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400 Virginia Ave., S.W. Washington, D. C. 20024

Telephone: (202) 554-2345

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UNITED STATES NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
SUBCOMMITTEE ON DECAY HEAT REMOVAL SYSTEMS

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Room 1046
1717 H Street, N.W.
Washington, D.C.
Tuesday, March 16, 1982

The Subcommittee on Decay Heat Removal Systems convened at 9:00 a.m., David Ward, Chairman of the subcommittee, presiding..

PRESENT FOR THE ACRS:

SUBCOMMITTEE MEMBERS:

DAVID WARD
JESSE EBERSOLE
HAROLD ETHERINGTON
JEREMIAH RAY

ACRS CONSULTANTS:

I. CATTON
Z. ZUDANS
P. DAVIS
E. EPLER

ACRS STAFF:

ANTHONY CAPPUCCI

DESIGNATED FEDERAL EMPLOYEE:

RICHARD SAVIO

P R O C E E D I N G S

MR. WARD: The meeting will now come to order. This is the meeting of the Advisoı. Committee on Reactor Safeguards, Subcommittee on Decay Heat Removal Systems.

I'm David Ward, the Subcommittee Chairman. Other ACRS members present today are Mr. Ebersole, Mr. Etherington and Mr. Ray. Also in attendance are consultants: Mr. Epler, Mr. Davis, Mr. Zudans and Mr. Catton.

The purpose of the meeting is to discuss the status of Task Action Plan A-45, the effectivess of the feed and bleed heat removal processes, and the Combustion Engineering response to the ACRS comments on the CESSAR System 80 decay heat removal systems.

This meeting is being concucted in accordance with the provisions of the Federal Advisory Committee Act and the Government in the Sunshine Act. Dr. Richard Savio is the designated federal employee for the meeting. Also present is Mr. Cappucci of the ACRS staff.

Rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on Monday, March 1st, 1982. A transcript of the open portions of the meeting is being kept and will be made available within five working days. We request that each speaker first identify himself or herself and speak with sufficient clarity and volume so that he or she can be readily heard.

We have received no written statements or requests for time to make oral statements from members of the public.

I would like to recognize some guests we have. Typical of students, it look like they all sat in the back row. But we have Dr. Cockrill and the senior engineering -- nuclear engineering students from North Carolina State University. We welcome you.

As I said, at today's meeting we are going to consider two subjects: first is Task Action Plan A-45, the unresolved safety issue dealing with the reliability of decay heat removal systems. We have heard previous reports on this plan and have made some comments. I think for the last several months the staff has had the plan under revision, and this is just a status report. This won't be the final report. We will hear more in the future or see the final plan in the future.

So there is not any formal response required of us on this today, but I'm sure the staff will be happy to receive any comments that we have to make.

The second issue is that of the effectiveness of feed and bleed cooling of PWR's, and in particular responses of the staff and Combustion Engineering to the ACRS letter last December, in which we expressed three concerns about the CESSAR design related to the feed and bleed issue, feed and bleed or no feed and bleed issue.

We will want at the end of the afternoon opinions from Subcommittee members and the consultants on how well the staff and CE have addressed the concerns expressed by the ACRS in the December letter.

So with that, we will go ahead and ask Mr. Andrew Marchese of the NRC staff to present.

(Slide.)

MR. MARCHESE: Can everyone see that okay?

For those of you who don't know me, my name is Andrew Marchese. I am serving as the task manager in the generic issues branch, working on unresolved safety issue A-45 shutdown decay heat removal requirements.

(Slide.)

This is an outline of the topics that I would like to cover today. Some of this the Subcommittee has already heard before, but since it's been about six months since we last met, in order to establish some sense of continuity I thought I would briefly run through the entire plan and concentrate mainly on giving you an update of what we have been doing since we last met in September, and also get into the changes that have been made in the Task Action Plan and concentrate on that later on.

(Slide.)

By way of background, the Commissioners approved shutdown dcay heat removal requirements as an unresolved safety issue on December 24, 1980, by means of this letter from Chilk to Dircks. The task manager was assigned on February 17, 1981. In terms of documentation of basically documents that have been published, that describe Task A-45, what we intend to do -- there are basically four documents that are available.

The first is NUREG-0705, which is identification of new unresolved safety issues relating to nuclear power plants, special report to Congress. That was the first one. That was published later on. The Division of Safety Technology asked me to put together a document that described all the work that was currently going on in the NRC that related to A-45.

We published a draft task action plan on May 22, 1981, which basically lays out in detail the staff's plan for resolution of this issue and describes the work that needs to be done to resolve this issue. Following that publication of draft, we had an extensive internal review, and I think about four separate meetings with the ACRS, both the Subcommittee and the full Committee, in which we revised the plan based on the written comments that we received.

And later, on October 7, 1981, we issued a revised plan.

(Slide.)

So that kind of brings us up to date, I think, since the last time we met in September. Now, in terms of what we have been doing since the last time we met, again our plan was approved by the former director of safety technology on October 7, 1981. This plan basically authorized a four-year program with a completion date of October 1985.

This plan was not approved by the director of NRR. We have reassessed this program to determine if the primary goals could be realized on a shorter schedule. Basically the objection here was that the program was taking too long, it was too expensive, and that there was work described in the plan that would probably be more appropriate for industry to take on.

We have now reasessed our primary objectives and feel that our goals can be achieved with a 30-month program. The last point is, assuming an April 1, 1982, start date, we estimate that a draft NUREG report containing our proposed recommendations, including any proposed new requirements along with the supporting technical and cost-benefit basis, will be available by October 1984.

(Slide.)

MR. WARD: Andy, could I ask you a question?

MR. MARCHESE: Sure.

MR. WARD: You say you have reassessed the program for a shorter schedule, presuming the goals are somewhat different. I guess you're going to tell us about that. But is the plan going to be reissued?

MR. MARCHESE: Yes, right.

MR. WARD: Okay. I'll let you get to it.

MR. RAY: May I have a question, please? Andy, you mentioned that the feeling was that there were things in the original plan that industry could do. Do you have any understanding with industry as to whether or not they will pick these things up?

MR. MARCHESE: I'm going to talk about that a little later on. In fact, remind me if I don't cover it.

In terms of how we reduced the schedule, there were basically four main items here. We deleted most of the work on future plants, although acceptance criteria for decay heat removal systems for future plants will need to be developed. The feeling was here that the action today is on existing plants. There are no new CP's that have been docketed the last several years, so the feeling was to concentrate on existing plants except for criteria. We will be developing criteria for future plants.

Quantitative acceptance criteria will be based on frequency of core melt due to decay heat removal system failures, rather than overall risk. If you remember, our subtask 1 includes development of quantitative criteria. We were originally intending to go forward and establish overall risk goals, but we have backed off from that to a core melt frequency due to decay heat removal system failure. We feel this will simplify the plan considerably.

The uncertainties that are involved in going from core melt frequency all the way up to risk are significant, and we feel there would be a lot more difficulty in doing that, plus we feel the performance of decay heat removal systems is more directly related to the frequency of core melt anyway. It made, I think, a lot of sense to back off in that regard.

The next point, we're going to be relying more on industry to perform more plant-specific evaluations of alternative decay heat removal systems where the staff can show significant improvements in safety. We feel the work that has remained in the plan -- basically, we will be in a good position to know what plants or groups of plants do not meet our acceptance criteria, and where improvements in decay heat removal systems would allow those specific plants to meet our criteria they would be prime candidates for improvement, and that's an area where we're going to rely more on industry to take a lead there.

The fourth point that has resulted in a reduced schedule: We are now recommending that one contractor should be selected that would have overall responsibility for project management, technical direction and integration, including selection and management of subcontractors.

Basically, we feel that we have a lot higher chance of success in pulling off the program in 30 months by having basically one contractor as a technical lead, that all subcontractors that are selected would be managed by this prime contractor, and we in turn would manage the lead contractor.

MR. WARD: Before going on, would you help me understand that? The first one, you said deleting most of the work on future plants, but you are going to specify acceptance criteria for future plants in terms of core melt frequency?

MR. MARCHESE: Core melt frequency due to decay heat removal system failures, and also breaking that down even further to establishing reliabilities of the various systems that are involved in decay heat removal on a per-demand basis. That is, once we set this goal we will then establish reliability goals for the various systems.

MR. WARD: Okay. It will be an overall core melt frequency goal, and you will also specify individual subsystem reliability?

MR. MARCHESE: Right. As you are aware, the goal of 10^{-4}, the overall goal for core melt due to all causes, not just decay heat removal system failures, of 10^{-4}, is kind of receiving sort of a broad consensus. We will probably start with that and break that down into a goal of failures due to decay heat removal systems, and then break that down even further to establishing reliabilities on the various systems that are involved in the decay heat removal system.

MR. WARD: Can you tell me what sorts of things you're deleting on future plants? You are going to get into that?

MR. MARCHESE: I will show you specifically.

MR. RAY: Maybe you can help me with a clearer understanding of the second item. I didn't remember, and maybe this is a sign of onset of old age, but I didn't remember that the overall risk of a core melt was going to be applied to decay heat removal system reliability. I'm a little bit confused by that.

MR. MARCHESE: Well, if you remember back -- let me just pull out --

(Slide.)

This is the October version of the plan that we had talked about in September. If you remember, we were integrating the work on the degraded core rulemaking which has now been, I think, termed the severe accident rulemaking. And also, there was a lot of work going on and Commission action on safety goals, which were actually going to set forth quantitative goals based on overall risk, as well as core melt frequency.

We were intending at this point, in terms of our criteria in establishing some interim quantitative goals, interim in the sense that we would later on iterate, after we have the information coming in from the Commission.

MR. RAY: Yes, but those interim quantitative goals were on reliability of the decay heat removal system, weren't they?

MR. MARCHESE: No. We were intending to go forward, starting with overall risk and then breaking it down further.

MR. RAY: Okay. I missed the point. Thank you .

MR. ETHERINGTON: Is core melt something worse than TMI-2 or isn't TMI-2 a core melt?

MR. MARCHESE: It would be worse in terms of 30 percent of the fuel becoming molten, similar to the ACRS definition.

MR. HANAUER: Andy, I think that answer needs to be amended a little. In the models used for this kind of work, TMI and a meltdown of the core are indistinguishable. These models do not have that kind of fine structure, and so TMI would be predicted as a core melt by the probabilistic risk assessment models now in use.

So we do not in general have the ability in the calculations which we need to tell the difference between what happened at Three Mile and a core melt. This is a fairly crude assumption. The TMI core did not melt through the bottom of the vessel, as would be predicted by the models which we have, and that is one of the many approximations in the use of present day probabilistic risk assessment.

MR. MARCHESE: Thank you.

All right. The remaining steps required to start work on the program are as follows.

(Slide.)

We need to receive approval by director of NRR -- and I might add that we met with Mr. Denton early yesterday and he gave us the go-ahead, subject to his staff taking a look at the package that has been prepared. We met with his staff yesterday and there are a few changes they want us to make, but nothing that is going to cause any delay.

So we are expecting to get a package to the senior contract review board this week, and basically that's required, because we're talking of expenditures in excess of $500,000 and we require their approval. Once we get their approval, we will send the contract package out, solicit a proposal, and after we receive a proposal evaluate it and start work shortly thereafter.

(Slide.)

The overall purpose of the program has remained the same. Basically, it is to evaluate the adequacy of current licensing design requirements to ensure that nuclear power plants do not pose an unacceptable risk due to failure to remove shutdown decay heat.

MR. WARD: Andy, could I reverse you a minute here? If we go back, the remaining steps to start work on the program, we have not seen the revised -- when is the ACRS going to see the revised action plan?

MR. MARCHESE: You're going to hear about it today.

MR. WARD: That's what I'm asking. Is this your review for us?

MR. MARCHESE: This is it.

MR. WARD: Well, we have not seen a document.

MR. MARCHESE: Well, you are going to see the plan that Mr. Denton approved.

MR. RAY: Well, will there be a document?

MR. MARCHESE: Yes. We have marked up the October 7 version, okay, and gave it to Mr. Denton to make sure he did not have any problems with it. We got his concurrence yesterday.

Now we're going to go forward and revise that plan. But you're going to hear the details today. You're going to know exactly what we're doing. And I guess I might add that the plan by and large has remained intact, except certain subtasks will be deleted, because we are trying to save money and save time.

I might add, I think all your detailed comments have been thoroughly considered. Now, if you object today on parts that we have taken out, I would like to hear about those. But basically we are giving you today what has been approved in terms of funding, what we have funding for.

MR. WARD: Okay. Well, I think there might have been some misunderstanding. You know, in general before we are going to review something at a Subcommittee meeting like this we like to have a copy of the document, to give the consultants and members a chance --

MR. MARCHESE: We did not want to give you another document and then have that document later be turned down by the director of NRR. We want to give you something that we know has been approved. We have gone through this before.

I think I told you in September that the document we gave you in October would be the final plan. It turns out it was not, because Mr. Denton did not approve it. So the next document we give you will be one that he has approved.

MR. WARD: Well, we may be left with some questions at that time. We'll just have to see.

MR. MARCHESE: I'm hoping, like I said, that

I'm going to cover the details of the revised plan, and I'm hoping that any major comments we can get today, because we need to get on with the work.

MR. WARD: I agree with that.

MR. RAY: Andy, on past occasions you never explicitly said it, but I had the distinct impression you were having problems getting resources. Do you have resources committed to this objective of October '84?

MR. MARCHESE: Internally or externally?

MR. RAY: Total.

MR. MARCHESE: Internally, I received some commitments, but I am finding out those commitments didn't mean anything.

MR. RAY: That was the case in the past. How can you guarantee meeting October '84, which incidentally I think is a big improvement?

MR. MARCHESE: Because we're going outside for the majority of the work. We will have one contractor doing the majority of the work.

MR. RAY: You're satisfied you will be able to meet October '84 looking forward from here?

MR. MARCHESE: As we get on with the program and start around April 1st, we need to start the program.

MR. WARD: What has happened in the past on other projects -- I can see five years slipping by very easily.

MR. MARCHESE: Carl, would you like to add something?

MR. KNIEL: Carl Kniel, NRC staff.

We do have Mr. Denton's concurrence now that we can go ahead and use the money that he has authorized. So we do have the money resources to do this with contractor assistance. I wanted to make that point clear.

MR. CATTON: Would you call out the tasks and subtasks that you have deleted by number, so I can just strike them?

MR. MARCHESE: Sure. I think on one of the handouts I'm going to show you a chart lining out the parts we have taken out.

MR. RAY: I would like to react to Mr. Kneil's comment. I am disenchanted, I am not impressed at all, by the statement that you have resources, you have a commitment, because this has happened before and the time has slipped by and we have reached service dates, if I can use that terminology, and you still have a year or two years to go.

And it seems to me that decay heat removal systems have been so urgently required, the high reliability of those systems has been so urgently required to prevent catastrophic events that it should be on the front burner, with a commitment by everybody that that's where it stays and it's not going to be pushed into a back position.

There ought to be some cardinal objectives, and that's one of them, it seems to me, in the interest of public health and safety.

MR. KNIEL: Yes. That's what we've been trying to do. I was just distinguishing the fact that we did not have approval for the resources prior to yesterday morning, and that's what's been holding us up.

MR. MARCHESE: I agree with your point. I'm not sure our management agrees.

MR. WARD: How many staff people are assigned now full-time?

MR. MARCHESE: At this point in time I think it's just myself. I'm not getting any major help internally.

MR. WARD: Is this your total responsibility now? Are you 100 percent on it?

MR. MARCHESE: Right.

MR. RAY: So you're the task force?

MR. MARCHESE: Internally, right.

MR. ETHERINGTON: I realize the 10^{-4} number is not in question here, but considering the number of reactors in operation it does lead to a fairly high probability of a meltdown some time within the next 30 or 40 years. Does the probability of containing the core within the containment enter into this? Is there a number for the probability that the containment will remain intact?

MR. MARCHESE: No, we are not going to establish any quantitative goal for containment performance --

MR. ETHERINGTON: So it really is considered a rather high probability?

MR. MARCHESE: -- as part of this program. But I'm hoping as part of other programs there will be some quantitative goals for containment performance.

MR. ETHERINGTON: You're not studying it, but you do think there is a substantial probability of containment, is that your position?

MR. MARCHESE: Well, I really have not studied that particular issue. I'd rather not get into it.

MR. ETHERINGTON: Okay.

MR. MARCHESE: The overall objective of the program is to develop a comprehensive and consistent set of decay heat removal system requirements for existing and future LWR's, including the study of alternative means of decay heat removal and of diverse dedicated systems for this purpose.

(Slide.)

Definitions. This is something we gave you before. We are not covering the initial reflood phase of a severe LOCA, when the objective is to reflood the reactor. That is, those ECCS systems and components that are used during this phase will not be considered as part of this plan.

We are going to concentrate on two phases, namely the shutdown decay heat removal phase, which is a transition from reactor trip to hot shutdown, excluding the initial reflooding phase in a severe LOCA, and also the residual heat removal phase, that is the transition from hot shutdown to cold shutdown and maintaining cold shutdown conditions. And it is our plan -- our plan will encompass these two phases.

MR. EBERSOLE: I wish you'd eliminate that phrase "excluding the reflood phase of a LOCA," because it carries with it an implication of infrequent events. Shutdown decay heat removal and residual heat removal and decay heat removal are with us all the time. You have related that in kind of a secondary way to reflooding after a LOCA, and to that extent there's an indication that the last three items up there were infrequent events.

They are not. They occur time and again, year after year, month after month, week after week. We don't need that association with a LOCA for this function. This is why the RHR system is so important.

MR. MARCHESE: We're not getting into large break LOCA accidents in this plan.

MR. EBERSOLE: You're not even covering small break LOCA's alone. You're covering all shutdowns.

MR. MARCHESE: Normal operational transients and small break LOCA's.

MR. EBERSOLE: The ratio of normal to small LOCA shutdowns must be extremely large.

(Slide.)

MR. MARCHESE: In the context of A-45, the decay heat removal system is defined as those components and systems required to maintain primary and/or secondary cooling inventory control and to transfer heat from the reactor coolant system and containment building to an ultimate heat sink following shutdown of the reactor for normal events, off-normal transient events such as loss of offsite power, loss of main feedwater, and small LOCA's, that is one-half to two inches.

The decay heat removal system does not

encompass those emergency core cooling components and
systems ..ired only to maintain coolant inventory and
dissipate heat during the first two minutes following
medium or large LOCA's. Basically, we are not concerned
with large LOCA's.

MR. WARD: Has that definition changed from
the previous plan writeup?

MR. MARCHESE: No.

(Slide.)

MR. WARD: Before you get into this, I guess I
would want to comment to the Subcommittee and the
consultants that, contrary to what I said earlier, this
is our chance to review the action plan. I don't know
if that will make you more attentive.

(Laughter.)

But this could very well be one of your last
chances to use your influence.

MR. MARCHESE: This is the October version of
the plan. I don't want to talk about it in detail
because you have seen it, but I do want to go to the
next slide, which shows specifically what we have taken
out in terms of lining through with a black marker.

(Slide.)

MR. ZUDANS: I can ask a question now. You
say conceptual design studies on your second diagram.

Do you mean to say that your contractor will be asked to design a better, improved DHRS system?

MR. MARCHESE: Yes, in the framework of a conceptual design, that's correct. We felt we could not develop criteria and requirements in a vacuum, not knowing if those requirements would be effective both in terms of value and impact. So we felt that we really need to go forward, developing criteria and requirements along with developing a conceptual design to see if they make sense; are they cost effective, what's going to be the impact of retrofit?

In today's environment, with the issues we are talking about today, you cannot write criteria and requirements without doing value impact studies.

MR. ZUDANS: If you do that and if you tailor the criteria to the design concept that you lay out, do you plan then to go to industry and say, here is a design and criteria that meets that design? Or let's say, here's a criteria and a design that meets it, and you should do like that?

What is going to happen with that? Do you expect them to accept it?

MR. MARCHESE: We are asking them to basically do Subtask 4, which is for the plant specific decay heat removal system design work. The way I see it going right now -- in fact, you're asking what is going to be in our planned implementation, and I could only tell you what I think at this point in time is going to be in it.

But I think after we have done Subtasks 1, 2, and 3 -- that is, we have developed a criteria, we have done conceptual design work to basically establish, is the design feasible, get a feeling of the costs involved, and after doing Subtask 3 we will know which plans do not meet our criteria. Then I think we will be in pretty good shape to tell some plants or groups of plants that they don't meet our criteria and here are suggested ways that we have studied in terms of improving decay heat removal systems that would allow for a meeting of the criteria.

Now, I think it would give them the option of either selecting a concept that we have studied which would allow them to meet our criteria or proposing some alternative. I think we would allow them that flexibility. I don't think we would force them.

MR. ZUDANS: My concern probably comes from the fact that you do not fully understand your problem yet. I would hav; thought iten number 2 could not be done without industrial participation.

MR. MARCHESE: Well, we are doing item 2 on a generic basis. It is not what I will call plant specific, which we were intending originally to do in Task 4, which is really the plant specific decay heat removal system evaluation.

MR. ZUDANS: Okay.

MR. EBERSOLE: In the meantime, GE and Westinghouse are cruising ahead on their own concepts of improving shutdown heat removal. Are they ahead of us, or is there a meeting of the minds on criteria? Are they off in left field or going down the line you hope they will? What's going on here?

MR. MARCHESE: What I have seen in the Westinghouse effort in terms of their new plant design, I think I am impressed with it in terms of the work that they are doing. And I am looking for them to take the lead on the new plant work.

We are basically concentrating on the existing plants, and that is an area where future work on item number 3 or item number 4 for future plants, we are looking for the vendors to take the lead there, and it looks like Westinghouse has a good start on that. I have not seen anything from GE or the other vendors for future plants.

Okay. But anyway, this shows simply what items have been deleted from the old plan.

As I mentioned, on Subtask 1 we are leaving in developing criteria for future plants. We are no longer calling them interim, because we are not going to iterate on the plan in Subtask 5. They will be our recommended criteria.

The second item has by and large remained intact. That is, we're going to be breaking that down into three parts, both the phenomenological aspects, the engineering aspects, and the operational aspects. And I think a lot of the ACRS comments are in this area, and I think Subtask 2 came about largely because of the comments we have received in the past.

The third major element in terms of assessing adequacy -- we have taken out the work on future plants there, so basically Subtask 3.1 is deleted. Subtask 2 remains intact, except we are assessing existing plants on the basis of core melt frequency due to decay heat removal system failures and not on an overall risk basis.

Subtask 3 grouping has remained intact. 3.4 has been deleted, that is assess adequacy of selected future plants. And 3.5 has remained. That is assessing the adequacy on a deterministic basis, which again was heavily advocated by the ACRS.

MR. WARD: Are you going to tell us what that means? You know, you have told us what you mean in terms of the adequacy on a probabilistic basis of a core melt frequency of 10^{-4}. What deterministic criteria will be applied?

MR. MARCHESE: Up here in Subtask 1.3 we're going to be developing qualitative criteria for special emergencies. We talked extensively that it would not be the right thing to do to go forward on this program based strictly on quantitative goals, that really a two-part approach would be the better way to develop a quantitative and qualitative criteria to cover the special emergencies, things you cannot quantify very readily -- fire, sabotage.

And so we are going forward on a two-pronged approach, that is developing quantitative and qualitative criteria. Now, Subtask 3.5 will basically be to assess existing plants against those qualitative criteria and they will cover things such as separation, the bunkering approach that has been used over in Europe. Those events that could knock out redundant trains will be considered on this phase.

MR. WARD: Okay. So these are the usual separations, redundancy and diversity.

MR. MARCHESE: Right.

Okay. Subtask 4, at that point we were going to go in and do specific conceptual designs for specific plants or groups of plants. Well, we have found that they do not meet our criteria and we are improving the decay heat removal systems to allow for a breakthrough. This work has been deleted because the feeling is now that it would be more proper for industry to take on that job, and we feel that after doing the work above that we would be in a good position of knowing which plants or groups of plants we should then basically tell them to go out and improve their systems for. And we will have investigated various alternatives in a generic sense that would allow for meeting our criteria and probably would give them the option of either selecting something we have studied or proposing some alternative.

MR. WARD: Let's see. If I understand this, what you're saying is that Tasks 4 and 5 are all going to be done in a different way, perhaps in a less formal way. You will go out with the criteria and you will call them the final criteria, but then you are going to get feedback. After industry gets those they'll look at them and you're going to get feedback from them, and there's going to be some negotiation.

What I'm driving at, although you say you're going to finish the job a year earlier -- and maybe this is the fine way to go -- it doesn't look to me like anything is going to be in the plant any sooner than was expected under the last October --

MR. MARCHESE: You might be right. I think one thing that came about since we last met is there has been an organizational change. We now have this Committee to Review Generic Requirements. If we propose new requirements we have to make sure we have the supporting technical and cost-benefit basis to support that new requirement.

It will go to this Committee and they will review the new requirement, as well as the supporting cost-benefit evaluation, and make their own judgment. So that has added an extra time increment, and I think there are people working on the details of how we interface with them right now.

Carl, maybe you want to comment on that.

You might be right. We have deleted work and compressed the time schedule, but we got some organizational changes that could result in basically wiping out that year we've saved. I don't know that, but --

MR. WARD: It looks to me like your original Tasks 4 and 5 were an attempt to develop good cost benefit data.

MR. MARCHESE: They were.

MR. WARD: And I don't understand -- I mean, instead of doing that, you're going to have more committees looking at it and agonizing over it and talking about it.

MR. MARCHESE: It's a question too of what we can afford. We simply could not afford the previous plan. This plan we feel that, with budget realities, we can afford.

MR. HANAUER: Let me try a somewhat different viewpoint. The objective is to resolve the issue. The resolution of the issue, we being regulators, is a bunch of requirements. We felt that numbers 4 and 5 were too design-oriented and plant specific-oriented and that the regulators should stick to their tasks and not try to design plants.

You are quite right, this will not get the plants fixed any sooner, although it might get plants fixed sooner, because I don't think they would put into the plants anything we would design anyway, nor do I think they should.

The necessity for doing a good job in understanding the cost-benefit aspects of our work has always been with us in principle. This Committee now forces us to do our work correctly, and Andy is correctly recognizing that that requires of us probably a higher standard of work, which is probably good.

When we issue our draft report for comment, we find this generically and not just in A-45, that one of the things we really need comment on and one of the reasons for going out for comment is to get from knowledgeable people, particularly in the industry, some better idea of particularly cost data, but in more general terms the cost-benefit equation, than we could generate in our ivory tower.

Therefore, as you have suggested, the changes are changes in what we're going to do and perhaps not changes overall in what everybody always had to do. If it were really necessary to spend twice as much of the taxpayers' money to solve this issue, we would do it, and in fact twice this much money had been set aside to do it.

The objection from the office director, with which I concur, is that the plan included a large amount of government resources and time to do, as well as we could, what the industry needs to do for itself and is capable of doing much better. So that although the steps which have to be taken to get stuff in the plants have not been changed very much, we have perhaps gotten more realistic about which ones we can hope to do.

MR. EBERSOLE: Steve, is that based on past industry performance, that thesis?

(Laughter.)

MR. HANAUER: Past industry performance and past NRC performance. Both tell us not to try and design stuff for the plants in the government laboratories.

MR. WARD: Well, I hear your argument, and you know, it makes a lot of sense. I guess I have somewhat the feeling it may have been overstated, and that I sure did not understand the 4 and 5 -- that the NRC was going to try to design plants, but rather it was kind of a sensible approach, that the ivory tower criteria were going to be tested against some practical designs and then revised if that testing indicated they should be revised.

And I don't think there was -- there certainly was not any understanding on my part that the NRC designs were going to be used directly by the industry, but rather it was an attempt to help you to develop more appropriate requirements.

MR. HANAUER: Yes, and some aspect of this still has to be done. Anyone who uses the word "final" in connection with any of our requirements I think has got to reconsider the terms. Even at the end of the process which we foresaw a year ago, there would then be a period when this stuff was actually designed for implementation and those criteria would have to be refined or revised or reconfirmed, whatever the result would be, in any case.

We are going to do one of these steps instead of two of them, and rely on the industry designers instead of trying our own.

MR. EBERSOLE: In item 2 up there, the last two items, conceptual design studies and generic aspects, is that primarily oriented to modifications to existing plants or does it include new idealized configurations?

MR. MARCHESE: No, just existing plants.

MR. EBERSOLE: So really those are just tack-ons. It doesn't contain any conceptual idealization that might be put in new plants.

MR. MARCHESE: No. And granted, what one should do for plants on a drawing board is entirely different than when you have to worry about backfit.

MR. EBERSOLE: That's not made clear up there. That's just patches at the bottom.

MR. MARCHESE: I wouldn't say patches. We are going to be studying both improvements to existing systems, as well as the dedicated shutdown cooling system. That is something that would have its own dedicated building, power supply, and so forth. We are going to be studying both aspects, as well as improved operational.

So I think we still have a balanced approach on this subtask. I think we are going to be looking at operational aspects and improvements to existing designs, as well as the dedicated system in a generic sense.

MR. EBERSOLE: Except then for the extremely general criterion for breach of plants up there in Item 1, virtually everything is what are we going to do with the old plants.

MR. MARCHESE: Exactly.

MR. EBERSOLE: The way the new ones come in, it's going to be, however, it comes out of industry with little or no guidance from NRC, is that correct?

MR. MARCHESE: Well, I think we are going to be setting some quantitative criteria for future plants with respect to decay heat removal systems that I think should guide our designs.

MR. EBERSOLE: That will be the sharpest definition.

MR. MARCHESE: Right.

MR. WARD: Well, let's see. You have said not only quantitative but qualitative. I guess I worry about that.

MR. MARCHESE: The Westinghouse-proposed new design I think in terms of what they are doing for separation and protection against fire and flood and missiles, that goes a long way, I think, to meeting the kind of criteria we are going to be developing in this area.

MR. WARD: Mr. Ray?

MR. RAY: I would like one point clarified. Mr. Ebersole referred to the Westinghouse designs going ahead, and you think it's an improvement over existing plants. You're not setting the stage, though, where you absolve them from the need to retrofit in line with the goals and objectives you establish as a result of your studies subsequently, are you?

MR. MARCHESE: I'm not sure I understand your question.

MR. RAY: Suppose Westinghouse sells some of these plants and they are in being by the time the regulatory agency's mind is made up as to what they would like to have in the way of characteristic performance and reliability levels and so on for DHR's. There is no reason in the world to believe that Westinghouse -- I'm not zeroing in on Westinghouse because of any negative impressions -- there is no reason in the world to believe that they will not be required, if their plant does not measure up, to bring it up to standards, is there?

MR. MARCHESE: I don't think so.

MR. WARD: I guess, Jerry, you are suggesting that the standards developed for retrofiting will also be sitting there and applied to new plants?

MR. RAY: Certainly what they develop will --

MR. WARD: I agree, it makes sense.

MR. RAY: What they develop will apply to plants that are still on the drawing board and haven't been put into being yet, and I see no reason why, based on past policy, whatever you develop will not be required to be impressed or imposed on plants that are going into service in the meanwhile.

So I think there is sense and expediency in accomplishing the change of goals by concentrating on what belongs to the regulatory role and putting on industry a firm requirement subsequently on the existing plants that they modify their systems design appropriately to bring them up to desirable levels.

Too frequently in the past, we have said that the NRC staff does too much design work, and I think it's commendable and I'm impressed to see them, at least in this critical project, recognizing that and changing their mode of operation.

MR. WARD: Mr. Hanauer?

MR. HANAUER: Could I maybe comment on the different classes of plants? There are several. There is first of all the plants that are already designed, and this is in fact all the plants that we know about, including the ones, if any remain today, who are in for construction permits. These plants are all substantially designed.

The backfit equation is different for a plant that comes on line in 1990 from a plant that came on line in 1970. But the design approach and a large fraction of the design features are similar, and therefore this project will come out in 1984 with a series of requirements and some guidance upon how backfitting should be applied. And all plants in the pipeline now will have to be backfit if there are any changes, because they will all be too far along to describe them as plants still on the drawing board.

This is the class of plants on which we are concentrating this program, as several people have pointed out.

The second class of plants is the class foreseen in the Germans' initiative and discussed in

SECY 82-1, the severe accident paper, and being rediscussed. This is a class of plants characterized by GESSAR 2 and similar initiatives from Westinghouse and Combustion Engineering.

These plants too are largely designed, at least in their basic design approaches, and we are supposed to get applications within the next few months or at most the next year, and they are supposed to make licensing decisions on these plants in what I will crudely describe as the 1984 time frame. And the backfit equation will be somewhat different for these plants, since they still are truly on the drawing board and changes can be made, at some substantial engineering expense, but no hardware expense.

Now, if I understand Mr. Ebersole's question, it relates to some future plants not today substantially engineered. I don't know if there are ever going to be any. It would be nice to find some resources to give some guidance to these plants, but in view of our large backlog we have chosen not to give very much in the way of resources to these classes of plants.

MR. WARD: Well, certainly the 10^{-4} core melt, to the extent that is a criterion, that could be assumed to apply to any new plant.

MR. HANAUER: If this is finally adopted by the Commission, it certainly will. But along with it, if it survives the comment and reconsideration, is a foreseen improvement in safety with the guideline of \$1,000 per manrem averted. In a design where the only costs are engineering and future hardware, rather than backfit and down time, one would expect a different result from applying this equation, and 10^{-4} might be the beginning rather than the end of this cost-benefit consideration.

MR. WARD: I guess the numbers I have seen say if use \$1,000 it will go to 10^{-3}.

MR. HANAUER: As I read the safety goal, using the \$1,000 above 10^{-4} is not included.

MR. WARD: Okay. Mr. Zudans?

MR. ZUDANS: I want some clarification on number two, developments for improvement of this heat removal system. Specifically on conceptual design studies and operational aspects, this item refers to existing plants, right?

MR. MARCHESE: Right.

MR. ZUDANS: Are they similar enough in terms of design that you can pick the right one to base your conceptual design study on? How are you going to pick the right plant out of the package?

MR. MARCHESE: That's a good question. We're finding out that the plants are not similar in design. There's a lot of variation plant to plant, even within the same vendor. Westinghouse has maybe four different configurations.

In fact, that's what our Subtask 3.3 on grouping is all about. We're trying to get a handle on recognizing that the 70 or so plants that are operating -- we're hoping to group those plants into some manageable number, half a dozen or so groups. Basically, the group will be defined as a plant that is going to have a PRA or reliability study performed, and it will be a parent plant.

And those plants that will not have a risk study or reliability risk, we will look at their system characteristics and try and group them into these parent plants that will have a risk or reliability study performed. And in this way we feel that any decisions or recommendations we make with respect to the parent plant hopefully will apply to all plants within that group.

So to answer your question, we're hoping that we can get a manageable number of groups. I'm not sure we will be successful with that, but assuming we can do that we think that we can then study some improvements to the decay heat removal system that would apply to the different groups.

MR. ZUDANS: So from a time calendar point of view, you may have to do item 3 before item 2.

MR. MARCHESE: We have already started on that.

MR. ZUDANS: This is not the time sequence?

MR. MARCHESE: Right. I'll show you that a little later on the schedule.

MR. WARD: Have you concluded there are enough PRA's being done to make this a viable approach?

MR. MARCHESE: Between the RISMAP study and the IREP studies and some of the other risk studies that industry is doing, there must be at least a dozen or so risk and reliability studies we have -- if we have more than a dozen groups -- I'm hoping a dozen will be the maximum number.

MR. WARD: If the distribution is right, I guess.

MR. MARCHESE: Yes.

MR. WARD: Mr. Epler had a question.

MR. EPLER: This discussion seems to have going for it -- there was some other casual reference to dedicated system. It isn't spelled out very clearly, but there is a central issue here that I think has to be put on the table, and it hasn't been. It's the question of the airplane versus the parachute.

Do we have a place to go when our general purpose systems don't work? We're forced into residual heat removal. There is no escape. We must use general purpose plant systems. They're used for everything else and their own failure causes them to be needed. We don't have a dedicated system that is protected, separate, used for no other purpose, and uses all the rules that we have cherished in building our premium systems, which are themselves deemed to be inadequate.

We seem to be churning around with no objectives. Now, when we get criteria are they going to say anything about using these systems for other purposes?

MR. MARCHESE: Yes.

MR. EPLER: Or are we going to continue to ignore this question? I think this is fundamental. I think we must have resolved somewhere down the line that we are going to use general purpose systems and do the best we can with them. But I think we ought to say so if that's what we have decided to do.

MR. WARD: I guess that's under 3.5. Is dedication going to be --

MR. MARCHESE: I think the work under 3.5 could lead to a dedicated system for certain plants. I cannot tell you at this point in time that we're going to select a dedicated system versus upgrade of an existing system or improved operating systems. I think we've got to let the cards fall where they may.

There could be three likely outcomes of this program: One is, we may find that some plants are completely acceptable the way they are and nothing has to be done. The second outcome would be that there are plants that need upgrade of their existing systems, and that may involve improved operating procedures or some improved hardware changes. Then there could be a third category, that the plants are just completely unacceptable and require separate dedicated independent systems, such as you have been advocating.

By the way, we do have the criteria that you've suggested for dedicated systems, and I might add they will be given very thorough scrutiny and consideration on our Subtask 1.3. I think it's a good start for developing criteria for dedicated systems, and we look forward to receiving any further input you have in that regard.

But I cannot make up our mind right now that the dedicated route is the way to go across the board. It may be the way to go for some plants, but not for all of them. But I don't want to imply that we're not going to be taking a hard look at dedicated systems. We are.

MR. EPLER: I realize there is a whole spectrum of problems here, as you have indicated. Those plants under consideration and those we might hope to have in the future -- I realize the solution would be plant-specific. bserved light water reactor operation for several decades, that we have learned enough from this operation that we could be very firm in specifying what we expect for the future.

MR. MARCHESE: I think for the future hopefully we can do that.

MR. ZUDANS: I like Epler's point so much, I would say it's the only way to go for the future. There's absolutely no need to worry about any other criteria. Just fix what you have and that's what you need for the future. There is no question. It is a good system.

MR. MARCHESE: Okay. I'm not sure exactly where I left off, but let me put the new plan basically on one slide up next, and then I'll show you the relationship of how these tasks tie in together in the new plan.

(Slide.)

Basically, now we are down to four main elements: developing the criteria; developing means for improvement of decay heat removal systems in a generic sense, looking at both the phenomenological aspects and the engineering aspects and the operational aspects; third is assessing the adequacy of decay heat removal in existing plants; and finally, develop our plan for implementation.

(Slide.)

In terms of how these tasks interrelate, that is shown here. You can see this is much simpler than the previous diagram on the plan. We are going to be starting off with developing criteria, as well as with, in parallel with that, needs for improving decay heat removal systems.

There will be work coming in on the existing program from Sandia, in which they have ranked several candidates. There will also be some work we are going to be doing on the phenomenological aspects, looking at to what extent we can rely on single or two-phased natural convection, as well as reflux condensation, basically evaluating the existing thermal hydraulics work in that area. And that work could lead to other suggested means of improving the decay heat removal system. And also looking at the operational aspects --

MR. ZUDANS: Did you say Sandia already has ranked the various alternative systems?

MR. MARCHESE: For both PWR's and BWR's, they have a report.

MR. ZUDANS: That means they already have overcome the question that I asked with respect to this third item. What did they pick as the rest of the plant to match this improved decay heat removal system to? You can't just take this system itself and make a judgment on its merits. You have to look at the rest of the plant as well. So they must have picked some plant to gauge the systems on.

MR. MARCHESE: That's right. They picked some plant. I'm not sure I'm at liberty to discuss that. I think there was an agreement not to.

MR. ZUDANS: It means -- in response to my question, this part is already done?

MR. MARCHESE: It's not done entirely. We're going to be going further and looking at other ways of improving decay heat removal systems other than what Sandia has looked at. And so in essence there will be an iteration between the two.

MR. ZUDANS: My concern is this. They picked a system and when they picked a system they made an analysis and came up with some ranking. That's fine. There's nothing wrong with that.

But I have to see how th• ranking system applies to a specific plant. It may not apply at all or it may apply. Now, when you said that you grouped the plants, that made sense, because then that way there would be a different ranking for a group of plants.

Is this what you planned to do?

MR. MARCHESE: Yes, but not, I think, what Sandia has done. We have someone here from Sandia. Would you like to make a comment?

MR. BERRY: My name is Dennis Berry of Sandia Labs.

We are closing out the project that Andy was referring to. It involved looking at six PWR alternatives, three BWR decay concepts, in order to perform a value impact assessment of those alternatives. We used some probabilistic assessment techniques and some qualitative types that Andy is referring to to judge the value of the alternatives.

In addition to that, we solicited the help of an architect-engineer who has designed a number of power plants to evaluate the impact of the alternatives that we are considering. The architect-engineer considered the six PWR alternatives and the three BWR alternatives in a two-stage process.

First was a screening process in which the alternatives were judged on the basis of feasibility.

The feasibility assessment indicated that of the six PWR concepts two seemed to be the best from an engineering standpoint and the standpoint of practicality for a backfit. For the BWR, one of the three concepts was chosen.

For these two PWR concepts and the one BWR concept, the A-E then performed a conceptual design considering interface requirements and backfit ability for these concepts on six different power plants that are actually existing and that the A-E had familiarity on design. That was a CE, a Westinghouse and a B&W plant, onto which the two PWR concepts were applied. For the BWR concept there were three GE plants that were being considered.

Questions regarding interfacing and other things were factored into the evaluation and out of that came a cost evaluation by the A-E. That is the type of work that has been completed. Without considering all power plants, we tried to get as much as we could in that project.

MR. ZUDANS: Thank you.

MR. EBERSOLE: There is zero quantitative criteria for future plants? The only relationship you have to future plants is quantitative acceptance?

MR. MARCHESE: And also in this area, too, the qualitative criteria will be developed f^r both existing and future --

MR. EBERSOLE: For special emergencies.

MR. MARCHESE: For special emergencies.

MR. EBERSOLE: Thank you.

MR. MARCHESE: Okay. All right, so I talked about Subtask 1, development of criteria, subtask 2, developing improved means. Subtask 3 gets into developing the adequacy in existing plants, both against qualitative and quantitative criteria. And in the grouping effort, hopefully we will be successful in terms of any recommendations or proposal requirements that are recommended will apply to all plants within a group if this effort is successful.

And then finally, develop a detailed plan for implementing these new requirements.

(Slide.)

This is basically a markup of the previous schedule. But you can see we are projecting most of the work starting around April 1st. We have gotten started on the criteria and the grouping effort. However, we did run out of money towards the end of the year and those efforts were stopped for about three months. But we are hoping to get them on their way very quickly again, with the final completion date now projected for

October of '84.

We do feel, though, that there will be significant interim milestone reports that will be coming out of this program, that we will be reviewing certainly with the Subcommittee at appropriate dates in the future. So as you can see, we have a number of milestones for interim reports and final reports coming out.

MR. CATTON: How are you going to get that work started on the 1st of April? That's only two weeks away.

MR. MARCHESE: When I did this in February, I thought April 1 was a good date. It may be April 15th.

MR. EBERSOLE: That's April Fools Day, isn't it?

(Laughter.)

MR. DAVIS: You said in one of your earlier slides that the remaining steps to start work on the program culminated with the approval of a contractor proposal. Now, I've done work for the government before and I don't really see how you're going to get a contract approved by April 15th unless you can go to a national lab and everything works very quickly and expeditiously.

What are your plans in that regard? I don't see that designated on the schedule, either.

MR. MARCHESE: That's not. That's a fair question. I've had extensive discussions over the past six months with various organizations, at national labs mainly, and some private firms have indicated an interest. I talked to a number of them over the phone in terms of what Task A-45 was all about, but emphasizing to them that any work that would go to private firms would have to go on a competitive bid process.

I have discussed this plan with a number of national labs in detail and we are now recommending to select Sandia as the lead contractor, because they would have overall responsibility for project management, technical direction and technical integration, including selection of subcontractors and managing of those subcontractors. And they in turn would be managed by the NRC.

We have had extensive discussions with Sandia on this program. We feel as soon as we get the go-ahead from the contract review board we could have a program in place very quickly.

MR. DAVIS: How long does it normally take them to deliberate one of these issues, or is there any experience?

MR. MARCHESE: if they don't have any problems, typically a week. We can get the package to them and within one week they can turn it around. But if they have pr''ems with it, it could take them longer.

MR. ZUDANS: Could I ask you a question on your first completed slide?

(Slide.)

I understand what Sandia has done, and that seems to satisfy me in a sense, that they did use an A-E to see what they found for appropriate candidates would work out in actual designs. Wouldn't that really mean that that phase of work is already complete and there is no need to do any more?

That's item 1, number one.

MR. MARCHESE: For those alternatives that they looked at, I think we don't really need to go much further.

MR. ZUDANS: Then other alternatives might be considered?

MR. MARCHESE: Right.

MR. ZUDANS: In this chart you seem to leave out any interaction between your first column and second column until the final point. And I think from what you said perhaps it is not that way. You develop criteria and somebody else develops something else, and there is no communication. I assume that more appropriately you would have lines between 1.2 and 2.1. You really have communications there.

MR. MARCHESE: That's a good point. There should be. We'll put that in. There is definitely going to be communication here.

MR. ZUDANS: All right. Thank you.

(Slide.)

MR. MARCHESE: Industry involvement. I think the Committee has commented on this a number of times, and I am in full agreement that industry should get involved in this program. It would not be proper for us to go down a three-year program and develop requirements that could cause industry a great deal of problems and expense. They should get involved in the beginning.

I have been trying to encourage them to do that. I have had discussions with a number of organizations that represent the industry. A number of people from the vendors have called me. I've talked to them on the phone about this. I've had discussions on the phone with AIF and just recently made a trip out to EPRI and discussed this aspect with them.

The options that I feel they should consider in getting involved in the program are three. There may be others. First is for them to set up their own parallel program in this area. The second one is for them to actually do specific parts of A-45, such as Subtask 4 and the plant-specific design of alternative decay heat removal systems, which is an area we deleted. I would like to see them get involved in this and actually do Subtask 4.

At the minimum, I think we plan to establish an industry peer review group for A-45 milestone reports. We would select representatives from industry. They would serve as sort of a peer review or design review group. As we published reports in this area, we would send them a copy and come and meet with them and solicit their comments and problems and recommendations and any other kind of feedback they might have. I see that as a minimum effort.

In terms of which plants are candidates for improvement, I think the priority for development of conceptual designs for an improved decay heat removal systems for a specific plant will depend on two main factors. The first is the core melt frequency due to that plant and on the effectiveness of improvement of decay heat removal system as a means of reducing that frequency and their capability for handling special emergency situations.

So we see these two items as setting the priorities for which plants or groups of plants need --

MR. EBERSOLE: Are you now talking about old plants or new plants?

MR. MARCHESE: Old plants.

MR. ZUDANS: This objective strikes me as an attempt to have the industry work out a single common standard design. I am just wondering what kind of industrial role one can take in terms of generic issues. In other words, if you could convince industry that they had to go back to the drawing board and design a single perfect decay heat removal system and everybody henceforth would use it, that would be very consistent with this. But it's not quite thinkable that way.

MR. MARCHESE: No, I don't suspect we will wind up that way.

MR. ZUDANS: That would be the ideal way.

MR. MARCHESE: Yes, it would.

MR. ZUDANS: Maybe your plan should include some point for future consideration of that nature.

MR. MARCHESE: As I have mentioned, I think if you're doing Subtasks 1, 2 and 3, we hopefully we will be in a pretty good position of knowing which plants or groups of plants do not meet our criteria, and we will have examined -- not in a generic sense, but I think we will have examined enough alternatives to know in terms of improvement, to know which of those improvements apply to which group of plants.

I'm hoping we will be in that position, that at this point we will know which plants or groups of plants are good candidates for improvements of the decay heat removal systems. I hope it comes out that way, but I can't guarantee it.

MR. ZUDANS: And a group of standard designs may emerge?

MR. MARCHESE: Yes.

This is my final slide.

MR. RAY: In your discussions with industry, have you had any reactions?

MR. MARCHESE: I think we received a favorable reaction from EPRI. They want very much to work with us very closely in this area. I did not get a commitment that they would take the lead. I think they're kind of in a precarious situation. You know, they get their support from utilities and I don't think probably -- at least they felt that probably it would not be appropriate for them to get in the mill. But they are doing some related work, and we're going to cooperate in sharing that work. And so they do want to cooperate with us.

MR. RAY: Have you gone into detailed discussions with AIF?

MR. MARCHESE: On the phone, yes. They recommended that I talk to some people in terms of getting a program started in this area. The people that I have talked with basically felt it was a good idea, but I think the way it turned out they went to their management and their management said basically they did not have the funding to do this.

There was also the feedback that their existing systems, you know, are acceptable and they meet our present requirements and criteria.

MR. RAY: So their status might be that they endorse motherhood and apple pie, but they haven't made any commitments yet.

MR. MARCHESE: Right.

MR. ZUDANS: I have to return back to my very first question again. Given that this is what you have to do to come up with a reasonable set of criteria, I can't question that, but supposing you proceeded down a different path. You have a certain ultimate objective. You could study different relative levels of reliability for difference pieces on the system and come up with some limits that say, if you satisfy this level at this location and this level at some other location, without being very design specific and say, these are the criteria, and say then, give that to the industry and you go ahead and design. If you design this and this, we'll be happy, and we don't care where you put your hardware.

Could you achieve that objective without going through extensive design studies or not, or is it conceivable?

MR. MARCHESE: In today's environment, to get new requirements out we have to have a value impact evaluation. To do that I think you have to do some conceptual design work to establish feasibility and get some rough idea of what costs are involved. I mean, isn't that what value impact is all about?

MR. ZUDANS: And you really are not after criteria alone. What are the old safety goals --

MR. MARCHESE: I don't think we can write criteria requirements in a vacuum today.

MR. ZUDANS: Because it wouldn't be accurate, no.

MR. MARCHESE: It would depend on the people and experience and judgment that's involved. We would like to get as much subjectivity on this as possible and get some more of the quantitative aspects in here.

MR. ZUDANS: There are several plants, and I guess you said maybe as many as 12, that are already committed or have done PRA studies. Are there ways you could extract information just related to this particular contribution, related to decay heat removal systems, and see what criteria they satisfy in the overall picture? That is, real life as it exists now.

MR. MARCHESE: We're going to be doing that.

MR. ZUDANS: That is a good thing. So you have done that.

The next question would be naturally, where do you want to go from that point. Do you really want an improvement? Do you need it, without design conceptual studies? If you cannot make that decision, where you want to go, but it is really premature to try to make that decision, I think we have to let the industry develop its own ideas until you can have a basis to make such statements as to what your safety goal really is.

MR. MARCHESE: Right. We may find out that some plants -- that failures of decay heat removal systems do not represent a significant contribution to core melt frequency, and I would think we would stop there. But I don't think all plants are going to be in that category, and those plants that are not in that category, that we find where failures of decay heat removal systems contribute a significant contribution, they would be candidates for improvement.

MR. ZUDANS: Once you find a plant that satisfies your ultimate criteria, that's the criteria you want. You don't have to analyze every plant and say that this satisfies that. It's none of your business in principle. You find one that pleases you and say, that's the way it will be -- not design-wise, only criteria-wise -- and let the industry fix it to meet the set of criteria.

If you're unable today to tell by whatever analysis that this is satisfactory and this one isn't, then you're already where you should be without doing most of this work.

MR. MARCHESE: I think it's kind of a question of details. I'm talking about conceptual design work. I'm talking about very preliminary engineering, to get some rough ideas, cost. I'm not talking about detailed final design work.

MR. ZUDANS: I'm talking about something completely different. I'm saying if you're in the position today to take a specific plant and go through all the analysis and come up with an answer where you can state that this decay heat removal system in this plant satisfies the requirements, it's a small contributor to core melt frequency, then you already have a design criteria that you can live with.

All you have to do is turn it around and say, all you other fellows shall do as well as this fellow, and that's the end of the story.

MR. MARCHESE: But the plants are not that similar.

MR. ZUDANS: They don't have to be similar. Your goals are similar, not the plants. If you found out this particular plant that you're happy with has --

MR. MARCHESE: We're happy with it, but we find out if we try and adopt those criteria for that plant design to another plant in terms of backfitting and it's so cost prohibitive, we would have to propose something that made more sense from a cost standpoint.

I don't think that one approach is going to work across the board on this program. I may be wrong, but I just don't see it. I think you are suggesting that if we find one plant that is acceptable, that all the other plants -- all they have to do is measure up to that plant's design.

MR. ZUDANS: The set of criteria.

MR. MARCHESE: That's one thing. But we're talking about backfitting things, and I don't think it's that simple.

MR. ZUDANS: I do understand the problem that you're faced with. I feel the approach that you're taking is too hard. It's a very hard approach. It takes you at least three years before you get there, and of course getting a subcontractor on board will take a lot more time, for you to get Sandia on board. And all of that is time-consuming.

My feeling is that after you went through it, all you have is a great variety of different things and you will find it very hard to sort out what is it that you really want to accept at that point. And I don't think that you would be much better informed at that point than you would be by finding one now that satisfies what you perceive as an adequate level of reliability to meet some core melt frequency goal and say, this is the set of criteria, let the industry worry how they can meet it.

They will come back with recommendations and say, we can't do this because of that and that. If you start looking at all the other plants and see how it fits, you are forced to tailor your criteria to the existing plants, and I don't know whether that is a good approach or not.

So I am not critical. I think you are going the wrong way. It may never lead to results. It will be a perpetual program.

MR. MARCHESE: Well, we don't want any perpetual programs.

Does anybody else have any comments? I guess I've exhausted everything I can think about on this.

MR. WARD: Pete, go ahead.

MR. DAVIS: Yes. Andy, I had one comment. It seems to me like the basic thread of this program is the assessment of the reliability of decay heat removal systems. In other words, there will be some numerical value below which the plant is okay and above which there might be some questions.

Now, this is going to require reliability analyses of the decay heat removal systems, which I presume the industry will be required to submit, to see if the criteria is met. Well, the thing that bothers me a little bit is, there is always considerable latitude in the selection of the methodology and the numbers that you put into a reliability study, and you can get a rather wide variability in the answer.

And I am wondering if part of this requirement will be to specify the methodology to be used in these reliability analyses and to provide some guidelines on what data is to be provided and so forth. The reason -- one of the reasons I have this concern is recently I read some information which indicates that the reliability of auxiliary feedwater systems, for example, based on data is quite a bit lower than what has been coming in as part of PRA's or separate studies of auxiliary feedwater reliability.

And it seems to me like you're setting the stage here for quite a lot of work. You know, I'm wondering how you're going to review all of these things, what kind of prescription you're going to have on how they handle common cause failures, human errors, and these kind of things. Decisions made at that point, as I said, can change the answer quite a bit, and I have even seen studies where completely different numbers can be justified, and it seems logical to use different numbers to get different results.

I'm wondering if you're concerned about this and if there is going to be something in the criteria which will help you evaluate these things as they come in. I know there is more than 12 PRA's done, but they are all different levels. RISMAP is not nearly as complex in the consideration of system reliability as IREP is.

So you can't say auxiliary feedwater from the RISMAP study has the same degree of robustness as one from an IREP study, and it's going to be hard to compare

them just on the basis of existing PRA's because of this
problem.

MR. MARCHESE: That's a very good point. We were intending to utilize the existing risk and reliability assessments in terms of extracting the information out of those documents, in terms of what contributions of our systems involving decay heat removal contribute to overall core melt frequency.

We were not intending to do any substantial -- or request substantial new reliability or risk assessments as part of this program. I was hoping there would be enough uniformity in those studies, because there are a lot of people working on trying to establish the procedures one should do a reliability study for core melt, and we were not intending to set a uniform kind of procedure in terms of doing the reliability study, but that could be a problem.

MR. CATTON: Andy, it seems to me that if you have an absolutely reliable decay heat removal system you don't have any risk. You know, I've heard you and ot hers make the comment frequently that the decay heat removal system is sometimes not the dominant contributor to risk. I just don't understand that.

MR. MARCHESE: The overall core melt frequency could be made up of several causes. You have either failures of the decay heat removal system, failure to scram, the ATWS event. You could have failure of major pressure vessel structures, like the reactor pressure vessel.

There is a limit in terms of improving the decay heat removal system, in terms of how much you improve the overall core melt frequency or risk. The overall core melt frequency is composed of a number of fault sequences and decay heat removal system failures is just one of them. There are others.

And so if you improve decay heat removal system reliability by a factor of ten, it doesn't mean you gain a factor of ten in core melt frequency. It may be a factor of three or five, because there are other faults or other sequences one has to consider that don't involve decay heat removal. So this is not going to solve all the problems.

MR. CATTON: I guess what you're saying is if the vessel splits in two it really doesn't matter.

MR. MARCHESE: Right. And if it fails to scram you have problems.

MR. WARD: Or if you have a large break LOCA.

MR. MARCHESE: Hopefully this will catch --

MR. CATTON: Unless he's separating out how you will get heat out of the system under those circumstances. That's decay heat removal again by my view. But I understand these others, like ATWS or if the vessel cracks or something likle that.

MR. EBERSOLE: That's merely due to the limited definition of what you call decay heat removal systems. If they're all encompassed, Ivan would be right.

MR. MARCHESE: If you consider these systems for a large break LOCA, you get into other systems. You could wind up including everything. We can't do that.

MR. CATTON: But when you say decay heat removal, I was including everything.

(Laughter.)

MR. WARD: Let me ask you one more question, Andy. You're going to be developing two different type of criteria, the quantitative and the qualitative deterministic criteria, and assessing the existing plants against those two sets of criteria?

MR. MARCHESE: Right.

MR. WARD: What is the split in that effort that you see, or what percent of the total effort are you spending on the quantitative and what percent on the qualitative criteria and assessment?

MR. MARCHESE: I think the qualitative criteria will have more resources devoted to them.

MR. WARD: The qualitative?

MR. MARCHESE: The qualitative, yes. The quantitative criteria we got started in terms of developing rather early. We have an excellent fellow working in that area, Lesley Kaye, whom I think made a presentation here at one time. He will be interacting extensively with Sandia.

But qualitative criteria for the special emergencies really involves a lot more work, I think, because one of the things is you've got to get out there and walk through the plants, review the information that exists, PNID diagrams, plant general arrangement drawings, talk to the operators, get a feeling for the problems they have had, look into a maze of existing qualitative criteria to see which makes sense; is it consistent?

Look at the proposed new criteria that you all have put together in this area, namely Dr. Okrent, Dr. Ebersole, Dr. Epler. That criteria needs to be considered. I think there's a lot more work than the plan reflects in terms of resources.

MR. WARD: I guess sometimes I remain a little bit puzzled as to how a PRA that means anything can be done without doing that same sort of thing. But that's not a question for this meeting.

MR. MARCHESE: We're not going to be doing any new PRA's or new extensive reliability studies. We're going to be extracting from the existing ones.

MR. EBERSOLE: The absence of existing criteria for future plants is intentional, isn't it, because the policy is that infringes on the design area too much?

MR. MARCHESE: No. I think -- I don't know how it's going to turn out, but I'm hoping that we can have, in terms of acceptance criteria a set of quantitative and qualitative criteria that apply to both existing and future plants.

MR. EBERSOLE: You don't have qualitative for future now?

MR. MARCHESE: No, but we're going to be developing some.

MR. EBERSOLE: Thank you.

MR. WARD: When can we expect to see a copy of the revised plan?

MR. MARCHESE: I would think within a month. As soon as we get the go-ahead from the contract review board, which mainly is my main focus right now, to try and get this program approved and work under way. I'm devoting my resources today -- it would not make sense for me to start revising the plan in detail and then have this program not approved by some organization like the contract review board.

I want to get that thing done, and then I will revise the plan and issue it, and I would think that can be done within a month.

MR. WARD: What are you going to do if we have some major problems with the plan as we see it as it's written, rather than the summary that's been presented here today?

MR. MARCHESE: Well, we would have to consider that and get together and meet and discuss it, negotiate, recognizing that if you want to slow the program down, fine. But don't come back later and tell me that, why doesn't it work the way it started.

MR. WARD: Well, maybe we can get a draft of the plan. I'll bet you've got one.

MR. MARCHESE: We've got a marked up version that I have no problems with giving you.

MR. WARD: Well, I think it would be a good idea of we could get one soon.

MR. MARCHESE: It hasn't been fine tuned to make everything consistent, but it's marked up to the extent that you can see what work has been deleted and what remains.

MR. WARD: All right. Are there any other questions?

(No response.)

Okay. Thank you, Andy.

Before we take a break, I'd like to get comments from Committee members and our consultants on what we heard. And you might address the question of whether you believe this review has been adequate or whether we need to make a more detailed review of the written plan.

One option might be that we could each review the written plan and reflect comments without another Subcommittee meeting, and not have a Subcommittee meeting unless some particular problem came up from that review. So I would like to hear your general comments on the plan as described by Mr. Marchese. Do you think it's adequate? Do you have any recommendations that you think the Subcommittee and the Committee should make?

Let's start with Mr. Epler.

MR. EPLER: I have a general feeling that this is a continuation of the effort to make general purpose plant systems adequate for a very sensitive application, thus causing a great deal of effort on everybody's part, the regulatory, the industry. We heard a month or so ago that the backlog of NRC-mandated changes has become unmanageable, that priorities have to be established in order to get the important ones established, and the cost of changes in most cases would be greater than the initial cost of the plant.

This tells me it's very much in the self-interest of the utilities to come up with a scheme which they could propose that would take care of residual heat without being -- not told, but suggested or hinted, coerced, into making some existing systems behave in some unspecified manner.

I think from this plan I see a great incentive for the industry to come up with something that works.

MR. WARD: Mr. Davis?

MR. DAVIS: I guess I would like to see the draft plan, Mr. Chairman, and maybe make some comments on that. I guess I think the program is moving the right direction by eliminating those parts that I didn't think were really NRC responsibilities anyway. And the schedule looks a lot better now.

But I still have some concerns about some parts of it, and I would like to see the draft plan.

MR. WARD: Thank you.

Mr. Zudans?

MR. ZUDANS: Well, I stated my concerns before. I'm not going to repeat those.

I think that it may lead to -- I think it could be done in the right way or it shouldn't be done at all. Let the industry design the system and then find out what are the limits that such systems are acceptable.

MR. WARD: Could I just ask a question on that? When you were discussing this previously, I got the impression you were limiting the criterion to a quantitative criterion. Did you mean that, or do you think there should be some separate qualitative criterion?

MR. ZUDANS: I don't quite see how one can make a distinction between qualitative and quantitative. Each qualitative criterion goes with some quantitative number that is associated with it. I find it hard to separate qualitative from quantitative. But one could do some artificial values.

What is a qualitative criteria, that you shall have a wall that separates these things? Once you say that, you have to say how thick the wall should be and what it's supposed to do, to protect against, missiles or just human error or what.

I find it difficult to distinguish these.

MR. WARD: I guess that's the question. Do you think that setting a core melt frequency and then perhaps some background reliability numbers on individual subsystems is enough?

MR. ZUDANS: It's enough for me.

MR. WARD: Then you don't think it would be necessary to have some requirements on separation, dedication, diversity, redundancy?

MR. ZUDANS: The reliability of a particular unit will be affected by separation.

MR. CATTON: Don't those things all feed into that number?

MR. ZUDANS: Yes. Therefore, the industry who designs the plant can demonstrate that they specify that number. So I think you phrased it better than I did. The core melt frequency goal associated with some reliability numbers, that's all we need.

MR. WARD: Well, I may have raised it, but I'm not sure I agree with you. But --

MR. ZUDANS: At least you rephrased it so that it's clear.

The other thing is of course -- and maybe that's what we need to go through this program -- can you get such numbers and defend them? This is a number I would like to have, a reliability number, and these are the reasons why I want to have it, other than core melt frequency.

If you cannot get such a set of numbers

without doing that study, I'd say that's the way it should go. If you cannot and the reason is given why you cannot, then of course a program like this could be acceptable.

MR. CATTON: I have a couple of comments. I think basic criteria on the frequency of core melt is good. To get from core melt to risk involves too much speculation in my view. I don't think you completely avoid it, however, because it's a risk you're trying to avoid. So you have to go backwards through that speculation to some number.

At least the frequency of core melt is something that you can do with PRA that's believable. I think going to risk is too much speculation.

I'd like to emphasize what Jerry said. I think heat removal or lack of it is or should be a primary concern, and in looking through at least the October 7th version the staff doesn't appear to share this view to the extent that sufficient staff manpower is allocated. I find about four man-years is what's being allocated to this particular task, and I think that is kind of minimal.

I like Epler's arguments for dedicated single purpose residual heat removal systems. I think he's right when he says we're trying to back up general purpose systems. I'd like to see a little more emphasis on that spelled out in the -- whatever this is called, this report.

And finally, I was concerned about the time schedule. April 1 is just around the corner, and the usual procedure going out for RFP's is six to eight months. I think the only way it can be done in a reasonable time is a single contractor, to avoid the whole RFP process by doing that.

MR. WARD: You think the dedicated system is attractive whether or not it contributes to a reduced frequency of core melt?

MR. CATTON: I think it would contribute to reducing the frequency.

MR. WARD: What if you have a frequency that it's already low enough without the dedicated system?

MR. CATTON: I'm not sure how you establish that the frequency is low enough to have a lot of faith in it. Every time you turn around something else happens. You find a particular set of pumps didn't run because something is not included in the PRA reliability study.

We have lots of examples of these and more come up every day. A lot of them aren't even available through things like LER's. You find out that a particular plant had a particular problem from somebody who happened to be there, and these things keep adding up.

I can think of two examples where all the HPI pumps didn't work, and that's a number of 10^{-3} already, and those particular incidents are not included, I don't believe, in a typical PRA study. So maybe it's just a lack of faith in how they're going to get their number.

MR. WARD: Exactly, and I think that's exactly the reason why we have been talking about a dual set of criteria, of PRA quantitative and deterministic qualitative.

MR. CATTON: I meant to ask about that. In reading through all of this paper, I came to a statement that along with the PRA there was going to be a deterministic evaluation made, and I couldn't understand what they were talking about. Maybe at some stage somebody can explain that.

MR. WARD: Well, I think your discussion there is exactly what they're talking about.

MR. CATTON: If you don't believe PRA, then it's deterministic. I understand that.

(Laughter.)

MR. EPLER: Could I have one more comment? I liked your question, what if the plant doesn't need an improvement by probabilistic techniques? I think the answer is rather clear. It may not be in the interest of NRC or this group to improve risk, but I think GPU would surely like to have had a residual heat removal system that worked. They would be a billion dollars in your debt. I think we should capitalize on their interest to get something that works, even though it may not be our primary concern.

MR. CATTON: I think they would like to have known that the one they had would have worked if they had needed it after the event.

MR. WARD: Thank you.

Mr. Ray, do you have any comments you'd like to make?

MR. RAY: I concur with what's been said. I won't repeat any of those things. I think the NRC staff has moved in the right direction and I like the idea of minimizing considerations of design from the viewpoint of correction of existing plants.

However, I still feel that they are delegating too much to contractors. I think a one-man task force is inadequate. Let's assume that industry does respond and they do initiate an effort. They're going to have to interface with whom? One man in the NRC or with the contractor.

My reactions are that interfacing with the contractor is not the way industry would like to work. Certainly if I were out there I wouldn't. I'd want to talk to NRC. It seems to me more than one man is going to be necessary to follow, manage and control the progress and the implementation of the plan.

When I say more than one man, I mean internal forces. I can see this thing being a series of reiterations between Marchese and the contractor and reiterations between the managing contractor and each of the supporting contractors, and it can become almost interminable.

I feel very strongly in this area. That's about all the contribution I think I can make as an individual, in view of what's been said.

MR. WARD: Mr. Etherington?

MR. ETHERINGTON: I feel a little uneasy still about the 10^{-4} number as a criterion, and I would hope that if reasonable additions or improvements to a system would materially reduce that number it would be considered, and that is that 10^{-4} not be considered as the speed limit.

I also was not quite clear what was meant by an industry peer review group. Industry comments are always invited on industry findings. A peer group suggests more of a steering function, which I would think is inappropriate. I'm sure industry comments will all be objective.

(Laughter.)

But the manufacturers clearly think more highly of their own individual systems than that of their competitors, and perhaps think too highly of them. And maybe that's not what you had in mind, to bring them in as kind of partners in the steering of the work.

That's all I have.

MR. WARD: Andy, did you have any comment on that?

MR. MARCHESE: We were thinking of -- in fact, we have asked Sandia for their recommendation in this area, because apparently they have used this on other programs very successfully, where they invite a number of experts in in a particular field they were talking about.

We anticipate that we would get some in from the various vendors who have expertise in this area, as well as A-E people who have expertise, and people from the utilities, and solicit their comments both pro and con against the internal reports that we published.

I would think it's like a design review team..

I hope it will be successful. Obviously, a lot of the approach will not be successful, but we're going to at least try it and see if it works.

MR. WARD: Okay. Thank you.

Mr. Ebersole.

MR. EBERSOLE: For future plants which includes -- all include the Westinghouse and GE designs -- I believe Mr. Marchese said that there will be qualitative criteria developed, however, included in the plan; and I think this should be explicit in the plan.

I will personally be suspicious of shutdown heat removal systems which are not dedicated and which are well described on a deterministic basis and given a thorough qualitative description, primarily because of the difficulty of getting a common mode failure into the PRA analysis.

The traditional industry position is always what we have now is good enough, and I think we know frequently that PRA techniques are invoked to prove their point. Notable among this is the proof of the GE ATWS case of some months ago.

MR. WARD: Thank you.

To wrap up, let me ask if Mr. Marchese could get us a copy of the draft plan, and I will ask Mr.

Savio to distribute that to the members and the consultants. And if we could do that within the week, perhaps we could get any comments back directly to Mr. Savio or written comments on sort of time scale that will be appropriate for the staff schedule on their review.

MR. RAY: I was wondering what the consensus might be on the possibility of a brief discussion or presentation on the nature of the revised plan to the full committee in April. This is a major change, and there was a significant reaction from the committee on the plan as it was originally set up. I wonder if there wouldn't be interest on the part of the members on this.

MR. WARD: Okay. Any other comments on that? Okay. I think that's a good suggestion, Jerry.

Do you think some sort of condensed 30-minute review?

MR. RAY: Yes. If Mr. Marchese were to concentrate on the changes that were made. This change in philosophy I think is significant, and that in itself is going to be of interest to several influential members of the committee from the viewpoint of influencing their actions. And I feel there is a deep-rooted interest in hearing this kind of thing in an abbreviated manner.

MR. WARD: Fine. Thanks. If we could plan then on that.

MR. MARCHESE: We have no problem with the April date provided that we really get the go ahead and the program is truly approved. I have no problem with April.

MR. WARD: You mean providing that you have the go ahead from your own management by that time, and you expect to get it?

MR. MARCHESE: Total management approval to go ahead and get the work started, which means not only Denton but his staff and the Contract Review Board, assuming they give us the go ahead. I would be only too glad to come in and talk to the full committee, but if there's a problem downstream and somebody raises an objection and we have to iterate another time, I don't want to come in here and give you another draft presentation.

MR. RAY: We certainly would be sympathetic with that.

MR. WARD: Fine. We can negotiate that. Thank you.

Okay. Let's take a break until 11:15.

(Recess.)

MR. WARD: We will go now into discussion from the staff on the feed-and-bleed capability for existing plants; and I believe Mr. Sheron will lead that.

MR. SHERON: My name is Brian Sheron from the Reactor Systems branch. We have a presentation this morning on the generic assessment of the feed-and-bleed capability for the operating PWRs.

The first two items on your agenda, which are the capability and the analyses performed to date by the industry will be presented by Dr. Walt Jensen of the Reactor Systems branch. Following Dr. Jensen's presentation I will give you a brief presentation on some analyses that staff is performing through its research organization, and also to share with you some additional insights, I guess, that we've learned about feed-and-bleed capability through operational experience and other means.

Following that then we would plan to go into the CESSAR System 80 discussion for this afternoon. At that time Dr. Rowsome and Mr. Thadani from the staff will give you a presentation on the work the have done regarding probabilistic risk assessment on the aspect of PORVs and their relation to decay heat removal requirements.

MR. WARD: Okay. Thank you. Let's go ahead.

(Slide.)

MR. JENSEN: My name is Walter Jensen with the Reactor Systems branch of NRC. I'm going to give you the general overview on the capability of existing plants to feed and bleed, and from there perhaps you can get an idea about what is required for plants to cool the core in the feed-and-bleed mode.

I have divided all the operating plants into three categories: Type 1 plants that can cool the core by actuating high pressure HPI systems so that water is injected at high pressure and steam exits the steam generator and would exit the reactor system to the PORVs or the safety valves.

Type 2 are plants that do not have high pressure HPI capability and which would have to depressurize the plant to feed and bleed. There is some overlap here because some of the plants that can be cooled in the high pressure mode can also be cooled in the low pressure mode.

And lastly, plants that cannot be cooled by feed and bleed because of insufficient high pressure injection capability or having PORVs that are too small to depressurize.

(Slide.)

This slide shows a summary of the feed-and-bleed analyses that have been presented to the staff by the vendors.

(Slide.)

Some of the requirements that the plant must have to cool the core in feed and bleed and the high pressure mode: the operator must manually actuate the high pressure injection system in the event of loss of all feedwater, since the reactor system would not automatically depressurize. He needs a high pressure injection flow of approximately 40 pounds per hour per megawatt to match the decay heat boiloff. This number comes from calculations made by B&W and Westinghouse and evaluations of the core boil-off rate at the time of minimum reactor system inventory.

In the calculations done by the vendors, the reactor system water level drops to the upper plenum so that only the lower parts of the reactor system are filled with water. The core is covered and cooled by boiling in the core, and steam then passes into the upper parts of the system and out of the PORVs or safety valves.

MR. EPLER: In the first line on the 40 pounds per hour per megawatt, is that megawatt rating or is that megawatts being generated at that time?

MR. JENSEN: Yes. That's the megawatt rating of the plant, assuming that the plant in fact has been operating for a long period of time at full power and is generating the decay heat that would be associated with that level.

MR. ETHERINGTON: Is that megawatts thermal?

MR. JENSEN: Yes, sir. At the time when the reactor system reaches this minimum water inventory, the amount of decay heat generated is about one percent of the initial power level.

MR. CATTON: Are you sure of that? Isn't that per megawatt decay heat?

MR. JENSEN: No.

MR. EBERSOLE: In paragraph 3 there can be at least two reasons that water can drop down that far. One of them is prior to getting down that far there is a two-phase loss of fluid out of the pressurizer through the PORV and gets up high. The second is it takes time. Therefore, by the time it gets down that far, the decay energy is lower.

Which of these two causes predominates? Is it the loss of water in two-phase flow out of the PORV, or is it just the fact that the core is higher and the water comes down?

MR. JENSEN: I haven't looked at that in detail. I would guess it's the two-phase effect.

MR. EBERSOLE: In other words, the pressurizer vessel itself is not a very good steam separator, and so you lose water out of it until it gets down that far?

MR. JENSEN: Well, what happens in these plants is I think the bubbles would separate in the pressurizer, but as the plant became depressurized and separated, flashing would occur within the reactor loops, and as that occurred that would tend to cause the liquid to swell up in the pressurizer.

MR. EBERSOLE: Would there not be a lot of frothing as long as the water were not down in the plenum due to the transport of steam bubbles through the water?

MR. JENSEN: There would be some frothing, yes.

MR. EBERSOLE: Anyway, you don't know now what the predominant reason is it falls down to that level and then stops.

MR. JENSEN: Both of those reasons are certainly valid reasons. They both have an effect. And by the time the reactor system level was dropped down to the point where the vendors calculate that the core would be uncovered, it's down below the surge line entry location in the hot leg, so then there's no more water being lost from the primary system. Only steam goes into the pressurizer then. And then whether or not -- well, I believe the pressurizer is finally drained, but whether it's finally drained or not is no longer primary system.

MR. EBERSOLE: That condition when it's in the upper plenum is a pretty nervous one, and it would suggest that is where the core water level indicators would serve their most useful purpose, is that correct?

MR. JENSEN: If they were, they would certainly show this condition.

MR. EBERSOLE: Thank you.

MR. WARD: Let's see, Mr. Jensen. Are you going to go into this in more detail? I still don't have a very good picture on I guess the fluid transport and the energy transport from the low level -- the core covered at low level and steam boiling off that, and somehow this fluid and the energy goes out the PORV.

What are we talking about? You said at some stage apparently the pressurizer drains the liquid, and so you've got a straight shot for steam going through it. Are you going to get into this more and explain that or is this the right time for the question?

MR. JENSEN: Well, I have a curve of reactor system pressure as a function of time, and water level is a function of time. It's really hard to show this on a slide.

(Slide.)

This is a B&W calculation where they injected water with a high pressure injection system and blew fluid out of the safety valve. You see, the reactor pressure drops down with initial overcooling. The system heats back up again, goes to the safety valve set point, and I believe they actuated the high pressure injection system in twenty minutes, so it would be about here. But still the pressure stayed right up at the safety valve set point.

(Slide.)

And what the reactor vessel water level did in this time, the reactor coolant volume contained the drop, and so it looks like at about 9,000 seconds it reached a minimum, and at this time the water was in the upper plenum, the hot legs were drained, and there was really a finite level in the reactor system with steam at the top, boiling in the core, steam going out of the safety valves, and high pressure water being injected into the cold legs and flowing to make up the boiling in the core.

MR. EBERSOLE: Did they calculate the progressive change of quality in steam emerging from the safety?

MR. JENSEN: Yes, they did. I didn't bring it.

MR. EBERSOLE: Did it ultimately get to be 100 percent steam?

MR. JENSEN: Yes, it did, and this is 100 percent steam here.

MR. EBERSOLE: Was it not a hundred percent steam before then?

MR. JENSEN: No, sir.

MR. EBERSOLE: What about on down the curve?

MR. JENSEN: Even before the high pressure injection system was actuated, I believe, the pressure surge in the reactor system caused the safety valves to open way back here and blew the steam bubble out of the pressurizer. Then water started to flow, and then the high pressure injection system actuated by the operator continued to force water and steam out of the safety valve. There was more water being lost than was being added until the level dropped down so low that the surge line then was uncovered, so only steam would exit from the pressurizer.

MR. WARD: So some fraction of water that's originally in the pressurizer goes out the PORV, and some of it ultimately drains back to the rest of the primary system, is that it?

MR. JENSEN: I think the significant thing here is that this plant has the capability to add more water to the core than can be boiled away in this period of time when this occurs. So if they can add more water, that could be boiled away even though the level drops within the reactor system. Eventually you will reach the point before the core is uncovered, but there will be only steam coming out of the pressurizer since the surge line is located at a higher elevation than the core. If you finally drop down below the surge line elevation before the core is uncovered, then only steam will exit from the reactor system.

MR. WARD: Okay. I guess I'm surprised that there isn't some kick up in level. This is supposedly the level in the reactor vessel, right, this curve?

MR. JENSEN: This is total system volume, I believe.

MR. EBERSOLE: It's down in the vessel at the lower end, though.

MR. JENSEN: Yes, sir.

MR. EBERSOLE: It's all in the vessel.

MR. EPLER: Can I ask a question?

MR. WARD: Could I pursue this one?

MR. EPLER: You might ask how you're going to measure this level.

MR. WARD: I wonder how they're calculating it right now. Where on that curve does the pressurizer drain back into the rest of the primary system?

MR. JENSEN: I don't know whether this curve shows the pressurizer drain back or not.

MR. WARD: Well, no, I guess it doesn't. But where in time in the transient depicted here, where in time does the pressurizer drain back?

MR. JENSEN: I don't know. In this time the water level was down to the upper plenum. The hot legs would be drained. The pressurizer would either drain back -- I don't know; it might just continue to be blown out of the reactor system.

MR. WARD: That was my original question, I guess.

MR. JENSEN: It doesn't make a great deal of difference. If it drains back, it will have perhaps a little more water. But the important thing is you have to have enough ECCS water to make the core boil off, and if you do have enough ECCS water, you can keep up with it, and the decay heat rate is fairly constant in time. It's about one percent of the reactor initial power level, and it doesn't decay very much with time, so you have to have enough ECCS water to make up one percent of boil-off or the core gets uncovered.

MR. WARD: What's bothering me is that somebody has calculated that curve and they're concluding that you end up with the core covered out here after 4,000 or 6,000 seconds or something. But in order to calculate that intelligently -- in order to calculate it accurately, they have to know -- have some means of calculating how much of the pressurizer water is going out the PORV and how much is draining back into the remainder of the primary system. Unless they know that, I don't see how I can believe that curve up there.

MR. JENSEN: They know it, but I don't. This is the basis of the ECCS small break modeling technique.

MR. SHERON: I was going to address this a little bit later but since --

MR. WARD: If that comes in the next presentation, we'll wait.

MR. SHERON: I'm not going to have too much more to add other than to say the question of whether the pressurizer drains once you uncover the hot leg or whether you get a counter-current flow limit rates in terms of steam going up the pressurizer and holding up the water in the pressurizer, I think that is dependent upon a number of things. One is the model itself that you use for counter-current flow, and you have to remember that these pressurizers are not just a straight pot going into a big tank. There is usually some sort of a baffle or flange. Each vendor is unique on that. And the actual drain behavior I think is uncertain in the calculation.

I think what Dr. Jensen is trying to tell you is that we really don't see any reason or we don't see any great significance whether the pressurizer drains back and adds the inventory to the vessel or whether the inventory stays in the pressurizer, and steam as it enters the pressurizer will either carry out some liquid through the break -- in other words, your PORV flow would go from almost a solid liquid to a two-phase transition period in which there would be a period of two-phase flow where the steam was actually carrying out liquid droplets until you basically got all the water out of the pressurizer, and then it would be a steam flow coming out.

I think what Dr. Jensen is saying is that it doesn't matter, because at this point in time you're adding more water to the system than you're carrying out from the PORV, so there would start to be a net inventory increase in the system.

MR. EBERSOLE: But this must be based on one or the other conclusion that the water did or didn't stay up there, because it's time-dependent.

MR. SHERON: We will have to check. This would have to be very specific to the B&W model that was used.

MR. WARD: I suspected that this might be difficult to calculate and there would be a great uncertainty in it. And I guess I'm wondering if that uncertainty has any profound effect on the transient and what you conclude about the transient. I think what you're telling me is you don't think it does, that the bottom line of the transient is pretty much the same no matter what you conclude about the uncertainty of this mechanism.

MR. SHERON: In a situation like this where you're trying to go to a type of feed-and-bleed decay heat removal, so far all we've said is that the operator has to manually actuate the high pressure injection. Now you're assuming that he does nothing else except stand there and watch his plant does its thing. And in fact, I think the recommended approach would be for an operator to latch open that PORV and try and get down the pressure, so that would even promote the high pressure injection flow.

This is sort of like a bounding case when the operator manually actuates HPI and then walks away.

MR. EBERSOLE: It would be nice if he could latch it open and keep it open, but he can't. He has to keep the potential on the solenoid valves. So it's not as reliable as a latched open valve.

MR. JENSEN: In this calculation he's actually pumping through safety valves, and he's not depending on the PORV loop.

MR. WARD: But the mass flow he is getting through those valves has to be profoundly dependent on whether it's water or steam going through or some mixture.

MR. JENSEN: Well, back here he's pumping in about 40 pounds per hour per megawatt, and he's getting about 40 pounds per hour per megawatt coming out of the safety valves.

MR. ETHERINGTON: But that is as steam. If it was passing water you'd be removing less heat.

MR. JENSEN: If they were passing water -- if he were removing less heat, then the valves would -- the heat is going to get out of there through these valves somehow or other. If more water gets carried out, then the level would drop down a little quicker; but he still has enough ECCS water to make the boil-off.

MR. ETHERINGTON: But the point is if you're not removing as much heat because there's a large amount of water flowing through the PORV, the pressure is going to go up.

MR. JENSEN: The pressure is held up by these safety valves that are fluttering at the set point.

MR. ETHERINGTON: Can the safety valves handle all the water that goes in and remove all the steam and heat that's being generated?

MR. JENSEN: That's what we calculate. We don't have a great deal of data on safety valves for liquid flow. But this -- they assume -- I believe it is the Moody flow out of these valves, and valves have a margin because they are fluttering. If the calculation is wrong and they show lesser capability, then first the valves would be open a larger fraction of the time. They would have to make a considerable error in valve flow. So instead of opening and closing, the valves would actually be open all the time with not enough capability.

MR. ETHERINGTON: What I'm trying to establish is this is all based on the PORV operation, isn't it?

MR. JENSEN: No, sir. It's a safety valve operation.

MR. ETHERINGTON: It is based on the safety valves coming into operation to handle whatever is coming out, water or steam.

MR. JENSEN: Yes, sir. This is one calculation by one vendor for plants that have high pressure injection capability with a sufficiently high shut-off head to be able to force the safety valves open. Most plants cannot do that, and I'm going to show you a list in the next couple of slides as to which plants can indeed feed and bleed in this manner.

MR. EBERSOLE: When your first liquid solid from the HPIs come up, you are emitting solid water from the safety valves. It will flash at the interface in the throat. What's the heat rejection rate at that point in time? Isn't that what you're asking?

MR. JENSEN: No.

MR. EBERSOLE: What's the heat rejection rate when the system is water solid and there's nothing but water coming out of the safety valves?

MR. JENSEN: The system I don't believe in this calculation, I don't believe ever got water solid. The system heated up during the time when the feedwater was lost and bubbles formed in the primary loops which sends forth water into the pressurizer. The pressurizer probably did go solid, and then there was solid water going through the safety valves; and this vendor used the Moody model for liquid flow out of the valves. And as I say, there is not a great deal of data for liquid flow in this particular pressure with high pressure going out of safety valves.

MR. EBERSOLE: The systems are integrated so all of the reactor main coolant pump seals are presumably leaking. Is this quantity that you quote here, does it account for the fact that you don't have a liquid hermetically sealed system? You've got leaky seals and other ways of loss of water?

MR. JENSEN: There weren't any leaking seals assumed in this calculation. Some plants may have safety grade capability to inject seal water into the reactor coolant pump seals. But this calculation is just looking at feed-and-bleed capability.

MR. WARD: I think what we're going to need is some sort of a mechanistic explanation of the mass flow and the energy flow at the PORVs or out the safety valves, how it gets from the core to the path of the pressurizer with a picture for the simple minds here.

Will that come later, Brian?

MR. SHERON: No. We had not brought anything with us, I guess. If I could, let me say that we will provide the committee with more detailed information of exactly the heat rejection I guess out of the safety valves. When the heat rejection out of the valves is exceeding the heat generation in the core, the mass flow that was calculated to exit the safety valves, the quality versus time and the like.

MR. ETHERINGTON: If hypothetically we say the pressurizer has gone solid and it's only high temperature water that is escaping through the safety valves, then that would answer the question.

MR. SHERON: Okay.

MR. EBERSOLE: I wish you would include consideration of the seal leakage, because since the input to the pumps is fairly large it may represent a substantial fraction of that.

MR. JENSON: This is not an NRC calculation. It's by Babcock & Wilcox.

MR. WARD: We had some questions over here.

MR. ZUDANS: That scale is in seconds?

MR. JENSON: Yes, sir.

MR. ZUDANS: Do you have any idea how much water has overflowed in the containment at this time, and what is the state of affairs? How long can you go with this process here without having some problems that are fairly sizable, with the quantity of water that you blow out in the containment? Plus what is your supply in this case? How long can you go?

MR. JENSON: As far as the containment is concerned, I don't see any problem with this particular process. You can keep going here until you inject all the water out of the borated water storage tank.

MR. ZUDANS: How long is that on this time
scale?

MR. JENSON: I have not calculated that
number, but it would be a number of hours, because of
the fairly low flow rate from the high pressure
injection system. Supposedly, the containments have
been designed to hold the water from the primary system
plus the water in the borated water storage tank, as it
would be for a LOCA.

Then after that time to continue operation in
this mode the operator would have to switch to the
recirculation mode and inject water from the containment
sump and continue feed and bleed in that manner.

MR. EBERSOLE: Would it be to his advantage to
continue this low level if he had some way of knowing
where he was or, to go on back later on in time, when
the core heat is down, to go back and water fill it? I
see the curve is turning up. Does that indicate that he
is going to go back and fill up some?

MR. JENSON: Yes.

MR. EBERSOLE: Should he do that or should he
just maintain that stable where it is?

MR. JENSON: We would hope that he would be
able to restart his feedwater system very quickly and
not even get out this far. I haven't really looked at

how an operator would recover a plant in the feed and bleed mode. It's a fairly complicated thing to do, I think.

MR. EBERSOLE: You've got him out at about 100 minutes, haven't you?

MR. JENSON: I haven't talked to you about the downcomer temperature or the thermal shock on the reactor vessel. I was just looking at the water inventory calculations, comparing the water injected to water lost.

MR. EBERSOLE: Thank you.

MR. WARD: Mr. Davis, did you have a question?

MR. DAVIS: Just a quick one. The amount of water that leaves the system depends, I think, to a large extent on the quantity that enters the surge line, and that can depend on whether the primary coolant pumps are operating. For this case do you know whether they were on or off, or how long they operated after the start?

MR. JENSON: I don't believe this calculation had primary coolant pumps included. I'm not sure what the operating instructions would tell the operator to do. For a small break LOCA where the high pressure injection was automatically actuated, the operators are told to turn off the reactor coolant pumps. But for this calculation, it's not a small break LOCA and the operator manually actuates ECCS, and I suppose he could leave the coolant pumps go.

I mean, yes, you're correct, that would certainly affect the quantity going into the surge line.

MR. DAVIS: The pump also has some energy, and I don't know how much that is compared with the decay heat level. But that would be another parameter that would maybe influence how the system behaves.

MR. EBERSOLE: It would be a risky thing to do, because if the pumps were to inadvertently stop late in the cycle the water would collapse below the core.

MR. JENSON: Yes, sir, that's right.

MR. WARD: Let me ask you a question. Out there at equilibrium, after 6,000 or 8,000 seconds, seeing that the water is well above the top of the core, and you're assuming that the pressurizer is empty, what if for some magic reason the pressurizer is really full of water? How much volume is in that and where would that leave -- so you still have the same volume in the system.

Would the water be below the top of the core then?

MR. JENSON: The volume of the pressurizer is about 1500 cubic feet. So if you added that to the 4,000 -- yeah, the pressurizer then, if it were full and it drained into the reactor system water level, it would bring the reactor system water level up to here.

MR. ETHERINGTON: The tank is only half full normally, isn't it?

MR. JENSON: Yes.

MR. WARD: But that's basically my problem, and there probably just needs -- that's why it's not clear to me why it's unimportant exactly what goes on during this period. I mean, I can see out there when you're at equilibrium it's commonly steaming and flowing out the pipe and out the valve, and everything is nice.

But it looks like it's tremendously complicated getting from the top equilibrium line to the bottom equilibrium line.

MR. JENSON: There is a long time out here where the thing would be steaming and because of the decay heat level was almost constant, and there's an awful lot of heat being added here, I think, in comparison to the water in the pressurizer.

MR. WARD: Are you confident that people really understand that that well? I mean, I don't, but that's not very important. What is important is whether

--

MR. JENSON: I have some confidence in the thermal hydraulic calculations, but I'm less confident in recovery of the system without any feedwater in terms of not overcooling the reactor vessel and getting the vessel wall to hold at a high pressure. I'm not sure how the operator would control that if he were trying to bring the system down.

But I feel that this would be the best step for the operator to take if he didn't have any feedwater available, and whether or not we're completely sure it works, it's still --

MR. WARD: Let's go ahead. Thank you.

MR. JENSON: I'm not sure whether we finished this slide or not, but I did want to indicate that you need to put in 40 pounds per hour per megawatt, and of course you need to have a pressurizer relief or safety valve capacity of about 40 pounds per hour per megawatt.

MR. ZUDANS: I have to ask, is this megawatt of decay heat at that particular time?

MR. JENSON: Initial power level.

MR. ETHERINGTON: That's equivalent to about one and a half percent of the full power, so it will take care of the decay heat after a short time. What about initially when the decay heat is a little more than the 40 will handle?

MR. JENSON: During that time the reactor loses more water than it gets. It boils the water in the system and some of it is blown out of the system. It is a complicated process and is dependent on the phase separation model.

MR. DAVIS: Incidentally, that 40 pounds per hour does not seem to agree with the 7 gallons per minute per megawatt thermal that is in Dr. Sheron's memo that was supplied to us for this meeting. You may want to check that. Those two numbers don't agree.

Seven gallons per minute per megawatt thermal is much, much more flow than 40 pounds.

MR. ETHERINGTON: That's nearly 500 pounds per hour.

MR. DAVIS: The 40 pounds per hour seems to agree with what I have got here as being the amount required.

(Slide.)

MR. JENSON: The B&W calculation was looked at as applicable to these five plants, and they have a high head injection capability larger than 40 pounds per hour per megawatt, with one ECCS train. The analysis then indicates that these plants can be cooled by feed and bleed out of the safety valves using one high pressure injection pump.

I believe again they assume the best estimate decay heat for this calculation of 1.2 times ANS.

MR. DAVIS: You said that was one pump out of how many available?

MR. JENSON: Two.

MR. DAVIS: So they assume one has failed. They could actually double that capacity if the system worked as designed?

MR. JENSON: Yes, sir, they could double their injection capability, and I believe the procedures would tell the operator to operate both of the high pressure pumps if they were available.

MR. DAVIS: Thank you.

(Slide.)

MR. JENSON: Westinghouse has also done calculations of the capability of a number of their plants to cool in the high pressure feed and bleed mode using high pressure charging pumps.

MR. EBERSOLE: Wait a minute. You changed the ground rules. That says the PORV set point. The other said safety valve set point. So that ought to be noticed.

MR. JENSON: Yes.

These Westinghouse designed plants are slightly lower shutoff heads.

MR. EBERSOLE: So you have to invoke the PORV, which is a non-safety device, and so these things cannot respond in a safety context. They have to respond in a less than safety-grade context.

MR. JENSON: Yes, sir. Probably all of the PORV's -- some of the plants have three PORV's. This is basically using all of the PORV capacity.

MR. EBERSOLE: They have modes of failure which are closed, I believe. But the safeties do not. At least that's the rationale.

MR. JENSON: So the mode of cooling here is similar to the B&W calculation, except that the PORV's are utilized and the operators are assumed to actuate the high pressure injection system and pump water through the PORV's, which have a set point, I believe, of about 2385.

MR. EBERSOLE: To put the plants on a relative basis, why wasn't it presented that the B&W plants had PORV's, too, which could be operated at any presure you wanted and the pressure kept down?

MR. JENSON: PORV's at the B&W plants are fairly small and they really don't have the capability to depressurize the plant.

MR. EBERSOLE: They're small, so they can't count on them?

MR. JENSON: Yes.

MR. EBERSOLE: You can't count on the safeties here because the pump can't reach that set pressure.

MR. JENSON: Yes, sir.

MR. EBERSOLE: Thank you.

MR. WARD: Why aren't these plants type two in your classification?

MR. JENSON: Well, they don't have two -- the operator does not have to open the PORV manually. He can turn on high pressure injection and the high pressure injection system will pump water over the PORV at set pressure.

MR. WARD: Okay. The difference between this and type two is the head from the high pressure injection pumps, and these are greater than the system pressure?

MR. JENSON: Yes, sir. These high pressure injection pumps have a shutoff pressure that is higher than a PORV set point. Now, they can also be operated in the type two mode. I guess I didn't classify the plants --

MR. EBERSOLE: The Westinghouse plants are pilot-operated valves.

MR. JENSON: They need both air and electricity.

MR. EBERSOLE: Even though they're operating under high pressure, so they have a pilot function which has to be invulnerable to the conditions of the containment, which is fairly hot, since they've lost all cooling.

MR. JENSON: Yes.

MR. EBERSOLE: So this is somewhat more marginal in the context of reliability than B&W, which is full safety-grade.

MR. JENSON: In this sense: they also need to have two HPI trains.

MR. EBERSOLE: That's all they've got.

MR. JENSON: Two high pressure trains. Let's see. They don't need all the PORV capability, I guess, because they're pushing water out of the PORV's.

MR. EBERSOLE: It's fair to say, then, that Westinghouse capabilities are a good deal more marginal than B&W.

MR. JENSON: At least in mode one, yes. Let me point out that Westinghouse does not recommend this mode of feed and bleed. And even though they have done an analysis to show the capability for these plants, they recommend that the operator feed and bleed in mode two by opening the PORV's first and depressurizing the plant.

MR. EBERSOLE: That means he has to invoke non-safety-grade functions.

MR. JENSON: Yes, sir.

MR. EBERSOLE: Thank you.

MR. JENSON: Although some of the PORV's have been upgraded to have emergency power, and I believe some have even been environmentally qualified, so they may be safety-grade for such circumstances. And also, although Combustion didn't do a specific calculation for Maine Yankee, they have high pressure HPI capability and they should probably be put in with these mode one plants. They could probably be cooled in the high pressure feed and bleed mode.

(Slide.)

For type two feed and bleed, the operator must manually actuate the PORV's to depressurize the plant, and he has to do it before the steam generators dry out. If he waits until he's completely lost his heat sink, then the primary system begins to store the core decay energy and heat up, and then to depressurize the plant he not only has to relieve the decay heat but also the stored energy in the primary system. So he'd better open the PORV's before the steam generators dry out.

It's much harder to get the plant down and you'd need a much larger PORV capability than most plants have. So then if he depressurizes the system the ECCS flow increases, but the PORV mass flow capability decreases because the steam gets bigger as the pressure goes down. So he needs larger PORV's than just to be able to relieve 40 pounds per second -- 40 pounds per hour per megawatt of steam, because the PORV flow capacity is degraded as he goes down in pressure.

So at 1500 psi he needs 74 pounds per hour per megawatt. In the Westinghouse plants with high pressure ECCS from the previous slides -- Westinghouse has presented calculations showing they can cool the core with one ECCS train by depressurizing through the PORV's down to 1500 psi, and he needs 74 pounds per hour per megawatt of installed PORV capability to do that.

Then plants that only have low head ECCS have to depressurize still further to get down below the shutoff head or the low head pumps, and they have to generally be pressurized to about 1250 psi, and this requires still bigger PORV capability to relieve core steam because of the effect of getting less flow out of PORV's as the pressure goes down. So they have to have an initial rated capacity of PORV's of 114 pounds per hour per megawatt.

(Slide.)

MR. DAVIS: Question. It's true, isn't it, that all of these plants have charging systems to make up a minimal amount of leakage? Are those systems considered in any of these analyses? I suppose their capacity is so low they can't handle this kind of flow rate; is that correct?

MR. JENSON: Yes. Largely, the capacity is too low to provide sufficient makeup. The systems are not safety-grade. I have only included safety-grade systems here. So for plants that have the high-head ECCS, these would be combination charging pumps and ECCS pumps, and they'd be used for both purposes. But they would generally have a larger capacity than positive displacement pumps, they would be nonsafety-grade and only used for charging.

(Slide.)

MR. EBERSOLE: Let me ask a general question. You talk about depressurizing through the use of PORV's. PORV's are multipurpose devices designed to relieve under high pressure and be manually remotely operated as well?

MR. JENSON: Yes.

MR. EBERSOLE: You don't need the automatic relief capability if you need to have PORV's. All you need is just plain valves. Why do we keep implying that we need PORV's rather than just more plain valves?

MR. JENSON: That's very true. In one plant, which is Arkansas Unit 1, I don't believe they have a PORV. They just have a relief valve on top of the pressurizer. It's fairly large and it probably gives them the capability to feed and bleed.

MR. EBERSOLE: I'm talking about manually invoked valves which are invoked by the operator as I think a good deal more reliable valve than a PORV, just a valve, period.

MR. JENSON: If the valve were properly sized --

MR. EBERSOLE: There's no reason for us to keep saying we need more PORV's. We need more valve capacity, right, in the general context?

MR. JENSON: Yes, for this purpose that's correct. It doesn't have to be a PORV. It can be any valve on the pressurizer that the operator can open and relieve the pressurizer steam.

MR. JENSON: Okay. For the type one plants, all of the Westinghouse plants with high pressure ECCS that I gave you in the previous slide have at least 105 pounds per hour per megawatt, and analysis shows they can cool the reactor and keep the core covered with one HPI train. They only need PORV capability of about 74 pounds per hour per megawatt and they have 105.

For the plants that have only low head ECCS, most of them can be cooled, because they have a PORV capability of 139 pounds per hour-megawatt, and they only need about 114 to depressurize down to the shutoff head, down below the shutoff head, the low pressure safety injection system.

And then ANO-1 has a pressurizer relief capacity, though it's not a PORV but it's a manual valve that the reactor operator can open, and I think it's about 200 pounds per hour megawatt. I'm not real sure of that.

Fort Calhoun, which is a CE plant, has a fairly large PORV capacity. It can be cooled easily in the feed and bleed. I don't have analysis for either of these two plants.

(Slide.)

MR. EBERSOLE: It's ANO-2. You said ANO-1. That's a Combustion plant, too.

MR. JENSON: ANO-1 is a B&W plant and it has feed and bleed through the safety valve.

(Slide.)

Now, these plants, I have listed them as marginal. They have somewhat lower PORV capacity than the plants on the other slide. Combustion submitted an analysis for Calvert Cliffs, which probably has the smallest PORV capability. As the core begins to be uncovered, there's a steaming rate that's calculated to be reduced, and then with the lower steaming rate and the PORV's open the steaming rate became less than the PORV relief capacity.

The pressure dropped down on the reactor system and the ECCS was unable to come on and fill the system back up again. So I have listed these as marginal because some core uncovery was calculated.

And then Yankee Rowe has one PORV and 118 pounds per second megawatt per hour, and it looks to me to match the decay heat boiloff with low pressure pumps you need about 114 pounds pressure per hour megawatt.

(Slide.)

In summary, for type one plants you need to have an ECCS flow of 40 pounds per hour megawatt and a PORV safety valve capability of 40 pounds per hour megawatt. For type two, if the PORV's manually open, you still need to replace the same decay heat boiloff, but you need to have higher PORV capability to depressurize the plant and about 74 pounds per hour per megawatt for plants with the high pressure ECCS pumps to be able to depressurize, so that one-pump flow is sufficient.

For plants with low pressure ECCS you need a still larger PORV capacity.

(Slide.)

As for type three plants that cannot be cooled by feed and bleed, the only operating plant I could identify was Davis-Besse. They have a low pressure ECCS and they have small PORV's, so they don't have enough PORV capacity to pressurize the plant below the hugh pressure injection pump shutoff head, and they don't have a high pressure ECCS pump.

I understand there are a number of plants now being built that don't have PORV's and they would also fall in this category.

MR. EBERSOLE: Originally Davis-Besse only had turbine-driven aux feed pumps. Does it now have motor-driven? So the loss of steam here is also the loss of aux feedwater?

MR. JENSON: Yes. They have given us a calculation showing they can keep the core covered by using their startup feedwater pump, which is a small electric feedwater pump, in combination with the non-ECCS charging pump. They can operate that way.

That concludes my presentation.

MR. WARD: Thank you.

Are there any questions for Mr. Jenson?

MR. ZUDANS: Just to point out that you need the AC power for any one of these combinations.

MR. JENSON: Yes. It can be from the diesel generators, but it has to be AC power to run the ECCS pumps.

MR. ZUDANS: Any feed and bleed system requires AC power.

MR. JENSON: Yes.

MR. WARD: Mr. Epler?

MR. EPLER: I guess if this were a design meeting I would have some revisions to make. First, this is strictly a manual operation. Whether or not the equipment is safety-grade becomes a little bit irrelevant when you're depending on the operator, especially if you don't know exactly what he's going to use to read the level that he is constrained to hold.

MR. WARD: You don't think the operator is safety-grade?

MR. EPLER: I don't think so.

(Laughter.)

And I want to point out that we are misusing the high pressure injection. Its purpose should be dedicated to keep the core covered, but we are misusing it for cooling. And I would like to observe that keeping the core covered, whose primary function it is, we aren't doing very well, because we have the problem of overpressurization at low temperatures, wherein it is not doing its job as well as we'd like.

So I would accept what we just heard as a last resort, but only as a last resort.

MR. WARD: Any other comments or questions? Mr. Etherington?

MR. ETHERINGTON: It appears to me that the type two capability is also dependent on the PORV's passing only steam; isn't that correct?

MR. JENSON: Yes, it is. Those calculations -- as far as the core level, the level drops down above the core, below the surge line elevation.

MR. ETHERINGTON: Is the steam release service on the pressurizer sufficient to get reasonably moisture-free steam?

MR. JENSON: I believe it is, based on some bubble rise calculations using the Wilson model. The only time the pressurizer would fill up is if the primary system loops were starting to flash.

MR. ETHERINGTON: What you're saying is it couldn't fill by frothing?

MR. JENSON: I don't think so.

MR. WARD: Okay, thank you, Mr. Jenson.

(Slide.)

MR. SHERON: My name is Briann Sheron, with the Reactor Systems Branch.

On this part of the agenda I was going to inform the Committee about two additional topics. One is a summary of some of stuff the staff is doing in this area with regard to feed and bleed, and also to just pass on to the Committee for information some other aspects that we picked up as part of our investigating feed and bleed. I don't claim it's complete. It's just information we received and we're passing on for what it's worth.

On April 2nd last year we had requested the Office of Regulatory Research -- they have two programs. I think one is called TRACK calculation of assistance and the second is the SASA program, the severe accident sequence analysis system. And we asked them to look at feed and bleed and certain variations of it from the standpoint of allowing us or helping us to review the industry's guidelines, the vendor guidelines that are presently the only place you will right now find instructions for feed and bleed.

(Slide.)

The calculations which we have asked for, one is a loss of feedwater which would open up PORV as an anticipated transient. We assume that the PORV stuck open, causing a small break loss of coolant accident and the HPI did not start. What would happen? How would it progress?

Second is the loss of main feed -- loss of auxiliary feedwater and one HPI available, sort of a confirmatory calculation of what Dr. Jenson pointed out that B&W had already done.

For Combustion plants, which are rather unique, particularly those that are coming on line without PORV's, one question we had is, is there any way you can get the pressure down on those things without relying on steam from the steam generators. And one way we thought of is the auxiliary spray in the pressurizer. If the operator was to turn on auxiliary spray, what does that buy you in either time that an operator has to restore feedwater to the generators, and also is there any possibility that that can keep the core covered until the feedwater systems can be restored?

Now, neither of those analyses are complete yet. I believe I told the Waterford Subcommittee the status of Combustion as I had known it at that time -- EG&G is doing the calculation. They had calculated to the point where the level had dropped into the upper plenum. At that point they extrapolated out the inventory loss and calculated that by turning on auxiliary spray at essentially time equals zero it bought you somewhere a little bit beyond 20 minutes additional time, 30 to an hour. They weren't sure because it was an extrapolation.

The question they were asked was, if I let it go and continue the calculation such that the level continued to drop to below the hot legs, then would the pressurizer drain, would steam now exit into the pressurizer and out the valve, and would the auxiliary spray become effective in producing a depressurization to below the HPI shutoff head, which is somewhere from around 1300 pounds, such that one could pump in some additional inventory until you raise the level back above the hot leg and stop the steam flow to the pressurizer, and then you would get a repressurization and you would lose inventory again.

It would be a cyclic type of phenomenon, but it may stave off core uncovery until you could get some feeiwater systems back.

MR. EBERSOLE: What's the pressure of the aux spray system?

MR. SHERON: It comes off the charging system and therefore it's usually around -- well above the safety valve set point, because the charging systems can pump against the safety valves.

As I have found out I guess a couple of days ago in just talking with EG&G people over the phone, they had started a calculation with RELAB-4, Mod. 7, and they extended it, and the pressurizer did not drain. There was a countercurrent flow limit. They told me, though, they were having a little bit of trouble believing it, because of the modeling in RELAB-4, Mod. 7.

I don't know the details of why. All I know is they were planning on going to RELAB-5 to see if they could get a better handle on whether the pressurizer drained or not. That's the status of those calculations.

There is a question of whether the pressurizer will or will not drain. We don't have any further information.

MR. ETHERINGTON: Why does it have to drain?

MR. SHERON: In order for the auxiliary spray to be effective, it has to condense steam, and in order to condense steam you've got to get water out of the pressurizer.

MR. ETHERINGTON: Get the water out of the pressurizer?

MR. SHERON: Yes. The spray is at the top of the pressurizer.

MR. ETHERINGTON: But it's only half full to begin with.

MR. SHERON: No. When you lose feedwater, you loss all feedwater.

I made some cartoons here and they may be more confusing than informative.

(Slide.)

MR. WARD: I think we've been crying out for cartcons all morning.

MR. SHERON: All right. That's about the best I could do.

At the initiation of an event, you can see the primary system is water solid here except the pressurizer has a level, and it's the steam space. The secondary side of the generator is full, as well as the primary side.

(Slide.)

I don't have any exact times here, but the first thing that happens is that you reject decay heat by boiling off the remaining inventory in the secondary side of the generator. Once you boil off the inventory, you have lost your secondary heat sink. What happens is the primary coolant starts to heat up. As the coolant heats up, it expands. During its expansion process, what happens is it pushes water out of the soft spot in the system, which in this case is the steam space in the pressurizer.

So you would have initial rejection of the steam in the steam space until the water expanded to fill the primary system solid. Once that happens, you now start pushing water out of whatever relief device you're going to assume is up there, be it a PORV that's working properly or a safety valve. And you're going to reject water.

(Slide.)

The next thing that happens is that as the primary system continues to heat up, but its pressure is held at the safety valve set point, it will continue to heat up until it saturates. At that time you will get boiling in the core in the hottest point and steam bubbles, because this is saturated, they are not going to condense, will rise up.

And now this is where one can get into

speculation on how good the models are. There may be branch flow where bubbles get dragged into the hot legs, but for this purpose let's assume that the bubbles rise up and they will collect in the top of the vessel, the high point. As they collect there, they displace water.

That water is being pushed out of the vessel and up into the pressurizer. So you continue to displace water through the valves up here.

MR. WARD: Are the recirc pumps on now?

MR. SHERON: No, I'm assuming they're tripped.

MR. WARD: Okay. So as bubbles get dragged out the side path, that's because of the flow --

MR. SHERON: Only because there is a flow path here, and I think the question of branch flow -- two-phased branch flow that our Office of Research has been studying.

(Slide.)

Once the level in the vessel pushes down and displaces enough water such that you start to uncover hot legs -- and you've got to remember there are other loops around here. In the Westinghouse plant there may be three others you don't see that may have a pressurizer.

What's going to happen is the steam will now be able to travel along the top of the hot legs and it's going to seek the high points, and for the loops that don't have a pressurizer it's going to go into the generator and displace water at the top of the generators. So this is the generator drain period.

For the loop that has the pressurizer, it will travel along the top of the hot legs until it finds the pressurizer surge line and travel up through it, and you will start to get probably a two-phased discharge at this point coming out of the relief device.

MR. EBERSOLE: Won't there initially be some condensation with extremely severe chugging as the water -- I mean, as the steam enters the subcooled water?

MR. SHERON: If the water up here is subcooled, yes, there will be some condensation initially until it's saturated out.

MR. EBERSOLE: And won't that be cyclic?

MR. SHERON: Eventually the whole system will saturate.

MR. EBERSOLE: It's the interim stage --

MR. SHERON: If there's any subcooled water, the steam bubbles would probably condense prior to exiting as steam.

(Slide.)

Now, I have put on here Option A. Once the level drops down and your generators have drained, the question is now, steam will exit up into the pressurizer. This is the only relief path for steam. In this picture what I have shown is that I have an aux spray which is now effective, because I have assumed that the water in the pressurizer has drained back into the loop, and now if I have a pressurizer full of steam with no water in it, because the water has drained out, the spray is effective in condensing steam.

And so one might hope that I could drop the pressure down far enough to get my HPI system back on and pump a little bit of water in the system, which would raise this level up until I have basically shut off the flow path right here. Once I have shut off the flow path, steam generated in the core cannot find its way into the pressurizer. So system pressure will go up, the HPI pumps will shut off, and now I get back into where I was about so many seconds ago, and I just repeat the process.

MR. CATTON: What will that cold water do to the pressurizer?

MR. SHERON: It depends on the plant. Yesterday Combustion told us that the pressurizer auxiliary spray nozzles have a thermal sleeve. This is

Combustion plants and it may just be CESSAR. I don't know about the older plants, like Calvert. As I understand, they are designed for a number of cycles with hitting it with cold water because of the thermal sleeve. I'm not sure that Westinghouse plants have that thermal sleeve. So there may be a thermal stress problem on some plants.

MR. ETHERINGTON: If you put the aux spray on right at the beginning, then you wouldn't go through all of this.

MR. SHERON: Yes, you would.

MR. ETHERINGTON: Why?

MR. SHERON: If you look at the -- let me go back.

(Slide.)

Initially when the pressurizer was at time zero, when the pressurizer was half full of steam, it would be effective. It condensed the steam and dropped the pressure down probably further than it would normally drop due to the shrinkage.

MR. ETHERINGTON: You wouldn't go through all of these cycles.

MR. SHERON: Yes, you would, because after your generator dried out the primary system would expand, and once it expands it pushes the steam out of the pressurizer by displacement, okay, just by expansion of the coolant due to the heat-up.

And when a pressurizer goes liquid-solid, the spray is no longer effective because there is no steam to condense any more.

MR. ETHERINGTON: But you have already depressurized, haven't you?

MR. SHERON: No. The auxiliary spray would not have the capability to depressurize all the way down.

MR. ETHERINGTON: I see.

MR. WARD: What sort of mass flow is there compared to the numbers --

MR. SHERON: I know the charging system typically is about 100 gpm, so one might assume it's in that ballpark. I think there are ways you can divert flow from the charging to split it to go to charging and the auxiliary spray. At St. Lucie that's exactly what happened. They diverted -- they were initially splitting the flow between the charging and the cold leg and the auxiliary spray, and when the operator diverted it all to the auxiliary spray to depressurize he got a bubble in the upper head, because he depressurized way too fast.

So you can put all the charging flow through the auxiliary spray.

(Slide.)

The second option is where the pressurizer will not drain. You hold the water up in there. In this case the steam flow -- if you calculate the steaming rate of the core and if you know the diameter of the surge line, you can calculate the velocity of the steam that would probably be entering the surge line.

And if you use the appropriate countercurrent flow type of correlations, you can determine whether liquid will or will not flow back down that pipe. One of the complications is that right at this point most vendors have a baffle arrangement here, and I'm really not too sure how that affects countercurrent flow-type correlations. Some have a screen, some have a plate cross here. So this is one of the questions that we have.

MR. CATTON: I think that would make it a little more sure to hang up.

MR. SHERON: It very well might. So I guess the next question is, what does that mean. Well, if you're pushing steam through this liquid here, one question would be, does it carry -- do you entrain liquid drops and carry it out the valve, which means that you would be going through a boiloff period and this level would continue to drop.

And the other question is, do you drop all the way into the core and do some damage before you eventually sweep out enough water out of this pressurizer so that the spray can become effective and start condensing a sufficient amount of steam to drop the pressure? This is the question we're at right now. This is what Idaho is looking at.

When they did their initial calculation the pressurizer did not drain. And so right now the best we can say is, aux spray buys you maybe 30 or 35 minutes if they turn it on at T equals zero.

MR. DAVIS: On option A, it sems to that rather than depressurizing when you turn that spray on, all you're going to do is flash a lot more of the liquid that's in the system and steam will rush into the pressurizer, holding liquid into the pressurizer that cc · from the spray and its condensation.

MR. SHERON: That may very well be. Notice I have said one would hope that the auxiliary spray might drop the pressure down to a point to get safety injection. We don't know.

MR. DAVIS: I got the impression --

MR. SHERON: No, it's not. I think we have reached a point where once you start to uncover the hot legs we have a big question mark as to exactly where the event progresses.

One other point I wanted to bring to your attention, for what it's worth, is that LOFT did run a test. L9-1/L3-3 was a combination test, and what they were trying to do was they lost feedwater in the steam generator. The generator did go essentially dry. They sat there and let the PORV cycle at its set pressure, and I do believe it's probably the same set pressure as Zion because LOFT is scaled to the Zion plant.

And at time later on -- and I don't know the exact times because I didn't bring the curves -- they latched up on the PORV as they said -- and I defer to Dr. Ebersole on what latching means, but they used the word "latched up" in the PORV -- and let the pressure come riding on down.

And what they did then is after they reached bulk saturation in the primary system and the pressure all of a sudden started to hang up due to bulk boiling and steam generation, what they did is close the PORV and reinitiated feedwater to the generator and re-established natural circulation.

So while this test does not conclude that feed and bleed indeed works, what I think we learned is, number one, that PORVs when they are open do indeed drop the pressure rather rapidly. We saw that in LOFT. I think if one looks at Ginna you can see that the pressure drops very rapidly when a PORV stays open.

Research has told me that if they had the ECC systems valved-out in this test that were very specific to this test, they told me if the ECC systems were valved in they would have come on. In other words, opening the PORV would have dropped the pressure to below the shut-off head of the ECCS high pressure pump. And they showed if you fill the generator, natural circulation picks right up again. The pressure just took a nosedive, they said, once they put water back in that generator.

And as a side note, McPherson told me they hit the generator with cold water and nothing shattered.

And this is the report, this is the quick-look report that was issued on the test, if you're interested in seeing further comparisons.

(Slide.)

The last slide I had was, as I said, just to give you the benefit of some stuff we have picked up about feed and bleed. One, I think, is that operability of PORVs is not a given. We have not performed a plant specific review, but indications are that operability with the capability of an operator to open or close whatever PORV is very plant specific in some respects. Some examples, Calvert Cliffs has PORVs.

My understanding is on the control board they have a switch for the PORV that says either close or automatic. It doesn't say open. We asked how one opens the PORVs in Calvert Cliffs, and I was told the operator goes behind the panel, opens the door and pulls out two control modules, and the PORVs go flying open. So that's one where you just don't tell an operator open the PORV.

MR. WARD: In the automatic mode is the set pressure adjustable in some way?

MR. SHERON: As I understand, there is an adjustable set pressure, because for this type of plant they would use the PORV for the L-TOP system. So one may say that yes, an operator could dial down the set pressure and therefore let it go open. We did not examine that. But from the standpoint of telling the operator is there a switch on the board that says open or close, no, there is not one that says open, as we understand it.

At Ginna we looked into that a little bit, and what we found is their PORVs are air-operated. They actuate off the instrument air system, and I think there is a backup nitrogen supply to them.

But what happens is when you get an ECCS actuation, the instrument air is isolated. And in order to restore instrument air you have to reset your safety injection signal.

MR. EBERSOLE: Isn't that a catch-22 situation then?

MR. SHERON: No. We thought about that. Of course, the next thing that would happen would be that if you reset SI and opened your PORV and produced a high containment pressure signal, it would reactuate ECCS, and therefore, you would isolate the air and close your valve.

We understand once SI is reset that an another ECC signal will not cause a re-isolation. So once they do the initial reset on safety injection, then the valve can be operated.

MR. EBERSOLE: And you can operate high pressure injection.

MR. SHERON: Yes. My understanding is there is an override in there somewhere. If they did not want to restore instrument air, they could override the isolation signal and I think use the accumulator on it. But, again, it's the type of thing that's unique to the plant. The operator has to know what he's doing in order to get this.

Other areas -- one which Dr. Jensen did not specifically point out -- is that on the Type 2 feed and bleed where one has to open a PORV and depressurize to get safety injection on, it assumes the operator takes action at a certain time to open the PORVs. You don't just wait and decide gee, I will open it.

The Combustion calculation, although which was conservative -- I think they used 1.2 ANS and the like -- but their assumption was that the operator opened both PORVs within ten minutes after a loss of all feedwater. And for that calculation they showed the clad temperature reached 2040 degrees.

So here's the question now that if an operator is faced after losing all feedwater to open my PORVs in a short period of time and blow down the plant and lord knows what else, trash up containment, or should I be more optimistic and hope that I will restore feedwater in say thirty minutes to an hour, which is when they could restore it, and still not do any damage.

So an operator is kind of faced with a question right away do I blow down the plant, do I try to go into feed and bleed and mess up containment. I'm going to be out for months maybe. Or should I wait, should I say I'm going to get my feedwater systems back on. And if they wait beyond the necessary period, then what is it a matter of? Is it all for naught? Should I not try feed and bleed because I know I'm going to uncover the core? There's a lot of questions that have to be asked.

MR. EBERSOLE: Isn't the basic reason is it was never conceived in the first place that you would have to invoke just the primary system for heat removal? You always have the secondary system, and therefore, there was no steam suppression system provided.

MR. SHERON: Correct. PORVs were initially included in plants -- I think you will hear more from Combustion this afternoon.

MR. EBERSOLE: If the exhaust from the primary loop could be fed into the dump tank to some place where it could be repressed, then that would not invoke a mess-up of the containment. It would be suppressed and condensed.

MR. SHERON: I always used to think I'd put a heat exchanger in there and pump it back to the primary system. I'd have a high pressure or HR system then.

MR. EBERSOLE: Right. So the reason he's caught in that box is it is not conceived that there would be any fallibility of the secondary circuit, but we find out that there is a degree of it which is not considered acceptable.

MR. SHERON: I wouldn't go so far yet to say that it's found unacceptable. I think, though, you'll find that PORVs were installed originally to protect challenges to the safety valves. And now we are looking at them -- and I agree with Mr. Epler's comment -- as we look at feed and bleed it's a last ditch.

MR. EBERSOLE: It's a poor last ditch.

MR. SHERON: But when you're faced with that, you use that.

MR. EBERSOLE: A parachute with a hole in it is better than none at all.

(Laughter.)

MR. WARD: Are there any other questions or pithy comments?

(Laughter.)

MR. ETHERINGTON: In all of this at some time you're going to have to react with the thermal shock portion of the community, aren't you?

MR. SHERON: Yes. The presentations that were made were just to demonstrate capability. As I pointed out this morning, I think I said in previous meetings we would rather -- I think I'll use the Westinghouse terminology which they used. They presented the capability of Sequoyah to feed and bleed to the Sequoyah subcommittee I think about a year and a half ago, and their conclusion was that if you're going to feed and bleed -- they used the term bleed and feed versus feed and bleed. Bleed and feed means open the PORV, get the pressure down. If you're going to do it, do it at low pressure. Don't fool around up at 2,500 pounds.

And I think we subscribe to that, and we are trying to make sure that the emergency operator guidelines -- the inadequate core cooling part where one would invoke this last ditch feed and bleed is done at low pressure rather than at high pressure, just to stay away from that very concern you have of pressurized thermal shock.

MR. WARD: Okay. Thank you.

Let's break for lunch until ten minutes to 2:00.

(Whereupon, at 12:50 p.m., the meeting was recessed for lunch, to be reconvened at 1:50 p.m., the same day.)

AFTERNOON SESSION

(1:50 p.m.)

MR. WARD: Let's reconvene.

Our first speaker this afternoon is, I believe, Mr. Rowsome.

MR. ROWSOME: My infinite infamous memorandum of January 29th of this year was a response to a request from the Division of Licensing. They asked for our views on the desirability of adding PORVs or feed-and-bleed capability for the CE System 80 standard plant application.

The request was made on very, very short notice. They wanted an answer as soon as possible. We were not aware at the time that the final design approval was referenced in pending OL applications and that the issue was one on the near-term OL docket.

In any case, the recommendations we made there were overstated. We did wish to respond to the query from DL to provide a recommendation on whether PORVs were worth adding or not, but by the same token, the one day, quick, back-of-the-envelope scoping did not warrant a positive recommendation for a ratchet. At most it would warrant further consideration and more careful study. Therefore, I feel I owe an apology to those utilities who do have CE plants, to CE itself, to NRR and to you gentlemen of the ACRS for overstating the recommendations.

With a couple of minor exceptions we continue to believe that the analysis to the memorandum is basically correct, although it is incomplete and characterized by very broad uncertainties.

It was our intention in assessing uncertainties on at least one of the classes of sequences we looked at to put on subjective uncertainties that reflected our judgment of what the possible correct answer would be; that is, something inside the bounds would not surprise us, something else in the bounds would surprise us. In that sense they are subjective basian, if you will, uncertainty bounds.

The clearest case of an outright mistake in that memorandum is part of the memorandum that so far as I know no one has read. It's at the very tail-end and is an evaluation of the economic incentive associated with avoiding a very high head HPI design whose spurious actuation could lift the safety valve and blow a pressurizer quench tank rupture disc.

That analysis failed to distinguish the fraction of such spurious ECC actuations that would be arrested by operators turning off the pumps before the pressure quench tank rupture disc would blow. We would judge something in the range of one in three to one in ten would blow the quench tank, based largely on B&W experience. Therefore, the economic incentive in that calculation is exaggerated by about three to ten. In other words, the present worth of expected loss is somewhere between $5 and $15 million associated with the very small spills originating in spurious ECC actuation.

Another error in the memorandum was that of the evaluation for the benefit of PORV addition or feed-and-bleed addition and the loss of offsite power sequences. No accounting was made of the finite unavailability of the PORV itself, which limits slightly the benefit that would accrue to adding PORV, although it does not affect the controlling subsequences, and so it is a second order effect on the answer. It doesn't change the answer very much.

As I get into talking about the individual sequences I will correct a couple of other features we now think are not quite right.

The analysis looked at simple loss of main feedwater, loss of offsite power, very small LOCA, the attendant risk of stuck-open PORV LOCAs if PORVs were installed, and looked at the reduction in economic losses, projected losses associated with adding a feed-and-bleed capability.

The analysis results suggested that for the simple loss of main feedwater -- I should say all losses of main feedwater not associated with loss of offsite power -- we concluded that the core melt frequency might be fairly high in the first year of service, which is characterized by higher than normal frequency of interruptions in main feedwater and higher than mature case frequency failures in the auxiliary feedwater system.

We do not have a good data base or good statistics on that, but our judgment is reflected in the numbers in the memorandum which suggest that for the first core the frequency of core melt due to loss of all main feedwater, main and auxiliary feedwater might be in the range of a little over 10^{-2} per year to 10^{-5} per year with a best estimate of 10^{-3} during the first core where those break-in problems or debugging problems are still going on.

At maturity the range is equally broad but a good deal lower, from a little over 2×10^{-4} to 4×10^{-7}, somewhere in that band. The central estimate was about 10^{-5} for loss of all feedwater.

I might say in this context that both CE in their memorandum to NRR or their letter to NRR responding to, among other things, my memo and some preliminary calculations by DST have second-guessed those numbers by multiplying the historical frequency of interruptions of all feedwater with the auxiliary feedwater system reliability numbers, or unavailability numbers, to be more accurate, obtained from the fault tree analyses of auxiliary feedwater systems that are now required in the licensing process.

I think that is a legitimate way to get a lower bound on the frequency of core melt from this class of accident. But I think it is worthy of note that there are several classes of contributors to that core melt frequency that such an analysis does not consider, and we were attempting in our judgmental call in this memorandum to consider those. They include the following.

First, the fault tree analyses of auxiliary feedwater typically use what we believe to be industry average frequencies for equipment failures, for pump failures, valve failures and the like. We know that actual industry experience is not well represented by these averages in the sense that each pump has a failure frequency closely represented by the industry average. We know there are a lot of pumps out there that are very much worse than the industry average and a lot that are very much better than the industry average.

And as a result, in an actual plant one might come into the system reliability very much higher or very much lower than one predicts with that fault tree analysis.

Another problem with the fault tree analysis is that such methods routinely ignore design adequacy problems and do not consider finite test efficiency; that is, blind spots in surveillance testing through which faults might remain undetected and unrepaired and accumulate significant probability before a genuine demand reveals their presence and solicits repair.

Another class of limitations has to do with the fact that the standard aux feedwater fault tree analysis consider only one of the common cause failures, potential common cause failure mechanisms which would link the occurrence of the loss of main feedwater with the occurrence of the failure in the mitigating system, and that is AC power.

AC power is specifically looked at in those fault tree analyses, but faults in instrument air, service water, fires, floods, all those other contributors to that class of sequences are not pulled out, as a result multiplying a frequency of loss of main feedwater, but those fault tree numbers get you at best a lower bound and not a good central estimate.

In light of the fact that several industry risk assessments are showing that fires and seismic are among the dominant contributors to risk, it seems ill-advised to take an analysis that ignores those terms as a good realistic estimate for that class of sequences.

In the second class of sequences, those involving loss of offsite power, we found the numbers to be quite low and quite acceptable provided that each of the diesel generators in these plants were capable of energizing a motor-driven auxiliary feedwater pump. Both NRR and CE assure me that is the case. So that issue is a non-problem in the plants that are up for licensing.

MR. WARD: Frank, that is indeed the case at Palo Verde, for example.

MR. ROWSOME: That's what I'm told. I gather it's somewhat of a Rube Goldberg system in which the operators manually patch into a diesel generator power supply for the non-safety grade auxiliary feedwater pump, but it can be done, and I gather it can be done from the control room. So that given the time available it's probably deserving of reasonable credit.

MR. EBERSOLE: When they patch in the aux feedwater pump don't they perhaps patch in many other things concurrently?

MR. ROWSOME: I don't know.

MR. EBERSOLE: Do they patch in a switchboard to a diesel that's normally not patched in?

MR. ROWSOME: As I understand it, they are rigging up from the startup of the feedwater pump, which is what I believe it to be, a not normally nor automatically energized path to an essential switch gear bus energized by a diesel generator. I doubt they can wire in much more that way, although the wrong breaker alignment might of course get you power all over the place. But I presume they've dealt with that. I haven't reviewed that item, but both NRR and CE tell me that's been dealt with and is okay; and I haven't pursued the matter further.

MR. DAVIS: On a couple of plants that I'm aware of the diesel generators are already loaded to capacity with safety equipment loads, and I wonder if they were actually sized to handle this additional load and whether or not that might cause some problems.

MR. ROWSOME: I haven't looked at it in this particular context, but I doubt it because you don't need those very power-thirsty low head ECCS pumps in this scenario; so it would surprise me if the diesels were heavily loaded for loss of offsite power, though they might be for an ECCS event.

Third, we looked at very small break LOCA. DL had suggested to us a concern that these plants in requiring auxiliary feedwater as well as high head safety injection to mitigate the very small in the LOCA spectrum might be perhaps on thin ice in reliability space and would we look at that, too.

We did look at it, and our conclusion was that aux feed reliability is not controlling but that HPI reliability might well be controlling and might well be inadequate. We based that on the small break LOCA frequency emerging in recent experience which does have a wearout trend -- there does seem to be a ramping-up frequency of occurrence -- together with the HPI high pressure injection reliability numbers, broadened in our uncertainty judgment, obtained from a number of risk assessments -- none of them, incidentally on CE plants -- and came to the conclusion that S2D, this very small break LOCA, accompanied by failure of high pressure safety injection, might have a frequency of occurrence between 2×10^{-3} and about 1×10^{-5}, again using our judgmental uncertainties to reflect what range would surprise us versus what would not.

CE has suggested that their plants may have higher reliability HPI by virtue of their dedicated role. Unlike the B&W plants they do not also serve as charging pumps, and that may well be something reasonable that's deserving of concern.

Another point made by DSI is that on the very small end of the break spectrum, the charging pumps really do provide a way of replenishing the reactor coolant; and therefore, when it's talking about a spectrum of break sizes, that ought not to include many of the historical events where the break flow was very small indeed. And that perhaps when aiming at that window where you really need HPI pumps, and neither charging pumps on the small end of the spectrum nor the low head pumps on the high end of the spectrum can cut it for you, you're talking about a smaller frequency of events in that window than the number we chose, and that, too, may be a legitimate argument.

In any case, our assessment indicated that providing a feed-and-bleed capability was not necessary to mitigate the small break LOCAs, that the dependence on auxiliary feedwater here did not appear to be limiting, and if it were limiting, it would already be a low enough frequency of occurrence not to warrant a backfit or a ratchet, even in a forward-fit mode.

Third, we looked at the attendant risk of increased frequency of small LOCAs if a PORV were added -- both the transient-induced LOCA and a spurious opening of an unblocked PORV -- and concluded that the latter was a sensitive function of the reliability of the control object of the valve. But it was quite plausible to suppose -- and in fact, the industry average experience has been that that frequency is low enough that having a PORV would increment only negligibly the frequency with which small LOCAs would occur.

We did a value determination in the spirit of the executive order 12291 which calls for a comprehensive evaluation of the societal benefits versus the societal cost associated with major rulemakings and regulatory action, and it is clearly not mandated by the Commission's safety goal, but is mandated by the executive order and is mandated by the CRGR to take a look at the cost-benefit.

We also looked at the value associated with the improvement by adding PORVs as a way of second-guessing the criterion of 10^{-4} per year in the safety goal, to try to identify in a back-of-the-envelope way whether ratchets that brought you in or under 10^{-4} per year would in fact have a value warranting such backfits as a way of exploring the cost effectiveness of compliance with the safety goal.

The way we did this it is quite clear that the kinds of accident sequences in which having a depressurization in feed-and-bleed capability could make the difference between core melt and no core melt or ones in which you have AC power available to operate the high head pumps, so they are not likely to be those sequences in which you have common cause failures of the containment heat removal systems.

So they are likely to be among the class of comparatively well-contained core melts in large, dry PWRs. Therefore, it is rather unlikely that even at fairly high frequencies of occurrence such accident sequences would push the safety goal in the health effect related terms a tenth of a percent background on accidental background or a tenth of a percent background on latent cancer.

It's also unlikely that effects would be warranted on the basis of $1,000 a man-rem, because again, too, the accident sequences which are at the margin tend to be relatively well-contained. The big term that is acted upon is the damage to the plant, the TMI-like cost associated with core damage. And so the people whose interest is really affected by saving these plants are the utilities themselves and their insurers. Damage to the plant, the replacement power, the capital investment down the drain, the site cleanup -- those terms.

We guestimated the cost of a severe core damage or well-contained core melt to produce something on the order $10 million cost could be a decade high or low. An equivalent present worth factor levelized to ten years of exposure and a frequency of occurrence at one in 10,000 reactor years implies that if we were to improve upon that by a design change such as the addition of PORVs so that the core melt frequency dropped a whole decade, that would be worth on the order or $10 million.

If you started at 10^{-3} per year and dropped that by a decade, that would be worth $90 million or $100 million, in that range. If you started at 10^{-5} and dropped that a decade, it would be worth about $900,000. So that 10^{-4} per year criterion in the safety goal seems to be cost effective if you can get there for cost in the neighborhood of millions or at most tens of millions and probably not cost effective for this type of accident sequence if the fix is much more expensive than that.

We made no cost determinations in the paper, though in the clarified recommendations I'd like to give you now it seems pretty clear to me that there is no way you could critical-path the startup of a plant now approaching an operating license and make such a change for anything like $10 million, which is roughly the value we came up with. Therefore, on economic grounds we do not recommend conditioning and OL for any plant in the pipeline in making this fix. There are no deterministic requirements now on the books that mandate installing PORVs that we know of.

And finally, the Commission's safety goal is not now a requirement. It is not now even necessary or sufficient. If it were, we would like to see the fix mandated by the public health and safety terms in that, but one might possibly see it driven by the 10^{-4} per year core melt number. That's an ambiguous call on the basis of our findings.

So we would recommend that PORVs not be made a licensing requirement for plants now in the pipeline; that, however, the issue should be studied more thoroughly and considered possibly for future applications in the standard -- future applications referencing the System 80 considered, not made mandatory without further consideration. And that the issue should be further considered in severe accident space.

Let me mention before I sit down several dimensions other than decay heat removal where a depressurization capability looks as though it might help reduce risk. These are subjects which were not mentioned in the infamous memorandum but are subjects for the severe accident rulemaking, subjects to be considered in the research program to underpin standards development for the severe accident rule.

In addition to the decay heat removal function associated with loss of all feedwater in liberating the small LOCA mitigation requirement for secondary heat sink, a depressurization capability to enable in sequences like station blackout TMLM' in which there is no replenishment of either primary or secondary coolant, depressurization to enable the accumulators, the ECCS accumulators to discharge could buy a great deal of time, over an hour, to restore AC power before the point of no return was reached.

In interfacing system LOCA in Event V, which is classically envisioned as failure of a pressure boundary which exposes the RHR heat exchanges and a lot of plumbing in the auxiliary building to full reactor pressure, the LOCA takes place in the auxiliary building, and the reactor coolant system blows down.

ECCS may fail in a direction associated with the break, but it will surely fail in recirculation if it has not failed in injection, because there is no way to close the loop and go into recirculation. The break is in the auxiliary building. There, inability to depressurize would not save the core but would buy time. It would reduce the break flow and buy a little more time for evacuation, or in the case of a small break where you had a good deal of time to begin with, might even buy you enough time to start topping off the borated water supply and perhaps carry on with once-through cooling a good deal longer.

In anticipated transients without scram additional pressure relief capacity would reduce the hazards associated with the pressure excursion. In pressurized vessel thermal shock the depressurization capability could be useful, perhaps particularly useful with an automatic actuation lodging that precludes repressurization under cold conditions.

In pressurized vessel melt-through a depressurization might be useful to avoid sudden energetic pressure vessel failure attendant missiles, possibly to limit particulate formation. We do not know at this point what effect explosive decompression of molten core does to the formation of particulates or the source term in the containment atmosphere. It might make an appreciable difference to be able to gradually depressurize the molten fuel rather than have it suddenly depressurize from safety valve set point pressures.

It may be also useful to have a depressurization capability to avoid the energetic dispersal of core debris which might threaten the containment heat removal system particulates in the fan coolers or particulates in the sump.

In steam generator tube rupture, which as near as we can make out from our preliminary reviews is of more than cosmetic concern only in the event that you fail-open a steam valve to the atmosphere on the steam generator, thus producing an interfacing system LOCA.

It would be useful to have a rapid depressurization capability to avoid that interfacing system LOCA character.

And finally, ninth, the recent experimental results coming out of Sandia on steam explosions associated with the dump of molten core in the water are suggesting that in the large scale one has large efficiencies in the range of three to five percent, perhaps conversion of thermal energy to explosive energy associated with the explosion.

This is not enough to make a reality out of the WASH-1400 containment failure mode, ALPHA, in which the steam explosion blows the lid off the reactor vessel, and that in turn holds the containment. On the other hand, it is high enough to produce a very nasty pressure excursion in reactor coolant systems which could very possibly threaten steam generator tubes or other weak spots in the pressure boundary.

The steam generator tubes seem to be of particular concern, because that would provide a containment bypass in communication with the molten core, if it were to take place, and change the risk profile for those plants that we think of otherwise as being well equipped to bottle up core melt accidents. So those are some of the considerations we are investigating in the context of the severe accident rule.

MR. CATTON: Have you read the Zion report?

MR. ROWSOME: Yes, parts of it, not all of it.

MR. CATTON: If they didn't have the melt-through taking place under pressure, it would reall· change the whole risk study.

MR. ROWSOME: They assume that the in-core instrumentation tubes will fail and the core extrudes in a well-behaved fashion.

MR. CATTON: But then they need the pressure to drive it out of the cavity to wind up with benign circumstances at the end of all of that. Are you suggesting here that they depressurize before vessel melt-through?

MR. ROWSOME: What I'm suggesting here is not answers, but questions that need further investigation.

One can imagine that either in that plant or others -- and I think their argument is plausible -- that their in-core instrument tubes are likely to go. You are likely to get coriam spaghetti coming out of the failed tubes.

But imagine a circumstance in which the vessel is under water, you are melting a core and have a puddle of core in the bottom of the vessel, and you get freeze plugs in the in-core instrument tubes, but there is enough of a heat sink on the outside of the vessel that molten core beginning to extrude out of the in-core instrument tubes solidifies and plugs it up. So the whole thing fails coherently.

The forces associated with a large sudden failure of the vessel are astronomical and could produce very nasty missiles, very plausibly holding containment under those circumstances, particularly when you have the inertial confinement of the blowdown.

MR. CATTON: The only reason I mention that is that with all of our in-depth knowledge of these kind of events, I would sure hope that we wouldn't do anything with respect to PORV's that would have anything to do with a Class 9 accident. We really don't know what's going on one way or the other.

I just mentioned Zion because it was kind of opposed to what you were saying, to bring it up but not get into any kind of discussion.

MR. ROWSOME: That's why that belongs in the arena of severe accident research, rather than in the arena of ratchet.

MR. CATTON: It's science fiction.

MR. ZUDANS: You mentioned something that I would like you to clarify. Having a PORV would increase only negligibly the small break LOCA frequency, isn't that true, based on experience that exists in plants?

MR. ROWSOME: Yes, that is true. That is caveated, of course, on having anticipatory trips, so that unlike the B&W experience before TMI you do not routinely lift the PORV. But if you lift it no more often than CE and Westinghouse plants do and B&W plants have since they have debugged their anticipatory trip system, then one chance in 100 of sticking open and one chance in 100 that the operators will not promptly close the black valve provides a truly negligible enhancement to a frequency of small break LOCA's that's already running in excess of 10^{-2} per year.

MR. ZUDANS: And in many of these, the way you state it as useful to the pressurizer in many of those cases, what role does the time element play? How fast do you have to depressurize, for example, when a steam generator tube breaks? Would you have any benefit?

MR. ROWSOME: It's very scenario-specific. If you go through the list of the nine severe accident concerns I mentioned, you will get it at the circumstances in which you use it and the size you need and the control logic, if any, you need, are all very different.

I don't mean to suggest that there's one design basis that envelopes all those things or that you would want one design basis to envelope all those things. The costs associated and the considerations and attendant risks associated with extending the performance envelope for your depressurization system to envelop all those concerns need to be investigated thoroughly.

It's not at all obvious what the answer will be. In the case of the steam generator tube rupture, it's really a non-problem beyond the cosmetic, beyond the nuisance value of spilling a little reactor coolant and its associated activity, a little gap activity. It's only a problem in risk space if you were running an appreciable chance of running out of water. You have to not only provide the containment bypass that the steam generator tube rupture provides for you, but also lose the core, lose core coolant.

I think the window for that in frequency space is fairly small, but not necessarily negligibly small. If you have a medium-sized break, if it's not just one tube, it is let us say several tubes, and you do stick a valve so that you cannot pressurize the affected steam generator, you have to bring the plant to cold, cold shutdown, more than cold shutdown, before you run out of borated water with which to replenish the break flow and boil down in the core.

What you have going for you in the way of break pressure is the gravity head between the core and where those steam valves release to the atmosphere, 100 feet of water gauge, perhaps. So that to arrest the break flow you have to bring that down to just a few degrees over 212 F. in temperature and bring the pressure down to just a few psi over atmospheri

It doesn't matter how quickly you do that, except that you have to do this with great confidence before you run out of water to replenish the break flow, and so one gets involved in trying to assess scenarios in which operator error or confusion or attendant fault distracts the operator and allows him to run low on borated water inventory before he's been able to permanently arrest this flow.

MR. ZUDANS: One more on that list. You had depressurization would buy time if you had Event V.

MR. ROWSOME: We don't know that it will be a large break.

MR. ZUDANS: If it fills the secondary system -- I see. What you're saying is --

MR. ROWSOME: It may be a large break, a small break, or a very small break. It may buy you nothing, it may buy you something, depending on where you are in the break spectrum.

MR. ZUDANS: If you had a real depressurization system such as AWS, certainly that would be different than this little PORV.

MR. ROWSOME: In the severe accident circumstance here, we are not limiting our consideration simply to a little PORV. Obviously, a lot of the functions I've suggested there would not be well met by a little PORV, you're quite right.

MR. CATTON: In your infamous memo, you indicated a core melt probability of 10^{-3}. Now that you've redone it, what would you change that number to or is it, as you said, essentially the same?

MR. ROWSOME: Well, I think what I ought to say is that, given the uncertainties in what we have done, it could be anywhere from a good deal higher than that to a great deal lower than that. We do not believe there is enough specificity in that answer that a best estimate is meaningful enough to warrant ratchets on the basis of that information alone.

MR. CATTON: When I read your memo, I put that 10^{-3} as kind of a best estimate based on the time you had to do it. What would that number be now with the same qualifications?

MR. ROWSOME: I think in the first core. That isn't my best estimate today.

MR. ZUDANS: Do you plan to re-issue this infamous report, which has become famous at this time?

MR. ROWSOME: No.

MR. CATTON: He's trying to forget it.

MR. DAVIS: I got the impression from reading it that if the diesel generators were each connectable to an aux feed motor that there would be a substantial improvement in the numbers. Did I read that number wrong?

MR. ROWSOME: There would be a substantial improvement in the class of accident sequences involving loss of offsite power and induced loss of main feedwater, and that in fact is the case, because I understand in the plant licensing pipeline that has been done.

MR. DAVIS: But it wouldn't change your 10^{-3}

number, is that right?

MR. ROWSOME: That's separately tagged out on the little value part in the back of the memorandum. That does take some of the incentive away from the PORV addition. If you had a plant that did not have that feature already, it would make it much less important to add that feature. But given that it's there already, we're in a situation -- let me see if I can find that memorandum.

We are not starting with base case for the plants at issue. We are starting down here. They already have base case with diesel generators aligned to both auxiliary feedwater motor-driven pumps. So this appears to be what Palo Verde, for example, or San Onofre 2 and 3 looks like today, to the best of my understanding.

And therefore, I believe, with very broad uncertainties that aside from all those severe accident concerns that we have all agreed need a lot more research and information before you can nail them down one way or the other. But from what we know today the only group whose interest drives this is the utility in protecting its investment.

Possibly the 10^{-4} criterion, if that were the requirement, which it is not, and in my best estimate the value in economic risk reduction to the utility of adding the PORV then would be the $10 million indicated, but with very broad uncertainties.

MR. ZUDANS: You have a number there. I can't find it. What was the frequency of losing all feedwater and yet having the electric power available from diesel or offsite power?

MR. ROWSOME: Our number was .1 per year. DSI has looked at it -- DST has looked at it and looked at it rather more carefully than we did and came up with .03 per year. That is once in about 33 reactor years.

It's worth pointing out in that context that many of those occurrences have been associated with failures of feedwater valves, instrument error fault, or something of that kind.

Let me make one thing clear here, that we are talking not about non-interruptions or brief interruptions of main feedwater, but the subset which is a small fraction which are irrecoverable in a period of a half an hour or an hour. In that small subset, the ones that are not restorable within half an hour or an hour must involve failed-closed valves in the system. Some entail loss of condenser vacuum and inability to close the loop, and in that subset involving closed valves the condensate pumps would not serve as a backup, would not serve as an alternative, because of the failed closed valves in the system, unless a path around the control valves and isolation valves were provided.

CE has suggested that they can use these condensate pumps in depressurization of the steam generators to enable the reduced head of the condensate pump to provide a flow, and that is fine for those events in which the fault is not in the flow path. But if the fault is in the flow path, that is not a viable alternative.

MR. WARD: Any other questions?

(No response.)

MR. WARD: Okay, thank you.

Okay. We will go ahead with the next item.

MR. ISRAEL: I am with the Reliability Risk Assessment Branch in NRR.

After Frank had written his memo, I was asked to look at the situation in terms of whether we should be supporting putting feed and bleed on, and my review was very narrow. I only looked at simple loss of main feedwater events. I did not look at other potential situations where PORV's or feed and bleed capability may be beneficial.

What I'm going to present here is my simple analysis of what we did and say where we reached our conclusions. We looked at two different types of main feedwater events, what I will call a non-loss of offsite power -- that's simply one where the main feedwater system goes out, and we have a frequency here of .1 per reactor year. That frequency is based on my review of the loss of coolant feedwater events that were presented in NUREG-0611 and 0635 for Westinghouse and Combustion plants. Those reports were issued after Three Mile Island, discussing the small breaks and feedwater, et cetera.

What .1 per reactor year represents are those situations that I estimated would result in total loss of main feedwater. This number does not include loss of one train of feedwater, it doe not include perturbations in the feedwater system, it does not include loss of pressure, suction pressure because of heater drain situations.

These seem to boil down to events that were loss of lube oil to the main feedwater pumps, loss of steam to the feedwater pumps, the main feedwater pumps, electrical disturbances in the plant that somehow knocked out the main feedwater system, loss of condensate pumps. I think those are the four, and they boil down to about .ˆ per reactor year. But that was for events I said were immediately obvious to me where you could recover feedwater.

However, I said, look, Wash-1400 talked about recovery for extended loss of main feedwater of .03 per reactor year. They arrived at it a little different way, and that represents potentially a restoration of main feedwater like .3 per demand. Obviously, even some of those demands I have included up here, such as loss of lube oil, electrical disturbance, it's not immediately obvious that some of those could be recovered.

In addition to which, most of these plants have condensate pumps or condensate boost pumps which will pull out 400 or 600 psi. These are electrically driven pumps that will provide suction to the main feedwater pumps, which are steam-driven. And after discussions with Combustion yesterday, it only reconfirmed my concept that the steam dump valves and the steam generators are of sufficient size so that it is potentially plausible to depressurize a steam generator down to the 400 or 600 psi range and utilize the electric condensate pumps to put water into the steam generator.

So combining these two, I'm coming up with extended loss of main feedwater of about .03 per reactor year, which is the same as what was used in WASH-1400, though I arrived at it slightly differently.

The event I am considering is the loss of offsite power. The Electrical Branch did a survey I guess about a year ago, and they have a value of about .27 per reactor year for loss of offsite power. There is work going on in Research on station blackout. There was information received from Oak Ridge sort of compiling restoration -- compiling many things, but one of the items was restoration of offsite power.

And integrating that information, I would estimate that you could get about .3, the probability of not recovering offsite power in this one and a half hour time period which may be critical. So that combining these two items with loss of offsite power initiation and restoration, we get about .08.

So combined non-loss of offsite power and the loss of offsite power, we have a factor of about .1 per reactor year on extended loss of main feedwater.

The next thing we talked to was the auxiliary feedwater reliability. The staff had a problem about a year ago. We had gone through and done these auxiliary feedwater reliability studies on all of the plants. You're probably familiar with the graphs that show that three-train systems had very good reliability, two-train systems had poor reliability

And the question arose, what kind of reliability should we be requiring for the plants, especially the ones who are going through the OL review stage. Well, in WASH-1400 the frequency of core melts related to loss of main feedwater on the order of about 6 times 10^{-6}, which is comparable to core melt frequencies for other events, small LOCA's, et cetera. And the auxiliary feedwater reliability that was determined in WASH-1400, it was about 3 times 10^{-5}.

So that the standard review plan was changed, I guess last summer. I believe I said, look, all of these near-term OL's are required to perform auxiliary feedwater reliability studies, again in the range of 10^{-4} or 10^{-5}.

It's important to note, I think, that what we're talking about is a three-train system that is also diverse. It has two electric pumps and a turbine-driven pump, at least for the CE plants that we're dealing with.

There was some question originally about one of the electric-driven pumps being a non-safety-grade, not being originally connected to emergency power. But that issue has been squared away.

In these auxiliary feedwater studies that were done early on on the Westinghouse and CE plants, most of the difficulty arose in the suction line, where you may have had only one suction line or you may have had a passive isolation valve or a check valve, and it was passive failure of that valve that could degrade reliability of this three-train system. So people have gone to two suction lines to reduce that.

Another big contributor is misalignment of the system during test and maintenance. Operators may have isolated part of the system. And in the study there were certain requirements in terms of human error probabilities related to whether procedures required isolating the system and whether there was a realignment check.

So basically we're talking in terms of auxiliary feedwater reliability of 10^{-4}, 10^{-5}. And as Frank pointed out, these are simple systems reliability analyses and do not include a total plant analysis. We'll get to that in a minute.

MR. CATTON: Do they include common mode failures?

MR. ISRAEL: Common mode failures were looked at in the studies to see if there are significant common modes.

MR. CATTON: Could you give some examples of the common modes they looked at? Maybe I should ask CE when they get up.

MR. ISRAEL: I can't off the top of my head.

MR. EBERSOLE: Didn't WASH-1400 ignore the interdependencies between the -- didn't they ignore the interdependencies between the AC systems?

MR. ISRAEL: That's correct. But in the plants that we are dealing with now that interdependency is checked for. I'm thinking other than hardwire interdependencies, and here again they looked at DC power supplies to the various trains and AC power supplies.

I'm not sure to the extent they may have looked at common manufacture or location and things like that.

MR. CATTON: I'm thinking of things like component cooling water filters coming apart.

MR. ISRAEL: No, they did not look at support systems or ventilation in these types of analysis.

MR. CATTON: Without looking at those things, those numbers you have up there are really suspicious.

MR. EBERSOLE: They didn't look at ventilation?

MR. ISRAEL: No.

MR. DAVIS: Do you recall what you used for the demand failure rate for the turbine-driven pump?

MR. ISRAEL: The demand failure rate used in the analysis for the turbine-driven pump is 10^{-3}. However, they do a separate analysis on the steam emission valve and that essentially drives up the failure rate for the system probably to around 10^{-2} or something.

They just looked at the pump itself as having a failure rate of 10^{-3}. However, you had a steam emission problem to drive the pump and that added probably about 10^{-2} or something like that.

MR. DAVIS: The overall demand rate was 10^{-2}.

MR. ISRAEL: Right.

MR. WARD: I think Mr. Ebersole had a question that Mr. Rowsome was answering.

MR. ROWSOME: The question on WASH-1400 was the extent to which, as I understand the question, the implicit dependence on AC power through the batteries and battery chargers affected the reliability of the auxiliary feedwater system. It turns out that in Surry the turbine-driven auxiliary feedwater pump failed on on loss of offsite power.

So the deplenishment of the batteries will not fail auxiliary feedwater, although there is of course a finite success window. You can't go on cooling with the turbine-driven pump forever, so that you do need AC restoration ultimately. But that did not appear to be a contributor then, although in our current station blackout studies it does appear to be an important contributor to worry about how long you can go without AC power.

The other question of support system dependencies in both WASH-1400 and in the auxiliary feedwater system fault trees, the licensing-required fault tree analysis, explicit functional dependence on AC power through such media as service water auxiliary cooling is considered, lube oil cooling and the like. But other common cause failure mechanisms associated with auxiliary systems, DC power, room coolers and the like, are not considered.

MR. EBERSOLE: But aren't they necessary?

MR. ROWSOME: To get a comprehensive answer to the frequency of core melt through loss of all feedwater, yes, they would be necessary.

MR. EBERSOLE: Then we're dealing with partial answers.

MR. ROWSOME: That's right, and that was my point in asserting that that kind of calculation merely gives you a lower bound.

MR. EBERSOLE: Thank you.

(Slide.)

MR. ISRAEL: Combining the numbers that we discussed on the first page of the first slide, we come up with a core melt frequency due to the simple loss of main feedwater of 10^{-5} to 10^{-6}. As I mentioned earlier, the number in WASH-1400 for similar types of events is 6 times 10^{-6}.

True, we didn't look at external events, but I think I have to put this in context. Looking at this in terms of whether or not one would require feed and bleed because of some imagined or projected high frequency of core melt due to loss of main feedwater, certainly external events is a common mode that would not only affect the auxiliary feedwater system, but any other mode of cooling that you may be contemplating.

In particular, much of what I have seen, much of the problem with external events, is it will take out electrical systems. So that would indeed compromise using HPCI for a substitute of auxiliary feedwater or to take out auxiliary building walls, which would fail all the piping in the containment, which would also compromise potential use of feed and bleed as a backup to auxiliary feedwater.

We mentioned that -- I think the common modes of interest here are the common modes that would fail both the main feedwater and the auxiliary feedwater system, those linkages, and of course that has not been looked at in this analysis. I am less concerned about the common modes that deal with room cooling and overall electrical stability in the plant, because here again it may also affect the potential for feed and bleed.

MR. CATTON: Aren't there common mode failures of other types, like the one I suggested? Or isn't that considered a common mode failure? There's an example in a particular plant where the filter that was in the component cooling line just gave way, and it fed three pumps and all three pumps were put out. That's common mode.

MR. ISRAEL: Right.

MR. CATTON: There are a couple of other examples like that. There are enough of them that you get a lot bigger number than you've got here. Yet I never hear that mentioned as common mode. All I hear is electrical.

MR. ISRAEL: Yes. Obviously, those have to be found, and to whatever extent they are looked for or hunted for in these auxiliary feedwater studies, they are picked up. In one of the plants they have startup strainers in the auxiliary feedwater lines. Obviously when they have to shake down the plant they want to pick up whatever debris they have in the system, and the startup strainers have to be removed before they go into operation. And there is a potential area for common mode.

MR. CATTON: I recall at TMI they didn't know whether they had taken them out yet.

MR. ZUDANS: Could you demonstrate with those numbers from the previous slide how you got the top line?

MR. ISRAEL: Well, as I mentioned, if we added up the initiating events, both loss of offsite power and non-loss of offsite power, they came to about .1 per reactor year. Multiplying the initiating event by the restoration value, that gives about .1 per reactor year.

We are talking about aux feedwater reliabilities of --

MR. ZUDANS: That's reliability per demand. But how do you relate it to reactor year?

MR. ISRAEL: That's the initiating event I gave you. That gives me .1 per reactor year times a given event is the probability that the system won't work.

MR. ZUDANS: Okay.

MR. ISRAEL: Basically, our conclusion was, notwithstanding the large uncertainties in these analyses, obviously one of the range of values -- and as Frank pointed out, in all the studies the systems are biased low because of unknown and incomplete missed events.

Notwithstanding that, the results are within the range of WASH-1400, and we feel on that basis that there is no need for requiring feed and bleed solely on the fact that we're concerned about loss of main feedwater events. However, that does require that on these plants that we are evaluating, that there is some verification of the auxiliary feedwater reliability.

Also, our study indicated that it's very important to have a procedure for restoring main feedwater. Main feedwater is a very important aspect of mitigating these events.

Let me give you a simple example. We tripped the plant about ten times a year, and on CE plants and Westinghouse plants you need main feedwater to provide decay heat removal, and at 10^{-4} and 10^{-5} that gives you 10^{-3} to 10^{-4} potential events, which you don't have auxiliary feedwater but you still need to provide decay heat removal.

So even on those simple plant trips you're still relying on main feedwater as a backup to auxiliary feedwater for decay heat removal. Obviously, in some of these other events the restoration of main feedwater may be more complicated. But we feel there should be procedures available so that the operator can in fact implement main feedwater in the event the auxiliary feedwater is just not available.

MR. WARD: Do you know anything about the status of procedures for restoring main feedwater out there in the plants?

MR. ISRAEL: Procedures have been reviewed in two areas. One is inadequate core cooling. That was initiated I guess two or three years ago, after Three Mile Island. And obviously, you must have a heat sink. If the auxiliary feedwater system isn't working, you go to the main feedwater.

I think the problem of definitive procedure guidelines, which was also initiated after Three Mile Island -- in this program, we said, look, never mind our traditional licensing posture; if we had a single failure, consider more than a single failure, what kind of procedures would you give -- information do you want to give to the operators, so if they see multiple failures they can cope with it?

Because it may be a cope-able situation. It may not be hopeless. But at least they should be tuned into it. I have not reviewed that, but I am sure that restoration of main feedwater must be part of that also.

I'm sorry. There's a voice in the back.

There's no voice in the back.

(Laughter.)

The operators are familiar with handling main feedwater. It's a manual process. At these low heat levels the automatic system doesn't work very well, at least at Westinghouse and CE. Somebody correct me if I'm wrong. It's different than B&W. B&W does rely on its main feedwater for these low power levels, and they may have control systems and valving.

But at least at Westinghouse and CE, they have to bring the plant up manually to about 15 percent power, manually controlling the main feedwater. And so at least they have had experience on whatever the dynamics are on that particular plant.

MR. WARD: Are there any questions for Mr. Israel?

(No response.)

MR. WARD: Thank you.

MR. LOBELL: I am with the NRR Branch.

I would just like to make a couple of comments in regards to the auxiliary feedwater system reliability studies that we were talking about a second ago. I'd like to point out that, even though some of these things that we discussed just now, the AC dependency, heating and ventilation and lube oil and cooling, may not be included in all reliability studies, it's something that is addressed in our other criteria when we do a review, what I guess you call a deterministic review.

We don't approve a system design that does not have the supporting systems powered by emergency power or cooling systems available under all conditions, or an auxiliary feedwater system that at least one train can't be operated AC-independent. So while the reliability studies may not cover all of those things, those factors are still considered in the review of a system before it's given final approval.

MR. WARD: Thank you.

Any other comments or questions?

MR. ZUDANS: I think the idea was to find out what effect that would have on the number that was given to us.

MR. ISRAEL: It was a very detailed study on the Palo Verde auxiliary feedwater system on common cause failures. So just because I wasn't able to present to you exactly what it was, there was a significant effort. At least it was reported in the study. My recollection was that they identified something like 25 potential common modes and then they went through each one and esentially dismissed them in terms of relevance to the quantification process.

MR. CATTON: How was this done? If you're looking for things like that, I would think you would search through some utility's files just to find out what kind of things have happened in the past and try to construct from that the various kinds of common mode failures and then maybe pick the ones you should address for your plant.

Was that procedure gone through?

MR. ISRAEL: I think that was the process. They did go through LER's and the open literature, too.

MR. CATTON: What about the closed literature? You guys get these things.

MR. ISRAEL: What we get is the open literature. The closed stuff the utilities have themselves.

MR. CATTON: But you do, too. NRC is part of this international consortium. And the particular common mode failure I keep mentioning is the three pumps were out because the filters had come loose. Is that one of the common mode failures that was considered in CE's analysis?

MR. ISRAEL: As I mentioned, they have strainers on the auxiliary feedwater.

MR. CATTON: These were filters that were in there in part of the operating system.

MR. ISRAEL: That presumably would show up in the PNID and that should show up to the reviewer.

MR. CATTON: I understand it should be obvious. I'm asking, was it.

MR. ISRAEL: The first question is, was there one in the system. I don't know that.

MR. THADANI: If I may make a comment, I believe you're asking the wrong guy. The person who reviewed the aux feed system is not here.

MR. CATTON: Okay.

MR. WARD: Do you want to get an answer to that?

MR. CATTON: I guess I would like to see CE's study that Mr. Israel is referring to, and then I can come to my own conclusions. I guess I would like an answer to that question, too.

MR. EBERSOLE: I remember a case where that kind of system would -- that system would not be subject to the same failure mode. It would be diverse in character, and if you had a common mode failure of all the strainers, the main feed system would certainly not be the --

MR. CATTON: They would have separate component cooling water systems in each one of the strainers?

MR. EBERSOLE: That's not necessarily true.

MR. CATTON: This was component cooling, and the filter let loose and the pieces plugged up all the small holes, and they were out, all three.

MR. EBERSOLE: That's a general service system.

By the way, what cooled the turbine-driven aux feed pump room and steam chases in Palo Verde? What kept the ambients down? Is it an AC-driven power system?

MR. GOODWIN: No one here knows the answer.

MR. EBERSOLE: Do you know how they protected against a steam supply failure at Palo Verde? Didn't they have temperature trips for the main steam isolation valve to the main turbine-driven pump? And wouldn't they be subject to high ambient as a secondary effect?

MR. THADANI: We don't have the right people with us to answer those kinds of questions.

MR. EBERSOLE: Okay.

MR. WARD: Yes, Pete?

MR. DAVIS: Just a quick one. I noticed in

Dr. Olsen's memo there was a statement which said that the NRC precursor study suggests that the failure probability of auxiliary feedwater is 10^{-3} per demand, which is quite a bit worse than the numbers we have just seen. I'm wondering why that number isn't used as being a little better basis than the reliability studies that were done conventionally with fault trees and so forth. Is it not a good number, or is it not based on good data? Just what is the situation there?

MR. ISRAEL: 10^{-4} and 10^{-5} that I gave you is what I will characterize as a central estimate, and that's what we consider for an average or typical auxiliary feedwater system. I'm not familiar with the 10^{-3} you're referring to, unless it came out of Frank's memo. I'll let Frank talk to that. That's just for the first year, I believe, that Frank was talking to.

MR. THADANI: If I may clarify that, that estimate comes from the precursor report wherein they had -- I forget the number of events listed. We did take a look at those events and our judgment was that the estimate of 10^{-3} unreliability of the aux feedwater system was awfully conservative.

They had treated those failures as if they were complete failures. No consideration was given to changes that had been implemented since the TMI-2 event. And one example talked about earlier was the question of strainers. I cannot remember all the eight or nine events that were listed there, but some of the events were not total loss of aux feed.

My own judgment is that that is an awfully conservative estimate, and I don't think it should be used without a much more careful assessment of the data.

MR. ROWSOME: I will go along with that and try to clarify a little more. The precursor study screened, among other things, LER citations which clearly indicated to the reviewers that an entire engineered safety feature redundant system was failed, all of its divisions were failed.

That screening has proven to be incomplete. They missed some. We know of at least three instances of entire failures of auxiliary feedwater systems which did not make the screen. They did credit restoration or feasibility of restoration in some of the historical events in coming up with their system unavailability on demand figure, though it can be argued they may have done so with a heavy dose of conservatism.

Some of the instances of whole system failure are of the kind that would be inapplicable to the designs that are out there. The failure mechanisms in several instances, as Mr. Thadani pointed out, were plugged strainers, and if they were properly removed or cleaned after the startup that would not be a problem. So that the numbers can be read many different ways.

Also, if we do succeed in getting a complete listing of instances in which entire auxiliary feedwater systems have been at least momentarily disabled, we can expect a wide range of reliability from both time to time in individual plants and from plant to plant, because of system differences. So that to use one number to characterize the whole industry would be a very shaky thing to do though it does seem that the ballpark figure that 10^{-3} per demand is the grand industry average for both surveillance tests and demand, and genuine demand challenges of auxiliary feedwater systems. When you count in the failures we know about that were not in the precursor study, but give a little bit more liberal credit for repair, one stays in the 10^{-3} range for the industry average experienced to date.

MR. WARD: Anything else?

MR. ISRAEL: Maybe I should read off some of the events that came out of the precursor study.

MR. WARD: Okay.

MR. ISRAEL: Essentially, there were eight events that dealt with loss of auxiliary feedwater. One of them was the failure of pumps to start, failure to install fuses. This event should be totally recoverable because the operator can manually initiate the auxiliary feedwater system. The only thing that was failed was the auto start process, and in all of these plants the operator is trained to make sure he has a heat sink, make sure he's got feedwater going into the steam generator. They have little measuring devices that give the operator that information, rather than just watching a level on the steam generator.

Two of the events were clogged strainers, as just mentioned. Two of the events were failures of the controllers in plants that only had turbine-driven feedwater pumps. The plants we're dealing with here are plants that have diverse pumps. They have electric and turbine-driven. So you wouldn't expect that common mode failure in control. This is basically problems with the steam emission valves in the turbine-driven pumps.

One of the failures was a failure of turbine-driven pumps to start, plus open bypass valves. This is a problem. When they test the auxiliary feedwater system they have a bypass line to get full flow recirculation back to the condensate storage tank.

Since Three Mile Island we have required that redundant checking be done to make sure these valves are restored, and while the test is going on if it's a local valve someone is supposed to stand by in case the auxiliary feedwater is required to close the valve locally. I'm not sure if this particular problem pertains to the CE plants.

One of the problems was the Rancho Seco event, where you had one power supply feeding everything in the plant. They gave you all the information, initiated auxiliary feedwater, et cetera. This seemed to be one of the failings of the B&W plants. Actions have been taken since Crystal River to require that you have redundant instrumentation, so that the operator knows what his conditions are in his plant after shutdown, even with failure in a single power supply. And I don't think this is applicable to the CE plants.

The last one, of course, is the Three Mile Island event, where they had all the valves closed on the auxiliary feedwater system. Here again, this was recoverable at Three Mile Island within eight minutes. Here again, the operators were trained as one of their immediate duties to make sure they have water going into the steam generators. They have flow indication devices to help them.

So we feel that all of these events that were identified in the precursor system, we would have different recovery factors on, and some of these don't apply at all to the CE plants, and therefore we don't feel that these particular events impact our estimate of 10^{-4}, 10^{-5} for auxiliary feedwater systems with CE plants.

MR. WARD: Sandy, you mentioned that flow meters have been added. Do they exist at all plants now? What's the status of that?

MR. ISRAEL: That was part of the Three Mile Island action plan for all auxiliary feedwater systems.

MR. LOBELL: They don't exist at all plants. They exist at all plants for which we have completed our review in the new plants, but they will when the review of the Three Mile Island action items is finished.

MR. WARD: Thank you.

Any other comments on this subject?

(No response.)

MR. WARD: Okay. Let's take a ten-minute break.

(Recess.)

MR. WARD: Before going on to the next topic, Mr. Lobell tells me he has answers to some of the questions that were asked a few minutes ago about Palo Verde, so if you would go ahead, please.

MR. LOBELL: Let me restate the question and give you the answer. One of the questions was what cools the environment with the loss of AC power. The answer is the applicant has done an analysis that shows that for two hours after loss of forced air cooling, that two hours is sufficient after loss of all forced air cooling.

Like I say, this was done as an analysis, and an actual test will be run for two hours to demonstrate this. Have I made myself clear? The question was --

MR. WARD: No, I didn't quite understand you. The analysis shows that for at least two hours after loss of AC cooling --

MR. LOBELL: Right, it can operate the turbine-driven auxiliary feedwater pump with no forced air.

MR. EBERSOLE: Did that include an investigation that will show -- where the steam chases -- they sometimes have temperature trips on the isolation valves.

MR. LOBELL: This will be done as part of an endurance test. We require a 48-hour endurance test be run on all the auxiliary feedwater pumps, and this will be done as part of that test. So the whole system will be tested in an endurance run or 48 hours and look for things like bearing temperatures, vibration, room conditions, anything related to the operation of the pump.

MR. EBERSOLE: Will you verify -- is there a steam chase in this design? You know, the have to monitor for steam supply line breaks and they usually use temperature to identify a hypothetical break in the steam pipe.

MR. LOBELL: There probably is. I wasn't involved on the review and I just asked the reviewers the specific question that we have before us.

MR. GOODWIN: Ed Goodwin on the staff.

There are no thermal trips on any of the auxiliary feedwater system steam supply lines. We checked that during the plant review several months ago.

MR. EBERSOLE: So what do you do if you don't trip --

MR. GOODWIN: There are no environmental temperature trips.

MR. EBERSOLE: How do you cope with a break in the steam line?

MR. GOODWIN: I don't.

MR. EBERSOLE: Thank you.

MR. LOBELL: The next question addresses that a little. You asked what protection is there against steam supply failure. The auxiliary feedwater pumps -- there are two safety grade feedwater pumps that are in separate compartments, and as part of the review, we asked this question, and the answer is that these are safety grade pumps that are not used for startup or shutdown and as such they are not pressurized except during actual operation.

So the issue was not addressed as to failure of the steam pipe in the room. This follows staff guidance in an SRP and branch positions that go back to 1972. The lines are pressurized less than 2 percent of the time.

MR. EBERSOLE: This is the steam supply lines to the turbine-driven pump.

MR. LOBELL: Right. The isolation line is outside the compartment.

MR. ETHERINGTON: Are the pumps fed from either steam generator?

MR. LOBELL: I believe it is usually done that way, but I cannot answer the question specifically for Palo Verde.

MR. ETHERINGTON: In a situation where they had a tube ruptured like in the Ginna accident, would the lines rupture?

MR. LOBELL: In that case you would have the motor driven pump, and I believe the operating procedures would call for a -- if that were the case, if that is the only steam generator he had, the operator would try to use the motor driven pump.

The final question was: In reliability studies for Palo Verde, did we look for common mode failures from filters in the lines? Yes, we did.

MR. CATTON: What did you do with it? What kind of number did you give it?

MR. LOBELL: I believe the only ones there are are filters that are in just for startup, and they will be removed as soon as the testing is done, and our I&E people will do that.

MR. CATTON: Do they require setpoint startup filters? This particular filter that I was interested in that did fail was in the line that led to the bearings of the pump, and I guess it is part of the system, it is not something just for startup.

MR. LOBELL: Yes, that is a different system.

MR. CATTON: That is not common?

MR. LOBELL: I would be guessing. I don't know.

MR. EBERSOLE: We had an interesting figure at Ginna, and suppose I compound it a little bit by saying that such a failure was due to general tube degradation and one of them failed, which always results in turbine trip due to high water in the generator. On the other turbine trip you get a rise to the pressure on the secondary side and carried away a steam generator tube into the other steam generator.

How do you execute cooldown from that point without a PORV?

MR. SHERON: Brian Sheron, Reactor Systems Branch.

Right now the operator -- and I will not say that his instructions are out there at the plant today -- but the upgrade to operator guidelines and procedures will address instructions to an operator for cooling down with either more than one rupture in a single generator or multiple ruptures in multiple generators.

In essence I think that if the ruptures in both generators -- if you have a 2 x 4 plant -- if the ruptures are not large or you are losing a lot of primary coolant through the leak and you can see that you are not losing your inventory very fast, basically you would tell the operator to decide which generator has the smallest leak and cooldown on that, isolate the one with the largest leak, and then cooldown using the one with the smallest leak.

You will continue to leak primary coolant to the secondary. You will continue to blow it if you lose your condenser. You will continue to reject it to the atmosphere. It is a messier event from the standpoint of an offsite release, but you can cool down.

One of the questions which we will be addressing later this afternoon after the Combustion presentation is the question of what if you get massive pipe failures in both generators for some unknown reason where it is essential to pump the RWST drive prior to getting down to RHR cooling? Then what?

MR. EBERSOLE: That is a harder question. Thank you.

MR. WARD: Okay. We had better move on to the next topic. It looks like we are aiming for about 7 o'clock now.

MR. GRIMES: I am the Project Manager for CESSAR and I am going to provide an NRR status report, I believe is the agenda item. I am going to endeavor to try and help the schedule a little bit by cutting a 30 minute presentation down to about 3 minutes.

In December the staff met with the full committee to describe the results of our review of the

Combustion Engineering standard nuclear steam supply system, which is trademarked designated System 80, and at that time we discussed with the committee the open and unresolved issues that the staff was working on.

In its December 15th letter to Chairman Palladino, the ACRS noted that CESSAR does not have the capability for rapid direct pressurization of the primary system and decay heat removal without the use of the steam generators and recommended that the staff give consideration to adding valves to allow direct heat removal.

In response to that, the staff requested that CE provide an assessment of the need for PORV in CE plants for consideration of the issues that the staff had identified in a draft evaluation and in consideration of the PRA work that had been performed. CE will describe the results of that issue in just a moment.

The staff has got that document under review and we are currently developing a request for additional information so that we can complete our evaluation of the request that the ACRS made of us.

As part of that request we will ask CE and the related applications, which are San Onofre and Waterford, the other CE plants currently under review which do not provide PORVs -- we will ask them to provide a basis for proceeding with licensing while we have this matter under review.

I think you got the impression during Dr. Rowsome's presentation and Sandy Israel's presentation that there are some of these questions that might take a while to wrestle with, so we will endeavor to do that as quickly as possible and provide the results of our evaluation in a revision to the SER for CESSAR and supplements to the Safety Evaluation Reports for San Onofre and Waterford.

We will provide some additional comments in terms of the status of our review in our commenting on the CE presentation which will follow their presentation. Other than that, I can only add in terms of CESSAR's status that we are working towards resolution of the open and unresolved issues that were previously presented to the ACRS and that we should have those wrapped up shortly.

Are there any questions? If not, then I will turn the microphone over to --

MR. CATTON: In your CESSAR review -- well, actually, to pursue the question I raised a few minutes ago, is there any way that I can get a schematic or a drawing or something that shows me how the water to the bearings and the pumps gets there, where it comes from, what kind of processes it goes through?

MR. GRIMES: For the auxiliary feedwater pumps?

MR. CATTON: I am more interested in all the pumps, actually. High pressure injection and the feedwater pumps. Where does that water come from, particularly the water that goes to the bearings?

MR. GRIMES: That information can be provided to you, but it will be slightly confusing because not all of that is within the scope of the standard steam supply system. I can work with the project manager for Palo Verde and get that information for you.

MR. CATTON: That would be fine.

MR. GRIMES: All right.

MR. ZUDANS: Do you at least know at this time whether or not the bearing lubrication -- is it an outside supply source?

MR. GRIMES: I do not know that but I can find out.

MR. CATTON: CESSAR is going to specify some requirement like 10^{-4}, 10^{-5} in the auxiliary feedwater system, and if there are systems like this that are outside of their scope, how do you get assurance you are going to meet those requirements?

MR. GRIMES: Endeavor to do as good a job on the review of future plants as we do on this one, and I am sure the issues that have been raised will be reflected in the CESSAR evaluation and will be picked up on reviews of future reference plants.

MR. CATTON: I am not sure I get a lot of comfort from those words.

MR. GRIMES: Other than to incorporate them to into CESSAR scope of supply, all we can do is to highlight those areas of specific concern for the reference plant as interface requirements. That is how we typically deal with issues that pertain to the balance of plant.

MR. GEORGE DAVIS: I am George Davis, Manager of the Standard Plant Licensing Group at Combustion Engineering. We have a set of presentations on System 80 capabilities for rapid depressurization and decay heat removal this afternoon, but prior to beginning, I would like to make one opening remark.

We were requested by the ACRS and the NRC staff to reevaluate the need for depressurization and decay heat removal capability for a System 80; that is, reconsider whether some type of remotely operated valve should be added to the pressurizer.

We did such a review and provided a written response to the staff recently, and if for the moment we disregard the issue of steam generator integrity, we concluded from that review that we saw no significant increase in safety at this point for adding motor operated valves to the pressurizer.

We based that on the existing design leading to all current licensing requirements and all requirements that we felt were appropriate within Combustion, and also on the fact that if something was required beyond the design basis, such as the feed and bleed capability, that we thought secondary depressurization might be proven to be an acceptable alternative.

Providing that response to the staff, they have asked questions concerning the implementation of secondary depressurization and also what the impacts might be of steam generator failures. We intend to work with the staff over the next several months or however long it takes to answer those questions to their satisfaction. The technical presentations are intended today to provide the ACRS Subcommittee with our feeling of the adequacy of the present System 80 design and some information on secondary depressurization capability.

One final point is that one of our presenters was to provide a critique of the PRA that was done by Mr. Rowsome's group. Based on Mr. Rowsome's presentation, I think if it would be agreed by the Subcommittee that the conclusion from the presentation was that no significant increase in plant safety was identified by the PRA for adding PORVs to the System 80 design, and therefore if the Subcommittee wishes, we can delete that presentation from our agenda. We do have the slides in your handout.

MR. WARD: I think that is reasonable. Does anybody have any comment on it?

MR. CATTON: The report indicates a 10^{-3} probability of core melt, and the CE response had a 5×10^{-6} volume. I would just like to see where the difference came from.

MR. WARD: Perhaps you could limit the presentation to an explanation of that.

MR. GEORGE DAVIS: If you would like, yes, we could give a very brief explanation of that item.

MR. WARD: Okay. Just let that come in your sequence.

MR. GEORGE DAVIS: Okay, fine.

With that, I will introduce Rick Turk from our Plant Engineering group.

(Slide)

MR. TURK: My name is Rick Turk from the Plant Engineering group. Essentially the consideration being discussed is, as Mr. Grimes mentioned in the ACRS letter on CESSAR, to give consideration to the potential for adding valve of a size to facilitate rapid depressurization of the System 80 primary coolant system to allow more direct methods of decay heat removal.

As George said, CE at the request of the staff and the ACRS has been giving the matter consideration, really focused at two points, one focus being a generic point -- as was mentioned, both Waterford and San Onofre are also affected by this consideration -- and the second focus being a more specific directed particularly at the CESSAR immediate FDA approval.

With regard to the more generic issue, that of alternate decay heat removal going beyond current licensing or design bases, I think we are in agreement with the staff that it is a many-faceted issue. As Brian Sheron mentioned, the many elements of steam generator tube rupture, pressurized thermal shock, many things come into it.

We have reviewed in a draft form the questions that Chris Grimes alluded to that we will work over the next period of time to try and resolve on a generic basis.

What I want to direct the discussion to today is the second issue or the second point of focus, that is, specifically the CESSAR FDA approval.

(Slide)

The point of contact in that particular review was a copy of the draft supplementary Safety Evaluation Report that the staff provided along with the DRA study that was mentioned a moment ago, and we will just touch briefly on that, as George said. And finally, a point of focus was other alternatives, other contingency methods of potential decay heat removal, which I will discuss at the end.

(Slide)

With respect to the issue of current approval of the System 80 design, we have reached the conclusion that strength in interface requirement on the availability of the auxiliary feedwater system, that the current design adequately protects the health and safety of the public such that we can proceed with licensing of the CESSAR design and resolve the more generic issue on a schedule that will allow us to look at it and all the details thereof.

The bases for our conclusion are essentially the highly reliable emergency feedwater system. A point of clarification here. The emergency feedwater system is not part of the System 80 scope of supply. It is specified by interface requirements as being the addition of just one more interface requirement on that system.

MR. EBERSOLE: Could I ask you: In quantitative terms or deterministic terms, what do you call the highly reliable EFW system?

MR. TURK: In qualitative terms it is essentially a system with three or more pumping sources, at least seismic design Class 1E power supplies, redundant actuation circuitry. I think I have a slide later on that will spell out exactly --

MR. EBERSOLE: Would you call those safety grade?

MR. TURK: Yes, I would.

MR. EBERSOLE: What do you do about Palo Verde?

MR. TURK: Palo Verde, although the design was not originally a safety grade design, the modifications that have been made to the system, which essentially are aimed at this third pump that was available as startup pump, being able to supply it with emergency power supplies we feel meets the intent of those interface requirements, including the one that we intend to add with regard to availability.

MR. EBERSOLE: Is that pump tech spec'ed?

MR. TURK: I think I would have to defer to somebody from Arizona.

MR. EBERSOLE: What is the quality grade of that pump in the context of its original specification on testing or occasional testing on safety grounds?

MR. TURK: I will ask Arizona to correct me if I misstate anything. The upgrade is more than simply just putting electrical power to this pump. It is included in technical specifications and in surveillance testing; is that correct?

MR. WARD: Is it now on the Q list?

MR. TURK: I am not sure I know what that means. For Palo Verde the qualification --

MR. WARD: Was it identified as an item for which there would be a formal QA program in construction?

MR. TURK: I don't have an answer to that. Somebody from Arizona may. No, it is not.

MR. EBERSOLE: Is it in the safety classified environment? Would you protect it from the influence of pipe failures?

MR. TURK: No, there was no physical movement of the pump.

MR. EBERSOLE: Is it out in the turbine building?

MR. TURK: Yes.

MR. EBERSOLE: And it is called seismic?

MR. TURK: I doubt that it is seismic.

MR. EBERSOLE: So it is somewhat less than your standard pattern.

MR. TURK: Yes, that is true.

MR. EBERSOLE: But you endorse it.

MR. TURK: We feel that it meets our interface requirements.

MR. EBERSOLE: Thank you.

MR. WARD: Maybe we do need to hear something more about the PRA. Does this particular pump show up with a greater unavailability?

MR. TURK: CE did not do the PRA on the auxiliary feedwater system. It was done by Bechtel and supplied to the staff for review.

MR. EBERSOLE: Is the availability of this pump any lower than that of the counterpart to the electric pump?

MR. TURK: Using the methodologies, I don't know, but a different failure rate --

MR. EBERSOLE: Is this due to the fact that the methodologies cannot identify the real differences?

MR. TURK: I can't answer that.

MR. LOBELL: Maybe I could try to answer that. First of all, I think you have to keep in mind that the types of event you are talking about, seismic events, floods, tornadoes -- there are two safety grade pumps already that are protected from all those things. What we are really talking about are random failures of eqipment and things that were included in the common mode type things that were identified like the strainers I talked about before that were included in the study. Those are the kinds of things the third pump was put in for, to increase the reliability of the system. Things like seismic events, floods and tornadoes are not part of the reliability analysis for any pumps.

As far as -- well, okay, I guess I stated my point. This pump was just meant to increase the reliability against random failures and other failures that the reviewer had some background information on and could identify and included in the study. But I think you have to keep in mind that there are two safety grade pumps protecting against all these other things.

MR. EBERSOLE: Would you be happy with the two safety grade pumps without the third pump?

MR. TURK: The qualitative interface requirements that existed prior to any addition of this interface could be met with two safety grade pumps. I doubt that a quantitative availability of the range associated with this requirement could be met without crediting a third pump.

MR. EBERSOLE: Thank you.

MR. ZUDANS: May I ask one more point, sir, if I may? The emergency feedwater system that you are talking about here is not CE-supplied?

MR. TURK: That is correct.

MR. ZUDANS: When you say the interface requirement on the availability is specified -- will be specified -- does that include every system and subsystem required to operate this emergency feedwater system?

MR. TURK: I think as I get on, I will show what the actual requirement is, but the requirement is related to the methodologies of NUREG-0635 which, as we stated earlier, looks really only at the auxiliary feedwater system proper.

MR. ZUDANS: The auxiliary feedwater system requires some lubrication system, whether it is the same process or comes from outside. It requires electric power and many such things. And if you talk about availability of emergency feedwater system, you are not talking about that unless you include all those things.

MR. TURK: Or account for them in some way.

MR. ZUDANS: That is right.

MR. TURK: I think as we look at the interface requirements that we have in a qualitative sense, just as the staff pointed out in their review of ancillary type functions, that they are covered from a qualitative point of view if not within the actual numerical answer of the reliability study.

MR. EBERSOLE: Where does this pump exhaust? In the turbine hall?

MR. TURK: The startup pump is a motor-driven pump. The startup feed pump is a motor-driven pump.

MR. EBERSOLE: Thank you.

MR. TURK: The second item -- and I really did intend to go through some of these; in particular, the emergency feedwater system, and this one, the capability to achieve cold shutdown in a little bit more detail. But essentially, there have been significant changes made to the CESSAR design over previous designs directed specifically at the capability to achieve cold shutdown.

Steam generator design features -- again, there have been many changes to the System 80 steam generators aimed at correcting problems that are known within previous steam generator designs.

The fourth, basis for a conclusion regarding CESSAR FDA approval. The modifications do not appear justifiable. This, in essense, was a reference to our comments on the DRA study which we will at least briefly discuss.

(Slide.)

And finally, the bases that Mr. Davis alluded ɔ is that we believe that there is a potential for alternative or contingency decay heat removal capabilities that appear viable, using the steam generators. In other words, we are saying that maybe there is another parachute here, if I can use an earlier analogy.

(Slide.)

The question of whether or not to go with feed and bleed -- as I said, I think we are in some agreement with the staff that it is a many-faceted issue. We do have some feelings regarding possible advantages of not providing feed and bleed.

We feel that even as a contingency, using something else that will allow the reactor pressure coolant boundary to be maintained intact would provide a large advantage. Associated with that, working on the secondary side would enhance equipment accessibility.

Using atmospheric dump valves, emergency feedwater pumps or other feedwater pumps or accessible equipment combined with the release to the containment would also affect accessibility. Use of a feed and bleed system would impede any containment entry that might be necessary to combat a particular casualty.

And additionally, not pursuing a feed and bleed would offer operating and decay heat removal strategies that are essentially consist. In other words, that the heat removal process is being carried out at the steam generator, the pressure control function within the pressurizer, and using the charging system as opposed to putting all those processes -- heat removal and inventory control -- in one process.

But I will restate that.

MR. WARD: Aren't all those advantage really advantages only if there is a proposal to use feed and bleed as an alternative to some other decay heat removal system?

MR. TURK: That is true.

MR. WARD: I have not heard anyone proposing that sort of thing. It has always been talked about just as a last-ditch thing.

MR. TURK: I heard that this morning and I found that encouraging. I am not so sure that I realized that prior to today. I think there had been some talk of feed and bleed as a system, as a means. So you are correct, that is what those comments are really directed at.

(Slide.)

The question of feed and bleed has been intimately related with PORV's. I think it is worthwhile to go through some background on PORV's in the CE designs.

As was mentioned earlier, the PORV design function was only to reduce challenges to the safety valves. CE removed PORV's from our post-1970 designs essentially because we were unable to substantiate any advantages. We found that pressurizer spray in conjunction with a high pressure reactor trip performed the required functions.

There were operational problems associated with PORV's. Essentially, leakage. At least one of our plants was operating with its PORV's isolated. And the fact that they were never credited in the over-pressure protection analyses all led to the decision to remove the valves from the design.

MR. EBERSOLE: Before you move that, what is the most frequent challenge to your safety valves in the primary circuit? What sort of operational history do you anticipate?

MR. TURK: I think the next few slides give an answer to that. It essentially looks at the transients and accidents associated with challenges from really three standpoints: the FSAR analyses, our post-TMI best estimate analyses and our operating experience.

(Slide.)

And briefly, from an FSAR standpoint, the PORV's are not even credited in the FSAR analyses.

(Slide.)

So there are essentially four analyses that result in safey valve operation in the FSAR: loss of vacuum, the feedwater line break, the control element, withdrawal and ejection. Of those, I believe loss of vacuum would be the only one that would be in the anticipated category. Is that correct -- from an FSAR standpoint?

MR. EBERSOLE: That would cause loss of offsite power, also.

MR. TURK: No, this really deals with a loss of vacuum which loses the secondary heat sink without necessarily tripping the reactor for a while. A loss of offsite power would bring the reactor down immediately with a loss of secondary, so that is not a true statement.

MR. EBERSOLE: I see.

(Slide.)

MR. TURK: From a best estimate standpoint, analyses were done following TMI for the purposes of supporting operator guidance development, and these were analyses that tried to predict expected plant behavior based on crediting not only safety systems, but non-safety systems. And the analyses here included the PORV's since we were working with one of our operating plants, pressurizer spray, the steam bypass control system and the reactor trip on turbine trip as it existed in those operating plants, and none of those transients resulted in PORV operation.

(Slide.)

From an operating history standpoint, we have really one good data point here without PORV. Since Arkansas Nuclear 1, Unit 2 is a plant without PORV's, even though they do have the manual valve that was alluded to earlier. We had a high pressure reactor trip or we had a turbine trip at that plant, and essentially the high pressure reactor trip prevented challenge to the safety valve in that instance.

(Slide.)

That occurred in January of 1980 and you can see the transient shown here with the reactor trip setpoint on high pressure, the excursion over the trip setpoint but well below the safety valve setpoint, without PORV.

(Slide.)

So in essence, the System 80 design without PORV's, from a functional standpoint, the design -- the original design base function of PORV's -- it is conducted using pressurizer spray. On System 80 plants we have a reactor cutback system designed to prevent reactor trip on down power maneuvers in the secondary plant and a reactor trip on high pressure.

There is a secondary design basis that was provided to PORV's on operating plants, and it was mentioned earlier. Low temperature, over-pressure protection on System 80 is provided by the shutdown coolant system relief valves essentially, when the shutdown coolant system is aligned and those valves have sufficient capacity for the design base L-top events, what I will call the non-design base functions; functions that have at one time or another been attributed to these valves although they were not necessarily designed for them.

I think that was evident in some of the things said this morning in that, for instance, there is no control switch capability to remotely open the valve.

But it is conceivable in the non-bases functions or the venting of non-condensibles.

The reactor head and pressurizer vent systems being added in the post-TMI environment, RCS depressurization, the auxiliary spray system which I should point out has been the design system for that function with the main spray unavailable on all CE plants, and reactor coolant system heat removal. The auxiliary feedwater system and the safety grade shutdown cooling system in modes 4 and 5. These two are, of course, inherently linked in that you cannot depressurize beyond the saturation temperature of the reactor coolant system.

MR. ZUDANS: I don't seem to be familiar with this shutdown cooling.

MR. TURK: The RHR system?

MR. ZUDANS: No. The shutdown cooling system. Is that in the secondary?

MR. TURK: No, that is in the primary. That is the equivalent of the RHR system. That is our terminology.

MR. ZUDANS: And those relate valves are located where? Before the valve can isolate, or is this a high pressure system?

MR. TURK: No, it is a relatively low pressure system and the relief valves are located on the system side of the isolation valve, on the low pressure side.

MR. ZUDANS: How can you use these?

MR. TURK: It is low pressure protection. In other words, at points below NPT, the pressure limit is now 500 pounds or 400 pounds.

MR. ZUDANS: You are saying this system would not be used without a pressure of its own?

MR. TURK: Correct.

MR. ZUDANS: So it does not --

MR. TURK: We use these reliefs to limit the combined pressures of the shutdown cooling system and the reactor coolant system to less than the shutdown coolant system design pressure.

MR. ZUDANS: Therefore, at a higher pressure these are useless, right?

MR. TURK: They have to be isolated.

MR. EBERSOLE: Isn't it true that on rise to high pressure, the isolation valves close, and when they do these valves here which must be set at 500 pounds or something like that become unavailable for subsequent repressurization?

MR. TURK: That is correct. This is not an answer to pressurized thermal shock transients. This is a requirement for automatic NPT protection.

MR. EBERSOLE: That protection is bypassed by automatic closure of the valves when you go to high pressure, so what are you going to do about the other question of pressure protection?

MR. TURK: This system was also -- if PORV's were used for low temperature over-pressure protection, it was done with a dual setpoint. As the RCS pressure at pressure, that system is realigned to its setpoints, so in essence it is the same question for each, and in a repressurization --

MR. EBERSOLE: Do you contemplate having to put any kind of intermediate pressure relief on your intermediate primary load?

MR. TURK: No.

MR. EBERSOLE: You will stick with the safeties?

MR. TURK: That is correct.

MR. EBERSOLE: Thank you.

(Slide.)

MR. TURK: With background on the PORV's we turn again to the emergency feedwater system. This is the interface requirement that, as we expect, to be requested in the supplementary safety evauation report. We intend to add to CESSAR that the emergency feedwater system shall have an unavailability in the range of

10^{-4} to 10^{-5} per demand, based on an analysis using methods and data presented in NUREG-0611 and 0635, which were the post-TMI auxiliary feedwater reports.

Compensating factors such as other methods of accomplishing safety functions of the emergency feedwater system or other reliable methods for cooling the reactor core may be considered to justify a larger unavailability.

MR. EBERSOLE: Ten to the minus 4 per demand is a fantastic reliability. I am using fantastic in the general context now.

MR. TURK: The number is consistent with the methodologies described here. Obviously -- well maybe not obviously, but we felt it would be very difficult to just place a number without an explanation or at least tying it to a particular methodology. We talked a little bit about these methodologies today. They do focus only on the emerg [illegible] feedwater system. I think they specify failure d[illegible]a that some people might disagree with.

MR. EBERSOLE: Isn't it borderline to automatically excluding common mode failures and considerations?

MR. TURK: I do not know that I can answer that with methodology, but I think in fact 0635 says that they have not included common caused failure.

MR. EBERSOLE: So that number that we are looking at is an imaginary requirement that you have set down, which now the user has to -- either by imagination or other means -- rise up to meet. So we have a convergence based on that rather than on a reality.

MR. TURK: Well, I think reality answers the question, at least to my mind. And the other interface requirements that have already existed on the system in the next two pages in your handout -- and I do not intend to go through these in any degree of detail except to summarize them on the third page -- but these are the interface requirements that have always existed in CESSAR for emergency feedwater systems.

(Slide.)

MR. CATTON: Could I pursue that a moment? It is fine to specify interface requirements between NSSS and the auxiliary feedwater, but who specifies them between auxiliary feedwater and its support systems? Does anybody?

MR. TURK: Its support systems are also other support systems of the NSSS. For instance, the emergency power component cooling water, the ultimate heat sink. So to some extent, we have got other interface requirements, and we went through these I think in quite a bit of detail on the CESSAR docket with the committee on how we specify interface requirements for things like air systems, cooling water systems, electrical systems and I -- it is a valid point.

And there is a degree of reliability then upon the designer of the emergency feedwater system to insure that his complete design including its ancillaries meet the interface requirements.

MR. CATTON: I think, Jesse, we really need to be talking to the person who designed the emergency feedwater system and not CE.

MR. ZUDANS: I have one more question on the same subject. If you will put back your slide on EFWS availability.

(Slide.)

The second sentence in that statement, essentially is qualitative and not as quantitative as the first one. And it would tell me that I could get any number provided I was eloquent enough to explain how I did achieve the objectives in some other way.

MR. EBERSOLE: Eloquence is a good word.

MR. ZUDANS: In other words, it is not quantitative at all. I could use 10^{-2} or 10^{-1} provided I cooked up a good story.

MR. G. DAVIS: I would like to point out that we see adding this interface as a belt and suspenders approach, but we had qualitative interface requirements on the other slide which we feel spell out the specifics of what should be in the auxiliary feedwater system, and this is just another requirement on top of those, and a belt and suspenders combination.

MR. ZUDANS: But there is a great deal of difference between the situation where you say I shall have 10^{-4}, period. And then putting in a whole lot of other comments that really eliminates that number without any specific quantitative allowance. You don't say you could reduce it by an order of magnitude, or increase it by an order of magnitude, if you have such-and-such.

MR. TURK: Okay. Our intent follows that with the compensating factors supplying the -- alternately supplying the function that the net result is still within this numerical range.

MR. ZUDANS: It does not say so there; it says compensating factors such as -- . Maybe you can justify larger unavailability. That is all right, it is not greatly important. What is important is does it really cover the entire system. There is another interface to somebody else, and has anyone ever integrated all these interfaces and come up with a single number for this particular point?

When you walk up to your emergency feedwater system and push the button 10,000 times and only once does it start --

MR. WARD: Wait a minute. I presume that this unavailability defines the emergency feedwater system and includes the analysis of its support systems.

MR. TURK: Only to the extent that the methodology of 0635 does, which admittedly, is not complete. They do address loss of offsite power. They do address some turbine functions, AC independence, but it is not a completely treatment of common-cause failure. And I believe it says that right in front.

Now, taking the case of the question that you asked about whether or not the anlysis that is done has to address the entire plant, or is there such an analysis done, on Palo Verde the analysis done by Bechtel was considerably in excess of the stripped 0635 methodology with, as mentioned earlier, considerable treatment of common-cause interactions.

MR. CATTON: We really should take a look at that.

MR. ZUDANS: Yes, because the number is so small it is hard to believe.

MR. TURK: I believe it is included in the

FSAR. Is that correct? The reliability study is in the FSAR's. I believe it should be available.

MR. CATTON: You are probably right, but I am not sure it is that readily available to us. Could we get the chapter and verse spelled out?

MR. TURK: Appendix 10B to the FSAR.

MR. CATTON: I see Dick wrote it down so we will get it.

MR. EBERSOLE: What is the frequency of the aux feedwater system, the demand frequency? How many times a year?

MR. TURK: Used as a point in this particular methodology? I don't recall. I believe it was mentioned earlier by Sandy Israel.

MR. THADANI: It is our understanding these systems are challenged about ten times per reactor year.

MR. TURK: I believe that assumption was made and the fact that a reactor trip challenges the emergency feedwater system, which is a true statement in that the shrink associated with a reactor trip does give a low level but it does not isolate the main feedwater system. So it is a true statement that the system is challenged, but it is not a true statement that we have a loss of feedwater.

MR. EBERSOLE: Loss of feedwater was -- like one time a year, as I recall.

MR. TURK: Right, I think that is correct.

This slide is intended to be basically a listing of the typical features that result from the interface requirements, certainly subject to the earlier discussion regarding Palo Verde and the third startup pump.

(Slide.)

But in essence, the typical design features on these plants are generally three pumps. They are ASME III Class 3 systems, with the exception of those systems inside containment which are Class II, seismic category 1 systems, electrical class 1-E, automatic actuation and isolation of ruptured steam generators. They contain pump drive and power diversity, both turbine and motor-driven pumps. One train is AC independent, and they have redundancy and separation to meet the branch technical requirements regarding line breaks and subsequent single failures.

MR. ZUDANS: Is this where both motor-driven pumps can be driven from both diesels?

MR. TURK: As a rule, that is not true. Each motor-driven pump is dedicated to a given diesel. Again, we are dealing with systems designed by architect engineers for given plants and not a CE design. But as a rule, each motor-driven pump is initially aligned to one diesel generator, and then separation criteria essentially dictate that.

Any other questions regarding CE's interfacing with the auxiliary feedwater systems?

MR. EBERSOLE: Just a quick comment. Am I right in my arithmetic when I say you will really need the aux feedwater pump about 40 times in the life of the plant?

MR. TURK: Assuming a 40-year and once a year call, I think that appears correct.

MR. EBERSOLE: So it is somewhere like .5 times 10 -- well actually, it is not considerably greater than one in a thousand that you will have a core melt.

MR. TURK: It might be slightly misleading in tht I think, more correctly, there would be a loss of feedwater where the auxiliary feedwater system would be expected to function. It might not be needed in the sense that the loss of main feedwater might have been such that it could have been engaged in a short period of time and could have not really needed the auxiliary feedwater system.

But as far as its design -- John?

MR. HERBST: Excuse me, this is John Herbst, from Combustion Engineering. I believe that the correct number for actual need of the aux feedwater system is closer to .1 per year.

(Slide.)

MR. TURK: I would like to turn now to an integrated look at the overall question of decay heat removal, not just the question of getting the heat out of the steam generators but the other systems that are involved and how that is accomplished in the CESSAR design.

Essentially the functions that need to be accomplished are reactivity control, inventory control, pressure control, RCS heat removal -- in other words, heat removal out of the reactor coolant system -- and core heat removal as heat transfers from the core to the primary fluid.

The systems that we have available in all cases -- really several systems -- both our chemical volume control system and the safety injection system are capable of adding borated water, and therefore are also available for inventory control.

Pressure control is supported by the pressurizer heaters, reactor coolant system spray when the reactor coolant pumps are available, and as we have mentioned earlier, auxiliary spray through the chemical volume control system.

Heat removal from the reactor coolant system through the steam generators using the main steam system and the main feedwater systems as well as the atmospheric dump valves, the emergency feedwater system, and in shutdown conditions -- I think I have shifted abbreviations on you there -- but the shutdown cooling system again.

Core heat removal: besides the reactor coolant system pumps being available for natural circulation, the elevation is designed to support natural circulation.

MR. WARD: Let's see. On those systems over there in the righthand column are all of those safety grade?

MR. TURK: Not all. Let's take a look here a minute. The safety injection system is a safety grade system. The charging portion of the CVCS system is also a safety grade system. The pressurizer heaters are not safety grade in that they are not -- I'm not sure what a safety grade heater would mean, but they are capable of being power supplied from the emergency diesels, or more correctly, a portion of them is capable of being supplied from diesel power.

The main reactor coolant system spray is not safety grade in that it requires reactor coolant pumps for driving head, and the reactor coolant pumps are not a safety grade system.

The aux spray system is a safety grade system. Here the dividing line is essentially at this point. The main steam and main feedwater in general are not safety grade systems. However, the atmospheric dump system, the emergency feedwater system and the shutdown cooling system are in essence safety grade systems. And since the reactor coolant system pressure boundary is in effect a safety grade system, that particular function of circulation could be considered safety grade.

MR. WARD: What about the vessel head vent?

MR. TURK: That is a safety grade system. That is the Palo Verde supplied system on Palo Verde, but that is a safety grade system.

(Slide.)

The next several pages in your handout are one-line diagrams taken from various sources of some of these systems. Unless there are some specific questions, there are just a couple of them that I want to make some points on.

One in particular is the auxiliary spray system or the auxiliary spray portion of the charging system, and that was mentioned to some extent earlier in the day.

The auxiliary spray consists of two redundant valves that are two-inch globe valves, solenoid-opened, controlled from the control room with position indication and each supplied from an independent diesel generator bus.

(Slide.)

They essentially supply water to the pressurizer from the charging system on the downstream side of the regenerative heat exchanger. This would be the normal charging line.

(Slide.)

Any other particular systems?

MR. EBERSOLE: The atmospheric dump valve being safety grade -- that's the first time I've heard of this other than on Palo Verde. What did you do to those to upgrade them to safety grade? The typical configuration is not safety grade.

MR. TURK: That I would disagree with.

MR. EBERSOLE: I'm talking about on all PWRs.

MR. TURK: I believe starting really at the point of -- looking at post-LOCA long-term cooling of 5, 6 or more years ago, most of those valves were upgraded to safety grade status. I know that they are safety grade on San Onofre, Waterford, and in System 80 we require them to be.

There is some difference in their sizing and number. Most notably, the difference in the System 80 design is that we have two of them per steam generator, and they're shown here as being two separate steam lines out of the steam generator into the main steam isolation valves, one atmospheric dump valve, one atmospheric dump valve here.

MR. EBERSOLE: Are they on separate control power trains?

MR. TURK: That's correct. You can see they are supplied with redundant solenoids. This diagram that this was taken off of is a representative diagram that is in CESSAR. There may be plant specific differences on some particular System 80 designs, but the requirements for the atmospheric dump valve system --

(Slide.)

I mentioned before we have interface requirements for other systems obviously than just the emergency feedwater system. Although you don't have a handout, this is the kind of interface requirement that we supply on the atmospheric dump valve related to its heat removal capabilities, its operating control; but it has even manual operator's hand wheels so that it can be achieved. Its size is such and in location that in the event of either a steam line break or a tube rupture or loss of power operation, its personnel access to the operators on the other steam generator is possible.

(Slide.)

But I think it's incorrect to say that other plants were not safety grade.

MR. EBERSOLE: You're talking about Combustion plants.

MR. TURK: That's all I can talk about authoritatively, but I would not be surprised to find other PWR vendors that are safety grade.

MR. EBERSOLE: I doubt that.

MR. TURK: In essence, then, just to kind of summarize, plant depressurization for these plants relies on pressurizer heat removal, RCS heat removal, and degasification. This would provide redundant safety grade auxiliary spray essentially looking at the safety grade capability here.

The engineered safety features are the emergency feedwater, the four atmospheric dump valves and the safety grade reactor head and pressurizer vent system.

(Slide.)

Some idea of capability. Depressurization with auxiliary spray -- there are really two numbers here. The first relates to the entire cooldown to cold shutdown which requires also reactor coolant system cooldown accomplished in approximately two and half hours. A spray down from operating pressure just down to reactor coolant system saturation pressure just by quenching the steam bubble in the pressurizer can be accomplished on the order of ten minutes, possibly even faster if multiple pumps are used, into the auxiliary spray.

The overall cooldown from operating temperature down to shutdown temperature with only one atmospheric dump valve would require a little over four hours, and the design basis for the reactor coolant head and pressurizer vent is that that system can turn over one-half of the RCS volume in standard cubic feet of hydrogen in one hour.

MR. ZUDANS: We saw a number of cartoons Brian showed us with respect to this pressurizer and depressurization with auxiliary sprays and the different stages of it.

That did not relate to you?

MR. TURK: What Brian was saying? No. What Brian was talking about earlier related to potential use of the auxiliary spray and a total loss of feedwater type of situation where the function of RCS heat removal was not taking place.

MR. ZUDANS: I'm looking at your first slide of the two and a half hours.

MR. TURK: No. It has nothing to do with that, an CE really has not done any calculations along the lines of the kind of operation that was being discussed this morning.

MR. ZUDANS: In other words, you might have different regimes there and you might not be able to --

MR. TURK: It was essentially in a very abnormal accident type situation. What I'm discussing here was the way the system was intended to be used, which is that the bubble in the pressurizer -- that is, the controlling pressure in the loop -- the spray is there to spray into the pressurizer bubble, bring the temperature down and bring plant pressure down to the point of saturation, RCS saturation. So this is the normal, if you will, use of the system as opposed to what it was on a very abnormal and somewhat, I think, hypothetical use of the system, certainly not what it was intended for.

MR. ZUDANS: I'm just wondering whether to pursue this or not, because I got the impression from the other presentation that there might be some situations where you could really predict the history of depressurization by use of this auxiliary spray.

MR. TURK: I am not prepared to discuss that. We really haven't spent too much time other than it was suggested actually by Mr. Sheron in some other discussions that we had. We will go back and take a look at it.

MR. ZUDANS: Okay.

(Slide.)

MR. TURK: The essential bottom line with regard to cooldown and depressurization and our conclusion that we feel we should be able to move ahead with approval of the standard System 80 design independent of the issue of decay heat removal in a generic sense is that the design does provide the capability to achieve cold shutdown conditions using only safety grade systems, assuming a loss of offsite power in any additional single failure, essentially the traditional design base as opposed to the more generic question of capabilities beyond those design bases.

(Slide.)

At this point we were going to talk -- originally John was going to make his comments on the DRA study. Maybe he would like to just address the questions that were asked earlier.

MR. HERBST: This is John Herbst.

I would like to address the question that was specifically asked before as to what is the difference between 10^{-3} presented by Mr. Rowsome in his memo and the value that was presented here. To that I would like to say a few things.

Mr. Rowsome based his 10^{-3} number on a first core estimate of his, and that first core estimate was based on two factors: the frequency of loss of main feedwater and the unrealiability of the auxiliary feedwater systems, both of them in the first year.

For the total loss of main feedwater Mr. Rowsome estimated a frequency of .3 per year and a frequency of .1 per year for mature plants. Those numbers can be derived rather easily from an EPRI report on initiating events which gives the frequency of total loss of feedwater per year of commercial operation. And yes, indeed, the number does come out to be .3 per year for the first year. The only problem is that all of the events that occurred in the first year of commercial operation occurred on one specific plant. All of the other plants in the first year of commercial operation did not have a total loss of main feedwater. It seems then inappropriate to place the onus of the first year criterion on all plants when it is extremely plant specific.

I believe that Mr. Israel and Mr. Thadani addressed the appropriateness of the data as far as the auxiliary feedwater system information is concerned, and we support that decision.

We have not taken a very close look at the auxiliary feedwater system performance as a function of commercial operation, but I feel that the differences would be very similar to those that we found in the main feedwater losses.

CE believes that it is inappropriate to use first-year data, but rather it is appropriate to use mature plant data for performance of probabilistic risk assessment calculations, particularly if comparisons are to be made to proposed plant safety guidelines.

The numbers presented in our response to Mr. Rowsome's memo were performed using mature plant data, and we used mature plant data that Mr. Rowsome used. The only modification that we made to any of the scenario information was the auxiliary feedwater system unreliability where we substituted unreliabilities calculated by Bechtel for the Palo Verde plant and submitted the appendix in the FSAR, because that study accurately represented the correct configuration of the auxiliary feedwater system for the plant and is representative of System 80 plants with the other plants at least as reliable as the auxiliary feedwater systems as Palo Verde.

Thank you.

MR. WARD: Questions?

Mr. Zudans.

MR. ZUDANS: Yes, I have a question. I feel a little bit uneasy, not with what you said but with a part of the statement which said that if you want to compare your reliability or probability results with Mr. Rowsome's results to the Commission's safety goal, whatever that number might be, you should not use first-year numbers; you should use mature plant numbers.

That statement functionally is all right but intuitively I feel uneasy because you have opened it to the first year. That means the Commission should give you another set of numbers, one for the first year, one for the second year, one for the third year, and one for the duration of life.

The physical fact is you have to operate it the first year and you have to say whether your risk is acceptable or not for the first year. I don't know that you can make that argument that easily, .4 per year regardlessk. 10^{-4} per reactor year as a safety goal, if it's stated that way, should apply to any year for the life of the plant. There is no average. Average doesn't help you, in my opinion.

How is the staff looking at that? Do you make a distinction between your number one, your number two, your number three? See, in an automobile I have a warranty for the first year. If it breaks down, I go back and they fix it, I hope.

(Laughter.)

MR. WARD: I guess you're looking at the average for four years, and that's pretty close to the average for the last 39. Isn't it as simple as that?

MR. ZUDANS: That's right, except I had to lead to that first year.

MR. WARD: Well, that's right. You have to make the assumption that the risk isn't so big during the first year that it affects the average.

MR. ZUDANS: I have to assume that the risk is so small here that no one has to worry about it, is that the case?

MR. LOBELL: Could I try to answer that? I'm Richard Lobell.

I think -- I hate to characterize the attitude of the whole staff. Let me just give you my opinion, and I'm the one that overlooks these reviews.

The reliability study isn't the be-all and the end-all. It's considered, as Mr. Israel said before, a central tendency or an indication, and it was used in earlier times in reviews of the operating plants as a ranking to try to get an indication of where the problems were in the systems designs for the operating plants, the auxiliary feedwater systems in the operating plants. What were the main contributors in reliability and what needed to be fixed.

And the next step in that was to go out and identify from the actual designs what changes needed to be made based on these studies and based on the standard review plan requirements and make those changes.

So to answer your question, we don't look at first year separately from the other years. We treat this in the sense that it's just an indication of weaknesses in the system's design that should be fixed. And I think in the reviews that I participated in so far that really is its most effective use.

As far as any problems that arise from plants that do not not meet the standard of 10^{-4}, like I said, it's just a simple tendency, and when we identify problems in the LERs or from some other place that auxiliary feedwater systems are not performing up to what we think the expectation should be, then we take actions based on that.

We have our I&E people and people in other branches of NRR look at what has been causing the specific problems and try to work with the licensee to fix those problems. So everything is not done in terms of just the reliability study.

MR. ZUDANS: What you're saying is that you know things are not as -- when the plant is mature, therefore, you simply do more inspections, more of this, more of that. In other words, you make sure that as far as risk to the public is concerned, there is no distincti n between the first year and the second year.

MR. LOBELL: I don't want to mislead you. I think what you're saying is different from what I meant to say. I'm not sure -- I'm pretty sure that we don't do any extra inspections the first year.

We are aware that the auxiliary feedwater system is a piece of machinery. It obeys the same type of behavior that we expect from a piece of machinery when it's first being used. It will have some problems and some bugs that have to be worked out.

What I'm saying is when we see a problem occur more than once or a severe problem, loss of more than one pump or one train, we will investigate that and try to work with the licensee and see what the problem is. I wouldn't say that we do any special investigation of the first year behavior unless some obvious problem shows itself.

MR. TURK: The final point in our considerations that we feel we can move for, that we should be allowed to move ahead with the CESSAR design, looking separately at the issue of the alternate decay heat removal beyond design basis on a generic sense, is this concept that maybe we have got a contingency capability that we can implement easier than we could implement an actual valve and change in the system.

(Slide.)

And this would be a contingency or last ditch, if you will, that would involve depressurizing the steam generators with the atmospheric dump valves to use some sort of surrogate feedwater pump. A condensate pump was mentioned earlier, but it wouldn't necessarily be limited to a condensate pump, conceivably even a fire pump or some other pump in the plant. Arrangements could be made either through connections or spool piece connections or even hose connections. Again, a last ditch, if you will.

Essentially, such a last ditch would have certain attributes that might be attractive in that it does maintain the reactor coolant system intact. It's consistent with the operator's normal decay heat removal procedures. In other words, he's trying to get feedwater back to the steam generators. It doesn't require primary depressurization if that is not necessary.

There is time for operation action. It's not the case, as was mentioned this morning, where a decision has to be made to feed and bleed in a very short time frame. The kinds of equipment we are talking about here generally would be accessible to the operators.

[Slide]

In essence, what we are talking about is setting up the steam generator in essentially an off-design kind of condition where flow through the steam generator would be maintained at some low pressure to remove decay heat.

Again, let me point out that what we are discussing here is conceptual. It s a conceivable last resort, not something that is in place at Palo Verde or an interface requirement for CESSAR. But we have looked at it in a conceptual sense.

This curve represents the atmospheric dump valve area that would be necessary to maintain a given steam generator pressure at a certain time after shutdown which corresponds to a given heat input.

This curve, as time went out, would become less restrictive in that at lower heat rates a lower flow would be necessary to remove decay heat and that flow could be maintained with a lower steam generator pressure.

So what we are saying here is that as the available flow areas increases we can maintain the required decay heat removal flow with a lower steam generator pressure.

As a point of reference, a single atmospheric dump valve in a System 80 plant has about .125 square feet, which would mean that depressurization even below 200 pounds in a generator is conceivable to maintain a decay heat flow. Now, 30 minutes was chosen here essentially to maximize the heat load, not to be representative of any kind of time of application.

MR. RICHARD DAVIS: Question on that.

MR. TURK: This is just a heat balance.

MR. RICHARD DAVIS: It seems to me like if you attempt to do this, you are going to impose substantial stresss on the tubes because you are primary and secondary pressure differential would just about double, will it not? And during the blowdown process you are going to also impose thermal stresses on the tubes and tube sheets. I just wonder if the components can really stand that kind of abuse.

MR. TURK: Those are certainly very good questions that are inherent in this. And we are in the process of looking at it. And I do not mean to imply that we have categorical answers. The tubes are designed for full primary to atmospheric pressure, full 2500-pound design pressure, with regard to putting the cold feedwater into the steam generator. These steam generators, the feedwater enters through a separate nozzle.

[Slide]

This being the main feedwater economizer nozzle whose main purpose is to allow the introduction of cold feedwater. This feedwater is introduced through a top discharge and actually dumps out onto the deck where the moisture separators are located.

[Slide]

So that even under normal circumstances, that cold feedwater is introduced into a steam environment. So the conditions inherently do not appear to be too much different than we see under normal actuation of the emergency feedwater system. I am not representing a conclusive answer here. It is something that we are looking at.

MR. RICHARD DAVIS: Thank you.

MR. ZUDANS: At any rate, it is about a fraction of the rates of full power.

MR. TURK: Correct. I believe these are per generator.

MR. ZUDANS: You are only removing a lot less heat than you would remove in a full-power operation, therfore your flow rates are flow velocities in the steam generator itself on the outside of the tubes are much lower than normal.

MR. TURK: Well, conceivably. The generators could be virtually empty after the depressurization. So it is not really correct to be talking about velocities or recirculation. It is not a well-defined regime within the steam generator.

MR. ZUDANS: Wculd this not mean that cold water drops might impinge on the pipes?

MR. TURK: That is what I was just saying, that the tank room of the generator, that is really the condition they normally enter the steam generator in. It is a point we have to look at, there is no question.

We then did parametrically some transient work using simulation codes to look at transient situations.

[Slide]

We looked at several conceivable pump configurations. These pumps here were not chosen because of any particular availability to the steam generator, they were just chosen because they represented a range of pump characteristics that we thought might be available within the plants:

Things like a condensate pump that is used directly to a feed pump suction, with delivery pressures in the order of 700 pounds and flows of several thousand g.p.m. Similarly, a condensate pump that might be used with a condensate booster pump in a three-pump type of cascade, which would have lower delivery pressures and higher flow rates.

A LPCI pump, not because it presents any availability but it presents a flow characteristic of relatively low head, less than 200 pounds, but a relatively high flow rate, something around or just under 1000 g.p.m.

And then maybe something that might represent a fire pump, less than 100 pounds and flow rates of hundreds of g.p.m.

The next few curves just represent one of those computer simulations. I do not really intend to go through all plant parameters.

[Slide]

I think of interest just the steam generator pressure in this particular case, associated with the depressurization of the generator from 1000 pounds essentially through the dump valve. This particular case was using the very low head, low flow pump, the one that represented effectively a fire pump and a single atmospheric dump valve roughly of the size that is on System 80, essentially, the depressurization and in this particular case, steam generator dryout down to a low pressure -- the next curve of interest then might be --

MR. ETHERINGTON: How does that last cut compared to the speed of cooldown if you have a valve on the pressurizer?

MR. TURK: Actually, in terms of primary cooldown -- and I think if I can just hold off for a minute, I will get to it -- it is actually less because once the generator drys out, the heat is no longer really being removed from the primary.

So the final stage is depressurization. It does not bring the primary down with it. It does not try to drag the entire primary down. But what the emergency feedwater shows here, that at a time out slightly beyond 10 minutes pressure is low enough to start getting delivery from this pump at a flow rate of somewhere a little above 200 gallons per minute.

[Slide]

And then if we look at primary system temperature -- this is one on hot-leg and cold-leg temperatures -- we can see the initial temperature drop associated with the initial depressurization. And the steam generators effectively dry out. So the primary temperature drops stop and actually begin increasing in primary temperature until we get up to a point in time, that point in time actually being beyond the emergency feedwater delivery time where we begin to balance the heat load.

And as you can see in this particular case, we have not quite balanced heat removal with heat input from the core. We still have a very slight temperature gradient, but it certainly is a situation that is far better than a loss of feedwater.

I present this again as a concept that represents another type of last-ditch effort.

MR. CATTON: Is there a lot of activity by the operators to accomplish this?

MR. TURK: Yes. Especially if the pump involved a spool piece connection or breaker line-up of some part. It would definitely be an operator-controlled type of evolution.

I might add that I think my own feeling is that a feed-and-bleed operation, once it gets going, also requires a lot of operator control, or at least a lot of operator attention.

MR. CATTON: I have a feeling that what you are asking to be done here will require more. But that is based on ignorance. You would have to put a rather large unavailability number against this technique, would you not?

MR. TURK: The answer is yes. But please keep in mind that what we are presenting here is just another last-ditch type of --

MR. CATTON: I understand.

MR. TURK: It would be, I think -- we saw this morning that maybe the unavailabilities on some of these feed-and-bleeds might be rather large also.

MR. ZUDANS: You require a steam generator that you can use for this purpose. Right?

MR. TURK: Correct. You are using a steam generator as a heat sink. The steam generator is availabile as a heat sink. Even if it does have a tube rupture, available for that heat removal function, separating that from the question of atmospheric releases.

MR. WARD: Would you put that last slide up again, please?

MR. TURK: Which one is that? The temperature?

MR. WARD: Yes.

[Slide]

Now, let us see, what is going on there at 1000 seconds. It starts to level out, so you start to remove heat again?

MR. TURK: We have got a heat balance going on on the secondary side, which is relatively constant. So there is a constant Q secondary. Q primary, of course, is decay heat.

MR. WARD: Why are those not separated?

MR. TURK: In this particular case, in order to maximize, heat input is in, the reactor coolant pump is running --

MR. WARD: There is a little delta-t there.

MR. TURK: Yes, but it is not noticeable.

MR. WARD: And in the secondary side you have got a pretty tried steam generator, but you have got a great big delta-t now.

MR. TURK: Yes.

[Slide]

I guess then, just to summarize, we have really got two considerations at this point. We feel on is generic. It is the issue of alternative decay heat removal, so it is probably tied very closely to the unresolved safety issue.

But we feel that the time frame for resolution is such that we need to proceed with the design approval of System 80, and we feel that that is justifiable based on the design features of that plant.

That is all that I have.

MR. WARD: Okay, now, one of the concerns that the ACRS letter expressed was with the total reliability on the steam generators. And the draft memo addressed that. You have not talked about that today.

MR. TURK: Basically, the draft memo listed the design features that are inherent in the System 80 design.

[Slide]

Essentially, flow distribution baffles, explosively expanded to joints in tube sheets, the stainless-steel and income annealed materials, the high blowdown capacity. John Alden from our Chattanooga components group is here today, and I think he can answer any specific questions.

But with regard to the issue of proceeding with System 80, we feel there are two factors here. One is we are doing everything we can to address the known problems in steam generators, and we feel that resolution of any steam generator integrity issue, whether it is operating plants or new plants, is of a time frame that is compatible with generic resolution of the decay heat removal considerations.

MR. WARD: I do not want to put words in your mouth, but you seem to have made the argument a couple of times here today that the steam generator integrity as related to this issue, you are essentially saying you have a situation where in this last-ditch effort you might be willing to give up relatively minor releases to the environment through a failed tube but you have not given up the capability of keeping the core cooled.

MR. TURK: Correct. Better a little bit of normal primary coolant than a little bit of crapped up primary coolant.

MR. WARD: Well, that is an interesting point. It seems to me a very valid point. But you have only made that in an oblique sort of way. Am I missing something?

MR. TURK: Well, yes. The person who was going to come down and talk about steam generators is in Taiwan. It is logistical more than -- George Davis will. I think the intent of any presentation on steam generator integrity was to address the fact that the ACRS had expressed concern about decay heat removal capability for something beyond the present design basis, beyond what is presently required by the NRC Staff.

What we presently see from the existing data of operating history that is needed when you get into heat removal capabilities beyond the design basis, such as conditions of when would you need feed-and-bleed capability or secondary depressurization capability, that you get into concerns of steam generator integrity as being a strong factor.

And therefore, the Staff has indicated to us in our recent discussions with them that they would wish

to pursue the questions of steam generator integrity and
what effects that might have upon secondary
depressurization capability.

MR. WARD: Yes. But you still seem to be
saying that -- is your position something like this:
that the steam generator integrity as far as its ability
to remove decay heat is extremely high?

MR. TURK: That is very true.

MR. WARD: The steam generator integrity as
far as avoiding relatively small releases to the
environment is not as high?

MR. TURK: It may not be.

George?

MR. GEORGE DAVIS: That may be a true
statement by relatively small releases in the
environment, yes.

MR. EBERSOLE: This is going to necessitate
something that has been long coming, and this is as good
a time to bring it up as any other. And that is, the
criteria by which you deliberately release radiation to
the atmosphere on the grounds that subsequent releases
will not be larger. I do not know of the existence of
any such criteria like that.

Is the Staff contemplating anything on this
issue? It is the issue of to what extent can I allow a

larger integral release? We have no generic approach to that at all.

MR. GOODWIN: There is at present under consideration a clarifying modification to the tech spec rule. I do not remember the section. But the thrust of it was to make explicit the implicit authority that the operator has to take those actions necessary to protect his plant and the surrounding population against harm even though it involved exceeding a tech spec limit.

This is a case in point where prudent operation will require a release in excess of tech spec limitations, given a certain configuration in a certain accident. The Staff has never deliberately tried to place the operator in a position where he was legally prevented from doing that which was necessary to protect the public health and safety.

And it is now in the rulemaking that is underway, and I do not know if that is exactly appropriate. I know the rule has been drafted -- I do not know what the status is -- to make explicit the authority and responsibility that an individual licensee has to protect the public health and safety even if it means disobeying a tech spec.

MR. EBERSOLE: Thank you.

MR. WARD: Are there any other questions for

Mr. Turk?

[No response]

MR. GEORGE DAVIS: That concludes the CE presentation.

MR. WARD: All right. Thank you, Mr. Davis.

Let us go right ahead with Mr. Sheron again.

[Slide]

MR. SHERON: I guess, as you have heard in this afternoon's presentations, we have a report from Combustion. We have had it a couple of days now. It is under review. We have met with Combustion. We have sent them a set of what I would call very preliminary questions, sort of like thinking out loud and putting our thoughts on paper. And we sent it to them last Thursday.

We met with Combustion yesterday to clarify, I guess, some of our concerns, where we are coming from on this. And before I put up the next slide, I just want to say that as you can see this is not a very simple question, there is no overwhelming evidence that says PORVs are wonderful and do great things and prevent core melt and the like.

It is a question that there is a requirement for PORVs on these plants, it will impose a cost on the industry and we have to weigh that cost against the benefits that a PORV or any other optional system that they may recommend would offset.

You have heard all of the arguments right now regarding the PRA studies.

[Slide]

I think based on everything we have seen so far, the Auxiliary Systems Branch reliability criteria in which they do a detailed review of the auxiliary feedwater systems and they basically confirm that the auxiliary feedwater system for a given plant meets their criteria and their branch technical position which is 10^{-4} and 10^{-5} on reliability.

CE in their report also concluded their PRA studies that the auxiliary feedwater system design had an unreliability in that ballpark, that the Auxiliary Systems Branch had required. The Staff PRA studies that you have heard about concluded that from an auxiliary feedwater standpoint, the addition of PORVs was marginal, if anything. It is just too close to call.

And when you put all these together in what we have tentatively concluded is that we would say that PORVs are probably not necessary, if one is concerned solely with auxiliary feedwater system reliability.

Now, notice I did not say decay heat removal reliability.

MR. ETHERINGTON: Would you cost-benefit a study if you changed from PORV to, say, a two-inch stop valve, as was suggested? That does not sound like a very big cost item.

MR. SHERON: I do not think so. Putting a valve on?

MR. ETHERINGTON: Yes.

MR. SHERON: The problem is, as I understand, that most of these plants are well under construction. It is not just that you have to put a hole in the top of the pressurizer and tap into an existing line.

MR. ETHERINGTON: Why could you not attach it to the safety valve piping?

MR. SHERON: You probably could. That is what I am saying.

MR. ETHERINGTON: That is not putting a hole in the pressurizer.

MR. SHERON: It is a question of space available. Well, Mr. Thadani wants to address this.

MR. THADANI: Dr. Etherington, it seems to me that one cannot do a good value impact analysis without looking at perhaps other scenarios that could lead you to core-melt type of situations. It may be that the estimates that we make for the scenario may not make this as significant event in terms of the overall core melt frequency for these types of plants.

So it seems to me that one has to look further, take a broader look before making any decision as to requiring, whether it be a two-inch line with a stop valve or two isolation valves or is there another way, are there other scenarios that could be mitigative by different design?

A big valve might in fact have ATWS-type of pressure as well. But the point is that what we are talking about is a very narrow look that we gave to this issue. We did not see the other scenarios. Other scenarios ought to be considered to see how much of a benefit can one really derive from putting a two-inch line or a four-inch line or whatever it is to be able to do a reasonable value impact assessment.

MR. EBERSOLE: What is the current pressure estimate for ATWS, do you know?

MR. THADANI: I can go back to my memory. I think that CESSAR-80 plants were better than the earlier version of CE plants of the Calvert Cliffs type. The pressures they were caculating, the peak pressures, were in the range of 3700 to 4000 pounds, I believe.

MR. EBERSOLE: Thank you.

[Slide]

MR. SHERON: To pick up on what Ashok was pointing out -- that is, that you have to look beyond the narrow scope of auxiliary feedwater reliability when one wants to do a cost-benefit. You have got to see what else can a PORV buy me? For example, if one has as a given that steam generators are perfect and do not fail, then there may be much more merit to looking at a secondary side depressurization and putting in different sources of feedwater.

But when one gets concerned about steamwater integrity, maybe one says, I do not want to rely on that, I want to rely on the PORV.

So when you start to do this overall integration, I guess, as I would call it, which is what we are trying to do right now, is look at other scenarios, other functions, other benefits, we initially tried to put our thinking down on a piece of paper here and we categorized what I would call safety functions -- you may not want to call them that -- the things a PORV can do for you.

One is decay heat removal, which we have been discussing for most of the day, feed-and-bleed. The second is mitigation of transients and accidents: are there any events out there where we need a PORV really to do a good job in mitigating the event.

A third is not a function. This says the PORV is not absolutely necessary to mitigate an event, but it sure would be nice to have to reduce the consequences of the event; perhaps I can reduce a calculated off-site release if a PORV were available.

And the last category is the beyond design basis, I call it, or other events. This is, I guess I would call, the back-pocket margin that a lot of people like to think of it is nice to have. I feel good that I can depressurize this plant rapidly. For example, ppressurized thermal shock.

We have put down a first cut of what we think advantages and disadvantages are for -- this is for the CESSAR design without PORVs. Abd what we said is: what are the good things about not having a PORV and what are the bad things?

Obviously, the one that keeps cropping up all along is that if you do not have it it cannot get stuck, it cannot cause a small break. The second is that you do not have to pay for them, it saves you a lot of money.

Over here, if you do not have it, then the operator is not told to use it and maneuver it, it is just one less piece of equipment that he has to fool around with during an event.

MR. CATTON: Under some circumstances, though, there will be more equipment, though, will there not? And that would strike number two.

MR. SHERON: Well, one question is are there any events that really need a PORV? Within the context of our design base, the Standard Review Plan, Chapter 15, obviously we have written off and said within the confines of the design base their plant meets the Standard Review Plan criteria without a PORV.

I think another point which is well taken is that operators are generally familiar with removing decay heat with the steam generator, and they would be very uncomfortable in fooling around with the PORV trying to feed and bleed. And one always like to consider an operator and say he should fool with systems he's comfortable with, not with systems he is not. He is used to maneuvering, he is used to throttling feedwater or regulating steam pressure manually or whatever he does, but he's used to it. He does it daily.

Under an accident condition, you're going to still ask him to work the secondary side, and without it you're asking him to use a system maybe he's not that familiar with. So these are some of the pros and cons one has to consider. I'm sure some people could think of others.

The disadvantage is that you're totally relying on auxiliary spray during a natural circulation cooldown regarding some sort of pressure control. You don't have aux spray to keep the pressure down. You may saturate and go to a two-phase unless you have a PORV which can relieve pressure.

An inherent assumption from the decay heat removal standpoint is that your steam generators remain essentially intact at all times. Without a PORV, although the analysis they have done shows that one doesn't really change the reactor protection system, one could conclude that without a PORV you're going to challenge safety valves more often, perhaps. And if a safety valve sticks you cannot isolate it with a block valve like you could with a PORV.

As I pointed out, for example, the Westinghouse design tells an operator specifically on a steam generator tube rupture, turn on the aux spray and try to get that primary system down, to try to stop the leak as fast as possible. Combustion plants probably tell the operator to use the auxiliary spray.

And one of the questions we will be asking them is, is there any benefit in a PORV versus auxiliary spray regarding radiological release that might occur from steam generator tube rupture? Can I buy something in terms of releasing any radioactivity?

And again down here, when you look beyond the design base and you start talking about, if I don't have a PORV and I want to cool the core, I'm going to try and find any source of water I can to put in the steam generator. And once one goes outside of condensate feedwater, one is faced with a question of water chemistry problems and how it affects the tubes.

High sulfide -- and I'm not an expert in this, but I understand high sulfide content can really do a number on the tubes very quickly. So there's questions of extended operation with poor water chemistry.

MR. ZUDANS: One question. The auxiliary feedwater, were it to be used as a pressure-reducing mechanism, it would require AC power?

MR. SHERON: Yes, sir.

MR. ZUDANS: For a PORV you could achieve the same function -- how is the PORV operated, with air, or is it also AC power required?

MR. SHERON: I'm not sure what it is on the CESSAR plant. I know that plants have both.

(Laughter.)

MR. WARD: What would you like?

(Laughter.)

MR. SHERON: I'm trying to think of the other CE plants.

MR. ZUDANS: I just thought if you could operate the PORV without the AC power, you have a pressure-reducing mechanism without AC power, which you don't have with the auxiliary spray.

MR. SHERON: I'm not sure even if you have an air supply to operate a PORV whether you still need an electrical source.

MR. ZUDANS: It's a question of a time element, then, too.

(Slide.)

MR. SHERON: This is a table we put down as advantages and disadvantages of the CESSAR design with a PORV. Again, for decay heat removal it does give you some sort of a diverse means for removing decay heat, feed and bleed, provided you size the valves properly, qualify them, et cetera. You would not be depending upon auxiliary spray, for example, to keep you out of potential two-phase natural circulation condition when you're cooling down.

Again, the disadvantages is, it costs money and you possibly are increasing the probability of a small break. Mitigation of transients and accidents; there's a possible reduction to challenges in the reactor protection system, and one might want to try and translate that into a reduction in ATWS probability.

It does give the operator an increased flexibility regarding pressure control. And again, when you're coming down after whatever event you've had and you're trying to come down on natural circulation, again it has a potential for maintaining a single phase natural circulation.

The same disadvantages.

Reduction of consequences. As I pointed out, the steam generator tube rupture, there may be some benefit. It's not clear yet, and when one goes beyond the design basis again you have a direct means of decay heat removal from the primary system. You are not relying on structural integrity being maintained in the steam generators.

Pressurized thermal shock considerations. You have a rapid depressurization capability, and as I pointed out here and one other one which is not on here is the LTOP system, low temperature overpressure protection. Most plants use PORV's rather than safety valves on the decay heat removal system. So such a valve would possibly show more protection from a low temperature overpressure protection.

(Slide.)

MR. DAVIS: Excuse me. I didn't see one disadvantage on your chart that seems to me as important for decay heat removal. If you use the PORV, don't you run a high chance of discharging eventually into the containment with high temperature steam?

MR. SHERON: Yes.

MR. DAVIS: Presuming you dumped it into containment, isn't that a disadvantage for equipment and other reasons?

MR. SHERON: Yes, it's a small break and it's a cleanup problem. There's always the question of, you know, putting an adverse environment in the containment.

MR. DAVIS: That wouldn't occur if you used the CE method.

MR. SHERON: Correct.

Okay. These are the vugraphs we put together which basically were our thinking as of about Thursday or Friday, I guess, regarding what kind of questions we had to ask Combustion before we could make any sort of competent decision. One is the question of steam generator tube integrity, and I think this is rather central to our problem or our concern. Obviously, if one is totally questioning decay heat removal reliability by auxiliary feedwater systems or what have you and one can show that I can fix that by having an alternative source of water for the generators, I personally think that would be a preferable mode from the point of view of what Pete said and the like.

It doesn't crap up the primary system. The operator is more comfortable using the steam generators to bring the plant down.

However, as we said, there are questions of integrity. You lose all feedwater, you dry out the generators, the operator says, I'm going to put in this new supply of water. He hits it with cold water. Calculations may be wonderful to show the tubes don't fail, but five or ten years from now when you start getting wall-thinning and the like, you know what happens then.

MR. CATTON: What are you going to ask CE to tell you that would convince you one way or the other that the steam generator tube integrity has been improved?

MR. SHERON: Well, I guess we're going to ask them what they believe the probability is with, for example, their alternate depressurization capability; how they feel their tubes can respond without failing. And they'll have to provide whatever evidence they have available. They have to address the subject of tube degradation and thinning and how that affects the calculated response, whether a tube fails or not.

I think the other thing you want to look at is, after Ginna we saw how the Ginna tube failed. One question is that, as Dr. Ebersole brought up, what happens if you get some substantial ruptures in both generators for some reason? Something, some event, whatever it is, causes some sort of pressure wave that rattles the tubes and you wipe out a bunch. How do you cool the plant down then?

Because now you have the problem of primary coolant with a direct leak path from both generators to the environment. If you can't bring the plant down fast in the steam generators, you have the potential of pumping all the RWST water out into the environment with primary coolant, and when you run out your RWST level goes down and the operator tries to recirc on the sump there is no water in the sump.

So there is that question.

Some of the questions we had regarding their proposed use of the low pressure system was, we're not really sure what system they're talking about. As I said, there are a lot of pumps available and one has to look at whether you're going to put in spool pieces or valving arrangements or what have you. So they really haven't provided any details of such a system so that we can really evaluate it and say what we think of it.

The second is the question of where they're getting the water from. If you're going to take it right out of the river, now you have to answer questions of tube integrity due to poor water chemistry over an extended period of time, and the obvious question of thermally shocking the tubes by pumping cold water into a dry generator, especially one which has tubes that have been in there a while and are thin.

Another question is, can we manage certain events, like steam generator tube rupture -- and I'm not just really thinking about one tube, but looking at a spectrum. Can we do it with the PORV than with aux spray?

MR. EBERSOLE: This idea of pumping water from a strange source, does that permanently render the steam generators damaged to a point of no further value?

MR. SHERON: It would depend where they got the water from and how long it was circulated and the like. We have to learn better where they were planning to take their source of water from.

(Slide.)

These questions here were developed by Mr. Thadani and his branch, dealing with the probability aspects. Again, they look familiar to what you just saw. Again, probability and consequences of a loss of all feedwater; risk associated with multiple tube failures in one generator and failure of relief valve in the faulty steam generator; probability of and risk associated with tube ruptures in two steam generators; frequency and consequences of PORV-initiated LOCA. How does it make it worse by putting a PORV in?

To look at potential benefits from PORV's under various accident conditions, including ATWS and reduce the severity of pressurized thermal shock. You may ask, what does the PORV do with that. Well, right now as I understand the pressurized thermal shock issue, the industry totally relies on an operator to turn off high pressure injection pumps to prevent a repressurization.

So there is an inherent assumption that the operator knows what he's doing and that he takes the right action. And there has been evidence that says maybe the operator doesn't do that all the time. So one has to look at other ways one can prevent the system from repressurizing.

I think Mr. Rowsome pointed out one way would be to put in an automatic depressurizing system.

MR. EBERSOLE: You tell me that at St. Lucie and ANO-2, without all this intensive investigation, apparently they put in primary relief or primary valves. Did they have any reasons that we don't know about? They just went ahead and did it?

MR. SHERON: I would ask CE to address that.

MR. TURK: To the best of CE's knowledge, the decisions were made as follows: Arkansas Unit 2 added their valves to meet long-term cooling requirements imposed in the time frame because of the single train of

RHR shutdown cooling that they had. So that valve is there to provide an alternative long-term cooling method.

The St. Lucie PORV's were part of the St. Lucie 1 design and because it was intended to be a duplicate plant PORV's were maintained in the design.

MR. EBERSOLE: How did they get on Unit 1?

MR. TURK: That was of the same vintage as Calvert Cliffs and our other CE plants before we made the decision to remove them.

MR. EBERSOLE: I see, th you.

(Slide.)

MR. SHERON: The last item we would be asking them about is trying to get a better handle on what it's going to cost to put the PORV's in, the feasibility. Is there room in the plants right now to put these valves in without mucking up concrete or whatever? And if we delay a decision down the road, what does that cost?

I guess the next question is where we all go from here with this. This is what we intend on doing. The first is that we are going to put our questions that we have formally in the form of a letter, and I said to all applicants with CE NSSS designs without PORV's. I'm including Waterford and San Onofre 2 and 3.

San Onofre 2 and 3 and Waterford will also be asked the question, how does the CE report regarding rapid depressurization capability of the CESSAR System 809 plant and the arguments made in that report regarding reliability of steam generators with water chemistry -- how does that apply to their plant? They're not a System 80 plant.

So that's the first thing they're going to have to do is say, all this wonderful stuff that Combustion told us about System 80 -- how does that affect you? Are you as wonderful or not as wonderful?

We are going to ask that they respond to our questions on a schedule consistent with a decision date that has to be made prior to full power operation. Now, each plant has its own schedule for going to full power operation. So each plant is going to have a unique problem, maybe, with the schedule.

So what we said is, if they cannot respond on a schedule consistent with making a decision prior to full power operation, then keeping in mind the kind of questions that we've asked and what our problems are where we're having problems, on the steam generator tube integrity and the like, all the stuff with that, they ought to tell us why they are justified in going to full power operation without PORV's pending their answering our questions and us making a decision.

So if they can make an argument that early in life steam generators don't fall apart as much as later in life, then maybe that's the way they would want to justify it.

However, we don't want to let this drag on forever. So what we're going to do is we're going to say, we'd like the answers to our questions consistent with deciding on full power operation. But even if you can't do that, we want to hold you to about a 12-month schedule on dealing with questions regarding the steam generator tube integrity and the like. They will have to come back to us and tell us what their schedule is.

I don't think we want to accept anything much more than 12 months. If it's earlier, fine. And much of it will depend on the justification they provide why they can go to full power operation, if that's what they choose.

So that's presently what our schedule is. If there are any questions --

MR. ZUDANS: I have one small question. In case of steam generator tube break, where can that mixture of primary and secondary coolant go? What are the alternatives?

MR. SHERON: If the offsite power is available and the condenser is availabe, one typically likes to dump it to the condenser and let it go through the steam jet air ejector. And I believe there are filters and the like on there. That would be the preferred mode.

If the condenser is not available, the only alternative is -- it would be a release to the atmosphere, provided you could not prevent the faulty valves from opening or having a relief valve open for some reason and then not reclose. The method is to detect the event of the steam generator tube rupture, and try to isolate the faulty generator. And this is just accident mitigation philosophy: isolate the faulty generator and reduce the primary pressure to equal or below the faulty generator pressure, so that you don't have the potential for continuing a leak into the secondary and lifting any valves.

MR. ZUDANS: The plant vent valves that discharge in the plant, there are relief valves in the steam line that discharge into the plant as well.

MR. SHERON: I think they discharge to the atmosphere.

MR. ZUDANS: Now, how is it different from any other plant that has a PORV? This is the same thing except that with a PORV you potentially could reduce the primary pressure faster, maybe. If the steam tube breaks, that primary water will have to be directed in one of those ways that you described, PORV or no PORV. That's a correct statement, isn't it?

MR. SHERON: Correct.

MR. ZUDANS: So what does a PORV provide --

MR. SHERON: The mitigation strategy of a steam generator tube rupture is, once the operator detects that he has a primary or a secondary leak, okay, if it's small enough one likes to go into a controlled shutdown, okay.

If the leak is large enough that you depressurize, you're going to get a low pressure trip and you're going to get safety actuation on low pressure. It's going to look like a small break in the primary system, and the only thing that's going to tip the operator off right away is the steam jet air ejector radiation signal.

And like I said, the object is, once you have identified the leaking generator, the object is to isolate it and to stop the leak. And the one way to stop the leak -- remember, the primary system pressure is just decaying down. It's leaking into the generator and starting to fill that generator up.

The coolant is physically moving from the primary to the secondary through the leak, depending upon the hole size and the pressure differential. Left to its own devices, obviously the primary system would bleed down until there was an equalization between the primary and the secondary.

But you may wind up filling the faulty generator, and if the primary pressure at this equalization point is above the secondary side relief valve you'll open that valve. So what you would like to do is get that primare pressure down as fast as you can to below the secondary side relief valve set point.

One way you can do that is to start spraying down the pressurizer with auxiliary spray, for example. Another way is to open the PORV and get the pressure down. If you're familiar with the Ginna event, that's exactly what the operator did, is to try and get that primary pressure down to below the faulty generator pressure by opening the PORV.

The only thing you would have in there is a stuck-open -- auxiliary spray may be equally effective in reducing the pressure, but there is a lot of question of, is it available immediately to an operator, does it drop the pressure as fast as the PORV might, how does that affect the primary-secondary leakage?

These are questions we would like Combustion to answer for us.

MR. ZUDANS: Thank you.

MR. ETHERINGTON: It will drop the pressure rapidly to the saturation point of the system. Then it will be very slow after that, won't it?

MR. SHERON: Yes. Once you hit the full temperature of the hottest fluid in the system, which will flash --

MR. ETHERINGTON: It won't bring it down to steam generator pressure very quickly?

MR. SHERON: If you look at Ginna, I think it came down very quickly.

MR. CATTON: We've seen a number similar to that. I think it was two and a half hours.

MR. WARD: We had a chart that showed two and a half hours down to 250 or something like that.

MR. SHERON: I think if you look at the Ginna event and you look at what the pressure did when they opened the PORV, it came down like a shot until they got the bubble in the upper head.

MR. ETHERINGTON: The PORV would bring it down quickly. But I thought the auxiliary spray would not.

MR. SHERON: The auxiliary spray will also bring the pressure down.

MR. ETHERINGTON: It goes very quickly to saturation. But beyond that it's not going to be very effective because you're going to have boiling occurring all through the system.

MR. SHERON: Yes. Now, the question is at what pressure would you get this boiling. Obviously, if you get a reactor trip and the coolant pumps are running, the primary system -- the temperature rise across the core collapses and the entire system basically goes to the cold leg temperature and then starts to drift down towards a --

MR. ETHERINGTON: Yes, here we have the figures given, to saturation in ten minutes, which we'll say is fairly quick, and then down to 350, which of course is much lower than we're talking about, but that's two and a half hours. There's going to be mass transfer required once you get down to saturation.

MR. SHERON: You're also dealing with a non-leaking system. I think there is a difference.

MR. SHERON: This is one of the questions we have, is, what is a more effective way to get the pressure down using the PORV or using auxiliary spray.

MR. CATTON: The effectiveness is not in question, is it? You know that you will get it down faster with the PORV.

MR. SHERON: Well, does that buy you anything?

MR. CATTON: Yes, that is the question.

MR. ZUDANS: You may not need a PORV.

MR. SHERON: Are there any other questions?

MR. WARD: Any more? Okay, thank you, Bryan.

Before I ask particular consultants for their thoughts on what they have heard on this subject, let me review briefly what we are about.

We have kind of had a charge from the full Committee in the December letter. In that December letter, the Committee expressed a concern about three things related to the System 80 design, the high independence and the reliability of auxiliary feedwater system, and on the integrity of the steam generators for decay heat removal, and the Committee said that special attention should be given to these matters in connection with any plant employing the System 80 design.

Okay, then the Committee said also that it believes consideration should be given to the potential for adding valves to facilitate rapid depressurization of System 80 primaries, and then the Committee wishes to review this matter further with the cooperation of CE and the staff.

Now, I think we have a couple of questions here. One, that CE and some of their customers are primarily interested in at the moment is whether the Committee intended there to be anything in particular that needed to be done on the near-term operating licenses with regard to this question -- these questions. The staff has interpreted -- or from their own resources determined that some of these questions should be dealt with in advance of a full operating license, and I guess I would like to -- it is not crystal clear that that is what the Committee intended, but as usual, we have to ask the full Committee whether they intended that.

So, I think we need to plan on a report to the Committee at the April meeting and in fact we have set a couple of hours aside for this general subject of decay heat removal. We said earlier that we wanted to use about half an hour of that. Perhaps a 15 or 20-minute presentation for the description of the task action plan A45, and that would leave us about an hour and a half total for discussion of this question.

So, we would like to do probably three things there. One, bring to the Committee any assessment or consensus that the Subcommittee and its consultants have reached regarding what they have heard today, and then permit both the staff and CE to give their presentation, and I think in particular Mr. Sheron should give the presentation, or at least part of the presentation he wound up here with in stating that the staff intends to require of applications with CE plants in the near term.

My impression that is at least everything the Committee was asking for, but I think we will let the Committee hear that, and then it will be up to the Committee to respond on both the short-term question and the longer-term question that you have already addressed.

So maybe Mr. Savio can work with Mr. Sheron and CE to work out some summary of the presentations that we have had today, but particularly I think the staff should address -- well, let's say the issue of -- one particular point I am not sure that was covered all that well. I guess the one thing we didn't talk about today, and I know you have dealt with it, but I think you will want to be sure and address in the staff's presentation to the full Committee is exactly how the staff intends to address the interface problem. I mean, how do you intend to assure in the future CESSAR plants, that the balance of plant is in fact designed to match the requirements that are put on decay heat removal for the plants. I know that is not a new question, but I think that is of particular interest for the full Committee.

I would like to ask our consultants and the members who have anything to say for their comments on this question. Mr. Epler, we will give you the honor again if you would like to take it.

MR. EPLER: I would not like to see us go into future plants with this question unresolved, and with it partially answered with the PORV. I am very unhappy with the pressurized thermal shock issue unresolved and left to the devices of the operator. I think that must be resolved, and I think this proposal does not do anything for it that I can see, and if that is resolved and the heat removal question is resolved, then I think we are ready to go to future plants. I would hate to see a partial answer that would preclude a full answer. I believe that is what we are faced with.

I think if we go ahead and put in a PORV, then we have cut ourselves off from a more complete resolution of the question. So I would like to see some priority given to resolving the larger questions of pressurized thermal shock and decay heat removal, and would like to see some movement in the direction of encouraging utilities to do chis in their own self-interest.

MR. WARD: Okay. Thank you, Mr. Epler.

Pete?

MR. DAVIS: Just one item that is still lingering in my mind as possibly a problem. It seemed to me like this kind of thing we talked about today puts a tremendous burden on the operator, and I am concerned that he is not going to have the training or the diagnostic information or the procedures available to be able to determine what to do in these abnormal situations.

I guess we have already had TMI II and Ginna in which the operator at least did some questionable things, not because he was incompetent, but because he just didn't have the procedures or the diagnostic information available, and I am not just talking about this kind of problem. There are other things that are being considered for the operator to do that go beyond really what his basic experience is in other kinds of accidents.

I didn't hear too much about that today, and I think that any conclusions about how effective and how reliable these things are must take into account what the operator knows and what his training is and what kind of procedures he has, and the instrumentation available to him to decide what to do.

There are, it seems to me, cases where he could make the wrong decision and then foreclose options that would have still been available to him if he had done the right thing, and I really think that needs some attention.

Thank you.

MR. WARD: Dr. Zudans?

MR. ZUDANS: Well, I feel that there is steam generator integrity as designed by combustion engineers. I think it is pretty good. I think their arguments are valid. The thermal shock problems associated with it have been fairly well addressed, so I feel fairly comfortable with that design. That particular question is well answered. I think that auxiliary feedwater non-availability probabilistic numbers probably are all right, but I don't accept the qualifiers which would allow them to wander all over the place. So maybe they should sharpen the definition of interface requirements more precisely as to what is intended and what is understood to be there other than just making the reference to particular documents which, for one, I don't know right now what that document requires.

I don't like the thermal shock aspects of PORV's used in a feed and bleed mode. I think that may create much more headaches than anything else. So, in overall evaluation, I think their system is just as good as any other one.

MR. WARD: Thank you.

Ivan?

MR. CATTON: I think first CE requiring a 10 to 10^{-5} unavailability of the emergency feedwater system is admirable. I think interface requirements are one thing and meeting them is another. I am not sure combustion engineering is the group we ought to be talking to. I think we ought to be talking to Bechtel or somebody who is actually going to build that system to meet these requirements. I don't think we should forget the example of the scram discharge volume at boiling water reactors and what we were told by the reactor vendor with respect to its unavailability. I think we were told the unavailability was zero.

In the second one, the steam generators, the secondary side hydraulics and the steam generator is kind of a black art to me. The words in the report are comforting. I would like to know what the studies are that formed the basis for the CE design. For example, full visualization studies of any magnitude, have they been conducted? I think some of those kinds of things would leave you with a feeling of confidence in the statements that are made in their report. They discuss water chemistry. I think that is another example of interfacing. How can CE be sure that a given utility will meet the standards they assume exist?

Another thing, is there a history of optimization of deep water chemistry by utilities, and do we really know what optimum chemistry is? They conclude that section in the report by saying that CE feels its design modifications will assure adequate steam generator integrity. I think that is rather a weak statement. It may take a number of years to prove the various design innovations they have incorporated into the steam generator.

Finally, the need for pressurization, I think I agree with the staff. I don't think I really know enough to make any kind of positive statement. However, I like the sound of it. There has already been a way of handling the thermal shock that was suggested by Rowsome. I think that was the three.

And just a final comment. I would like to emphasize that I think the burden on the operator is going to be tremendous, whichever way you go, and that needs to be given strong consideration.

MR. WARD: Thanks.

Jerry, did you want to add anything?

MR. RAY: No, I can't add anything of significance to what our consultants have said, but this burden on the operator, it seems to me that whichever way we go, the emergency restoration procedure guidelines that are made available to the licensees by the NSS suppliers have to recognize that problem, and the emergency procedures be written and the training appropriate for the methods that are used in the particular design.

MR. WARD: Harold?

MR. ETHERINGTON: I think Combustion Engineering has made a persuasive presentation of the no necessity for PORV's. I have a feeling it would be nice to have. Still, the Committee's letter asks the staff consider additional valves. They didn't say PORV. I certainly think the staff is doing this, and I think we don't need to make a final report on it at this time. It is something which is in the future.

MR. WARD: Do you think there should be any restriction on the -- if used in the future, there should be any restriction on the operating licenses that are under way right now?

MR. ETHERINGTON: No, I don't think so.

MR. WARD: Jesse?

MR. EBERSOLE: Combustion has the range of reliability by giving us 10^{-4} as the bottom. Then I heard discussions which said it was really, in attempting to meet this, they were qualified reliabilities expressed which really didn't interface with support systems and so forth. I would like to have another expression of integral reliability of the auxiliary feedwater system, and then having got that, considering the interface systems reflect this contribution to core melt as a fraction of the total probability of core melt on a non-PORV design. This is only a fraction of the total probable core melt failure of this system. It didn't come clear to me what percentage of the total probability of core melt this represented.

MR. CATTON: Jesse, I think in Andy's report it suggested that 80 percent was associated with -- no way that was decay heat removal systems. That is 80 percent.

MR. WARD: Ashok, can you answer that?

MR. THADANI: Our general understanding is that most of the rest would come from all events except large LOCA. ATWS, a rulemaking presumably is going to take place, proposed rules. Decay heat removal considerations under A45 do include considerably more than the auxiliary feedwater system. If you were to accept generic calculations of overall core melt frequency, and let's go to something like WASH-1400 for the pressurized water reactor, and if you believe some of these estimates, they would come out to be in the order of 10 to 20 percent of the total core melt frequency.

I think we all recognize the large uncertainties in these calculations, so it could be higher, but it is in that range, I think.

MR. EBERSOLE: Is that also true for the PORV plants?

MR. THADANI: It is also true for the PORV plants for the following reason. WASH-1400 defined the so-called TML sequence, which is loss of main and auxiliary feedwater system as one that would lead to core melt because they assumed that no credit would be given to the operator to open PORV's to depressure -- the feed and bleed concept was not applied.

MR. EBERSOLE: They got zero credit for that?

MR. THADANI: That's correct.

MR. EBERSOLE: That is a distorted viewpoint.

MR. THADANI: You are right, but then we do have some other scenarios, such as small LOCA's, the failure of high pressure injection systems which could lead to core melt, which we think have estimated frequencies which are somewhat higher than this sequence.

MR. WARD: Okay. Well, thank you very much. We appreciate this.

MR. GEORGE DAVIS: Could I ask one question before we break up? Is it your intention to provide a recommendation to the full Committee as to whether this issue should be resolved prior to OL issuances for the various plants involved?

MR. WARD: Yes, we will provide a recommendation which will reflect what we just heard.

MR. GEORGE DAVIS: I assume at this point there is no chance of getting an indication of that recommendation.

MR. WARD: I think the consensus recommendation is, we don't think that this should be a cause for delaying operating licenses. But that is just a recommendation to the full Committee.

MR. GEORGE DAVIS: We understand. Thank you.

MR. WARD: Thank you very much.

(Whereupon, at 6:20 o'clock p.m., the meeting was adjourned.)

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before the

in the matter of: ACRS/Subcommittee on Decay Heat Removal Systems

Date of Proceeding: March 16, 1982

Docket Number:

Place of Proceeding: Washington, D. C.

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

Ann Riley

Official Reporter (Typed)

Ann Riley

Official Reporter (Signature)

LOSS OF MAIN FEEDWATER

- FREQUENCY
  - INITIATION — NON-LOOP — 0.1/RY
    - LOOP — .27/RY
  - RESTORATION OF MFW
    - NON-LOOP — .3/D
    - LOOP (1½ HRS) — .3/D
  - PROCEDURES FOR RESTORATION

- AFW RELIABILITY — 10^{-4} - 10^{-5}/D
  - SRP REQUIREMENT
  - 3 TRAINS
  - SUCTION LINE
  - MISALIGNMENT OF SYSTEM

- CORE MELT FREQUENCY $10^{-5} - 10^{-6}$/RY
  - WASH-1400 LMFW 6×10^{-6}
  - NO EXTERNAL EVENTS
  - NO COMMON MODE

- CONCLUSION
  - WITHIN RANGE OF WASH-1400
  - VERIFICATION OF AFW RELIABILITY
  - PROCEDURE FOR RESTORING MFW

GENERAL OVERVIEW OF FEED AND BLEED CAPABILITY FOR OPERATING PLANTS

TYPE 1. PLANTS WHICH HAVE HIGH PRESSURE ECCS TO FEED AND BLEED WITH DEPRESSURIZING

TYPE 2. PLANTS WHICH HAVE SUFFICIENT PORV CAPACITY TO DEPRESSURIZE TO FEED AND BLEED.

A) THOSE WITH HIGH PRESSURE ECCS

B) THOSE WITH LOW PRESSURE ECCS

TYPE 3. PLANTS WHICH DO NOT HAVE SUFFICIENT PORV CAPACITY TO DEPRESSURIZE AND WHICH HAVE ONLY LOW PRESSURE ECCS (NO FEED AND BLEED CAPABILITY)

FEED & BLEED ANALYSES BY THE INDUSTRY

B&W

"SYSTEM RESPONSE TO TOTAL LOSS OF SG HEAT SINK", B&W DOCUMENT NUMBER 86-1103585-00, AUGUST 7, 1979

WESTINGHOUSE

"LOSS OF FEEDWATER INDUCED LOSS OF COOLANT ACCIDENT" WCAP-9744, MAY 1980

CE

"REVIEW OF SMALL BREAK TRANSIENTS IN COMBUSTION ENGINEERING NSSS, CEN-114-NP, JULY 1979

TYPE 1 PLANT

CORE COOLING REQUIREMENTS

OPERATOR MUST MANUALLY ACTUATE HPI

HPI FLOW OF APPROXIMATELY 40 LBS/HR. Mw PREVENTS CORE UNCOVERY

REACTOR SYSTEM WATER LEVEL DROPS INTO UPPER PLENUM BUT CORE IS NOT UNCOVERED.

CORE IS COOLED BY BOILING. STEAM EXITS THROUGH PRESSURIZER VALVES.

PRESSURIZER RELIEF OR SAFETY VALVE CAPACITY OF APPROXIMATELY 40 LB/HR. Mw REQUIRED

B&W

TYPE 1 OPERATING PLANTS

B&W PLANTS WITH HIGH HEAD HPI HAVE INJECTION CAPACITY OF 46.8 LB/HR. Mw AT THE SAFETY VALVE SETPOINT WITH ONE ECCS TRAIN. B&W ANALYSIS INDICATES THAT THE FOLLOWING PLANTS CAN BE COOLED BY TYPE 1 FEED AND BLEED.

ANO-1
CR-3
OCONEE
RANCHO SECO
TMI-1

WESTINGHOUSE AND C-E

TYPE 1 OPERATING PLANTS

WESTINGHOUSE PLANTS WITH HIGH HEAD HPI HAVE INJECTION CAPACITY OF AT LEAST 42.1 LB/HR. Mw AT THE PORV SETPOINT WITH TWO ECCS TRAINS. WESTINGHOUSE ANALYSIS INDICATES THAT THE FOLLOWING PLANTS CAN BE COOLED BY TYPE 1 FEED AND BLEED.

BEAVER VALLEY	SALEM
D.C. COOK	SAN ONOFRE
FARLEY	TROJAN
HADDAN NECK	ZION
NORTH ANNA	

MAINE YANKEE HAS AN HPI CAPACITY OF ABOUT 70 LB/HR. Mw AND CAN PROBABLY BE COOLED BY TYPE 1 FEED AND BLEED.

TYPE 2 PLANT CORE
COOLING REQUIREMENTS

OPERATOR MANUALLY ACTUATES PORVs BEFORE STEAM GENERATOR DRYOUT.

AS PLANT IS DEPRESSURIZED ECCS FLOW INCREASES AND PORV MASS FLOW CAPACITY DECREASES.

PORVs MUST HAVE SUFFICIENT CAPACITY TO DEPRESSURIZE THE PLANT SO THAT ECCS FLOW MATCHES CORE BOIL OFF.

WESTINGHOUSE PLANTS WITH HIGH HEAD ECCS MUST DEPRESSURIZE TO ABOUT 1500 PSI REQUIRING PORV CAPACITY OF 74 LB/HR. Mw IF ONLY ONE ECCS TRAIN IS AVAILABLE.

WESTINGHOUSE AND CE PLANTS WITH ONLY LOW HEAD ECCS MUST DEPRESSURIZE TO ABOUT 1250 PSI REQUIRING PORV CAPACITY OF 114 LB/HR. Mwt.

TYPE 2 OPERATING PLANTS

(PORVs MANUALLY OPEN)

WESTINGHOUSE PLANTS WITH HIGH PRESSURE ECCS HAVE A PORV CAPACITY OF AT LEAST 105 LB/HR. Mw. WESTINGHOUSE ANALYSES INDICATE THAT THESE PLANTS ARE ABLE TO COOL THE CORE IN THE FEED AND BLEED MODE WITH ONE ECCS TRAIN.

WESTINGHOUSE ANALYSES INDICATES THAT MOST PLANTS WITH ONLY LOW HEAD ECCS CAN BE COOLED BY FEED AND BLEED. THESE PLANTS HAVE A MINIMUM PORV CAPACITY OF 139 LB/HR. Mw.

GINNA	POINT BEACH
INDIAN POINT	PRAIRIE ISLAND
KEWAUNEE	TURKEY POINT
H.B. ROBINSON	

ANO-2 HAS PRESSURIZER RELIEF CAPACITY OF ABOUT 200 LB/HR. Mw. FORT CALHOUN HAS A PORV CAPACITY OF 140 LB/HR. Mw WHICH IS PROBABILY SUFFICIENT FOR FEED AND BLEED.

TYPE 2 OPERATING PLANTS
MARGINAL FEED & BLEED
PORVs MANUALLY OPEN

C.E. PERFORMED ANALYSIS INDICATING THAT THE FOLLOWING PLANTS COULD BE COOLED BY FEED AND BLEED, BUT ONLY WITH SOME CORE UNCOVERY.

THESE PLANTS HAVE A PORV CAPACITY OF BETWEEN 113 AND 120 LB/HR. Mw AND ONLY LOW HEAD ECCS

CALVERT CLIFFS	PALISADES
MILLSTONE 2	ST. LUCIE

YANKEE ROWE HAS ONE PORV WITH A CAPACITY OF 118 LB/SEC. Mw.

CORE COOLING REQUIREMENT SUMMARY

	ECCS FLOW REQUIRED 1B/HR. Mw	PORV OR SV FLOW REQUIRED 1B/HR. Mw
TYPE 1 (ECCS OPEN PORV OR SV)	40	40
TYPE 2 (PORVs MANUALLY OPEN)	40	74 HIGH ECCS 1500 PSI 114 LOW ECCS 1250 PSI

TYPE 3 OPERATING PLANTS

ONLY DAVIS BESSE PROBABLY CANNOT BE COOLED BY FEED AND BLEED BECAUSE OF INSUFFICIENT PORV CAPACITY TO DEPRESSURIZE BELOW THE ECCS PUMPS SHUTOFF PRESSURE

PORV CAPACITY FOR DAVIS BESSE IS 36/LB. Mw.

NRC STAFF STATUS REPORT

ON UNRESOLVED SAFETY ISSUE (USI), TASK A-45

"SHUTDOWN DECAY HEAT REMOVAL REQUIREMENTS"

FOR THE

ACRS SUBCOMMITTEE ON DECAY HEAT REMOVAL SYSTEMS

MARCH 16, 1982

ANDREW R. MARCHESE
TASK MANAGER FOR A-45
GENERIC ISSUES BRANCH
DIVISION OF SAFETY TECHNOLOGY, NRR
PHONE: 49-24712

PRESENTATION OUTLINE

- BACKGROUND ON TASK A-45
- UPDATE ON TASK A-45
- PURPOSE
- OBJECTIVE
- DEFINITION OF DECAY HEAT REMOVAL SYSTEM
- MAIN ELEMENTS OF TASK ACTION PLAN A-45
- INDUSTRY INVOLVEMENT IN TASK A-45
- DISCUSSION/QUESTIONS/FEEDBACK

BACKGROUND

- COMMISSIONERS APPROVED SDHR REQUIREMENTS AS AN USI (REF., MEMO, S. J. CHILK TO W. J. DIRCKS, SECY-80-325, DATED DECEMBER 24, 1980)
- TASK MANAGER ASSIGNED TO TASK A-45 ON FEBRUARY 17, 1981
- NUREG-0705 (MARCH 1981), "IDENTIFICATION OF NEW USIs RELATING TO NUCLEAR POWER PLANTS - SPECIAL REPORT TO CONGRESS," PROVIDES AN EXPANDED DISCUSSION OF TASK A-45
- MEMORANDUM, A. R. MARCHESE TO T. E. MURLEY, "ACTIVITIES RELATED TO TASK A-45," DATED APRIL 8, 1981
- DRAFT TASK ACTION PLAN (TAP) FOR TASK A-45 ISSUED ON MAY 22, 1981
- REVISED TAP A-45 (APPROVED BY DST DIRECTOR) ISSUED ON OCTOBER 7, 1981

UPDATE ON TASK A-45 SINCE ACRS SUBCOMMITTEE MEETING OF SEPTEMBER 8, 1981

- A TASK ACTION PLAN FOR USI A-45 WAS ORIGINALLY APPROVED BY DIRECTOR, DST, ON OCTOBER 7, 1981
- THIS PLAN, WHICH AUTHORIZED A FOUR-YEAR PROGRAM WITH A COMPLETION DATE OF OCTOBER 1985, WAS NOT APPROVED BY DIRECTOR, NRR
- WE HAVE REASSESSED THIS PROGRAM TO DETERMINE IF THE PRIMARY GOALS COULD BE REALIZED ON A SHORTER SCHEDULE
- WE HAVE NOW DETERMINED THAT OUR PRIMARY OBJECTIVES CAN BE OBTAINED WITH A 30 MONTH PROGRAM
- ASSUMING AN APRIL 1, 1982, START DATE, WE ESTIMATE THAT A DRAFT NUREG REPORT CONTAINING OUR PROPOSED RECOMMENDATIONS INCLUDING ANY PROPOSED NEW REQUIREMENTS, ALONG WITH THE SUPPORTING TECHNICAL AND COST/BENEFIT BASIS, WILL BE AVAILABLE BY OCTOBER 1984

- REDUCED SCHEDULE OBTAINED BY:
  - DELETING MOST OF WORK ON FUTURE PLANTS, ALTHOUGH ACCEPTANCE CRITERIA FOR DHRS' FOR FUTURE PLANTS WILL BE DEVELOPED
  - QUANTITATIVE ACCEPTANCE CRITERIA WILL BE BASED ON FREQUENCY OF CORE MELT DUE TO DHRS FAILURES RATHER THAN OVERALL RISK
  - RELYING MORE ON INDUSTRY TO PERFORM MORE PLANT-SPECIFIC EVALUATIONS OF ALTERNATIVE DHRS' WHERE THE STAFF CAN SHOW SIGNIFICANT IMPROVEMENTS IN SAFETY
  - HAVING ONE CONTRACTOR WITH OVERALL RESPONSIBILITY FOR PROJECT MANAGEMENT, TECHNICAL DIRECTION AND INTEGRATION, INCLUDING SELECTION AND MANAGEMENT OF SUBCONTRACTORS

- REMAINING STEPS TO START WORK ON PROGRAM:
  - RECEIVE APPROVAL BY DIRECTOR, NRR
  - RECEIVE APPROVAL BY SENIOR CONTRACT REVIEW BOARD
  - RECEIVE PROPOSAL FROM CONTRACTOR
  - RECEIVE APPROVAL OF CONTRACTOR PROPOSAL

PURPOSE

- THE OVERALL PURPOSE OF TASK A-45 IS TO EVALUATE THE ADEQUACY OF CURRENT LICENSING DESIGN REQUIREMENTS TO ENSURE THAT NUCLEAR POWER PLANTS DO NOT POSE UNACCEPTABLE RISK DUE TO FAILURE TO REMOVE SHUTDOWN DECAY HEAT

OBJECTIVE

- TO DEVELOP A COMPREHENSIVE AND CONSISTENT SET OF DECAY HEAT REMOVAL (DHR) SYSTEM REQUIREMENTS FOR EXISTING AND FUTURE LWRs, INCLUDING THE STUDY OF ALTERNATIVE MEANS OF DHR AND OF DIVERSE "DEDICATED" SYSTEMS FOR THIS PURPOSE

DEFINITIONS USED IN TASK ACTION PLANT A-45

- REFLOOD PHASE (RFP): THE INITIAL PHASE OF A SEVERE LOCA, WHEN THE OBJECTIVE IS TO REFLOOD THE REACTOR

- SHUTDOWN DECAY HEAT REMOVAL (SDHR) PHASE: THE TRANSITION FROM REACTOR TRIP TO "HOT SHUTDOWN," EXCLUDING THE INITIAL REFLOODING PHASE IN A SEVERE LOCA

- RESIDUAL HEAT REMOVAL (RHR) PHASE: THE TRANSITION FROM "HOT SHUTDOWN" TO "COLD SHUTDOWN" AND MAINTAINING COLD SHUTDOWN CONDITIONS

- DECAY HEAT REMOVAL (DHR) PHASE: SDHR AND RHR PHASES COMBINED

DEFINITION OF DECAY HEAT REMOVAL SYSTEM

IN THE CONTEXT OF TASK A-45, DHR SYSTEM IS DEFINED AS THOSE COMPONENTS AND SYSTEMS REQUIRED TO MAINTAIN PRIMARY AND/OR SECONDARY COOLANT INVENTORY CONTROL AND TO TRANSFER HEAT FROM THE REACTOR COOLANT SYSTEM AND CONTAINMENT BUILDING TO AN ULTIMATE HEAT SINK FOLLOWING SHUTDOWN OF THE REACTOR FOR NORMAL EVENTS, OFF-NORMAL TRANSIENT EVENTS (E.G., LOSS OF OFFSITE POWER, LOSS OF MAIN FEED-WATER) AND SMALL LOCAs (I.E., 1/2" TO 2"). DHR SYSTEM DOES NOT ENCOMPASS THOSE EMERGENCY CORE COOLING COMPONENTS AND SYSTEMS REQUIRED ONLY TO MAINTAIN COOLANT INVENTORY AND DISSIPATE HEAT DURING THE FIRST 10 MINUTES FOLLOWING MEDIUM OR LARGE LOCAs.

MAIN ELEMENTS OF A-45 TASK ACTION PLAN (Oct.'81)

- DEVELOP INTERIM ACCEPTANCE CRITERIA FOR ASSESSMENT OF DHRS
  - EXISTING PLANTS
  - FUTURE PLANTS
  - DEVELOPMENT OF INTERIM QUALITATIVE CRITERIA FOR "SPECIAL EMERGENCIES"

- DEVELOP MEANS FOR IMPROVEMENT OF SDHRS
  - PHENOMENOLOGICAL STUDIES
    (1) REVIEW OF CURRENT THERMAL-HYDRAULICS RESEARCH RELEVANT TO SDHRS
    (2) ON-GOING REVIEW OF THERMAL-HYDRAULICS RESEARCH
  - CONCEPTUAL DESIGN STUDIES (GENERIC)
  - OPERATIONAL ASPECTS OF ALTERNATIVE SDHR SYSTEMS

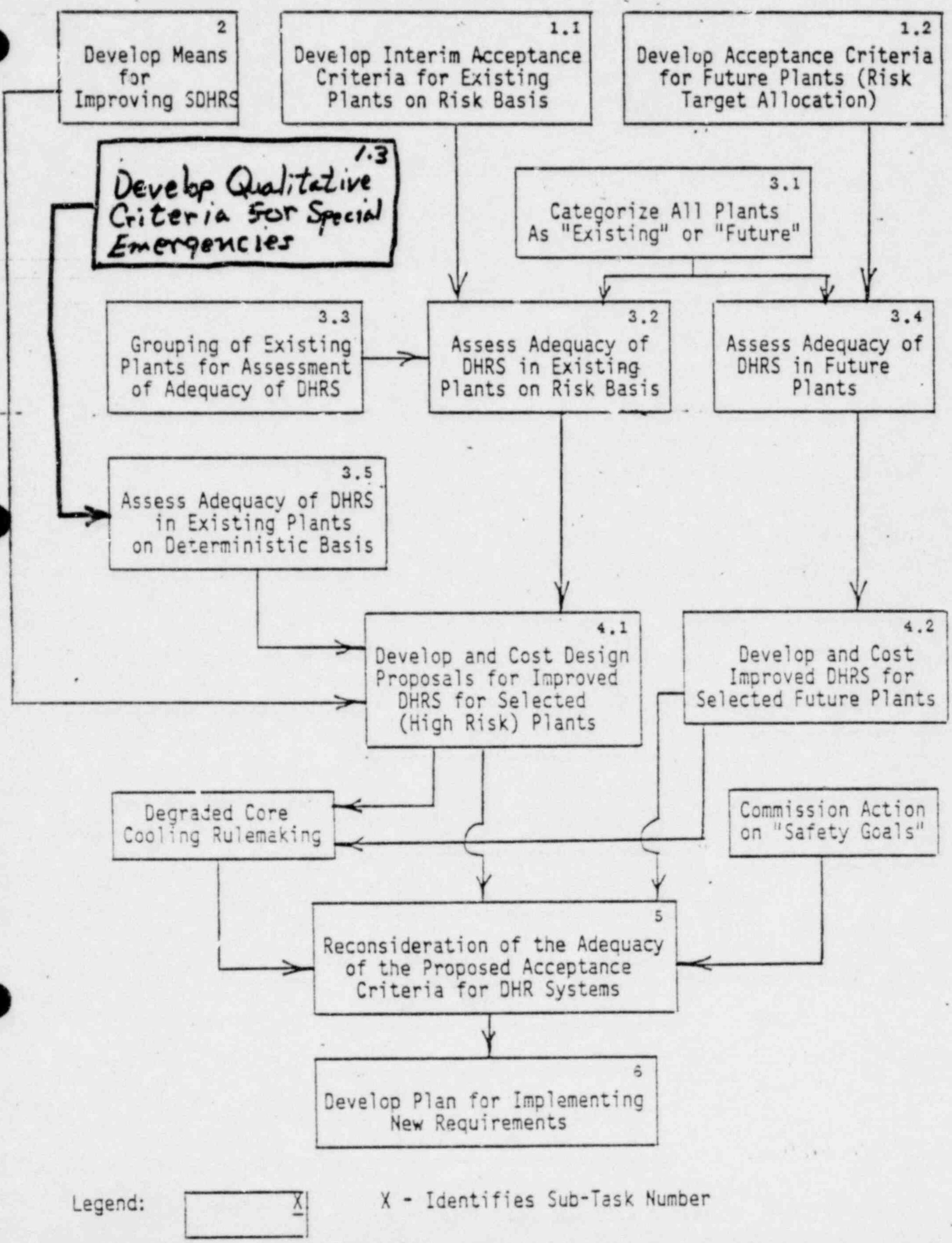
- ASSESS ADEQUACY OF DHRS IN EXISTING AND FUTURE LWRs
  - CATEGORIZE PLANTS AS "EXISTING" OR "FUTURE"
  - ASSESS ADEQUACY OF DHRS IN SELECTED EXISTING PLANTS ON RISK BASIS
  - GROUP OTHER EXISTING PLANTS FOR ASSESSMENT OF ADEQUACY OF DHRS
  - ASSESS ADEQUACY OF DHRS IN SELECTED FUTURE PLANTS
  - ASSESS ADEQUACY OF DHRS IN EXISTING PLANTS ON DETERMINISTIC BASIS

- DEVELOP AND COST IMPROVED DHRS IN SELECTED PLANTS.
  - SELECTED EXISTING PLANTS
  - SELECTED FUTURE PLANTS

- RECONSIDER ADEQUACY OF ACCEPTANCE CRITERIA FOR DHRS
  - REVIEW INTERIM DHRS ACCEPTANCE CRITERIA AND TECHNICAL REQUIREMENTS, REVISE IF NECESSARY

- DEVELOP PLAN FOR IMPLEMENTING NEW REQUIREMENTS (E.G., PREPARE NUREG, REG. GUIDE)

Figure 1. Inter-Relation of Sub-Tasks in Task Action Plan A-45 - (Oct. 1982)



MAIN ELEMENTS OF A-45 TASK ACTION PLAN (Feb-82)

- DEVELOP ~~INTERIM~~ ACCEPTANCE CRITERIA FOR ASSESSMENT OF DHRS
  - EXISTING PLANTS
  - FUTURE PLANTS
  - DEVELOPMENT OF ~~INTERIM~~ QUALITATIVE CRITERIA FOR "SPECIAL EMERGENCIES"

- DEVELOP MEANS FOR IMPROVEMENT OF SDHRS
  - PHENOMENOLOGICAL STUDIES
    (1) REVIEW OF CURRENT THERMAL-HYDRAULICS RESEARCH RELEVANT TO SDHRS
    (2) ON-GOING REVIEW OF THERMAL-HYDRAULICS RESEARCH
  - CONCEPTUAL DESIGN STUDIES (GENERIC)
  - OPERATIONAL ASPECTS OF ALTERNATIVE SDHR SYSTEMS

- ASSESS ADEQUACY OF DHRS IN EXISTING ~~AND FUTURE~~ LWRs
  - ~~CATEGORIZE PLANTS AS "EXISTING" OR "FUTURE"~~
  - ASSESS ADEQUACY OF DHRS IN SELECTED EXISTING PLANTS ~~ON RISK BASIS~~
  - GROUP OTHER EXISTING PLANTS FOR ASSESSMENT OF ADEQUACY OF DHRS
  - ~~ASSESS ADEQUACY OF DHRS IN SELECTED FUTURE PLANTS~~
  - ASSESS ADEQUACY OF DHRS IN EXISTING PLANTS ON DETERMINISTIC BASIS

- ~~DEVELOP AND COST IMPROVED DHRS IN SELECTED PLANTS~~
  - ~~SELECTED EXISTING PLANTS~~
  - ~~SELECTED FUTURE PLANTS~~

- ~~RECONSIDER ADEQUACY OF ACCEPTANCE CRITERIA FOR DHRS~~
  - ~~REVIEW INTERIM DHRS ACCEPTANCE CRITERIA AND TECHNICAL REQUIREMENTS, REVISE IF NECESSARY~~

- DEVELOP PLAN FOR IMPLEMENTING NEW REQUIREMENTS (E.G., PREPARE NUREG, REG. GUIDE)

MAIN ELEMENTS OF A-45 TASK ACTION PLAN - FEBRUARY 1982

- DEVELOP ACCEPTANCE CRITERIA FOR ASSESSMENT OF DHRS
  - EXISTING PLANTS
  - FUTURE PLANTS
  - DEVELOPMENT OF QUALITATIVE CRITERIA FOR "SPECIAL EMERGENCIES"

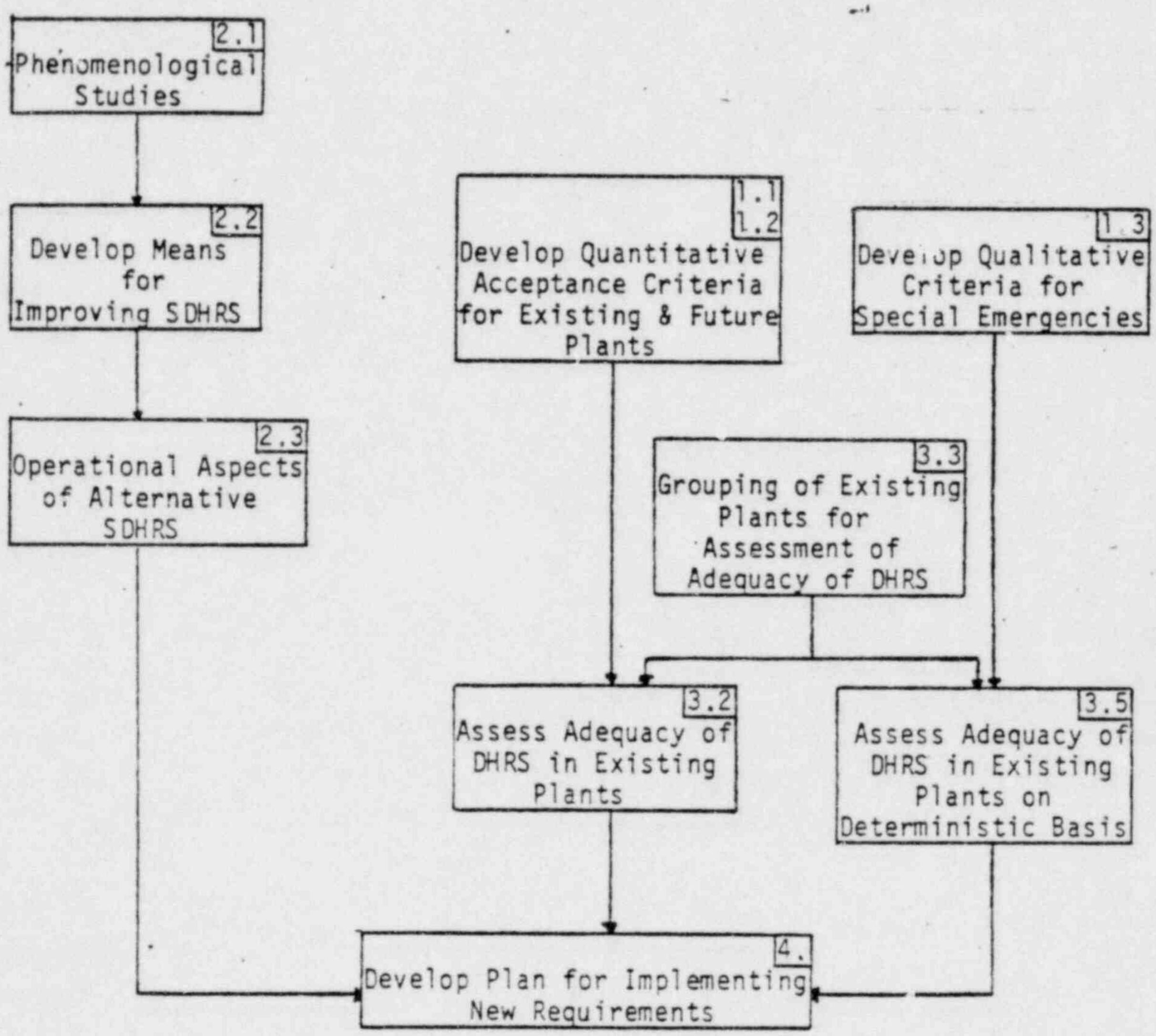
- DEVELOP MEANS FOR IMPROVEMENT OF SDHRS
  - PHENOMEMOLOGICAL STUDIES
    1. REVIEW OF CURRENT THERMAL-HYDRAULICS RESEARCH RELEVANT TO SDHRS
    2. ONGOING REVIEW OF THERMAL-HYDRAULICS RESEARCH
  - CONCEPTUAL DESIGN STUDIES (GENERIC)
  - OPERATIONAL ASPECTS OF ALTERNATIVE SDHR SYSTEMS

- ASSESS ADEQUACY OF DHRS IN EXISTING LWRs
  - ASSESS ADEQUACY OF DHRS IN SELECTED EXISTING PLANTS
  - GROUP OTHER EXISTING PLANTS FOR ASSESSMENT OF ADEQUACY OF DHRS
  - ASSESS ADEQUACY OF DHRS IN EXISTING PLANTS ON DETERMINISTIC BASIS

- DEVELOP PLAN FOR IMPLEMENTING NEW REQUIREMENTS (E.G., PREPARE NUREG, REG. GUIDE)

Figure 1. Inter-Relation of Sub-Tasks in Task Action Plan A-45

(FEBRUARY 1982)

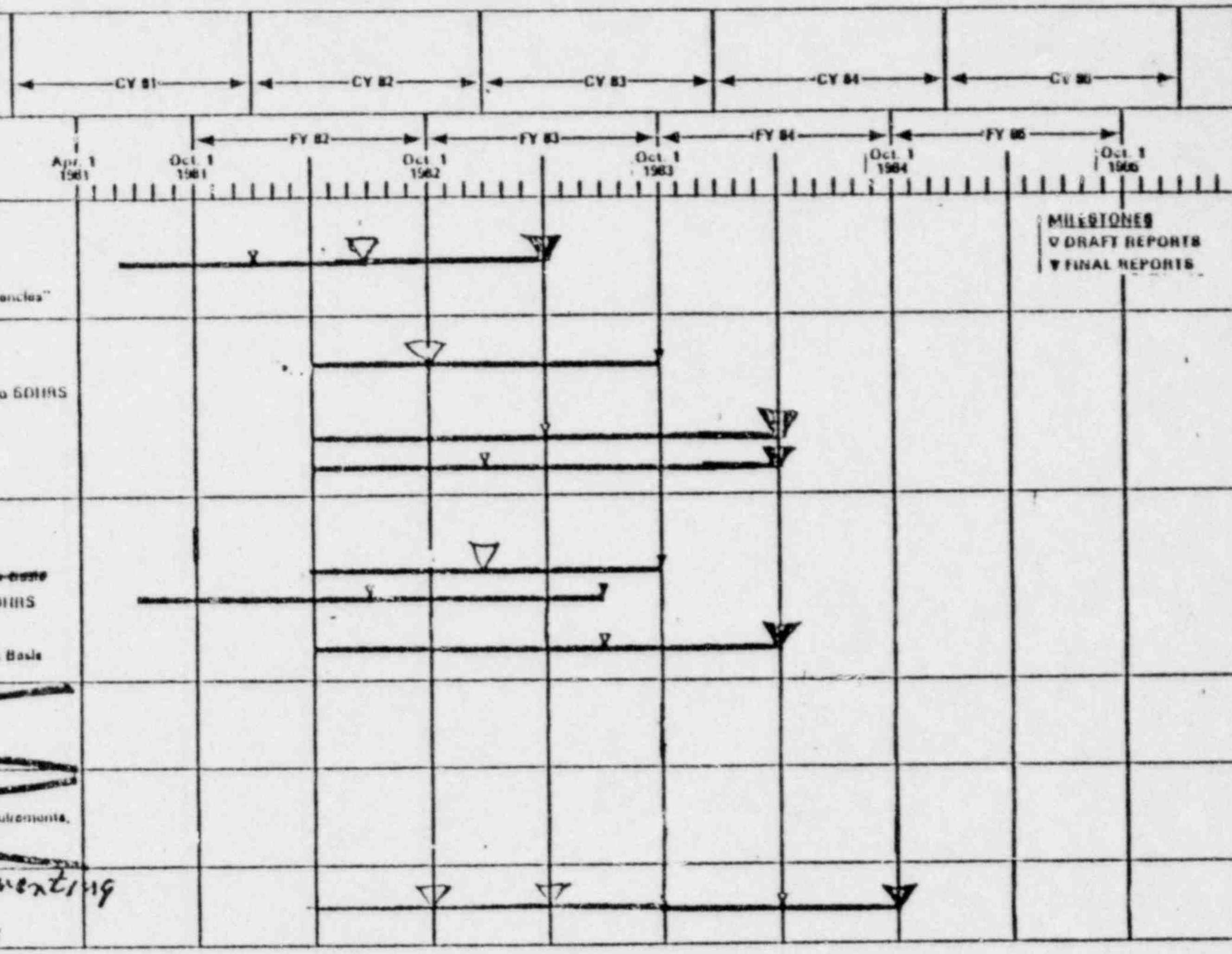


~~OPTION III. b.~~

Figure B-1

DETAILED SCHEDULE FOR TASK A-45, "SHUTDOWN DECAY HEAT REMOVAL REQUIREMENTS"

Sub Task No.	Content of Sub-Task
1	Develop ~~Interim~~ Acceptance Criteria for Assessment of DHRS
1.1	Existing Plants
1.2	Future Plants
1.3	Development of ~~Interim~~ Qualitative Criteria for "Special Emergencies"
2	Develop Means for Improvement of SDHRS
2.1	Phenomenological Studies
	(1) Review of Current Thermal Hydraulics Research Relevant to SDHRS
	(2) Ongoing Review of Thermal Hydraulics Research
2.2	Conceptual Design Studies (Generic)
2.3	Operational Aspects of Alternative SDHR Systems
3	Assess Adequacy of DHRS in Existing ~~and Future~~ LWRs
3.2	Assess Adequacy of DHRS in Selected Existing Plants ~~on Risk Basis~~
3.3	Group Other Existing Plants for Assessment of Adequacy of DHRS
3.5	Assess Adequacy of DHRS in Existing Plants on Deterministic Basis
~~4~~	~~Develop and Cost Improved DHRS in Selected Plants~~
~~4.1~~	~~Selected Existing Plants~~
~~4.2~~	~~Selected Future Plants~~
~~6~~	~~Reconsider Adequacy of Acceptance Criteria for DHRS~~
	~~Review Interim DHRS Acceptance Criteria and Technical Requirements, Revise If Necessary~~
7	Develop Plan for Implementing New Requirements



DISCUSSION WITH EPRI ON INDUSTRY INVOLVEMENT IN TASK A-45

- ENCOURAGE INDUSTRY COOPERATION AND INVOLVEMENT IN TASK A-45
- OPTIONS TO CONSIDER:
  - INDUSTRY SETS UP ITS OWN PARALLEL PROGRAM, OR
  - INDUSTRY DOES SPECIFIC PARTS OF A-45 ACTION PLAN (E.G., SUB-TASK 4 ON PLANT-SPECIFIC DESIGN OF ALTERNATIVE DHRS)
  - INDUSTRY PEER REVIEW GROUP FOR TASK A-45 MILESTONE REPORTS
- PRIORITY FOR DEVELOPMENT OF CONCEPTUAL DESIGNS FOR IMPROVED DHRS FOR A SPECIFIC PLANT WILL DEPEND ON:
  1. CORE MELT FREQUENCY DUE TO THAT PLANT AND ON THE EFFECTIVENESS OF IMPROVEMENT OF DHRS AS A MEANS OF REDUCING THAT FREQUENCY, AND/OR
  2. CAPABILITY FOR HANDLING "SPECIAL EMERGENCY" SITUATIONS

NRR STATUS REPORT

- In Response To D. Eisenhut's Letter, CE Has Provided Staff With Report On Depressurization And Decay Heat Removal Capabilities For CE System 80 Nsss
- Report Is Under Staff Review Preliminary Questions Have Been Fowarded To CE
- We Will Formally Transmit Questions To CE And Request Formal Response

AFW RELIABILITY

ASB RELIABILITY CRITERIA, CE REPORTS, AND PRA RESULTS LEAD STAFF TO CONCLUSION THAT PORV'S ARE NOT NECESSARY TO COMPENSATE FOR AFW UNRELIABILITY

CESSAR DESIGN WITHOUT PORVS

SAFETY FUNCTIONS	ADVANTAGES	DISADVANTAGES
DECAY HEAT REMOVAL	1. ELIMINATES POSSIBILITY OF STUCK-OPEN PORV 2. REDUCED PLANT COSTS	1. ELIMINATES A DIVERSE MEANS OF DHR 2. RELIES ON AUX SPRAY TO PREVENT 2-ø NC DURING COOLDOWN 3. ASSUMES S.G. INTEGRITY MAINTAINED
MITIGATION OF TRANSIENTS AND ACCIDENTS	1. ELIMINATES POSSIBILITY OF STUCK-OPEN PORV 2. LESS EQUIPMENT REQUIRING OPERATOR ACTION 3. REDUCED PLANT COSTS	1. POSSIBLY MORE CHALLENGES TO RPS 2. RELIES ON AUX SPRAY
REDUCTION OF CONSEQUENCES FROM TRANSIENTS AND ACCIDENTS	1. ELIMINATES POSSIBILITY OF STUCK-OPEN PORV 2. REDUCED PLANT COSTS	1. POSSIBLY MORE SEVERE RADIOLOGICAL CONSEQUENCES AFTER AN EVENT (E.G., SGTR) 2. RELIES ON AUX SPRAY
BEYOND DESIGN BASIS	1. ELIMINATES POSSIBILITY OF STUCK-OPEN PORV 2. REDUCED PLANT COSTS 3. OPERATORS USE SYSTEMS THEY ARE FAMILIAR WITH	1. NO DIRECT MEANS OF PRIMARY SYSTEM DEPRESSURIZATION 2. NO CONTINGENCY TO AUGMENT AFW SYSTEM 3. RELIES ON STRUCTURAL INTEGRITY OF SG' 4. WATER CHEMISTRY CONCERNS FOR SECONDAR

CEASSR DESIGN WITH PORV

SAFETY FUNCTIONS	ADVANTAGES	DISADVANTAGES
DECAY HEAT REMOVAL	1. DIVERSE, DIRECT MEANS OF DHR (FEED & BLEED) 2. ELIMINATES RELIANCE ON AUX SPRAY TO PREVENT 2-ø NC	1. EXTRA COST TO PLANTS 2. INCREASES POSSIBILITY OF STUCK-OPEN PORV
MITIGATION OF TRANSIENTS AND ACCIDENTS	1. POSSIBLE REDUCTION IN CHALLENGES TO RPS 2. INCREASES OPERATIONAL FLEXIBILITY 3. ELIMINATES RELIANCE ON AUX SPRAY TO PREVENT 2-ø NC	1. EXTRA COST TO PLANTS 2. INCREASES POSSIBILITY OF STUCK-OPEN POR
REDUCTION OF CONSEQUENCES FROM TRANSIENTS AND ACCIDENTS	1. POSSIBLY REDUCE RADIOLOGICAL CONSEQUENCES OF EVENTS (E.G., SGTR) 2. ELIMINATES RELIANCE ON AUX SPRAY TO PREVENT 2-ø NC	1. EXTRA COST TO PLANTS 2. INCREASES POSSIBILITY OF STUCK-OPEN POR
BEYOND DESIGN BASIS	1. PROVIDES DIRECT MEANS OF DHR FROM PRIMARY SYSTEM 2. DOES NOT RELY ON STRUCTURAL INTEGRITY OF SG'S 3. PROVIDES MEANS FOR RAPID DEPRESSURIZATION OF PRIMARY SYSTEM 4. IMPROVES ATWS MITIGATION CAPABILITY 5. ABILITY TO REDUCE PTS CONDITIONS	1. OPERATORS POSSIBLY LESS COMFORTABLE USING A F&B SYSTEM 2. INCREASES POSSIBILITY OF STUCK-OPEN POR 3. EXTRA COST TO PLANTS

SOME QUESTIONS

- o SG TUBE INTEGRITY (WHAT IS PROBABILITY OF SGTR'S IN MORE THAN ONE GENERATOR?)

- o CE HAS PROPOSED USE OF LOW PRESSURE SYSTEMS TO PROVIDE EMEREGENCY WATER TO SGs.

  - NO IDENTIFICATION OF SYSTEMS PROPOSED
  - POOR WATER CHEMISTRY COULD RAPIDLY DEGRADE TUBES
  - COLD WATER ADDITION TO A DRIED-OUT STEAM GENERATOR WITH DEGRADED TUBES COULD INDUCE TUBE FAILURES

- o CAN PORV's MANAGE A SGTR BETTER THAN AUX SPRAY?

- PROBABILITY AND CONSEQUENCES OF LOSS OF ALL FEEDWATER
- RISK ASSOCIATED WITH MULTIPLE TUBE FAILURES IN ONE STEAM GENERATOR WITH FAILURE OF RELIEF VALVE IN THE FAULTY STEAM GENERATOR
- PROBABILITY OF AND RISK ASSOCIATED WITH TUBE RUPTURES IN TWO STEAM GENERATORS
- FREQUENCY AND CONSEQUENCES OF PORV-INITIATED LOCA
- POTENTIAL BENEFITS FROM PORVs UNDER VARIOUS ACCIDENT CONDITIONS INCLUDING ATWS & REDUCED SEVERITY OF PRESSURIZED THERMAL SHOCK
- COST OF INSTALLING PORVs/COST OF DELAYED DECISION

WHERE DO WE GO FROM HERE ?

- o Staff Will Formally Transmit Questions To All Applicants' With CE NSSS Designs Without Porvs
- o We Will Request Response Schedule Consistent With A Decision Date Prior To Power Operation
- o If Response Cannot Be Provided On Above Schedule, Applicant Must Provide Justification Why Operation Can Proceed Without PORVs
- o In Any Event, We Will Require Response To All Staff Questions Consistent With A Decision Date Within About 12 Months, Depending On Applicant's Justification.

CESSAR ACRS LETTER

"....GIVE CONSIDERATION TO THE POTENTIAL FOR ADDING VALVE OF A SIZE TO FACILITATE RAPID DEPRESSURIZATION OF THE SYSTEM 80 PRIMARY COOLANT SYSTEM TO ALLOW MORE DIRECT METHODS OF DECAY HEAT REMOVAL."

ACRS SUBCOMMITTEE ON DECAY HEAT REMOVAL

REVIEW OF DRAFT SSER	R. TURK
COMMENTS ON DRA STUDY	J. HERBST
ALTERNATE DHR (A-45)	R. TURK

RESULTS OF C-E REVIEW

THE CURRENT SYSTEM 80 DESIGN, STRENGTHENED BY AN INTERFACE REQUIREMENT ON THE AVAILABILITY OF THE EFW SYSTEM, ADEQUATELY PROTECTS THE HEALTH AND SAFETY OF THE PUBLIC.

BASED ON:

1. HIGHLY RELIABLE EFW SYSTEM.
2. CAPABILITY TO ACHIEVE COLD SHUTDOWN.
3. STEAM GENERATOR DESIGN FEATURES.
4. MODIFICATIONS DO NOT APPEAR JUSTIFIABLE.
5. POTENTIAL ALTERNATIVE DHR APPEARS VIABLE USING STEAM GENERATORS.

POTENTIAL ADVANTAGES
IN NOT PROVIDING
FEED AND BLEED

1. RCPB IS MAINTAINED INTACT.

2. EQUIPMENT ACCESSABILITY IS ENHANCED.

3. OPERATING AND DHR STRATEGIES ARE CONSISTENT.

BACKGROUND

PORV DESIGN FUNCTION

- REDUCE CHALLENGES TO SAFETY VALVES

PORV REMOVED FROM POST 1970 C-E DESIGNS

- UNABLE TO SUBSTANTIATE ANY ADVANTAGES
  PZR SPRAY AND HIGH PRESSURE REACTOR
  TRIP PERFORMED REQUIRED FUNCTION
- OPERATIONAL PROBLEMS WITH PORV's
- NEVER CREDITED IN OVERPRESSURE
  PROTECTION ANALYSES

TRANSIENTS AND ACCIDENTS

- FSAR ANALYSES
- POST TMI BEST ESTIMATE ANALYSES
- OPERATING EXPERIENCE

FSAR ANALYSES

- HISTORICALLY PORV HAS NOT BEEN CONSIDERED IN THE OVERPRESSURE AND SAFETY ANALYSES OF CHAPTERS 5 AND 15.

- THE FOLLOWING CHAPTER 15 ANALYSES RESULT IN SAFETY VALVE OPERATION.

  1. LOSS OF VACUUM
  2. FWLB
  3. CEA WITHDRAWAL
  4. CEA EJECTION

POST TMI BEST ESTIMATE ANALYSES
(I.C.1)

- INCLUDED
  1. PORV
  2. PZR SPRAY
  3. STEAM BYPASS CONTROL SYSTEM
  4. REACTOR TRIP ON TURBINE TRIP

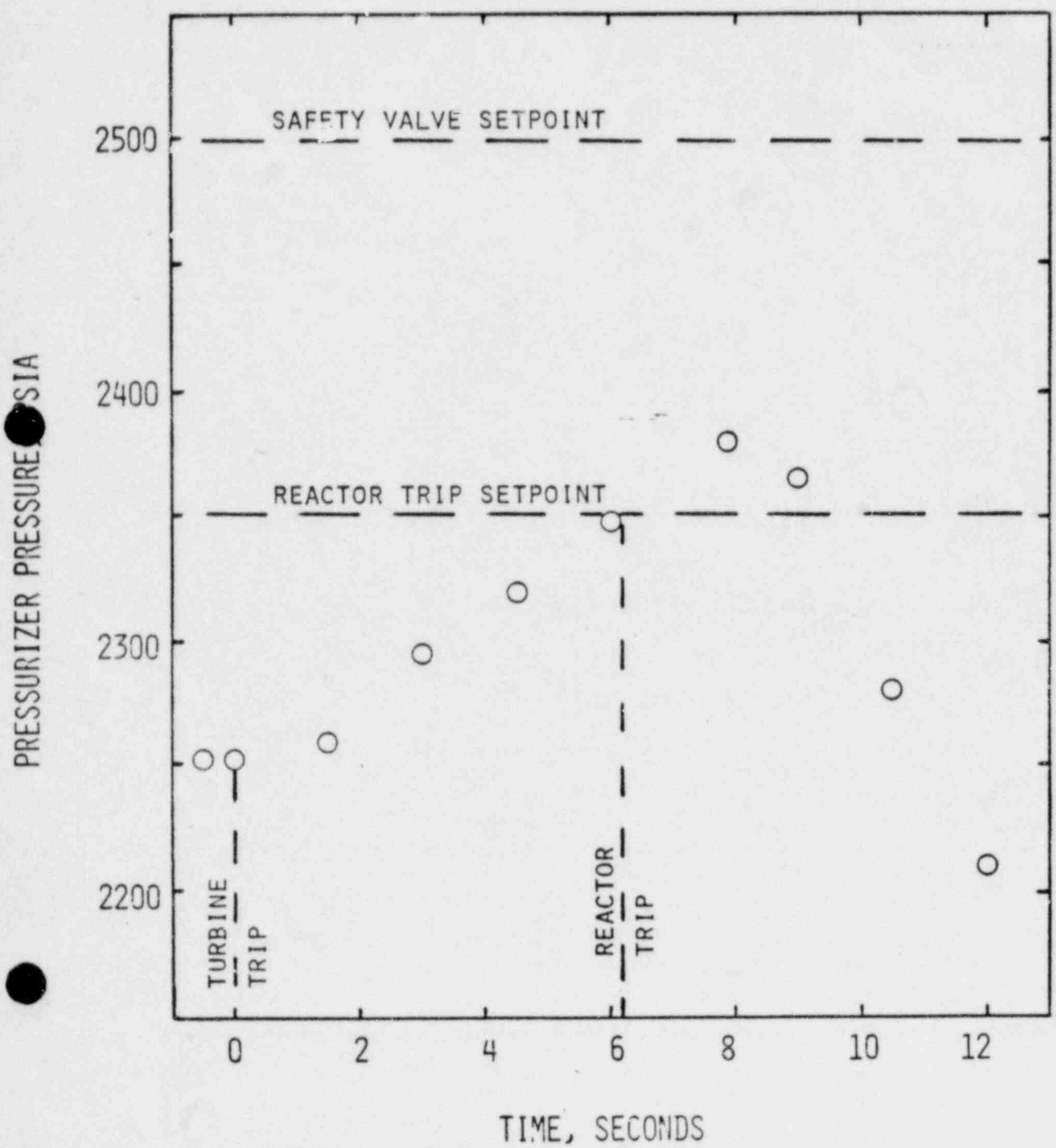
- NO TRANSIENTS RESULTED IN PORV OPERATION

OPERATING EXPERIENCE

- TURBINE TRIP AT ANO-2
- HIGH PRESSURE REACTOR TRIP PREVENTED CHALLENGE TO SAFETY VALVE

ANO-2 TURBINE TRIP (1/29/80)

PRESSURIZER PRESSURE VS TIME



PORV FUNCTIONS

DESIGN BASES	WITHOUT PORV
1. PREVENT SAFETY VALVE LIFT	PZR SPRAY REACTOR CUTBACK SYSTEM REACTOR TRIP ON HIGH PRESSURE
2. LOW TEMPERATURE OVERPRESSURE PROTECTION	SDCS RELIEF VALVES

NON-DESIGN BASES	
1. VENTING NON-CONDENSIBLES	REACTOR HEAD AND PZR VENT
2. RCS DEPRESSURIZATION	AUXILIARY SPRAY
3. RCS HEAT REMOVAL	AUXILIARY FEEDWATER, SAFETY GRADE SDCS

EFWS AVAILABILITY INTERFACE

"THE EMERGENCY FEEDWATER SYSTEM (EFWS) SHALL HAVE AN UNAVAILABILITY IN THE RANGE 10^{-4} TO 10^{-5} PER DEMAND BASED ON AN ANALYSIS USING METHODS AND DATA PRESENTED IN NUREG-0611 AND NUREG-0635. COMPENSATING FACTORS SUCH AS OTHER METHODS OF ACCOMPLISHING SAFETY FUNCTIONS OF THE EFWS OR OTHER RELIABLE METHODS FOR COOLING THE REACTOR CORE DURING ABNORMAL CONDITIONS MAY BE CONSIDERED TO JUSTIFY A LARGER UNAVAILABILITY."

F. INDEPENDENCE

9. No single active or passive component failure, single passive or active electrical component failure, or power supply failure shall preclude adequate operation of the Emergency Feedwater System such as the following events:

   a. Loss of normal feedwater with or without a concurrent loss of normal onsite or offsite AC power.

   b. Minor secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.

   c. Steam generator tube rupture with or without a concurrent loss of normal onsite or offsite AC power.

   d. Major secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.

   e. Small LOCA with or without a concurrent loss of normal onsite or offsite AC power.

10. The ability of the Emergency Feedwater System to perform its design function considering a power supply failure, a single active or passive mechanical component failure, a single active or passive failure of an electrical component, or the effects of a high or moderate energy pipe rupture shall be demonstrated.

11. The Emergency Feedwater System shall provide double isolation from the Main Feedwater System during plant conditions when the Emergency Feedwater System is not required.

I. OPERATIONAL CONTROLS

11. The Emergency Feedwater System shall be controllable in a post-accident environment from either the control room or a remote shutdown station.

12. The Emergency Feedwater System shall be controllable such that post accident operation will not result in overfilling the intact steam generator(s).

13. If the Emergency Feedwater System is used as an auxiliary feedwater system, the emergency feedwater pumps shall be designed for operation when steam generator pressure is negligible and not result in damage to the pumps or effect the ability of the system to deliver the required emergency feedwater flow. Such a condition can exist during startup or shutdown operation subsequent to an EFAS which starts the emergency feedwater pumps and fully opens the system isolation and control valves.

EFWS - FLOW REQUIREMENTS

G. THERMAL LIMITATIONS

5. Following the events stated in Section 5.1.4.F.9, the emergency feedwater system shall maintain adequate inventory in the steam generator(s) for residual heat removal and be capable of the following:

   a. Maintaining the NSSS at hot standby with or without normal offsite and normal onsite power available.

   b. Facilitating NSSS cooldown at the maximum administratively controlled rate of 75°F/hr. from hot standby to shutdown cooling initiation with or without normal offsite or onsite power available. (The Shutdown Cooling System becomes available for plant cooldown when the RCS temperature and pressure are reduced to approximately 350°F and 400 psia.)

6. The Emergency Feedwater System shall be available to deliver flow to the steam generator(s) automatically upon receipt of an EFAS as follows:

   a. Within 10 seconds when normal offsite or normal onsite power is available.

   b. Within 45 seconds when both normal onsite and normal offsite power are not available.

7. The required emergency feedwater flow, based on residual heat removal requirements is 875 gpm delivered to the steam generator(s) downcomer feedwater nozzle. Maximum expected steady state steam generator pressure at the downcomer nozzle is approximately 1275 psia.

8. Emergency feedwater temperature shall be at least 40F and no greater than 180F.

9. A minimum of 300,000 gallons of secondary quality makeup water as defined in Section 10.3.4 shall be available to the Emergency Feedwater System for delivery to the intact steam generator(s).

B. PROTECTION

4. All components and piping of the Emergency Feedwater System between the steam generators and the containment isolation valves shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

TYPICAL

AFWS

DESIGN FEATURES

3-100% CAPACITY PUMPS

ASME III CLASS 3 (CLASS 2)

SEISMIC CATEGORY 1

ELECTRICAL CLASS 1E

AUTOMATIC ACTUATION AND ISOLATION

PUMP DRIVE AND POWER DIVERSITY

ONE AC INDEPENDENT TRAIN

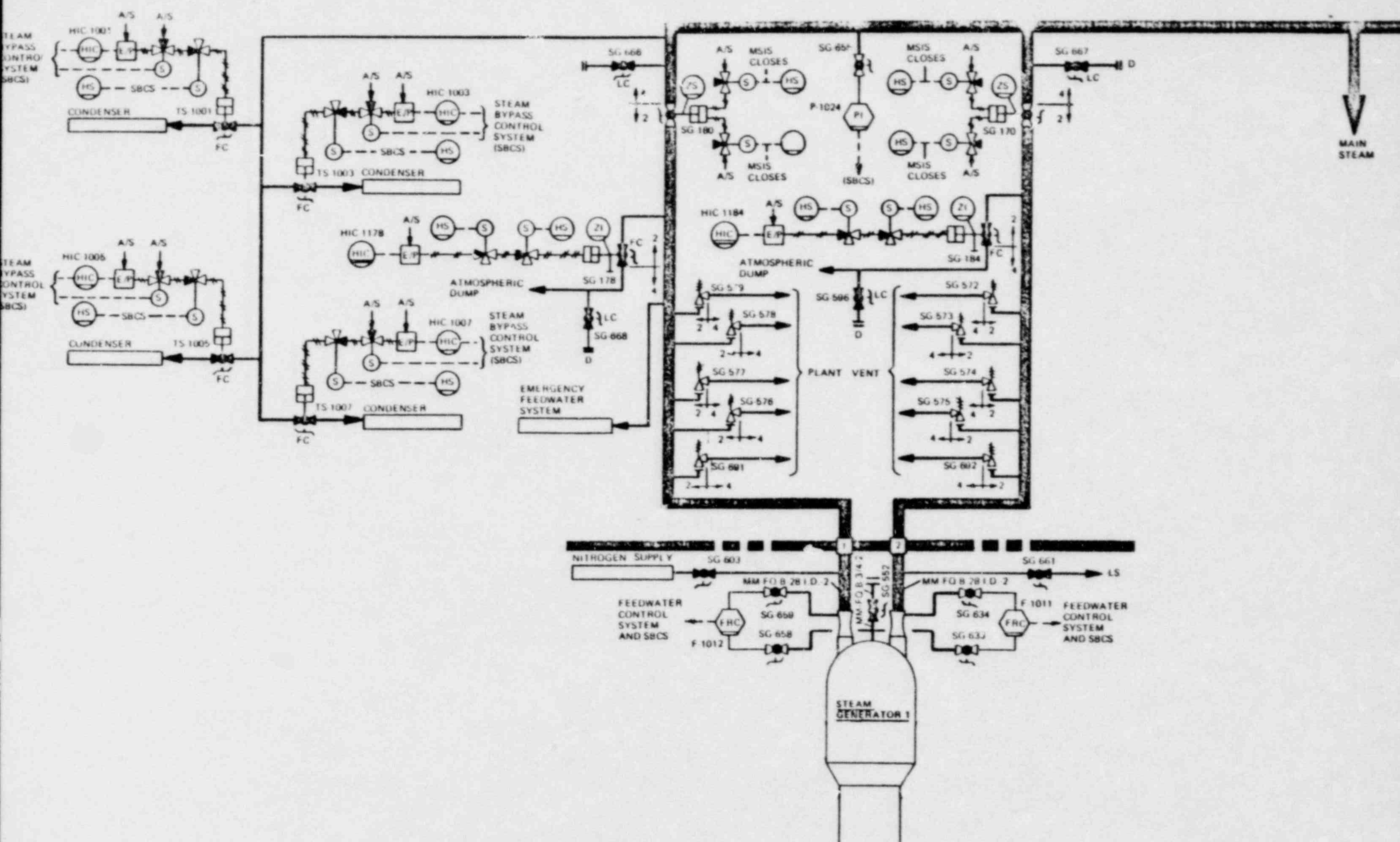
REDUNDANCY AND SEPARATION TO MEET
BTP ASB 10-1

COOLDOWN AND DEPRESSURIZATION

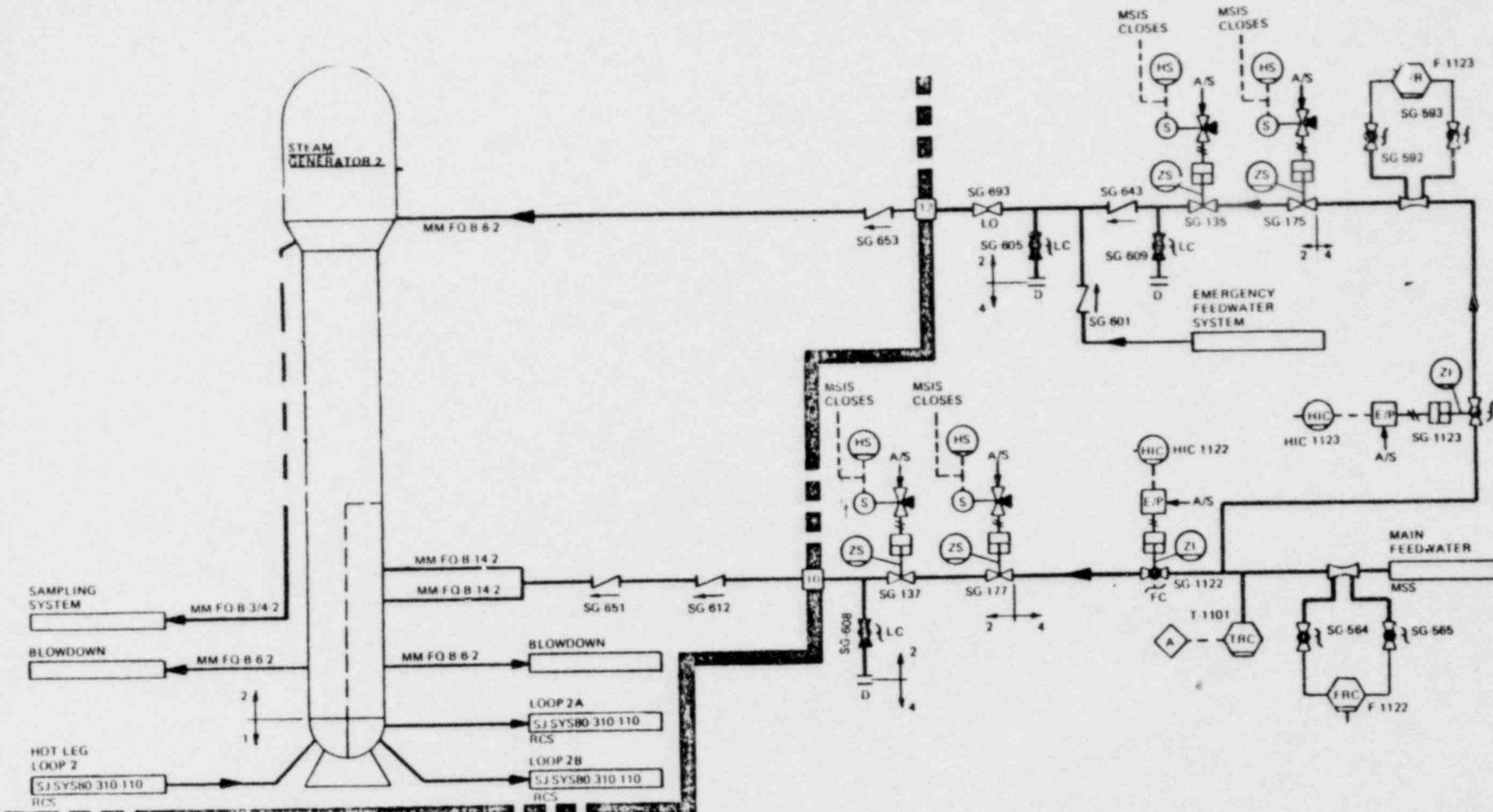
SYSTEM 80 DESIGN PROVIDES THE CAPABILITY TO ACHIEVE COLD SHUTDOWN CONDITIONS USING ONLY SAFETY GRADE SYSTEMS, ASSUMING A LOSS OF OFFSITE POWER AND ANY ADDITIONAL SINGLE FAILURE.

DESIGN DHR SYSTEMS

FUNCTION	SYSTEMS
REACTIVITY CONTROL	CVCS, SIS
INVENTORY CONTROL	CVCS (CHARGING), SIS
PRESSURE CONTROL	PZR HEATERS, RCS SPRAY, CVCS (AUX. SPRAY)
RCS HEAT REMOVAL	MSS, MFWS, ADVs, EFWS, SCS
CORE HEAT REMOVAL	RCS (NATURAL CIRCULATION)



MAIN STEAM
STEAM BYPASS CONTROL SYSTEM (SBCS)
HIC 1001
HIC 1003
HIC 1005
HIC 1007
HIC 1178
HIC 1184
TS 1001
TS 1003
TS 1005
TS 1007
CONDENSER
ATMOSPHERIC DUMP
EMERGENCY FEEDWATER SYSTEM
MSIS CLOSES
P 1024
(SBCS)
SG 170
SG 180
SG 178
SG 184
SG 667
SG 668
SG 586
PLANT VENT
SG 572
SG 573
SG 574
SG 575
SG 576
SG 577
SG 578
SG 681
SG 682
NITROGEN SUPPLY
SG 603
SG 661
LS
SG 552
FEEDWATER CONTROL SYSTEM AND SBCS
F 1011
F 1012
SG 634
SG 658
SG 659
STEAM GENERATOR 1


STEAM GENERATOR 2
MM FO B 6 2
SG 653
SG 693
LO
SG 605
LC
D
SG 643
SG 609
SG 135
SG 175
SG 601
EMERGENCY FEEDWATER SYSTEM
MSIS CLOSES
HS
S
ZS
A/S
F 1123
SG 593
SG 592
ZI
HIC
E/P
HIC 1123
SG 1123
FC
HIC 1122
SG 1122
T 1101
A
TRC
MAIN FEEDWATER
MSS
SG 564
SG 565
FRC
F 1122
SG 137
SG 177
SG 608
SG 651
SG 612
MM FO B 14 2
SAMPLING SYSTEM
MM FO B 3/4 2
BLOWDOWN
LOOP 2A
LOOP 2B
SJ SYS80 310 110
RCS
HOT LEG LOOP 2

CVCS Figure 4

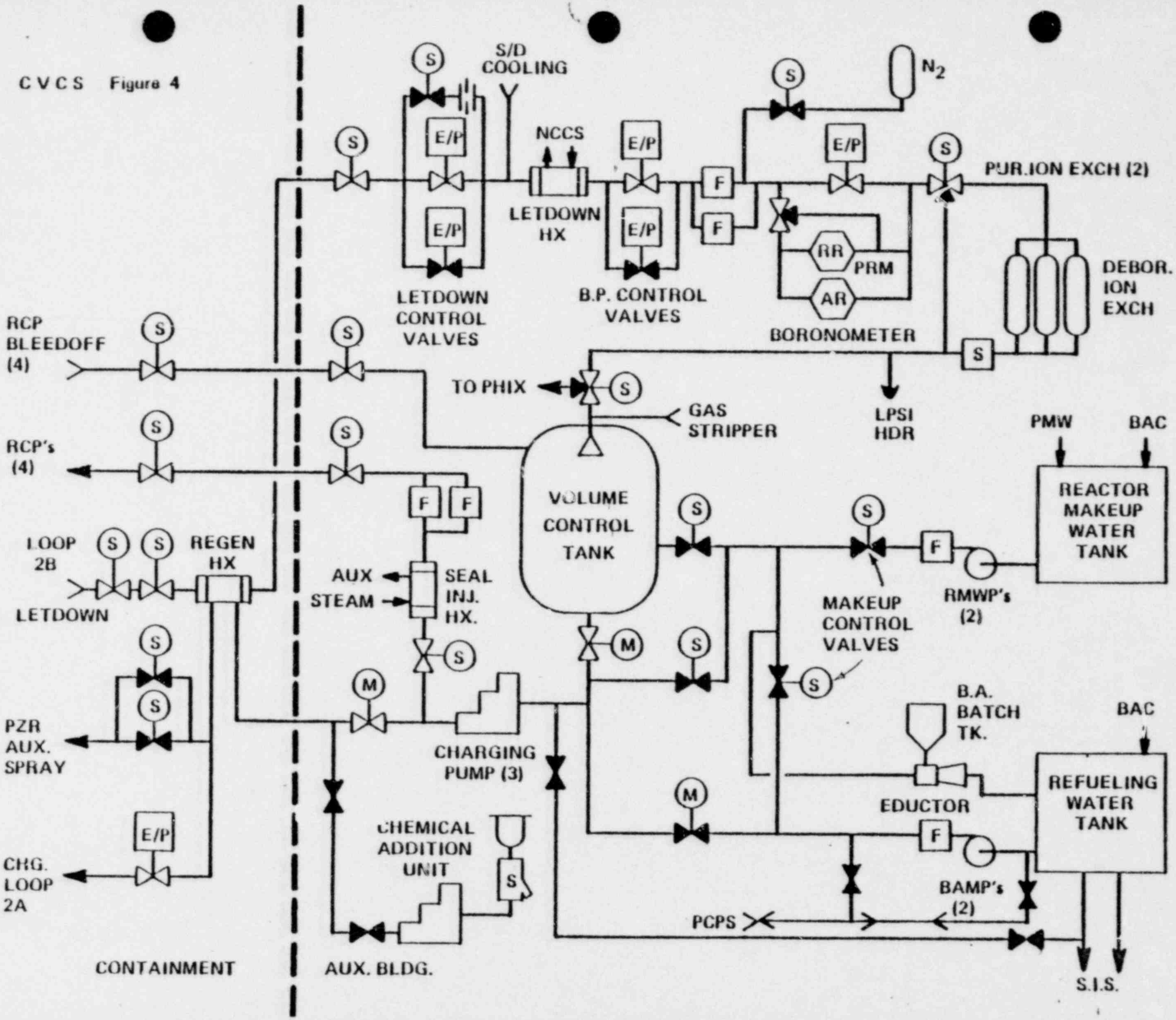
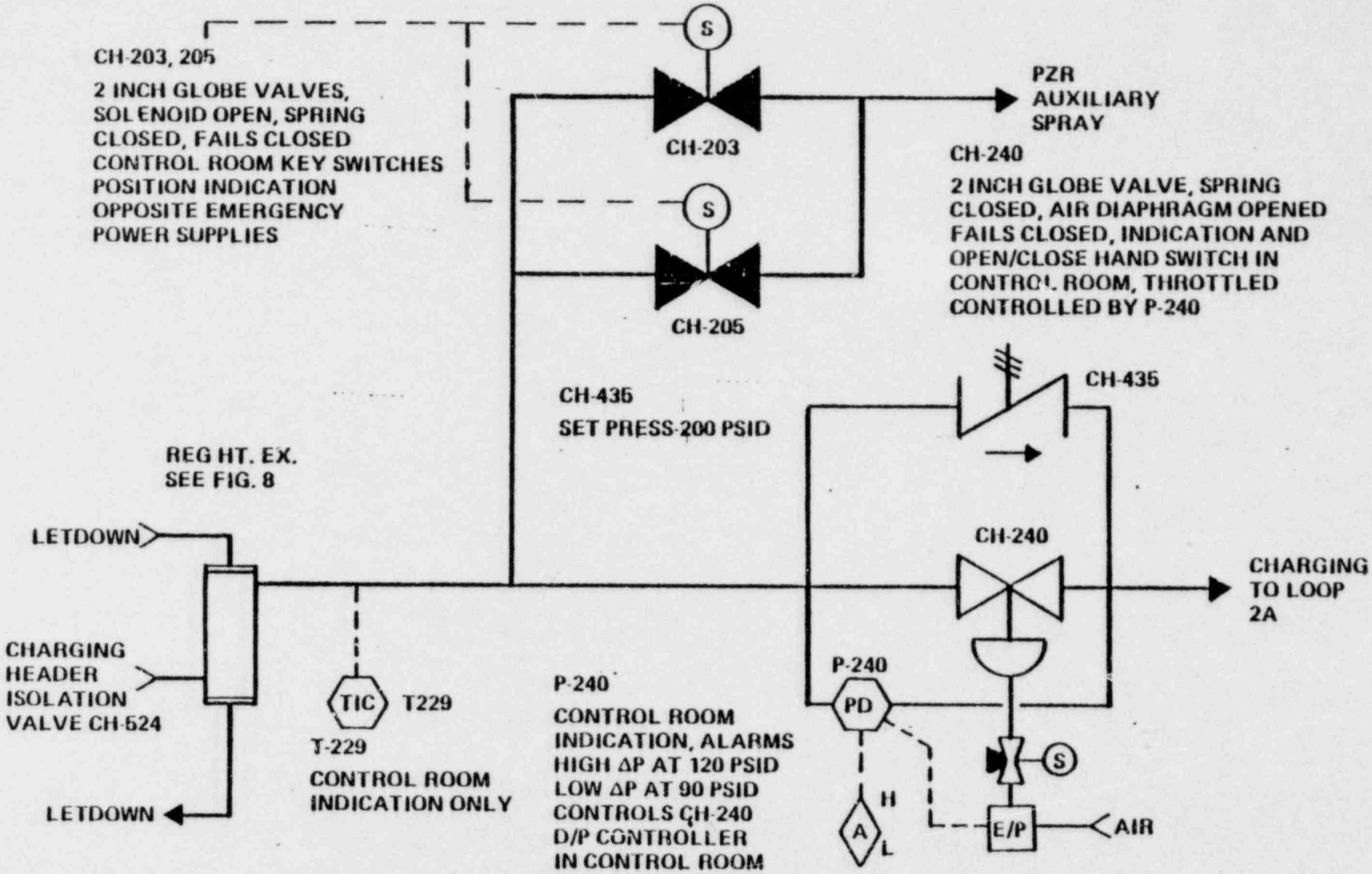
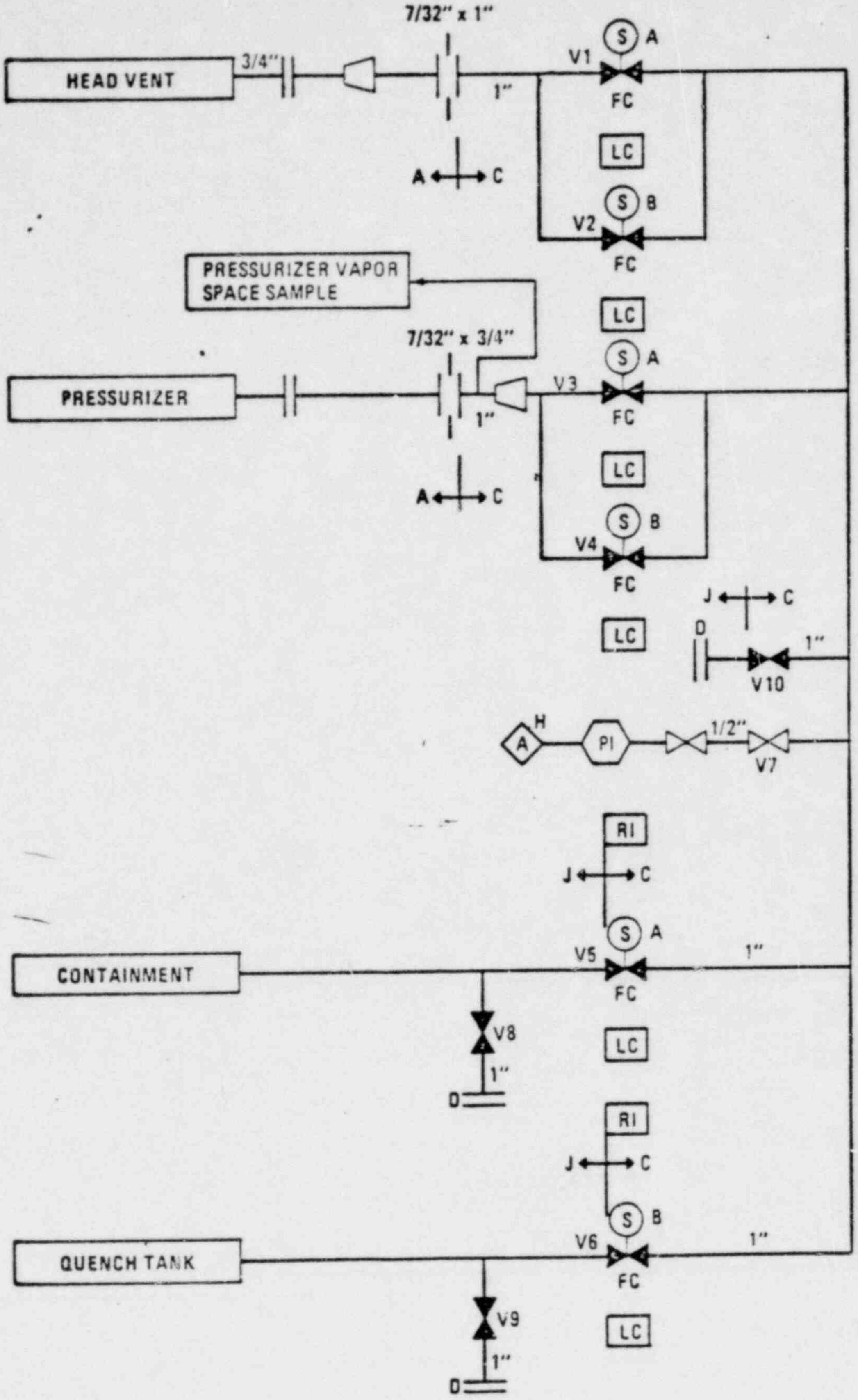


Figure 33

CHARGING HEADER – CONTAINMENT





REACTOR COOLANT GAS VENT
SYSTEM SKETCH

Figure II.B.1-1

PLANT DEPRESSURIZATION

1. PRESSURIZER HEAT REMOVAL

2. RCS HEAT REMOVAL

3. DEGASIFICATION

PLANT DEPRESSURIZATION

1. PRESSURIZER HEAT REMOVAL
   - REDUNDANT SAFETY GRADE AUXILIARY SPRAY

2. RCS HEAT REMOVAL
   - ENGINEERED SAFETY FEATURES GRADE EFWS
   - FOUR ATMOSPHERIC DUMP VALVES

3. DEGASIFICATION
   - REACTOR HEAD AND PRESSURIZER VENT

SYSTEM CAPABILITIES

PRESSURIZER DEPRESSURIZATION	
2250 PSI TO 350 PSI	2.5 HOURS
2250 PSI TO RCS SATURATION	10 MINUTES
RCS COOLDOWN (T_C)	4.1 HOURS
574^{o}F TO 350^{o}F	
1 ATMOSPHERIC DUMP VALVE	
RCS DEGASIFICATION	1. HOUR
1/2 RCS VOLUME IN SCF H_2	

C-E COMMENTS
ON DRA MEMO
"FEED AND BLEED ISSUE FOR C-E APPLICANTS"

J. J. HERBST
3/16/82

KEY DRA ASSUMPTIONS

AUXILIARY FEEDWATER SYSTEM

- ONLY ONE DIESEL GENERATOR IS CAPABLE OF ENERGIZING THE MOTOR DRIVEN AUXILIARY FEEDWATER TRAIN

- THE SECOND MOTOR-DRIVEN AUXILIARY FEEDWATER TRAIN REQUIRES OFFSITE POWER

AUXILIARY FEEDWATER SYSTEMS

PLANT	PUMPS	ELECTRIC POWER
ARIZONA PUBLIC SERVICE (PALO VERDE)	2 MOTOR 1 TURBINE	AUTO MOTOR - DIESEL A MANUAL MOTOR - DIESEL B AUTO TURBINE - DC BUS A, C
DUKE (CHEROKEE) WPPSS (WNP-3) TVA (YELLOW CREEK)	2 MOTOR 2 TURBINE	1 AUTO MOTOR - DIESEL A 1 AUTO MOTOR - DIESEL B 1 AUTO TURBINE - DC BUS A 1 AUTO TURBINE - DC BUS B

DEPRESSURIZATION & DECAY HEAT REMOVAL

THREE SCENARIOS CONSIDERED.

- LOSS OF OFFSITE POWER
- TOTAL LOSS OF FEEDWATER
- STATION BLACKOUT (LOSS OF ALL AC)

SCENARIO COMPARISONS

DRA RESULTS - FROM 1/29/82 MEMO

C-E RESULTS - UTILIZES AFW RELIABILITY STUDY OF PALO VERDE SUBMITTED AS APPENDIX TO FSAR

- STUDY PERFORMED BY PALO VERDE ARCHITECT

- ASSUMPTIONS CONSERVATIVE WITH RESPECT TO NUREG 0635 METHODOLOGY

LOSS OF OFFSITE POWER

DRA CONCLUSIONS - FOR ASSUMED CONFIGURATION

$$\lambda_{CM} = 1.2 \times 10^{-4}/\text{YR.}$$

PROPOSED AFW MODIFICATIONS TO INCREASE RELIABILITY

$$\lambda_{CM} = 6.4 \times 10^{-6}/\text{YR.}$$

NOTE: SYSTEM 80 PLANTS ALREADY HAVE INCREASED RELIABILITY CONFIGURATION

C-E RESULTS - USING FSAR AFW CONSERVATIVE RELIABILITY RESULTS

$$\lambda_{CM} = 1.9 \times 10^{-5}/\text{YR.}$$

TOTAL LOSS OF FEEDWATER

DRA CONCLUSIONS - USING ASSUMED AFW CONFIGURATION

- WILL NOT MEET 'COMMISSIONS CRITERION' OF $< 10^{-4}$ CORE MELTS/YEAR DURING FIRST CORE (9×10^{-4})
- MAY NOT MEET CRITERION AT MATURITY USING UNCERTAINTY BOUND OF 3 ORDERS OF MAGNITUDE. (2.6×10^{-4} - 3.9×10^{-7})

C-E RESULTS - USING FSAR AFW RELIABILITY RESULTS

- $\lambda_{CM} = 2 \times 10^{-5}$ AT MATURITY

  (INCLUDES PROBABILITY OF CONSEQUENTIAL LOSS OF OFFSITE POWER)

STATION BLACKOUT

DRA CONCLUSIONS - USING ASSUMED CONFIGURATION

- INCLUDING OFFSITE POWER RECOVERY PROBABILITY

  $\lambda_{CM} = 1.2 \times 10^{-5}$/YEAR

- WITHOUT OFFSITE POWER RECOVERY PROBABILITY

  $\lambda_{CM} = 6 \times 10^{-5}$/YEAR

C-E RESULTS - USING FSAR AFW RELIABILITY RESULTS

$\lambda_{CM} = 7.3 \times 10^{-6}$/YEAR

VERY SMALL LOCA FREQUENCIES

DRA CONCLUSIONS - HPSI UNRELIABILITY OF 5 X 10^{-3}/DEMAND FOR C-E PLANTS BASED ON WASH 1400 AND " MOST PRAs".

$$\lambda_{CM} = 1.5 \times 10^{-4}/\text{YEAR}$$

C-E COMMENTS - WASH 1400 AND "MOST PRAs" NOT APPLICABLE TO C-E DESIGNS

C-E HPSI - SINGLE PURPOSE, MULTI-TRAIN DEDICATED SYSTEM

$$\lambda_{CM} = \text{SIGNIFICANTLY LESS THAN } 10^{-4}/\text{YEAR}$$

GENERAL COMMENTS

- "QUICK AND DIRTY" PRAs NOT APPROPRIATE FOR COMPARISON TO PROPOSED SAFETY GUIDELINES
- MATURE PLANT ANALYSES ARE ACCEPTED PRACTICE IN PRAs
- NUREG-0880 RECOMMENDS "REALISTIC ASSUMPTIONS AND BEST ESTIMATE ANALYSES" FOR PRAs
- PROPOSED POLICY STATEMENT BY COMMISSIONERS LIMITS THE BENEFITS IN BENEFIT-COST EVALUATIONS TO REDUCTIONS IN RADIOLOGICAL RISK
- DESIGN SPECIFIC RECOMMENDATIONS SHOULD BE BASED ON SPECIFICS OF THE DESIGN

CONCLUSION

USING PRA METHODOLOGY WITH APPROPRIATE AUXILIARY FEEDWATER SYSTEM CONFIGURATION DOES NOT RESULT IN CORE MELT FREQUENCIES GREATER THAN THE COMMISSION'S PLANT PERFORMANCE GUIDELINE FOR SEQUENCES INVOLVING LOSS OF DECAY HEAT REMOVAL CAPABILITIES.

ALTERNATE DHR CAPABILITY

SECONDARY DEPRESSURIZATION

- STEAM GENERATOR DEPRESSURIZATION WITH ATMOSPHERIC DUMP VALVES.

- FEEDWATER MAKEUP USING LOW HEAD PUMP (E.G. FIRE PUMP).

SECONDARY DEPRESSURIZATION

1. RCPB MAINTAINED INTACT

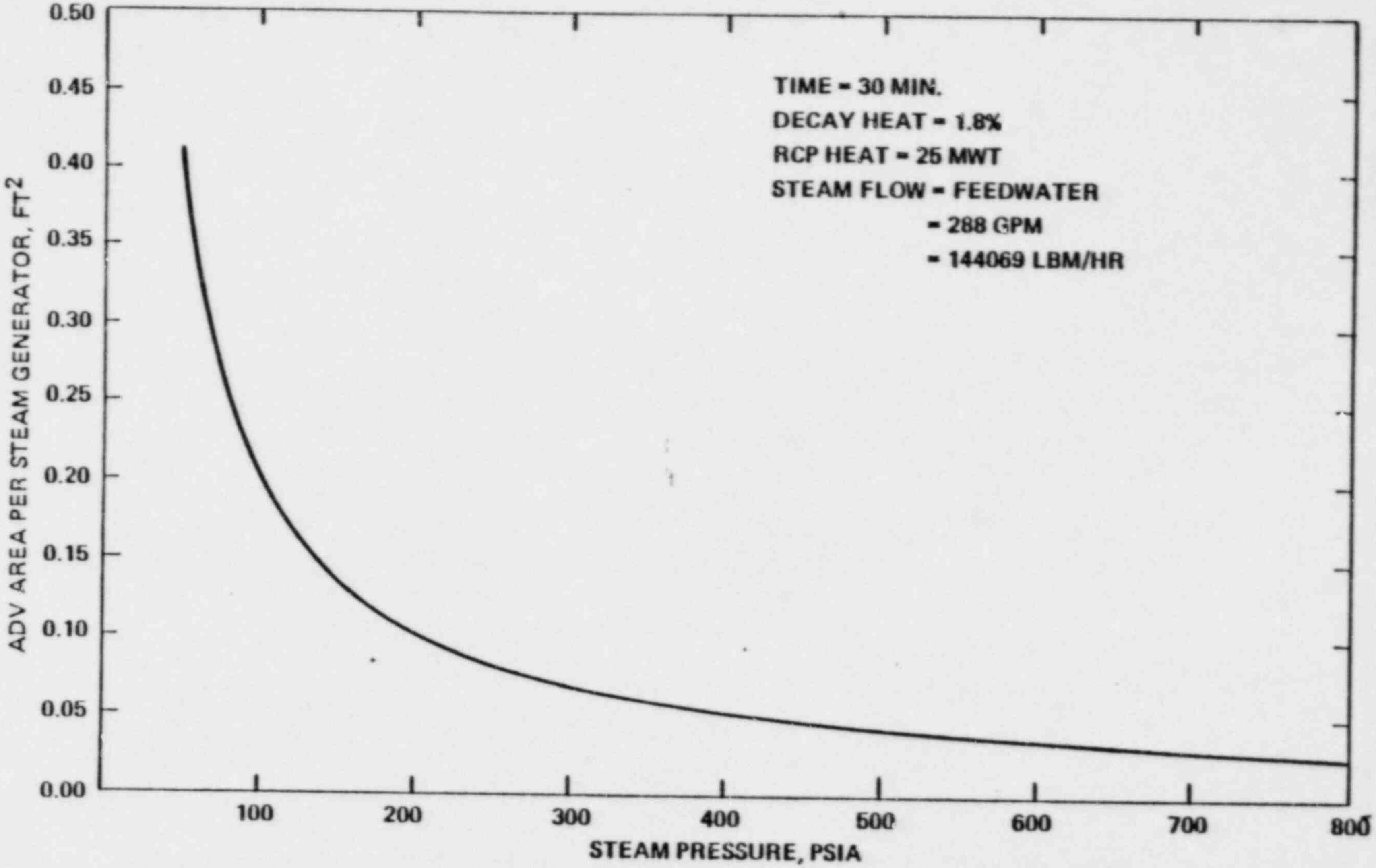
2. CONSISTENT WITH NORMAL DHR PROCEEDURES

3. DOES NOT REQUIRE PRIMARY DEPRESSURIZATION.

4. TIME FOR OPERATOR ACTION IS AVAILABLE.

5. EQUIPMENT IS ACCESSIBLE.

REQUIRED ATMOSPHERIC DUMP VALVE AREA PER STEAM GENERATOR vs STEAM PRESSURE
(3800 MWT PLANT)



PUMP PRESSURE vs FLOW

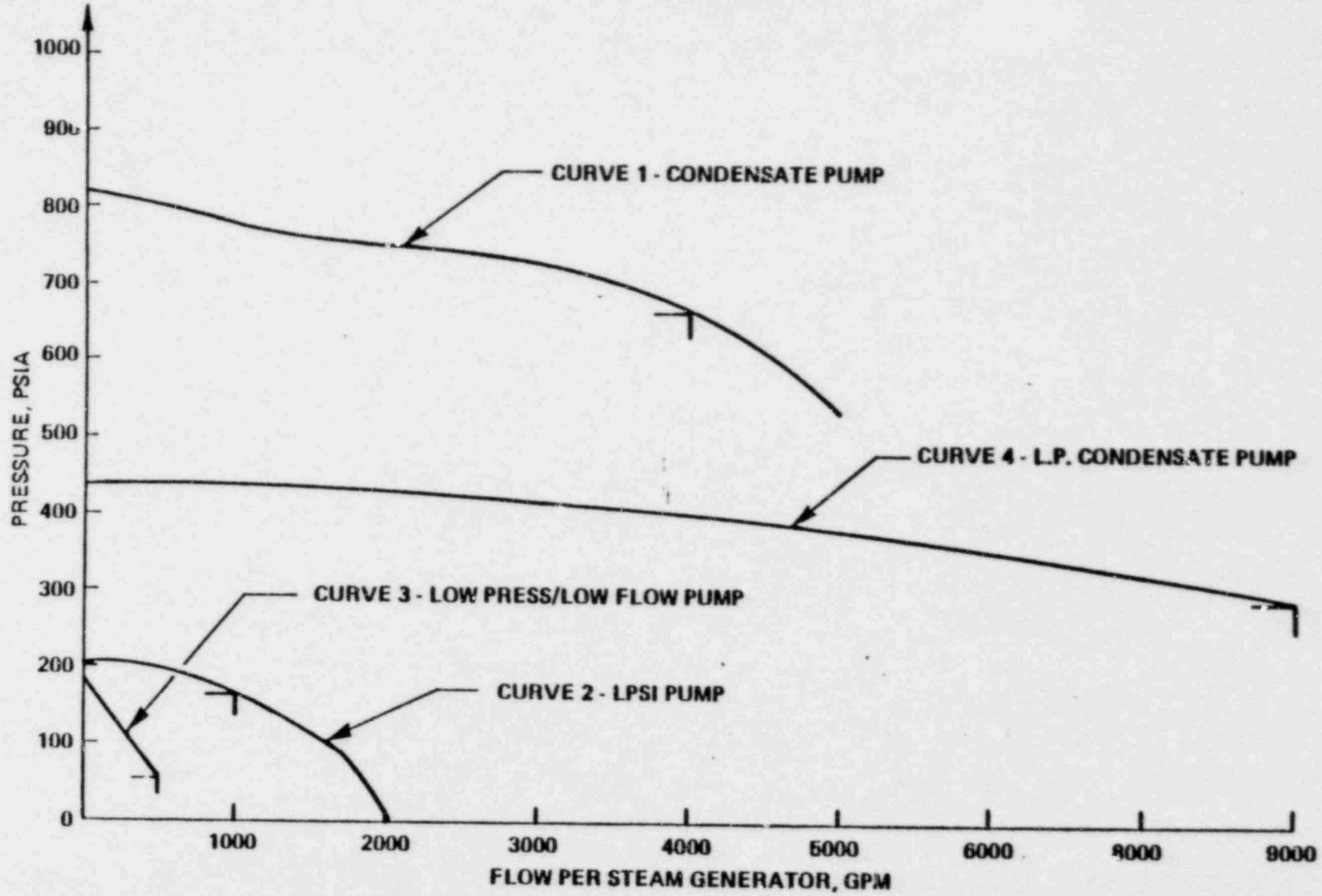


FIGURE 1
. ALT DCY HT REMVL CASE 3A
CORE POWER

DRAFT

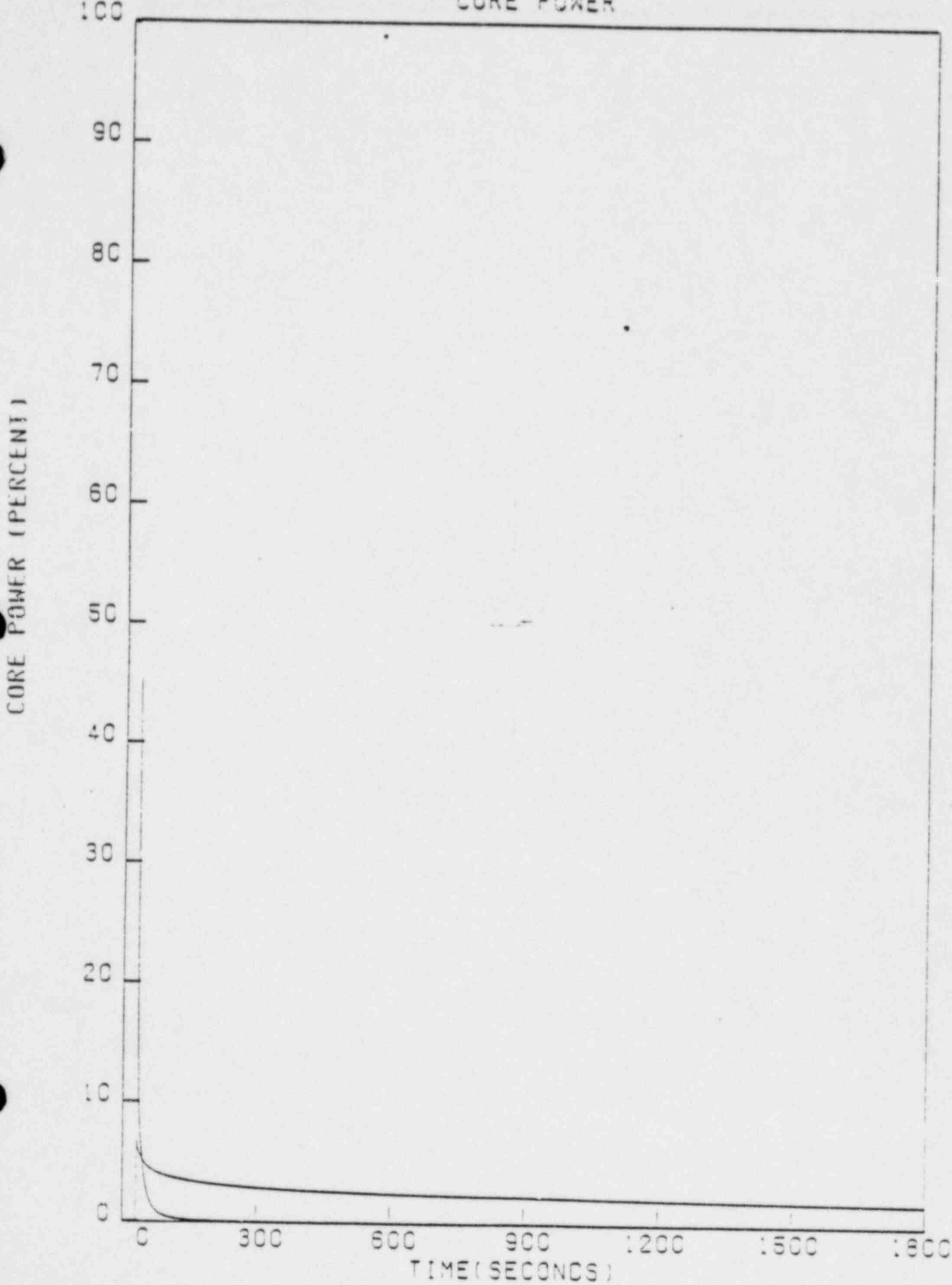


FIGURE 2
ALT DCY HT REMVL CASE 3

PZR PRESSURE

DRAFT

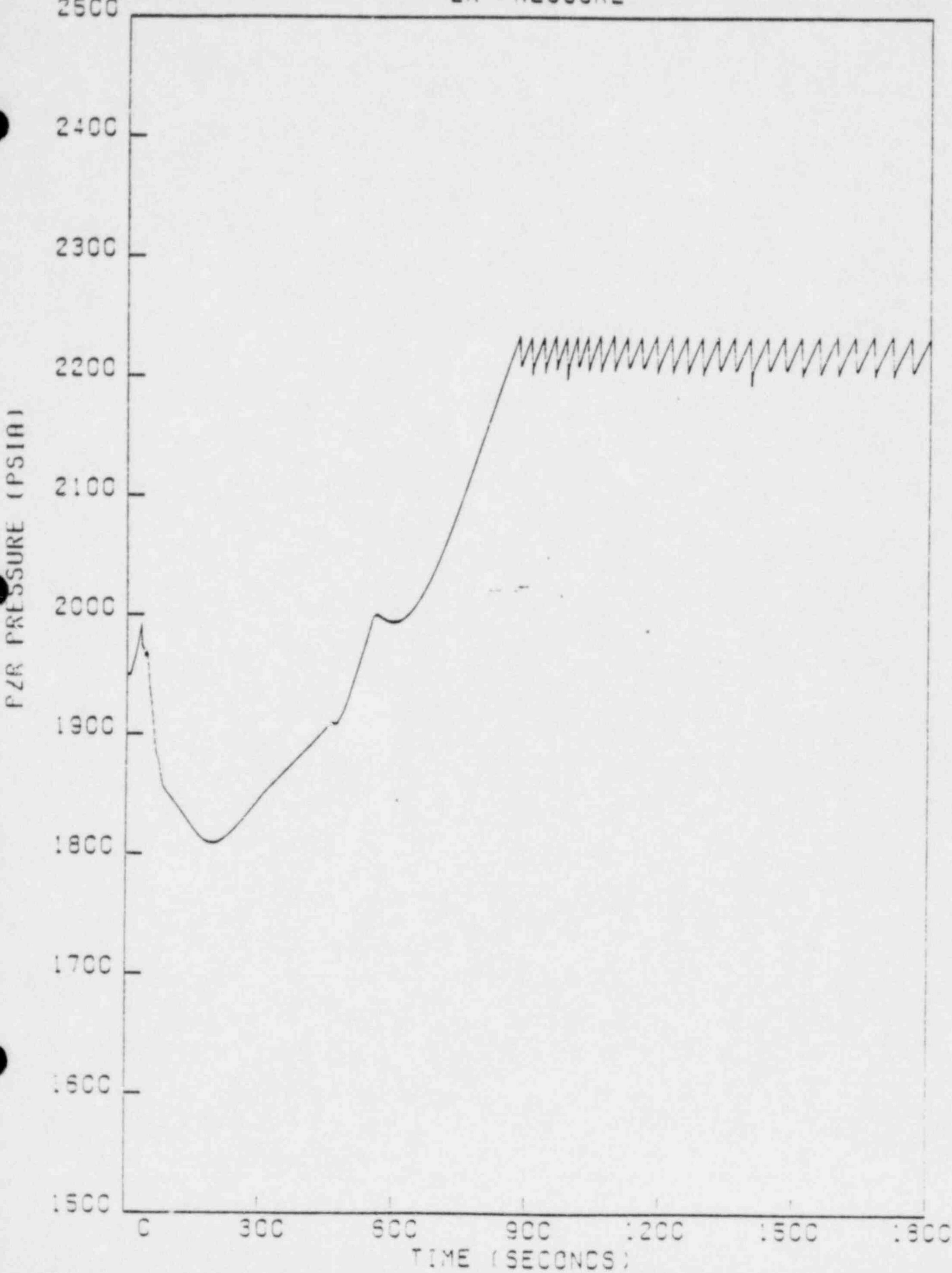


FIGURE 3
ALT DCY HT REMVL CASE 3A
S.G. A PRESSURE

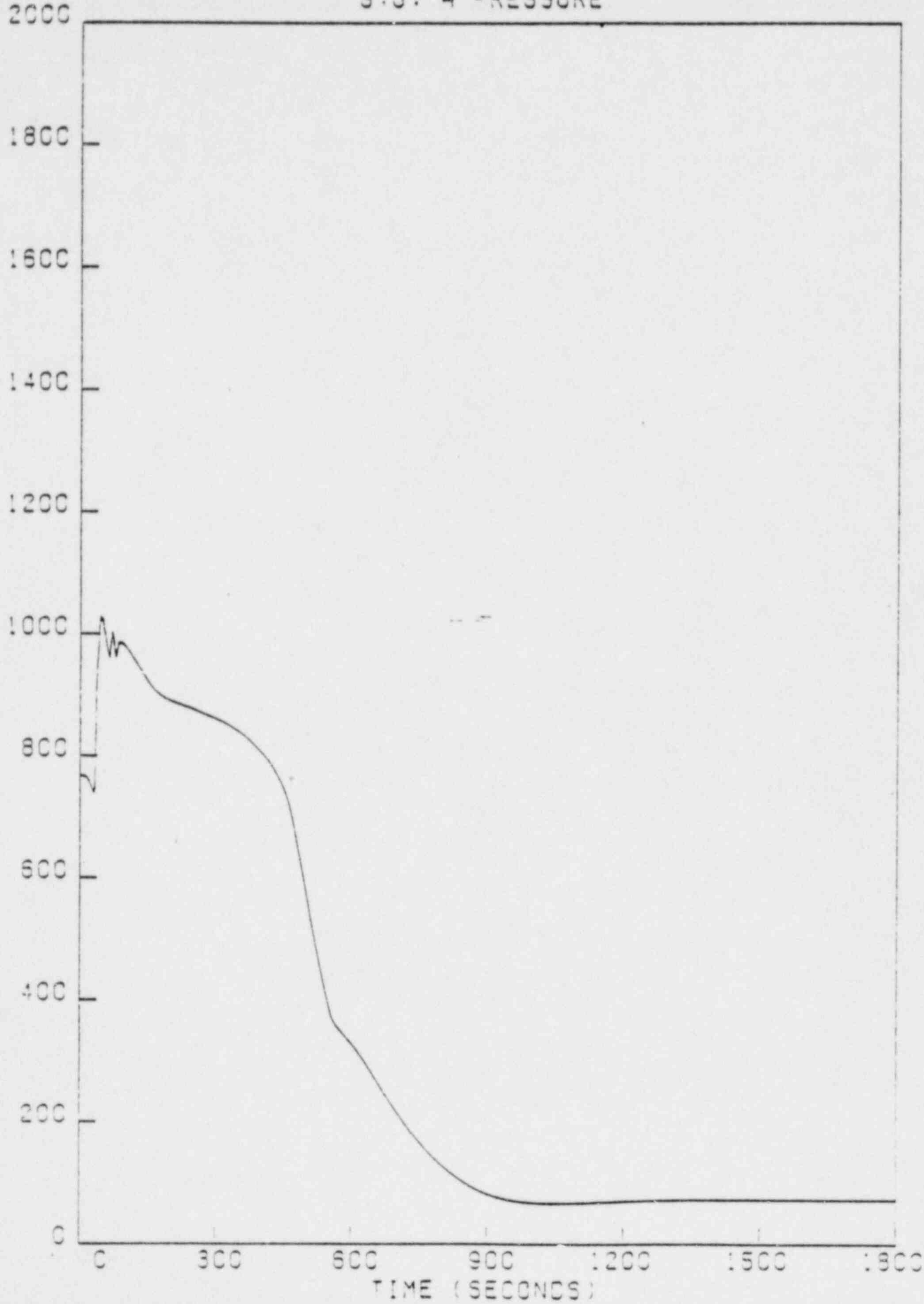


FIGURE 4
ALT DCY HT REMVL CASE 3A
S.G. 6 PRESSURE

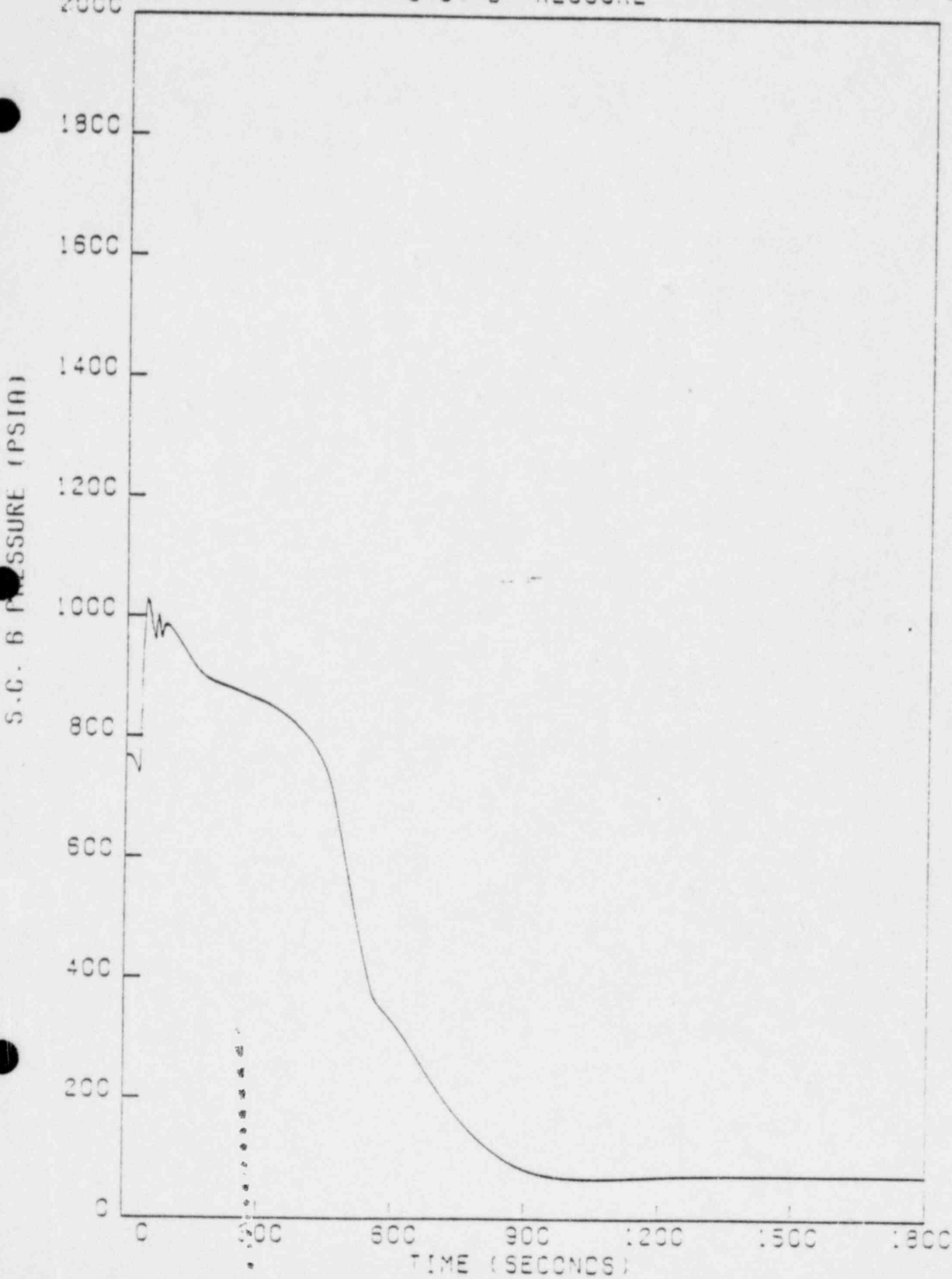


FIGURE 5
ALT DCY HT REMVL CASE 3A
S.G. A AUXILIARY FEED FLOW (GPM)

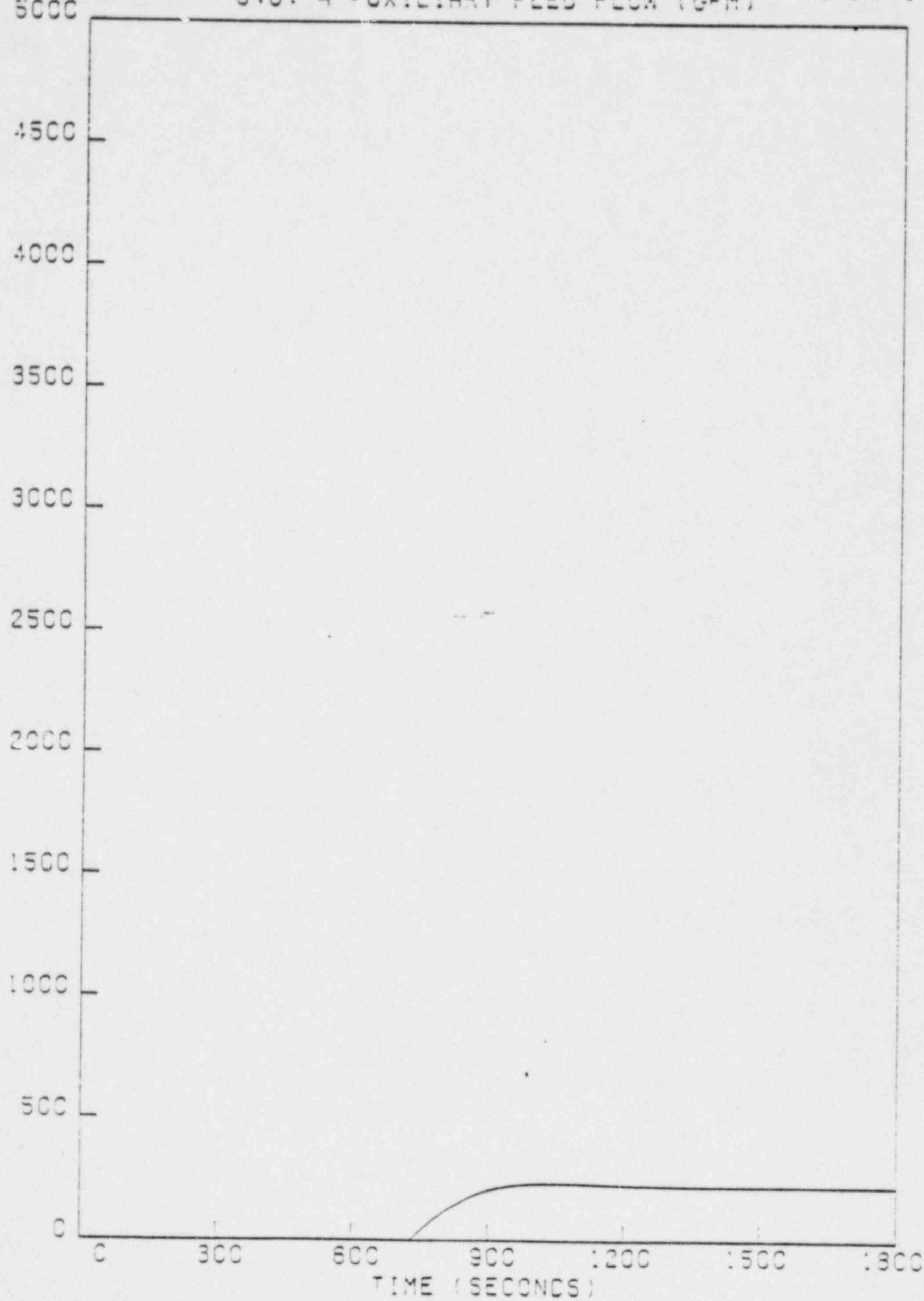


FIGURE 6
ALT DCY HT REMVL CASE 3A
S.G. 6 AUXILIARY FEED FLOW

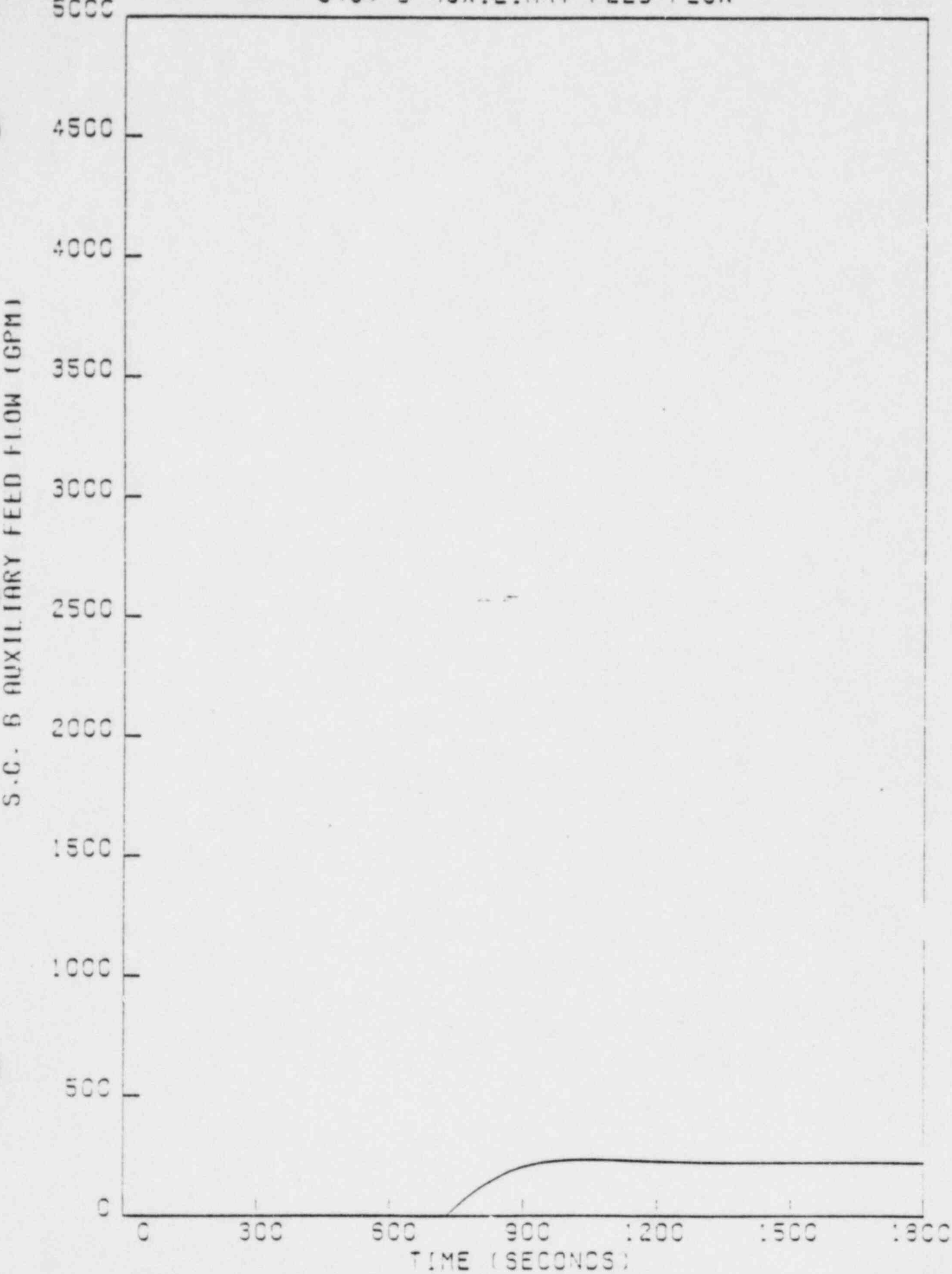
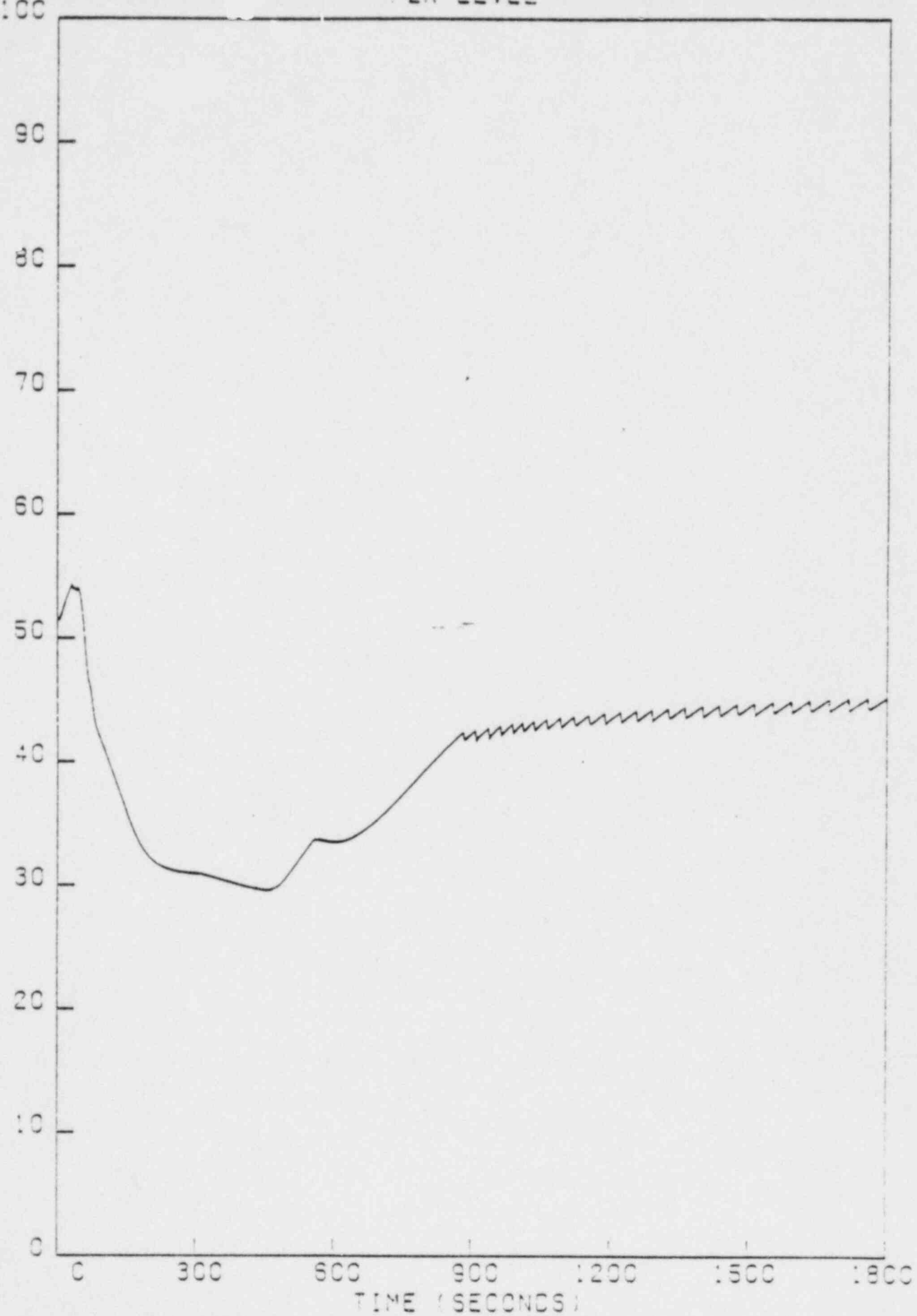


FIGURE 7
ALT DCY HT REMVL CASE 3A
PZR LEVEL

DRAFT



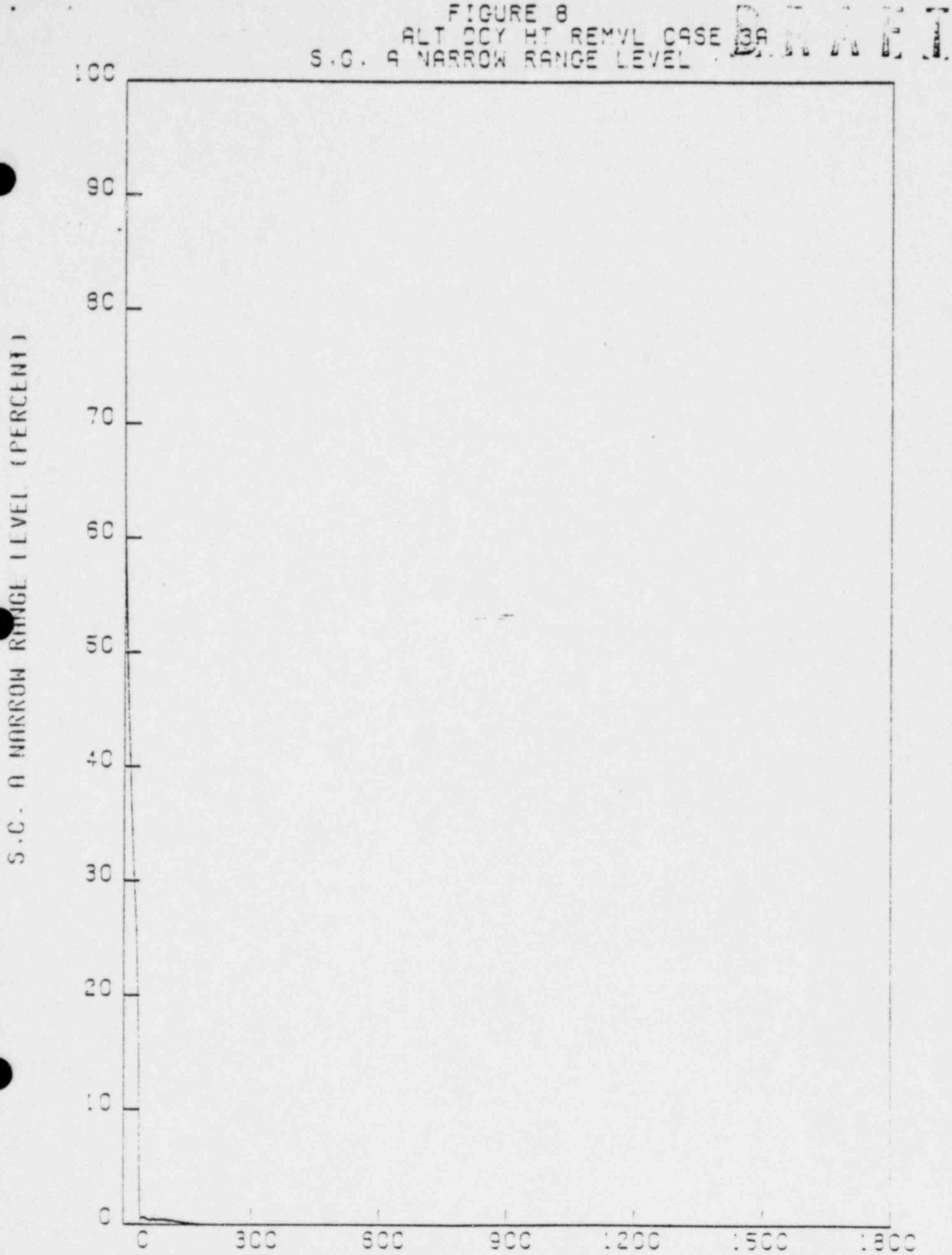


FIGURE 8
ALT DCY HT REMVL CASE 3A
S.G. A NARROW RANGE LEVEL
S.G. A NARROW RANGE LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
300
600
900
1200
1500
1800
TIME (SECONDS)

FIGURE 9
ALT DCY HT REMVL CASE 8A
S.G. B NARROW RANGE LEVEL

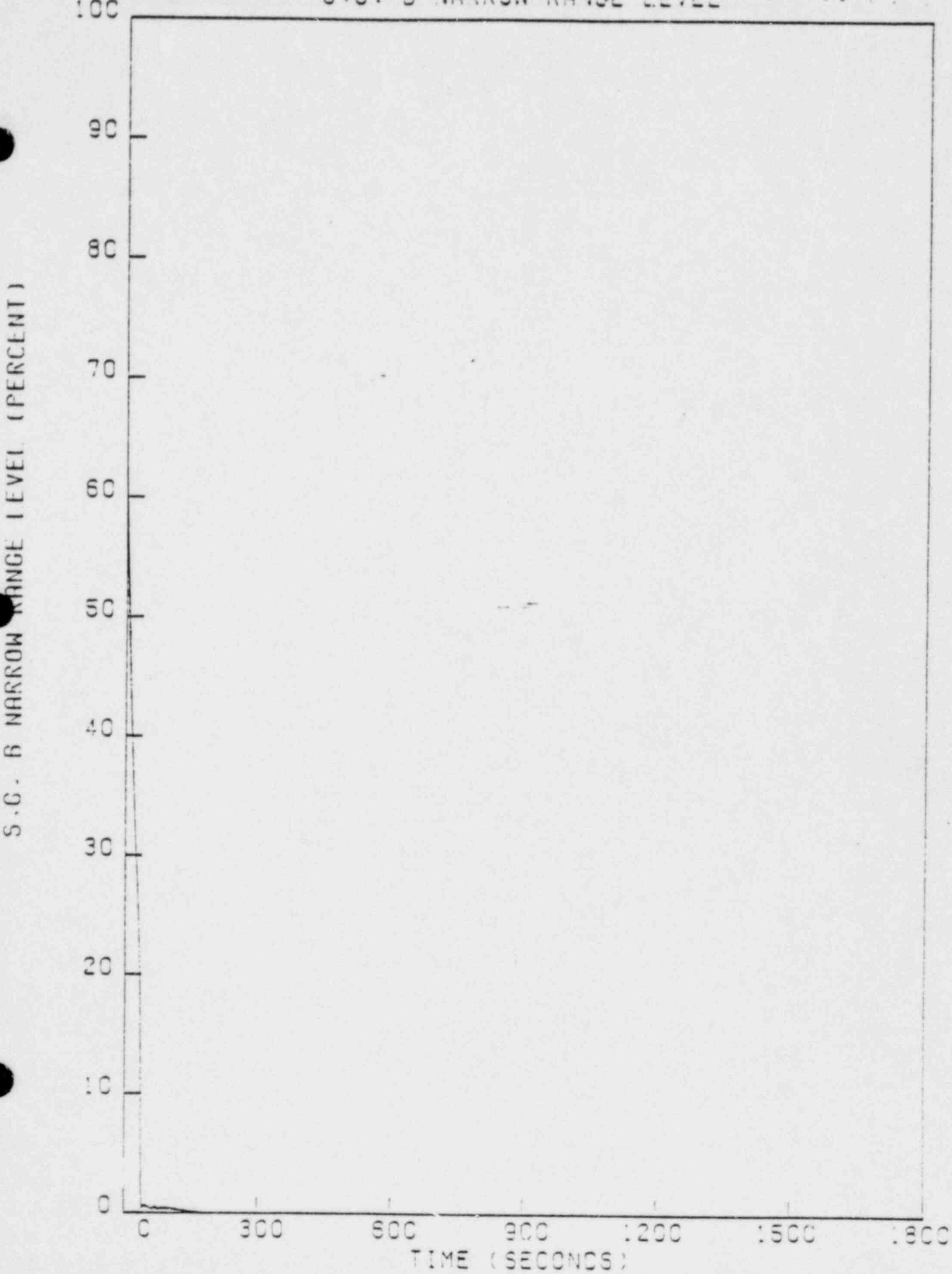


FIGURE 10
ALT DCY HT REMVL CASE 39
LOOP A TEMPERATURES

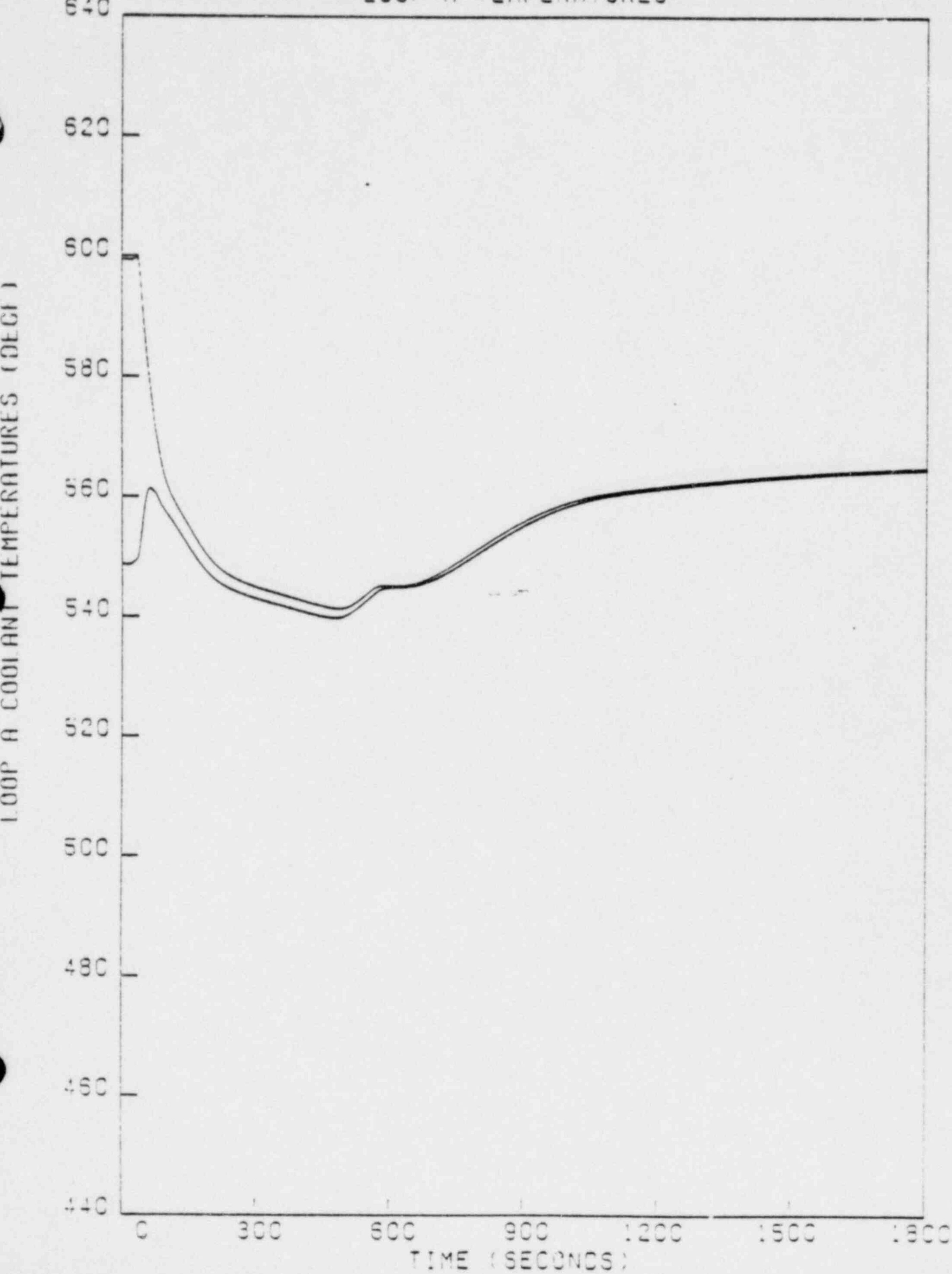


FIGURE 11
ALT DCY HT REMVL CASE 3A
LOOP 6 COOLANT TEMPERATURE

DRAFT

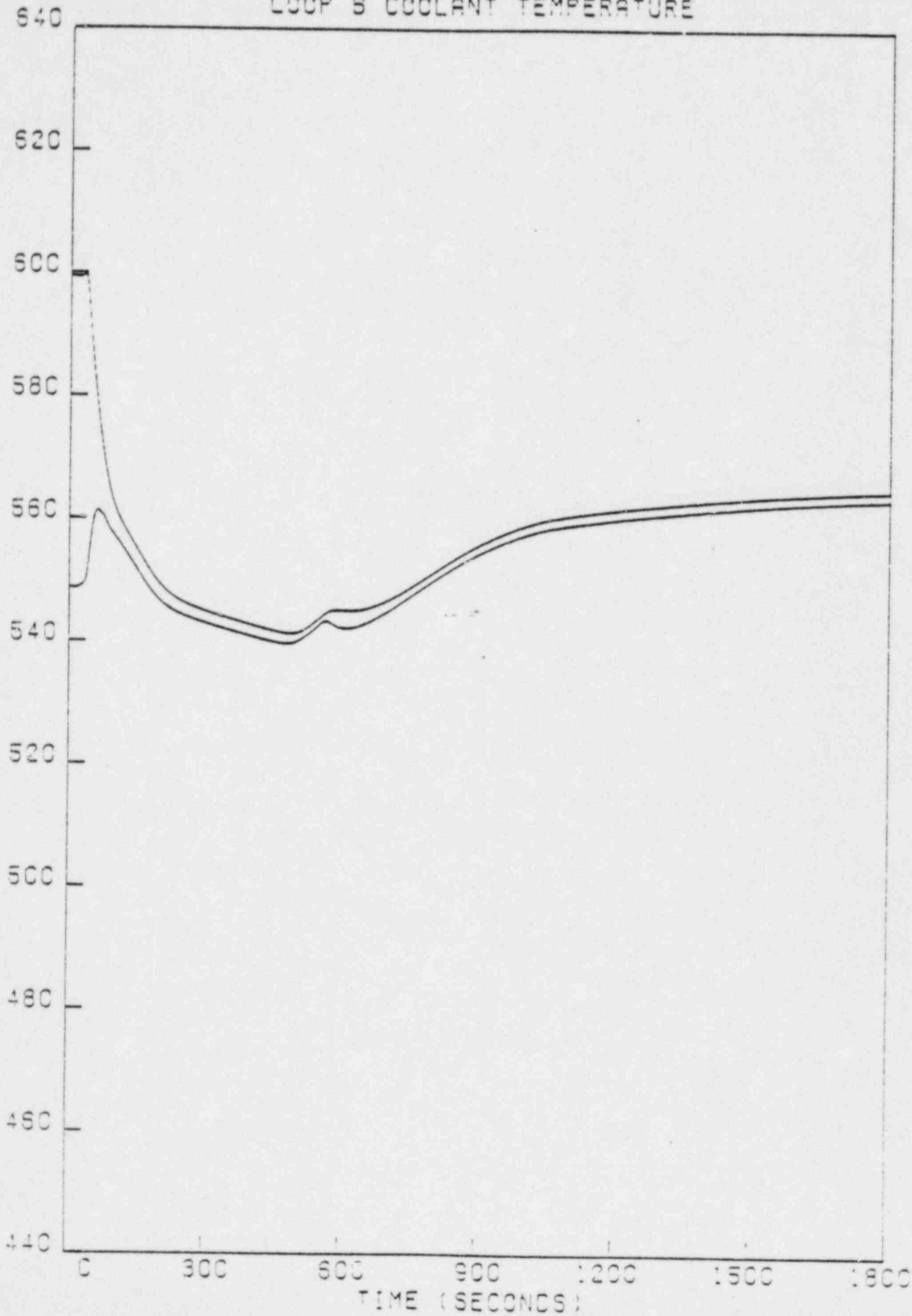


FIGURE 12
ALT DCY HT REMVL CASE 3
S.G. A WIDE RANGE LEVEL

DRAFT

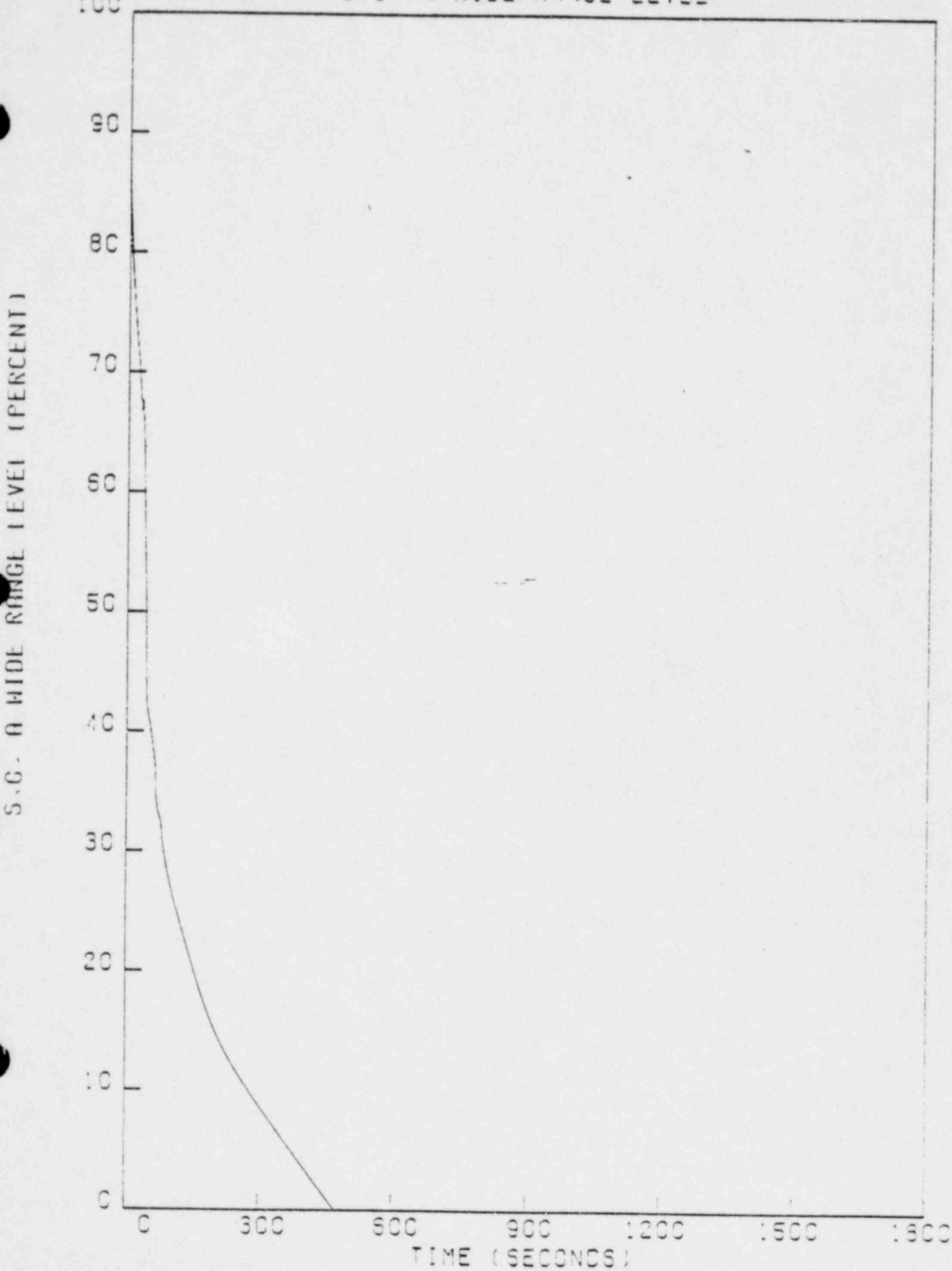


FIGURE 13
ALT DCY HT REMVL CASE 3S
S.G. 6 WIDE RANGE LEVEL

DRAFT

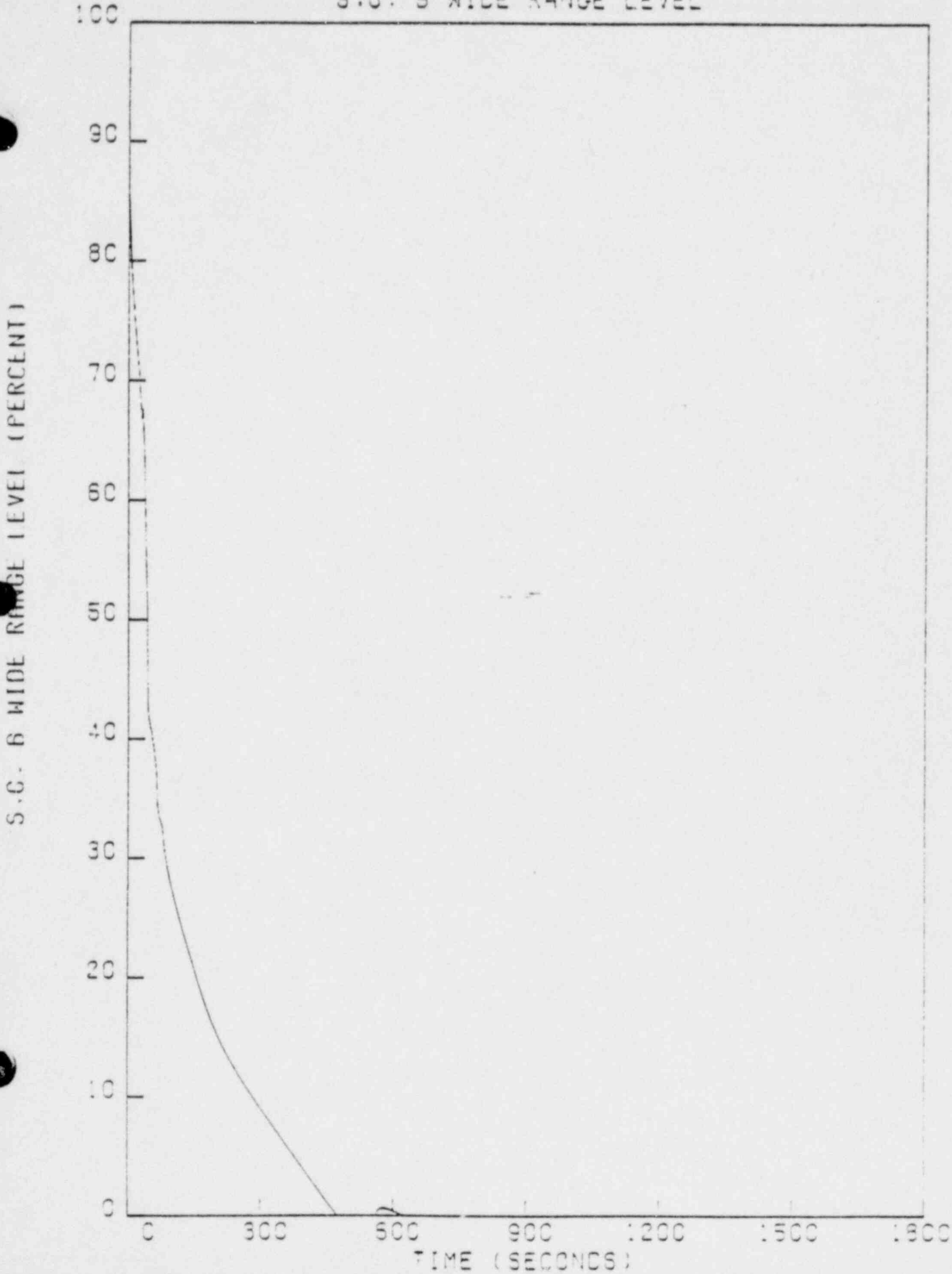


FIGURE 14
ALT DCY HT REMVL CASE 3B
S.G. A STEAM FLOW

DRAFT

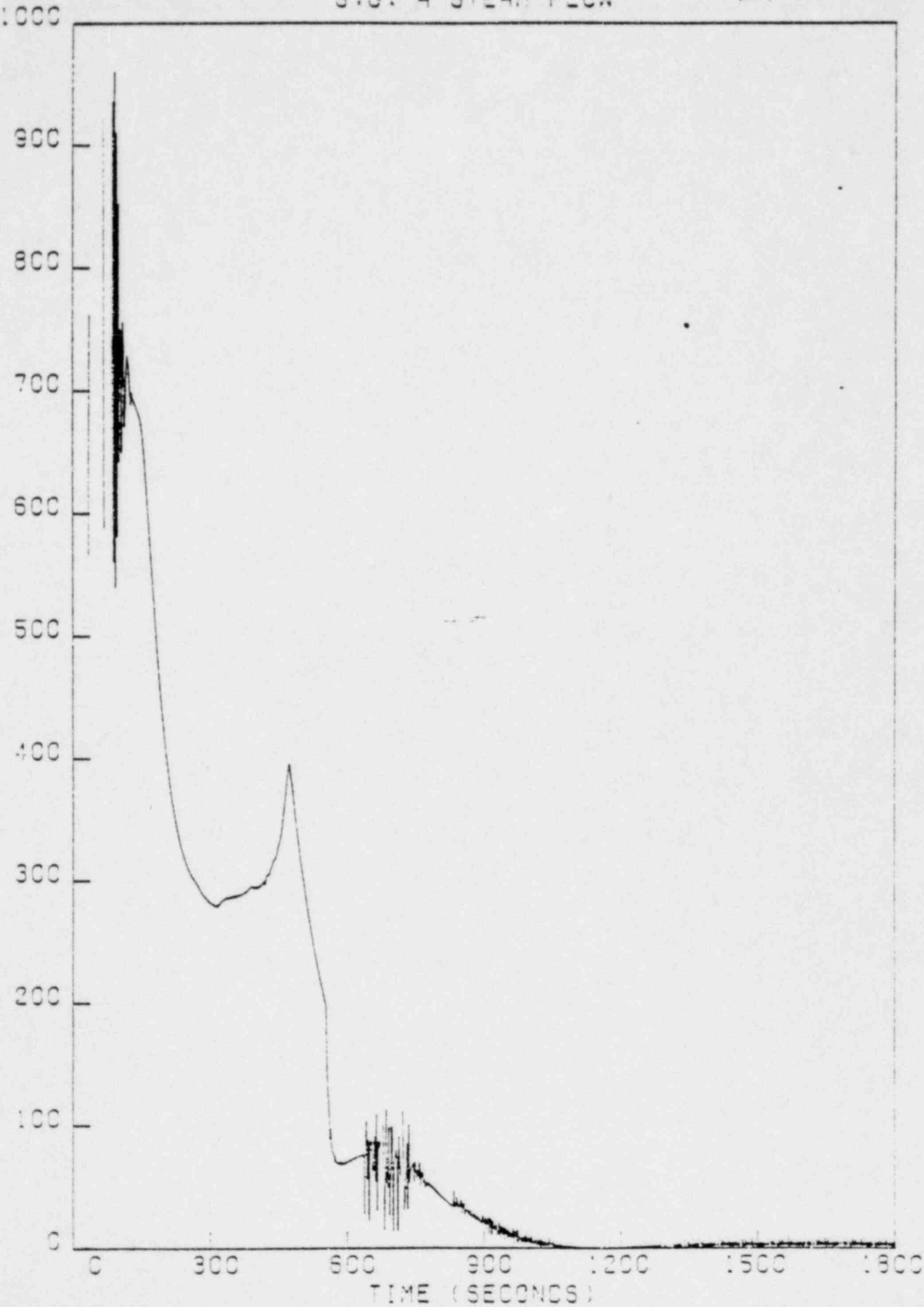


FIGURE 15

ALT DCY HT REMVL CASE 3A

S.G. B STEAM FLOW

DRAFT