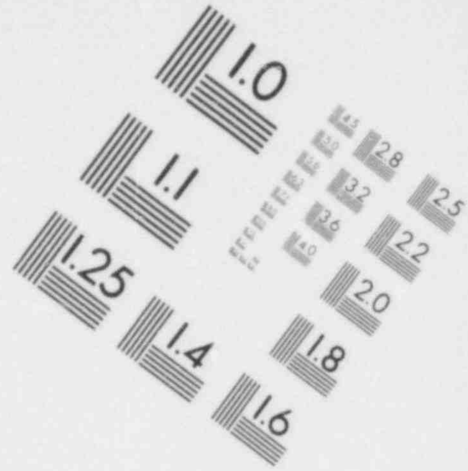

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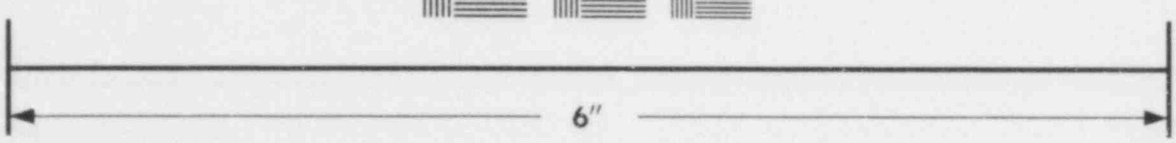

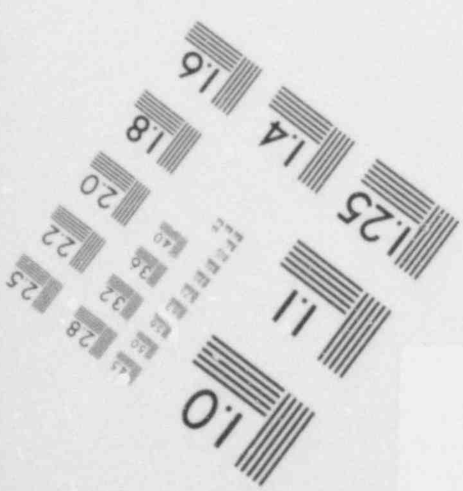

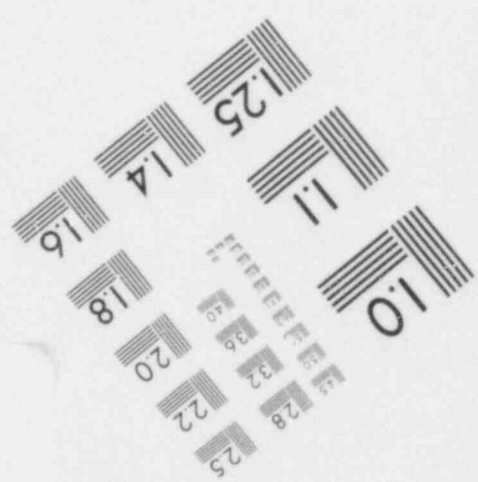

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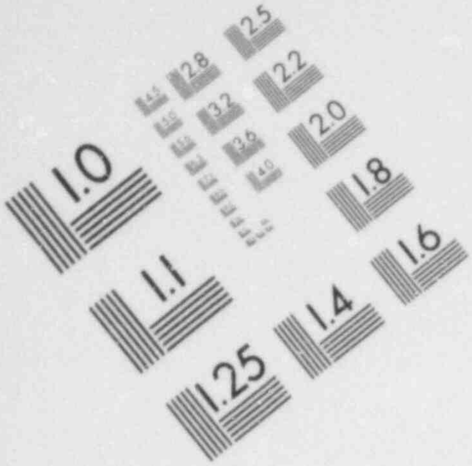

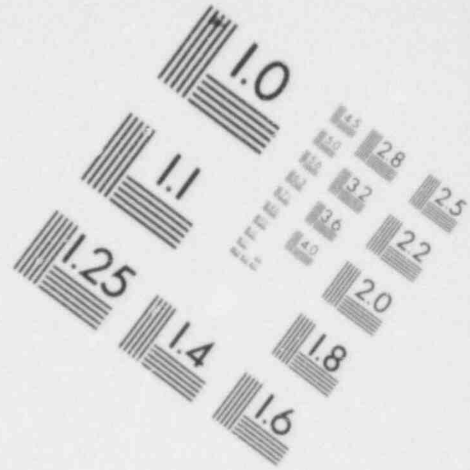

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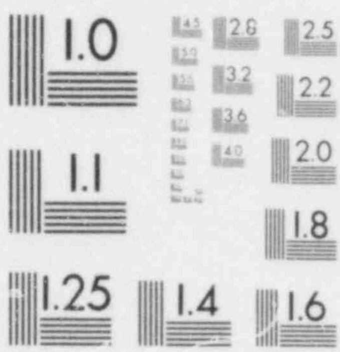

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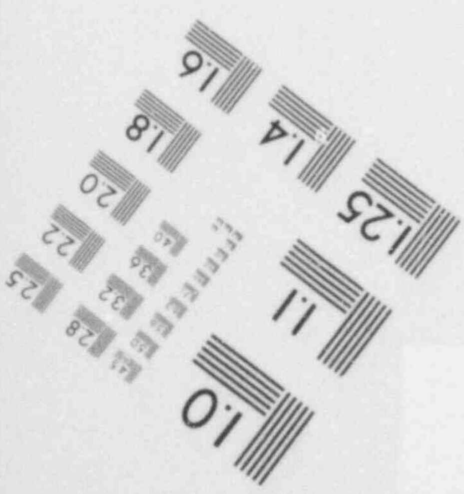

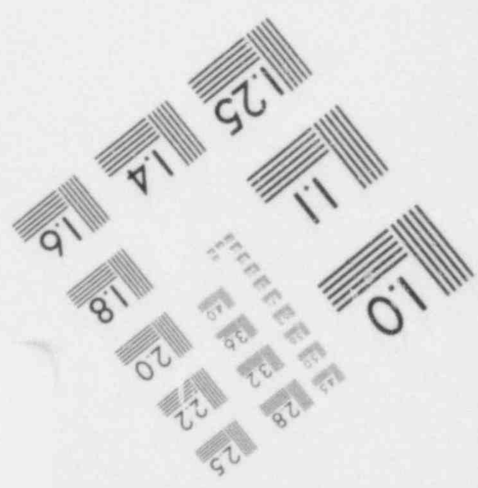

account such things as General Electric's stress rule index number for the welds, the material composition -- that's a typo; that's not "math composition" -- that is, determine its susceptibility to sensitization, as well as history of cracking in the particular lines. And we think that this is a very important program to do if we are to have a better chance to detect cracks before they leak and cause difficulties.

That's all I'd planned to say. Any questions?

DR. CARBON: Bill?

PROF. KERR: Has the staff made an estimate of the probability of cracks occurring in the various-size pipes?

MR. HAZELTON: Not specifically. The only thing that I can say that might pertain to that --

PROF. KERR: At various points in various slides, comments were made that the probabilities were very low or that there was a low probability of occurrence. I just wondered if efforts had been made.

MR. HAZELTON: Well --

(Slide.)

-- this is a slide that essentially was prepared by General Electric, in which -- it sort of highlights something about the frequency, the frequency of cracking in terms of the percentage of total welds. So with the exception --

PROF. KERR: I was thinking more in terms of the probability of a crack occurring in some interval of reactor life. It must be integrated over the life of the pipe or something.

MR. HAZELTON: Yes, I understand.

DR. SHAO: Warren, let me answer this question.

Prof. Kerr, we have not looked at the probability of pipe cracks. We have a research program where we're going to look at the probability of cracking, the probability of partial breaks and the probability of full breaks. And this program will be together with our BC program and the lobe combination. It will be another two years before we will get some results.

PROF. KERR: Do you plan to combine that with or at the same time have a look at the probability of leaks?

DR. SHAO: Yes. In this program we will address the probability of cracking, the partial break, which is a leak or it could be more than a leak, and also full breaking.

MR BENDER: Hal, do you have enough information about the piping that you have observed cracks in to know, in addition to the stresses, what its fabrication history is?

MR. HAZELTON: I think that we have enough information to make some rather shrewd guesses, yes. This has been a subject that General Electric and others have put a great deal of effort in. Yes, we can determine it.

MR. BENDER: Would that lead you to conclude that the Japanese approach of doing some kind of in-place stress relieving might really be advantageous? Or can you go that far?

MR. HAZLETON: I don't know. First you have to realize that the staff has not really taken a position on these items. If you asked me personally, I would think yes, I think the Japanese approach of improving the residual stresses would be very helpful. I have some reservations about how long you would continue to have the help. That is, the residual stresses may get wiped away and it's conceivable you may have to redo the process.

MR. BENDER: Once you get rid of them, you never get them back, do you? So you just eliminated that cause and effect. That's what I thought.

MR. HAZLETON: Yes.

MR. BENDER: I guess I don't understand the approach on the welds.

MR. HAZLETON: It isn't just the residual stresses that caused the problem. It's the combination.

DR. SHAO: The concept is very good. It's called induction heating. It's get rid of the tensile stress on the inside of the pipe by putting compressor stress through this induction heating. But there is some reservation. When they're putting the compression on the inside of the piping, they may overstress it.

They're still looking at this process, but the concept is very good, to try to get rid of the tensile stress on the inside which would initiate cra.king.

DR. CARBON: Ivan?

DR. CATTON: Is there any relationship between the piping systems that show an increased amount of cracking and hydraulic effects like water hammer? Some of those piping systems that you listed under the Japanese study look like ones that have problems.

MR. HAZELTON: We've tried to get the story on that, o- :he water hammer, and we've had contradictory information.

Larry, you were over there.

DR. SHAO: Water hammer is merely a substitute . heat cracking, though, this inter-granular corrosion cracking.

PROF. KERR: In evaluating the risk and I guess in deciding whether you do more, you must have done at least informal evalua..on. Do you plan to, or have you thought about, looking at the simultaneous probability of the . r-rence of a crack and additional stress caused by something like water hammer which might lead to break before leak or leak before break?

MR. HAZELTON: I see that as part of a staff effort in evaluating the significance of the cracks regarding leak before break. We have to take some of those simultaneous events into consideration, yes.

DR. SHAO: Chapter 9 of this pipe crack study group partially addressed this question. What they do is assume a pipe of 28-inches diameter with a 100 degree segment of so-called "through-wall cracking," and then 260 degrees with three-quarter inch, and they put a movement caused by an earthquake and see whether the pipe is stable or not.

The results show that so long as the pipe radius ratio is less than 300, it's stable. Usually the common dimension for this kind of line is usually around 20.

PROF. KERR: So independently of the size of the earthquake, if you stay within those limits you will always leak before break?

DR. SHAO: Right. That's what the analysis showed. Hopefully, I would like to see some results with the so-called "degraded pipe," and put on some kind of loading to see how it behaves.

MR. HAZELTON: I touched on that briefly.

MR. BENDER: Hadn't we done something like that years ago?

DR. SHAO: Not really on the degraded pipe.

MR. BENDER: They put cracks in the pipe. They may not have put the right kind.

DR. SHAO: It wasn't cracking, but I'm thinking of putting a larger crack. They have put some small cracks, yes.

MR. BENDER: Yes. Okay.

PROF. KERR: Is there an effort to try to assess the probability of a meaningful crack that might not be detected? There were exhortations to develop that with ultrasonic methods. I couldn't tell whether these were just exhortations, or whether something existed which might improve the technique appreciably.

MR. HAZELTON: There are vastly improved techniques now being used, but they are not required by the code. In addition to those that are sort of improvements in conventional ultrasonic methods, there are much more advanced methods using adaptive learning networks and things of that kind that we see coming on in the next several years, again to improve the detectibility very much.

PROF. KERR: Is there some likelihood that these will be specified by the code in the foreseeable future?

MR. HAZELTON: Yes, sir. That's one of the major follow-on efforts that the staff is working on right now.

DR. SHAO: The staff already talked to the committee to show them that the present code is not adequate, and we are asking for revision.

MR. HAZELTON: In this particular case, we're not having a big argument with the code. The people involved realize that the code is very deficient. So we have prepared sort of a proposed revision to the code that's in the code's hands, and they're discussing it. And in addition, we're working on a Regulatory Guide that will accomplish the s kind of thing.

So this is not something way in the future. We have been doing this all along, and we're talking about hopefully near-term within a year that we'll have this done.

MR. BENDER: How would you find Duane Arnold's type cracks with present nondestructive examination methods?

MR. HAZELTON: The Duane Arnold cracks were found by ultrasonic examination. They were found by what we call currently used improved methods. They weren't found by code. We have to differentiate. I don't know whether we're back -- Are we back to that confusing situation?

They were not originally reported. They said they were reported as no indication. That's because they were reported according to the code.

DR. SHAO: According to Section 11 they are not reportable, but according to our latest criteria which the staff is proposing, they are reportable. You see, they are using a different level base. Twenty years ago you'd use a higher base, and the new proposed code uses a lower base.

With the lower base, these cracks are reportable indications.

DR. CARBON: Steve?

DR. LAWROSKI: Is there a threshold value for the oxygen concentration below which you don't get corrosion?

MR. HAZELTON: I don't think we know, yet. Some of the work that's been going on indicates that the threshold value -- or, to put it another way, the most harmful value, depends on the temperature. Okay?

And this, there is work going on --

DR. LAWROSKI: But the temperature is pretty well set, isn't it?

MR. HAZELTON: Except during startup. I don't know that anybody has really defined a lower limit.

DR. SHAO: To give you some numbers, for the PWR reactors they're a process level of about 100 to 300 parts per billion, but BWR only 5 parts per billion. There's a tremendous difference.

DR. CARBON: If there are no further urgent questions, let's move on to the next topic.

Does that pretty much take care of that one, Warren? Are you presenting the next one?

e-15

MR. NOONAN: Good afternoon, gentlemen.

My name is Vince Noonan. I am Chief of the Engineering Branch of the Division of Operating Reactors.

I am here to address four questions that were submitted to Mr. Stohl in the June 6th letters by Mr. Libarkin.

I guess, at the committee's preference, we have a number of people here from the Office of Inspection and Enforcement: Mr. Ed Jordan, the Assistant Director; Mr. Joe Collins, from the Washington office; and also Mr. Cordell Williams, who was directly involved in the allegations at the Duane Arnold facility.

If you would like, we could start out with a summary of those allegations. Then I could proceed into the method by which we at the NRR resolved the problem with the welds, or we could go directly into the welds, I guess, depending on the committee's preference.

DR. PLESSET (Presiding): What's the pleasure of the committee?

Do they want a brief resume?

MR. BENDER: I think we need it, Mr. Chairman.

DR. PLESSET: If you can make it brief.

MR. NOONAN: Okay.

Cordell, would you care to come up here, please?

MR. WILLIAMS: As Mr. Noonan has indicated, I am Cordell Williams, one of the inspectors from Region 3 who is intimately involved in the resolution and investigation associated with the allegations.

Principally, we had two series of allegations. One involved alleged nonconformance in terms of welder qualificatio documentation control. There were instances wherein it could not be established clearly, from the written record, what the status of a welder's qualification had been.

Our investigation demonstrated that in each of those instances adequate related documentation resolved any serious problem -- that is, we found no circumstances where a welder actually had failed to meet the qualification requirements of ASME, Section 9.

Now, associated with the repairs was an additional requirement that any welder involved in this work demonstrate his proficiency in a simulated restricted environment. The recirculation inlet piping in some instances is bounded by supports and other equipment, to the extent that a welder had only about 15 or 16 inches of clearance to do his work.

This additional requirement placed upon him required that he weld at least 18 inches of a similar joint configuration in that environment.

In many instances the record was not clear as to his having accomplished that.

The second major category of allegations involved misinterpretations -- alleged misinterpretations -- of radiographic film quality, involving two of the wells, 2 and 6. In this instance, three of the contracted agents -- I'm sorry, three of the radiographic inspectors who were contracted by the Licensee alleged that they had perviously rejected radiographs during their end-process accumulation data, and ultimately had found that the Licensce, in his further considerations, had accepted those radiographs.

These allegations involved, again, welds 2 and 6. In this instance, two inspectors from Region 3 reviewed the subject radiography after the fact of acceptance by the Licensee and concluded that in several instances the welds did not, in our best judgment, meet the requirements of the code, ASME, Section 3, paragraph NB4424.

Faced with this finding, I&E headquarters dispatched a consultant to the site. We had a Mr. Rostow, certified Level 3, ASNTC1A, and a Dr. Weiss, a metallurgist, review the welds, also.

In this instance, we arranged it so that those gentlemen could review the radiographs without having the benefit of the specificity of the allegation or having their judgments colored, if you will, by the interpretations that I and another gentleman in Region 3 had made.

Once they had finished their review, we compared our records. And while there are areas where we don't agree, there is substantial agreement between the consultant's interpretation of the rejectable conditions of certain of those welds and Region 3's interpretations and that of the alleger.

The Licensee has maintained -- he and his associated consultants, and other references -- that the radiographs, though having certain anomalies where are readily apparent, are not questionable to the extent that they should be rejectable.

These issues were not resolved; both of their interpretations are part of the record, and the matter was passed to Mr. Noonan for his resolution.

Are there any questions?

DR. PLESSET: I guess there are no --

MR. ETHERINGTON: Is this a functional case? Or is it clearcut?

Is there an understandable difference of opinion?

MR. WILLIAMS: It's an understandable difference of opinion. I don't, in terms of my interpretation, consider it to be marginal.

It is complex to the extent that each of the interpreters, including Mr. Collins, a member of the IE3 headquarters group, have seen and will acknowledge seeing the same sorts of things in the radiographs.

Where we differ is really in coming to the simple conclusion, is this indeed rejectable or is it not?

And here's what I mean by that. I recognize that it isn't clear. It's fairly complex. We all see oxidation. Oxidation is a phenomena that occurs through the root surface of a weld, and we see it very significantly. It's not a marginal indication. It's not something that one wonders about. It's very, very clear.

What we have not agreed upon is the simple conclusion as to its acceptability. It seems, by my reading, that it clearly is not in compliance with the ASME Section 3 -- and by theirs, quite to the contrary -- each of which have been presented to Mr. Noonan, and he's prepared, I suppose, to address that part.

MR. ETHERINGTON: I was really trying to get at whether it's a technical difference or whether it's an allegation of bad faith, or coverup, here.

MR. WILLIAMS: I understand your question to mean did indeed the three radiographers who made the allegations to us, NRC, share the same concerns that we had? And their management had seen the same thing and come to another conclusion?

No, it was not bad faith. There was no complicity. The fact that the interpretation had been changed is not unusual in the process of acquiring a radiograph.

MR. ETHERINGTON: Thank you.

DR. WIESS: It's not unusual for it to be changed, either direction.

MR. WILLIAMS: By my experiences, it is not unusual for it to changed either direction.

DR. CARBON (Presiding): Thank you, Mr. Williams.

MR. NOONAN: After the disagreement as to the interpretation of the code on the acceptability or rejectability of the welds, the problem was handed to NRR, and specifically my branch.

The first thing that we did to look at the problem was to take a look at all of the summary statements and summary reports made the Region 3 people and their consultant, and also Mr. Collins from I&E headquarters -- basically for our own purposes, to see what each person was saying about each weld.

In addition, we had a meeting here in Bethesda where Mr. Williams and Mr. Keye brought the radiographs down with Mr. Collins, showed by staff -- which was Mr. Hazleton, Mr. Johnson, and Mr. John Fear -- just what each radiograph meant and what their interpretations of each radiograph was.

So, effectively my staff could see, when they said there was oxidation, what that looked like and look at any disagreements that might have been made as far as the acceptability or rejectability of these welds.

Very briefly, to talk about what welds we're talking about --

(Slide.)

DR. SIESS: Excuse me.

A question -- do any of your staff have independent expertise in X-ray interpretation? Are they qualified?

MR. NOONAN: I do not, and my Stress staff does not. But Mr. Hazleton has looked at a number of radiographs in his career, and I think he can speak to that.

DR. SIESS: Warren, could you qualify as an inspector under the code?

MR. HAZLETON: I would say, categorically, I am not a qualified inspector.

DR. SIESS: Could you if you wanted to be?

MR. HAZLETON: I think so.

Most of my experience in radiography was in the aircraft business, and I haven't been involved in code standards and things of that nature personally.

MR. NOONAN: The two welds in question -- is weld number 2, indicated on this graph here, and weld number 6 -- these were two welds; both involved a pressure boundary.

My particular staff decided not to address the question of acceptability of the welds for codes, but look at problem, given what we knew about the condition of the welds: Are the welds safe from a standpoint of stresses? And the postulated load, both normal and faulty load conditions on these welds, given those conditions.

jl 8

The staff basically made a summary chart of the types of indications --

(Slide.)

MR. NOONAN: -- that were reviewed on the radiographs, and these are basically schematic sketches.

But to give you the type of indications we're talking about in terms of the wal' thickness, radius, and about the depth of the potential defect in the welds -- if that's the proper word to use -- as you can see, the indication here indicated about 10 percent overall, and resulted in the highest stress concentration factor of 4.

That particular type of indication was used in our analysis, and we evaluated the safety of the safe end, using this type of given indication in that weld.

MR. ETHERINGTON: Those are not the scale, are they?

MR. NOONAN: These are not the scale. These are strictly schematics. This was drawn first; in almost all cases they are larger than 10 percent. There are some only 2 percent wall thickness, and some 5 percent wall thickness.

The one that we worked with, the 10 percent one, cut-shaped indication, the 10 percent thickness with a stress concentration exactly of 4. We had very similar type of indications on the other weld, number 2.

(Slide.)

Again, this is a schematic, and again we evaluated it, considering the worst-case type of indication: and this is the point, 096, and again with a stress concentration factor of 4. Our evaluation was made on that basis.

In all cases, the safety was shown to meet the current FSAR allowables.

So we handled it on that basis, and we did not try to get involved in the discussions as to the acceptability or rejectability of a weld.

DR. SIESS: Is that a legal procedure under the code, this component?

As I recall, for vessel piping, if you have an unacceptable defect, you can make a stress analysis an a fracture mechanics analysis, or at least under the regulations, if not under the code.

Is that the same procedure?

MR. NOONAN: I guess I am not positive.

Can any of my staff answer that question?

Warren, can you?

We passed this through our Legal Department, and I am not qualified, really.

DR. SIESS: Am I right, for the vessel and piping, the code permits you to do a fracture mechanics? The regulations do.

The NRC regulations permit you -- okay, it's not a question of code.

jl 10

DR. CHAN: C. Y. Chan of DOR.

This is a repair, and you find some indication there. The indication he's talking about -- they're within the code allowable. They have not exceeded the code allowables.

DR. SIESS: Thank you.

DR. CARBON: Mr. Noonan, try and wind up quickly if you can. We're falling farther and farther behind.

MR. JORDAN: Could we clarify something here?

The authorized code inspector for that facility, from the standpoint of legality for th site, they satisfied the code. It was the inspection process, and it was the allegation on the part of the employees for one of the inspection agencies who questioned whether or not it had been legal.

MR. NOONAN: The second question that was asked by the committee was a number of defects were noted in the welds, and to what extent could any of them be characterized as drop-throughs or undercuts, and at a size large enough to cause concern from stress concentration?

I think this viewgraph would answer that question.

Basically, like I said, we used what we considered to be the worst case indication, which had a stress concentration of 4, in all our stress analyses.

The third question asked by the committee was the thermal sleeve was redesigned to eliminate or minimize the crevices and residual stresses due to sleeve attachment.

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However, other welds -- number 2 staff s SER Figure 1 -- will generate residual stresses. Has the thermal sleeve annulus been large enough to prevent reoccurrence of intergranular stress corrosion cracking?

(Slide.)

To answer that question, I guess what I'd like to show is a copy of the new redesigned version. And maybe I'll back up very briefly, if I could, to show you a copy of the old version first.

(Slide.)

This being the old design, where we had the cre .ce, and where the crack initiation point started.

This is a very tighet crevice here. In fact, it was initiated in this area.

The new design has been enlarged sufficiently to allow a flow of water. The tests conducted by General Electric indicated that there would be a washing in this area at least once every 12 hours.

We're not saying, in any case, that we'll prevent stress corrosion cracking. But we are saying that we think the welds are safe from the stress standpoint, and we have initiated an augmented ISI inspection program. Using the current techniques as described by Mr. Hazleton, we did a complete baseline UT of all of these welds; and we are now in the augmented portion.

The plant is required to look at four out of the eight points at every outage.

The last question asked by the committee was: Lead concentrations within the primary system were addressed and found to be acceptably low; to what extent was that addressed when reviewing the lead contamination?

To answer that question, all pieces of the lead were found. There was one piece of lead that we could not find for awhile, but that was found in the bottom of the vessel.

Inspection by General Electric and photographs taken by them indicated in the riser pipe, where most of the lead was concentrated, there was some slight smearing of about 1/10,000th of an inch indication.

In the lower part of the vessel, where the last piece was found, the lead was found, but there was no indication of smearing.

Start-up procedures were initiated on Duane Arnold, and the procedures were such that we would melt away this lead, and it would be taken out of the cleanup system before the reactor went to full power.

That was part of the SER evaluation.

Gentlemen, that's the end of my presentation if there are no further questions.

DR. CARBON: Fine.

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Thank you.

MR. JORDAN: I'm Ed Jordan, Assistant Director for the Technical Programs Office of the Office of Inspection and Enforcement.

Forgive my hoarse voice. It's getting better.

I came here to report on D. C. Cook. We have information from at least one other plant at this point that we'll also discuss very briefly.

The subject cracking and carbon steel pipes this time, and these are in the feedwater lines to Westinghouse pressurized water reactors.

On May the 19th of this year, Unit 2 of D. C. Cook shut down because of unidentified leakage of 3 gpm.

Inspection of the source of that leakage revealed that they had through-wall, circumferential cracks in two of their feedwater lines near the nozzle to the pipe welds.

Nondestructive testing of other Unit 2 nozzles identified cracking in those nozzles also. Unit 1 was in refueling outage at this particular time. They examined those feedwater nozzles and found that all four nozzles on Unit 1 also had cracks. These were examined by UT and by RT.

So we had obviously, for that plant at least, a generic problem. Unit 1 operating something four years, and Unit 2 only one year.

I'll give you a brief description of the piping that we're talking about.

(Slide.)

The D. C. Cook plant is an ice condensor plant, so it has a relatively crowded area around the steam generators. They're in a shielded enclosure, so that the pipes out of the steam generator -- assorted feedwater pipes into the steam generator turn immediately downward, which is the first difference between that plant and the non-ice condensor plant.

The elbow is a 16-inch elbow with Schedule 80. There's a transition immediately below it, to a 14-inch pipe. The elbow is Schedule 80; the nozzle itself is Schedule 60. There's a blend between the elbow and the nozzle itself.

(Slide.)

The blend -- this is, I guess, ideal insofar as the design from the inspections at the side. The blend is somewhat irregular. There is in every case, I believe, an angle there -- these, all except for one connection, I believe, are backing ring installations.

This is the nozzle side. That's the elbow side.

We'll come back to that slide.

(Slide.)

This is to give you an idea of the extent of the cracking. After cutting one of the elbows away, or in fact all of them, and looking back from the opposite side of the weld and back into the elbow, they did UT testing, first of all, and they saw this kind of a profile, cracking.

And consistently, in eight out of eight of the nozzles, the cracking was in the upper quadrant -- that is, the greatest extent of cracking that was seen.

And as I said, two of the nozzles had cracks that were through-wall -- these were both in the upper quadrant.

There was evidence of cracking sporadically,in the same line,around the pipe.

I'll go back to the other figure and show you where on the pipe -- where on the picture it was occurring.

The cracks were, in each case, at this particular area -- they were progressing practically normally in this fashion.

There were also cracks of much lesser magnitude found all along the surface of both the elbow and in the nozzle. Those -- the nozzle had been satisfactorily ground. There was evidence of corrosion pitting, and the cracks were originating circumferentially in the pits.

DR. LAWROSKI: What did you say about the Unit 1?

MR. JORDAN. Unit 1 had the same thing, to a lesser extent -- no through wall, but all rejectable. There were definitely cracks.

DR. LAWROSKI: Had it showed this before?

MR. JORDAN: No. And now is a good time to point it out. This is all Class 2 piping. It's examined --

radiographed at installation. It's not subject pre:ently to a periodic, in-service inspection.

DR. SIESS: Was this intergranular cracking?

MR. JORDAN: This is transgranular.

I'll give you a quickie shot of what the piping run looked like.

(Slide.)

This is coming out of the steam generator. The elbow that we were talking about -- the reducer, 16 to 14; and then there's a 27-foot, vertical run; another elbow, and an average of, I think, five or six feet to the first snubber, and then the restraint.

The system is essentiall; under restraint up to this point.

Then there are subsequent restraints and snubbers in the system.

We did examine these welds, in a fashion, based on the problem here. And we found no evidence of problems with those welds.

R. SIESS: Why would you have a pipe run with a 16- to 14-inch transition?

MR. JORDAN: Why would you do what, sir?

DR. SIESS: Why would you go from 16 to 14 inches on a pipe run? It just seems trivial.

MR JORDAN: I don't know, in this case, why it was done.

DR. SIESS: Is it a flow question, that you want to do that?

MR. JORDAN: That was a design consideration, and I'm sorry, I don't know.

It's just a strange looking --

DR. SIESS: It's just a strange-looking design.

If you put 16-inch nozzles on a 14-inch pipe, --

MR. HAZLETON: I might add a little light to that.

Essentially, Westinghouse designs the steam generator; and if they put a big enough nozzle on, then they, of course, specify the flow parameters. Then the architect-engineer, or someone else, designs the rest of the system to induce those flow parameters.

They might have decided that they needed a smaller pipe than Westinghouse allowed them.

DR. SIESS: My worst fears are confirmed -- designed by a committee.

(Laughter.)

DR. CARBON: Go ahead, Ed.

DR. SIESS: What's more, a committee that can't agree.

MR. JORDAN: The A&E is responsible beyond this. The A&E in this case is American Electric Power.

DR. CARBON: Go on with your presentation.

(Slide.)

MR. JORDAN: The repairs that the Licensee -- I'm sorry, that's just another figure, reversed, showing where the cracks were found in the examination.

(Slide.)

Okay. The repairs that the Licensee is making in this case include replacing the elbow -- it's an identical elbow; making a new preparation, so that the surface finish is improved and so that they've radiused this machine to dimension with a half-inch radius, rather than a break.

They've also built up the wall thickness in this region; and they've made a blend weld, rather than a backing in. And they have ground and cleaned up the interior surface of the nozzle.

MR. BENDER: To conclude from that, that they think that stress concentrations are the real cause of the problem?

MR. JORDAN: Okay.

Quite honestly, the real cause of the problem is not identified at this point. Metallurgy says -- and I'll put in in quotes -- that it's "fatigue-assisted corrosion."

MR. BENDER: That's what we used to say when we were saying "stress corrosion."

DR. SIESS: This happens to be "fatigue."

MR. BENDER: I understand, because carbon steel can't undergo stress corrosion.

(Laughter.)

DR. SIESS: What code is this piping designed to?

MR. JORDAN: To Section 3.

DR. SIESS: This is Section 3; it's not primary system piping?

MR. JORDAN: No. This is secondary. This is all Class 2 piping.

MR. BENDER: B-31.

MR. JORDAN: B-31.

DR. SIESS: Okay.

MR. JORDAN: I beg your pardon.

So the Licensee and Westinghouse have done stress analyses, which do not clearly indicate that this material was overstressed.

Metallurgy does show some evidences of fatigue, and so the bottom line is to repair them here. And then a set of test instrumentation is being installed on Unit 2 piping on two steam generators, so that we have it fully instrumented with strain gauges, accelerometers, differential motion to characterize the fatigue aspect of it; and a commitment to reexamine, at a minimum, at the refueling outage, which is a couple of months.

So that's where that unit stands.

Before we go beyond that unit --

DR. LAWROSKI: Are you going to talk about where else this has been suspected?

MR. JORDAN: Yes.

DR. SIESS: I have one short question.

On one figure is says "Commercial Backing Ring" -- and three or four connections in Unit 2. What was in the fourth one?

MR. JORDAN: It was a buck weld.

DR. SIESS: This is optional under B-31, or can you do it either way you want?

MR. JORDAN: Yes.

MR. BENDER: Have you established that they really had the materials in there that they designed for?

MR. JORDAN: Yes.

Hardness and metallurgy says it was what was prescribed.

A generic letter was issued by NRR on May the 25th, which was requesting design fabrication inspection data from all operating pressurized water reactors and the results of this.

There was a request for answers within 20 days. Those are coming in now.

At the same time, I&E asked all of the pressurized water reactors which were shut down for refueling outages to physically examine repres‹.ıtative feedwater nozzles.

As a result of these two actions, San Onofre, which had shut down on June 2nd due to a steam generator tube leak, conducted inspections of similar piping; and they found indications of cracking.

We've gotten a preliminary report from them yesterday, and their cracking is of apparently a different character. That plant has been operating some 11 years. The cracking, in their case, is in the weld, which was of any significance.

The depth of the cracks there was some 90 mils in depth.

The Licensee has cut out the crack sections, and is in the process of replacing those sections without a design change.

So we have two related, but dissimilar, findings; and there the bottom line is, that this is stress-assisted corrosion.

We have the same metallurgical review by Westinghouse, giving different answers. Our metallurgists are looking over their shoulder, and at this point don't disagree with what the Licensee's representative is saying.

We are also having an independent consultant do the metallurgical work-up specimens that we received from both Licensees to verify those findings.

DR. LAWROSKI: Have any of them said that they have not found it?

MR. JORDAN: I kind of thought you'd ask that. Yes.

MR. BENDER: Was San Onofre also transgranular cracking?

MR. JORDAN: Yes, it was. It was branching and blunt and old, is our understanding. And it was primarily in the wold as far as the deeper cracking.

There was also cracking noted from corrosion pits in both pipe and nozzle on either side of it.

(Slide.)

These are the facilities which have thus far inspected, in addition to D. C. Cook. San Onofre is the facility that has cracks in their three nozzles.

We had a report that Zion had cracks when they did their inspection. They had an outage that involved feedwater, water hammer. And so we required them to inspect those nozzles at that time.

Their initial indication was that they had indications on the nozzles to review, with out inspector present, those radiographs of the reinspection against the regional construction radiographs, and subsequently with radiographs from D. C. Cook, and find that it appears that their construction indication is not cracking.

So that unit is being allowed to resume operations.

We have preliminary information that we received on H. B. Robinson that they have as suspicious indication on one nozzle, and we have a similar indication about Salem 1. So this is very preliminary information. The indications may be due to construction anomaly, or there may be additional cracking.

Surry, Turkey Point, Farley, Prairie Island, Kewaunee, Trojan -- all came out clean. The inspection there indicated that there was no change since the original construction, and there were no indications that were rejectable.

Obviously, this is an issue that we're extremely interested in. And we anticipate issuance of a bulletin requiring further inspections.

We have not, as you might guess, set the time frame within which those inspections will be required.

It will also depend on the additional review of metallurgy that our people are doing. Both Joe Collins, from our staff, and Warren Hazleton, from NRR, can give you more of the metallurgical side of this problem if you'd like to pursue that.

DR. LAWROSKI: You don't have one there -- did you put both Surry units down?

MR. JORDAN: They're the only ones that cut out the nozzles, replacing the steam generator.

DR. LAWROSKI: What did it show?

MR. JORDAN: Unfortunately, it cut through the section we'd like to look at.

MR. BENDER: All I'd say is that that's a typical story.

(Laughter.)

MR. JORDAN: They had done that cutting before the problem camd up. We're trying to see if there's anything to salvage, because that would certainly be important.

DR. CARBON: Any other questions?

(No response.)

DR. CARBON: Thank you, Ed.

I believe that ends tHat, and we're ready then for item 3.3.

Do you anticipate about an hour?

Let's just take a quick break of about 10 minutes.

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(Recess.)

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DR. PLESSET (Presiding): Mr. Russell, are you ready to proceed?

MR. RUSSELL: My name is Bill Russell. I am the NRC Task Coordinator for the review of the plants were shut down by the show cause order of March 13, 1979.

That order was related to a code analysis pro.lem for seismic analysis of piping systems. The specifics of the order addressed methodology of algebraic summation and intra-modal responses. And the code that was involved was a code called Shock 2, which was a proprietary code of the Stone & Webster engineering.

The order required the Licensee to show cause why he should not be required to reanalyze the piping system that was done using the code, Shock 2, originally; to show why he should not be required to modify the systems, as necessary, from that reanalysis; and to show cause why the unit should not be shut down while the reanalysis was proceeding.

A little background on the technical concern -- when you have a three-dimensional earthquake input, into a piping problem, each input develops three directions of responses, or three vectors, such that on a 3-D input you have nine vectors for each mode to combine.

The concern is how those co-linear responses, or the three resulting X responses, or three Y's, are combined.

In this case, methods which the staff has determined are acceptable are the square-root-sum-of-the-squares method of the absolute sum.

The algebraic method was used in the code, Shock 2. And our concern was that in using an algebraic method, without knowing the time sequence of the occurrence of the loading, because a spectral response analysis was done, loadings would actually cancel, such that you would potentially get a numerical result which would indicate you had no inertia or seismic loading, when in fact you had a significant load.

The safety concern, which we had, is that systems were affected, which could both cause an accident -- that is, the reactor coolant system pressure boundary, and systems were affected which would mitigate that accident.

Over the weekend of the 10th and 11th of March, we sent a review team to Stone & Webster, up in Boston, to review some results of analyses which were being done at that time from the Beaver Valley facility.

The stresses, or the analysis problems, which were originally done on Shock 2, were being reanalyzed at that time, and the loading conditions which were coming out were factors above the original loads -- in some cases, three to six times what the original analysis showed.

(Slide.)

We came back from that meeting. Over that weekend, the staff reviewed the information with the Commission; and it was decided that we should issue the orders to show cause.

The Licensees' response to these orders were that the plants were in fact shut down. No Licensee requested a hearing, and the Licensees proceeded with the analysis that was required by the order, and have proceeded with modifications to the facility.

I'm now going to take a quick jump in time, from March up to today.

(Slide.)

And indicate what's happened over the last three months.

The situation at Maine Yankee -- they had approximately 19 piping analyses which were done, using the computer code, Shock 2. Those analyses have been redone, and in no case did we find piping which was above the code allowable prescribed.

We did find two supports which required modification to account for base plate flexibility. Those modifications were made. The total analysis in the last submittals from the Licensee were submitted to the staff about the 2nd of May, and on May 24th an order was issued which allowed the units to resume operation, and cancelled the early show cause order.

The situation at Beaver Valley -- the piping reanalysis is complete. Three piping systems do require modification in order to get the piping stresses within code-allowable for the design basis earthquake condition.

Those modifications involve the installation of shock suppressors, one each on two lines, and piping reinforcements on the river water system, where the smaller branch lines tie in to a larger diameter line.

MR. BENDER: Excuse me, which code are you taling about?

MR. RUSSELL: The code we're talking about now is

B-31-1, the Power Piping Code. B-31-7 was not a requirement at the time these plants were licensed, so we are using the FSAR commitments and the basis by which the plants were orignally licensed, which in this case was B-31-1.

MR. BENDER: Does B-31-1 have in it requirements for seismic loadings?

MR. RUSSELL: It has requirements for load combinations and the requirement that you develop seismic loading conditions.

It does not specify how those conditions are calculated or how the results are obtained.

MR. BENDER: Thank you.

MR. RUSSELL: On Beaver Valley, there are 732 pipe supports associated with the 86 piping problems. These have been reviewed, and 97 are above code-allowable, are above their design capacity.

They are proposing at this time to modify 15 of those 97 and proposing that the others are acceptable for an interim period of time of about six to seven weeks, until they shut down for a refueling outage.

Until then, they'll be in a window, where they can refuel the core.

They're proposing arguments on a generic basis for the remaining 82. Such arguments include one-time loading on shock suppressors or snubbers, up to 100 percent overload, and then inspection subsequent to that.

We have some information from Grenelle, which says that is acceptable. These generic arguments are to be presented to the staff next week in a submittal on the 18th, at which time we will review it.

We have had discussions with the Licensee, and we're generally know!edge about what they're going to propose. We've not yet seen details of their submtittal.

The modifications that they are making to get the three piping analyses within code-allowable, and the modifications to the 15 supports, will be complete about July 6th, at which time the would propose to resume operation.

If they are able to continue their submittals to the staff, and satisfactorily respond to the staff questions, that would be a reasonable date for resumption of operation for an interim operation period of about six to seven weeks.

The situation on Fitzpatrick -- the piping analysis will be completed by July 1st, and the support analysis, in inaccessible areas inside the dry well, will also be completed by July 1st.

They will not have completed the support analysis outside the dry well.

That's the estimated date for completion of all support analysis -- is about the 1st of October. They hope to have those inside the dry well by July 1, at which time they will propose interim operation while the support analysis continues, based upon having completed the modifications inside the dry well.

That proposal has not yet formally been made to the staff, but they will also be providing bases as to why they feel the margins that exist in the supports outside the dry will are acceptable for an interim basis of operation for about two to three months.

The situation at Surry is a little bit different in that they are not quite as far along in the piping analyses, yet they are proposing the earliest resumption of operation to be 33 of the 69 piping problems which were originally done under Shock 2 have been completed, with the remainder to be complete by the 30th of June.

They have completed -- honored -- and 60 out of 887 support analyses, and have determined that only one requires modification. There are other minor modifications that they're making, which are related to as-built conditions and other minor deficiencies that they discovered in the process of walking the piping and verifying the reanalysis.

Those modifications will also be made, and they're expecting that the modifications will be completed by the 20th of June, at which time they will have complete the reanalysis of the reactor coolant pressure boundary and will have a technical basis for why they feel it's acceptable to resume operation.

The staff has that under review at this time.

MR. BENDER: Is this the only design error that has been found in these piping systems?

MR. RUSSELL: No, sir; it's not.

MR. BENDER: Is this one more serious than the others?

MR. RUSSELL: We briefed the Commission on the 30th of May and identified that one of the lessons we're learning from this effort is related to the as-built condition in the plants. We are finding that there are differences between the way the plant was designed, based upon the drawings of record, and the way the plant actually exists in the field.

This has been documented in Licensee event reports to us. It was the case that we had at Surry for some modifications. That's the case that we have at Fitzpatrick. That is the reason that Brunswick 1 and 2 were shut down approximately a week to 10 days ago.

It's also applicable to the situation that existed at Pilgrim when they shut down. The staff is looking into this generically. We will be taking action. The most probable vehicle would be a bulletin, and we are working on that on an expedited basis at this time.

MR. BENDER: You didn't find this out until this mistake was reported?

MR. RUSSELL: At the time -- way back on the 10th of March, when we first started getting the very high stress results, we were finding increases in loading of three, to six, to ten times allowable.

We thought -- and it was reported to us at that time -- that that difference was due to the algebraic summation method which was used in the code, Shock 2. That was the best information we had at that time.

Subsequently, we found out that the reanalysis that was done over that weekend was done doing preliminary design information, some construction drawings, and some information that was just not representative of actual conditions in-plant.

It was an as-built problem.

Subsequent to that time, these units have gone out, and they have inspected the hardware in the field, and we have verified that the reanalysis that they are doing is representative of the actual as-built condition.

We are finding that we don't orders of magnitude, or even factors of increase, above allowable stresses. In fact, it appears that the algebraic summation problem could be mounted by about a 50 percent increase in stress.

MR. BENDER: If the stress occurred simultaneously, if the earthquake-induced stresses were encouraged simultaneously with other stresses --

MR. RUSSELL: If you look at the load combinations that are required by B-31-1, say in the SSE case, where you take pressure plus dead load, plus seismic, plus your faulted load, that total load, if you look at the inertial loading only, which is calculated using a code which has algebraic sum, and then you recalculate with a code which does not use algebraic sum, what is experience is -- that we're not seeing more than about a 50 percent increase at the highest loading point.

The load locations move throughout the piping, such that the highest loading point may not be the same, but the highest load, as compared to allowable, doesn't look like we have more than about a 50 percent increase.

MR. BENDER: Does that say that it's not a severe load problem?

MR. RUSSELL: That's correct.

MR. BENDER: Then the question is why are the plants being shut down?

MR. RUSSELL: We have a combination of problems. We've discovered the as-built problem. The order specifically addressed the question of algebraic summation. We found that stresses were significantly above allowable. We are finding that piping is overstressed; we're finding that supports do need to be modified.

And the Licensees are in the process now of making technical arguments as to why it's acceptable to resume operation now that they have reanalyzed the condition which actually exists in the plant. Until this time, we have not had proposals from the Licensees to resumer operation. We're in the mode of reviewing their proposals in response to the show cause orders and resolving the problem technically.

MR. BENDER: Are these the only plants that are a question?

MR. RUSSELL: No, sir.

If we could hold that, I have another viewgraph that I could put on later, and I can address that.

MR. BENDER: Okay.

MR. RUSSELL: Thus far, the only point that I've addressed is the algebraic summation question, related to the code.

(Slide.)

On April 2nd, we issued a letter. We identified that there were some related areas which the staff felt it was necessary to evaluate.

We wanted to make sure that the codes which were being used, particularly in the case where the algebraic sum was used, that we have a code listing provided.

We wanted to perform code verification for the codes which were being used for reanalysis. This was a three-part verification.

We required that they provide the codes listing, such that we could review it and determine that it did not use algebraic summation and review it to determine it did not have other obvious errors.

We required that they perform benchmark problems, using their code, that they actually solve a cam problem; and we provided four problems to Stone & Webster. That bench-marking has been completed.

In addition, for each of the plants, we required that they provide a problem which the staff would compute, model, and run on our code, which we had our consultants at Brook Haven run for us.

The code verification for the codes used in reanalysis, and the codes' new pipe, and Shock 3 have been verified to provide adequate results. They agree with our analysis methods within about 6 to 7 percent.

We also determined that those analyses which were done by methods other than computer code -- that is, the hand calculational methods, or the equivalent static method -- that they should describe the methods that were used in sufficient detail that we could review them against the requirements of the standard review plan as it exists today. And we've determined that those methods were acceptable.

We had a related I&E bulletin, which addresses anchor bolts and base plates, associated with supports, the method of attachment to all the floors.

The concern was that anchor bolts had been experiencing a high failure rate in the field. It was thought to be related to a QA problem and an installation problem, and also the fact that the base plate flexibility had not been addressed.

This came out first on the North Anna review, at which time webs or gussets were attached to the base plates, to stiffen the base plates.

We asked the Licensees to provide us with their schedule for responding to that review and asked for a commitment that in cases where support loadings increased above what the original design load was that they address the question of base plate flexibility in a reevaluation of that support.

We also decided that it was prudent to evaluate other computer codes which were used in the analysis.

In this case, the codes, Shock 0 and Shock 1, which were predecessors to Shock 2, and the codes which were used for evaluating the main loop piping, and which were done by the vendors.

We reviewed those codes, and we've determined that they are, at that time, acceptable, and they provide sufficient margin such that the piping would not be expected to fail under earthquake conditions.

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MR. BENDER: "They are at that time" has some kind of connotation to it that I don't understand.

What do you mean by that statement?

MR. RUSSELL: For instance, the codes were one-dimensional codes. They were not codes which we would review and find accepable today. We reviewed them to see what the piping design was.

For instance, as an example, the piping which was designing using the code, Shock 0, we took a sampling of that piping and we evaluated it for the code, new pipe, a code which is currently acceptable.

We found that the results of the piping stress analysis were such that the piping would not be overstressed. So even though the piping was designed with an older version of the code, the pipe design was acceptable.

MR. BENDER: That means essentially the configuration was the same in either case.

MR. RUSSELL: That's correct.

MR. BENDER: Okay.

Thank you.

MR. RUSSELL: There was one aspect, and this is the main reason why Surry is proposing to resume operation before they complete their analysis -- this is in the area of soil structure interaction.

You had two Licensees who essentially proposed to go back and relook at the earthquake input to the piping analysis.

We required that they, in doing this, do comparisons to what would be currently acceptable today -- that is, that they use the Reg Guide 160 spectra and Reg Guide 161 damping values in doing comparisons between the amplified response spectra that are developed at various levels in the structure to that which they were generating, using the FSAR spectra and damping values.

Those comparisons were completed, and it was demonstrated that the methods they were using for soil structure interactions are methods which would currently be acceptable today and, in fact, are more comservative than would be required if they were to redo the analysis.

The soil structure interaction methodologies were approved for Surry and Beaver Valley on the 25th of May, with one minor modification that was imposed by the staff.

Licensees did not consider variations in soil properties and how those variations in properties would affect the soil structure interaction analysis methods. We required that they vary the soil properties by plus or minus 50 percent and develop additional amplified response spectra. In essence, it was a sensitivity study on soil properties.

We found that it was necessary to increase the inertial loading by 50 percent at the end of the analysis in order to account for this variation on Surry, and by 20 percent to account for the variation on Beaver Valley.

So the point that we are at today is that we have completed our review of the hand analysis methods. We've completed code verifcation. We've completed the review of soil structure interaction analysis methods. And those methods have significantly reduced the numbers of modifications which the Licensees would be required to make for both Beaver Valley and Surry -- in the Surry case, on the order of 50 to 75 percent of the piping analyses are being done using soil structure interaction analysis. That's piping systems which would be overallowable had they not gone to the newer techniques or supports, which would be overloaded such that they had to redo the piping analysis in order to reduce the support loadings.

That's the extent of the discussion that I have on the status of the five plants.

There was a question which was asked about other plants which also use the algebraic summation method.

(Slide.)

And I have another handout. A little background on how we got to the point of issing I&E Bulletin 7907 -- on about the 2nd or 3rd of May, we received an anonymous phone call that indicated that an additional unit had used algebraic summation methodology and that the code that was involved was the code ADL Pipe.

At that time, we initiated phone calls to Licensees to determine whether in fact they had used that code. And the fallout from those phone calls was a report by Florida Power and Light for the Turkey Point Units 3 and 4, that they had in fact used an algebraic summation in code called Westdyn, which was a follow-on code to the original ADL Pipe, and that they had in fact reanalyzed the main loop piping system and found that the piping was within allowables.

We met with the Licensee and with Westinghouse in Washington, and upon discovery of that additional information that there was another unit, we elected to go with the bulletin and require all Licensess for operating reactors to respond within 10 days, to indicated whether or not they had in fact used algebraic summation in their analysis.

The results of that bulletin was that there were a total of 25 facilities which to some extent had used algebraic summation. The original five, which were shut down by the show cause order, all used the code Shock 2. It was subsequently determined that Point Beach Units 1 and 2, in a modification to the rad waste system, had also used Shock 2 on four cooling water lines associated with that modification.

These lines are not related to the integrity of reactor system coolant pressure boundary and are not related to the mitigating systems that have been reanalyzed.

The staff has not completed its review for the code ADL Pipe, which is a code developed by the Arthur D. Little Company, and the code DAPS, which is Dynamic Analysis Piping Systems, which is a General Electric proprietary code.

That was used on Brunswick 1 and 2. DAPS was used for the General Electric scope of supply, and ADL Pipe was used for the architect-engineer scope of supply for all safety-related systems.

I've characterized the algebraic sum used as being extensive. We've had several meetings with the Licensee from Brunswick.

I mentioned that we had the as-built problem on Brunswick, and the unit shut down and corrected the as-built problem in the facility.

And based upon the methods of analysis that were used, and the conservatisms in that analysis, and based upon being able to make projections from the original seismic stresses to the seismic stress that we would see after analysis, it was determined that it was acceptable for Brunswick 2 and Brunswick Unit 1 to resume operation following the modifications to correct the as-built condition and to continue their analysis while they were operating.

The staff has issued a safety evaluation discussing that.

The X's on the viewgraph indicate those which are resolved, for which the staff has issued a document identifying the resolution of the problem.

Indian Point Unit 3 -- the cost Westdyn was used for analyzing the reactor coolant system. And the code ADL Pipe was used for design of the architect-engineer's balance of plant. It was also extensive; the unit is continuing to operate.

And it's a similar situation to that at Brunswick 1 and 2 in that the methods that were used for evaluating the facility were very conservative. They used a factor increase above the operating basis earthquake to get to the safe shut down earthquake loadings. And it was also a two-dimensional earthquake input, rather than three-dimensional.

And there are other conservatisms in the analysis, which were able to be identified, that justified the units' continued operation.

The safety evaluation supporting that we anticipate to be issued very shortly. The meeting summaries and the documents describing the conservatisms are available and in the public docket.

Salem Unit 1 used a code called Pipdyn 2, which is a code that was developed by the Franklin Institute. It was also used extensively. It used algebraic summation of intra-modal responses. That unit is currently shut down in a refueling outage. The staff position is that it needs to be resolved prior to starting up. Their start-up date is about the middle of July.

The remaining units -- Indian Point 2, Cooper, Ginna, Millstone 1, Millstone 2, and Nine Mile Point -- was very limited use of the code ADL Pipe. Only a few lines had been involved, but those lines had been reanalyzed. The staff has not completed their review of the reanalysis results.

On D. C. Cook Unit 1 and 2, initially they had reported there were approximately 20 lines that had been done using the code Westdyn.

Some of those lines were subsequently reanalyzed with a later version of Westdyn,which had been approved by the staff. And only one line was actually the analysis of record using the algebraic summation. That line has been reanalyzed, and the results are being submitted to the staff.

Robinson 2, Turkey Point 3 and 4 -- have been resolved. This is an error -- Zion 1 has not yet been resolved. It's the code Westdyn, and only for the larger reactor coolant system piping.

Pilgrim was involved with the code DAPS, which was a General Electric code, for the reactor coolant system and the main steam piping. That reanalysis has been done. Modifications to the facility were made, and the staff has issued a safety evaluation that supported resumption of operation for Pilgrim Unit 1.

That's the status. We have 25 plants, 25 operating reactors which used algebraic sums. I believe there are two units which are under operating license review which also used algebraic sums; Salem Unit 2, which is a sister to Unit 1, used the same code. And I can't recall what the other unit was.

MR. BENDER: Can I use the same generalization for these plants as was used in the others, namely that the stresses are not more than 50 percent over the total?

MR. RUSSELL: That's exactly what we're seeing on the reanalysis results that have been presented -- is that the stresses, after you correct for the algebraic sum, would typically bounded by a 50 percent increase.

Now, we did have some additional concerns where a square-root-sum-of-the-squares method was used for the modal combination on a two-dimensional earthquake. The staff position is that that's acceptable for a 3-D earthquake. An absolute summation should be used for 2-D, so we did have to increase the stresses there.

But in most cases we found that inertial stresses from the seismic event were small fractions of the total stress, such that we were not getting into conditions where we would expect reanalysis to show the piping to be over-stressed.

MR. BENDER: That's also true in the case of the primary coolant system piping.

MR. RUSSELL: The primary coolant system pip .ng was even moreso. That piping is very large bore; it's supported typically at three points. It's short runs of piping; it's relatively high frequency. And we're finding that there was not much change at all.

The cross-coupling effects from algebraic sum were essentially insignificant for that piping.

M. BENDER: Is that why none of these 25 plants are shut down? Or are any of them shut down?

MR. RUSSELL: The ones where it was extensive, where we indicated that the balance of plant piping -- for instance, the safety injection lines, the RHR lines, and the smaller lines -- were involved where it was extensive -- for instance, Brunswick 1 and 2 and Indian Point Unit 3.

We, in detail, reviewed the original analysis to be able to extrapolate from that to what it would show on reanalysis -- to be able to conclude that we would not have a piping stress problem.

In the case where the main loop piping was involved for the Westdyn code, in the main recirculation piping with the DAPS code, we found out that on reanalysis the stresses were within allowables.

We did find some as-built problems on Pilgrim, where some snubbers were undersized, but they would have been undersized whether you used the algebraic sum or you redid it not using the algebraic sum. We classified it as an as-built problem.

MR. BENDER: Thank you.

MR. RUSSELL: If there are no other questions, that's all I have.

DR. CARBON (Presiding): Thank you, Mr. Russell.

Let's move ahead then to Millstone 2.

Harold, may I call on you?

MR. ETHERINGTON: In a letter dated December 14, 1978, Northeast Nuclear Energy Company requested a license amendment that would increase the maximum operating power of Millstone Unit 2 from 2560 MWT to 2700 MWT.

Millstone 2 is essentially the same as Calver Cliffs 1 and 2, which were also initially licensed for 2560 MWT and subsequently authorized to operate at 2700.

On this basis, the Operating Reactor Subcommittee had no technical problem with the proposed increase in power. However, this does not appear to be a clear case of stretch power to a level that had been reviewed by the committee.

I'd like to go back to the history of licensing of this class of Combustion Engineering reactors as I understand it and to review the committee position on stretch power.

The Calvert Cliffs 1and 2 reactors were designed for were designed for 27 -- 700 MWT, but were reviewed by the NRC staff and ACRS for 2560 MWT and were licensed to operate at that power.

Subsequently, an application was made to operate up to 2700 MWT, and the NRC staff reviewed the analysis and approved operation to 2700. At that time, the ACRS had not asked to review applications for increases in power.

Shortly after these increases were authorized, the committee expressed a wish to have an opportunity to review authorization of incrased power, and the ground rules were formalized in Mr. Fraley's letter of May the 12th, 1978, to Mr. Gossick.

I'll read the two pertinent paragraphs:

Quote, "The committee expressed its desire for the opportunity to review proposed power level increases at operating facilities, including those that involved an increase from a reduced power level to the designed power level. Such proposals will be routinely reviewed by the Committee's Subcommittee on Operating Reactors on a case-by-case decision unless it needs a full Committee review. It is our understanding that the proposals to extend operating power levels beyond that originally established, as the designed power will not involve a formal ACRS review and report," unquote.

I'll speak for myself in case Mr. Mathis doesn't agree. I don't think this request for an increase in power is fully in the category of an increase from a reduced power level to the designed power level for the following reasons:

First, the committee reviewed the unit for operation, up to 2560 MWT, and neither his letter of June the 11th, 1974, to the Commission nor, I believe, the NRC SER of May 10th, 1974, made any mention of stretch power.

However, the FSAR did state that "Site parameters in the major systems and components, including the engineered safety features and containment structures, have been evaluated for operation at a core power level of 2700 MWT.

"Additionally, certain of the instances considered in Chapter 14 were evaluated at the higher power level," end quote.

The review at the higher power level was evidently not complete.

Now, secondly, it is my understanding that operation at 2700 megawatts cannot be justified with adequate trip margins by analytic methods in use at the time of the ACRS review.

Present justificatio[illegible]s on the basis of new codes and topical reports that have been accepted or adequately reviewed by the staff.

I don't know of any review by the committee of these methods. The new methodology is stated to be less conservative,

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but more precise than that available at the time of the committee review.

The NRC staff will give the chronology and the basis for their considering this stretch power within the meaning of our understanding. They may correct any misunderstanding of mine on my own part.

I'll just go briefly through the features of the modifications.

The Cycle 3 core consists of one-third new assemblies like those inserted at the last refueling, except for minor composition adjustments being applied by the Fuel Management Program.

It is in the range of 31,000 to 34,600 MW metric tons. Some of the elements have now been exposed to 26,000.

The staff finds their original performance conclusions are still valid.

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In nuclear analysis, for many nuclear parameters that do not require detailed pin power, the ROCS code has been substituted for the traditional PDQ.

PDQ is a two-dimensional, four-group code. ROCS is a one-and-a-half group code, stated to be nearly as accurate. It is thre[illegible]mensional, and it takes less computer time.

The staff finds this acceptable for the reload.

On therman hydraulics, for Cycle 3, Northeast has used newer combustion engineering and Northeast methods which have been approved by NRC, but which, so far as I know, have not been reviewed by the committee.

These, as I mentioned before, are stated to be less conservative, but more precise than the previously used methods. They include the use of the new NMBR correlation, DMBR 1.19, compared with the familiar 1.3 for the W-3 correlation.

There are new methods of combining uncertainties and evaluating frequent factor uncertainties.

Generic problems, common to many CE plants, include the proliferation of burnable poisons. They're studied during the first fuel cycle, and the control elements and the guide-through threading problems. These problems appear to be well under control and not power sensitive.

On the system capability and modifications, major systems are stated in the FSAR to have been designed to 2700 MWT.

The following modifications will be required:

Credit must be given to the charging pumps for their small break LOCAs.

The three charging pumps -- they already meet QA and seismic requirements. Other manufacturers' systems are using these pumps as part of the accepted LOCA systems and would appear to the subcommittee that there would be no problem here.

The reactor coolant pumps' speed sensing system will be added to provide additional early trip signal to the reactor protection system on loss of all four pumps.

Functionally, this is the same as the system at Arkansas Unit Number 1 -- Arkansas Nuclear 1, Unit 2. The staff finds this satisfactory, and will require additional seismic testing of some components before Cycle 4.

The analysis of the anticipated operational current transients affected by the power increase -- power and temperature increases, or departure from original design assumptions, have been reanalyzed and found satisfactory by the staff.

Accidents other than LOCA have also all been reanalyzed. New analyses have been presented for large and small breaks, ranging from .4 square feet for large and small breaks -- the .1 square foot is found to be more limiting than the .05 square foot break.

The radiological consequences of accidents have already been analyzed for at the preliminary stage and reviewed by ACRS to 2700 MW.

Some changes are planned, or have been made, as the result of operating experience, including installation of a chlorine detector in tbe control room and neutron shield around the upper part of the reactor cavity. This area does not come in my comment questioning whether it had been reviewed by the ACRS. This has been reviewed.

Other changes, not particularly power related, have been made in response to generic problems and NRC criteria.

The ACRS letter of June 11th, 1974, on the POL listed the following items for recommended staff follow-up:

1 -- reevaluation of operating limits in accordance with acceptance criteria for emergency core cooling of 10 CFR 50.46.

This has been done to the satisfaction of the NRC staff.

2 -- ACRS recommendations for heat-up and cooldown pressure relations. Be "as conservative as practical with reference to 10 CFR 50, Appendix G."

I don't know what the committee had in mind. The Applicant will conform to Appendix G, and I can't see that we could expect anything more than that.

Consideration of debris in the containment -- the Licensee and the staff have reviewed this matter and have concluded that appropriate precautions have been taken to minimize debris, chiefly from metal lags and minerals reaching into blocking pump suction lines.

4 -- the committee is recommending Section 11 in-service inspection be applied to the shell of the steam generators. This has been accepted by the Licensee.

5 -- recommended position of instrumentation following the course of an accident.

The Licensee has added high range instruments to measure radioactivity inside the containment and has provided data on instrumentation in the control room that can be used.

The Licensee has also responded satisfactorily to other matters that were outstanding at the time of the ACRS reviews.

The responses are covered by SER Supplements 1, 2, and 3, dated May 7, 1975; August 1, 1975; September 26, 1975.

That, I think, is all I have to say, Mr. Chairman, subject to questions.

I think we ought to hear the staff on their reasons for considering this a stretch power -- within my understanding at least, and I am sure most of you would like to hear at least a general statement, whether you wish to hear any further discussion.

DR. CARBON: Are there questions of Harold?

Steve.

DR. LAWROSKI: You said this was -- we had reviewed this up to 2700?

MR. ETHERINGTON: I said the committee had not, in my opinion.

DR. LAWROSKI: Okay.

I missed the "not."

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DR. CARBON: Are there other questions of Harold?

Charlie, did you have comments?

MR. MATHIS: No. The only thing is that we apparently have a procedural question more than anything else. From what we heard, we could see no obvious problems with increasing the power level except the change and the analysis hasn't been formally reviewed by ACRS. And we, as a subcommittee, don't think we want to jump off and change the rule book at this stage of the game.

Is that a fair statement?

MR. ETHERINGTON: Yes, that's a fair statement, and I think really the committee's approach is wrong, personally. I don't think we should be talking about looking at stretch power. I think we should leave that to the staff. But I do think we should look at changes in ground rules, and there have been some changes in ground rules that the committee, I believe, has never reviewed.

DR. CARBON: Is it your recommendation at this time that we call on the staff?

MR. ETHERINGTON: Yes, sir.

DR. CARBON: If there are no further questions, let us do so.

MR. REID: Okay. I'm Bob Reid; and Monty Conner who is the Project Manager, will address some questions that have been raised by the subcommittee.

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MR. CONNER: I perceive here that we have two questions before us, whether the final safety analysis report, in our review, originally was for 2700 for both Calvert Cliffs and for Millstone 2? I've prepared some data on that.

The second question has to do with generic -- I shouldn't say "generic" -- topical reports used in the analysis, and I've requested that the Licensee prepare himself to address that. This will be done by Mr. Rick Casey, following my presentation.

(Slide.)

This is a chart that we used at the subcommittee, and I want to just highlight a few things on here.

These are typical licensed power levels about three years ago. And, of course, some of them still exist.

This is the final safety analysis ultimate level, as identified in each of the final safety analysis reports.

Here is the application date; down to this point, all these different Applicants have applied for a power increase.

And here is the requested power level reached with these Applicants.

And then this is the final action that has been taken.

In many of the CE plants, because of the Reg Guide that was in effect at that time that Millstone, Calvert Cliffs, St. Lucie -- at the time these plants were designed, we requested that they indicate what the ultimate power level would be. This was pointed out in submittal that the staff made to the ACRS in December of 1977. It was also discussed at an Operating Reactor Subcommittee meeting in early 1978.

PROF. KERR: Can you explain to me which FSAR is beging referred to in connection with your chart?

DR. PLESSET: We don't have that chart. Maybe we can get it.

MR. CONNER: There are more copies over here. These were left yesterday. I thought we had enough to go around yesterday, but there's more here.

PROF. KERR: Your chart refers to the final FSAR -- I'm sorry, the FSAR ultimate level --

MR. CONNER: That's correct.

PROF. KERR: -- and indicates that Millstone 2's ultimate level is 2700 megawatts -- thermal, I assume.

But it indicates that the application date -- which I assume means the FSAR date -- was 12-15-79. I am therefore somewhat puzzled.

MR. CONNER: No, this is the application date for a power increase.

PROF. KERR: Then I guess I'm even further puzzled, because the subcommittee report indicated that the FSAR ultimate level, I thought, was 2560.

Did I misunderstand the subcommittee report?

MR. CONNER: We're going to look at that in just a minute.

But in the final safety analysis report, they identified 2560 as the power level they are requesting.

They further identified the power level of 2700 as the ultimate power level. I have a chart, in a minute, that will show that.

MR. MATHIS: I think there's one problem. Your application date I think is 12-15-78, not '79.

MR. CONNER: I'm sorry. You're sure right.

Please correct that.

PROF. KERR: Did the subcommittee see this chart?

MR. ETHERINGTON: Yes.

MR. CONNER: That should be an 8.

PROF. KERR: What is the significance of the -- what was the nomenclature you used, the designated ultimate power level?

MR. CONNER: Yes.

Let me show you precisely what the FSAR says.

(Slide.)

This is a statement that appears in the introduction section of the Millstone 2 Final Safety Analysis Report, and identifies the core thermal output of 2560 -- physics and core parameters, 2560. Of course, you have the extra 10 megawatts due to the reactor coolant heat sources and the coolant pumps and pressurized heaters.

Site parameters and major system components, including the engineered safety features and the containment structures, have been evaluated for operation at a core power level of 2700 megawatts.

Additionally, certain of the postulated incidents considered in Chapter 14 are evaluated at the higher power level. This is from the Millstone Final Safety Analysis Report.

Now, to show that it is no different in this light than Calvert Cliffs, I have reproduced a similar statement from Calvert Cliffs.

(Slide.)

Very, very similar -- it still identifies the 2700, showing that this is due to the reactor coolant pumps and then intends to eventually file an application for a license amendment to authorize operation at higher power levels, not exceeding 2700 megawatts.

PROF. KERR: That added sentence, you feel, does not have very much significance?

MR. CONNER: I beg your pardon.

PROF. KERR: That added statement, which says the total nuclear, does not have much significance -- you said the two were not significantly different.

MR. CONNER: If you start right here and you read the rest of it --

PROF. KERR: I'm starting at the first, with "an initial license."

MR. CONNER: This FSAR is dated approximately a year and a half earlier than the Millstone. It's an earlier application. The words are slightly different.

However, from here on down, the thought is identical.

DR. CARBON: It seems to me that what you're saying here is that you did not carry out a complete analysis on Calvert Cliffs at that time.

And my question is: Did you before it went up to 2700?

MR. CONNER: Yes. The committee was informed of this at a meeting. I didn't look up the date of it, but it was approximately about a year -- a little over a year ago.

MR. ETHERINGTON: And it was at that time that the committee expressed a wish to review future increases at that time?

MR. CONNER: Yes, we sent a letter to the committee telling them what we planned to do. And receiving no response, we assumed that it would be okay to go ahead and grant the increase.

Whereupon, we came down and told the committee what kind of analysis we performed, the calculations that had been redone, and it seemed to be all right.

And then we started this back-and-forth communication, that the committee wanted to become involved with the power increases as they occurred. So that's what the staff has been doing since that time.

MR. BENDER: Has everything that has been done for Millstone 2 that Calvert Cliffs was required to do?

MR. CONNER: Yes.

MR. BENDER: Unequivocally?

MR. CONNER: It would be nice to check, but I can't think of anything. You will see in a minute.

Well, the subcommittee went over the analysis that was done. It's quite extensive. All but two of the accidents were recalculated. Modifications were made the system. Calvert Cliffs has slightly more high pressure safety injection flow than Millstone, so Millstone took credit for the charging pumps to increase their flow going into the core in an accident condition.

DR. PLESSET: The limiting problem I take it is the large break? Is that the limiting problem that they had to examine?

Did you get my question?

MR. CONNER: Yes, but I'm thinking.

There's actually more changes in the analysis on the small break than there was on the large break; is that correct?

MR. CASEY: Yes, that is correct.

If the thrust of your question concerns what break resulted in highest peak clad temperature, it was from the large break.

DR. PLESSET: That's what I was thinking.

Then you did reanalyze that?

MR. CASEY: Yes, we did. We did a full spectrum for both the large break and the small break LOCAs.

DR. PLESSET: What kind of evaluation was that? Was it one that fits with Appendix K?

MR. CASEY: Yes, sir.

DR. PLESSET: Oh, well. Okay.

(Slide.)

MR. CONNER: The other chart that I prepared to show the comparison between the Calvert Cliffs and the Millstone at the suggestion of the subcommittee shows that the different power levels of where the analysis was performed originally; okay?

For the original final safety analysis report, if you look down the column, you'll find they're identical -- until you get down to here, where you have the steam line rupture. And at that point the Calvert Cliffs base, the steam line rupture and the steam generator tube rupture were performed for 2700, where it was still performed at 2611, 102 percent of 2560, in the case of Millstone 2. Now I can't tell you why that was done; I don't know. But those are the only two power levels that were different.

When you get down into our analysis, you'll see an interesting thing. The safety evaluation report mentions 2700 in the case of Calvert Cliffs, where it does not in the case of Millstone 2.

And just as peculiar as the final environmental statement -- mentions 2560 only for Calvert Cliffs, and mentions 2700 for Millstone 2.

ACRS letters, as pointed out before -- both of them mention 2650, without making any reference to 2700.

However, in the case of Millstone 2, in the ACRS letter, for the construction permit, 2700 is mentioned in that letter.

DR. PLESSET: What was the small break analysis? Let me go back to that. What was the highest temperature, and what small break was that associated with, and how close was it to the large break.

MR. CONNER: The small break was 1971 degrees for break size of .1 square feet.

DR. PLESSET: Was there any analysis on either side of that size?

MR. CASEY: Yes.

DR. PLESSET: There was.

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MR. CASEY: We have a viewgraph that summarizes the small break.

DR. PLESSET: Maybe they can show it to us later.

Fine.

DR. LAWROSKI: Did you say the letter mentioned 2700?

MR. CONNER: I'm sorry, the ACRS letter?

The ACRS letter for the construction permit mentioned 2700. The ACRS letter for the operator license did not mention 2700; it only mentioned 2560 megawatts thermal.

DR. LAWROSKI: Did anybody find 2700? That's the May 15th letter.

MR. CONNER: I didn't bring it up with me. It's in my other briefcase.

Does anybody else have it?

MR. ETHERINGTON: I don't think there's any question as to whether the hardware was designed for 2700.

The only issue is whether the analysis was at 2700.

MR. CONNER: Of course the important thing here is that the analysis for both Calver Cliffs and Millstone 2 was repeated extensively for the higher power level. And the staff has reviewed it and found it acceptable.

We can go back -- you know, originally, I agree, there's a lot of the core calculations that were not done for 2700, but they have been done and they have been reviewed in a way that is consistent with our normal cycle reloads that calculate, or evaluate, each year for the Licensees.

DR. LAWROSKI: Did you find 2700, John?

MR. MC KINLEY: No.

DR. LAWROSKI: I didn't either.

MR. BENDER: Does this open the door for everybody else to go to some increment above what was originally licensed to come in and do the same kind?

MR. CONNER: As you saw from that first chart, there are a number of them that planned on that, you know, when they bought their plants. When they originally designed them, they planned on this.

However, I think most of them that are interested and already identified -- I think this is going to wind down in a short period of time.

MR. BAER: May I say something that perhaps will clarify things.

This is Bob Baer, with the staff.

Back a number of years ago, we would require the Applicant to specify an ultimate power level if for no other reason so that the site accident doses would be reviewed at that power level independent of the staff review of any other portions of the staff review.

And then when you get into the details of, for example, core reload -- and I'm familiar from my previous assignment with Calvert Cliffs' history. We, on the staff, have taken the position that we would only review core reloads as the licensed power levels, because operating parameters change slightly, for example, between 2560 and 2700, and it wasn't clear to us that all the set points and all the tech specs for 2700 would be adequate if the plant was run 2560 unless we and the Licensee were very, very careful in the analysis.

So the staff position on the reloads has always been to look at the licensed power level and make sure that the operating conditions and the tech spec limits, and therefore the protection system set points, were applicable to that power level, because this came up on Calvert Cliffs when simultaneously they were requesting the 2700 power level. But the license level was 2560, and they did have the core reload.

They presented two separate, distinct analyses, and we reviewed them -- one for 2560 for the reload -- this is back a year and a half or so ago -- then later rereviewed for the 2700 megawatt analyses in connection with the stretch power application.

MR. ETHERINGTON: The thing that has always bothered the committee is erosion of margins by pencil sharpening, and the question that I have is: Can non-Combustion Engineering plants also get a 5 percent increase in power by cutting their DMBR from 1.3 to 1.19? Or is this too simplistic?

MR. CONNER: I think the first answer to that question is if you don't have the turbine generator, if you don't have the other equipment designed and purchased deliberately for the higher power level, then it does no good whatsoever.

That's why I say this was a planned evolution.

MR. ETHERINGTON: It was planned, but you found you couldn't get the power on the original basis, so you had to develop a new methodology.

MR. CONNER: That's not totally true, and I want the Licensee to address that when we're through this other, because that's part of their presentation.

MR. BAER: Mr. Etherington, may I comment?

The staff's criteria is that the combination of analytical methods to calculate flow distribution and heat flux within the core, in conjunction with the test program for DMB, to give a 95 percent probability, are -- I've got it backwards, there should be no more than a 5 percent probability, with 95 percent confidence that you won't encounter DMB during an anticipated operational transient.

That 1.3 number for Westinghouse does not apply to all Westinghouse correlations. They have other correlations which the staff has accepted which are below 1.3.

MR. ETHERINGTON: That in fact answers the question.

MR. BAER: The 119 in Combustion was basically the same number.

DR. PLESSET: Roughly, your statement is correct. As the company's ratio is down, you can go to higher powers, so you're right in that sense.

MR. CONNER: Are there any other questions on this part of the presentation?

(No response.)

DR. LAWROSKI: For the record though, I still haven't found the 2700 mentioned.

PROF. KERR: Mr. Lawroski, I think there is a date of 1970, and one could easily confuse that with the 2700. That's probably what happened.

DR. LAWROSKI: Oh.

MR. CONNER: Al was just telling me that I made a mistake there, that the 2700 was mentioned for Calvert Cliffs, not for Millstone. I apologize for that.

Thanks, Al.

Is is the staff's belief then that the Millstone final safety analysis report and that the staff review was the same as it was for Calvert Cliffs.

We realize there is the possibility of them -- to going to 2700 at some time, but at their choice. Their application was for 2560, to gain operating experience, and to see how at that time this new design plant would run at the lower power level.

Any other questions?

PROF. KERR: I presume that implicit in your statement is the evaluation that the operating experience they have gained is such that you would approve of their going to 2700?

MR. CONNER: Yes.

And the subcommittee -- we got an opinion of this form I&E. In fact, you all received copies of the safety evaluation -- attached at the very back of that safety evaluation was this letter from I&E evaluating their capability of operating at a higher power level.

DR. CARBON: Should we then hear from the Applicant? Harold.

MR. ETHERINGTON: I think you should.

DR. CARBON: And do we want to give them some specific directions on what we would like to hear about?

MR. ETHERINGTON: Perhaps I might express an opinion. Certainly if Calvert Cliffs can operate at 2700, Millstone 2 can. There's no question there.

I think perhaps, aside from this hearing, we ought to ask our Physics Subcommittee or the Thermodynamics Subcommittee to review the current combustion methods and then clear the air once and for all on this matter, because if we don't do that, it becomes a continuing problem -- at least in my mind.

DR. PLESSET: We've had some review of that, Harold, already.

MR. ETHERINGTON: You have done so?

DR. PLESSET: Yes.

But what I think I would like to hear, if that's agreeable with you, is just a presentation of their study of peak clad temperatures for different size breaks, because that we haven't seen.

MR. ETHERINGTON: I hadn't realized that your subcommittee had reviewed this.

DR. PLESSET: Yes, we've had some review of that. But I think if we could have the Applicant just give us the results of their peak clad temperature values for different break sizes, it would be of interest.

I don't think we need to have any detailed presentation otherwise, if that's agreeable with you and the rest of the committee.

PROF. KERR: I would endorse that.

DR. CARBON: Do you, if you will, then, please.

MR. CASEY: Would you like to hear about the break spectrum at this point?

DR. CARBON: Yes.

MR. CASEY: Mr. Robert Harris will explain that for us.

MR. HARRIS: Good afternoon. I'm Robert Harris of Northeast Utilities Service Company.

In 1978, a spectrum of small break analyses was performed at 2700 megawatts, applicable to Cycle 3 taking credit for half of the flow of one charging pump.

The results of these calculations are shown in the next viewgraph.

(Slide.)

This is the spectrum of small breaks that was investigated at 16-1/2 kilowatts per foot. The limiting break is the 0.1 square foot --

DR. PLESSET: I'm having a little trouble reading the numbers.

DR. CARBON: Do you have copies of that?

MR. HARRIS: Copies of this were distributed yesterday to the subcommittee.

MR. CASEY: Excuse me. We have additional copies of that.

MR. HARRIS: Would you care for me to read the values into the transcript?

I could read the values.

Should I continue?

DR. CARGON: Hold up till we get it.

(Pause.)

MR. HARRIS: There are two viewgraphs apparently that we had with us yesterday. One is showing Millstone 2 small break analysis, showing the range of break areas, .5 square foot to .02 square foot, for Cycle 3 and Cycle 2, side by side.

And I have another viewgraph here that is essentially the same viewgraph, but does not show the Cycle 2 data.

If this is satisfactory, I'll proceed. The other viewgraph is probably in my case.

It was in my case.

DR. PLESSET: I think that's all right.

(Slide.)

MR. HARRIS: This is the viewgraph that was in the handout.

The primary differences between the two viewgraphs are for Cycle 3; the limiting break is shown to be the 0.1 square foot break dealing with the temperature 1971 degrees F. in Cycle 3. That was analyzed at 2700 megawatts thermal, with required calorimetric errors, using Appendix K, approved methodology, and taking credit for the previously mentioned charging pump flow.

The Cycle 2 data shows the limiting break in Cycle 2 at 2560 megawatts thermal with, again, approved methodology, that being 1931 degrees F.

The shift in break area from .05 to .1 reflects some approved model changes in the C/4AS small break LOCA codes by Combystion Engineering.

I can briefly go over the model changes if they are of interest.

DR. PLESSET: It's up to the rest of the committee. I, myself, don't want to hear it again. But I think the committee would be interested in how high the small break numbers are when you compare the numbers on the previous page with the large break numbers.

That's the interesting thing.

MR. HARRIS: Would you like me to put on the small break viewgraph, the large break viewgraph?

DR. PLESSET: Yes, I think so.

(Slide.)

MR. HARRIS: Again, a large break spectrum was performed for Cycle 3, and the cases were applicable to Cycle 2. Breaks were analyzed, as shown, side by side. And the limiting large break for this cycle is 2081; that's at 15.6 kilowatts per foot.

MR. MATHIS: Your kilowatts per foot on your previous slide was a little higher, wasn't it?

MR. HARRIS: Yes, 16 kilowatts per foot -- we used the small break analysis. Keep in mind that LOCA analyses are sort of like transcendental equations -- you would like to come close to the criteria, but you can't run the computer programs backwards. So you do trial and error in looking at kilowatt-per-foot values.

And if you get acceptable results at a kilowatt per-foot value that is acceptable from an operational standpoint, you normally would stop there because of the long schedule time involved in the analyses and other computational costs involved.

Large breaks are also much more sensitive to kilowatts-per-foot than the small breaks.

DR. PLESSET: I think it's of interest to see how high the temperatures get in these calculations at the very small breaks. They're almost the same as the large break.

I think Dr. Catton had a question.

DR. CATTON: As you decrease the break area from .2 to .1, you have a fairly steep temperature gradient.

(Slide.)

MR. HARRIS: This is in the small break?

DR. CATTON: Between .2 and .1, the temperature is rising quite fast.

MR. HARRIS: I think the reason for that is that with the larger break area, there is a much more rapid depressurization of the system -- you come down on the HPSI pump curve, get higher delivered flow. And I think in that case we depressurize to the point of having both low pressure safety injection HPSI and accumulator injection.

DR. CATTON: With that kind of sensitivity, did you look at break sizes between .1 and .05?

Or did you just assume that that was the peak?

MR. HARRIS: I can't give a definitive answer.

Possibly Mr. Carpentino from Combustion Engineering can.

MR. CARPENTINO: We would normally develop the results for the spectrum by looking at a sufficient number of breaks to be able to plot a curve that implies transient peak clad temperature versus area.

And we felt that with these five breaks we definitely have a trend. We have defined the maximum peak clad temperature in this range of .5 and lower.

DR. CATTON: Yes, but normally when one finds a gradient that's so steep on one side of the peak and flat on the other, you usually check in between to make sure you found the peak.

I'm just surprised that you didn't do that.

MR. CARPENTINO: Well, we do realize that we incorporate a number of required conservatisms that sort of overemphasize the actual number of peak clad temperature, particularly in this region of break size.

One of those we feel is the accentuation of the amount of boil-off with decay heat.

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Disregarding that, we do feel that the number of breaks, at least these particular from Millstone, were adequate, despite, as you state, the steepness of the gradient, below .2 square feet.

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PROF. KERR: Is there some protocol that you should go home and look at five break sizes?

MR. CARPENTINO: We have general guidelines from the staff, sort of informal, which say that we should look at five small breaks.

PROF. KERR: And when you get to a situation of the kind Mr. Catton described, where if one weren't working under the guidance of the NRC staff, one might have a little curiosity, do you hark back to NRC guides?

MR. CARPENTINO: I believe we weren't under direct guidance of the NRC, or under the particular regulations we have to comply with, we'd do the analysis quite differently. And the shape of that curve would be less steep; the gradient would be less steep than it's shown to be by this Appendix K analysis.

PROF. KERR: What would it have cost to run those? I mean, would it have been $10 or 10,000 or 10 million, or something?

MR. CARPENTINO: Probably the second number you mentioned is more realistic. It is quite expensive.

PROF. KERR: I assume it may have been nearer 10,000, than either 10 or 10 million?

MR. BENDER: Nearer to 1000 than 10, I suspect.

DR. PLESSET: Is it all right if I ask another question?

Are you finished?

PROF. KERR: Yes, sir.

DR. PLESSET: Could you give us the date of this revision of this code that you used?

Do you have it?

MR. HARRIS: Again, I think the staff or Fred Carpentino would know the date. I believe it was sometime in either late '77 or sometime in '78. This is not a unique use of this version of the program.

MR. CARPENTINO: The date of the revision, the model's revision, is January '77.

DR. PLESSET: Now, one final question, and then I'll be quiet.

I believe that Combustion Engineering is reviewing small break analysis currently, following TMI.

MR. HARRIS: That is my understanding

DR. PLESSET: Have you had any input from them as regards to what effects this would have your numbers?

MR. HARRIS: My understanding of the status is that that effort, as far as an analytical effort, is just starting to become a substantial effort. And there's meetings going on currently with the staff.

If CE has any other assessment, they can supplement that.

DR. PLESSET: What we'd like to know is how this might affect these numbers as a result of further study, as a result of reevaluation of these things since TMI-2.

MR. MILLS: I'm Ray Mills, Combustion Engineering.

We made a presentation to the full ACRS committee on May the 10th. At that time, we outlined for you the small break analyses that we had been conducting and rerunning since the accident at Three Mile Island.

You probably remember, from that discussion, that there were no substantial changes in the peak clad temperatures at that time. We showed you degrees of postulated core uncovering, using some licensing-type models. And we don't expect any substantial change in the results that we get from our models. They are continuing to be reviewed.

And as a part of the on-going, staff generic review, we will be providing you with further verification of the small break mo[illegible]s.

MR. HARRIS: Are there further questions?

DR. CARBON: Are there other questions on this particular point?

(No response.)

DR. CARBON: I guess not.

There's one other aspect here. Let me address this partly to Milt.

I guess the subcommittee has looked at the burnout correlations which they're using, but the full committee has not reviewed this, at least to the best of my knowledge.

I think it might be more profitable, perhaps, Mr. Chairman, to wait until Combustion Engineering has completed their more recent analyses, at which time we can go into that point as well.

I think it is true the full committee would profit by it -- by the review.

Is that agreeable with you, Harold?

MR. ETHERINGTON: Yes.

DR. CARBON: I guess part of my comment and question, however, is should we approve an increase in power even without the committee having approved the procedures used in reaching --

DR. PLESSET: Let me give you some comfort. This is all on the basis of Appendix K, which is a very heavy penalty, and gives you a large degree of conservatism.

I don't feel that there's a great worry for the committee to proceed without having gone through the details of that code analysis. That's just my opinion.

DR. CARBON: Mike.

MR. BENDER: I think there's been some reason for concern about this procedural aspect. It seems to me we do not have anything as a precedent that says we have to follow some specific procedure as in deciding whether the plant should be operated or not.

If the safety questions are adequately satisfied and the staff has met all of its licensing requirements, I can't really see why we should be reluctant to do it -- to permit their operating.

I don't like the way in which it came about, but I don't think it's the fault of the Licensee. I think, if anything, it shows some weakness on the part of the staff's procedures in not thinking about what kind of questions they're establishing. But I don't think that should be a reason for penalizing the Licensee.

MR. ETHERINGTON: I agree with you completely. I just hope that we don't get another one coming just like this.

DR. PLESSET: Well, I want to repeat again -- I'm trying to give you some assurance -- this is not the first study of this kind.

Calvert Cliffs is the same situation. And, in a way, I think they've done more analysis than was done for Calvert Cliffs.

MR. BENDER: I think we all agree with that.

My only point was the staff ought to have a way of giving us some earlier warning, than the month before the meeting, when we're going to hear it, that this is the time for operating the plant.

We can know more than that.

DR. PLESSET: You have a point.

DR. CARBON: Are there further questions that you would like to raise with either the staff or the Applicant -- or the vendor?

DR. LAWROSKI: In response to a comment by Mike, when did we first get alerted about this operating?

MR. FRALEY: I don't know specifically, but I think it was more than a month ago. But I can check.

MR. BENDER: Please don't take me literally. I was trying to say it was a very short time, shorter than we normally have.

MR. ETHERINGTON: To be realistic, personally, I frequently wait until I get the staff's SER before looking over the whole thing. And only until I've got that, that I realize the proper question. And that was only a week ago.

DR. LAWROSKI: That's the date I think that counts, and that is short.

MR. ETHERINGTON: We tend to rely on the staff to alert us to particular problems.

DR. CARBON: Do you have, Harold, any recommendations to make at this point?

MR. ETHERINGTON: Yes, I would recommend that we approve the request, which would not require a letter, I believe.

DR. CARBON: Which would not?

MR. ETHERINGTON: I don't think that requires a letter, not under our procedure. In other words, the subcommittee would recommend that the committee approve the action proposed by the staff; but I agree with Milt, that we should try to resolve this question on a generic basis -- a complete study of the new analysis methods when they're completed.

DR. CARBON: Are you making a motion to that effect?

MR. ETHERINGTON: Yes. I make a motion to that effect.

DR. CARBON: Were you seeking --

MR. FRALEY: I think since the staff hasn't asked us for a letter, apparently they don't believe it requires a letter. But I think normally it has been committee practice to document this sort of decision, either in a letter or at least in a letter from me to Mr. Goss :, saying we have no objection. I think this is a change,beyond what the committee originally approved. And somehow, if you're going to approve it, it really ought to be documented, although apparently that's not legally required.

PROF. KERR: Mr. Chairman, I suggest we decide the question of approval first, and then perhaps we can decide the question of procedure -- perhaps even on Saturday.

I don't think we have to settle the procedure this evening.

DR. CARBON: There's a motion before the floor to approve. Is there a second?

DR. LAWROSKI: Second.

DR. CARBON: And we follow this procedure, then we would vote on simple approval and worry Saturday about the best way, except I guess we want to take a poll right now if we come up with a formal letter.

PROF. KERR: I would assume it would not be the usual letter, because we simply don't have that much to say. We could think of some things, I suppose.

DR. CARBON: Is there further discussion on the motion? Or is there discussion?

(No response.)

DR. CARBON: All in favor of the motion indicate by raising their hand.

(Show of hands.)

DR. CARBON: Opposed?

(No response.)

DR. CARBON: It's carried.

I believe that winds up that topic; is that not so?

(Whereupon, at 6:10 p.m., the Committee adjourned to go into Executive Session.)

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MILLSTONE UNIT NO. 2

POWER UPRATING TO 2700 MWT

ACRS SUB-COMMITTEE MEETING ON REACTOR OPERATIONS

WEDNESDAY, JUNE 13, 1979

(1) SITE AND PLANT DESCRIPTION

(2) LICENSING AND OPERATING HISTORY

(3) OVERVIEW OF POWER INCREASE

(4) CYCLE 3 CORE DESIGN

(5) POWER INCREASE METHODOLOGY CHANGES

(6) TRANS[illegible]NT/ACCIDENT ANALYSES

(7) CYCLE 3/POWER INCREASE MODIFICATIONS

-- CHARGING PUMPS
-- REACTOR COOLANT PUMP SPEED SENSING SYSTEM
-- NEUTRON SHIELD

(8) ACRS GENERIC LIST

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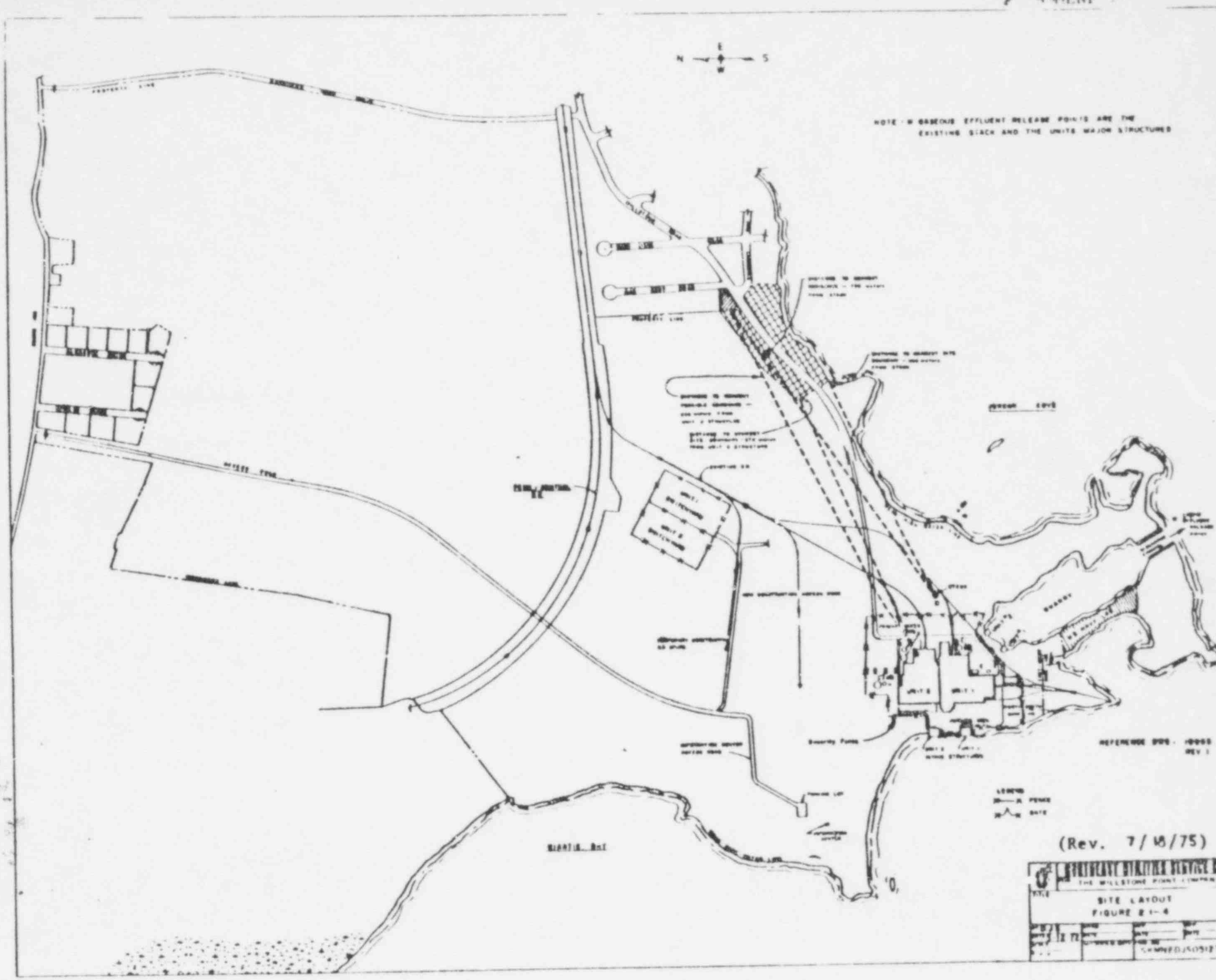
SITE MAP

FIGURE 2.1-3



(Rev. 7/18/75)

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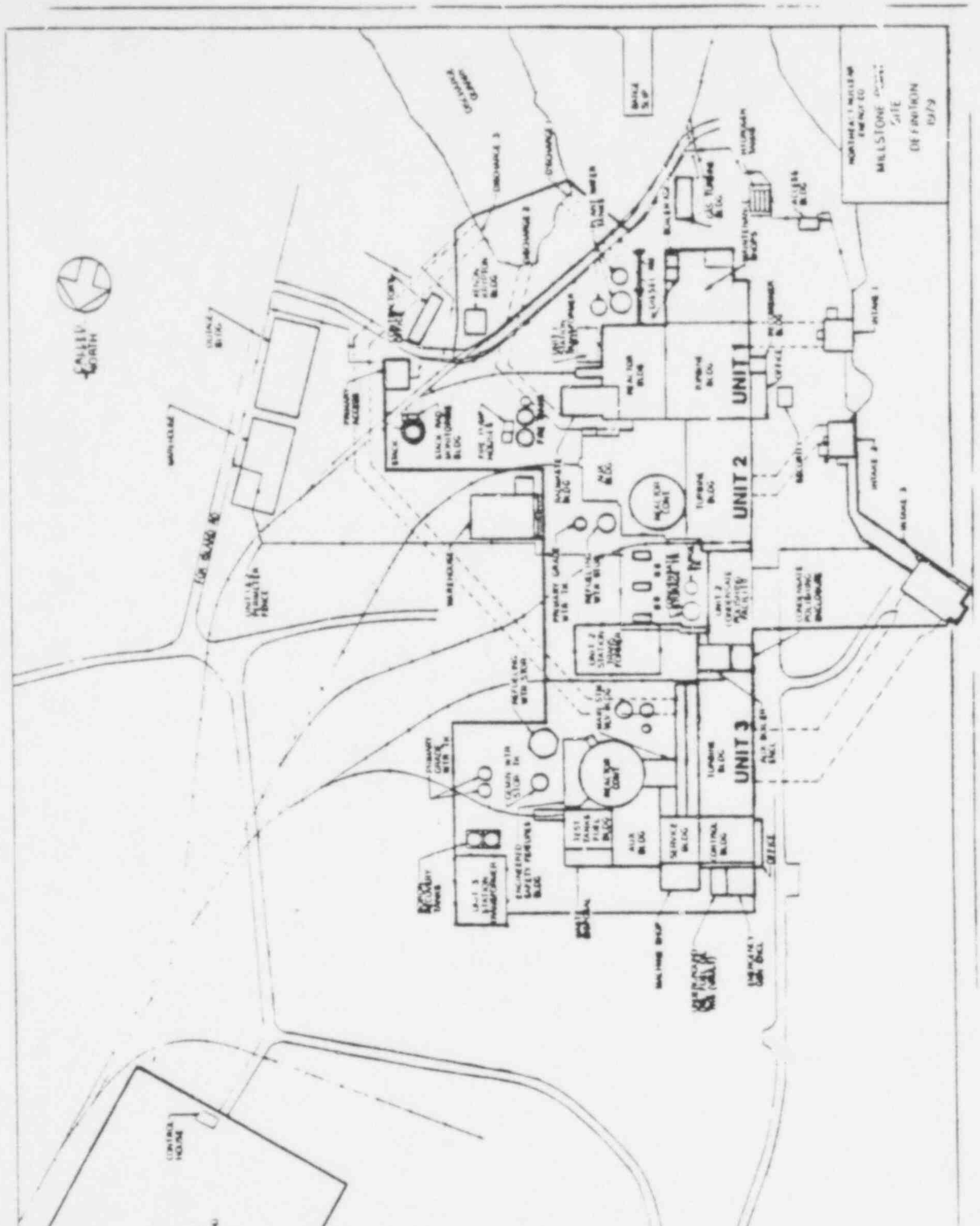

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MILLSTONE UNIT NO. 2

ACRS MEETING - JUNE 13, 1979

LICENSING AND OPERATING HISTORY

1. Construction Permit Application -- February 12, 1969.
2. Construction Permit Issued -- December 11, 1970.
3. Major NSSS Components Delivered -- February/March 1972.
4. FSAR Submitted -- August 15, 1972.
5. ACRS Subcommittee Site Tour -- January 26, 1974.
6. SER Issued -- May 10, 1974.
7. ACRS Subcommittee Meeting -- May 22, 1974.
8. ACRS Full Committee Meeting -- June 6, 1974.
9. Operating License Issued -- August 1, 1975.

MILLSTONE UNIT NO. 2 OPERATING HISTORY

CYCLE 1 (MDC CAPACITY FACTOR, BASED ON 796 MDC NET = 66.6%)

1. OPERATING LICENSE ISSUED -- AUGUST 1, 1975
2. INITIAL CRITICALITY -- OCTOBER 17, 1975
3. COMMERCIAL OPERATION -- DECEMBER 26, 1975
4. DIESEL GENERATOR REPLACEMENT OUTAGE (3.5 WEEKS)
   DECEMBER 20, 1976 - JANUARY 13, 1977
5. RETUBE MAIN CONDENSER (6.5 WEEKS)
   MAY 7, 1977 - JUNE 21, 1977
6. FIRST REFUELING/STEAM GENERATOR TUBE PLUGGING (35.5 WEEKS)
   NOVEMBER 20, 1977 - APRIL 27, 1978

CYCLE 2 (MDC CAPACITY FACTOR, BASED ON 810 MDC NET = 94.4%)

1. CRITICALITY -- APRIL 21, 1978
2. 100% POWER -- MAY 8, 1978
3. SECOND REFUELING (10.5 WEEKS)
   MARCH 10, 1979 - MAY 22, 1979

CYCLE 3

1. CRITICALITY -- MAY 18, 1979
2. 2560 MWT POWER -- MAY 31, 1979

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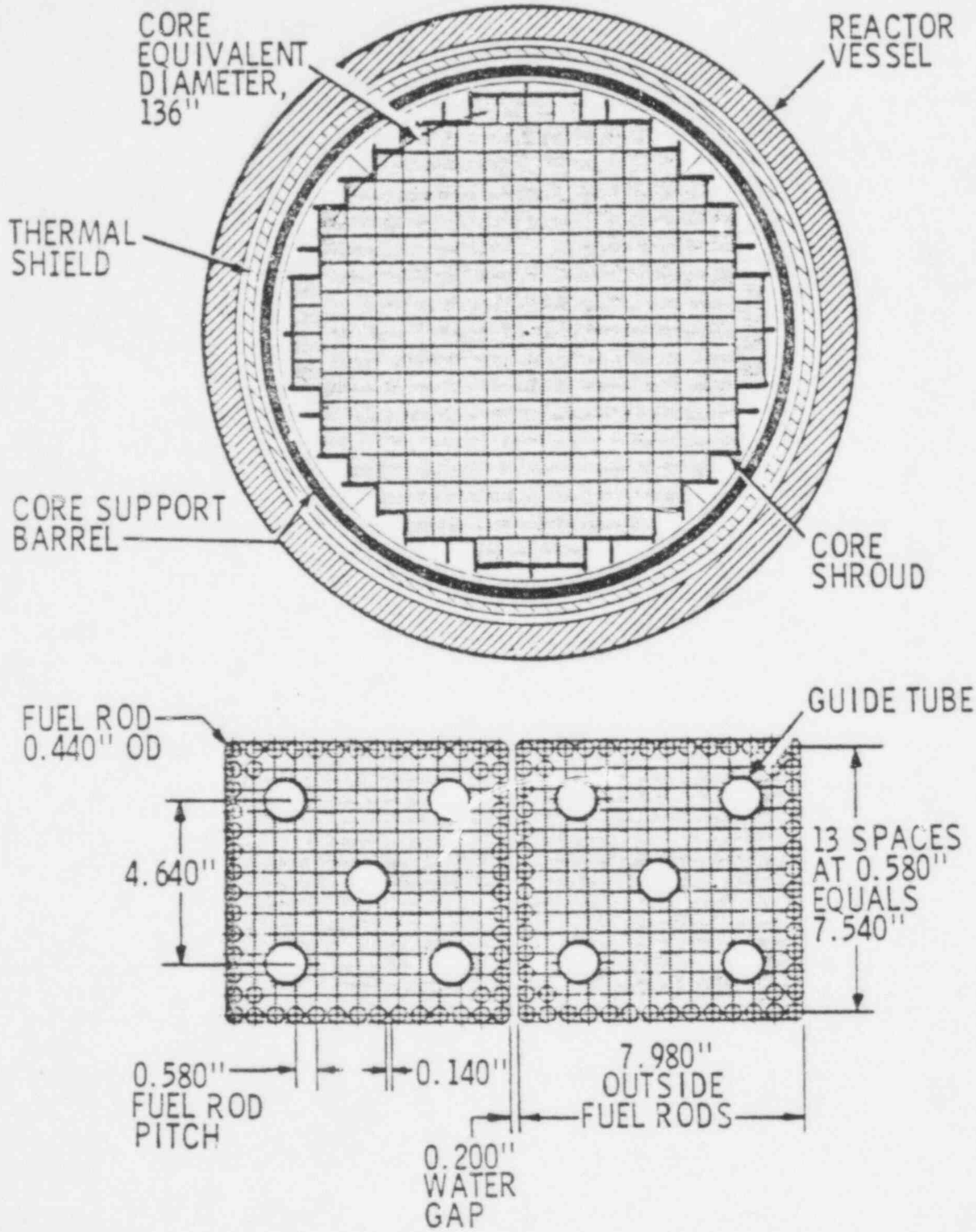
MILLSTONE UNIT NO. 2 - EXPECTED STEAM CYCLE PARAMETERS AT DIFFERENT CORE THERMAL CONDITIONS

CORE POWER/COLD LEG TEMPERATURE	CYCLE 2 2560 MWt/542°F	CYCLE 3 2560 MWt/549°F	CYCLE 3 2700 MWt/549°F
Steam Generator Outlet Flow	11,135,500 lbs/hr	11,151,200 lbs/hr	11,834,700 lbs/hr
Steam Generator Outlet Pressure	839 psia	880 psia	875 psia
Steam Generator Saturation Temperature	523.7°F	529.3°F	528.6°F
Steam Generator Outlet Moisture Content	0.2%	0.2%	0.2%
Turbine Inlet Steam Pressure	802 psia	841 psia	836 psia
Feedwater Flow to Steam Generator	11,151,000 lbs/hr	11,166,700 lbs/hr	11,849,800 lbs/hr
Final Feedwater Temperature	430°F	429.5°F	435.2°F
Condensate Flow	7,927,000 lbs/hr	7,893,300 lbs/hr	8,367,700 lbs/hr
Total Heat Rejected	5.83×10^9 Btu/hr	5.82×10^9 Btu/hr	6.13×10^9 Btu/hr
Expected Generator Output	851.9 MWe	854.8 MWe	901.4 MWe



Millstone Nuclear Power Station Unit No. 2	Reactor Core Cross-Section	

573098

MP2 CORE PHYSICAL PARAMETERS

NUMBER OF FUEL ASSEMBLIES	217
FUEL ASSEMBLY ARRAY	14 x 14
FUEL ASSEMBLY DIMENSIONS	7.98 in. x 7.98 in.
PELLET OUTSIDE DIAMETER	.3765 in.
CLAD OUTSIDE DIAMETER	.440 in.
CLAD THICKNESS	.028 in.
FUEL RED PITCH	.580 in.
ACTIVE FUEL HEIGHT	136.7 in.
CORE EQUIVALENT DIAMETER	136.0 in.
NUMBER OF CONTROL ELEMENT ASSEMBLIES	73

MILLSTONE POINT II CYCLE 3
CORE LOADING

ASSEMBLY DESIGNATION	NUMBER OF ASSEMBLIES	INITIAL ENRICHMENT WT% U-235	AVERAGE BURNUP* MWD/MTU	NUMBER OF SHIMS	INITIAL SHIM LOADING WT% B_4C	TOTAL SHIMS	TOTAL FUEL RODS
B+	5	2.33	25,400	12	2.7	60	820
C	40	2.82	19,700	0	---	0	7,040
C+	16	2.82	24,800	12	.83	192	2,624
C	12	2.82	24,900	12	.46	144	1,968
D	48	3.03	7,600	0	---	0	8,448
D*	24	2.73	10,600	0	---	0	4,224
E	48	3.24	0	0	---	0	8,448
E*	24	2.73	0	0	---	0	4,224
	217					396	37,796

NOTES

*ASSUMES A CYCLE 2 LENGTH OF 8,700 MWD/T.

EXPECTED CYCLE 3 LENGTH: 10200 MWD/MT.

570100

MP2 PHYSICS CHARACTERISTICS

		CYCLE 2	CYCLE 3
DISSOLVED BORON	ppm	660	830
HFP, BOC			
BORON WORTH	ppm/%$\Delta\rho$		
HFP, BOC		88	93
HFP, BOC		77	82
MODERATOR TEMPERATURE COEFFICIENT	$10^{-4}\Delta\rho/^{o}F$		
HFP, BOC		-.6	-.2
HFP, EOC		-2.0	-1.8
AVAILABLE CEA WORTH	%$\Delta\rho$		
BOC		9.0	9.7
EOC		10.0	11.0
STUCK CEA WORTH	%$\Delta\rho$		
BOC		3.0	3.1
EOC		3.1	3.5
EJECTED CEA WORTH	%$\Delta\rho$		
HFP		.31	.29
HZP		.74	.65
PEAKING FACTORS			
F_R		1.440	1.598
F_{xy}		1.540	1.584

MP2 LOW POWER PHYSICS TEST RESULTS

	MEASURED	PREDICTED
CBC (PPM)		
ARO	1212 (7@ 135)	1205 (ARO)
ARI	888	861
ITC ($x10^{-4} \Delta\rho/^{o}F$)		
BANK 7 THRU 2 INSERTED	-.686	-.721
ARO	+.269	+.372
BANK WORTHS ($\%\Delta\rho$)		
BANK 7	.637	.64
BANK 6	.250	.25
BANK 5	.172	.16
BANK 4	.875	.95
BANK 3	.671	.72
BANK 2	1.139	1.08
OVERLAP	3.743	3.80

POWER DISTRIBUTION CHECK AT 50% POWER MEASURED: POWER DISTRIBUTIONS AGREED TO WITHIN 5% OF PREDICTED.

5?3102

MP2 THERMAL HYDRAULIC PARAMETERS

PARAMETER	UNITS	CYCLE 2	CYCLE 3
CORE POWER	Mwt	2560	2700
INLET TEMPERATURE	^{o}F	542	549
CORE FLOW RATE	$x10^{6}$LBM/HR	135.0	133.7
CORE AVERAGE HEAT FLUX	BTU/HR-FT^{2}	177,700	183,000
TOTAL HEAT TRANSFER AREA	FT^{2}	47,940	49,100
AVERAGE LINEAR HEAT RATE	KW/FT	5.99	6.17
AVERAGE ENTHALPY RISE	BTU/LBM	65	69

578103

KEY CHANGES FROM CYCLE 2

MODEL CHANGES:

1. T-H MODEL - TORC/CE1 (CYCLE 2 - COSMO/W3)
   - TORC MULTICHANNEL CODE T-H CODE
   - CE-1 CHF CORRELATION (LIMIT 1.19)
2. SMALL BREAK MODEL - MODELING CHANGES TO CEFLASH - 4AS
3. RMS STATISTICAL COMBINATION OF UNCERTAINTIES:
   - SETPOINTS
   - THERMAL MARGIN

INPUT SYSTEM CREDIT CHANGES:

1. CORE POWER	2700 MWt	(CYCLE 2 - 2560 MWt)
2. T INLET	549^{O}F	(CYCLE 2 - 542^{O}F)
3. SCRAM TIME	3.1 SEC	(CYCLE 2 - 2.75 SEC)
4. UNCERTAINTIES	6% ON Fr	
	7% ON Fq	573104

5. RCP SPEED SENSING: CREDIT FOR RCPSS TRIP IN 4 PUMP LOF INCIDENT

NORTHEAST UTILITIES MILLSTONE POINT UNIT 2, CYCLE 3
DESIGN BASIS EVENTS (DBEs) CONSIDERED IN STRETCH POWER ANALYSIS

ANTICIPATED OPERATIONAL OCCURRENCES FOR WHICH THE RPS ASSURES NO VIOLATION OF SAFDLs:	ANALYSIS STATUS
CONTROL ELEMENT ASSEMBLY WITHDRAWAL	REANALYZED
BORON DILUTION	REANALYZED
STARTUP OF AN INACTIVE REACTOR COOLANT PUMP	NOT ANALYZED
EXCESS LOAD	REANALYZED
LOSS OF LOAD	REANALYZED
LOSS OF FEEDWATER FLOW	REANALYZED
EXCESS HEAT REMOVAL DUE TO FEEDWATER MALFUNCTION	NOT ANALYZED
REACTOR COOLANT SYSTEM DEPRESSURIZATION	REANALYZED
LOSS OF COOLANT FLOW	REANALYZED
ANTICIPATED OPERATIONAL OCCURRENCES WHICH ARE DEPENDENT ON INITIAL OVERPOWER MARGIN FOR PROTECTION AGAINST VIOLATION OF SAFDLs:	
LOSS OF COOLANT FLOW	REANALYZED
FULL LENGTH CEA DROP	REANALYZED
PART LENGTH CEA DROP	NOT ANALYZED
PART LENGTH CEA MALPOSITIONING	NOT ANALYZED
TRANSIENTS RESULTING FROM MALFUNCTION OF ONE STEAM GENERATOR	REANALYZED
POSTULATED ACCIDENTS:	
CEA EJECTION	REANALYZED
STEAM LINE RUPTURE	REANALYZED
STEAM GENERATOR TUBE RUPTURE	REANALYZED
SEIZED ROTOR	REANALYZED

578105

SUMMARY OF MP2 CYCLE 3 TRANSIENT ANALYSIS RESULTS

CEA WITHDRAWAL

MIN DNBR - 1.58

MAX PRESSURE - 2358 PSIA

TM/LP TRIP PRESSURE BIAS - 45 PSIA

BORON DILUTION

10 MINUTES EXISTS FOR OPERATOR ACTION

EXCESS LOAD

MIN DNBR - 1.41

LOSS OF LOAD

MIN DNBR - 1.33

MAX PRESSURE - 2555 PSIA

LOSS OF FEEDWATER

MIN DNBR - 1.33

MAX PRESSURE - 2476 PSIA

15 MINUTES TO INITIATE AUX FEED.

EXCESS HEAT REMOVAL DUE TO FEEDWATER MALFUNCTION
BOUNDED BY PREVIOUS ANALYSIS

RCS DEPRESSURIZATION

TM/LP TRIP PRESSURE BIAS - 35 PSIA

LOSS OF FLOW

MIN DNBR - 1.19

MAX PRESSURE - 2301 PSIA

CEA DROP

MIN DNBR - 1.21

578106

ASYMMETRIC STEAM GENERATOR TRANSIENTS

LOSS OF LOAD TO ONE STEAM GENERATOR

MIN DNBR - 1.24

CEA EJECTION

NO CLAD DAMAGE

STEAMLINE BREAK

FULL LOAD

SUBCRITICAL BY .15% $\Delta\rho$

BRIEF POWER INCREASE - 8% TO 12%

NO LOAD

BRIEF CRITICALITY - .21% $\Delta\rho$ MAX

STEAM GENERATOR TUBE RUPTURE

SITE BOUNDARY DOES ACCEPTABLE

SIEZED ROTOR

1% FAILED FUEL

SITE BOUNDARY DOES ACCEPTABLE

578107

MP2 CYCLE 3 LARGE BREAK LOCA ANALYSIS

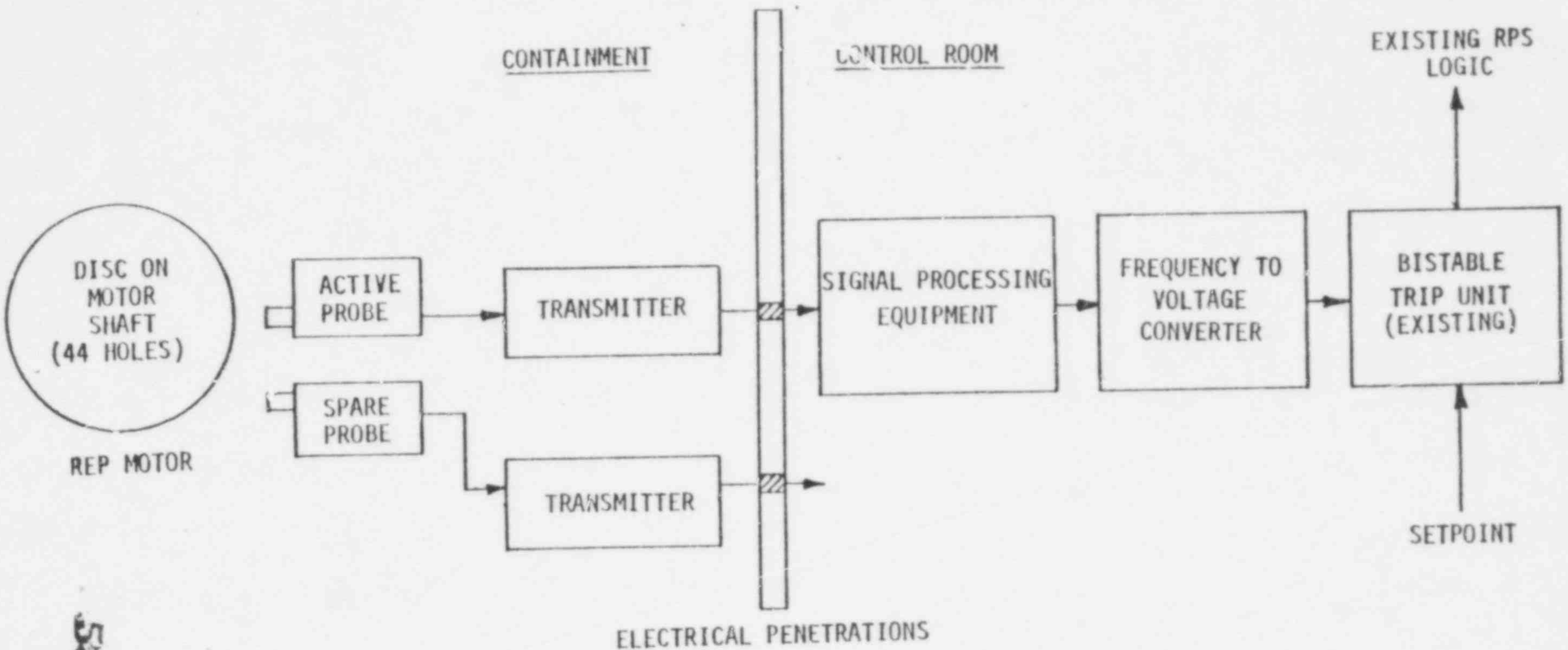
BREAK	PCT CYCLE 2	PCT CYCLE 3
1.0 DES/PD	2110°F	2079°F
.8 DES/PD	2160°F	2077°F
.6 DES/PD		1950°F
1.0 DEG/PD	2105°F	2080°F
.8 DEG/PD	2111°F	2081°F
.6 DEG/PD		1948°F
PLHR	15.6 KW/FT	15.6 KW/FT
MAXIMUM LOCAL CLAD OXIDATION	<10.7%	<16.0%
MAXIMUM CORE WIDE OXIDATION	<.58%	<.73%

MP2 SMALL BREAK LOCA RESULTS

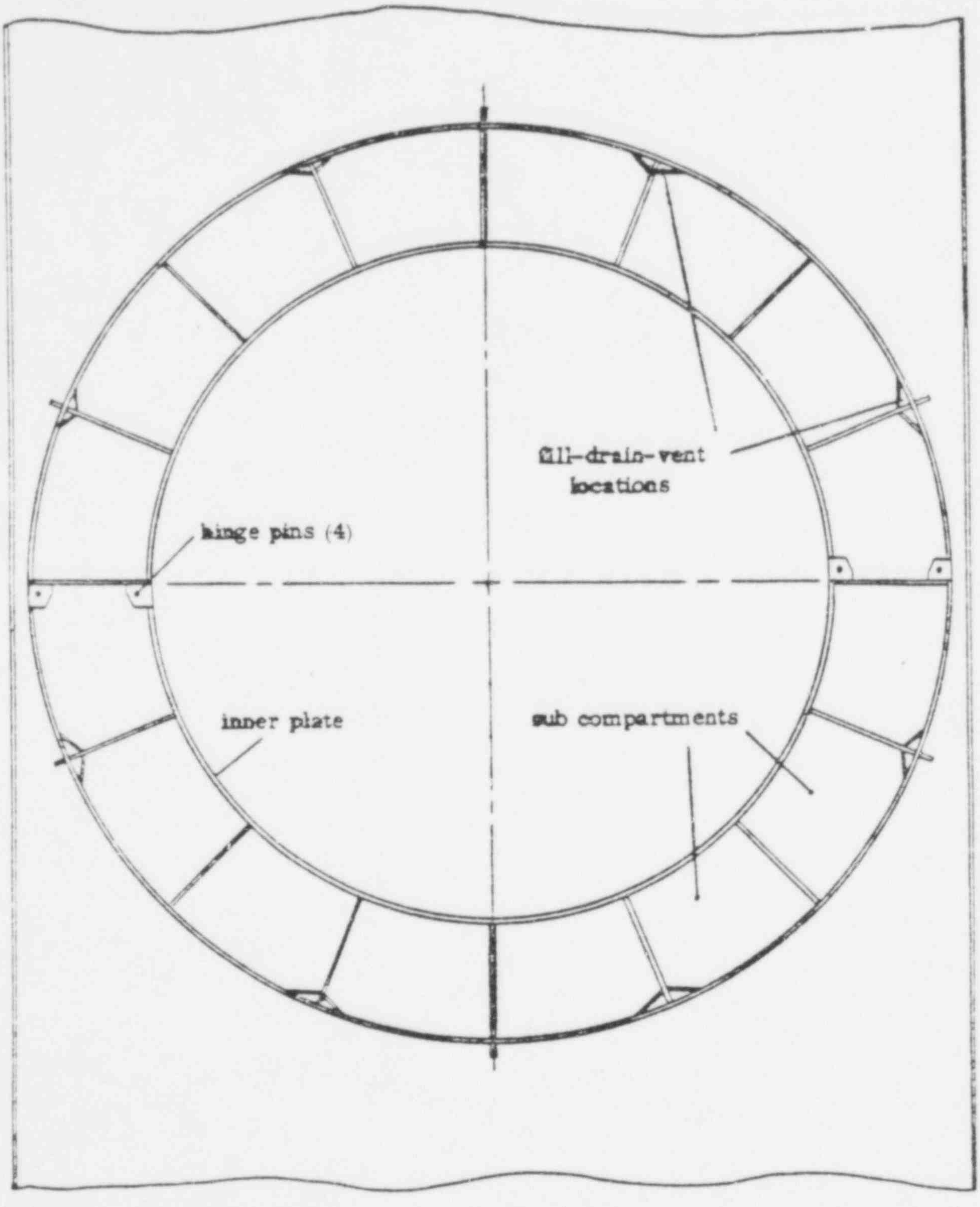
BREAK AREA	CYCLE 2 PCT	CYCLE 3 PCT
.5	1075°F	1629°F
.2	1562°F	1612°F
.1		1971°F
.05	1931°F	1824°F
.02	662°F	558°F

578109

REACTOR COOLANT PUMP SHAFT SPEED SENSING SYSTEM
(TYPICAL CHANNEL)

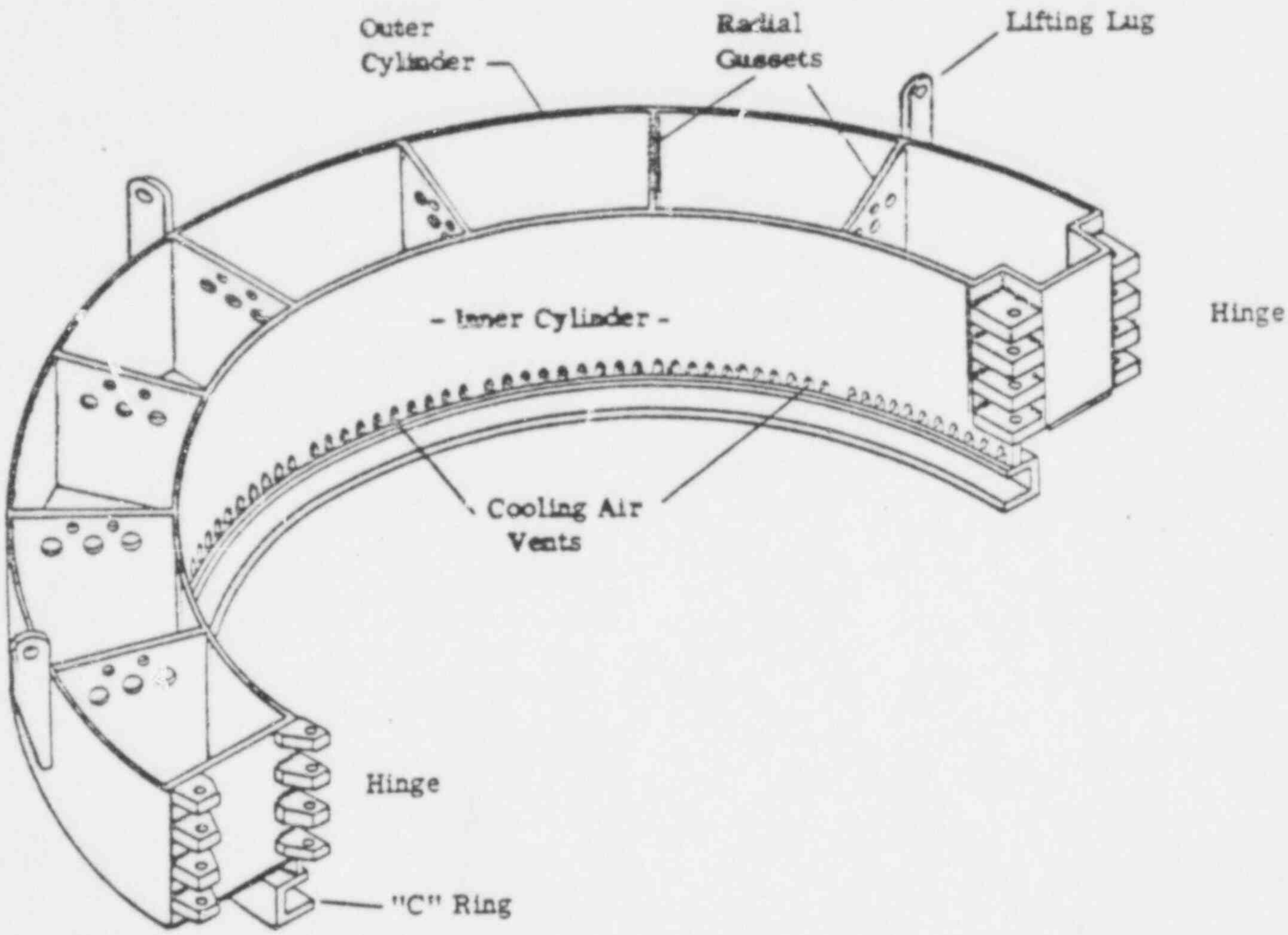


578110

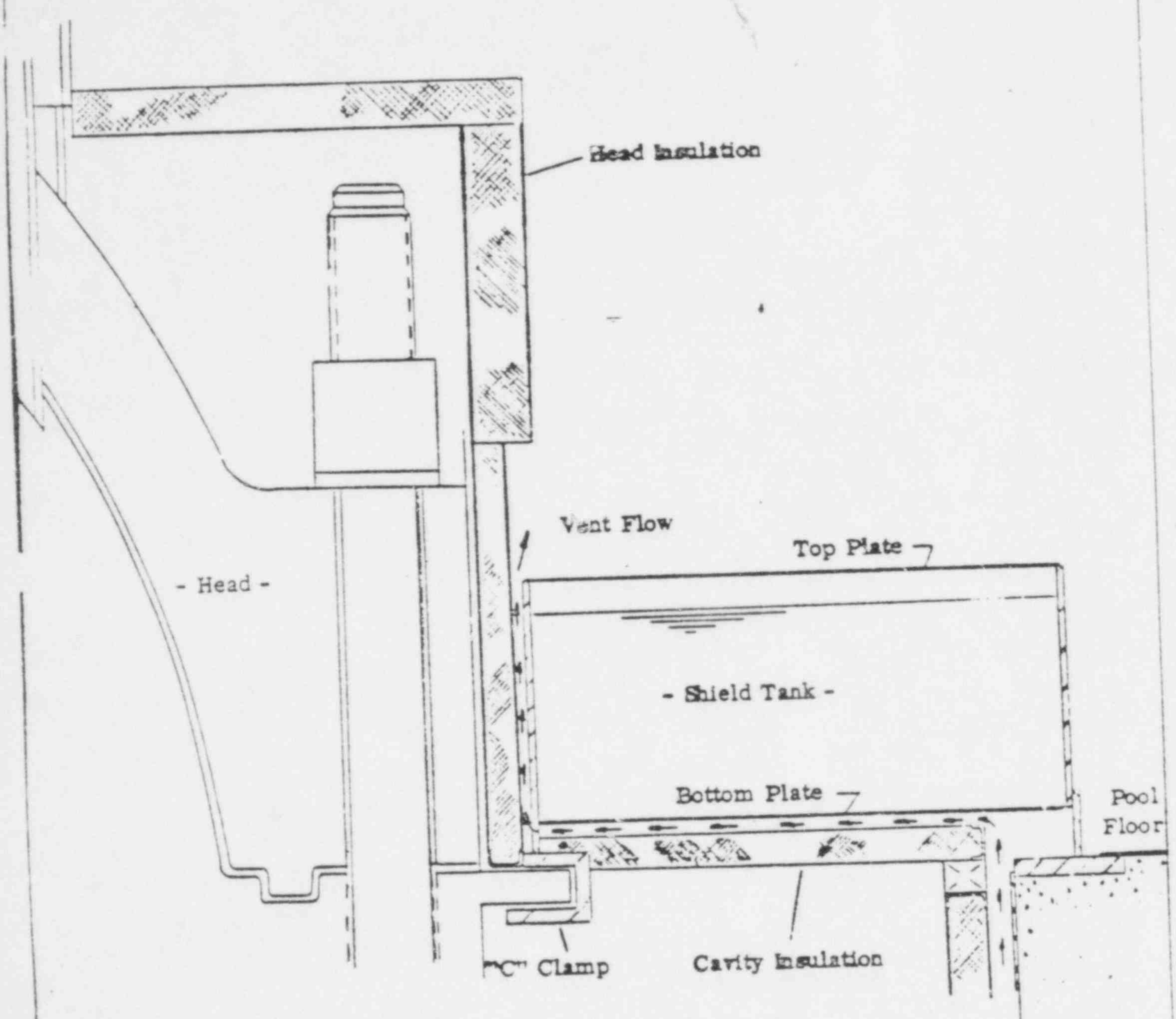


shield tank layout arrangement.

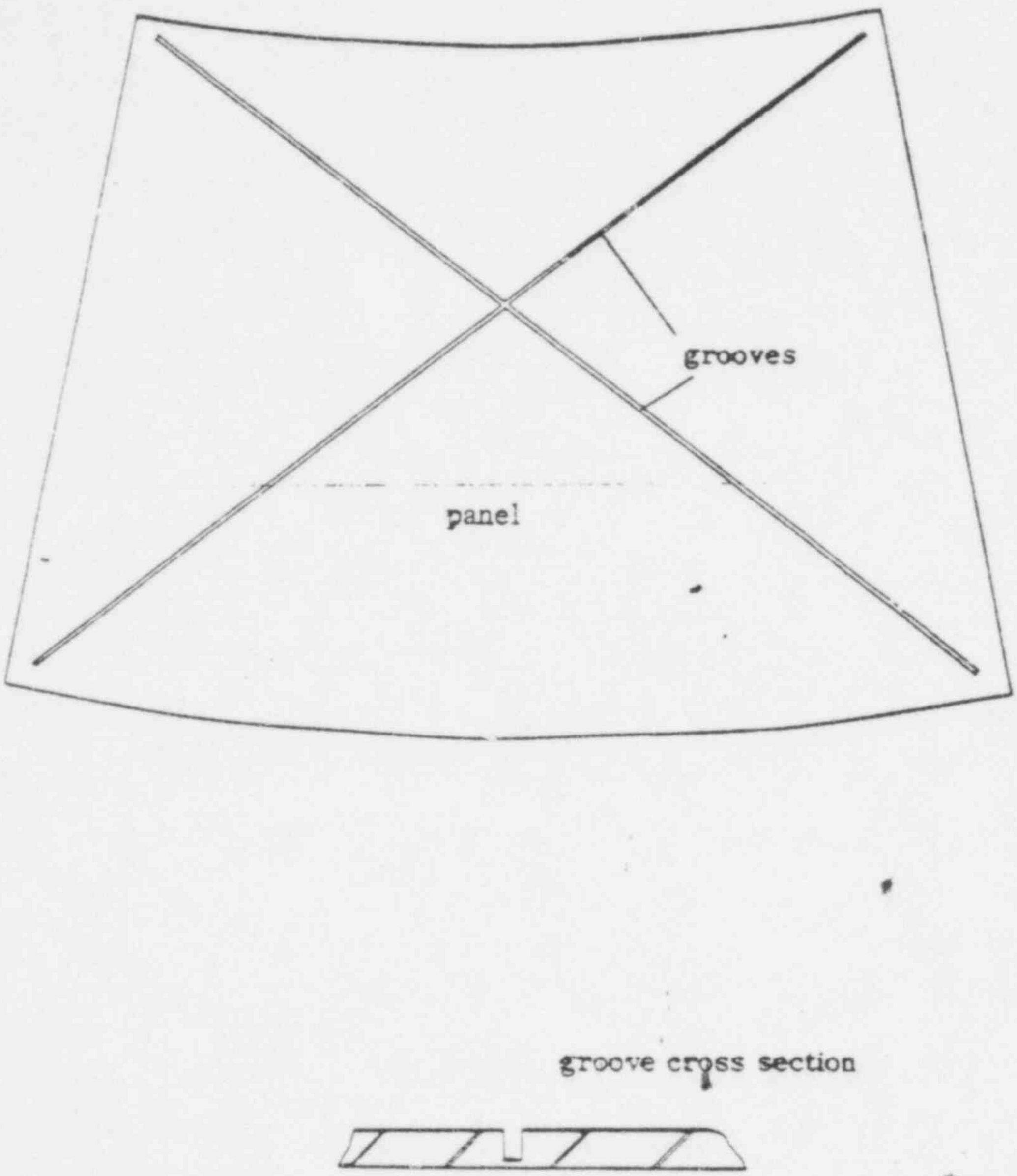
578111



SHIELD TANK ASSEMBLY (LESS TOP COVER AND THERMAL INSULATION).



SHIELD TANK CROSS SECTION ARRANGEMENT



Rupture panel layout

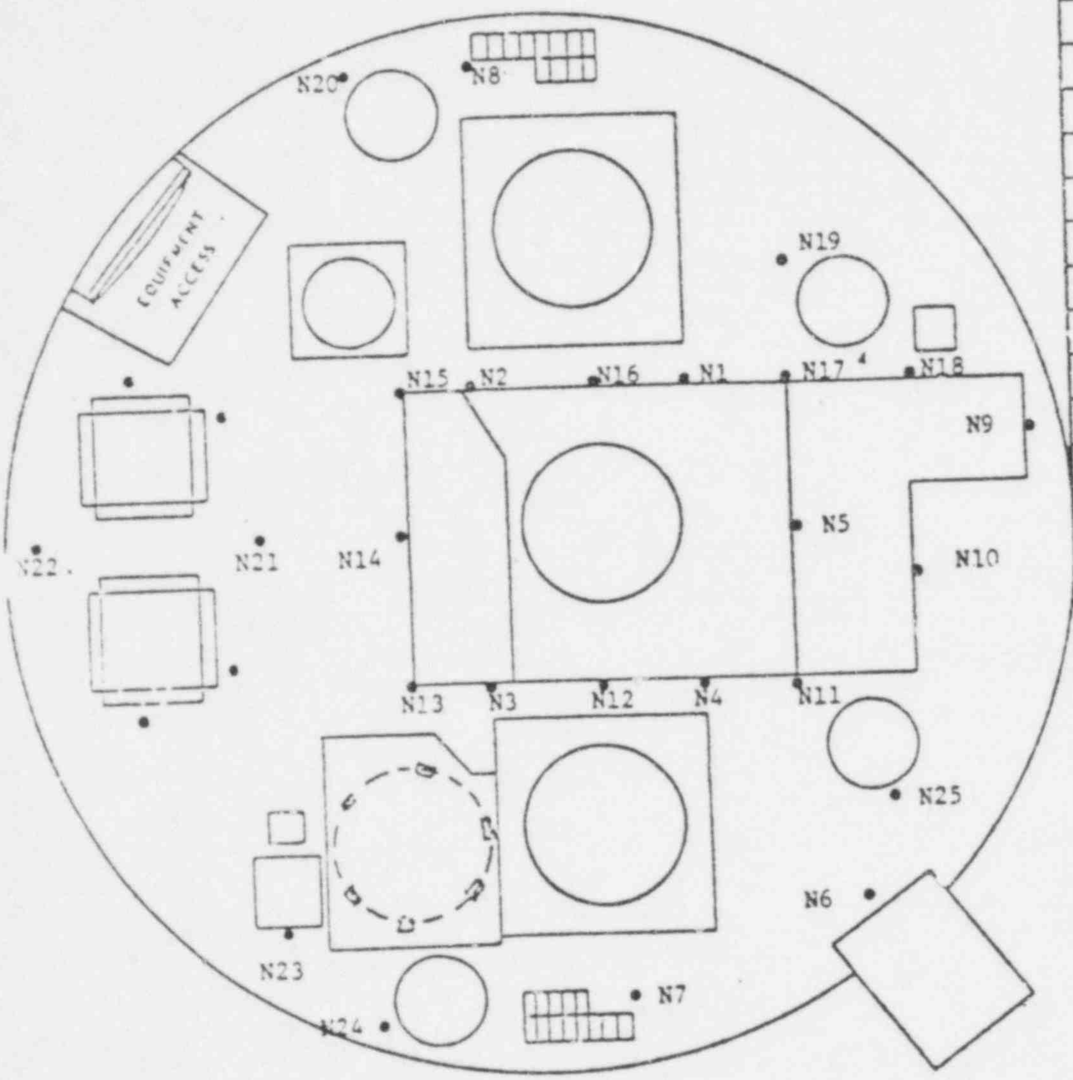
578114

MILLSTONE UNIT NO. 2

NEUTRON SURVEY

ELEVATION 38'6"

B = Before Shield
A = After Shield
RF = Reduction Factor
R = Thousands (R/hr)



mrem/hr

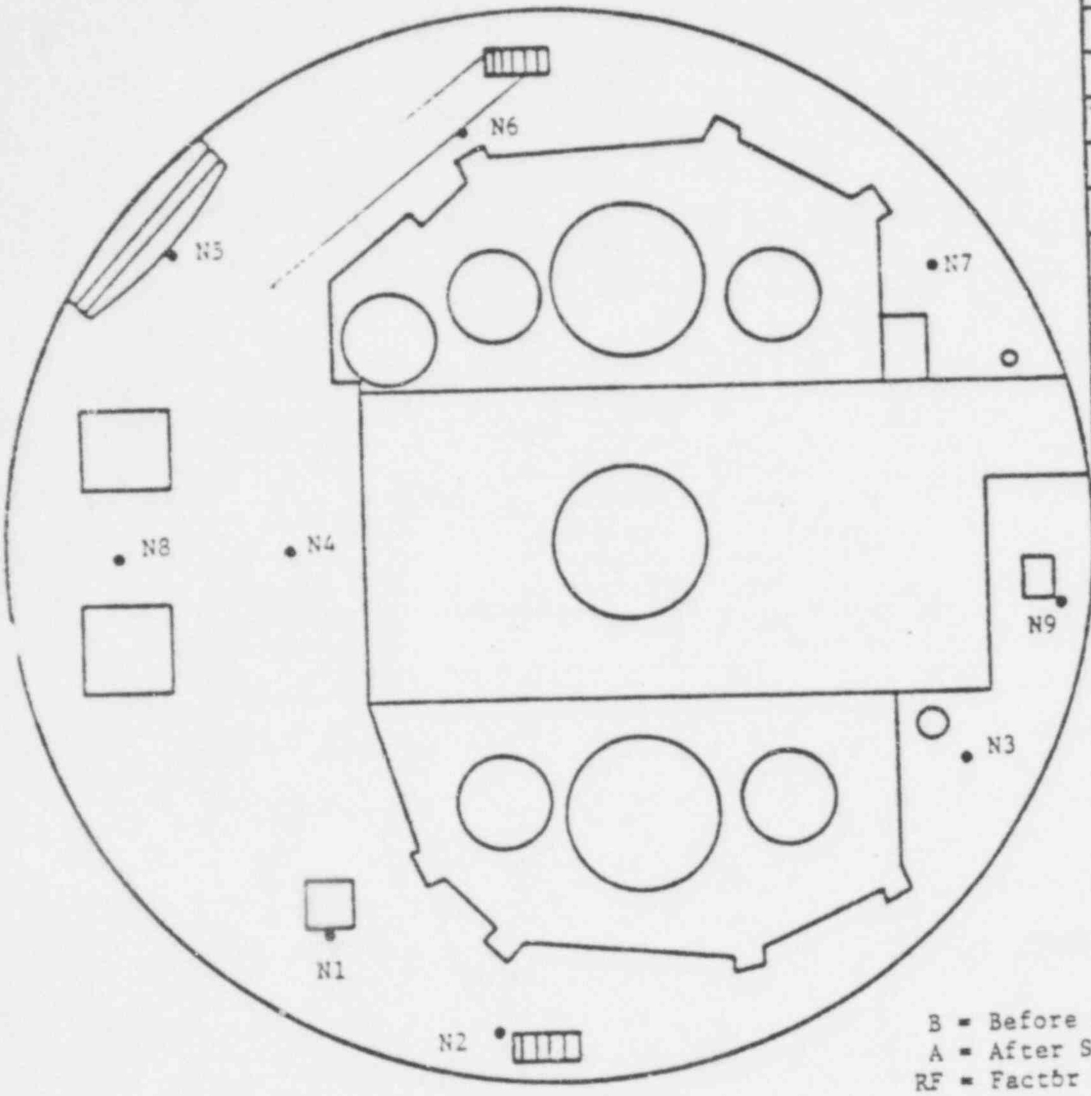
RESULTS			
POINT	B	A	RF
N1	60R	1R	60
N2	60R	1R	60
N3	60R	-	-
N4	60R	1R	60
N5	65R	1R	65
N6	4R	40	100
N7	1.5R	10	150
N8	1.5R	10	150
N9	5R	150	33
N10	20R	600	33
N11	10R	400	25
N12	6R	-	-
N13	10R	-	-
N14	10R	400	25
N15	10R	-	-
N16	6R	-	-
N17	10R	400	25
N18	6R	-	-
N19	5R	60	83
N20	4R	15	93
N21	[illegible]	80	85
N22	2R	30	67
N23	2R	30	67
N24	2R	30	67
N25	3R	40	75

EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

MILLSTONE UNIT NO. 2

NEUTRON SURVEY

ELEVATION 14'6"



mrem/hr

RESULTS			
POINT	B	A	RF
N1	400		
N2	300	6	50
N3	300	6	50
N4	800		
N5	900	10	90
N6	300		
N7	300		
N8	-	10	-
N9	-		

B = Before Shield
A = After Shield
RF = Factor of Reduction

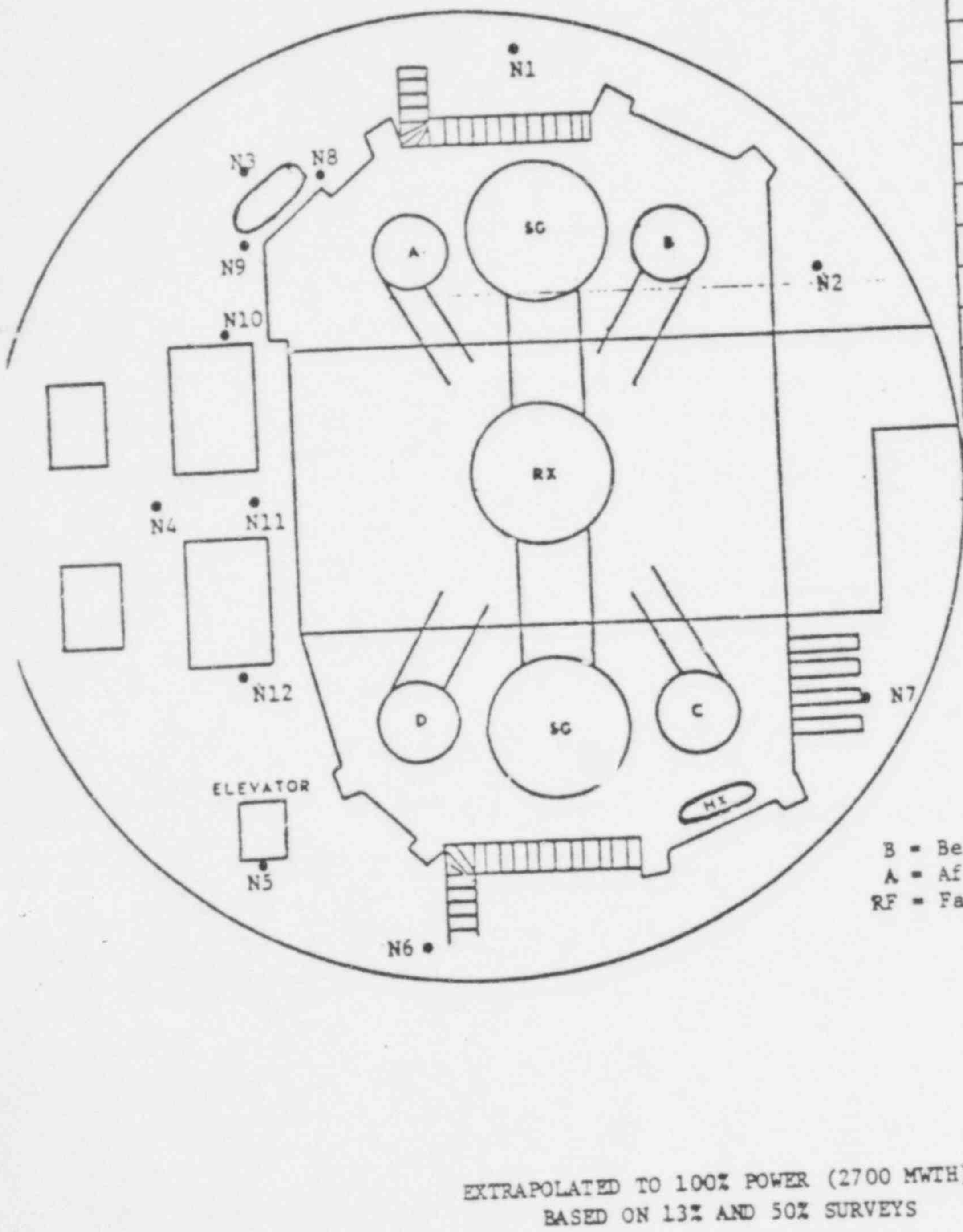
EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

578116

MILLSTONE UNIT NO. 2

NEUTRON SURVEY

ELEVATION -3'6"



mrem/hr

POINT	RESULTS B	A	RF
N1	200		
N2	175	25	7
N3	250	8	25
N4	250	10	31
N5	250		
N6	200	8	25
N7	200	8	25
N8	-		
N9	-		
N10	-		
N11	-		
N12	-		

B = Before Shield
A = After Shield
RF = Factor of Reduction

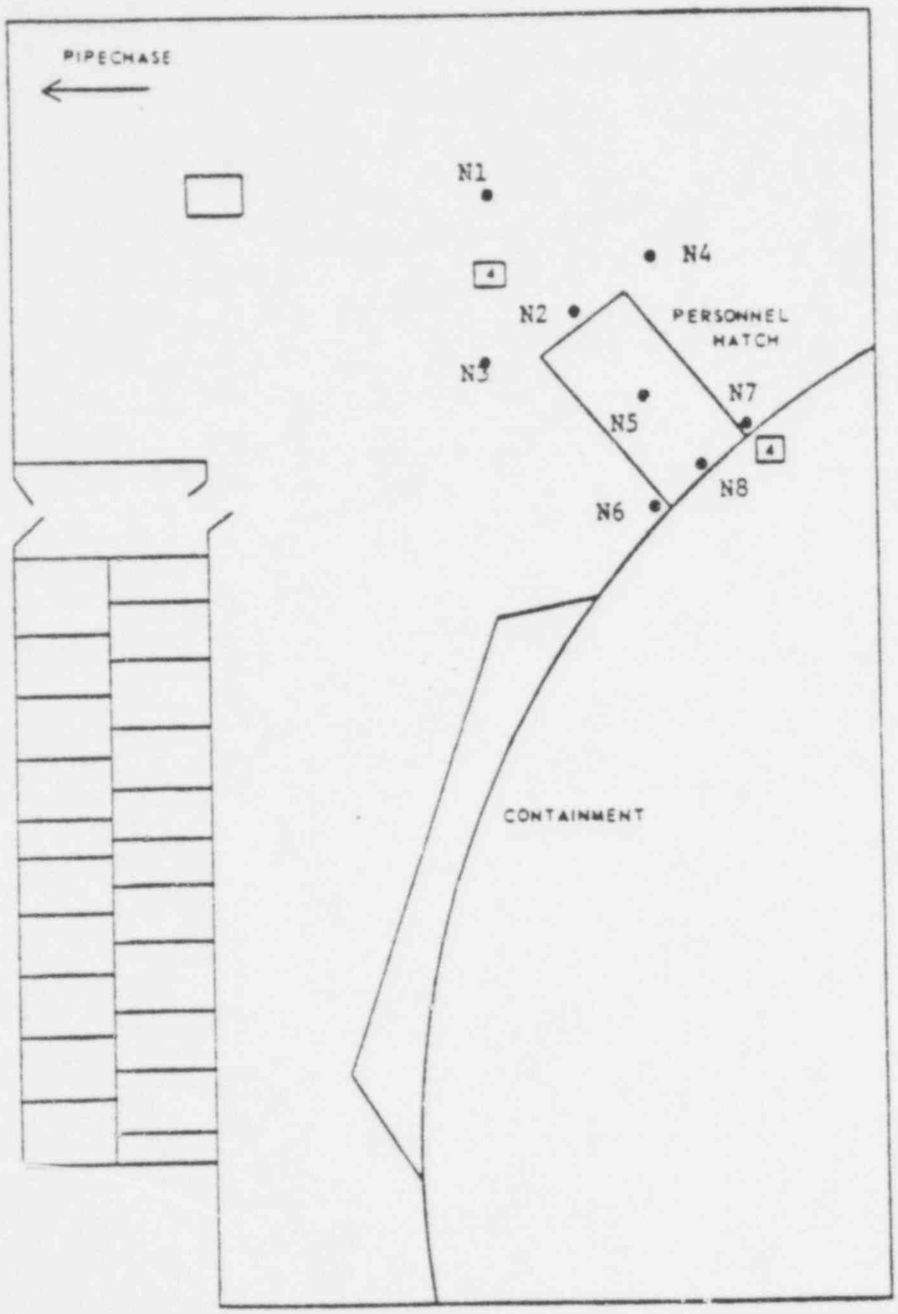
EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

578117

MILLSTONE UNIT NO. 2

NEUTRON SURVEY

ELEVATION 38'6"



mrem/hr

RESULTS			
POINT	B	A	RF
N1	20		
N2	100		
N3	30		
N4	30		
N5	300	6	50
N6			
N7			
N8	-	8	

B = Before Shield
A = After Shield
RF = Factor of Reduction

EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

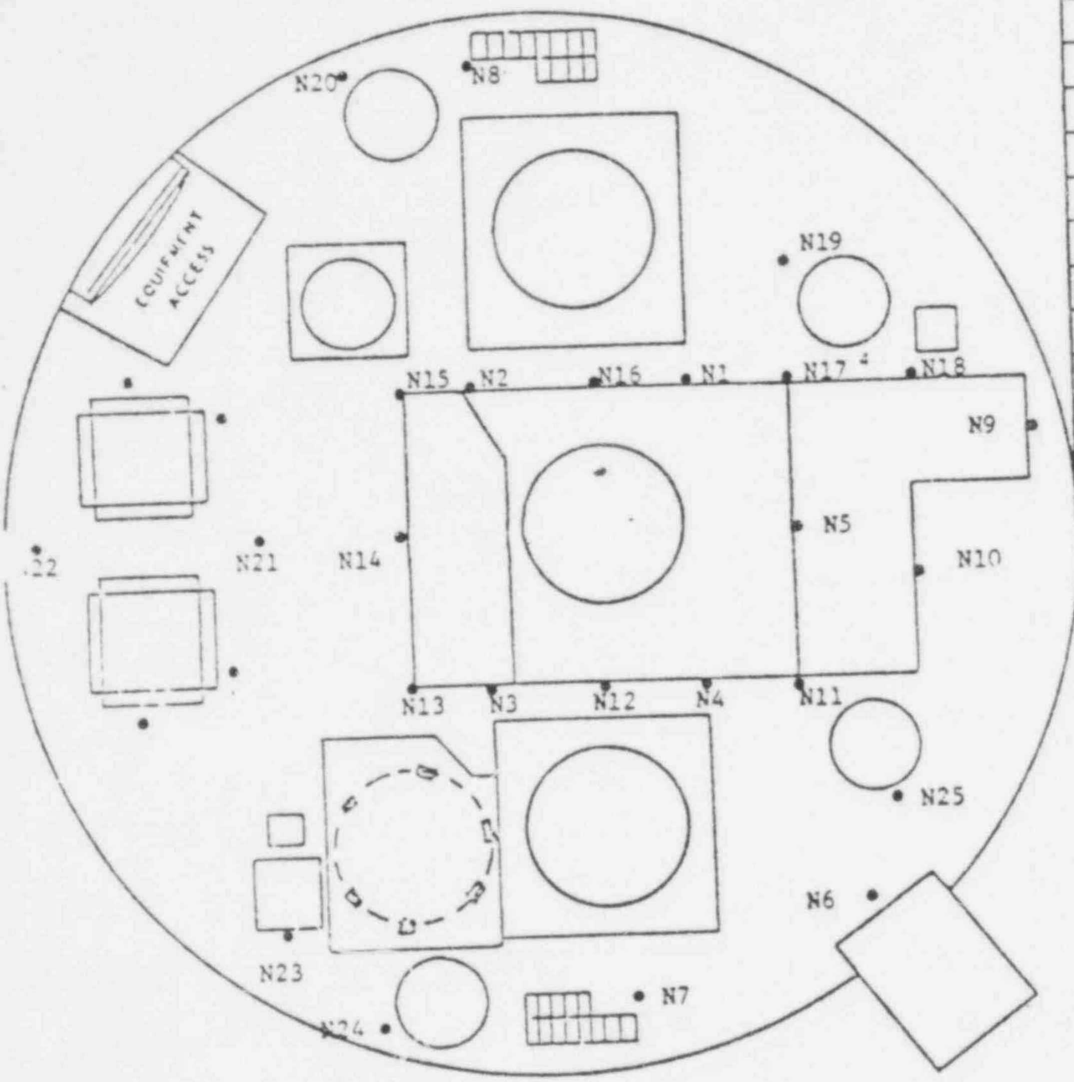
578118

MILLSTONE UNIT NO. 2

GAMMA SURVEY

ELEVATION 38'6"

B = Before Shield
A = After Shield
RF = Reduction Factor
R = Rem/hr



mrem/hr

RESULTS			
POINT	B	A	RF
N1	8R	1.7R	5
N2	8R	1.7R	5
N3	8R	-	-
N4	8R	1.7R	5
N5	10R	1.7R	6
N6	450	20	22
N7	225	10	22
N8	225	10	22
N9	1R	200	5
N10	4R	600	7
N11	2.5R	400	6
N12	1.5R	-	-
N13	2.5R	-	-
N14	3.2R	250	13
N15	2.5R	-	-
N16	1.5R	-	-
N17	2.5R	400	6
N18	1.5R	-	-
N19	1R	50	20
N20	180	20	9
N21	1.1R	40	27
N22	400	20	20
N23	350	15	23
N24	450	17	26
N25	450	25	18

EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

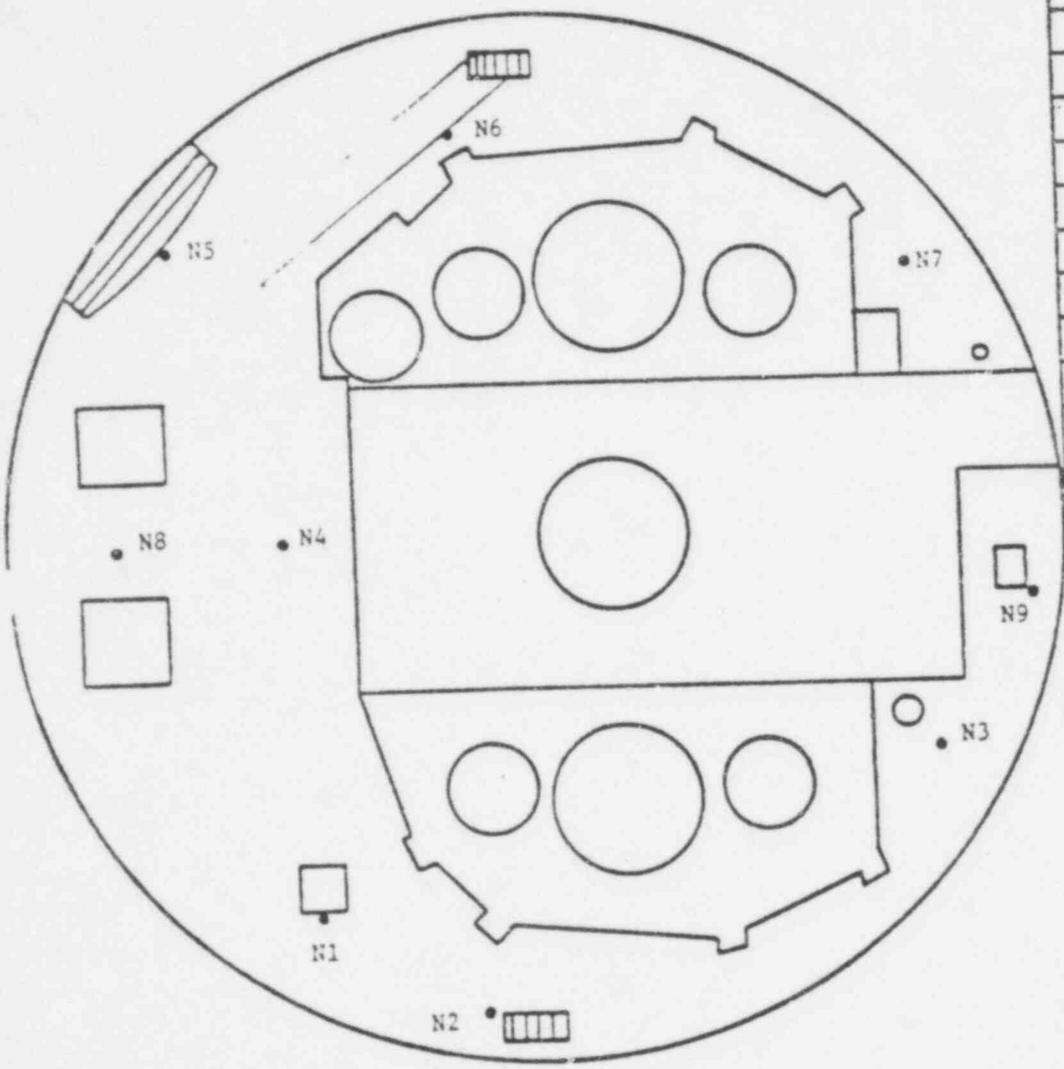
578119

MILLSTONE UNIT NO. 2

GAMMA SURVEY

ELEVATION 14'6"

B = Before Shield
A - After Shield
RF = Reduction Factor



mrem/hr

RESULTS			
POINT	B	A	RF
N1	60		
N2	50	6	8
N3	60	25	2
N4	130	8	16
N5	130	8	16
N6	50	25	2
N7	50	8	6
N8	-	8	-
N9	-		

EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED on 13% AND 50% SURVEYS

578120

MILLSTONE UNIT NO. 2

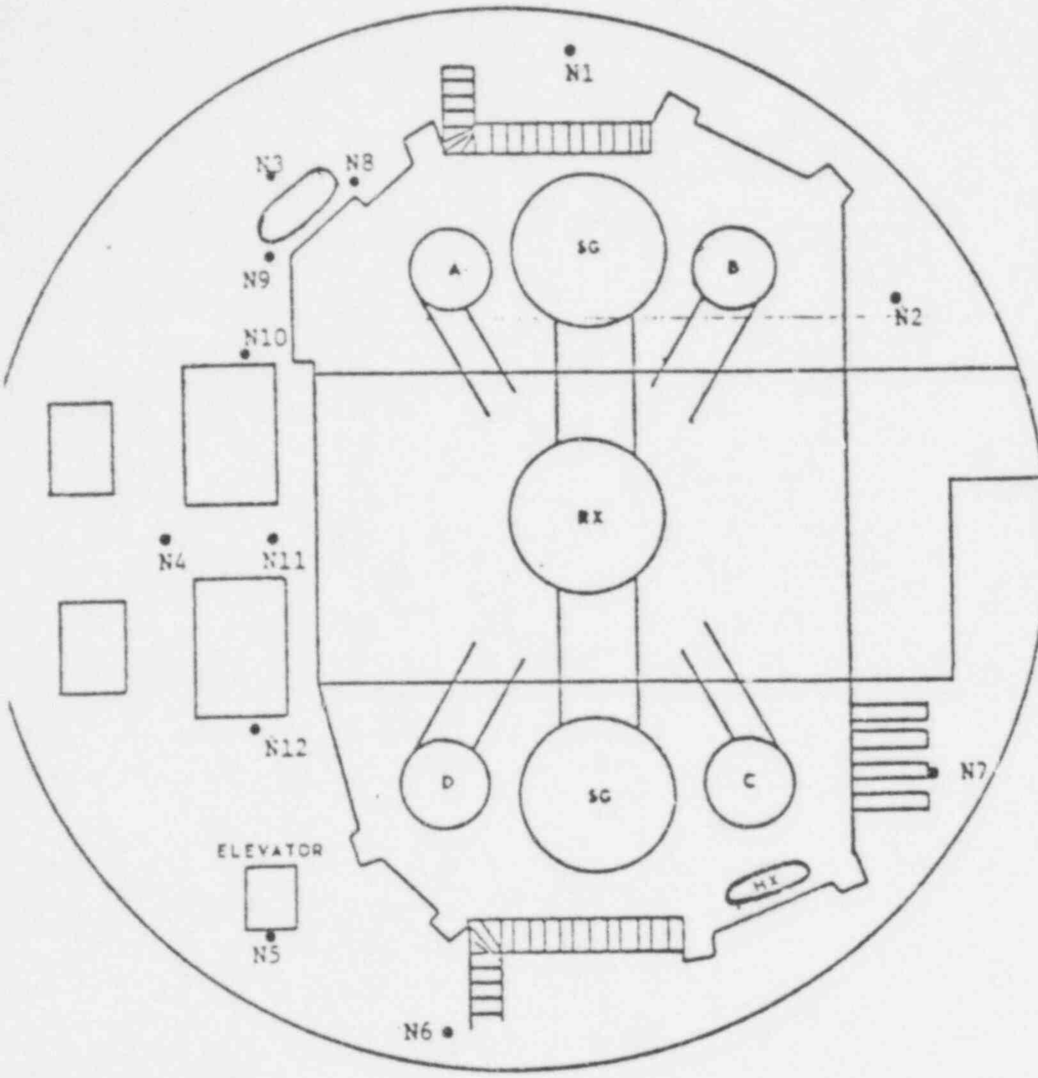
GAMMA SURVEY

ELEVATION -3'6"

B = Before Shield
A = After Shield
RF = Reduction Factor

mrem/hr

RESULTS			
POINT	B	A	RF
N1	15		
N2	20	24	0
N3	40	20	2
N4	40	6	7
N5	40		
N6	30	10	3
N7	250	280	0
N8	-	20	
N9	-		
N10	-		
N11	-		
N12	-		



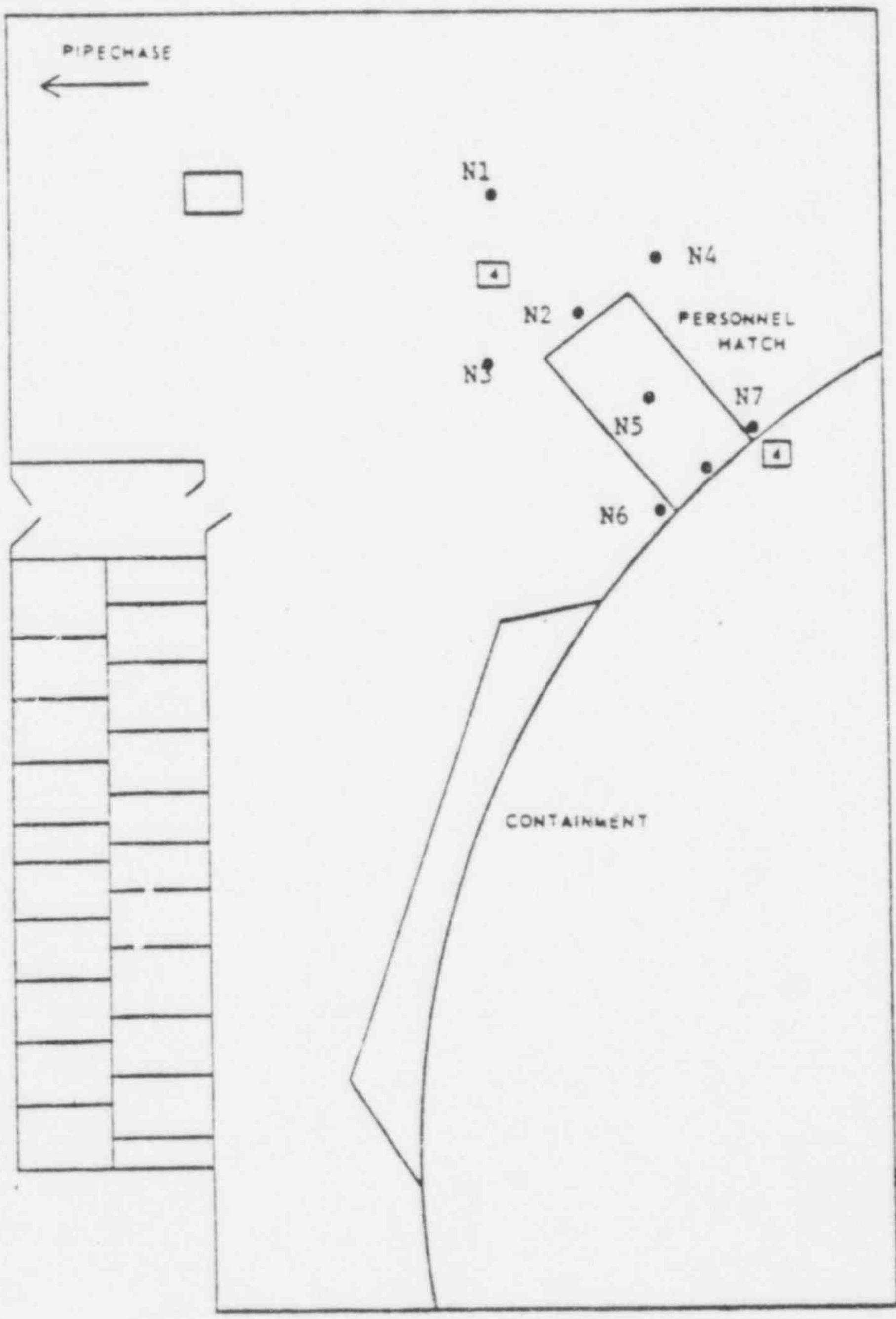
EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

578121

MILLSTONE UNIT NO. 2

GAMMA SURVEY

ELEVATION 38'6"



mrem/hr

RESULTS			
POINT	B	A	RF
N1	2.5		
N2	15		
N3	4		
N4	4		
N5	35	3	12
N6			
N7			
N8	-	6	

B = Before Shield
A = After Shield
RF = Reduction Factor

EXTRAPOLATED TO 100% POWER (2700 MWTH)
BASED ON 13% AND 50% SURVEYS

578122

POWER LEVEL USED FOR

LICENSEE ANALYSIS AND NRC EVALUATION

	MWT	
	CALVERT CLIFFS	MILLSTONE 2
FSAR		
CORE THERMAL OUTPUT	2560	2560
SITE PARAMETERS	2700	2700
MAJOR SYSTEMS AND COMPONENTS INCL. ECCS AND CONTAINMENT	2700	2700
AOOs		
• CEA WITHDRAWAL	2611	2611
• BORON DILUTION	2611*	2611*
• LOSS OF LOAD	2611	2611
• LOSS OF FEEDWATER FLOW	2611	2611
• LOSS OF COOLANT FLOW	2611	2611
• CEA DROP	2611	2611
• EXCESS LOAD	2611	2611
ACCIDENTS		
• CEA EJECTION	2611	2611
• STEAM LINE RUPTURE	2700	2611
• SG TUBE RUPTURE	2700	2611
• RCP SEIZED ROTOR	2611	2611
LOCA	2560	2621
SER	2700	2560
FES	2560	2700
ACRS LETTER	2560	2560

*OTHER POWER LEVELS ALSO ANALYZED.

57[illegible]

MILLSTONE-2

FSAR

An intial license is requested by the applicants to operate Millstone Unit 2 at a core thermal output of 2560 megawatts. Physics and core thermal hydraulic information in this report is based upon a core power level of 2560 megawatts, which corresponds to an NSSS rating of 2570 megawatts, recognizing other reactor coolant heat sources such as reactor coolant pumps and pressurizer heaters. Site parameters and the major systems and components, including the engineered safety features and the containment structures, have been evaluated for operation at a core power level of 2700 megawatts. Additionally, certain of the postulated incidents considered in Chapter 14 are evaluated at the higher power level.

CALVERT CLIFFS

FSAR

An initial license is requested to operate each of the facilities at a thermal output of 2570 megawatts (MWt), however, the applicant intends to eventually file an application for a license amendment to authorize operation at higher power levels not exceeding 2700 MWt. Physics and core thermal hydraulic information in this report are based upon a core power level of 2560 MWt, which corresponds to an NSSS rating of 2570 MWt recognizing other reactor coolant heat sources such as reactor coolant pumps and pressurizer heats. Site parameters and the major systems and components including the engineered safety features and the containment structures have been evaluated for operation at a core power level of 2700 MWt. Additionally, certain of the postulated incidents considered in Section 14 are evaluated at a power level of 2700 MWt.

AUGUST 28, 1972 SER

FOR THE CALVERT CLIFFS UNITS

THE APPLICANT INCREASED THE DESIGN POWER LEVEL FOR THE CALVERT CLIFFS REACTORS AND THE INITIAL POWER LEVEL FOR WHICH HE IS REQUESTING AN OPERATING LICENSE BY ABOUT 5% OVER THE 2440 MWT VALUE HE INDICATED DURING THE CONSTRUCTION PERMIT REVIEW. THIS 2560 MWT VALUE IS STILL SIGNIFICANTLY LESS THAN THE 2700 MWT VALUE BG&E INDICATED DURING THE CONSTRUCTION PERMIT REVIEW, AND NOW AS THE POWER AT WHICH BG&E BELIEVES THE REACTOR WILL ULTIMATELY PROVE TO BE CAPABLE OF OPERATION. FOR THIS REASON, AS DISCUSSED IN SECTION 3.1.8 OF THIS SAFETY EVALUATION, THE ENGINEERED SAFETY FEATURES OF THIS PLANT HAVE BEEN DESIGNED TO ACCOMMODATE THIS HIGHER POWER LEVEL.

MAY 10, 1974 SER

FOR MILLSTONE-2

The current application requests an operating license of 2560 thermal megawatts (MWt) which corresponds to a Nuclear Steam Supply System (NSSS) output of 2570 MWt and is equivalent to a gross electrical output of approximately 865 electrical megawatts (MWe). This is the same power level that was requested in the initial application.

POWER LEVEL INCREASE ACTIONS

(Last Three Years)

	Licensed Power Level	FSAR Ultimate Level	Application Date	Requested Power Level	Authorization Date
Zion 1	2760	3250	12/1/70	3250	6/25/76
Zion 2	2760	3250	12/1/70	3250	6/25/76
Calvert Cliffs 1	2560	2700	3/24/77	2700	9/9/77
Calvert Cliffs 2	2560	2700	7/13/77	2700	10/19/77
Palisades	2200	2650	7/17/77	2530	11/1/77
Maine Yankee	2440	2550	8/1/77	2630	5/10 & 6/20/78
Indian Point 3	2760	3083	4/20/77	3025	8/18/78
Palisades	2200	2650	1/22/74	2638	Pending
H. B. Robinson	2200	2300	2/1/74	2300	Pending
Crystal River	2452	2544	3/15/79	2544	Pending
Millstone 2	2560	2700	12/15/79	2700	Pending
Indian Point 2	2758	3083	-	-	Potential
Ft. Calhoun	1420	1500	-	-	Potential
St. Lucie 1	2560	2700	-	-	Potential

578128

PAST ANALYSIS AND EVALUATION POWER LEVEL

FSAR	MWT
Core Thermal Output	2560
Site Parameters	2700
Major Systems and Components Including ECCS and Containment	2700
Certain Postulated Incidents	2700
SER	
Staff Evaluation	2560
FES	
Staff Evaluation	2700

JUNE 11, 1974 ACRS LETTER UNRESOLVED ISSUES

1. EMERGENCY CORE COOLING SYSTEM
2. HEATUP AND COOLDOWN PRESSURE-TEMPERATURE LIMITS
3. CONTAINMENT SUMP
4. INSERVICE INSPECTION
5. INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT

ORIGINAL LICENSE CONDITIONS

1. Low Pressure Safety Injection
   Pump Mini-Flow Bypass Line

2. Neutron Shielding Measurements

3. Pre-Operational Reactor Coolant Pump Flow Test Data

SYSTEM CHANGES FOR OPERATION AT THE INCREASED POWER LEVEL OF 2700 MWt

1. LOCA Credit for Charging Pump Flow

2. RCP Speed Sensing RPS Trip

3. Installation of Neutron Shield

SIX SYSTEMS REQUIRING REANALYSIS

1. Volume Control Tank Changing Bypass Lines
2. Nitrogen Addition System
3. Charging System
4. Diesel Generator Exhaust Piping
5. Reactor Coolant Pump Tap Root Valve Instrument
6. Safety Injection and Containment Spray Test Line

LER COUNT FOR 1978

67	Operating Plant Average	45.4
25	BWR Plant Average	45.2
42	PWR Plant Average	45.5
25	W Plant Average	46.0
9	B&W Plant Average	47.2
8	CE Plant Average	41.9
	Millstone-1	31
	Millstone-2	32

MILLSTONE-2 ABNORMAL OCCURRENCES

Incident Date	Event	Status
July 1976	Degraded Grid Voltage	Closed
November 1977	Containment Electrical Penetrations	Interim Repair
December 1977	CEA Guide Tube Wear	Interim Repair
July 1978	Containment Purge Valves	Administrative Control

PERSONNEL RADIATION EXPOSURE

	Person-REM	
	1977	1978
LWR Average	570	497
BWR Average	828	604
PWR Average	396	428
Millstone-1	392	1239
Millstone-2	242	1621

ORDER TO SHOW CAUSE

- WHY THE LICENSEE SHOULD NOT REANALYZE THE FACILITY PIPING SYSTEMS FOR SEISMIC LOADS USING AN APPROPRIATE PIPING CODE;

- WHY THE LICENSEE SHOULD NOT MAKE ANY NECESSARY MODIFICATIONS FOLLOWING REANALYSIS;

- WHY FACILITY OPERATION SHOULD NOT BE SUSPENDED PENDING SUCH REANALYSIS AND COMPLETION OF ANY REQUIRED MODIFICATIONS

PIPING REANALYSIS STATUS REPORT AS OF 6/14/79

	MY	BV	F	S-1	S-2
PIPE ANALYSES TO DO	19	86	96	69	67
COMPLETED WITHIN ALLOWABLE	19	83	73	33	0
COMPLETED ABOVE ALLOWABLE (HARDWARE CHANGE REQUIRED)	0	3	0	0	0
PIPING SUPPORTS TO EVALUATE	2	732	875	887	808
COMPLETED WITHIN ORIGINAL DESIGN	0	635	263	160	0
COMPLETED ABOVE ORIGINAL DESIGN (HARDWARE CHANGE REQUIRED)	2	97	23	1	0
ESTIMATED ANALYSIS COMPLETION DATE	5/2	7/1	7/1 (10/1)	6/30 (9/15)	
ESTIMATED START UP DATE	5/24	7/6	7/1	6/20	10/1*

*ESTIMATED COMPLETION OF STEAM GENERATOR REPLACEMENT

578138

INFORMATION REQUESTED BY NRR
<u>LETTER OF 4-2-79</u>

- FOR COMPUTER CODES USED;
  - VERIFY WHERE ALG. SUM USED
  - PROVIDE CODE LISTING

- FOR HAND CALC. METHODS
  - DESCRIBE/JUSTIFY METHODS

- PROVIDE STATUS OF RESPONSE TO IEB 79-02

- IDENTIFY ALL SAFETY SYSTEMS AND ANALYSIS METHODS

- FOR CODES USED FOR PREVIOUS EVAL. OR REANALYSIS PROVIDE INFORMATION ON VERIFICATION

OPERATING REACTORS RESPONSE TO IEB 79-07

	UNIT	CODE	REMARKS
	BEAVER VALLEY	SHOCK 2	EXTENSIVE, ORDER S/D
	FITZPATRICK		
X	MAINE YANKEE		
	SURRY 1		
	SURRY 2		
	POINT BEACH 1		LIMITED, 4 LINES RADWASTE COOLING
	POINT BEACH 2		
X	BRUNSWICK 1	ADL PIPE & DAPS	EXTENSIVE
X	BRUNSWICK 2		
	INDIAN POINT 3	ADL PIPE & WESTDYN	
	SALEM 1	PIPDYN	EXTENSIVE
	INDIAN POINT 2	ADL PIPE	5 LINES
	COOPER		SRV LINES ONLY
	GINNA		2 LINES
	MILLSTONE 1		2 LINES
X	MILLSTONE 2		6 LINES
	NINE MILE POINT		LIMITED
	COOK 1	WESTDYN	1 LINE
	COOK 2	WESTDYN	
X	ROBINSON 2		RCS ONLY
X	TURKEY POINT 3/4		
X	ZION 1		
	ZION 2		
X	PILGRIM 1	DAPS	RCS & MAIN STREAM ONLY

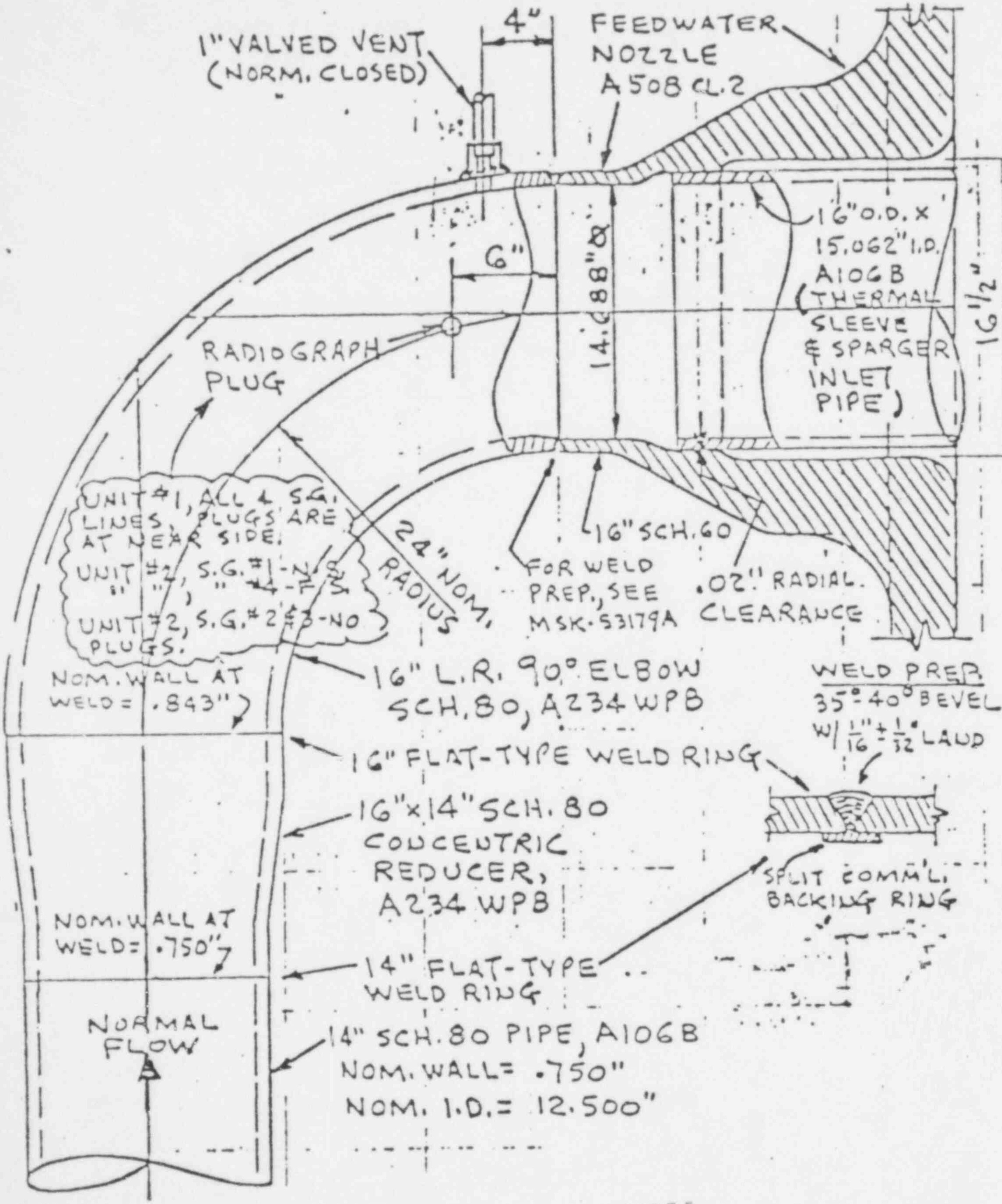
(6/14/79)

578140

51

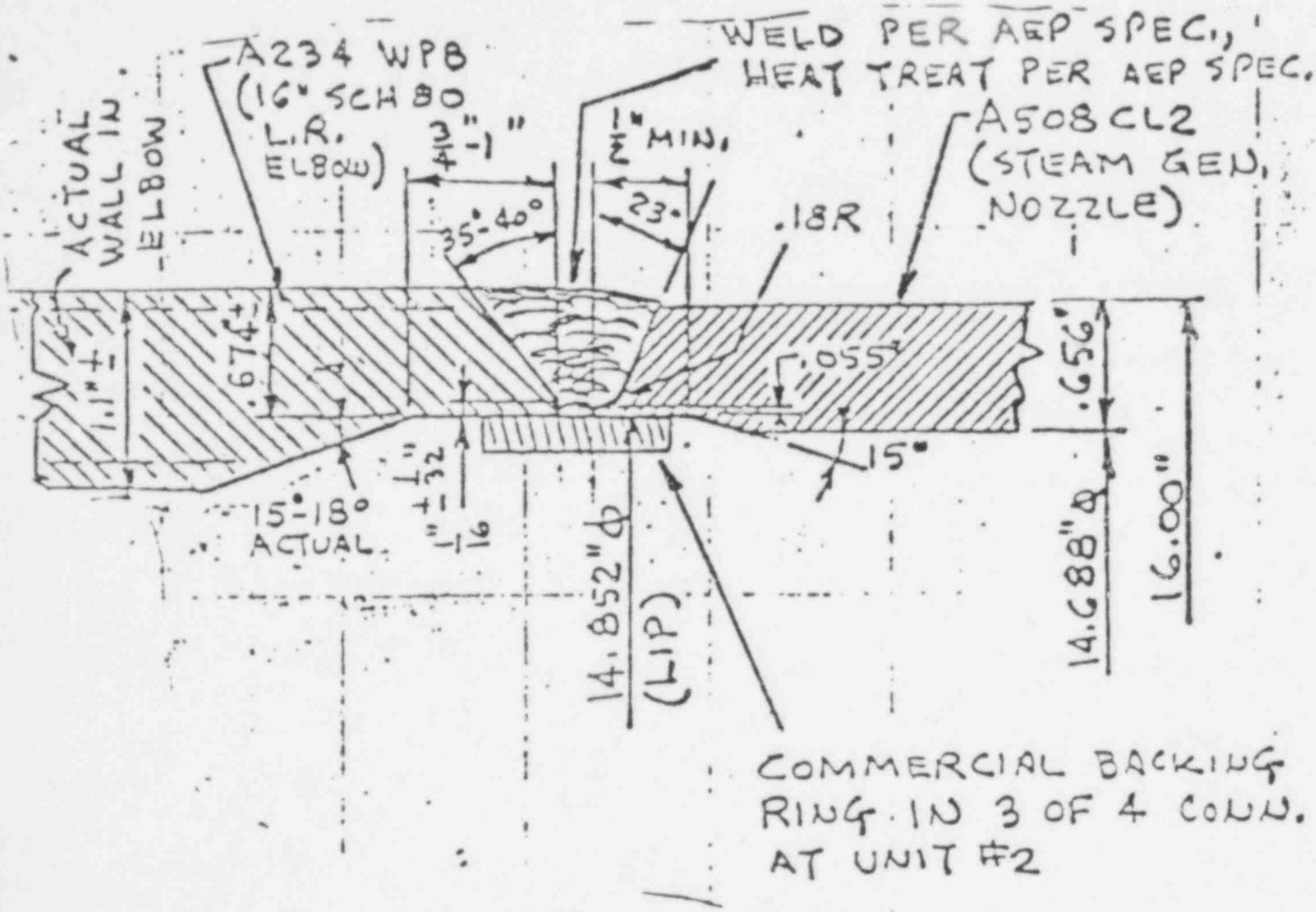
6/13/79

1



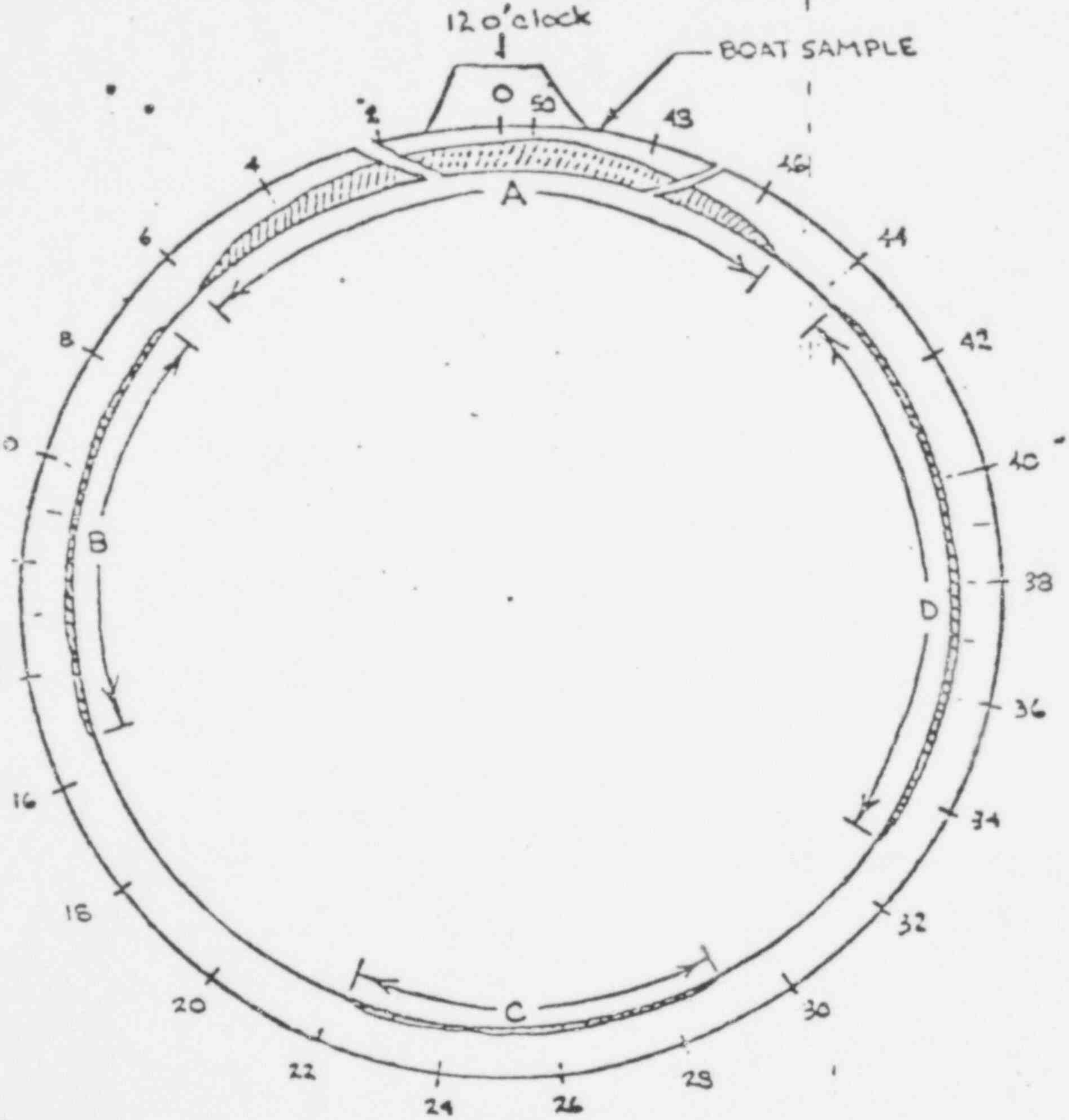
POOR ORIGINAL

578141


WELD PER AEP SPEC.,
HEAT TREAT PER AEP SPEC.
A234 WPB
(16" SCH 80
L.R.
ELBOW)
ACTUAL
WALL IN
ELBOW
3/4"-1"
1/2" MIN.
35°-40°
23°
.18R
A508 CL2
(STEAM GEN.
NOZZLE)
1.1" ±
.674"±
.055"
.656"
15°
15°-18°
ACTUAL
±1/32"
1/16"
14.852" ϕ
(LIP)
14.688" ϕ
16.00"
COMMERCIAL BACKING
RING IN 3 OF 4 CONN.
AT UNIT #2

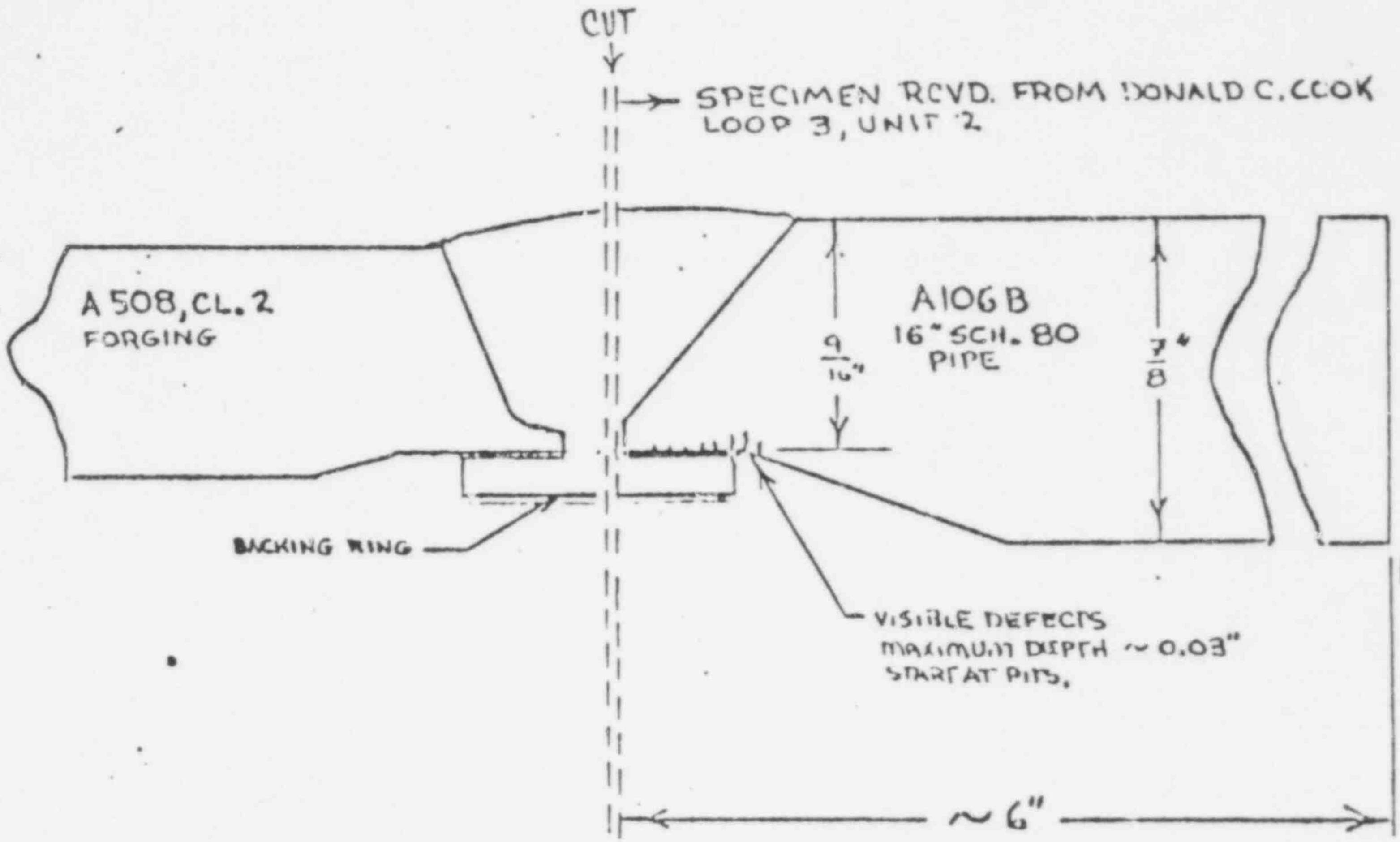
578142

DONALD C. COOK - LOOP 3, UNIT 2
ULTRASONIC TEST RESULTS
FEEDWATER ELBOW*

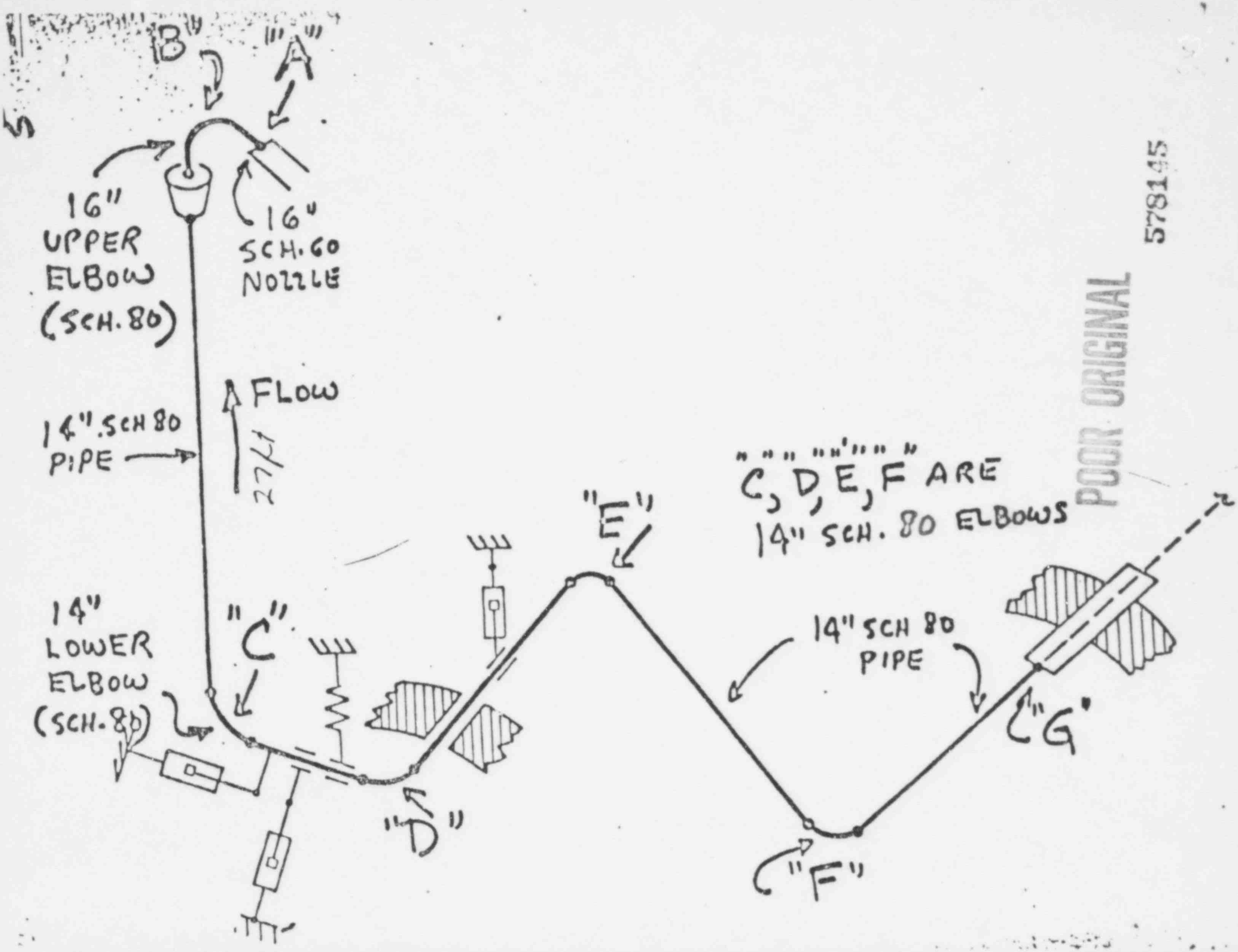


578143

4


CUT
SPECIMEN RCVD. FROM DONALD C. COOK
LOOP 3, UNIT 2
A 508, CL. 2
FORGING
A106 B
16" SCH. 80
PIPE
9/16"
7/8"
BACKING RING
VISIBLE DEFECTS
MAXIMUM DEPTH ~ 0.03"
START AT PITS.
~ 6"

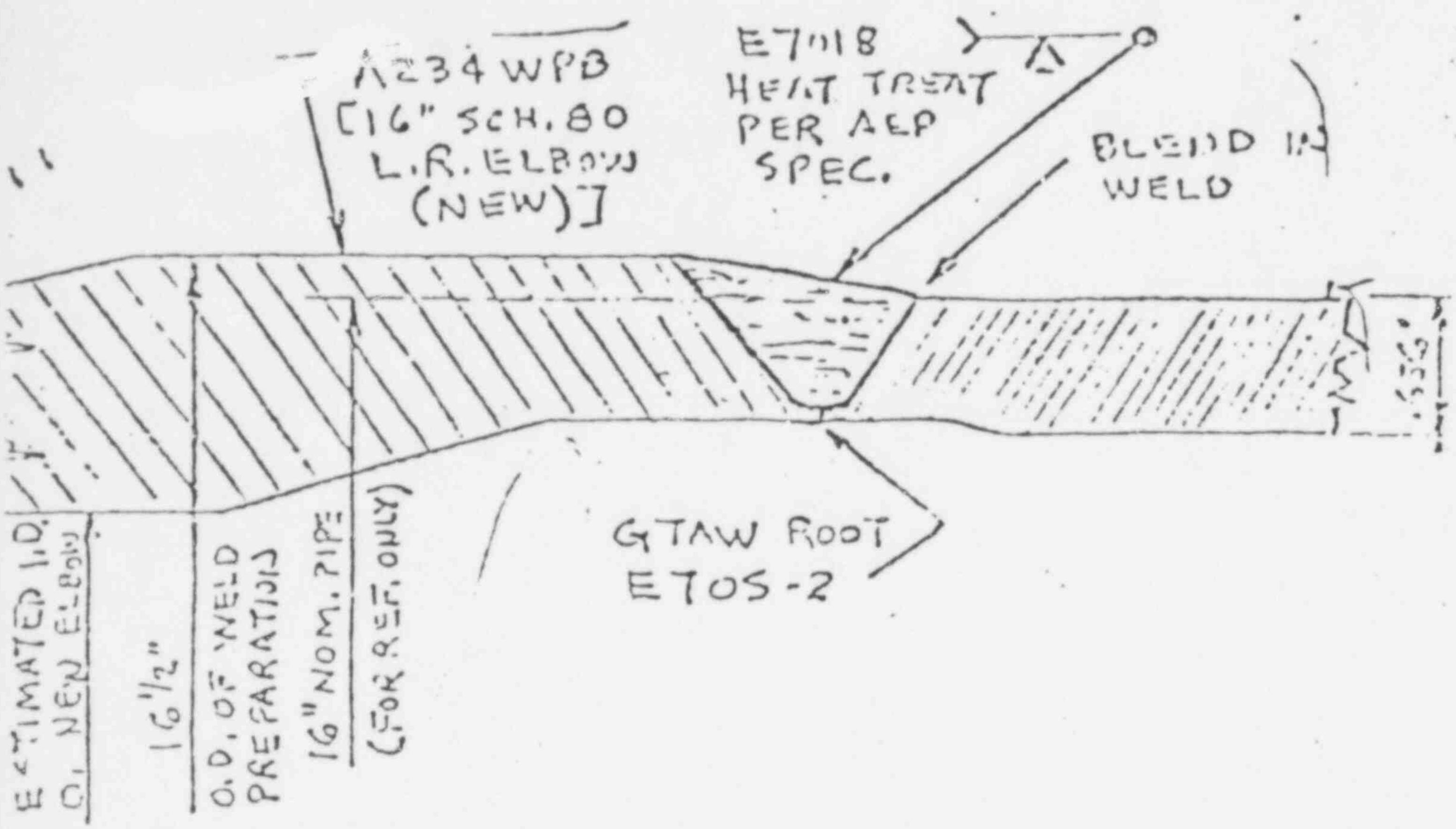
578144



POOR ORIGINAL

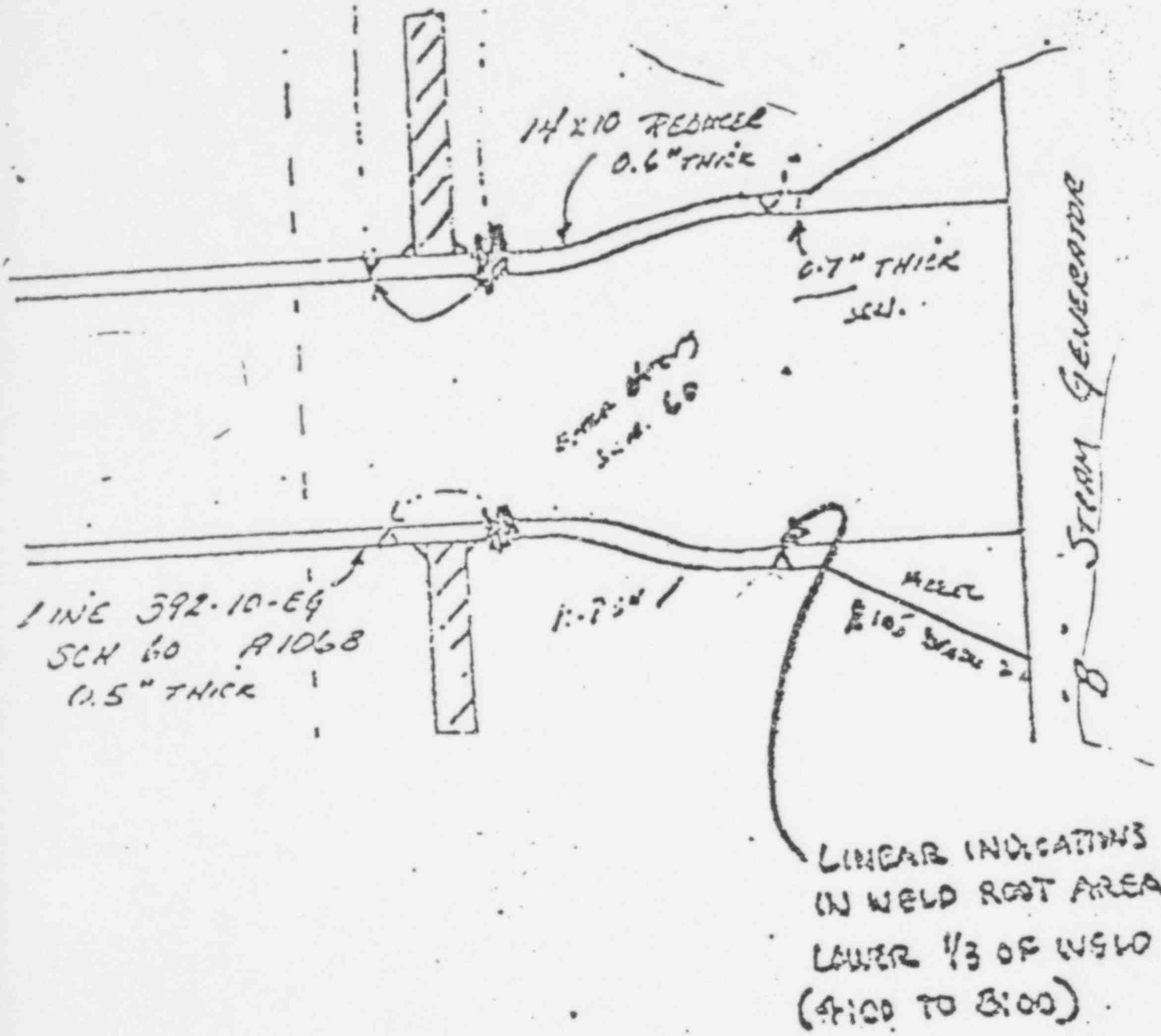
578145

6



POOR ORIGINAL

578146


14 x 10 REDUCER
0.6" THICK
0.7" THICK
LINE 392-10-EG
SCH 60 A106B
0.5" THICK
STEAM GENERATOR
LINEAR INDICATIONS
IN WELD ROOT AREA
LOWER 1/3 OF WELD
(4:00 TO 8:00)

5701 7

FACILITIES WHICH HAVE INSPECTED
FEEDWATER NOZZLES SINCE MAY 25, 1979

SALEM 1

SURRY 1

TURKEY POINT 4

FARLEY 1

PRAIRIE ISLAND 1

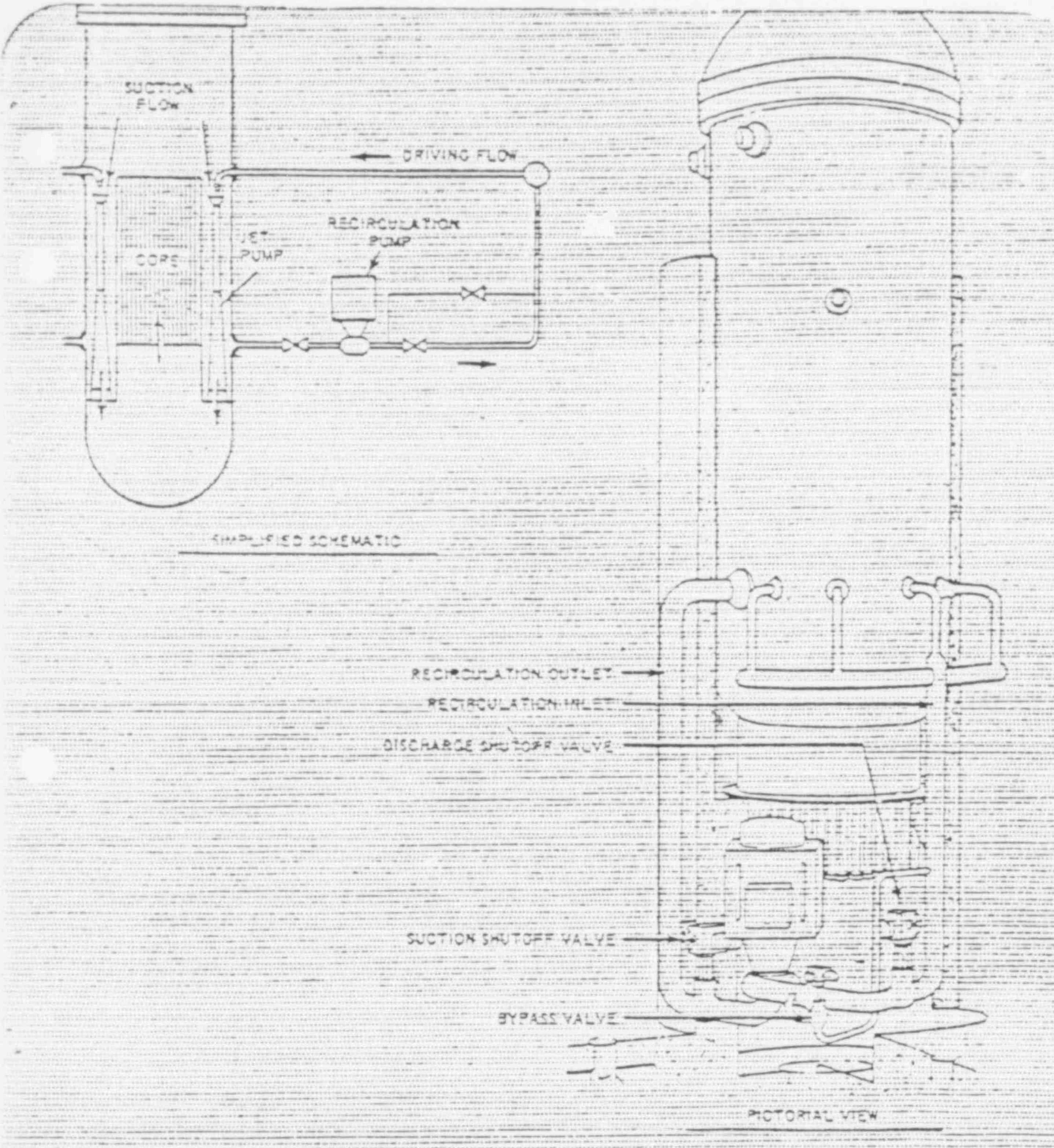
KEWAUNEE

TROJAN

ZION 1

SAN ONOFRE

H. B. ROBINSON 2

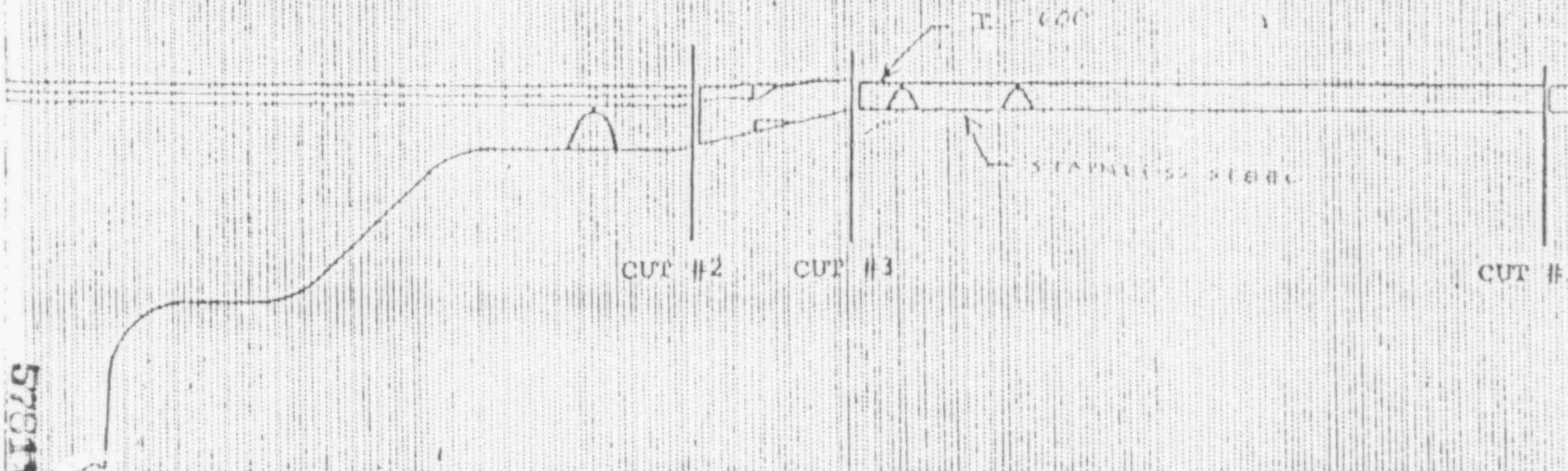


DUANE ARNOLD ENERGY CENTER
IOWA ELECTRIC LIGHT & POWER COMPANY

Recirculation System Elevation and Isometric

POOR ORIGINAL

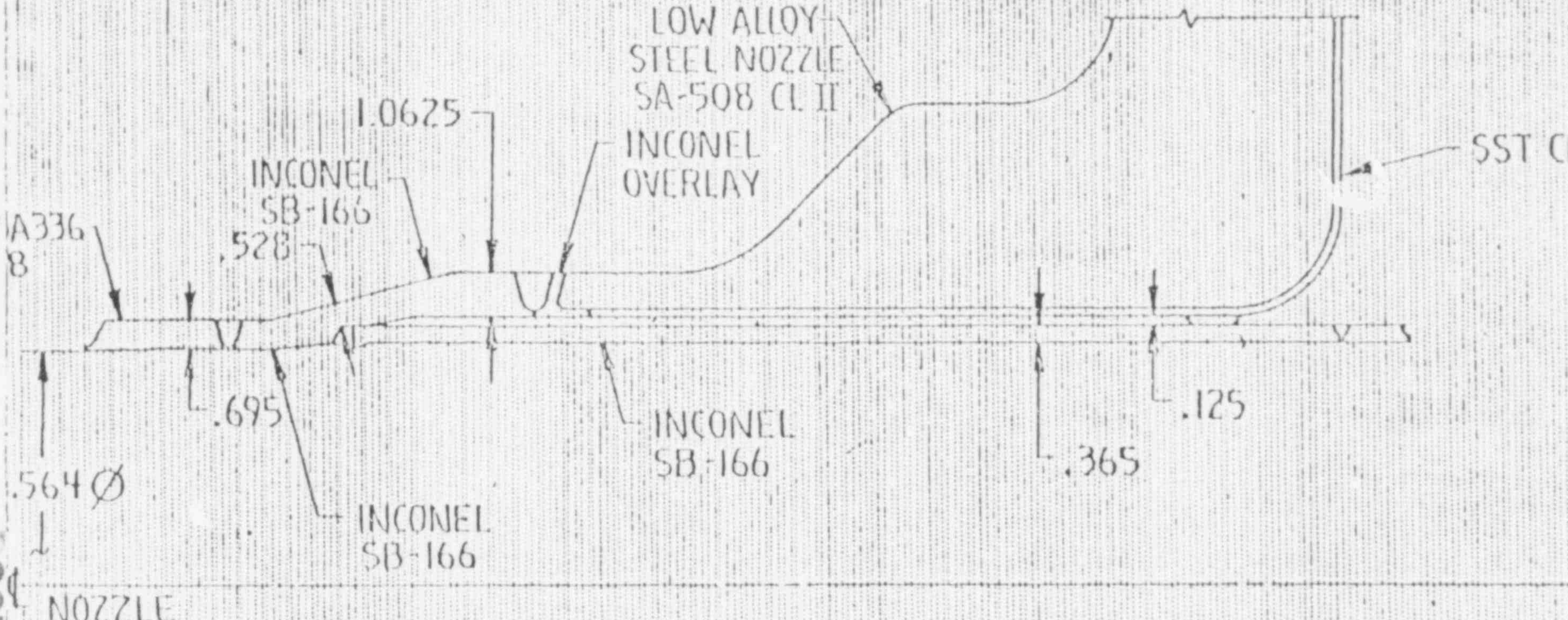
578149



CUT SEQUENCE FOR SAFE END REMOVAL

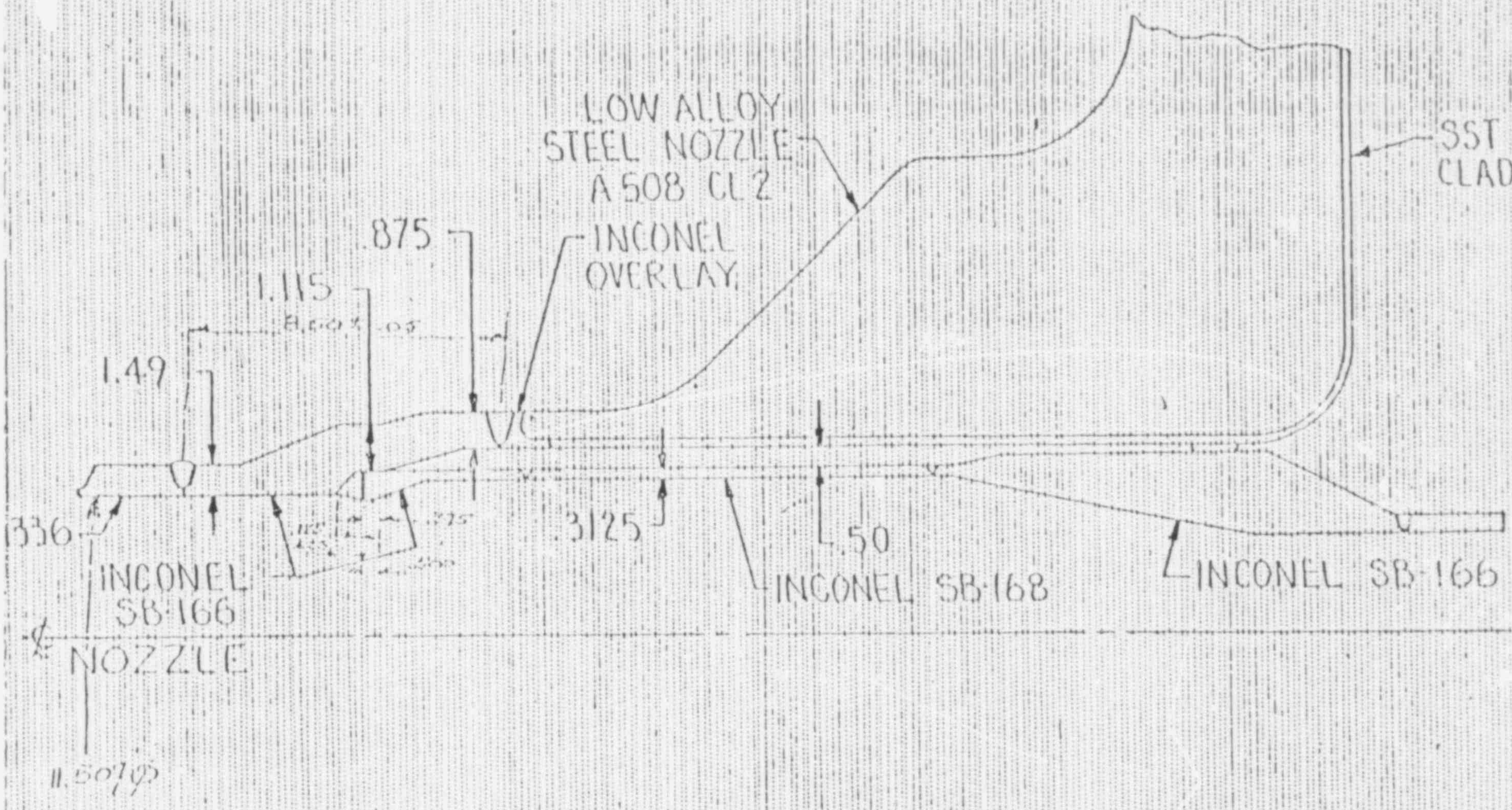
578110

61



DUANE ARNOLD

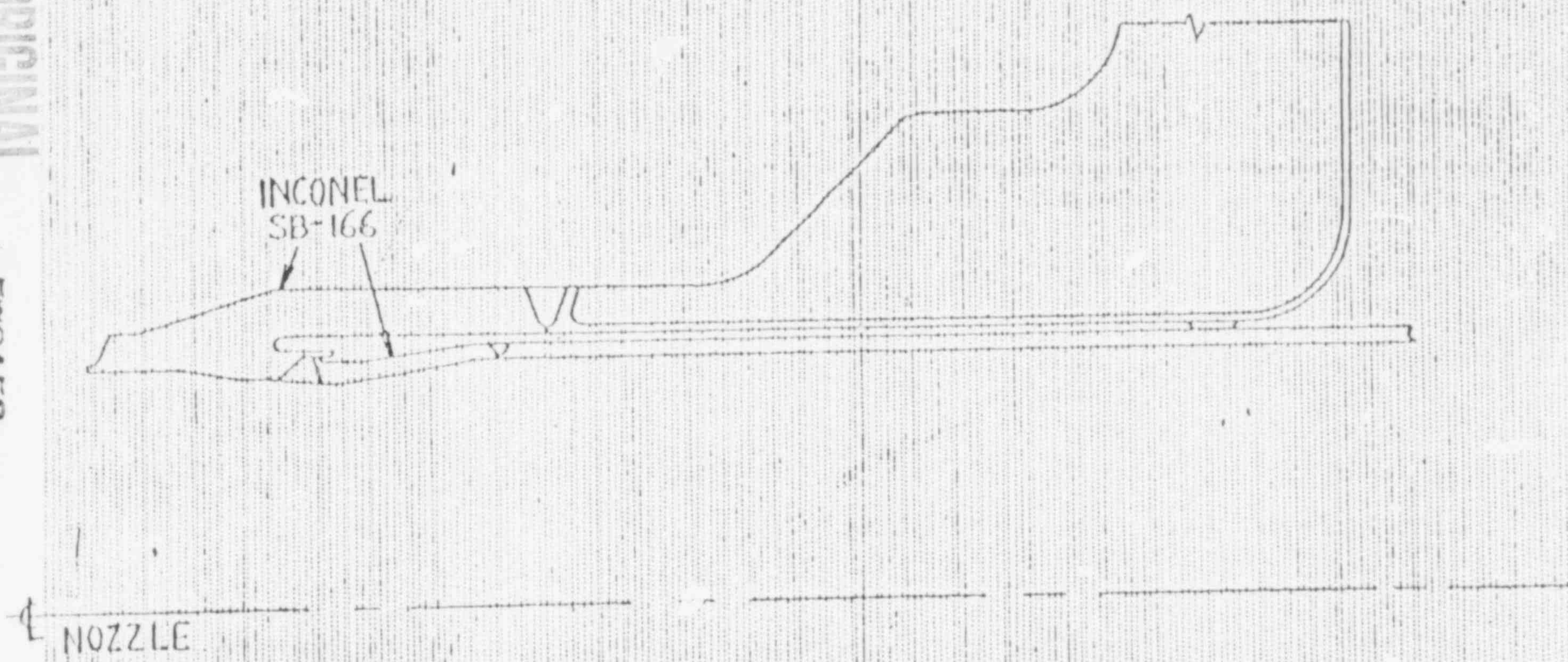
TYPE 1A



TYPE IB

BRUNSWICK I & II

578152



DUANE ARNOLD REPLACEMENT DESIGN

578154

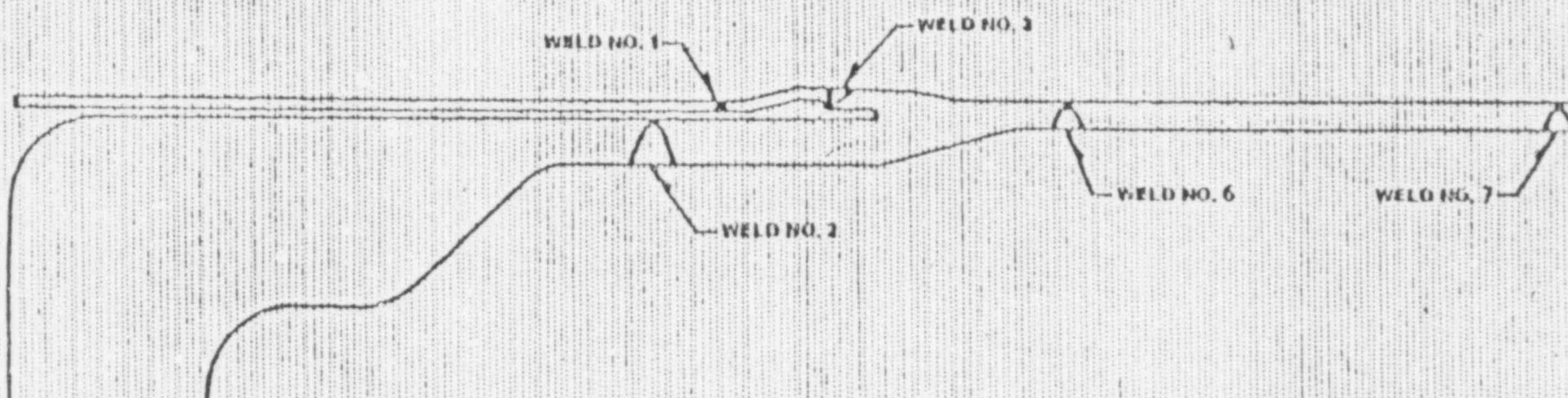
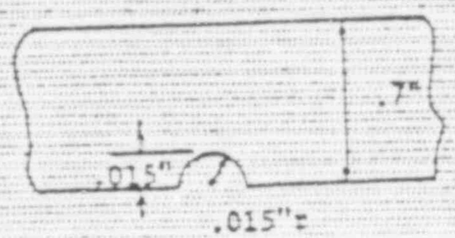
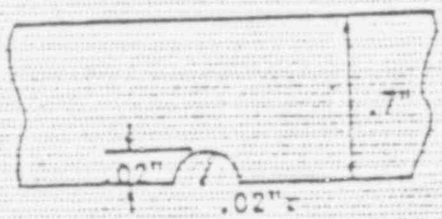
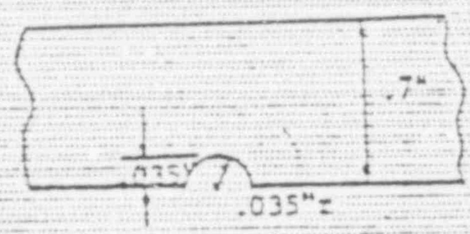
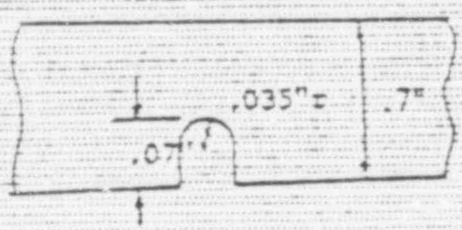
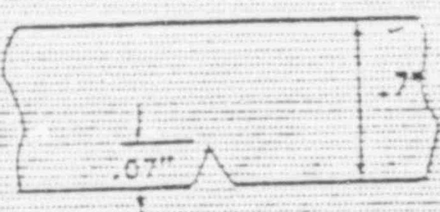
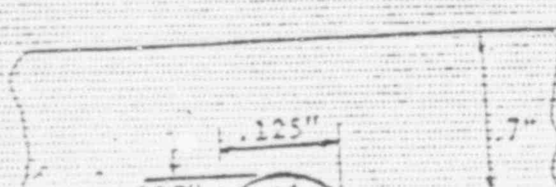


FIGURE 4.6-1

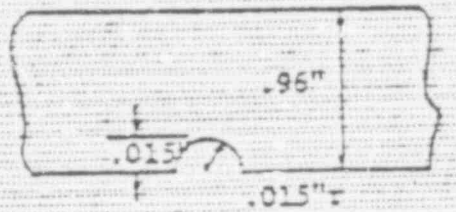
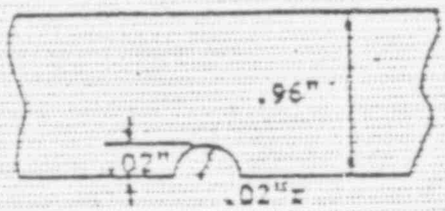
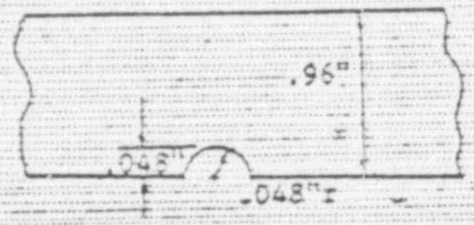
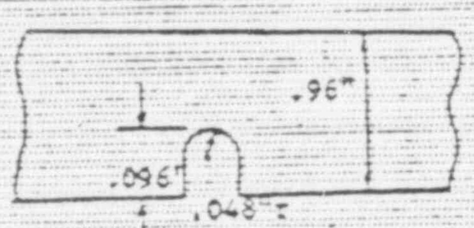
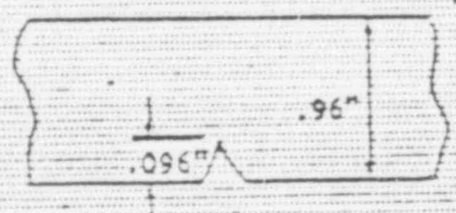
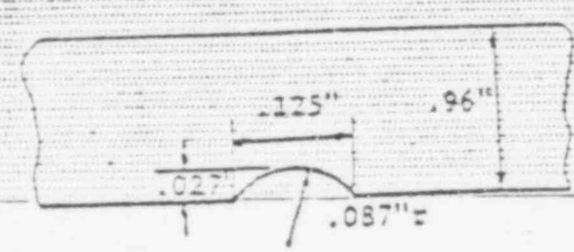
FIGURE 2: Analyzed Notch Configurations at Root of Safe End to Piping Weld (Weld #6)

CASE	NOTCH CONFIGURATION	% OF WALL	STRESS CONC. FACTOR
A		2.14%	2.93
B		2.86%	2.90
C		5%	2.83
D		10%	3.3
E		10%	4.0
F		3.86%	2.02

POOR ORIGINAL

578155

Nozzle to Safe End Weld (Weld #2)

CASE	NOTCH CONFIGURATION	% OF WALL	STRESS CONC. FACTOR
A		1.56%	3.1
B		2.08%	2.9
C		5%	2.8
D		10%	3.3
E		10%	4.0
F		2.81%	2.1

578156

BACKGROUND

PRIOR TO 1975

A STUDY GROUP INVESTIGATED AND EVALUATED THE SIGNIFICANCE OF CRACKS FOUND IN AUSTENITIC STAINLESS STEEL PIPING SYSTEMS OF BWR'S. (REF: NUREG 75/067). CRACKS WERE FOUND IN SMALL DIAMETER PIPING.

DURING 1978, IGSCC WAS REPORTED FOR THE FIRST TIME IN LARGE DIAMETER PIPING IN A GERMAN BWR.

THIS DISCOVERY, TOGETHER WITH REPORTED QUESTIONS IN GERMANY CONCERNING THE INTERPRETATION OF ULTRASONIC INSPECTIONS LED TO THE ACTIVATION OF A NEW PIPE CRACK STUDY GROUP.

SEPTEMBER 14, 1978

A NEW PIPE CRACK STUDY GROUP (PCSG) INITIATED BY MR. L. V. GOSSICK

CHAIRMAN - L. C. SHAO

VICE CHAIRMAN - S. H. BUSH (PNL)

JANUARY 21, 1979

PIPE CRACK STUDY COMPLETED

PIPE CRACK STUDY GROUP REPORT WAS PUBLISHED IN FEBRUARY 1979

5781 8

THE PIPE CRACK STUDY GROUP WAS CHARTERED TO INVESTIGATE AND EVALUATE:

- CRACKS FOUND IN LARGER DIAMETER PIPES THAN THOSE PREVIOUSLY REPORTED AND EVALUATED
- CRACKS FOUND IN FURNACE-SENSITIZED SAFE-ENDS AND RECOMMENDATIONS ON CURRENT NRC PROGRAMS
- FOREIGN CONCERNS RAISED REGARDING THE CAPABILITIES OF ULTRASONIC EXAMINATION METHODS IN AUSTENITIC STAINLESS STEEL MATERIAL
- CRACKING IN THE INCONEL SAFE-ENDS AT THE DUANE ARNOLD OPERATING FACILITY
- THE POTENTIAL FOR STRESS CORROSION CRACKING IN PWRs

5781 59

MEMBERS OF THE STUDY GROUP

L. C. SHAO (RES) - CHAIRMAN
S. H. BUSH (PNL) - VICE CHAIRMAN
W. S. HAZELTON (NRR)
R. M. GAMBLE (NRR)
K. V. SEYFRIT (IE)
A. TABOADA (SD)
J. MUSCARA (RES)

OTHER MAJOR CONTRIBUTORS

R. W. WOODRUFF (IE)
J. J. BURNS (RES)
J. WEEKS (BNL)
E. C. RODABAUGH (BCL)
R. KLECKER (NRR)

CONSULTANTS TO THE GROUP

R. W. WEEKS (ANL)	METALLURGY
J. GIESKE (SANDIA)	NONDESTRUCTIVE EXAMINATION
G. R IRWIN (UNIV. OF MARYLAND)	FRACTURE MECHANICS
W. BERRY (BCL)	CORROSION
R. W. McCLUNG (ORNL)	NONDESTRUCTIVE
P. PARIS (WASHINGTON UNIV.)	FRACTURE MECHANICS

E. IGNE OF ACRS STAFF HAD PARTICIPATED IN MOST OF OUR STUDY GROUP MEETINGS INCLUDING OUR MEETING WITH GERMANS AND FINAL MEETING AT BATTELLE-PACIFIC LABORATORY.

578161

FACTORS INVESTIGATED BY PCSG

- BWR CRACKING EXPERIENCE AND CORRECTIVE ACTIONS
- PWR CRACKING EXPERIENCE AND CORRECTIVE ACTIONS
- METALLURGY ASSOCIATED WITH PIPE CRACKING
- REACTOR COOLANT CHEMISTRY
- PIPE CONFIGURATION AND STRESS LEVELS
- DUANE ARNOLD SAFE-END CRACKING
- METHODS OF DETECTING CRACKS
- SIGNIFICANCE OF CRACKS
- RECENT DEVELOPMENTS RELEVANT TO CONTROL AND DETECTION OF IGSCC

PCSG MEETINGS

- GENERAL ELECTRIC - SAN JOSE
- EPRI
- IOWA POWER AND LIGHT
- FEDERAL REPUBLIC OF GERMANY
- JAPAN

SUMMARY OF GERMAN PIPE CRACK EXPERIENCE

- IGSCC OBSERVED IN A SINGLE SYSTEM OF THE OPERATING GUNDREMMINGEN NUCLEAR POWER PLANT.
- LOCATIONS:
  - 24 INCH DIAMETER SAFE-ENDS
  - HAZ OF WELD JOINING THE SAFE-ENDS AND RECIRCULATION PIPING
- MATERIAL TYPE 304 STAINLESS STEEL.
- DURING CONSTRUCTION THE SAFE-ENDS OF THE SECONDARY STEAM GENERATORS AND REACTOR VESSEL RECEIVED SEVERAL HOURS OF HEAT TREATMENT AT 600°C CAUSING SENSITIZATION.
- DYE-PENETRANT TESTS INDICATED:
  1) IGSCC ON INTERIOR SURFACE OF SECONDARY STEAM GENERATOR SAFE-ENDS.
  2) SUBSTANTIALLY LESS CORROSIVE ATTACK IN THE VICINITY OF PRESSURE VESSEL SAFE-ENDS TO PIPING WELDS.
- CIRCUMFERENTIAL INTERGRANULAR CRACKS, <5MM DEEP WERE FOUND ADJACENT TO THE WELD IN THE PIPE MATERIAL.
- GERMANY IS QUESTIONING INTERPRETATION OF ULTRASONIC INSPECTIONS OF RECIRCULATION PIPING WELDS OF THE AFFECTED FACILITY.

SUMMARY OF JAPANESE PIPE CRACK EXPERIENCE

IGSCC HAVE OCCURRED IN SEVERAL OPERATING BWRs

PIPE CRACK LOCATIONS (2 - 14 INCH DIA)

- RECIRCULATION BYPASS LINES
- RECIRCULATION RISER LINES
- CORE SPRAY LINES
- SHUTDOWN COOLING LINES
- CLEANUP LINES

CRACKING IN HAZ IN SOME INSTRUMENT NOZZLE SAFE-ENDS

NO FURNACE SENSITIZED SAFE-ENDS IN JAPAN

LARGE PERCENTAGE OF PART THROUGH-WALL IGSCC DETECTED BY UT

SUGGESTED COUNTERMEASURES

REPLACEMENT OF IGSCC SUSCEPTIBLE PIPING WITH:

1) ALTERNATIVE MATERIALS
2) TYPE 304 STAINLESS STEEL WITH
   a) SOLUTION HEAT TREATMENT (SHT)
   b) CORROSION-RESISTANT CLADDING (CRC)
   c) HEAT SINK WELDING (HSW)

IMPROVEMENT OF WATER CHEMISTRY

INDUCTION HEATING STRESS IMPROVEMENT (IHSI) IS UNDER STUDY

578165

CAUSES OF IGSCC CRACKING

THE CAUSES OF IGSCC FOR ALL PIPING ARE MORE OR LESS THE SAME NAMELY COMBINATIONS OF:

- HIGH STRESS LEVELS
- LIGHT SENSITIZATION OF HEAT AFFECTED ZONES OF WELDS
- CORROSIVE ENVIRONMENT AND IN PARTICULAR THE OXYGEN LEVEL NORMALLY FOUND IN THE COOLANT OF BWRs.

578166

QUESTION 1

"THE SIGNIFICANCE OF CRACKS DISCOVERED IN LARGE DIAMETER PIPES RELATIVE TO THE CONCLUSIONS AND RECOMMENDATIONS SET FORTH IN THE REFERENCED REPORT (NUREG-75/067) AND ITS IMPLEMENTATION DOCUMENT NUREG-0313."

- IGSCC MAY OCCUR IN LARGE DIAMETER BWR STAINLESS STEEL PIPING.
- IGSCC WILL BE LESS FREQUENT IN LARGE DIAMETER PIPING THAN IN THE SMALLER CORE SPRAY OR RECIRCULATION BYPASS PIPING.
- IT IS UNLIKELY THAT SIGNIFICANT IGSCC IN BWR PIPING WOULD GO UNDETECTED.
- IT IS UNLIKELY THAT IGSCC GROWTH WILL BECOME UNSTABLE.
- ECCS WILL PROVIDE ADEQUATE PROTECTION.
- THE RECOMMENDATIONS IN NUREG-0313 ARE ADEQUATE.

QUESTION 2

"RESOLUTION OF CONCERNS RAISED OVER THE ABILITY TO USE ULTRASONIC TECHNICS TO DETECT CRACKS IN AUSTENTITIC STAINLESS STEEL"

- IMPROVED UT EQUIPMENT MAY BE NEEDED TO DETECT VERY TIGHT OR BRANCHED IGSCC.
- MANY IGSCC WILL NOT BE PROPERLY IDENTIFIED USING PRESENT CODE EVALUATION STANDARDS.
- WE BELIEVE MOST IGSCC WILL BE DETECTED WITH FREQUENT ISI USING ESPECIALLY SUITED UT EQUIPMENT AND IMPROVED EVALUATION METHODS WHEN:
  - IGSCC DEEPER THAN 10% OF WALL THICKNESS
  - IGSCC IS SEVERAL INCHES IN CIRCUMFERENTIAL LENGTH

5781168

QUESTION 3

"THE SIGNIFICANCE OF CRACKS FOUND IN LARGE DIAMETER SENSITIZED SAFE-ENDS AND RECOMMENDATIONS REGARDING THE CURRENT NRC PROGRAM DEALING WITH THE MATTER"

- IGSCC MAY OCCUR IN THE LIMITED NUMBER OF FURNACE-SENSITIZED SAFE-ENDS REMAINING IN U.S. BWRs.

  IGSCC EXPECTED TO BE LESS FREQUENT THAN IN CORE SPRAY OR RECIRCULATION BYPASS LINES.

- IF IGSCC EXISTS, IT IS UNLIKELY THAT UNSTABLE CRACK GROWTH WILL DEVELOP.

- ECCS WILL PROVIDE ADEQUATE PROTECTION.

QUESTION 4

"THE POTENTIAL FOR STRESS CORROSION CRACKING IN PWRs"

PRIMARY SYSTEMS

- THE POTENTIAL FOR SCC IS EXTREMELY LOW
- OXYGEN IS LIMITED TO VERY LOW LEVELS

OTHER PIPING SYSTEMS

- NOT COMPLETELY IMMUNE TO SCC
- INCIDENCES OF SCC HAVE OCCURRED IN:
  - WELD HEAT AFFECTED ZONES
  - SENSITIZED BASE METAL
- HIGH OXYGEN LEVELS ARE EXPECTED
- CHLORIDE AND CHEMICAL ADDITIVES HAVE BEEN NOTED
- NRC HAS INITIATED PROPER ACTION OF CONTROL

QUESTION 5

"EXAMINE THE SIGNIFICANCE OF CRACKING IN INCONEL SAFE-ENDS THAT HAS BEEN EXPERIENCED AT THE DUANE ARNOLD OPERATING FACILITY, AND DEVELOP ANY RECOMMENDATIONS REGARDING NRC ACTIONS TAKEN OR TO BE TAKEN"

- IGSCC IN THE DUANE ARNOLD SAFE-ENDS WAS CAUSED BY A COMBINATION OF HIGH STRESS AND UNFAVORABLE CHEMICAL ENVIRONMENTAL CONDITIONS IN THE THERMAL SLEEVE TO SAFE-END ATTACHMENT WELDS
- INCONEL 600 IS NOT PARTICULARLY SUSCEPTIBLE TO IGSCC IN THE ABSENCE OF A CREVICE
- THERMAL SLEEVE ATTACHMENTS WITH CREVICES SHOULD BE AVOIDED
- WHERE THIS TYPE OF ATTACHMENT CANNOT BE REMOVED, AN I.S.I. PROGRAM SHOULD BE ADOPTED
- ALL WELD ATTACHMENT GEOMETRIES THAT DO NOT FORM CREVICES BUT ARE WELDED TO OR FORM A PART OF THE PRIMARY PRESSURE BOUNDARY, AN EXAMINATION SHOULD BE INCLUDED IN THE FACILITY IN-SERVICE INSPECTION PROGRAM TO EXAMINE THE WELDS AND SURROUNDING MATERIAL

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MAJOR CONCLUSIONS

THE CONCLUSIONS AND RECOMMENDATIONS REPORTED IN NUREG-75/067 BY THE PREVIOUS PCSG AND THE IMPLEMENTING DOCUMENT, NUREG-0313, ARE VALID.

THE PIPING DESIGN CODE DOES NOT CONSIDER ENVIRONMENTALLY INFLUENCED PHENOMENA.

IGSCC

TREATMENT OF BOTH OPERATING AND RESIDUAL STRESSES IS NOT APPROPRIATE FOR PREDICTING IGSCC

TECHNIQUES HAVE BEEN IDENTIFIED TO REDUCE THE POTENTIAL FOR IGSCC IN TYPE 304 STAINLESS STEEL WELDS.

SOLUTION HEAT TREATMENT

CORROSION-RESISTANT CLAD (CRC)

HEAT-SINK WELDING (HSW)

TIGHT WELDING SPECIFICATIONS

LIMIT THE AMOUNT OF GRINDING

MAJOR CONCLUSIONS

TYPE 304 SS SUSCEPTIBILITY AND NONSUSCEPTIBILITY, CAN BE DISTINGUISHED BY THE ELECTRO-CHEMICAL POTENTIOKINETIC REACTIVATION TECHNIQUE

INDUCTION HEATING STRESS IMPROVEMENT (IHSI) MAY PROVE EFFECTIVE IN REDUCING TENSILE STRESSES IN BWR WELDS.

CONTROL OF OXYGEN IN PRIMARY COOLANTS IS DESIRABLE.

ASME B&PV CODE, SECTION V PROVISIONS ON ULTRASONIC EXAMINATION PROCEDURES ARE NOT ADEQUATE FOR DETECTING AND EVALUATING IGSCC IN AUSTENITIC PIPING.

CURRENT IMPROVED UT TECHNIQUES AND PROCEDURES WILL DETECT AND EVALUATE SIGNIFICANT IGSCC RELIABLY.

THE G.E. "STRESS RULE" IS A POTENTIALLY USEFUL TOOL IN IDENTIFYING WELDS, SUSCEPTIBLE TO IGSCC FROM A STRESS STANDPOINT.

578173

5781774

RECOMMENDATIONS

- THE FUTURE USE OF REGULAR GRADES OF TYPE 304 AND 316 STAINLESS STEEL IN BWR PIPING SHOULD BE AVOIDED.

  IF THESE MATERIALS ARE USED, STEPS SHOULD BE TAKEN TO ENSURE THAT IGSCC CANNOT OCCUR.

- THE PRESENCE OF OXYGEN SHOULD BE MINIMIZED IN BWRs.

- SPECIFIC PROCEDURES SHOULD BE INCORPORATED IN THE ASME CODE TO IMPROVE ULTRASONIC DETECTION AND EVALUATION METHODS.

- ADVANCE IGSCC NONDESTRUCTIVE DETECTION AND EVALUATION METHODS NOW BEING DEVELOPED BE ACTIVELY PURSUED.

- EXPAND INVESTIGATIONS TO DETERMINE THE EFFECT OF ACTUAL BWR OPERATING STRESS AND THERMAL LOADING ON IGSCC.

- BASED ON JAPANESE EXPERIENCES, AUGMENTED IN-SERVICE INSPECTION SHOULD BE DEVELOPED FOR RECIRCULATION-RISER PIPING.

-15

STAFF FOLLOW - ON EFFORT

. CODIFY EFFECTIVE UT INSPECTION METHODS

REG GUIDE IN WORK
CODE REVISION IN WORK

. REVIEW, EVALUATE, AND IMPLEMENT

WATER CHEMISTRY IMPROVEMENTS

. EVALUATE LEAK BEFORE BREAK POSTULATION

. EVALUATE LEAK DETECTION CAPABILITY

. DEVELOP AND IMPLEMENT A FOCUSSED AUGMENTED INSPECTION PROGRAM

STRESS RULE INDEX
MATH COMPOSITION
HISTORY OF CRACKING

578175

L-8

REVISION OF NUREG 0313

- REDEFINE ACCEPTABLE MATERIALS AND PROCESSES

  NEW PLANTS
  PLANTS UNDER CONSTRUCTION
  OPERATING PLANTS

- REDEFINE REQUIRED AUGMENTED ISI

  "TARGET" LINES
  SERVICE-SENSITIVE LINES
  OTHER LINES WITH SUSCEPTIBLE WELDS

- RECONSIDER LEAK DETECTION AND LEAKAGE LIMITS

- RECOMMEND POSITIVE IMPLEMENTATION METHODS

  REG GUIDES 1.44, 1.45, 1.56
  BULLETINS
  ORDERS

578178

STAFF ACTIONS

TASK ACTION PLAN A-42

PIPE CRACKS IN BWRs

- REVISION OF NUREG 0313
- RECOMMENDED FOLLOW-ON EFFORT

MAJOR CONCLUSIONS

TYPE 304 SS SUSCEPTIBILITY AND NONSUSCEPTIBILITY, CAN BE DISTINGUISHED BY THE ELECTRO-CHEMICAL POTENTIOKINETIC REACTIVATION TECHNIQUE

INDUCTION HEATING STRESS IMPROVEMENT (IHSI) MAY PROVE EFFECTIVE IN REDUCING TENSILE STRESSES IN BWR WELDS.

CONTROL OF OXYGEN IN PRIMARY COOLANTS IS DESIRABLE.

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CURRENT IMPROVED UT TECHNIQUES AND PROCEDURES WILL DETECT AND EVALUATE SIGNIFICANT IGSCC RELIABLY.

THE G.E. "STRESS RULE" IS A POTENTIALLY USEFUL TOOL IN IDENTIFYING WELDS, SUSCEPTIBLE TO IGSCC FROM A STRESS STANDPOINT.

J. Milhoan

LESSONS LEARNED OPERATIONS SUBGROUP

- PLANT PROCEDURES
- PERSONNEL
- CONDUCT OF OPERATIONS
- MAN/MACHINE INTERFACE
- PREOPERATIONAL AND STARTUP TESTING
- INCIDENT RESPONSE
- REACTOR OPERATING EXPERIENCE

578179

COMMAND AND CONTROL

- AUTHORITY AND RESPONSIBILITY
  - SAFE OPERATIONS
  - LINE OF SUCCESSION
  - TRAINING
- SHIFT AND RELIEF TURNOVER
- CONDUCT OF OPERATIONS
  - MINIMUM SHIFT STAFFING
  - CONTROL ROOM ACCESS
  - TECH ADVICE AVAILABILITY
  - INCIDENT RESPONSE

578180

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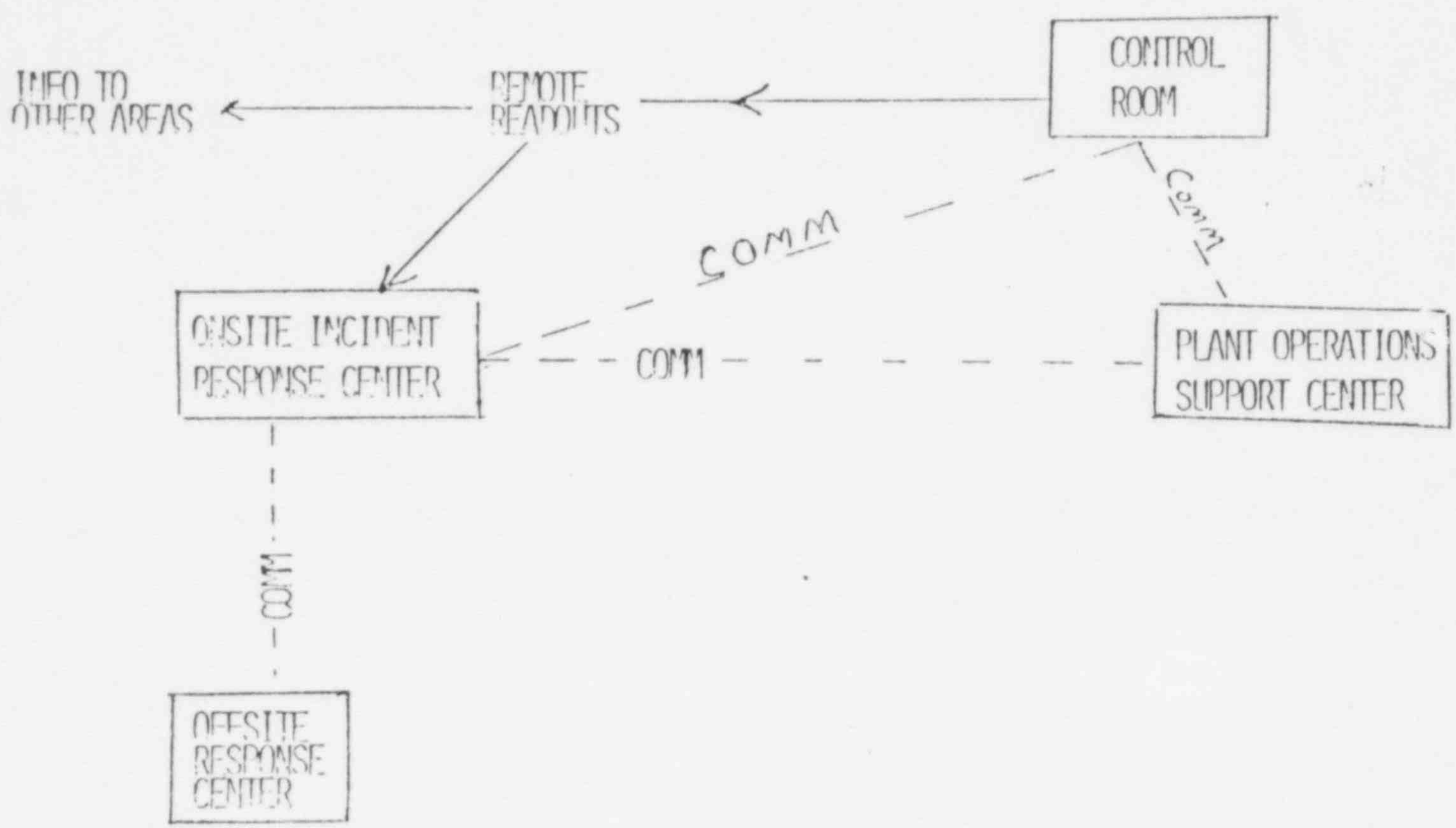
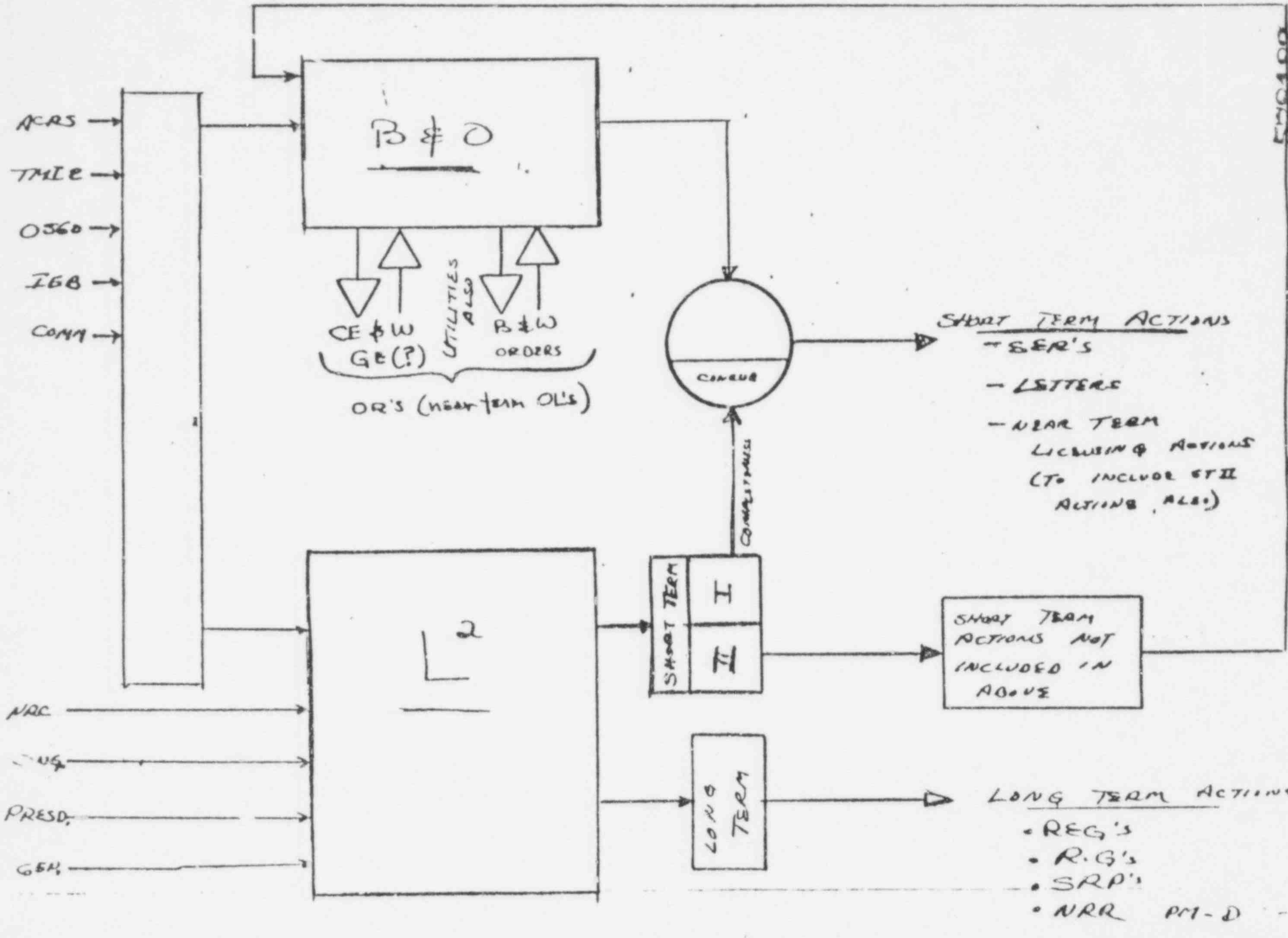
UTILITY INCIDENT RESPONSE CONCEPT



578181



POOR ORIGINAL

5?8182

STATUS REPORT

BULLETINS & ORDERS TASK FORCE

JUNE 14, 1979

578183

B & W FACILITY STATUS

OCONEE 1, 2, 3	ARKANSAS 1	RANCHO SECO	DAVIS BESSE 1	CRYSTAL RIVER 3
ORDER LIFTED 5/18	ORDER LIFTED 5/31	ORDER ISSUED 5/7	ORDER ISSUED 5/16	PLANT S/D FOR RELOAD 4/
UNITS 1&2 OPERATING UNIT 3 S/D FOR RELOAD (S/U WEEK OF 6/17)	ORDER ISSUED BY IE 6/2 RETURN PLANT TO COLD S/D: (1) EVAL & MOD PROCEDURES (2) TRAIN PERSONNEL	SE IN FINAL STAGES OF REVIEW	SE IN FINAL STAGES OF REVIEW	ORDER ISSUED 5/16
PROCEDURE FOR EFW FLOW TEST APPROVED BY NRC; WILL PERFORM WHEN ALL THREE UNITS OPERATING	LETTER FROM AP&L TO IE STATING CORRECTIVE ACTION ABOUT 6/14	ORDER COULD BE LIFTED AS EARLY AS 6/16	ORDER COULD BE LIFTED AS EARLY AS 6/20	SE IN FINAL STAGES OF REVIEW ORDER COULD BE LIFTED AS EARLY AS 6/20
TECH SPEC CHANGES SUBMITTED 5/25	FURTHER INFO REQUIRED ON DESIGN & PROCEDURAL CHANGES BEFORE RESTART PERMITTED			THREE MILE ISLAND 1 MEETING WITH LICENSEE HELD ON 6/11 TO DISCUSS RESTART REQUIREMENTS MEETING TO BE HELD AT SITE WEEK OF 6/25 TO DISCUSS RESTART COMMITMENTS AND REVIEW SCHEDULE CONFIRMATORY ORDER ANTICIPATED
LONG-TERM MODIFICATION SCHEDULE DUE 6/18				
TURBINE TRIP/FW TRANS. ON UNIT 1 6/11. ALL SYSTEMS OPERATED AS DESIGNED				

578184

I&E SHUTDOWN ORDER - ARKANSAS 1

* CONFIRMATORY ORDER OF 5/17 LIFTED ON 5/31 - ANO-1 AUTHORIZED TO RESUME OPERATION

* DURING RETURN TO POWER FROM COLD SHUTDOWN 6/2:

  * PROCEDURE REQUIRED SURVEILLANCE TEST OF MAIN FEEDWATER CHECK VALVES

  * AUTO EFW START SIGNALS BLOCKED TO PREVENT ACTUATION WHEN AFW PUMP STOPPED

  * NO PROCEDURE STEP REQUIRING THIS ACTION

  * TEST FAILED - SHIFT CHANGE - ONCOMING OPERATORS NOT AWARE EFW AUTOSTART BLOCKED

  * NRC INSPECTOR DISCOVERED VIOLATION - CALL TO IE HEADQUARTERS

  * AP&L AGREED TO IMMEDIATELY PROCEED TO COLD SHUTDOWN

* CONFIRMATORY SHUTDOWN ORDER ISSUED BY I&E 6/2

  * EVALUATE AND MODIFY METHODS FOR THE DEVELOPMENT AND APPROVAL OF PROCEDURES

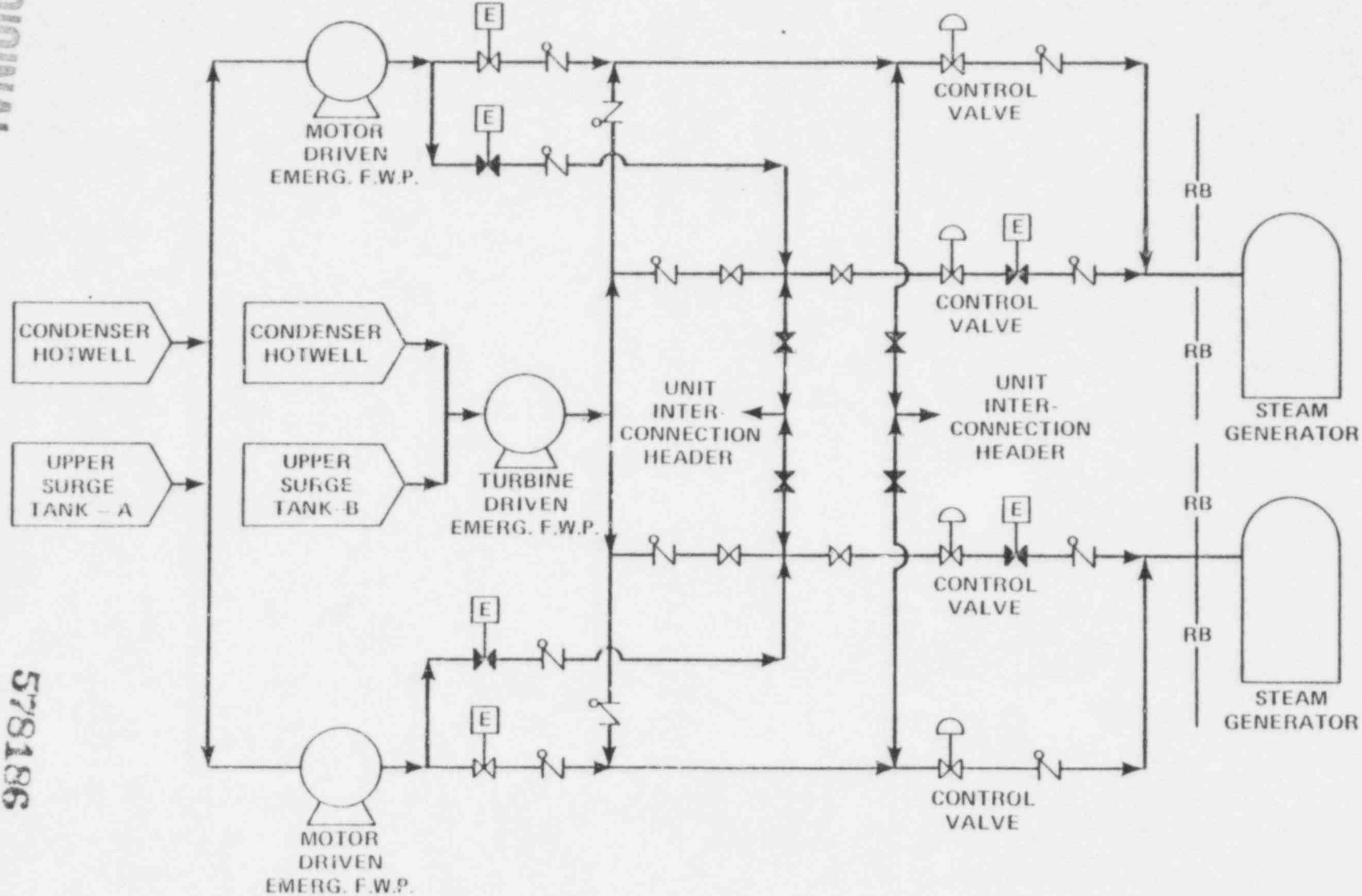
  * EVALUATE EXISTING PROCEDURES TO ASSURE ALL ACTIONS NECESSARY FOR SAFETY INCLUDED

  * TAKE STEPS TO ASSURE OPERATORS ADHERE TO APPROVED PROCEDURES AND DO NOT ADD STEPS

* REQUIRED ACTIONS UNDERWAY BY AP&L

* AP&L WILL INFORM I&E, BY LETTER, ALL CORRECTIVE ACTIONS TAKEN (~ 6/14)

OCONEE EMERGENCY FEEDWATER SYSTEM
MOTOR DRIVEN EMERGENCY FEEDWATER PUMP ADDITION



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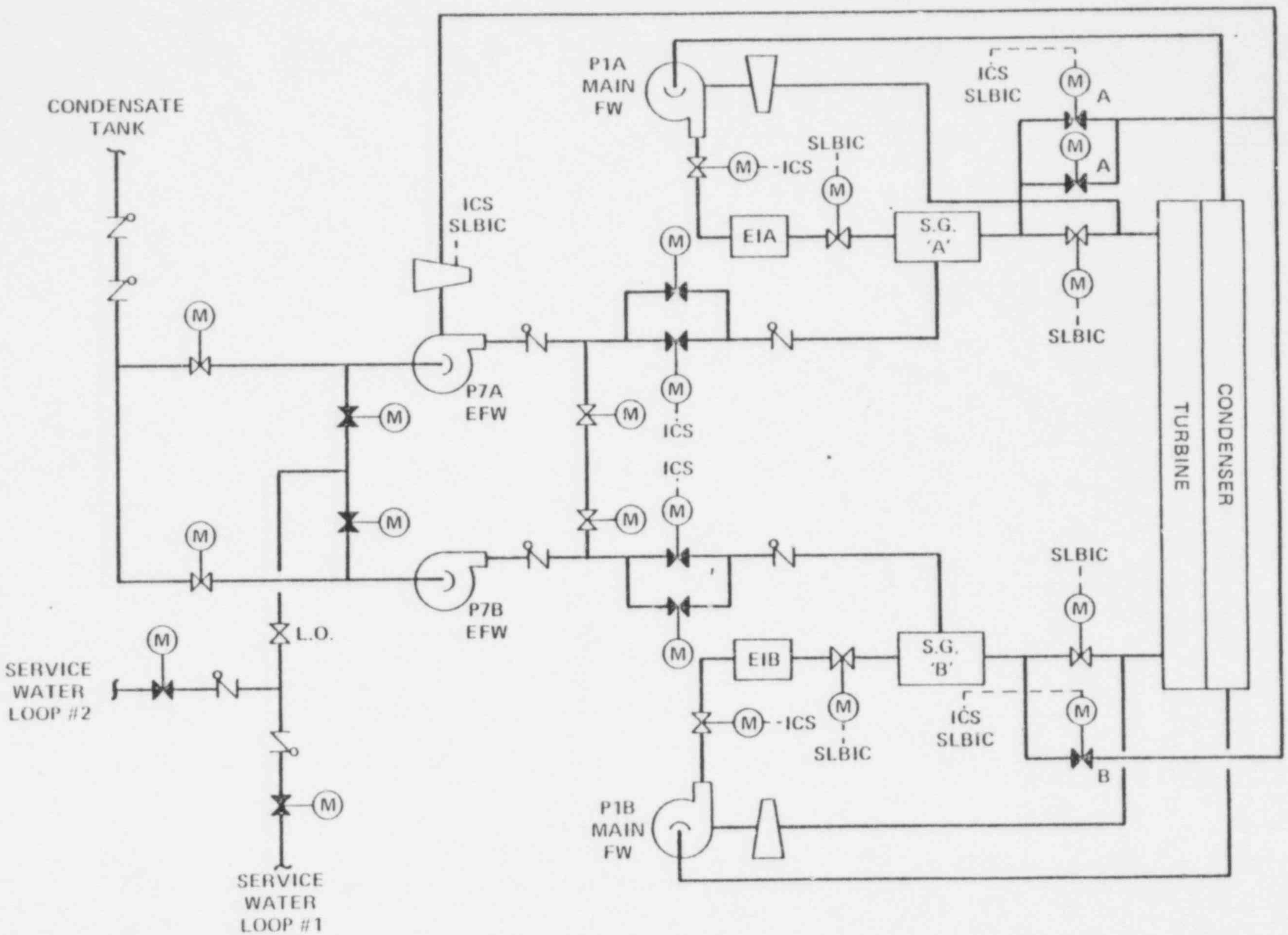
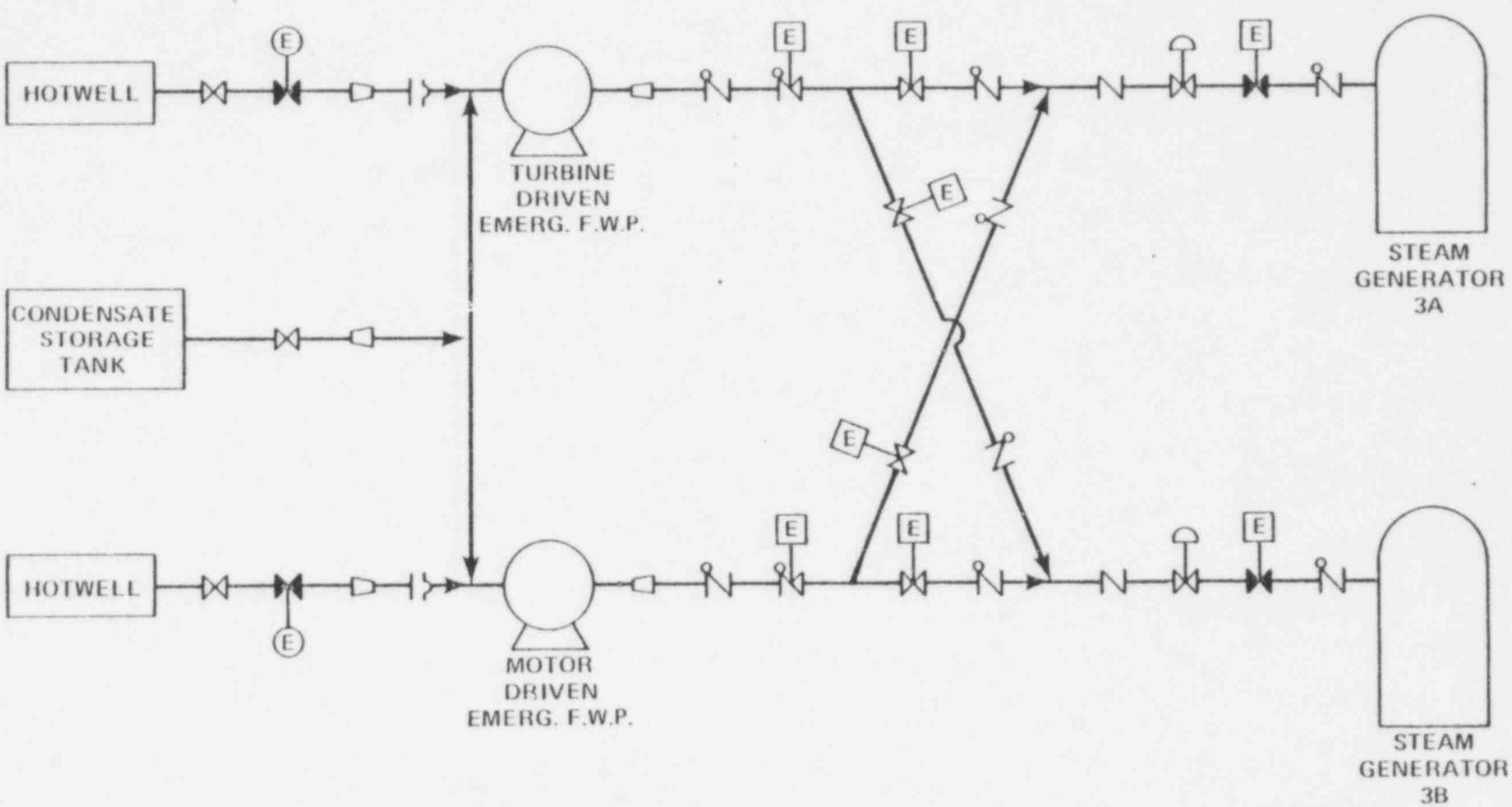
ANO-1 EXISTING FW SYSTEM



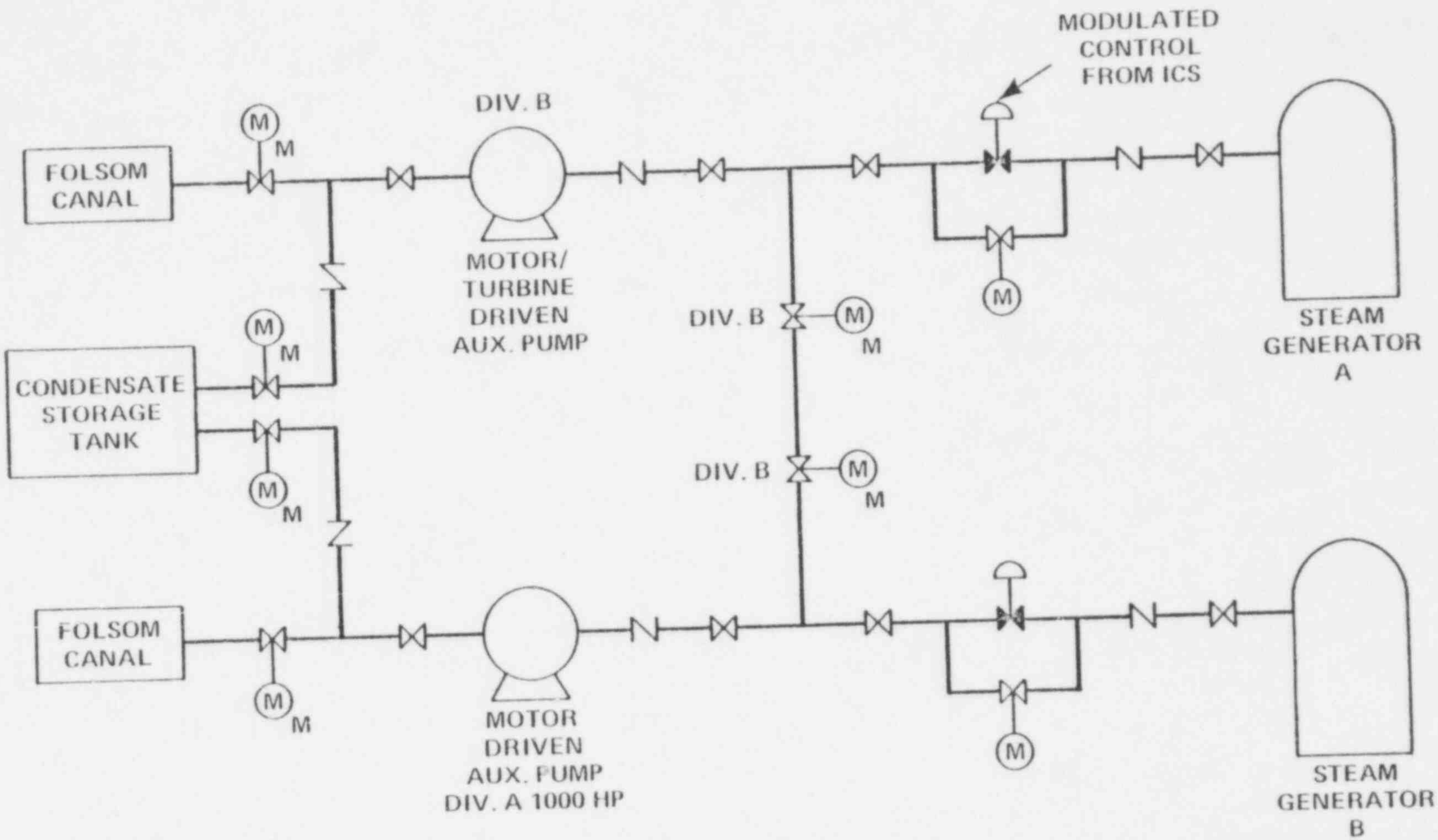
578187

CRYSTAL RIVER



578188

RANCHO SECO



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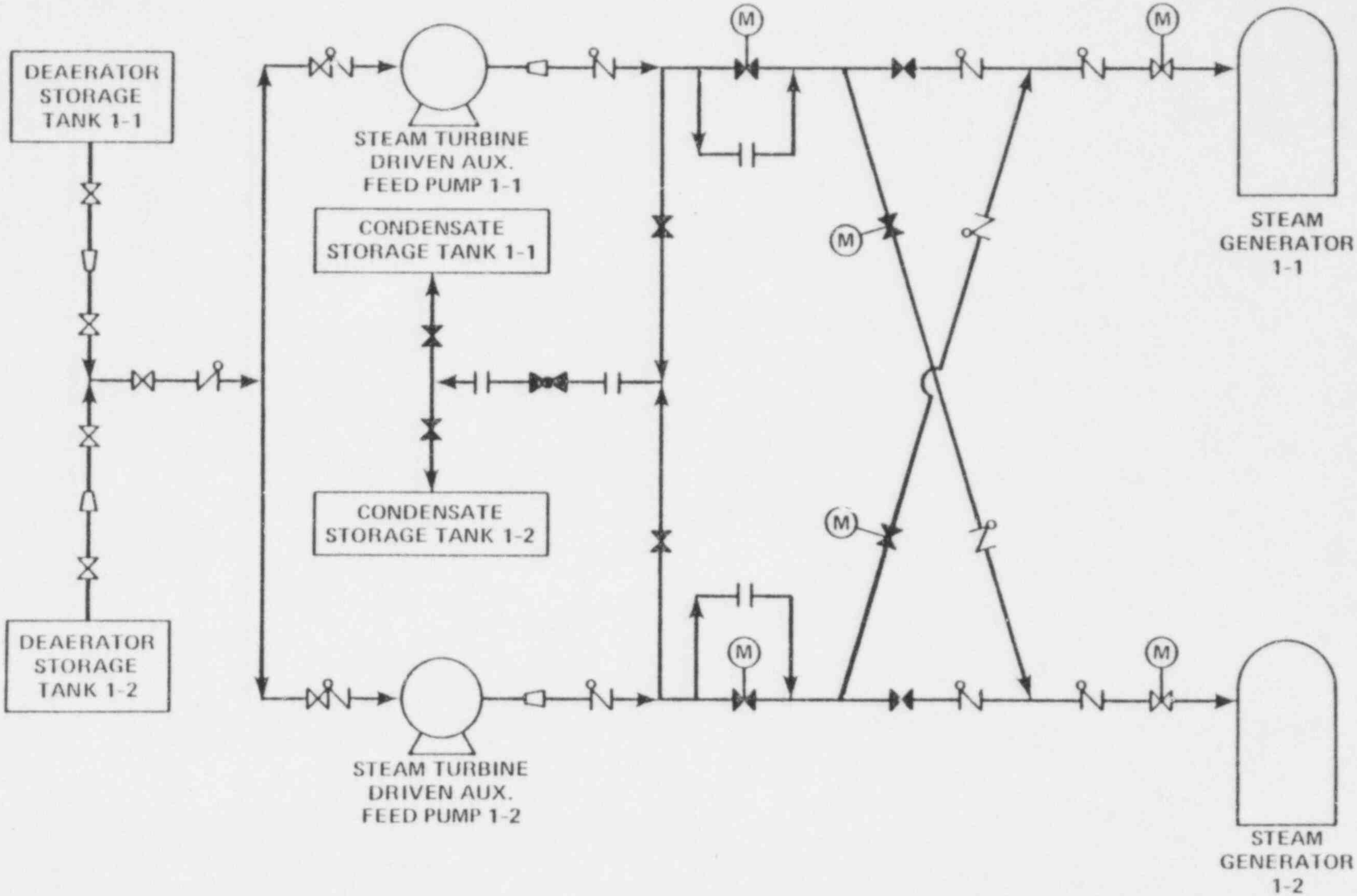
DAVIS-BESSE AUXILIARY FEEDWATER SYSTEM



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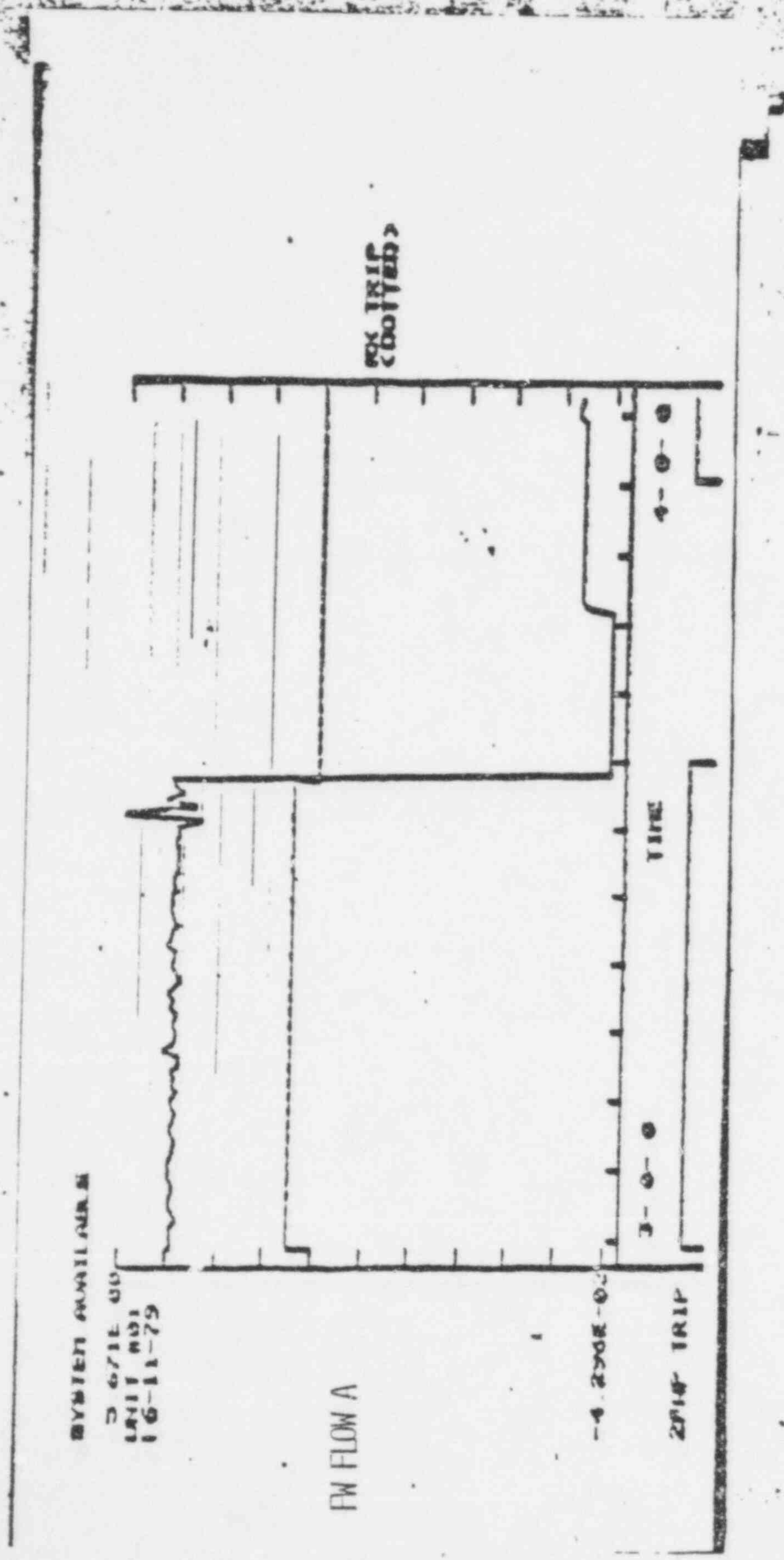
3:29:30	L.F. TURBINE INTERCEPT VALVES CLOSED
3:29:31	MAIN TURBINE CONTROL VALVES CLOSED
3:29:36	TURBINE BYPASS VALVES OPEN
3:29:34	RC-1 (PZR. SPRAY) OPEN
3:29:34	E2 H. D. PUMP OFF
3:29:42	MAIN TURBINE CONTROL VALVES OPEN
3:29:44	C. S. PUMP B ON
3:29:47	RC-1 (PZR. SPRAY) CLOSED
3:29:47	POWDEX BYPASS OPEN (D/P HIGH)
3:39:04	FDWP "A" SUCTION PRESS LOW 340#
3:30:04	H. D. PUMP DISCH HDR PRESS LOW 352#
3:30:15	MAIN STEAM PRESS LOW 805#
3:30:24	FDWP "B" SUCTION PRESSURE LOW 343#
3:30:34	C. S. PUMP SUCTION PRESS 76#
3:30:34	M. S. PRESSURE 870#
3:30:31	H. D. PUMP DISCH PRESS LOW 358#
3:31:06	C. S. PUMP SUCTION PRESS LOW 47#
3:31:16	FDWP SUCT. PRESS LOW 342#
3:31:29	D2 HTR. DRAIN PUMP OFF
3:32:04	FDWP A SUCT. PRESS LOW 325#
3:32:04	FDWP B SUCT. PRESS LOW 332#
3:32:27	DL HTR. DRAIN PUMP OFF
3:33:03	C. S. PUMP A OFF
3:33:03	C. S. PUMP B OFF
3:33:03	C. S. PUMP C OFF
3:33:04	FDWP A TRIPPED
3:33:04	FDWP B TRIPPED
3:33:04	REACTOR TRIP

578191

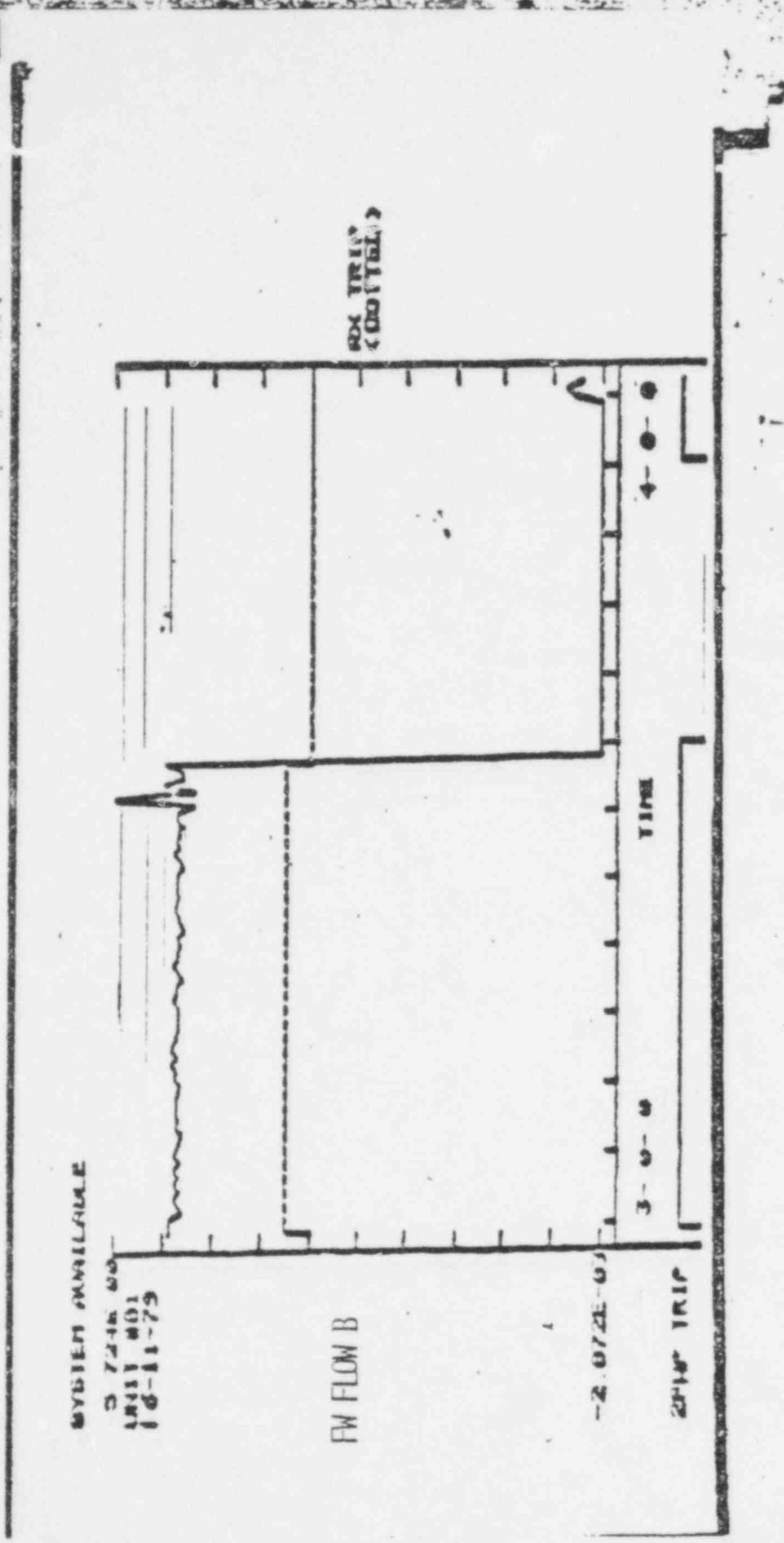
3:33:04	TURBINE/GENERATOR TRIP
3:33:06	C. S. PUMP B ON
3:33:10	MS-93 OPEN EFDW PUMP START
3:34:27	RP CH A TRIP - LOW PRESSURE
3:36:21	SG "B" S/V LEVEL 23 INCHES
3:36:40	MS PRESSURE A 1001#
3:36:40	MS PRESSURE B 1005#
3:37:05	RCS PRESSURE L920#
3:37:25	PZR. LEVEL 94 INCHES
3:43:2L	SG "B" S/V LEVEL 29.5 INCHES
3:43:57	FDWP "B" STARTED
3:44:25	RC PRESSURE 2155#
3:35:48	EFDWF STOPPED

578192



578193

POOR ORIGINAL



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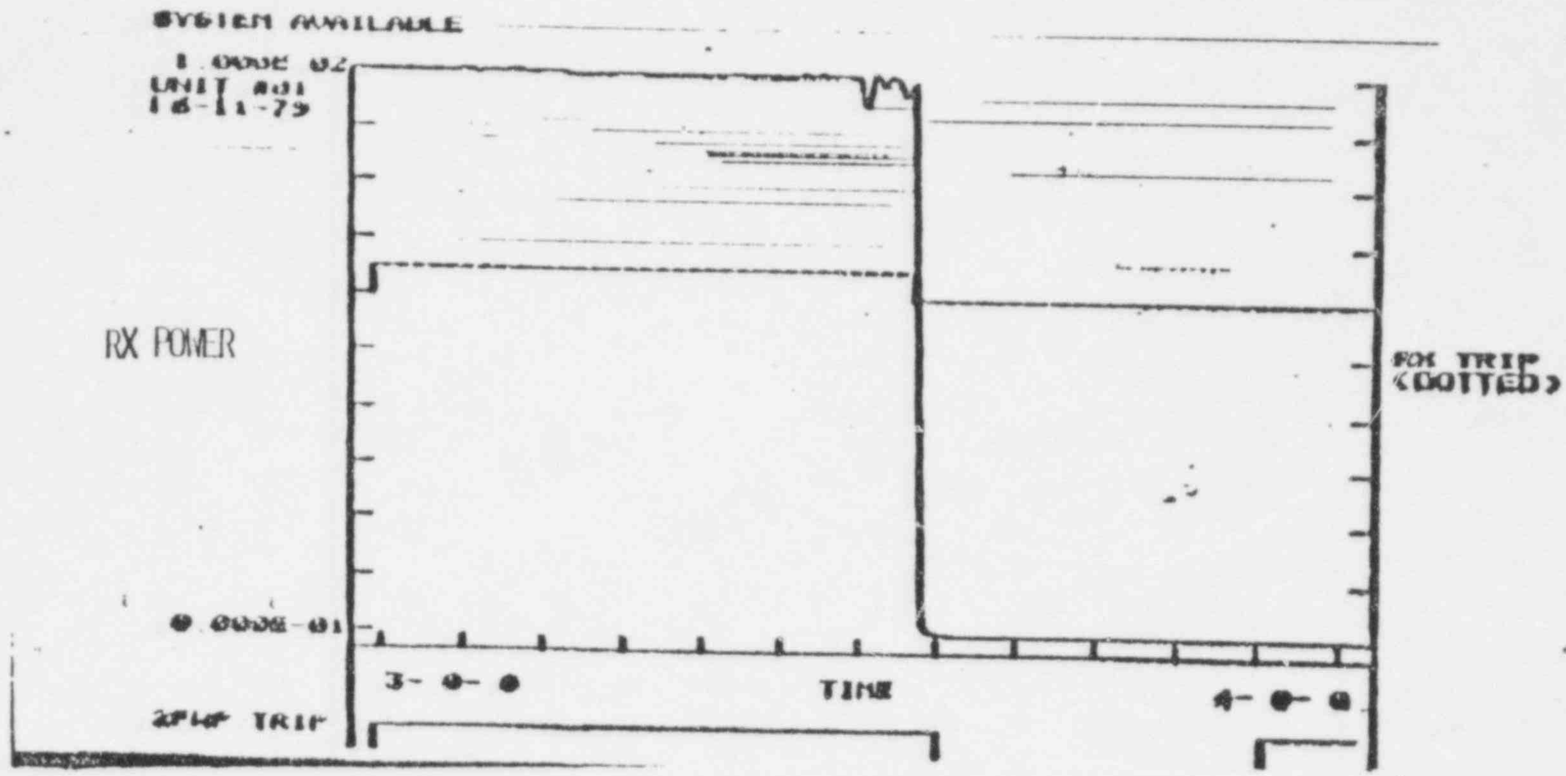
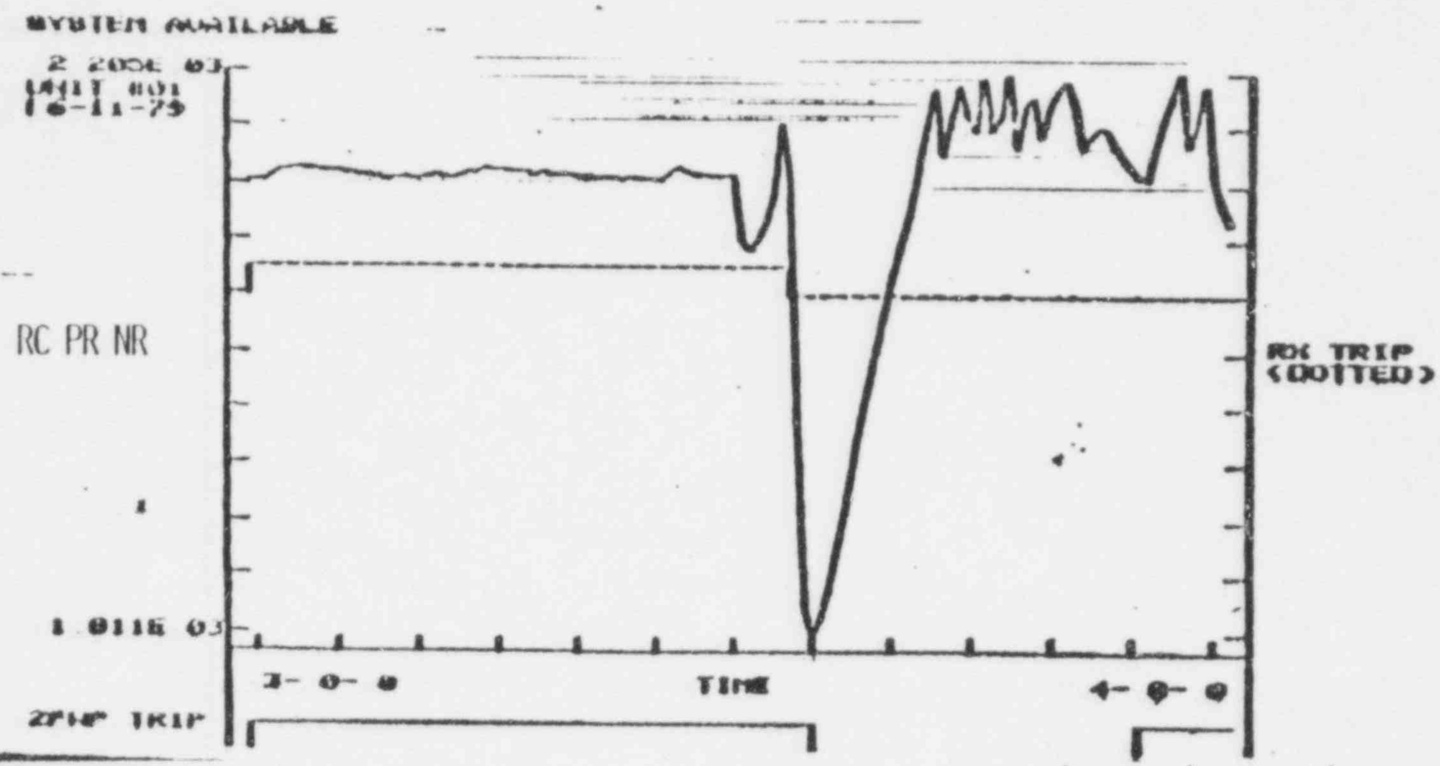
POOR ORIGINAL

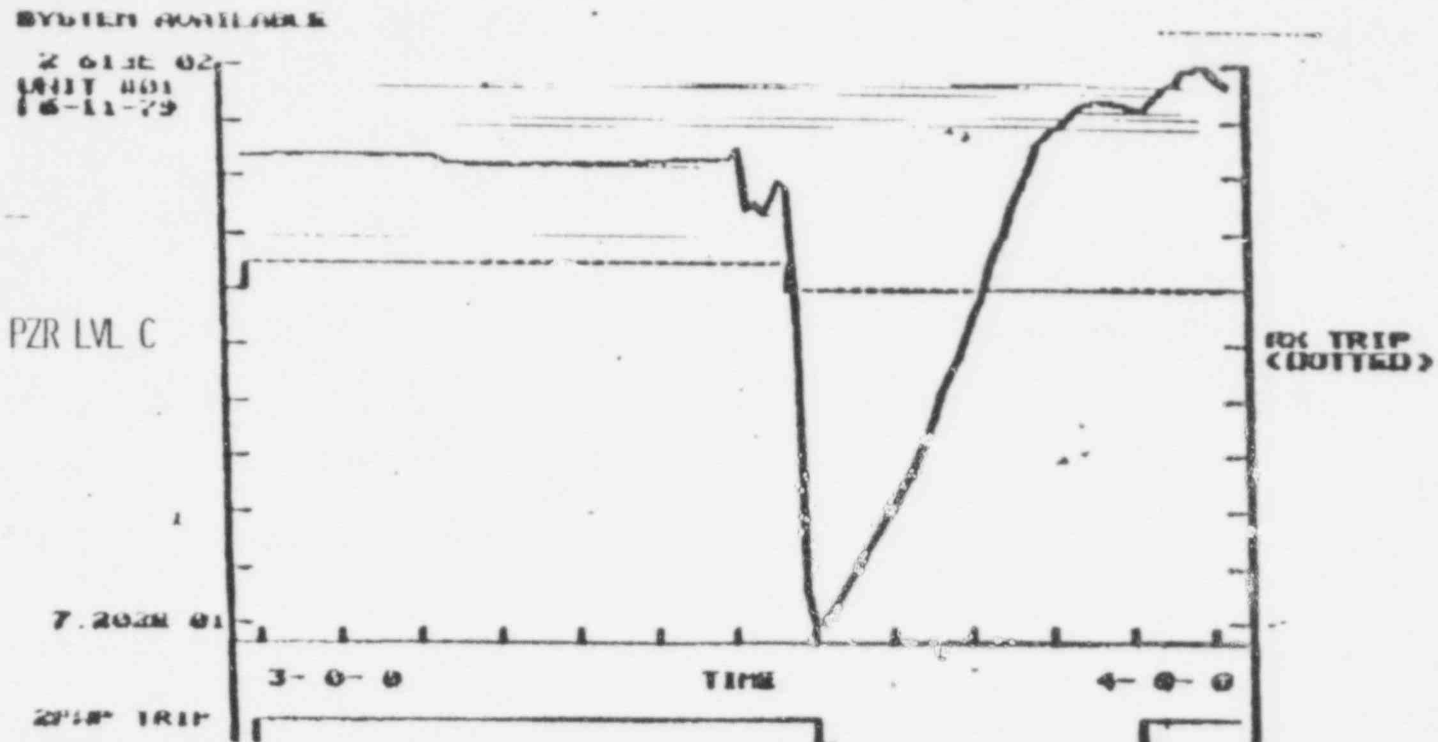

SYSTEM AVAILABLE
1.000E 02
UNIT #01
18-11-79
RX POWER
0.000E-01
3- 0- 0
TIME
4- 0- 0
2PWP TRIP
RX TRIP
(DOTTED)

578195



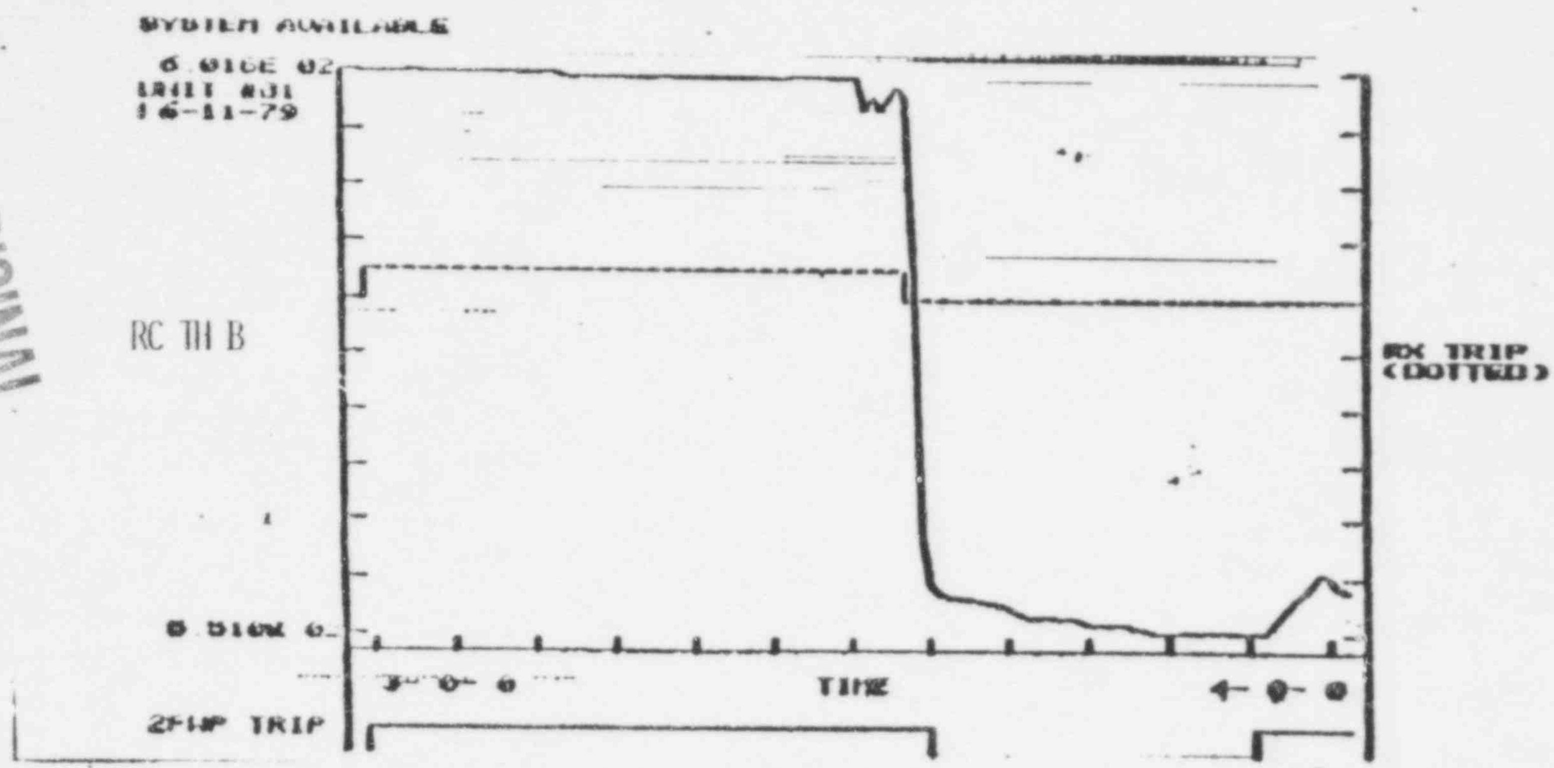
POOR ORIGINAL

578196



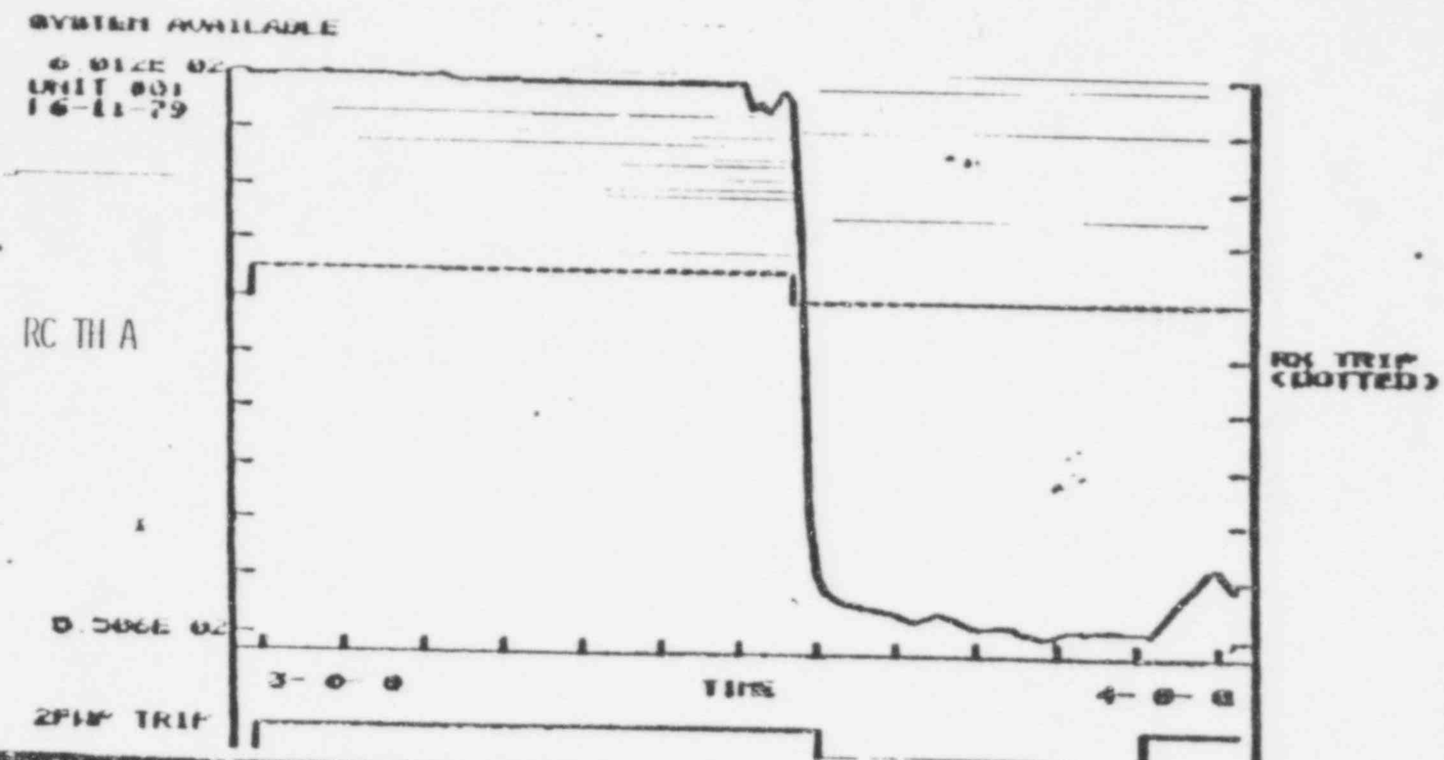
POOR ORIGINAL.

578197



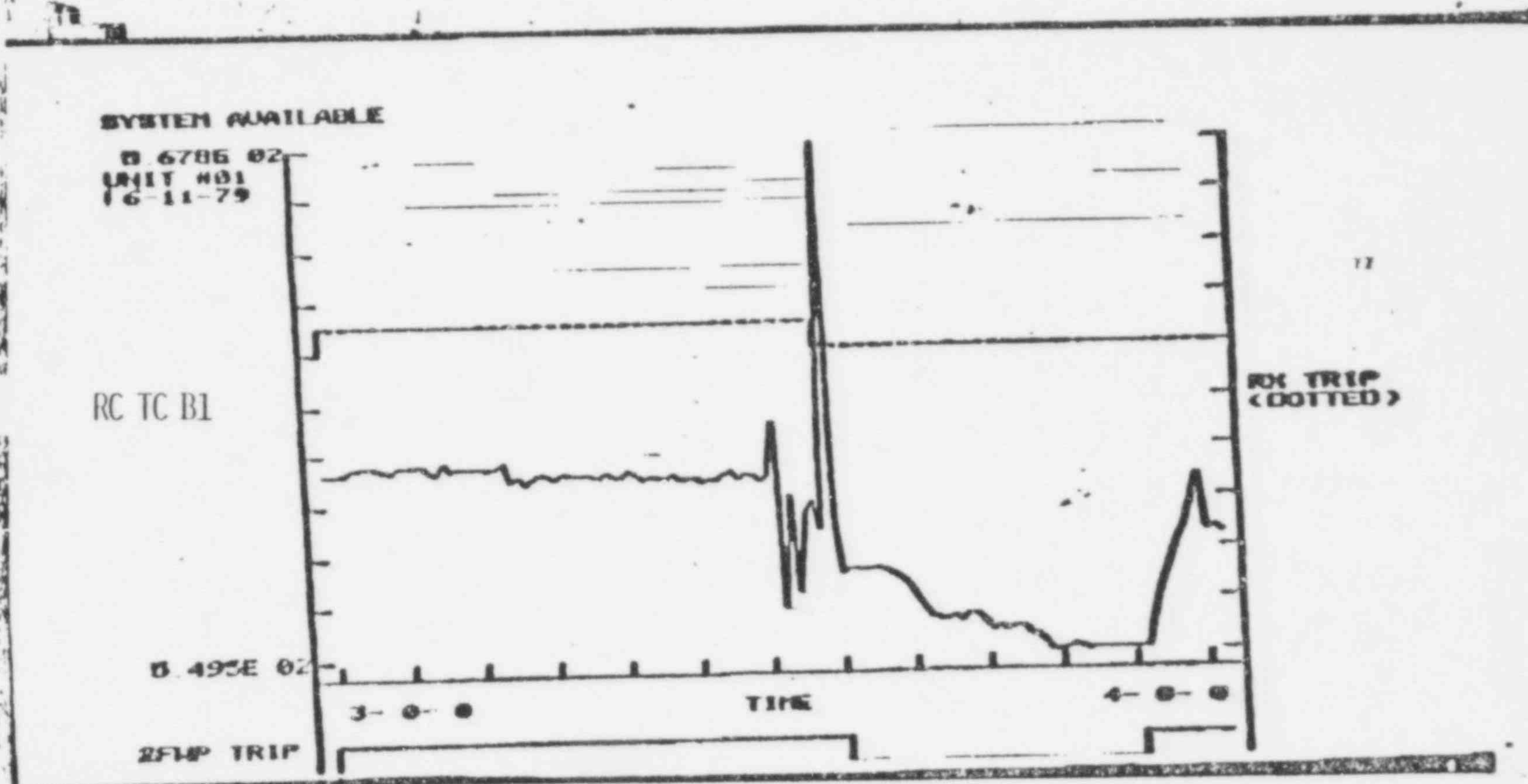
POOR ORIGINAL

578198

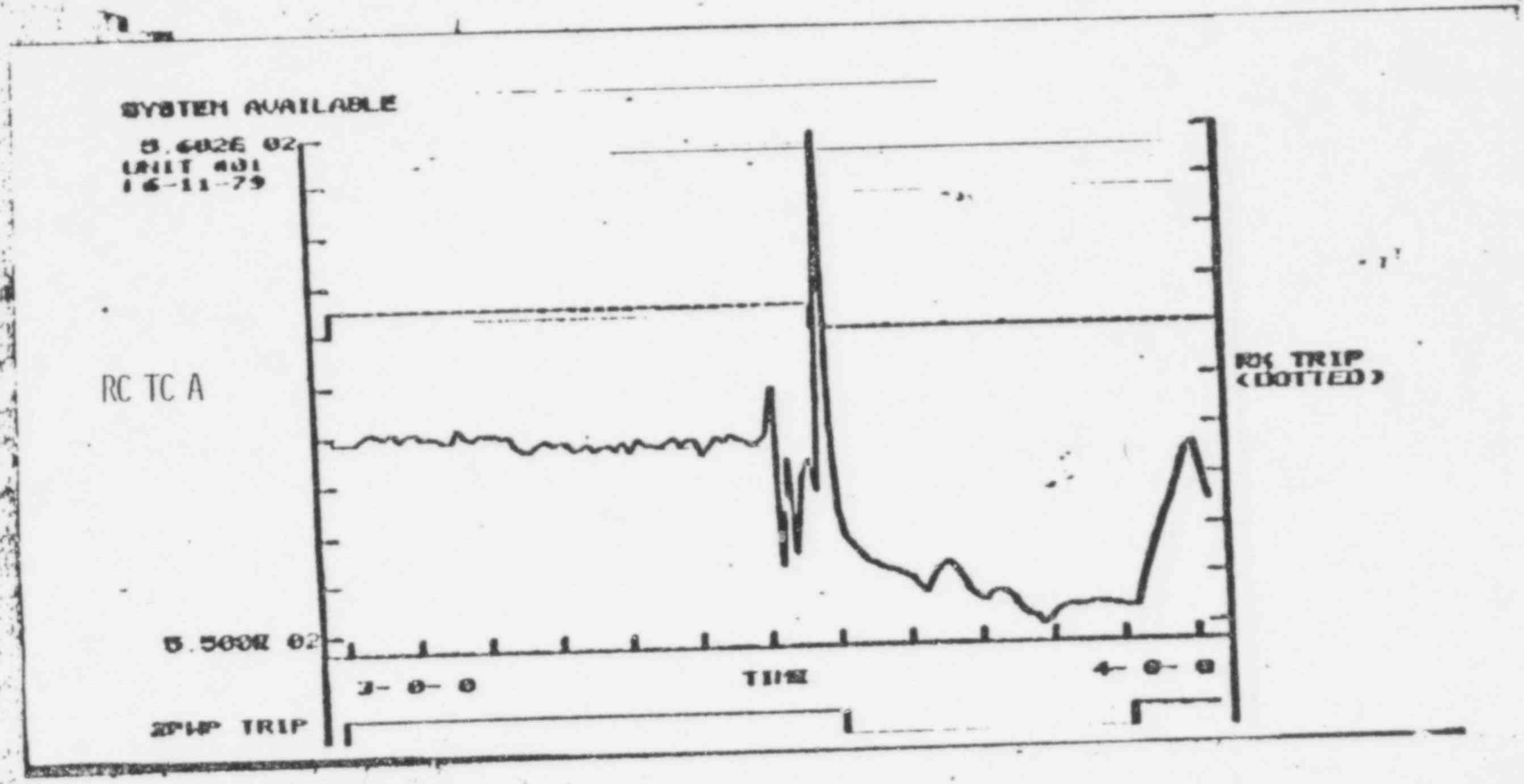


POOR ORIGINAL

578199

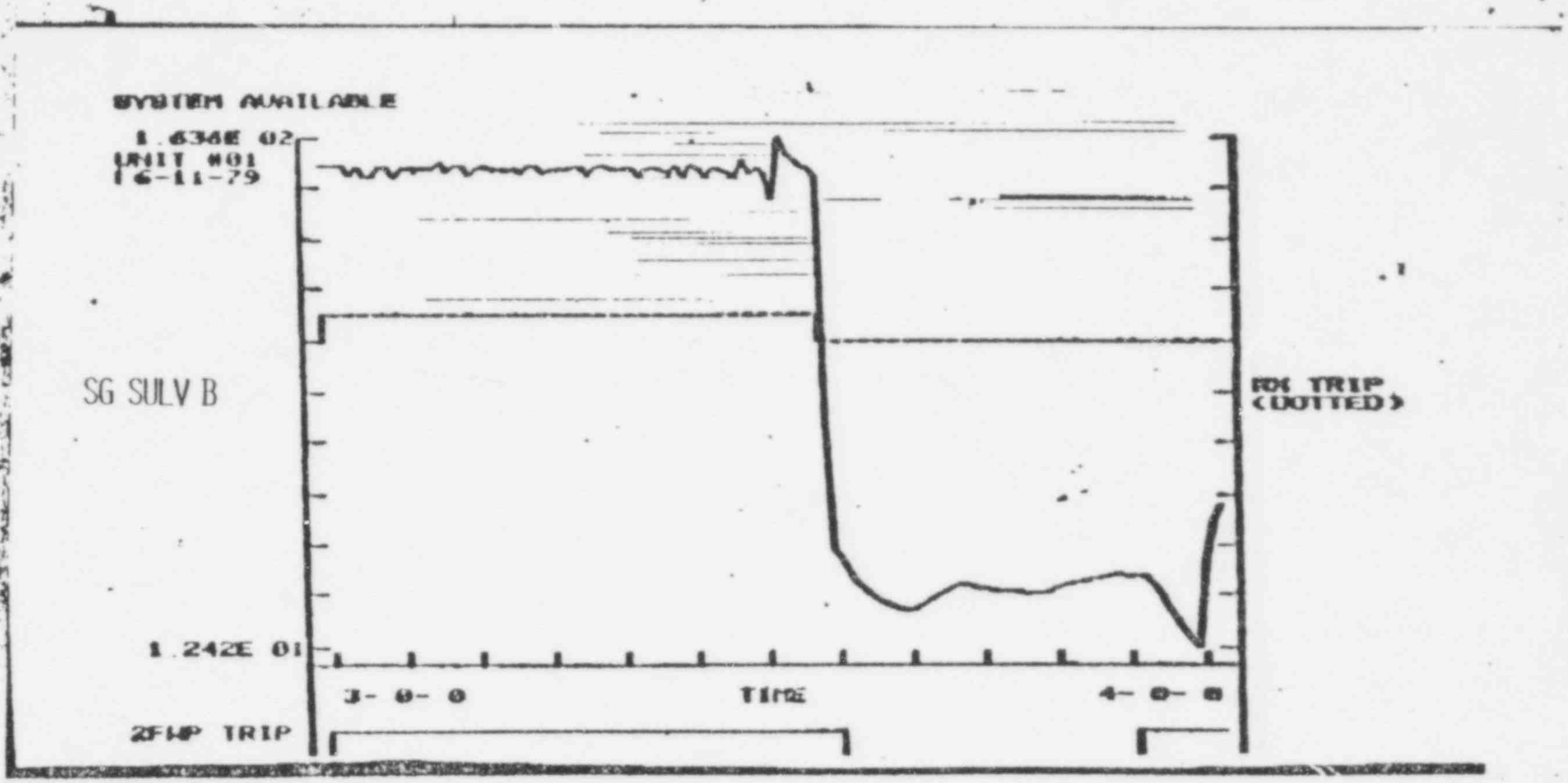


SYSTEM AVAILABLE
0.6786 02
UNIT #01
6-11-79
RC TC B1
RX TRIP (DOTTED)
0.495E 02
3- 0- 0
TIME
4- 0- 0
2FWP TRIP



POOR ORIGINAL

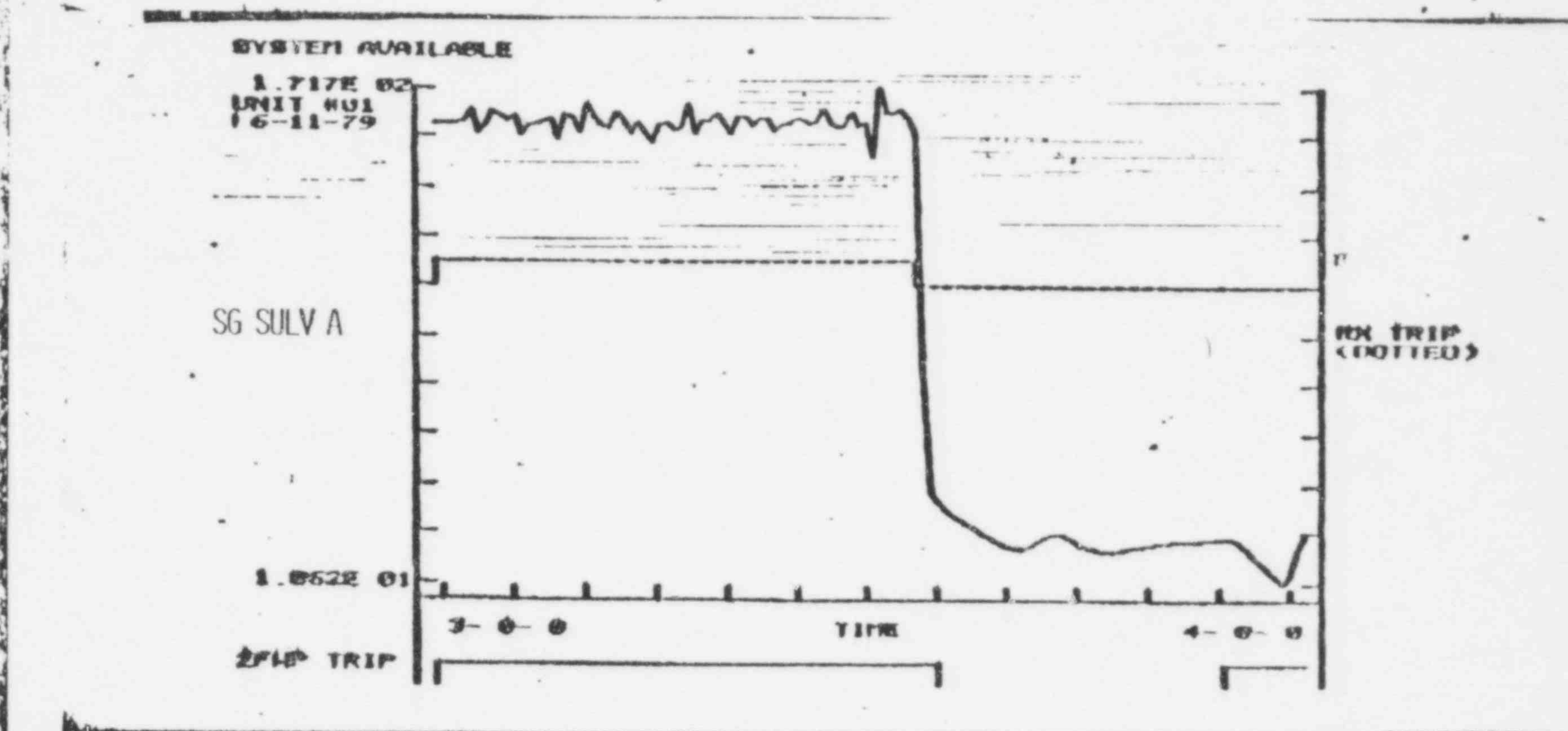
578201



POOR ORIGINAL

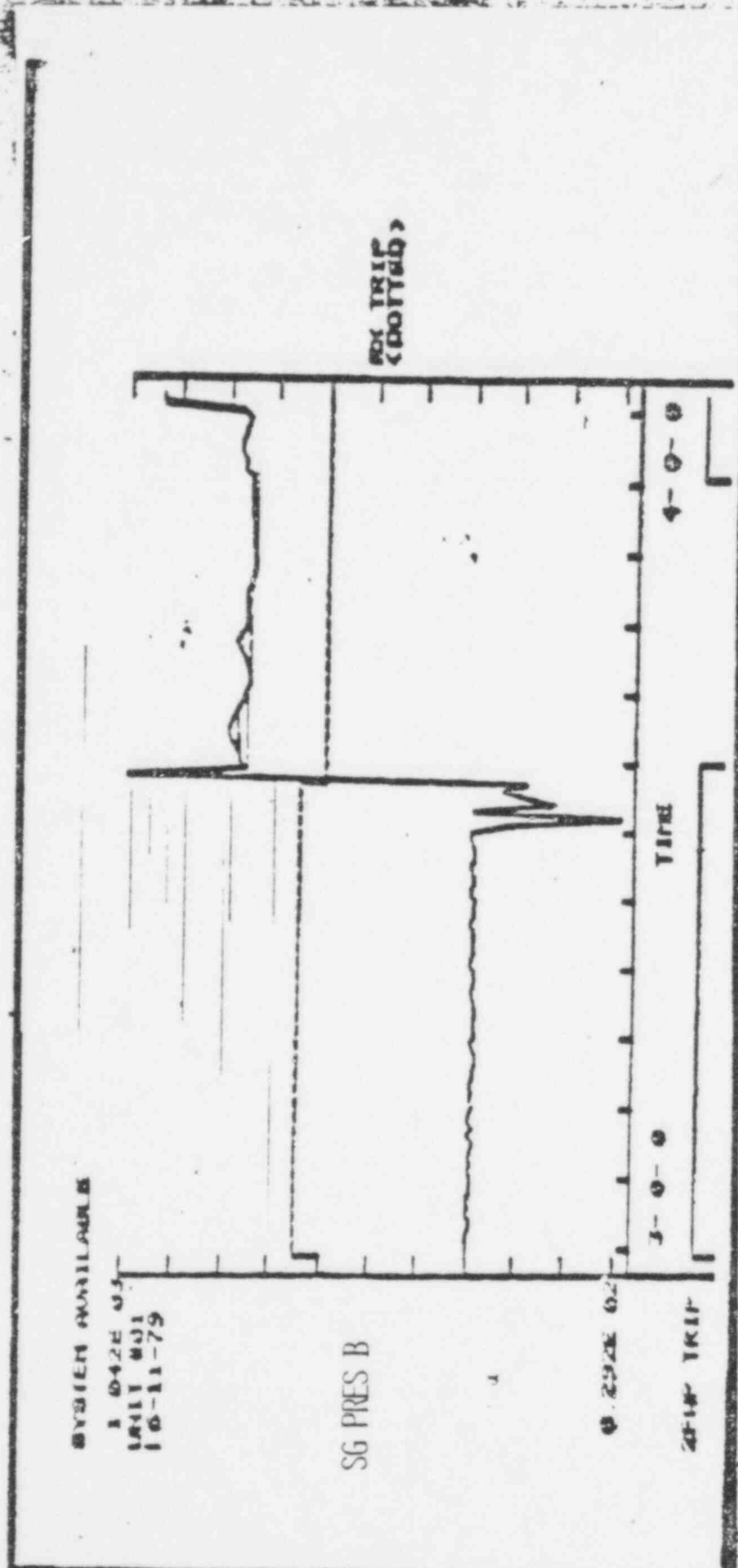
5782C2

13



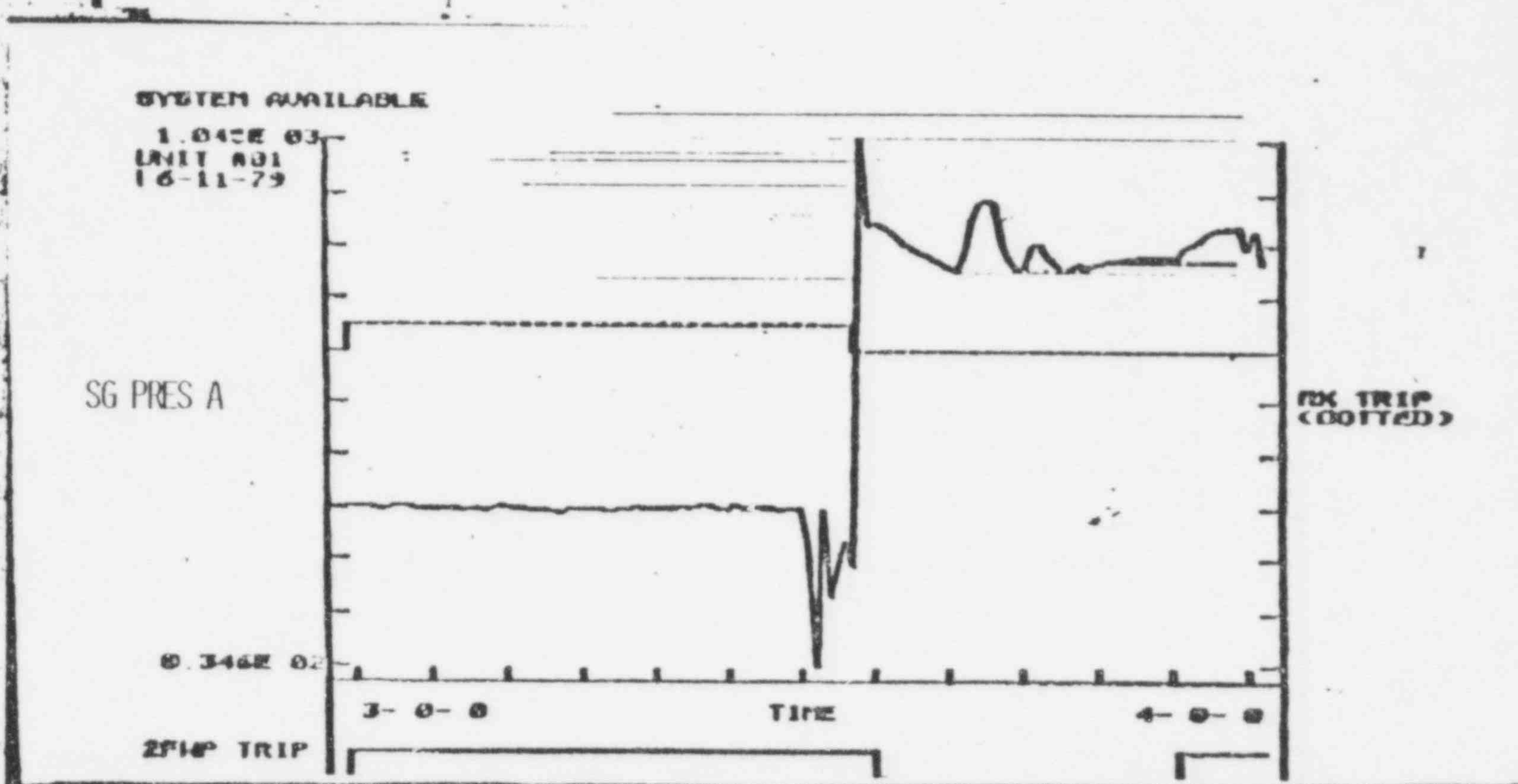
SYSTEM AVAILABLE
1.717E 02
UNIT #U1
6-11-79
SG SULV A
1.0622 01
3- 0- 0
TIME
4- 0- 0
RX TRIP
(DOTTED)
TRIP

578203



POOR ORIGINAL

578204



POOR ORIGINAL

578205

STAFF REVIEW IN GENERIC REPORT

MFW

AFW

CONTROL

SAFETY
INSTRUMENTATION
PORV,SV
CONTAINMENT ISOLATION
CHALLENGES TO PORV, ECCS
NATURAL CIRCULATION
ANALYSIS:

TRANSIENTS INCLUDING PORV
LOFW
SBLOCA
MICHELSON

ACRS
OPERATOR

578206

GENERIC RECOMMENDATIONS - SHORT TERM

GS-1 TECH SPEC LCO - TIME LIMIT ON OUTAGE OF 1 TRAIN

GS-2 TECH SPEC ADMINISTRATIVE CONTROLS ON MANUAL VALVES - LOCK AND VERIFY VALVE POSITION

- SINGLE SUCTION LINES AND VALVES

GS-3 RE-EVALUATE AFWS FLOW LIMITS TO REDUCE AFWS WATER HAMMER OCCURRENCE

GS-4 EMERGENCY PROCEDURE FOR CONNECTING BACKUP WATER SOURCE TO AFWS PUMP SUCTION

GS-5 EMERGENCY PROCEDURES TO ASSURE NECESSARY OPERATOR ACTIONS ARE TAKEN TO ASSURE AFWS AVAILABILITY IN EVENT OF AC BLACKOUT

EVALUATE FEASIBILITY OF INTEGRATED SYSTEM FLOW TEST TO VERIFY COMPLETE SYSTEM CONTROL AND FLOW LINEUP AND ASSURE SYSTEM AVAILABILITY

GS-6 AFWS FLOW VERIFICATION TO STEAM GENERATOR FOLLOWING MAINTENANCE OUTAGE WHICH AFFECTS AFWS FLOW CAPABILITY

GS-7 AFWS SHOULD BE AUTOMATICALLY INITIATED (CONTROL GRADE CIRCUITRY)

RETAIN MANUAL START AS BACKUP

GENERIC RECOMMENDATIONS - LONG TERM

GL-1 AFWS SYSTEMS SHOULD HAVE AUTOMATIC INITIATION (SAFETY GRADE CIRCUITRY). RETAIN MANUAL START AND STOP CAPABILITY WITH MANUAL START AS BACKUP TO AUTOMATIC INITIATION

GL-2 INSTALL REDUNDANT PATH (PIPING AND VALVES) WHERE PRIMARY AND ALTERNATE WATER SOURCES PASS THROUGH SINGLE PIPE AND VALVE.

GL-3 EVALUATE AFWS DESIGN TO ELIMINATE A-C DEPENDENCY FOR ONE AFWS

GL-4 EVALUATE AFWS DESIGN TO PREVENT MULTIPLE PUMP DAMAGE DUE TO DRY PUMP OPERATION RESULTING FROM NATURAL PHENOMENA DAMAGE (EARTHQUAKE, TORNADO) TO UNPROTECTED PRIMARY WATER SUPPLY CONCURRENT WITH AUTOMATIC PUMP START

5782208

INFORMATION REQUEST

A. AFWS

1. DESCRIPTION
2. PROCEDURES
3. P & ID'S
4. CONTROL. INSTRUMENTATION. & POWER DESCRIPTION
5. OPERATING EXPERIENCE
6. RELIABILITY ANALYSES
7. SG DRYOUT TIMES
8. DESIGN BASES
9. PORV DATA
10. ECCS AS-BUILT PERFORMANCE
11. TRIP SETPOINTS
12. CHALLENGES TO ECCS
13. NATURAL CIRCULATION PERFORMANCE
14. RCP FEATURE

B. ANALYSES

1. SB LOCA; FW TRANSIENTS; VARIOUS BREAK LOCATIONS (INCLUDING PRESSURIZER).
2. NATURAL CIRCULATION FOLLOWING SB LOCA: DISCUSS MICHELSON REPORT.
3. TRANSIENTS. SB LOCA PLUS STUCK-OPEN PORV.
4. GUIDELINES FOR RECOVERY FOLLOWING SB LOCA: INCLUDING RCP OPERATION, INFORMATION AVAILABLE TO OPERATOR

578209

POOR ORIGINAL

CONTROL SYSTEMS

INVESTIGATE THE ROLE OF CONTROL SYSTEMS TO CAUSE:

- TRANSIENTS
- MULTIPLE FAILURES (E.G., MAIN AND AUX FEED)
- INCREASE CHALLENGES TO PORV (E.G., SPRAY FAILURE)

INSTRUMENTATION

INVESTIGATE:

- VESSEL INVENTORY INDICATION
- INCREASE STRIP CHART RECORDER SPEED ON ACCIDENT
- VESSEL HEAD TEMPERATURE

POWER OPERATED RELIEF VALVES

GENERIC:

INVESTIGATE FEATURES (E.G., OPERATION AT LOWER INITIAL PRESSURE) TO ALLOW LOAD REJECTION WITHOUT LIFTING PORVs.

IDENTIFY FACILITY AND PROPOSE PLANS TO CONDUCT EXPERIMENTS TO BETTER UNDERSTAND THE VALVE BEHAVIOR UNDER TWO-PHASE AND SUBCOOLED FLOW CONDITIONS.

PLANT SPECIFIC:

CONFIRM DIRECT PORV POSITION VIA LIMIT SWITCH.
IF NOT AVAILABLE, PROVIDE.

INVESTIGATE AUTOMATIC CLOSURE OF THE ISOLATION VALVE ON PRESSURE BELOW PORV SETPOINT.

REVIEW T&M PROCEDURES TO DETERMINE IF PORV OPENING CAN BE MINIMIZED.

UPGRADE CIRCUITRY SO SINGLE FAILURES WOULD NOT CAUSE VALVE TO OPEN.

CONTAINMENT ISOLATION

REVIEW CRITERIA TO ASSUME:

- DIVERSE SENSORS FOR ISOLATING NON-ESSENTIAL LINES
- IDENTIFY LINES WHICH AID PLANT SAFETY

INSTITUTE ADMINISTRATIVE PROCEDURES FOR CORRECT POSITIONING OF ALL MANUAL VALVES.

EVALUATE THE VALIDITY OF SIGNALS USED TO ISOLATE CONTAINMENT

PREVENT AUTOMATIC TRANSFER OF POTENTIALLY RADIOACTIVE LIQUIDS & GASES OUT OF CONTAINMENT

EVALUATE IMPACT ON CONTAINMENT ISOLATION FROM RESETTING ESFAS.

NATURAL CIRCULATION

SHORT TERM

PROVIDE POWER TO PRESSURIZER HEATERS ASSUMING NO OFFSITE AC

VERIFICATION OF NATURAL CIRCULATION

CORE EXIT T/CS - TECH SPEC MINIMUM AVAILABLE

ROLE OF PROCESS COMPUTER

LONG TERM

INVESTIGATE MERITS OF INSTALLING FLOW MEASUREMENT DEVICE FOR LOW FLOW MEASUREMENTS

OPERATOR TRAINING

SIMULATOR TRAINING VALUABLE AND NECESSARY:

- TMI-2 SCENARIO TRAINING
- MULTIPLE FAILURES IN SAFETY AND CONTROL SYSTEMS
- NATURAL CIRCULATION
- TRAINING PROGRAMS NEED REVIEW

SIMULATOR PROGRAMMING REQUIRED

NEED TO DEVELOP BETTER EVALUATION OF SENIOR OPERATOR LICENSEE'S ABILITY TO DIRECT ACTIVITIES DURING ABNORMAL AND EMERGENCY CONDITIONS

TRAINING ON PROTECTING CORE NEEDS EMPHASIS:

- INVENTORY (LEVEL AND PRESSURE)
- INTACT SYSTEM
- HEAT SINK
- SUBCOOLING

SMALL BREAK LOCA METHOD REQUIREMENTS

1. SYSTEM NODING JUSTIFICATION (E.G. PRESSURIZER, STEAM GENERATOR).
2. JUSTIFY PRESSURIZER SURGE LINE REPRESENTATION - NEED TO CONSIDER FLOODING.
3. VERIFY BREAK FLOW MODEL AT EACH LOCATION.
4. VERIFY NATURAL CIRCULATION HEAT REMOVAL FOR TWO-PHASE NATURAL CIRCULATION.
5. JUSTIFY TREATMENT OF NON-CONDENSABLES.
6. VERIFY CORE COOLANT LEVEL CALCULATION.

578215 120

SMALL BREAK LOCA ANALYSIS REQUIREMENTS

1. TYPICAL ANALYSIS FOR EACH TYPE OF SMALL BREAK BEHAVIOR (DEPRESSURIZATION, PRESSURE HANG UP, REPRESSURIZATION).

2. ANALYSIS OF WORST BREAK SIZE AND LOCATION IN TERMS OF CORE UNCOVERY.

3. ANALYSIS OF PORV STUCK OPEN.

4. ANALYSIS OF COMPLETE LOSS OF FEEDWATER (NORMAL AND AUXILIARY) TO DETERMINE MINIMUM TIME FOR OPERATOR ACTION.

5. ANALYSIS ASSUMING ONE STEAM GENERATOR IS LOST.

6. ANALYSES ASSUMING RC PUMPS OPERATING AND NOT OPERATING.

7. TRANSIENT ANALYSES TO DETERMINE WHICH TRANSIENTS WOULD LIFT RELIEF OR SAVETY VALVES.

WESTINGHOUSE - DESIGNED OPERATING PWR OWNER'S GROUP

. MEMBERSHIP

ALL 18 UTILITIES WITH OPERATING W-DESIGNED PWR's AND PACIFIC GAS & ELECTRIC COMPANY (DIABLO CANYON 1 & 2)

. PURPOSE

TO INTERACT WITH THE NRC STAFF TO EFFECT RESOLUTION OF THE GENERIC TECHNICAL ISSUES FOR W - DESIGNED OPERATING PWRS ARISING FROM THE STAFF'S POST-TMI-2 REEVALUATION OF OPERATING PLANTS

. CURRENT SCOPE

- GENERIC ANALYSES
- DIAGNOSTIC EMERGENCY PROCEDURES

. SCHEDULE FOR RESPONDING TO STAFF'S JUNE 4, 1979 REQUEST FOR INFORMATION REGARDING SMALL BREAK LOCA ANALYSIS AND ANALYSIS METHODS, FEEDWATER TRANSIENTS, AND RELATED RECOMMENDATIONS FOR EMERGENCY OPERATING PROCEDURES

- JUNE 29, 1979

5782177

REVIEW OF RESPONSES TO IE BULLETINS 79-06A AND 79-06A, REVISION 1

- DRAFT SER PREPARED FOR EACH PLANT
- DRAFT SER TRANSMITTED TO EACH LICENSEE JUNE 1979
- LICENSEE GIVEN UNTIL JUNE 22, 1979 TO SUPPLEMENT BULLETIN RESPONSES

OPERATING PWR'S WITH WESTINGHOUSE-DESIGNED NUCLEAR STEAM SUPPLY SYSTEMS

	PLANT	UTILITY	POWER LEVEL (MWT)	DATE OL ISSUED
1.	HADDAM NECK	CONNECTICUT YANKEE ATOMIC POWER CO.	1825	06/30/67
2.	YANKEE ROWE	YANKEE ATOMIC ELECTRIC CO.	600	07/09/60
3.	SAN ONOFRE 1	SOUTHERN CALIFORNIA EDISON	1347	03/27/67
4.	PRAIRIE ISLAND 1 & 2	NORTHERN STATES POWER CO.	1650/UNIT	08/09/73 & 10/29/74
5.	FARLEY 1	ALABAMA POWER CO.	2652	06/25/77
6.	SALEM 1	PUBLIC SERVICE ELECTRIC & GAS	3338	08/13/76
7.	NORTH ANNA 1	VIRGINIA ELECTRIC & POWER CO.	2775	11/26/76
8.	D. C. COOK 1 & 2	INDIANA & MICHIGAN ELECTRIC CO.	3250, 3391	10/25/74 & 12/23/77
9.	INDIAN POINT 3	POWER AUTHORITY OF THE STATE OF NEW YORK	2760	12/12/75
10.	GINNA	ROCHESTER GAS & ELECTRIC CO.	1520	09/19/69
11.	KEWAUNEE	WISCONSIN PUBLIC SERVICE CORP.	1650	12/21/73
12.	ZION 1 & 2	COMMONWEALTH EDISON CO.	3250/UNIT	04/06/73 & 11/14/73
13.	POINT BEACH 1 & 2	WISCONSIN ELECTRIC POWER CO.	1518/UNIT	10/05/70 & 11/16/71
14.	TURKEY POINT 3 & 4	FLORIDA POWER & LIGHT CO.	2200/UNIT	07/19/72 & 04/10/73
15.	INDIAN POINT 2	CONSOLIDATED EDISON CO.	3025	10/19/71
16.	TROJAN	PORTLAND GENERAL ELECTRIC	3411	11/21/75
17.	H. B. ROBINSON 2	CAROLINA POWER & LIGHT CO.	2200	07/31/70
18.	SURRY 1 & 2	VIRGINIA ELECTRIC & POWER CO.	2441/UNIT	05/25/72 & 01/29/73
19.	BEAVER VALLEY 1	DUQUESNE LIGHT CO.	2652	01/30/76

RESULTS OF NRR REVIEW OF LICENSEE RESPONSES TO IE BULLETIN 79-06A, REVISION 1

ITEM NO.	PLANT NO. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
1																			
2	A	A	A	A	A	A	A,C	A	A	A	A	A	F	A,D	A	A	A	A,D	A
		D	D	D		C	D		D	C									D
3					F	F	E	E	E,F							B	B	F	F
4	B,F	D,F	B,F	D,F		F	D,F	D,F		F	F		F			C,F		F	
5																			
6		F			F						F	F	F				F		F
7A	B	B,C		B,D	B	B,C		B	F	E,F	B	F	E,F	F	B	B,E	B,F		B,F
7B	B,C	B	E	B	B	B	E	C,F	B	B,C	B	B	B,C	B,C	B	B	B		B
7C	B,D	B,C	B	B,C	B	B,C		C,F	B	B,C	B	B	B,C	B,C	B	B,C	B,C		B
7D		F		G		C,F	F		F	E	G	F		F		E		F	G
8	C	F	C,F	F	F	F	F	F	C,F	C,F	F	F	F	F	F	C,F	C,E,F	F	D,F
9	F	D,F	F	F	D,F	D,F			F	D,F	D,E,F		E,F	F	D,F		D,F	F	D,F
10	C,F	D,F	F	C,F	C,F	D,F	D,F	D,F	D,F	F	F		F	H	F	F	C,F	F	F

578220

ITEM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
11		F	E		E,F	F					E,F	F	E,F	B,E	F				F
12	E	F	E	F	C	E,F	D,F			F	F	F	F	F	F	D,F	F	B	B

LEGEND

A. RESPONSE INDICATES TOO NARROW AN INTERPRETATION OF THE BULLETIN REQUIREMENTS

B. DOES NOT COMPLY WITH BULLETIN REQUIREMENTS

C. REQUIRED REVIEW STILL IN PROGRESS

D. RESPONSE INCOMPLETE

E. CLARIFICATION REQUIRED

F. ADDITIONAL INFORMATION REQUIRED

G. NO RESPONSE

H. UNRESPONSIVE

5782221

RESPONSE MATRIX FOR I&E BULLETIN 79-06B

(STAFF'S PRELIMINARY ASSESSMENT)

ITEM \ PLANT	CALVERT CLIFFS	ANO-2	MILLSTONE	PALISADES	MAINE YANKEE	FT. CALHOUN	ST. LUCIE
1.							
2.							
3.				X			
4.							
5.							
6.A.							
6.B.	X			X			X
6.C.	X		X	X	X		X
7.							
8.							X
9.							
10.							
11.	X						
12.	(NOT APPLICABLE AT THIS TIME)						

X - INDICATES THAT REPLIES HAVE EITHER NOT BEEN RECEIVED OR THAT THEY APPEAR TO BE NON-RESPONSIVE

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POOR ORIGINAL

RESPONSE MATRIX FOR I&E BULLETIN 79-06B

BASED ON STAFF EVALUATION AS OF 6/14/79

ITEM NO. \ PLANT	CALVERT CLIFFS	ANO-2	MILLSTONE	PALISADES	MAINE YANKEE	FT. CALHOUN	ST. LUCIE
1.							
2.		X		X	X	X	X
3.		X		X			
4.				X			
5.							
6.A.							
6.B.				X		X	
6.C.				X	X		X
7.		X		X		X	X
8.							X
9.						X	X
10.							X
11.						X	

NOTE: TO DATE, ITEM 12 (TECH. SPEC. CHANGES) NOT APPLICABLE, I.E., NO CHANGES REQUIRED.

X-INDICATES THAT RESPONSE EITHER NOT ACCEPTABLE OR THAT FURTHER CLARIFICATION IS REQUIRED.

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SCHEDULE OF B&O ACTIVITIES FOR BWRS

ACTIVITY	TARGET COMPLETION DATE
BULLETIN REVIEW	
. ISSUE [illegible] 79-08	4/14/79
. INITIAL REVIEW OF RESPONSES	6/12/79
. COMPLETE REVIEW OF RESPONSES	EARLY AUGUST
GENERIC REVIEW	
. INITIATE GENERIC REVIEW	6/7/79
. MEET WITH UTILITIES	LATE JUNE
. MEET WITH GE	JULY
. DEFINE NEEDS FOR ADDITIONAL SMALL BREAK ANALYSES	EARLY JULY
. COMPLETE GENERIC REVIEW	EARLY AUGUST
. ISSUE INSTRUCTIONS TO UTILITIES	EARLY AUGUST
. REVIEW AND APPROVE UTILITY RESPONSES TO INSTRUCTIONS	OCTOBER

B&O GENERIC REVIEW OF BWRs

PRINCIPAL REVIEW AREAS

. ACRS RECOMMENDATIONS

. SMALL BREAK LOCA ANALYSES

. TRANSIENT ANALYSES

. DEGRADED PLANT CONDITIONS

. ADEQUACY OF PROCEDURAL GUIDANCE TO OPERATORS

. OYSTER CREEK EVENT

. NUREG-0560 MATTERS APPLICABLE TO BWRs

. CHALLENGES TO SAFETY SYSTEMS FROM NON-SAFETY SYSTEMS

ACTIONS TAKEN

. MEETING WITH ALL UTILITIES SCHEDULED FOR 6/28/79

. NEED TO RESPOND TO ACRS RECOMMENDATIONS IDENTIFIED TO UTILITIES AND GE IN LETTERS

. NUREG-0560 MATTERS APPLICABLE TO BWRs IDENTIFIED

. PROCEDURES RECEIVED FROM DRESDEN AND HATCH ARE UNDER REVIEW

- LOCA
- LOSS OF OFFSITE POWER
- STUCK OPEN SRV
- LOSS OF INSTRUMENT AIR

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STATUS OF TMI-2

- Natural circulation, steaming on "A" OTSG
- T(hot) - 161^{o}F, T(cold) - 152^{o}F
- Maximum in-core T - 279^{o}F
- Pressure $\simeq$ 325#, solid operation
- Reactor building pressure ~ 0±0.2#
- Reactor building water level - 7'
- Environmental releases -

  Water < Appendix I (since 3/28)

  Gas < Appendix I (currently)

6/14/79

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MODIFICATIONS

o Reactor Systems - "B" OTSG solid operation

Upgrade of decay heat removal

Alternate decay heat removal

Pressure/volume control

Emergency power

o Radwaste Systems - Supplemental filters

EPICOR-II

Tank farm

6/14/79

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FUTURE PLANS

- o Complete and test modifications
- o Cleanup of auxiliary building water
- o Cleanup of containment and primary water
- o Containment entry and cleanup

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