PRESENTATION TO THE UTILITY DESIGN AND REVIEW BOARD

DESIGN TO ACHIEVE AND MAINTAIN COLD SHUTDOWN

WEDNESDAY, APRIL 29, 1981

HELD AT: BECHTEL POWER CORPORATION OFFICE

ANN ARBOR, MICHIGAN, 1:10 P.M.

VOLUME II

Ann Arbor, Michigan

Wednesday, April 29, 1981

At or about 1:10 o'clock P.M.

- - -

MR. HUGHES: We have a new transcripter, would everybody please recall to say their name before they ask a question or make a comment, to get us started, until she is familiar with who everyone is.

We're going to go right into Section V of our presentation, which is Cold Shutdown following Chapter 15 type events.

Bob Schomaker of Babcock & Wilcox will start it off.

MR. SLADE: Do you want to get right through five before we ask questions again or do you want to ask questions as they arise?

MR. HUGHES: If it's acceptable to the Board, I'd like to go through the presentation. Then we will go to the questions for five.

MR. COOK: I think -- that's fine. Please proceed.

MR. SCHOMAKER: Good afternoon.

My name is Robert Schomaker. I would like to address Cold Shutdown as it relates to Chapter 15 type events. I would address post-accident conditions that may exist, and assess the capability of the Midland design to proceed to Cold Shutdown.

Can I have my first slide, please, 5-1.

All the transients that are analyzed in Chapter 15, except for the ATWS events, result basically in a reactor trip condition, subcritical core with decay heat being removed by one or two steam generators or by HBI cooling. The final plant condition that one would see, basically depends upon the accident that has been analyzed and the equipment that has been assumed to fail.

The equipment failures that are assumed in Chapter 15, are based upon determining and assuring a bounding response with respect to the established criterion for those accidents. These may or may not be the worse single failure, relative to the ability of achieving Cold Shutdown.

For most events analyzed in Chapter 15, the design objective of achieving Cold

Shutdown in 36 hours with safety-grade equipment can be met. The transient analysis of Chapter 15 demonstrates that the plant can reach a hot stable zero power condition with decay heat removal. The event may require operator action in order to insure long term heat removal or to insure adequate continuous subcritical margin. Sufficient time and indication exist for the operator to take the appropriate action.

Design basis event, such as a steamline break or feedwater line break, may result in the loss of one steam generator and may also result in the loss of forced reactor coolant flow.

May I have my slide figure 5-2, please. The essential control functions have been identified for Cold Shutdown capability, basically as reactivity and inventory control. The ability to control primary system pressure, and the ability to remove heat or temperature control. Any accident in combination with a single failure that eliminates any of these control functions, precludes the ability to go to Cold Shutdown with safety-grade equipment. The transients that are analyzed in Chapter 15 do not result in the loss of any one of these functions.

Let's look at each control function as we have identified them previously. For reactivity and inventory control, we said that these are provided in the short term by tripping the reactor control rods or by the emergency boration system, should we decide we want to stay at hot zero power for some period of time. In the long term or to go to cooldown, to go to a Cold Shutdown condition, one would use the chemical addition system or use high pressure injections from BWST. As long as you don't lose the rods, you don't lose EBS. You don't lose the chemical add system or lose HPI. You have reactivity and inventory control. In terms of primary system pressure control, discussion was provided on the use of auxiliary pressurizer sprays and the use of safety-grade heater banks.

My slide three, 5-3. In terms of temperature control, the normal and post-accident way of removing decay heat is by use of the steam generators; one or two generators, whichever happens to be available. We have also talked a little bit about natural circulation capability. The ability to cool the plant with two generators, with forced or with natural

circulation flows.

We have also mentioned that it remains to be evaluated whether or not a plant can achieve Cold Shutdown within 36 hours with one generator, under a natural circulation capability.

Along with the events of Chapter 15, we have also looked at a design basis tornado. This tornado -- survival of this event after a design basis tornado, is assured by having reactor trip, either by an operator performing a manual trip or by loss of offsite power, causing gravity insertion of the control rods. Reactivity and inventory control can be provided from boration, either by BWST, emergency boration system, or the chemical addition tanks. Temperature control is generally maintained by controlling steam generator pressure on the secondary side. Pressure control, once again, by heaters or sprays. Hot standby conditions can be maintained, essentially indefinitely. It's not always a requirement to go to Cold Shutdown following a Chapter 15 event.

In your handout, in table 5-1, there is a discussion, a summary of each of the accidents that are analyzed for the Consumers Midland

Plant.

My next slide, slide number four, summarizes that summary. In other words, I have chosen just a couple of events, some that result in different configurations, just for us to look at an example here today.

I chose steamline break, essentially because that event can result in a situation where Cold Shutdown is not achievable in 36 hours with safety-grade equipment. One could have a loss of offsite power; could have a loss of one HBI system; could lose one complete generator and therefore, having only one loop available, time in excess of 36 hours may be required.

For loss of normal feedwater, Cold Shutdown is capable of being achieved within 36 hours, assuming one has auxiliary feedwater system available to both generators. No limitations are placed on Cold Shutdown capability following the loss of feedwater.

Control rod withdrawals, these are single and multiple group withdrawals. Basically, reactivity excursions. No physical damage to the

system. Yes, Cold Shutdown is achievable. We assume that all auxiliary feedwater flow is available to both generators. There is nothing going on in the event which would say that I have lost auxiliary feedwater; okay? So therefore, there are no limitations on the ability to go to Cold Shutdown. I have chosen these just as examples. They are addressed for all events in your table 5-1.

Let me basically summarize by saying that the capability of achieving Cold Shutdown exists for the various conditions following Chapter 15 events. Various operator actions may be required. Times in excess of 36 hours may also be required. It may be desirable to stay at hot standby conditions or cool more slowly than this 36 hour requirement or design objective, if such an action would say minimize radiation doses.

So there are reasons for staying at a hot zero power condition and not proceeding to Cold Shutdown.

I thank you for listening and I will now introduce to you Robert Burg, who will discuss fire protection.

MR. BURG: My name is Rob Burg. I'd like to point out, this is a late addition to the presentation. You received a handout this morning that contains my text and my slides. I have been asked to discuss briefly the ability of the Midland Plant to achieve Cold Shutdown following a fire. We have described this analysis as the fire protection safe shutdown analysis.

The objective or purpose of this analysis is to insure that at least one means is available to reach and achieve -- to achieve and maintain safe shutdown, following a design basis or postulated fire.

The next slide, please. The regulations and guidelines we are using on analysis are 10 CFR 50 Appendix A Criterion 3, the Branch Technical Position ASB 9.5-1, and 10 CFR 50 Appendix R.

The assumptions in performing this analysis are that we assume that exposure fire can occur anywhere outside the primary containment. Inside the control room, interpret this to mean that the exposure fire can disrupt any single continuous cabinet. The goal of this analysis, given

those exposure fires, is to demonstrate that the plant can achieve hot standby immediately and achieve Cold Shutdown within 72 hours.

The criteria we use in the analysis is that first, only a single fire occurs. The fire can cause hot shorts, open circuits or shorts to ground. The failures in the plant, assume the analysis are only those failures caused by the fire. Offsite power may be available or it may not be available. The fire in the control room, we assume limited manual action is available to be taken inside the control room, but extensive manual action can be taken outside the control room.

The analysis, as we are performing it, takes the following approach: We identify the equipment needed to achieve and maintain safe shutdown conditions, we identify the possible effects of the exposure fire on those identified pieces of equipment, and finally, we provide protection to insure the operation of that equipment, if in fact the fire does affect it in some manner.

The systems identified needed to achieve this cold or safe shutdown condition are

basically the same systems that you have been discussing all morning. We have to look at a few more systems that we haven't talked about previously. These are the support systems to the systems you have seen before.

At the end of this analysis, we will be able to show -- to demonstrate that the Midland Plant will be able to achieve and maintain a safe condition, following any exposure fire. Thank you, Ed.

MR. HUGHES: Thank you, Rob and Bob.

All right, At this time, we will go ahead into Board questions on the area presented, Cold Shutdown and the Chapter 15 events and Cold Shutdown in the event of a fire.

MR. SULLIVAN: Question of clarification for Bob.

In talking about the tornado, response for the tornado, you had the BWSTs there, but those are not tornado protected things.

MR. SCHOMAKER: That is correct. That is not.

MR. SULLIVAN: You'd use them

if you had them, but --

MR. HUGHES: Correct.

MR. TAYLOR: The last two slides that were presented up there, the next to last slide, I think it said you would identify the equipment needed for Cold Shutdown and then the last slide went on over into the -- on a systems level basis.

Will the evaluation in terms of equipment needed, go down to a very final level of detail, down to the relay, switch gear, pump valve, et cetera, level?

MR. HUGHES: Yes, it will. When it talks about a system, it would encompass all those supporting features, whether it be a bus, a valve, solenoid, that are required to perform whatever safety function is required or Cold Shutdown function.

MR. TAYLOR: So this will be some sort of a matrix that lists all the equipment and then shows that it's redundant and protected against fires in an acceptable way?

MR. HUGHES: Jim, it will be an analysis. I'm not sure it will be in a matrix form in the final process. It's in the process now,

but yes, that type analysis will be conducted such that we have looked at all the necessary components and assured that they are available.

MR. TAYLOR: Down to basically the relay level?

MR. HUGHES: Yes.

MR. LEWIS: Further point of clarification. We are not necessarily looking at each of those entire systems. We are looking at those portions of those systems and those components within the system that are required to be operable in order to shut down safely following a fire.

MR. ANAND: In the item 5-K discussion, the Midland design being reviewed, when is that scheduled? When will we be getting this material for review? What is the schedule?

MR. HUGHES: Rob, can you answer that question? I don't know the schedule. You are talking about fire protection review, completion and submittal?

MR. BURG: We were discussing this with the NRC two weeks ago. We agreed to update and submit our fire hazards analysis in the early part

of July. That's -- for clarification, that's our Appendix 9A of our FSAR.

MR. ANAND: I'd just like to point out that on April 23rd, commissioners have ordered that all the near-term OLs licensee shall comply with the fire protection program set forth in Appendix R, 10 CFR part 50, and we will be writing a letter to all the applicants telling them that Appendix R, 10 CFR part 50, shall be used as a guidance for the review of the fire protection program and licensee compliance with the requirement set forth in the Appendix R, as modified by the accepted exceptions will be made as a license condition, as NRC has made on the following two license conditions. The licensee has to identify any exceptions to the programs that will be taken into Appendix R as alleged from the position 9.5-4 and the licensee will also describe any alternative which will be an equivalent level of the fire protection.

MR. HUGHES: Thank you, and this letter will be forthcoming?

MR. ANAND: Yes.

MR. HUGHES: This next week?

MR. ANAND: Something like that.

MR. COOK: I see the list of criteria here that you are going to conduct this review against.

MR. HUGHES: We're talking fire?

MR. COOK: Yes, fire protection. I guess my question is, do we have enough specificity in the individual criteria to be able to conduct, you know, a review that will enable us to fulfill all the expectations that the NRC has of us when they get this submittal in July?

MR. HUGHES: Rather than giving you my opinion, let me ask the reviewers, which are Rob Burg and Don Lewis.

At present, we believe we have sufficient specificity to conduct this review and supply this information in July, given the latest information on Appendix R?

MR. BURG: We are lacking a few pieces of information. The major piece of information we're lacking is the definition of the scope of the fire inside the control room. We have made this presentation to the NRC. We did it on, I think it was April 15. The NRC agreed to get back to

us within two weeks. Today is two weeks and we have still not heard from them.

MR. ANAND: We are still working on it and we haven't decided which way to go. There is a lot of difference of opinion.

MR. HUGHES: Are you in a position to tell us approximately when you think we will hear?

MR. ANAND: As we told Bob, he will have to keep on checking with us in the interval two weeks time. Whenever we come to a decision, we will let him know.

MR. HUGHES: Because that will have a direct affect on our expected submittal dates.

MR. COOK: Can one use the precedence being, you know, submitted in the near term OLs, in terms of how to get the specific definition down in the bowels of this review? I look at this list of criteria. To me, although I'm not working directly in the area, there is some questions, unanswered, as far as my recognition of exactly what these things mean.

MR. ANAND: Okay.

MR. GARRICK: Regarding your

Chapter 15 analysis, there is some language here that indicates that maybe you identified some troublesome areas as a result of instrumentation failure.

I'd be very interested to know about that, if you did, and what their impact was on achievement of Cold Shutdown and also, has the failure of an entire instrument power bus been analyzed when you considered these events?

MR. SCHOMAKER: The word instrumentation should not appear in your text. Equipment failures, single failures are not limited to instrumentation and no, there was no instrumentation single failure that was uncovered as being troublesome.

It was my impression that that word was going to be removed. That should not limit single failures to instrumentation.

The second question, I believe the answer was no, but I forgot the question.

MR. HUGHES: Was a failure of an entire instrument bus considered?

MR. SCHOMAKER: The answer is no. The failure of an entire instrument bus is not a normally considered Chapter 15 event, and what we reviewed

was -- were those accidents which are normally considered in Chapter 15.

MR. GARRICK: I noticed you avoided the language in your presentation, and I was just picking it up from your written material.

MR. VAN HOOF: I have got a question concerning the instumentation and control functions in the event of a fire which might require the abandonment of the control room and controls from the auxiliary shutdown panel.

Is there complete separation of the controls and instrumentation that goes to the auxiliary shutdown panel or do they go via the control room, in they're routing?

MR. BURG: To answer that, I have to explain that we are protecting one channel of safe shutdown equipment for a fire in the control room. Channel A will be provided with what we call transfer switches. These will provide complete electrical independence between the controls in the control room and the controls on the remote shutdown or auxiliary shutdown panel.

Channel B, the alternate

redundant train of safe shutdown equipment, will not be provided with transfer switches, and will not be electrically independent between -- there will not be electrical independence between the two panels, so if you have a fire in the control room, it's possible that you would lose channel B of controls on your auxiliary shutdown panel, but channel A would still be available.

MR. VAN HOOF: Where will these transfer switches be located?

MR. BURG: We are installing a transfer switch panel in the channel A electrical penetration area, which is, I believe, elevation 630 or 628 in the auxiliary building.

MR. VAN HOOF: In the design of the auxiliary shutdown panel, was consideration given to proceeding from a hot condition to Cold Shutdown and controlling it from the auxiliary shutdown panel?

MR. HUGHES: The design in -- uses the auxiliary shutdown panel, controls it from the auxiliary shutdown panel, but it does not utilize exclusively the auxiliary shutdown panel.

MR. VAN HOOF: I wasn't intending that you only use the auxiliary shutdown panel, but

all control panels throughout the plant, other than the control room. With that capability, can you attain Cold Shutdown?

MR. BURG: I'm sorry. Could you repeat?

MR. VAN HOOF: If you had to abandon the control room in case of a fire or some other occurrence and you were controlling the plant from the auxiliary shutdown panels, with those panels and any other controls in the plant such as local control of a pump or whatever, can you attain Cold Shutdown?

MR. HUGHES: Yes.

MR. BURG: The answer is yes.

MR. LEWIS: One clarification. You left out or omitted manual valves. There would be manual operation required as well.

MR. VAN HOOF: Manual valves included.

That's all the questions I have.

MR. MAZETIS: Going back to your slide, point of confusion.

On the steamline break, it was

indicated, as I recall, it was divided into short term and long term, and it was indicated that the emergency boration system was included as one of the systems available to cope with a steamline break.

With the idea of the traditional FSAR type calculations, is there -- does the emergency boration system play a role? Was there an intent for it to play a role in mitigating the consequences of a steamline break that -- to meet the acceptance criteria in the FSAR, during the short term?

The acceptance criteria I'm talking about, as I recall, are pressure, a hundred and ten percent of design pressure and I believe the other criteria is either DNB or return to power.

MR. HUGHES: For the criteria, I'm going to have Bob Schomaker answer that.

MR. SCHOMAKER: EBS is not a required system for mitigation of a steamline break event. Its use was not considered in any of the steamline break analyses presented in the Midland Chapter 15.

MR. HUGHES: I believe it's correct that that has to do with the long term timing

towards Cold Shutdown.

MR. TAYLOR: To what extent can you operate the service water system from the auxiliary shutdown panel?

MR. HUGHES: Mike? What do we have on that?

MR. GERDING: The controls for the service water system are not located at the auxiliary shutdown panel. They are -- the service water system is an automatically operated system. The controls are provided outside the control room at motor control center switch gear and the like.

MR. HUGHES: So the answer, Jim, really is there is no specific control of the service water system available from the auxiliary shutdown panel. It's available outside the control room.

MR. GIBSON: Do you have status indication of the condition of that system at the aux shutdown panel? If I can't control it, I'd at least like to know whether it's running.

MR. HUGHES: I believe we'll have to check on that and get back to you, rather than just speaking from memory.

MR. TAYLOR: Is the same true for the instrument air system?

MR. HUGHES: What do you mean?

MR. TAYLOR: The ability to know what it is doing or control it.

MR. HUGHES: No. Again, as we said earlier, we don't treat the instrument air system as a safety related system, so there would be no indication of status of the air system on the auxiliary shutdown panel. We don't consider the instrument air required for safe shutdown.

MR. HOOD: Did you comment on the ability to trip the reactor from outside the control room, from the auxiliary panel?

MR. GERDING: I believe the procedures -- I can't speak for the final procedures of -- for evacuation of the control room, but they may include tripping the reactor before leaving the control room; however, the capability does exist to trip the reactor outside the control room, at the control rod drive breakers themselves.

MR. HUGHES: Effective, we have no scram switch on the auxiliary shutdown panel.

MR. GARRICK: In your fire analysis, you talk about the -- considering exposure and exposure fire anywhere at the plant.

Can you elaborate on that a little bit as to how that was done? In other words, were you talking about different locations and fires in those different locations.

Are you talking about the growth of a fire from one location to another?

MR. HUGHES: Basically, for the exposure fire, it's assumed at different locations within the plant and it's not really the growth of a fire. It is a mechanism for evaluating different locations for their capability to withstand a fire.

MR. BURG: John, we look at an exposure fire everywhere in the plant. We don't select specific locations, so we have analyzed the whole plant, except for inside the biological shield.

MR. HUGHES: As opposed to a fire starting someplace and growing forward with the sequential cascading of items. Is that what you are talking about?

We don't analyze in that fashion.

We look at all the locations.

MR. BURG: Yes. The requirements are -- there are certain requirements in Appendix R that give you the extent of an exposure fire and that's as far as we have gone, basically. If you come to a fire stop, front rated fire barrier, 20 foot of free air space with no intervening combustibles, you don't have to assume the fire propagates any further than that.

MR. GARRICK: Does your analysis drew a distinction between the level of threat, as a function of location?

MR. BURG: No, it does not. We assume that we have certain pieces of equipment that are required to operate and we will protect those pieces of equipment so they will operate. We haven't done any more in depth level beyond that.

MR. SLADE: Do I understand you correctly that in evaluating the fire, the exposure fire, that you do not also evaluate simultaneous other events which may occur in the plant?

MR. HUGHES: That's correct.

MR. BURG: The only faults are those caused by the fire. They might occur someplace

else. Like, you may blow a fuse someplace else because of a fire in one location, but it's caused by a fire.

MR. BURG: One clarification on that. The only fire we look at in natural occurrence is your reactor coolant pump lube oil collection system where Appendix R forces you to analyze that as a result of an earthquake, and it's a non-seismic structure or system, so that in that one case, you look at a natural occurrence causing a fire, but that's the only one.

MR. TAYLOR: Miscellaneous question. Are the steam generator level instruments and their readouts qualified?

MR. HUGHES: Qualified, you mean 1-E?

MR. TAYLOR: Yes.

MR. GERDING: Yes, they are.

MR. SULLIVAN: Rob, can you comment on the fire protection analysis? The assumption of loss of offsite power throws you into a whole different mode of operation and calls into play a number of other systems that the operators wouldn't necessarily, normally

rely on. Is there a mechanism for -- well, or some credible association between an exposure fire somewhere in the plant and the loss of offsite power?

MR. BURG: The exposure fire that you would look at would be a fire in your electrical distribution system, of some sort, but you -- that would be one fire, but Appendix R requires you to look at the fire with offsite power available or offsite power unavailable, so you have to include that in your analysis.

MR. HUGHES: It is more by definition, as far as what the analysis has done, that we had to do both.

MR. SULLIVAN: It gets back to the earlier comments that John was making about risk and spending money and that kind of thing, and Raj mentioned earlier the business about exceptions to Appendix R and it would seem to me that if one is not talking about a fire in an area that could credibly be the result of a consequential loss of offsite power, and then, from a risk or reliability point of view, that you would want to look at what alternatives are available to the operator to accomplish a particular

function.

MR. HUGHES: I guess I can only ask Raj to comment on that. I believe in years past, there used to be some consideration of whether the fire caused a generator trip or a reactor trip, directly as being somehow tied to loss of offsite power, but presently, I believe it's just defined as look at it with offsite power and look at it without offsite power and no mechanistic coupling.

MR. ANAND: But safe shutdown should include the loss of offsite power.

MR. HUGHES: I believe Terry's question was with regard to a fire and any physical coupling, to loss of offsite power, as the fire causing loss of offsite power and whether that's a realistic analysis requirement; is that correct, Terry?

MR. SULLIVAN: Right.

MR. HUGHES: I can only say it's a requirement and if Raj cares to comment on that --

MR. SULLIVAN: Let me put it another way, then. I'm not trying to put you on the spot. I'm trying to find out what Bechtel is doing.

It seems to me that if we're

getting in a situation where as a result of the analysis, you are considering some change to the plant or whatever, then you ought to ask the question about whether it's -- how probable the event is and also what the consequences of the change are.

Again, getting back to John's point, could the change possibly result in a reduction of the risk, and if that's the case, then it seems to me we have the obligation to ask for an exception to the requirements and the question I guess is, are we considering that rigorously in our review of the plant for fire protection?

MR. HUGHES: Don Lewis, I guess I'm going to let you comment on that.

MR. LEWIS: What we're doing is performing an analysis to fairly reach criteria that are based on our understanding of the NRC requirements, really last summer and last fall -- as they were understood last summer and last fall, and performing analysis, identifying areas in the systems where design changes may be required, and then proposing those changes.

It's possible that the plant,

overall plant reliability is being impacted. It's possibly being reduced by inclusion of some of these transfer switches. The design is such that it's being reviewed to minimize that, but just the insertion of those transfer switches could potentially be reducing the plant reliability somewhat.

We're forced to that conclusion or that design option by the criteria that has been sent to us.

MR. SULLIVAN: Let me follow up further. If you find an area where, in your judgment, the change necessitated by, I guess, I prefer to call them guidelines, until I get the order or whatever, you know, are you making a conscious effort to assess whether an exception should be requested, based on the specific plant design? Realizing that when the NRC writes these types of criteria, they don't necessarily -- they can't assess the detailed impact on a plant, and do we have examples of areas where we might request an exception?

MR. LEWIS: I think we have some question in our mind, the general question of reliability. This was discussed both with Consumers and with the

NRC last summer and the decision has been to follow the course of action that we're on.

That is, to follow through the design changes, based largely on the precedent that the NRC has managed to force other plants to do this and Midland is likely not going to be an exception in the basic area of the fire analysis, so yes, the question has been raised. There has not been a specific risk analysis done or any type of a sneak circuit analysis done on the design.

In fact, the logic changes, I don't think are well enough defined yet to do that, in any case. This far, the decision has been based on a precedent, based on the realities of licensing life -- that we shall go on with the transfer switch.

Let me straighten one thing out. We don't have any reservations at this point or feelings that the designs we're creating are unsafe. That's not what I'm trying to say at all, but we have not done any reliability assessment -- risk assessment comparison between the old design and the new one.

MR. HUGHES: We are drawing a distinction between reliability of the plant and safety

of the plant and we have no qualms or doubts as to the safety of what we're putting in. The impact on reliability with any addition of transfer switches and others are not the subject of a risk analysis by Bechtel. Rather, given schedule considerations and precedent, we're proceeding with the designs that comply with the requirement as we interpret them and as precedent indicates.

MR. TAYLOR: I have one more miscellaneous question. Looking at the issue of single failures, and this is not just related to the Cold Shutdown capability, but the DHR system in general. Has an evaluation been made of the consequences of lifting and sticking open the big relief valve on the drop line, just after you go into the -- just after you activate the low pressure injection system?

MR. HUGHES: Tom Ballweg, are you familiar with any analysis?

MR. TAYLOR: It's the one inside the containment that goes to the sump.

MR. BALLWEG: I guess I'd like a little more clarification on that. You said after you initiate the low pressure injection

MR. TAYLOR: After you put the DHR system into operation, you are in the cooldown mode and you just open up the valves inside the containment in the drop line and this valve lifts and sticks.

MR. BALLWEG: To my knowledge, there has been no specific analysis done on that.

MR. HUGHES: What you have, in that case, is a small break LOCA, which has been analyzed. Not that specific case, but small break LOCA capability to meet them has been analyzed. Essentially, that's what has been created in the scenario you're talking about.

MR. BALLWEG: Well, except you are at depressurized condition.

MR. HUGHES: Correct.

MR. TAYLOR: It's a little bit unique, though, because you're going to go -- you're going to be trying to use those pumps to take suction on the reactor coolant system, which has just probably gone to saturated conditions.

Well, the overall question is, has an evaluation been made of that, and the answer is

no, not yet.

MR. BALLWEG: It goes a little bit further. I think the action would be -- should be, under those circumstances, to close the letdown valves, line back up to the borated water storage tank and start LP injection.

MR. TAYLOR: But then there is not a hole in the system.

MR. BALLWEG: That's right, but you can bring pressure back up and you can control the subcooling in the system and you can, if necessary, reestablish natural circulation or forced circulation, depending exactly where you are at, using aux feed and vent through the steam generators, and you have your energy release path.

MR. HUGHES: Tom, is the closing of those letdown valves automatic or manual?

MR. BALLWEG: I believe it's -- they're closed on high pressure.

MR. TAYLOR: I would recommend that consideration be given a little more carefully to the need for a study on that particular event, because it's such a big valve and it affects both the

pumps. It's on that common line.

MR. BALLWEG: Can you more specifically define --

MR. TAYLOR: Just that.

MR. BALLWEG: What I understood your request to say, you wanted us to do an evaluation as to whether or not a study would be required?

MR. TAYLOR: Consideration ought to be given a little more carefully than just in the room, as to whether that is needed.

MR. BALLWEG: So you want us to take that up as an action item?

MR. COOK: I certainly agree.

MR. JENSEN: I'd like to add something to that. Perhaps there is a possibility of damage here to the decay heat removal pump by cavitation, so that they could not be subsequently used, to either cool down the plant or inject water into the plant and in the injection pump.

MR. BALLWEG: Could you explain how you see them being subject to cavitation, if the safety valve is open due to a high pressure condition?

MR. TAYLOR: Stuck open in the

system. That very quickly could saturate the condition and it gets vapor bound.

MR. BALLWEG: The DHR pumps are very low in the system so that the static head of the water from RCS is more than sufficient to provide required NPSH to the pumps, so as long as the line is full of water --

MR. SLADE: That's the question. It may not be full of water. It may be full of bubbles or steam, as a result of flashing through the relief valve.

MR. BALLWEG: At that point, either you don't have an ECCAS or the DHR pumps are tripped on low flow. If you're not getting adequate flow through them, it could be the result of cavitation or whatever. The DHR pumps will trip and be protected.

MR. COOK: I think it gets into the details, what we're asking you to come back to. I think the question, as I have heard it from Jim Taylor, is a situation where he thinks he sees something which ought to be looked at from a preventative point of view. What would you do if that particular valve were to stick open? Can we sense it and can we cut it

off, and even in addition to that, look at the consequences of having something like that occur.

MR. HUGHES: Jim, can I ask a question? So far as I believe, you are postulating a non-mechanistic operation of this valve; is that correct?

MR. TAYLOR: No, no. That line, which is normally at atmospheric pressure, is -- when you open the block valves coming down the drop line, it now gets system pressure and maybe, because of set point drift or whatever, the valve lifts. As soon as it sees the pressure coming down the drop line --

MR. HUGHES: So you have an erroneous set point, followed by a failure of the valve?

MR. TAYLOR: Just lifts and sticks open.

MR. COOK: The relief valve on the system, it has to be postulated to operate sometime.

MR. BALLWEG: The relief valve set pressure is substantially above the pressure which permits opening of those particular valves. Those let down valves, I believe, have a set point permitted

300 PSI to permit opening to start with -- 340, okay. and I have to look what the set pressure is on those valves.

MR. PRATT: 360.

MR. TAYLOR: Just relief valves in general are notorious f·· problems, and it seems that if it's something as simple as a special procedure or special precaution, something like that could address it, then fine.

MR. HUGHES: My question really was, how do we get there because it's a relatively standard relief with a relatively high set point. It has to get some set point because of it, and that's where I was trying to get to, whether we start examining the random opening or not.

MR. COOK: If that's your evaluation at the time, you can tell us, but I want to understand what we can do to sense it, if it's open then.

MR. HUGHES: I understand the back end for the scenario. You want it looked at. I want to understand how we get there.

MR. SULLIVAN: First off, don't

forget -- the first part of the problem was what's the probability of the failure, so don't ignore that in your study.

I guess if your initial reaction is, it is not probable at all or not possible, then the study ends, it seems to me.

MR. HUGHES: Terry, so many things, you can't say it's possible.

MR. SULLIVAN: I'm not prejudging the answer. I'm just saying don't forget the first step in the problem.

MR. PRATT: I think you'd have to get your situation, where you're at a pressure lower than your relief valve set point, otherwise the automatic closer interlock prevents opening of the drop line valves at a high pressure.

You would then have to establish let down decay heat drop line valve flow and then have a pressure increase, such that the relief valve opens.

MR. GIBSON: We have had some occurrences in the industry where -- I don't know if it's been a valve failure open, but they have vapor bound DHR through some means or another. I think trying

to argue why this wouldn't happen, I don't think is too fruitful right here.

MR. HUGHES: We'll go ahead and provide this and open action the information the Board requested.

MR. GIBSON: I don't think the consequences are all that severe, if you know what you are doing.

MR. TAYLOR: Was there a particular reason why this valve was dumped into the sump, as opposed to maybe into the quench tank or something like that?

MR. BALLWEG: The specific reason it went to the sump is that the temperature of that was low enough that there was no real concern about the amount of energy that was being dumped in there, but like if it came out of the pressurizer, you'd have steam at normally 2,000 pounds here. You have got hot water at maximum 325 under the emergency mode and 280 normally, so the amount of flash wouldn't be that much of a problem.

MR. MAZETIS: The last area question is, there are some lines discharging water

to the ECCS sump. It's been our observation in the past, that depending on how the lines impact the surface of the water in or over the ECCS sump, the tendency to create air and training vortexes or air entrapment to the section of the ECCS pumps is increased with this impinging jet forces, so the question is has that been considered in these lines that discharge to the ECCS sump?

MR. BALLWEG: Are you referring to the dump sump lines, solenoid valves or --

MR. MAZETIS: Dump to sump lines, or I think Jim just mentioned the relief valve discharge.

MR. BALLWEG: Let's talk about one or the other. Do you want to talk about the sump --

MR. HUGHES: Start with that.

MR. BALLWEG: Dump to sump lines are only used long term after a large break LOCA, and in a case where the direct coolant system pressure is about eight pounds gauge or something like that, so the potential for entraining much air or inducing much of a vortex is very small.

MR. HUGHES: The basic answer is,

we haven't, in the modeling we have done of the sump, we did not consider the dumps into the sump.

MR. BALLWEG: The other part about the DHR valves we're talking about, that is downstream of the normal drop line letdown line. There is no mechanism that I could identify, which would require or allow that valve to open, under ECCAS conditions.

MR. HUGHES: The answer to Jerry's question is no, we haven't.

MR. BALLWEG: No, we haven't, but that valve can't lift then. There is no flow through that line.

MR. COOK: Does that answer your question?

MR. MAZETIS: Yes. It says that it wasn't considered, and I offer, as an open item, to evaluate the impinging dump to sump discharge of possible vortex formation.

MR. PRATT: We performed, for the Midland Plant, a containment sump modeling study. It was done several years ago, and the results of that study were submitted to the NRC for review. That

sump modeling program included a number of test series, including pressure drop across the grading cage and the sump trash racks, and it also included a test sequence in which vortices of a very high circulating strength were artificially created by flow veins and it was demonstrated in that series of tests, that the grading cage which immediately surrounds the outlet of the sump, successfully prohibited the formation of vortices.

In other words, it served as a last line of defense against vortex propagation into sump suction lines.

Now, admittedly, the trash racks, by virtue of their flow straightening capabilities, also do -- does some good in preventing vortices, but I think our position as described in that report, that the grading cage itself will handle a vortex of very high strength, and so the likelihood of a vortex being induced by a dump to sump line and through the grading cage, is negligible.

MR. HUGHES: Jerry, what I believe we're telling you is it was not factored in the model, directly, but Tom was telling you, yes, we

considered the reasons why it wasn't factored into the model and having to do with the pressure drop, and perhaps we may need to document that for a question, but the created or the modeling tests, we believe demonstrated that should a vortex from these lines be created, that they would be broken up. I don't know about the results of any review of that.

MR. MAZETIS: I guess the report you refer to has been submitted and we will have to take a look at the data to see if we agree.

Let me ask, do you remember if the discharge lines go down into the pit or are they well above the pit? Would the tendency -- would you expect post LOCA for the design basis flood elevation to be well above the discharge opening of the dump to sump lines?

MR. PRATT: I don't recall. I don't recall whether the dump to sump lines penetrate the trash rack sump cover plate boundary, and what elevation they're at. That's something we can take a look at.

MR. GIBSON: I have a question of Jerry. The NRC has commissioned to work on the part of Burns and Roe, on the containment sumps, and we sent

them our data package on that.

I'm curious if that is partly addressing some of the questions you brought?

MR. MAZETIS: I have no personal feeling for whether we have reviewed the package, but -- Midland's data along with others that have been submitted to Burns and Roe.

My presumption is their review results are available to us and we will be discussing with them their evaluation of the data.

Does that answer your question?

MR. COOK: Are they finished?

MR. MAZETIS: I don't know.

MR. HOOD: I don't believe they are finished. I believe their effort is ongoing. I might comment that the test reports from Consumers tests, that Jerry referred to, Jerry is not personally involved in the review of that report, but it's being reviewed by others from the NRC.

MR. SLADE: Will we be getting some feedback on that shortly or will we --

MR. HOOD: Yes. Now that the review has resumed, I would anticipate there would be feedback on that at the appropriate point, but as it

was mentioned, there is the Burns and Roe effort. I'm aware of the interactions we have had on this project.

One of the areas of concern of that project has to do with the determination of insulation used in the containment. What aspect that may give rise to in connection with the containment sumps.

There are other aspects of that as well, but I would expect there would be some interaction with the Burns and Roe effort as well.

MR. COOK: I don't see any further questions on the floor. I think you should proceed to the next item.

MR. HUGHES: The next section will be presented by John Gunning, a comparison of the present design to the applicable regulatory guidelines, and followed by Mike Gerding, on instrumentation and control required for safe shutdown.

MR. GUNNING: Thank you, Ed. You heard the present design capability of the Midland Plant. In addition, the Midland design has been reviewed against regulatory guidelines, applicable to

the Cold Shutdown issue.

My first slide, I want to briefly review the guidance that will be referenced. Standard review plan 5.4.7 is here, which addresses decay heat removal system. The major reason for its mention here is because it contains Branch Technical Position RSB 5-1.

Standard review plan 7.4 will be addressed in this section, but at the conclusion of my presentati by Mike Gerding.

This 7.4 addresses systems required for safe shutdown. Branch Techical Position RSB 5-1, the title of this is the design requirements of the decay heat removal system. This Branch Technical Position is attached to standard review plan 5.4.7, as I previously noted and contains functional requirements for decay heat removal and addresses concerns more general than just the decay heat removal system itself.

This document is a basis for a number of other design guidance documents, particularly NRC question 211.35.

Table 6-2 in your handout, contains a comparison of the Midland design to the

guidance of this document. Open items: Associated with NRC staff review. These open items come from the letter to Consumers of March 30, '79 or from meetings associated with staff review, dated April 10 through 11, '79 and April 19 and 20, '79. I won't mention here the subjects of these because the subjects will come up when we do the comparisons.

Regulatory guide 1.139, guidance for residual heat removal to achieve and maintain Cold Shutdown. This regulatory guide has been made available to the industry and it is intended to apply to construction permits issued after January 1st, 1978. It is therefore, not specifically applicable to Midland. The implementation section of the latest available version, which is drafted two, revision one, states that the guide will be used for plants docketed after January 1st, 1980 and this, therefore, excludes Midland. The section does state the applications docketed before this date will be reviewed against the guide on a case by case basis. This clarification, the Midland design has been reviewed against the guidance contained in this regulatory guide.

NRC question 211.35, contents of

this question are quite similar to the guidance contained in **Branch Technical Position** RSB 5-1, and a copy of this question response is contained in the Appendix or the last pages of your handout. These are the design guidance documents against which Midland Plant is being reviewed.

Many of these documents contain similar guidance; therefore, in the remainder of the section, I will address the subject of the guidance, list the applicable design guidance documents, then convey the Midland design that's related to the subject guidance.

So in slide 6-1, subject or the NRC -- we have had broken into NRC positions, the references that I have specifically been mentioning before and then what the Midland design is with respect to this particular position. The concern in the position here is that the decay heat removal drop line design be designed to accommodate a single failure.

The references contained in slide 6-1, Midland design complies. Parellel/series motor-operated valves are provided inside containment. The design has a single DHR drop line ; however,

this parallel/series valve arrangement precludes a single failure preventing decay heat removal system operation.

Slide 6-2, provide safety-grade steam dump valves. These are the power operated atmospheric vent valves or POAV valves which have been previously addressed. Applicable guidance contained in slide 6-2. Midland design here complies. Two POAV valves are provided per steam generators.

We can take a failure on either -- well, in this case, we can actually take a failure of one steam -- of one POAV valve on each steam generator, but that is not the guidance.

Slide 6-3, auxiliary pressurizer spray. NRC position, provide auxiliary pressurizer spray or show acceptable manual actions as contained in this applicable guidance of 6-3. Midland design complies farther than this in that an auxiliary pressurizer spray is in fact provided.

Slide 6-4, boration capability. Provide safety-grade boration capability. Show acceptable manual actions. References in slide 6-4. Midland design complies. Emergency boration system

and other safety-grade borated water sources provide sufficient boration. This design provides boration capability without letdown.

Slide 6-5, provide adequate DHR isolation. Applicable references of slide 6-5. Midland design complies. Suction isolation is provided by two series motor-operated valves. Discharge isolation is provided by two series check valves.

Slide 6-6, collect and contain decay heat removal pressure relief valve discharge. Again, the applicable references of slide 6-6. Midland design complies. The discharge is routed to the containment sump, which in fact is contained within the -- inside the containment building.

Slide 6-7, conduct a natural circulation cooldown and borated water mixing test. Applicable references of slide 6-7. Midland design, a partial compliance. Clarification required. Mentioned the 50 degree natural circulation cooldown test will be conducted or referenced if it's conducted before Midland, on a similar plant; however, a separate boron mixing test was planned. Previous discussions have shown that boron mixing tests are inadvisable

at the beginning of core life.

Slide 6-8, natural circulation -- provide procedures for natural circulation cooldown. Applicable references of slide 6-8, and again, this gets into the area of procedures. Midland will comply. Appropriate procedures will be provided before -- well, will be provided.

6-9, provide adequate seismic category one auxiliary feedwater supply. Applicable references of 6-9. Midland design complies. The normal feedwater supply is from the nonsafety-grade condensate storage tanks; however, automatic switchover is provided for the safety-grade service water system.

Slide 6-10, NRC position, provide boron monitoring capability with the safety-grade system. Applicable references to slide 6-10. Midland design nonsafety-grade boron monitoring capability is provided. They have continuous monitoring by a boronometer on letdown. Periodic monitoring by manual sampling capability is being provided.

Slide 6-11 -- I hope this isn't getting monotonous. Position, provide safety-grade steam generator water level indication and alarm.

This is regulatory guide 1.139. Midland design complies with the clarification. Safety-grade water level indication and nonsafety-grade alarms are provided.

Slide 6-12, provide safety-grade makeup and letdown to accommodate cooldown shrinkage and boration. Regulatory guide 1.139, as referenced partially earlier. Midland design complies with the clarification. Boration and cooldown shrinkage are accommodated using only safety-grade systems without letdown; therefore, safety-grade letdown is not provided.

Slide 6-13, address pressurizer heaters required to maintain natural circulation conditions. The applicable references of slide 6-13. Previous discussion has discussed this area. Midland area complies. Two banks of pressurizer heaters, backed by safety-grade power and controls are provided.

Summary: Slide 6-14, NRC position. Achieve Cold Shutdown with safety-grade systems. Applicable references of 6-14. Midland design complies with these clarifications:

Boration is accomplished without letdown. Boration is monitored and sampled by nonsafety-

grade systems. No separate boron mixing test is planned. Steam generator water level alarms are nonsafety-grade. Indication is safety-grade. One steam generator cooldown will take longer than 36 hours. This issue was previously addressed. Upgraded non-seismic chemical addition system can provide contraction volume in the case of a tornado. In this condition, we do not postulate a safe shutdown earthquake coincident with a tornado; therefore, we can use a non-seismic chemical addition system to provide appropriate contraction volume after a tornado.

That concludes my section and I now want to turn the floor over to Mike Gerding, who will provide a comparison to regulatory guide -- or excuse me. Standard review plan 7.4.

MR. GERDING: Thank you, John. Good afternoon. My name is Mike Gerding. I will be discussing Midland Plant instrumentation and controls required for safe shutdown.

Standard review plan section 7.4 provides guidelines for the review of these instruments and controls. I will briefly describe to you those provided in the Midland Plant and their conformance

to the acceptance criteria of the standard review plan.

The systems instruments and controls are discussed in your handout and are summarized in figures 6-17 A, B and C.

I will begin with figure 6-17A, reactivity and inventory control. Safety-grade redundant controls for insertion of the control rods are provided by the reactor protection system. Although no controls are provided for the emergency boration system as it is a manually operated system, safety-grade controls are provided for portions of the makeup and purification system which are used to inject the emergency boration system tank contents or provide makeup from the borated water storage tank or chemical addition system.

While the chemical addition system is not a safety-grade system, it is tornado protected and can be made available following a tornado, using the controls provided and various manual actions. For monitoring of reactivity and inventory control, safety-grade redundant indications are provided for control rod drive breaker position, source range neutron power, emergency boration system tank level and

pressurizer level. These indications are provided both inside and outside the control room, except where neutron power is provided inside the control room. Control rod drive breaker position, emergency boration system tank level and system valve indications are available outside the control room.

These indications considered with the reactivity capability of the emergency boration system, preclude the need to monitor neutron power outside the control room.

Figure 6-17B summarizes the systems used for pressure control. Safety-grade controls and redundant controls are provided for the pressurizer heater banks, 5 and 6, which have been upgraded to safety-grade. Safety-grade redundant controls are provided for the auxiliary pressurizer spray valve, which can be made available following local, manual system alignment and restoration of power to the valves. Safety-grade controls are provided for the letdown isolation valves.

Also, as discussed previously today, in the event of overpressure, the power operated relief valve on the pressurizer is set to automatically

open at 2260 pounds per square inch, and these are safety-grade controls.

Also, the pressurizer safety valve will operate at 2500 pounds on the primary system. These valves are mechanically operated; therefore, no controls are required. In the event that the power operated relief valve should stick open, safety-grade controls are provided to automatically isolate the PORV via the block valves which are set to automatically close on a decreasing pressure of 2100 pounds, coincident with the power operated relief valve not in closed position.

For monitoring of pressure control, safety-grade redundant indications are provided for reactor coolant system pressure and pressurizer level , and these indications are avaliable both inside and outside the control room.

Figure 6-17C, summarizes the systems used for heat rejection. Safety-grade redundant controls are provided for the main steamline and main feedwater line isolation valves. This includes automatic isolation in the event of a steam or feedline break and automatic feedwater isolation in the event of an

abnormally high steam generator level.

Safety-grade redundant controls for the auxiliary feedwater system include automatic initiation, steam generator level control and automatic switchover to the service water system, which is the seismic category one backup feedwater supply.

The main steamline relief valves operate open at 1,050 pounds per square inch steam pressure. These valves are mechanically operated and no controls are required. Safety-grade controls are provided for the power operated atmospheric vent valves.

Finally, the decay heat removal system controls include safety-grade controls, include the controls and interlocks on the drop line isolation valves, and the system pump and valve controls. The system is -- can be made available following local, manual alignment and restoration of power to some valves.

For monitoring of heat rejection, safety-grade redundant indications are provided on the primary system for hot and cold leg temperatures, and primary system flow rate. This is forced flow rate.

On the secondary side, indications are provided for steam generator level and pressure,

auxiliary feedwater flow, and power operated atmospheric vent valve position. These indications are provided both inside and outside the control room. Safety-grade redundant indications are provided in the DHR system, decay heat removal system, for flow rate and heat exchanger outlet temperatures. These are provided in the control room for accident monitoring purposes and can be available for safe shutdown monitoring purposes; however, they're not immediately required for shutdown monitoring. Sufficient time exists to connect portable instruments to line monitored equipment and therefore, permanent indications of these indications are not provided outside the control room.

The adequacy of these instruments was the subject of a detailed study of the FSAR Chapter 15 accidents by the independent nuclear safety task force. As a result of this study, significant upgrades have been made to enhance the Midland Plant instrumentation.

Now, I will review the Midland Plant conformance with the acceptance criteria of the standard review plan, Section 7.4. Detailed design and procurement of the controls and instruments

required for safe shutdown are nearing final stages for most equipment. The standard review plan acceptance criteria have been considered and are being implemented.

These criteria are summarized in figure 6-16. They shall be redundant in their intended safety function. They shall meet the single failure criteria. They shall have sufficient capacity and reliability to perform their intended safety functions whenever necessary. They shall be qualified to function after the design basis events for which their operation is essential, including the earthquake and all FSAR Chapter 15 accident. With clarification provided here by the Reg Guide 197, that the indications shall function within required accuracy following, but not necessarily during the earthquake. They shall satisfy applicable criteria for preoperational and periodic testing, quality assurance and design provisions for indicating system availability. Finally, they shall be operable from outside the control room at local control panels with appropriate readouts and they shall operate independent of those provided inside the control room.

I'd like to discuss this last criteria in more detail. We have mentioned at various points today, in today's discussions, the controls provided outside the control room.

Figure 6-15 summarizes these capabilities. The basis of organization of the controls and instruments provided outside the control room for safe shutdown, is to achieve and maintain hot standby at the auxiliary shutdown panel and then proceed through hot shutdown to cold shutdown, using these indications and controls, together with those provided at other locations, local control panels, motor control centers and switchboards.

As mentioned today, there are various manual actions required in some systems; examples are, the emergency boration system and decay heat removal system. The monitors provided at the auxiliary shutdown panel, these are safety-grade monitors, include emergency boration system tank level, pressurizer level, primary system hot and cold leg temperatures, auxiliary feedwater flow, steam generator pressure and level, primary system flow and pressure, and power operated atmospheric vent valve position.

The safety-grade controls include, pressurizer heaters, portions of the makeup and purification system, component cooling water pumps, power operated atmospheric vent valves, the pressurizer power operated relief valve and auxiliary feedwater system controls.

Controls provided at other locations include those for the systems of the diesel generator, the service water system, component cooling water system, chilled water system, plant heating, ventilation and air conditioning controls and the auxiliary pressurizer spray valves. These controls and indications are safety-grade and redundant, just as they are inside the main control room. They're designed to operate without mutual action of those provided in the control room and no single failure will defeat the capability to shut down the plant at either location.

In addition, as discussed previously, a study is in progress which will address the fire protection guidelines. The study evaluates the feasibility of the installation of transfer switches, relocation of signal processing equipment and improved

fire protection of safe shutdown control and instrumentation. This is being done to insure that the capability exists, both inside and outside the control room to safely shut down the plant after a fire.

In conclusion then, significant upgrades have been made to enhance the Midland Plant instruments and controls and these changes have been made consistent with the standard review plan, Section 7.4 acceptance criteria. Thank you, and this concludes my discussion.

MR. HUGHES: Thank you, Mike. That concludes our prepared presentation for today and at this time we can go on to questions on section six or anything else the Board wants to talk about.

John Wahl just pointed out that he has handed out copies of the reference provided earlier, regarding xenon. If anyone is lacking a copy, please say so and we will get them one.

MR. COOK: Would it be efficient to handle the questions just by going through the slides of individual points of regulatory guidance and just ask for questions on each one of those, individually, to kind of step through it in order?

MR. HUGHES: John, will you just--

MR. WAHL: I will be doing them in order, as they were in the presentation.

MR. HUGHES: This is the DHR dropline design to accommodate a single failure. We described a design that has a parallel/series motor operated valve provided inside containment.

MR. COOK: Questions from the Board or our colleagues of the NRC?

MR. HUGHES: Can I help you with a reference on the drawing numbers or anything else? That is drawing 6-1. Figure 6-1.

MR. MAZETIS: Is this where it was mentioned that the discharge sign was provided with two series check valves?

MR. HUGHES: That's later. This is where the line is inside the containment and a question relative to single failure. Where a parallel bypass line is motarized and given reliable power such that you wouldn't have an inability to open.

MR. COOK: No questions on it. Go ahead.

MR. HUGHES: 6-2 covered

safety-grade steam dump valves, and we have added to the design, two power operated atmospheric vent valves per steam generator.

MR. GIBSON: The POAVs, these are motor driven jog control?

MR. HUGHES: That is correct.

MR. GIBSON: Are the valve characteristics such that you can achieve -- are they linearized so you can achieve a decent control with them?

MR. HUGHES: Mike, are you able --

MR. GERDING: I would have to find out the answer to that question.

MR. GIBSON: But you didn't just take a standard open/shut valve and apply jog to it.

MR. BALLWEG: No. This is a control valve.

MR. HUGHES: These are new valves procured and replaced the original position referred to, MAD valves, which now are downstream of the main stream isolation valves. These POAV valves are upstream.

MR. GIBSON: But they were

designed for control, as opposed to back fitted for the control.

MR. BALLWEG: That is correct.

MR. GIBSON: That answers my question.

MR. GARRICK: I just would like your opinion on this. In order to allow control room isolation of the stuck open valve, do you think that the POAVs ought to be provided with motor operated block valves?

MR. HUGHES: Tom?

MR. BALLWEG: The analysis that's been done on this in the past indicates that that is not required. B & W has performed safety analysis on -- with the capacity that would equivalent to a single stuck open safety valve as not presenting any unacceptable consequence to the reactor coolant system or the core.

On that basis, we determined that it was not necessary to provide a motor operator on those valves. We did ask that question as we were going along and determined that it was not required.

MR. GARRICK: So you have that

analysis?

MR. BALLWEG: That is the analysis. That's all there is to it.

MR. HUGHES: Jim, can you address that?

MR. AGAR: I guess I really didn't understand the question. Could I hear the question again?

MR. HUGHES: The necessity of motor operated block valves downstream of the POAV valves. Upstream, pardon me, in the event that the POAV valve stuck open.

MR. GARRICK: Allow control room isolation.

MR. AGAR: I believe that our analysis on Chapter 15 accidents would cover such a condition, if the POAV were to stick open. This, of course, would be another single failure on top of single failure, on top of single failure. We get into a situation where if we failed enough pieces of equipment, we would be in an uncomfortable condition, but if it did stick open, you might be in a position where you would lose one steam generator and you would have one

loop, depending on how -- what the position of the valve was when it stuck open, whether it was wide open or just cracked. There is a whole bunch of scenarios you'd have to get into in this particular case.

MR. COOK: Let me see if I can restate the question, at least the way I'm reading it.

We have analysis somewhere in B & W that says there is no detrimental overcooling of the reactor, due to that POAV valve being wide open.

MR. HUGHES: Bob Schomaker?

MR. SCHOMAKER: Section 15.1.4 of the FSAR is analysis of an inadvertent opening of the atmospheric dump or safety valve, and the POAV is sized less than a safety valve, so the overcooling affect from a spurious opening of a POAV is bounded by the spurious opening of a safety valve.

MR. VAN HOOF: It might be noted also that under normal conditions, the POAVs would probably not be used, but that the modulating valve would be used, which are downstream from the main steam isolation valves.

MR. HUGHES: The reason we refer here to the POAV rather than the modulating

valves is that using class one equipment, we would resume the boundary to be at the main steam isolation valve.

The MAD valve Jim referred to are downstream of the MSIVs.

MR. COOK: Are they differently sized?

MR. HUGHES: The sizing is the same. The time for operation is different.

MR. COOK: There is no overcooling potential through an individual MAD valve? I see the isolation valves are there, if you want to, but --

MR. GIBSON: Once you open the MSIVs, you have got quite a potential for overcooling.

MR. BAUMAN: What's the total capacity of both valves on one steam generator if they're both open? Percentage.

MR. BALLWEG: The valves have independent, fully independent control and control switches. The combined capacity is approximately 13 percent.

MR. BAUMAN: I'm trying to see if this is related to the recent correspondence we have

received from B & W on total steam dump capacity exceeding 15 percent, and the fact that you get into DNBR problems. Is there any relationship, Jim, between that and these valves?

MR. AGAR: Yes. It's one in the same, except that the analysis of the 15 percent was to coincide with the mad valve and the condenser dump valves being opened at the same time and exceeding 15 percent capacity when we run into DNB problems, but the POAVs are sized such you wouldn't run into that.

MR. BAUMAN: By themselves, We're okay?

MR. AGAR: In addition to that, though, like Tom was saying, they're individually controlled, so the chances of having two of them stuck open at the same time would be highly incredible.

MR. BAUMAN: I'm not talking about having them both stuck open. This is a question that's in another department's hands at the moment, but we have a piece of correspondence from B & W that indicates that if we exceed, what is it? 122 percent or 22 percent steam dump, we have got some problems with the core potential problems, and I'm trying to see if there is

any relationship to -- between that issue and the sizing of these valves.

MR. TAYLOR: Let me see if I can clarify that. I think the original issue that you are talking about came about as a result of the question, can a single failure lead to the spurious opening of some dumping capacity, which has not been properly -- not been completely analyzed. This was related to control -- to the effects of the control system failures on safety.

I think this --

MR. BAUMAN: Let me --

not put it down as an action item and I'll go home and do some research on my own and see if there is any relationship.

MR. AGAR: It's been analyzed for Midland and not deemed to be a problem.

MR. HUGHES: Gentlemen, any more questions on this particular position?

MR. MAZETIS: I guess, just getting back to risk space, in addition to the cooldown part of this, it seems to me that there is another concern you eventually get to and that is for events

where you can't bottle up say a leak in the steam generator or a steam generator tube rupture where the capability to isolate intuitively has to be a plus. You know, it's a pathway to the atmosphere, and that's another side of the overall risk that some -- should be somewhere in there.

MR. AGAR: May I address that, Ed?

MR. HUGHES: Yes.

MR. AGAR: That particular item, Jerry, is -- would be addressed -- is being addressed now as part of the ATOG program, and there will be operator guidelines to depict what operation they should do. Whether they should isolate the generator or maintain the cooling side of that generator to reduce the pressure on the primary system faster.

I don't believe the analyses for Midland is other than having just been initiated, started, so it will be sometime before we have got the ATOG program completed, but your concerns will be taken into consideration, I'm sure.

MR. GIBSON: Jerry, isn't that a concern being asked pretty much of the whole industry,

other than PWRs. Just how are they balancing their courses of action to expedite getting below obviously the relief pressure?

MR. MAZETIS: Yes.

MR. HUGHES: Next position addressed is providing auxiliary pressurizer spray or showing acceptable manual actions. We have discussed Midland has auxiliary pressurizer spray. We have got some questions on that so far. Are there any others?

MR. SULLIVAN: Providing that auxiliary pressurizer spray involves some acceptable manual actions; right?

MR. HUGHES: Involves with the auxiliary pressurizer spray, yes. Do you want us to run down them or --

MR. SULLIVAN: No.

DR. GUNNING: The way this was worded in the requirements or in the guidance was provide one or the other, and that if one can show that acceptable manual actions could be performed, one need not in fact provide auxiliary pressurizer spray; therefore, yes, the auxiliary pressurizer spray requires manual action to align it, but there's still an "or" in the design.

MR. MAZETIS: It could be that I'm not interpreting our requirements correctly, but my understanding of our position -- I think I'd like to take issue with an apparent misunderstanding as to what you mean by compliance.

To make a general comment, manual actions, I perceive is three types. One is manual actions typically required during a normal shutdown process. Everytime you shut down. Manual action outside the control room. Let's talk about manual actions outside the control room.

The two manual actions needed because of the safety-grade requirement. In other words, in order to show the capability, to get to the Cold Shutdown with safety-grade equipment, it would require this safety-grade equipment to be actuated outside the control room, and three, those manual actions needed after a single failure.

The position 5-1 has a built in flexibility that's obvious with the latter. That is the third one of -- after the single failure, two. It's clear that it's a negotiated item; however, there is little to no flexibility for the former two.

So that the -- I'm not sure that I recall for the auxiliary spray, but your indication that it complies, I don't really think in this -- in a few of the other cases, too, that the compliance is to 5-1.

Maybe it is, in your own mind. A compliance is a viable capability. Just a comment.

MR. GUNNING: I was making reference to what's stated in Branch Technical Position RSB 5-1 with regard to Roman Numeral I, under the pressurization, which addresses aux pressurizer spray and it says compliance for -- with respect to the guidelines for the Midland Plant, compliance will not be required if dependence on manual actions inside containment after safe shutdown earthquake or single failure or remaining in hot standby until manual actions or repairs are complete are found to be acceptable for the individual plant.

Now, I can't speak about any further interpretation. I was referencing the specific document.

MR. MAZETIS: Those are the words I was looking at, too, as I spoke and those words you just read or referred to indicate the third category, and that is after a single failure the compliance would

not be required and limited operator action would be allowed outside the control room.

MR. HUGHES: Jerry, I believe what we're saying is that our operator action or manual actions are merely for the alignment of the system, and that this is a long term action rather than immediately required for depressurization, such that the time involved and the function or the objective, the depressurization we believe complies with the requirements and the intent both of the -- providing of an auxiliary spray, and that that requirement didn't require, in the long term, automatic action.

I'm really drawing a distinction on the timing of the need to start the depressurization as permitting the manual actions, and we can go through what those manual actions are if you are interested, because we are prepared for that, and can give you a feel for it, if you'd like.

MR. MAZETIS: I guess I'd like to separate a policy from a -- I will call technical argument. All I'm saying, it has been the policy to implement the position as I have described and your technical arguments, I presume are rational; however,

I'm just saying that this is the way we have been implementing for the near term OL's like yourself, this position.

MR. HUGHES: Fully automated auxiliary spray is a requirement?

MR. MAZETIS: Not automated, but the capability from the control room.

MR. HUGHES: Okay.

MR. GIBSON: When I read this over, I thought you guys were going to come back and say that compliance is not required because we are doing all these things, as opposed to saying that you are complying, because in the statement that was handed out, it said it's not required if you can show the following things, and I think you do show all those following things.

Referring to the item in table 6-2 under Roman Numeral IC. I'd at least like to note -- Jerry, do you feel that in not complying, that we have answered the other questions that are in that paragraph, such as dependence on manual actions inside containment after an SSE? We don't need that, and we can sustain a single failure.

MR. MAZETIS: I guess I question the relevance of how you have addressed that because it doesn't look like it's -- it doesn't look like we're in after the single failure space with your response in this column.

MR. LEWIS: As I understand the words in RSB 5-1, it says that manual actions for a plant such as Midland are acceptable if they can be justified. That is, if there is access and time available to take those manual actions. We feel we're in that condition. Do you disagree? If you disagree, please clarify why It's not clear to me.

MR. MAZETIS: I was just trying to describe the policy on how we have been implementing 5-1 and that is that the manual actions are divided into those three categories I described, and that we have not allowed normal shutdown of plants outside the control room.

The one exception that I could remember is recently, I believe it was on the San Onofre or Summer, that in order to restore the power to a valve, they had to remove the power for an unrelated requirement. They had to go outside the

control room.

I believe you have a similar situation. They had to go outside the control room and we evaluated in that one case; how far the operator had to travel, and it happened to be within one floor level, and we accepted that restoration of power, but to my knowledge, we have been requiring valves to be changed to motor operated valves, specifically.

There have been plants, mostly CE plants recently, like San Onofre, that they have -- my recollection was six or eight valves that were outside the control room, manual, and we required them to have motors.

MR. HUGHES: Operable from the control room?

MR. MAZETIS: Yes.

MR. BAUMAN: Is that related to Cold Shutdown? Were these valves necessary to achieve Cold Shutdown or was that necessary for some other safety function?

MR. MAZETIS: I can't answer your question. Maybe some of them were related to some other function, but some of them were related to Cold Shutdown.

MR. PRATT: That was for a normal Cold Shutdown?

MR. MAZETIS: Yes.

MR. PRATT: Okay. For example, we have manual isolation valves on the suction of decay heat removal. You are saying your position would be that those would require remote operators?

MR. MAZETIS: Right, and I guess, just to rehash, probably the -- I would assume that the Midland docket, although I haven't looked specifically, since the last time I was involved about three years ago, we pointed and we were to commence discussion on those particular areas, as to why we wanted motor operators on those valves, which never took place. I would presume the docket somewhere has our position.

MR. SULLIVAN: It wouldn't be on this particular case, because this capability wasn't a part of the design at that time.

MR. HUGHES: I believe Jerry's talking about the DHR suction valves.

MR. MAZETIS: Right.

MR. PRATT: And that this may have been listed as an open item?

MR. MAZETIS: Yes.

MR. HUGHES: For the purpose of this, I believe right now all we can do, Jerry, is note your discretion and take it under advisement.

MR. PRATT: Can I get one clarification on that?

The auxiliary spray capability is not required for a normal Cold Shutdown. Does that situation create a difference, as far as how the design is reviewed?

MR. MAZETIS: That's the second category of manual actions I told you about, if I understand what you are saying, and it falls into the same implementation as the first, and that is, in order to go to Cold Shutdown using safety-grade systems before a single failure, our requirement has been to do it from the control room. There is no identified flexibility in 5-1, that I can recall.

The only exception, again, I mentioned is if you have got the restoration of power to some valves, we would consider that and talk to you about how far away they are, the motor control centers and so forth.

MR. SULLIVAN: In terms of

clarification, as I read -- I don't have the Branch Technical Position. I assume this is out of it, it says or remain at hot standby until manual actions or repairs are complete, are found to be acceptable for the individual plant.

What you are saying is that ordinarily, what we're proposing here would not be found to be acceptable?

MR. MAZETIS: That's right. That -- that sentence you just read is after the single failure. The presumption is that a single failure had taken place and we have to look at that position, and the repairs reasonable to be expected to be effective while you are at hot standby.

MR. SULLIVAN: The way it's written here, it reads, to me, as an or. Compliance will not be required if A, dependence on manual actions inside containment after SSE or single failure or B, remain at hot standby until manual actions or repair is complete.

In other words, I don't read the logic as saying that in order to comply that I don't need the single failure space. I don't need to be

in that post single failure in order to not have to comply by reason of item B. Unless you come out and tell me, well, you can read it that way, but it's not acceptable. That gives you the way out.

MR. MAZETIS: I guess that's what I'm saying.

MR. HUGHES: Jerry advised us of the past policy practices and the best we can do ri t here, I believe, is take it under advisement.

Are there any other questions?

MR. GUNNING: As a clarification to that, there are only manual actions required inside containment, and that was one of them. The system is operable from the control room once it is lined up, so it does require manual action to align it. Once it is aligned, there are controls insi e the control room to permit continued operation.

MR. HUGHES: The next position discussed was providing safety-grade boration capability or showing acceptable manual actions. We believe the emergency boration system and other safety-grade borated water sources provide sufficient boration.

I believe we have discussed

so far today, the EBS borated water storage tank to a degree the chemical addition system.

MR. SLADE: In the presentation, I believe John indicated that we could provide safety-grade boration without letdown, and if I remember the earlier discussion, that is the emergency boration system; is that correct?

MR. GUNNING: Yes.

MR. SLADE: The part after EBS, other safety-grade, that does require letdown in order to provide sufficient boration; is that correct?

MR. GUNNING: One can borate sufficiently without letdown by using the emergency boration system, and in order to accommodate other contraction volume, one needs additional water that is borated, and one can use whatever available water source that may be. The borated water storage tank is a safety-grade source of water that can be used.

MR. SLADE: With letdown?

MR. GUNNING: No. You don't need letdown.

MR. HUGHES: If you're going for contraction volume only.

MR. GUNNING: If you cool down, if you contract the volume inside the reactor, the water will contract; therefore, one needs to supply additional water to keep the pipes filled. This water must come from somewhere and an available source is the safety-grade borated water storage tank. One needs additional water, even if one is not letting down, just because of the change in the specific volume of the water contained within the reactor coolant system.

MR. SLADE: My concern is in the event that you -- the operator, during the initial transient that we inject borated water from the borated water storage tank or the makeup tank, boric acid addition system, we inject borated water into the system automatically. We fill the pressurizer up. The heating transient brings you back up to 532. You compress the water into the pressurizer. You fill the pressurizer back up again.

Now, is there sufficient volume in the pressurizer to inject the emergency boration system which requires manual action at some later time?

MR. GUNNING: A detailed analysis of that has been done and I would probably

best reference it over to B & W, who has generated a report, to address those specific questions.

MR. AGAR: One point of clarification. I think the EBS, by itself, is not of course of sufficient volume to take up the contraction volume, and that is what that and is there between the EBS and other safety-grade systems.

In order to continue to cool down and supply contraction volume, you need other sources of water.

MR. SLADE: I understand that. What this is discussing is not inventory control. It's discussing reactivity control. Boration capability.

MR. PRATT: Let me try to clarify that. You need the 1800 gallons or perhaps less, depending on the scenario of six weight percent boric acid. In addition, credit is taken for a minimum in the Cold Shutdown contraction volume makeup, for a minimum of 1.3 weight percent, so the Cold Shutdown contraction volume provided cannot be demineralized water. It has to be at least 1.3 weight percent, and in that sense, it contributes to the boration capability.

MR. SULLIVAN: I think Jerry's problem goes away if the NRCs position says provide safety-grade boration capability and inventory control. It seems to me it's a matter of semantics really; isn't it? You're just saying the borated water source -- if you didn't have a volume concern, you don't care.

MR. SLADE: What I'm trying to establish is whether or not I have to get that emergency boration water into the system to have sufficient boron to assure the one percent delta K/K shutdown margin.

MR. PRATT: For what? Cold Shutdown or hot?

MR. SLADE: Hot shutdown.

MR. PRATT: No. You do not need to use chemical addition system or BWST.

MR. SLADE: That requirement is only for the Cold Shutdown condition, so that even if you don't get the emergency boration in prior to the cooldown, as you start to cool down, you will be able to inject the water from the emergency boration and stay ahead of the boron requirement?

MR. PRATT: Right.

MR. VAN HOOF: How about xenon? Don't you need the emergency boration for xenon? Even if you are hot?

MR. PRATT: Not if you have injected EBS.

MR. VAN HOOF: Your rods go in. The most important rod is stuck out. You go through your xenon **transient.** When you come down below equilibrium xenon, then you need the boration; do you not?

MR. PRATT: From EBS.

MR. HUGHES: You need the emergency boration system for that.

MR. VAN HOOF: Any contraction after that, you require the or, or the and **other** systems, such as the borated water system, and if you have contraction, you don't need letdown. You can put in your water.

MR. BALLWEG: That isn't the question Jerry has been asking.

MR. SLADE: You are skirting all around the question.

MR. BALLWEG: If I might try

and restate the question. You got a trip. HPI is still running. It's pumping water in. It raises the pressurizer level up.

MR. PRATT: Due to makeup?

MR. BALLWEG: Yes, and you don't have -- you fill the pressurizer up. Now you got it nearly full, but you don't have EBS in yet. Now what?

MR. SLADE: Now you go through your xenon transient. Where does your boron come from to take care of the decay xenon after you get through equilibrium concentration?

MR. BALLWEG: The answer part of that is, based on the B & W report, you have got over in your hands there -- under what you just put your hand on -- is that the injection has to be limited to 2200 GPM per that report, to assure that there is sufficient space in the pressurizer to permit injection of the 1800 gallons from EBS.

There is a conflict within that document that we have called to B & W's attention. They're requesting clarification on it.

MR. AGAR: Could we have -- Rich, would you address the concern? Is it clear enough

to you? Would you like it restated? Do you understand what the concern is?

MR. LANG: If you initiate HPI immediately and leave it on until you fill the pressurizer up, in order to get the EBS in, you will have to contract. You will have to cool down some, It's as simple as that.

MR. SLADE: In the meantime, if I don't cool down or initiate a cooldown, do I have enough boron in there to take care of my xenons that are going to be decaying out with time?

MR. LANG: No. You need -- if you're not going to cool down and you have a stuck rod and you are at the worse time in core life, you must have the EBS or its equivalent in within 24 hours for the most probable trip sequence.

MR. SLADE: And again, it gets into the -- and you don't have letdown capability. There is a lot of ands.

MR. HUGHES: Jerry, we're into a hypothetical situation where you do not have letdown, where you have had the unfortunate occurrence of the most reactive rod stuck out at the worse time in core

life, and if you go below the equilibrium xenon condition you need additional boration to assure more than one percent shutdown. That boration source, concentrated, is EBS. With that given set of conditions, you will need the EBS and you will need some volume available to inject it.

MR. GIBSON: The other thing you will need is a loss of auxiliary feedwater, in my estimation, because otherwise -- I can't understand any reason you couldn't do some cooldown.

In fact, usually with the B & W plant, the problem is not that you can't do some, but you do a little too much.

MR. HUGHES: Again, what we're into is a hypothetical situation. It doesn't assume loss of auxiliary feedwater. It deals with the definition of staying in hot standby, which is a temperature range.

MR. GIBSON: A large one.

MR. LANG: One other point of clarification. Without cooling down, you need approximately around, in round figures, about 125 inches in the pressurizer, so if you were to get down on hot

standby, if you were worried about your pressurizer level and you did turn HPI on, some source of makeup, as long as you terminated it about 270 inches or so, you would have enough room in the pressurizer to put the EBS water into the reactor coolant system.

MR. SLADE: As long as you stop the injection before it goes beyond normal levels, essentially.

MR. LANG: Yes, yes. That would be adequate.

MR. SLADE: I'm satisfied.

MR. SULLIVAN: Are your calculations for the need for the EBS, is this only for the first core or is it true for the life of the plant or --

MR. LANG: It's -- calculations have been done based on the design criteria for all normal cores. If you're going to talk about extended burnup type cores where you have higher boron concentration requirements because the worth of the boron toward shutting the plant down becomes less, so the number of PPM -- you have to raise the concentration to when in hot shutdown goes up, but for the design basis for all

normal reload cores, this has been accommodated, not just cycle one.

MR. HUGHES: Are there any other questions?

MR. PRATT: I've got a question for, I guess, Jerry. Given the previous comments on credit for manual actions outside the control room for depressurization, boration is one other of the essential functions that need to be performed to get to Cold Shutdown, and would the same definition as far as credit for manual action apply to the manual valve which isolates the emergency boration system from the makeup system?

MR. MAZETIS: Yes. That's categoric, too.

MR. HUGHES: Are there any more questions?

(Whereupon there was a short recess taken)

MR. HUGHES: All right. The NRC position, provide adequate DHR isolation. The project believes they complied by suction isolation by two series motor operated valves and discharge

isolation by two series check valves.

MR. COOK: Where is Jerry?

MR. HUGHES: I know he has a comment on that. If there are no other questions, we will go back -- oh, here.

Jerry, we have got this one on the board here. You have seen it and we're waiting. We thought perhaps you might have a comment.

MR. MAZETIS: Thank you. I was wondering, on the interface between the low pressure and high pressure discharge side, this is probably repetitive because I have presumed you have docketed it.

The concern on the potential for a loss of integrity of that low to high pressure interface, has dictated the past several years, to explore a test program and test capability to -- with accompanying criteria for leakage for those check valves.

The actual regulatory resolution to that subject, I believe, is probably in mechanical engineering branch, but I was just curious as to whether that's been a consideration here.

MR. HUGHES: Check valve leakage?

MR. MAZETIS: The capability to

check for check valve leakage.

MR. HUGHES: Tom, can you answer that?

MR. GUNNING: Well, in the review, I guess I could refer it over to Tom for a detailed design, but there are accommodations in the system to be able to measure the check valve leakage or leakage through those check valves. I guess I'd better refer over to Tom for verification.

MR. MAZETIS: Perhaps I could short cut it by asking if you recall if your position has been docketed anywhere that we can just refer to?

MR. PRATT: I believe it has. I believe we have gotten questions, or at least a question from the commission on that, and I don't recall just which question that was and which question and/or FSAR section documents our position, but why don't we leave that as an open item, or before we finish here, we can get some research going or look it up.

MR. HUGHES: Give us a few minutes to look it up. We'll give you a reference and/or tell you no.

MR. MAZETIS: Thank you.

MR. SULLIVAN: I guess for

clarification, I just got either an information notice or a bulletin yesterday, but I received it from the Palisade's people. It was received on their docket. Sometimes that kind of information is delayed a little bit before it gets to the applicant, as opposed to the operating class, so in terms of the specific information notice or bulletin that requires a response, we either have just received it within the last day or two or we will receive it soon.

MR. GIBSON: I'd like to elaborate a little bit. As I read that bulletin, it goes a little beyond leakage. What they're concerned about is that we have series check valves. One might be sitting open and you wouldn't know it, and therefore -- and I refer to how I read the current system for our plant, as far as detection capability.

I'm not sure we can detect leakage at each valve point, and they're concerned about leakage past the first valve, leakage past the second valve, and I believe also leakage past the third one, even though it's normally open.

I want to make sure you have the capability once -- that it can close, so this --

intersystem LOCA is the name of it, and --

MR. SULLIVAN: In fact, Davis Besse had trouble with their check valve in that system in their startup last fall, I think following the -- their refueling outage.

MR. GIBSON: Two plants were cited in there as having had the problem.

MR. COOK: Let's not try to speculate on new material. We can get back to it and give it some thought.

MR. SULLIVAN: I think the summary is, from the point of view of my department, it's still under investigation. The information may be on the docket already and we will respond in any case if we're required to, to the IE information notice or bulletin, as well.

MR. GUNNING: If there is a recent issue, I'm not aware of it; however, in the design review of the system, the system was checked to verify that one could check for leakage through the appropriate valves and be sure that one could measure it, and the system design had this capability. So recent additional concerns, I'm not aware of.

MR. HUGHES: All right. As I said, we will come back and provide a reference. Mike, you are prepared to do that?

MR. PRATT: Yes, Ed. The design position or features for intersystem leakage on the decay heat removal system are described in FSAR Section 5.2.5.2.3.

MR. HUGHES: What's the date on that page or the latest rev. on that page?

MR. PRATT: That would be revision 30, although it looks like the update was amendment 15.

MR. HOOD: I might clarify, that the letter for the Midland docket has been mailed out. I would also clarify that in the prior review that we did on the Midland docket of the FSAR, we did ask some questions with respect to the ability to test the two check valves.

MR. GIBSON: I'd like to ask Bechtel, I don't find that testing on the P&ID for decay heat removal. Is it located perhaps on the containment penetration pressurization P&ID, or where would I find it?

MR. PRATT: There is a pressure indicator between the three check valves.

MR. GIBSON: That's one indicator.

M' PRATT: That's one.

MR. GIBSON: That, I believe, only tells me --

MR. SLADE: It says you have pressure. It doesn't tell you the source of the pressure.

MR. C .: Let's go on. We'll address that whole question off lines.

MR. HUGHES: All right. We'll go on. Any more questions on this?

Next one, John. NRC position was collect and contain decay heat removal system pressure relief valve discharge. Midland discharge routed to the containment sump. We have had some discussion on the valve from the decay heat removal system to containment sump. Are there any other questions?

Go on to the next one. The NRC position has conducted natural circulation cooldown and borated water mixing test. Midland design complies, partially in that, presently,

the intention is to conduct a 50 degree Fahrenheit natural circulation cooldown test or reference in another appropriate test, but that no separate boron mixing test is planned. Experience to date has shown that boron mixing tests are infeasible. There is no feasible method of measuring boron mixing in this condition.

MR. TAYLOR: One question, really. Where is the -- I think we started to get to this this morning, but didn't make it.

Where is the sampling point for measuring boron concentration when you don't have any letdown flow?

MR. HUGHES: Tom Ballweg?

MR. BALLWEG: It's on the letdown line. It's at a connection on the letdown line, very near the large bore piping, the main loop piping. I think there is about three feet of two and a half inch letdown line. Then the sample line comes off through the containment penetration and out to the sample panel, so it would require some purged volume to purge that three foot leg of the -- approximately three feet of the two and a half inch line, and then

you should be drawing a full regular sample from the hot leg.

MR. TAYLOR: It's coming upstream of any letdown isolation **valve?**

MR. BALLWEG: Yes. There are actually two sample lines on that letdown line. One is downstream and one is upstream.

MR. GARRICK: You don't know **how** representative that sample would be of the system?

MR. HUGHES: I believe Tom indicated that after clearing the purge volume, we believe it would be fully representative.

MR. BALLWEG: It's representative of whatever is going to be in that pipe, because whatever has come through -- it's from the cool leg, so it's already come through the steam generator. It's mixed in the outlet plenum of the steam generator and mixed otherwise around the system, as it comes around, so by the time it gets there, it's representative of whatever is passing through that part of those systems.

MR. TAYLOR: This question is very much related to the need to demonstrate adequate mixing

with one loop in operation.

MR. BALLWEG: Yes, I understand that.

MR. VAN HOOF: That sample line, is it safety grade? In the one upstream?

MR. BALLWEG: To the outer containment through the containment and on out, it is. Beyond there, it's not.

MR. TAYLOR: So this is a hot sample then?

MR. BALLWEG: Yes.

MR. HOOD: With regard to the natural circulation cooldown test that will either be conducted or referenced, would you tell me if you have in mind now any candidate plants for referencing purposes?

MR. HUGHES: Darl, I'm going to ask Jim Agar to answer that. Jim?

MR. AGAR: I'm afraid I'm going to have to pass on that question. I don't know if there is any representative plants right at this sitting, right now or not. I think what he's looking for is a clarification of that statement. Would that be right, Darl?

MR. HOOD: That's part of it.

MR. AGAR: If you want to clarify what that says, in other words, that's a Consumer's commitment and perhaps, you know, they want to be a little more clear on what they commit to do.

MR. HUGHES: Well, Darl, maybe I don't understand your question. Basically --

MR. COOK: We do.

MR. HUGHES: There is some correspondence that --

MR. SULLIVAN: We just received a letter on the docket that references the natural circulation cooldown tests that have been required on, like Sequoia, and it's not only the demonstrated capability. It's also a matter of operator training and we still have -- that letter we just received yesterday, that I saw it, and it's under evaluation.

In terms of referencing another plant, I guess we work with the owners group and if the same requirements are going to be imposed on one of the other 177 operating plants, then we would certainly try to take advantage of any useful information we

could gain there, but it appears the NRC is approaching this now in -- different from this context and that is from the point of view of operators actually going through the natural circulation cooldown, like was required on Sequoia.

MR. HUGHES: The question I thought we started with was single loop cooldown. Maybe I misunderstood.

MR. COOK: It was analysis; wasn't it?

MR. SULLIVAN: That was a separate thing.

MR. HUGHES: You're only -- you're talking about a two loop natural circulation situation.

MR. HOOD: Yes.

MR. SULLIVAN: That's what I thought Darl was talking about, too.

MR. MAZETIS: Just to amplify what Ted just said, I don't know the details of the Sequoia test. I only know enough to say that the intent of the Sequoia test on natural circulation were not the same as 5-1. The test fell short of the

capability that is to be demonstrated in 5-1.

My recollection, for example, is they had let down and the major purpose of the Sequoia, if -- it was a unique test. It was almost solely operator training.

MR. SULLIVAN: That's the way I understood it, but like I say, it's under evaluation. The letter that we received talked about using pump heat; for instance, as opposed to decay heat and on end on. We just have to evaluate.

MR. MAZETIS: My only point in saying something was that Sequoia is still required under 5-1 to either conduct or reference, and in this case, their referencing tests by Diablo to be conducted later. A natural circulation cooldown test meets 5-1.

MR. SULLIVAN: Can we reference a test to be conducted at some later date?

MR. COOK: Next slide.

Go ahead.

MR. HUGHES: Are there any other questions on this?

MR. VAN HOOF: I've got one. I'd like to know a little bit more about the separate

boron mixing test and why it's infeasible.

Is there any way that a test could be conducted prior to fuel loading, during cold ops or whatever, to inject and make some measurement of this mixing mode? What isn't feasible

MR. HUGHES: It's really our understanding that this has been investigated on other dockets and has been determined, both by an applicant and the NRC personnel involved, that the test just wasn't a practical test. It would not either -- I'm not familiar enough with it to say whether it wouldn't prove or that the method of conducting it was not considered suitable.

Jim Agar has got perhaps a bit more information on it.

MR. AGAR: Were you going to say something, Walt? So I don't commit myself.

MR. JENSEN: I was just going to say that I didn't know of any NRC position.

MR. HUGHES: Not a position, but a conclusion.

MR. JENSEN: It's my understanding that such a test will be done on another plant.

MR. AGAR: Let me tell you what I know, Walt. On the North Anna plant, they were going to conduct a boron mixing test and what it amounted to, I guess, was it was robably an improvement over the test that was run on Sequoia, where they ran a very minimal test, and what Jerry was saying, is unacceptable results, very skimpy results anyway, and the North Anna test amounted to a mini boration dilution accident, in order to determine the effects of a slug of fresh water going through the core, after a slug of boron went through, to get a fast reaction indication that boron was reaching the core during natural circulation.

The determination was made by Westinghouse that the test was dangerous and the NRC agreed, and the test was not run. We had a man on the committee, Ivan Green, who is the resident manager of the Midland Plant for B & W, and my source of information was from him. I haven't been able to get a hold of any documentation, letters. There must be some documentation somewhere.

MR. JENSEN: I think that because the test on one facility was perhaps ran in such a way that it was judged not to be safe, doesn't mean

that a -- it's my understanding that this test brought -- either brought the reactor critical or brought it close to critical. Perhaps was even run when the reactor was critical. I don't see why, becaus. such a test was run, would preclude perhaps design test being run at Midland to show that the boron indeed mixed. Perhaps not to show its affect on the reactor criticality.

It's my understanding that part of the NRC concern is that the heavy boron will not -- that it will mix with the coolant, but will not perhaps form a pool or puddle in the lower part of the reactor coolant system. Your sample line seems to me to be in a fairly advantageous position. It requires that the boron travel completely around the coolant loop before reaching the sample point, so the indication of boron -- the predicted amount of boron at the sample point would seem to me to be a fairly good test, that the boron was being mixed within the coolant loop.

MR. AGAR: What we're saying is that we haven't identified a feasible way, at this sitting, to run the test, but I guess the only thing that really counts is that this boron gets in the core.

Not necessarily at the sample point, whether there is bypass flow around the core or backup through the loops. Unless you have some indication in the core that you have got boron in there, it isn't going to do you much good if you have a good boron mixing solution at the outlet of the sample line.

MR. COOK: What is the extent of analysis the project has done and discussed with the NRC on this particular issue?

MR. HUGHES: To my knowledge, we haven't held a discussion with the NRC on this issue.

The extent of our analysis has been discussed with B & W.

MR. SULLIVAN: We haven't done any analysis of the test.

MR. COOK: My sense of this discussion is that we're premature in reaching conclusions and until we can get back and get specifics, we're not going to get anywhere and we should just put it on the list of open items with the staff.

MR. BUDZIK: Two things. This has been looked at and there is two considerations that have gone into the feasibility of the test.

I guess the first thing is we don't know what the staff means by a boron mixing test because the primary system is not instrumented to measure in various positions and cross sections of the coolant system, the mixing in any kind of real time scenario. You're talking about long flushing lines and so forth, and the only thing you could predict is after the system reaches equilibrium, whether your sample points show an equilibrium amount of boron, but I would judge the test to be inconclusive because of the lack of sampling points.

The second thing is, I would also point out that this system, the boron is being added in a very slow time frame, compared to the loop cycle that we are looking at. You know, that the coolant passes around the loop, and so that it's not being injected as one slug, and you have to worry about it being spread throughout the primary system.

MR. COOK: Back to my original point. I think we owe a little more detailed discussion to the staff to clarify as you were alluding to, and also to get down to specifics on this design.

MR. HUGHES: All right. Are there--

Are there any more questions on the natural circulation cooldown or borated water mixing test?

MR. MAZETIS: One final one. Assuming a test is conducted and assuming it's what you indicate up there, 50 degree natural circulation test, I guess we'd be interested, when we get around to these discussions, in the basis for why 50 degrees would provide enough of a test to get something out of the test, as far as the cooldown. Why not 100 degrees or 75 degrees or 25 degrees?

MR. HUGHES: I believe the basis for the 50 degrees was a determination of some point to verify the computer code and confirm that it would be reasonable to expect it to be accurate all the way down, and there was no basis than that.

MR. AGAR: One point of clarification, Jerry. B & W would like to foresee more extensive cooldown tests because it would help with the code, but I think the 50 degrees would be what is determined to be a minimum point that would be of value in bench marking the code and it would determine also the ability to cooldown using natural circulation.

MR. MAZETIS: I guess it's on the record that when we talk about the test and what we're to get out of the test, that we'll probably expect to discuss further the adequacy of the 50 degree cooldown test.

MR. JENSEN: The concern in the cooldown that a -- that the -- there would be no bubbles formed in the primary system. For example, the upper head and I know that I have heard various people comment that the B & W plant has a larger amount of flow to the upper head than some other plants.

I haven't really seen that documented anywhere. Perhaps I didn't -- brought out in the evaluating possibility of vortex formation.

MR. HUGHES: Any other questions? I understand that there is a bulletin -- is it out on head formation? Head weight formation? Okay. Are there any other questions? I don't think we have any -- Walt, were you looking for an answer to that?

MR. JENSEN: I just took it as a comment.

MR. HUGHES: All right.

The next one. This is provide procedures for natural circulation cooldown and responses of the appropriate procedures will be provided. I don't know that there is any questions on that. They're in the process. I'm sure there will be function of the results of the computer calculations.

MR. MAZETIS: Do you have a feel for when?

MR. SLADE: Again, I just have one question and that is, will that be the subject of an operating spec -- operating procedure to be received from B & W?

MR. HUGHES: Let me --

MR. SULLIVAN: Time out.

As I said, we just received the one letter. This whole area is under consideration right now. It's going to be jointly developed, I'm sure, since the testing people and operating people will be involved, and I guess I don't see any reason to pursue it any further right now.

MR. SLADE: As I understand this one, though, Terry, this is talking about procedures

for operation and emergency procedures. Not just test procedures.

MR. SULLIVAN: I was reading that as the test procedures. These are emergency procedures that are referenced here? Okay.

MR. COOK: Jerry's question is already on the record. There was a process action from this morning.

MR. SLADE: I think that's a generic question. It covers a lot of ground.

MR. HUGHES: As you stated, I don't believe we're able at this time to give a date when those will be available, based on latest information provided to me. We may still have them under review.

I'd like to go on to the next one then. The adequate seismic category one auxiliary feedwater supply. A normal supply from non-safety-grade condensate storage tank, automatic switchover to safety-grade service water. Are there any questions regarding that?

MR. VAN HOOF: I have some very strong concerns as far as operation is concerned of

getting the chemicals in that service water system, inadvertently into the steam generator, and I see how you have taken care of the inadvertent automatic switchover with the four second delay with the pump low pressure, but under normal operating conditions, as I understand the isolation, there is two butterfly valves there.

What concern has been given to leakage by the butterfly valves which has been quite a problem over the years? Is there some indication that leakage is occurring by one of the valves, such that -- such as a telltale drain or an indication of pressure buildup or something? What is being done?

MR. BALLWEG: There is a telltale drain which is shown on the P&ID for the system.

MR. VAN HOOF: That's normally left open, such that it will normally drain in case there is a leakage by the one butterfly valve?

MR. BALLWEG: That's right.

MR. VAN HOOF: What size line is it?

MR. BALLWEG: Three quarter inch.

MR. LEWIS: I'd like to provide a

clarification at this time regarding the fire protection discussion we had earlier.

The criteria for the fire protection do not require combination with an earthquake or combination with -- or even necessarily use of only safety-grade systems and this is one area that is the source of suction water to the aux feedwater, where in fact we are relying on the condensate storage tank for the near term source -- suction for the aux feedwater, and we are not providing protection for those suction valves, those automatic switchover valves to the service water. Point of clarification. I don't think it was as clear as it could have been in the earlier discussion.

MR. HUGHES: Raj, is that clear?

MR. ANAND: Yes, it's all right.

MR. HUGHES: Any other questions on the switchover?

Boron monitoring capability with safety-grade system. Midland design has nonsafety-grade boron monitoring by continuous monitoring by a boronometer on the letdown and periodic monitoring by manual sampling, and it's Midland belief that this

is adequate.

MR. TAYLOR: Is the borononeter on the line downstream? Is that on the downstream letdown or downsteam sampling line?

MR. BALLWEG: Yes.

MR. TAYLOR: That one is not available if the letdown is not available?

MR. BALLWEG: That's correct.

MR. HOOD: Does the staff like to comment? Apparently not. No comment should not be taken as compliance. I don't know if that's on or off.

MR. HUGHES: All right. John, the next one. Provide a safety-grade system generator water level indication and alarm. I believe the Midland design complies with the clarification safety-grade water level indication and nonsafety-grade alarms are provided. Are there any questions?

MR. GIBSON: I assume that the reason for this is that the alarms were there before the others were added.

MR. HUGHES: I don't believe so. Mike?

MR. GERDING: I'm not sure I understand what you are --

MR. GIBSON: You are begging the question. Why aren't they all safety-grade? The obvious answer is because they aren't but is there a timing thing here?

MR. GERDING: No. Safety-grade alarms are not available and we have the redundant safety-grade indications on each steam generator, and it's felt that these are sufficient.

MR. GIBSON: Are the alarms off the indicators?

MR. GERDING: No. They have separate switches. In fact, the switches or the bistables that provide the alarms are themselves safety-grade, and they provide an isolated outlet to the non-Class I annunciator system.

MR. HUGHES: Isn't that a matter that the annunciators cannot be purchased to a safety-grade or qualified seismic or what-have-you situation. We believe that's state of the art in the industry.

MR. GERDING: That's correct.

MR. HUGHES: That's why I said if there is questions, we have to explain the rationale.

MR. COOK: You just did.

MR. HUGHES: The last one we just kind of -- everybody was quiet. There is a reason for all of these.

MR. SULLIVAN: Why don't you go back then.

MR. HUGHES: We'd be glad to.

MR. SULLIVAN: Okay. What's the rationale for the last non-compliance, nonsafety-grade?

MR. HUGHES: Nonsafety-grade boron monitoring? What's the -- Mike, what's the rationale for that? The fact was, it was an existing design.

MR. GERDING: I guess I would have to investigate that one further. I don't have, off the top of my head, an answer to that.

MR. HUGHES: Jim Agar, isn't that -- we considered just that itself. There is nothing really you can do about it.

MR. AGAR: I'll pass on that one.

MR. HOOD: What's been the practice on the recent near-term operating plant? Anyone know?

I might also point out that the way the staff slices up its pie for review, I believe this particular item would be outside the responsibility of anyone that is present for the staff today. today.

MR. GIBSON: I think it's obvious why the boronometer --

MR. HUGHES: It's based on its location.

MR. GIBSON: This is a very early procurement, from what I know of a -- it's a little -- kind of a difficult instrument to safety-grade, so the obvious question becomes manual sampling line. I think you have already addressed the fact that that is --

MR. HUGHES: The line is physically safety-grade out past the containment penetration.

MR. GIBSON: I think really we would be into maybe a lengthy discussion as to this

sampling, how much nonsafety-grade are you using, because it's an action that involves a lot of personal involvement. It's not just something you're looking to have happen.

MR. LEWIS: The post-accident sampling system is designed, based on nureg 0578 and nureg 0660, which do not require safety-grade systems. The normal sampling system had no safety design basis and therefore, was not a safety-grade system, so prior to this requirement, there was no indication of a need for safety-grade system.

The design does allow it, if an earthquake were to occur because of the seismic design out through the containment, there is at least a capability for access, long term, to take samples, make provocation if that were to be necessary.

MR. JENSEN: Would it be advantageous to move the boronometer to the sampling line upstream of the isolation valve? As I understand, it's on the sample line downstream of the isolation valve, and would be lost in case of the letdown being isolated.

MR. BALLWEG: The boronometer itself is a nonsafety-grade device and does not get --

does not get any qualified power supply to it.

In addition, if you were to take the sample from that point, you would be dealing with RCS cold leg temperatures in the range of 530, give or take a little, and you would have to cool that sample before you put it through and would require auxiliary cooling water supply as well, and simply would be a fairly elaborate modification to do it. The idea of the location as it is is to bypass the letdown isloation system, to take the pressure, the sample under pressure, and the temperature is whatever it might be at the point you take it, and to -- in general, there is no need to take a RCS sample within less than a half hour or so, maybe even two hours.

In the case of boron, you wouldn't be interested in measuring that until after you had injected the EBS and given it a chance to mix, so there is ample time to take the sample manually and have it analyzed.

MR. SLADE: Point of clarification, are you saying there is no cooler on that sample line? That you do take the sample hot at pressure and it has to be cooled by some other means before you can analyze

it?

MR. BALLWEG: There is a cooler on the post-accident sampling panel. I misspoke in that regard. It's at pressure, however.

MR. HUGHES: All right. Next one. Safety-grade makeup and letdown to accommodate cooldown shrinkage and boration. Midland design complies with clarification. The boration and cooldown shrinkage is accommodated using only safety-grade systems and we have demonstrated it can be done without letdown; therefore, letdown does not need to be safety-grade.

MR. SLADE: I think we beat this one to death earlier.

MR. HUGHES: This is the pressurizer heaters required to maintain natural circulation condition, and we believe we have two banks -- complied by having two banks of pressurizer heaters capable to safety-grade power and controls, and we have an action item to provide the Board with the size and basis of the contention that one bank of heaters alone is sufficient.

MR. MAZETIS: I guess I'm just

curious, not knowing the background. If you're in the process of depressurizing under natural circulation, trying to get to the RHR cut-in, is that - - during that process, is that when you need the pressurizer heaters or is it to maintain say hot standby where you need to have the pressure at times increased? Or both?

MR. HUGHES: I believe it's both the hot standby condition and the ability to control pressure on the way down, because we have a -- both pressure and temperature limitation on cooldowns.

MR. BALLWEG: It's primarily to maintain temperature at any point. Excuse me, maintain pressure at any point.

MR. MAZETIS: You don't think, as you depressurize, that the existing control systems to reduce pressure; i.e. the spray or PORVs are sufficient to control the depressurization rate, that you wouldn't want to turn them around? There is an apparent concern here that the operator would need to counteract the depressurization using the PORVs or the auxiliary spray. I can see it as a nice to have kind of thing, but --

MR. HUGHES: Based on, for some

period of time, being able to maintain using Class I systems in the pressure, it's available for the other function anyway.

MR. SULLIVAN: My recollection, we started this modification before TMI and the reasoning was the ability to maintain hot standby. Then nureg 0578 came out and I think the requirement was a little less stringent than what we were doing.

We went ahead with it anyway, because the design basis of the plant is hot standby. In addition, it's nice to have -- during a cooldown. That's my perception of what I have seen in this area.

MR. JENSEN: Are the heaters themselves safety-grade or just the power going to the heaters?

MR. HUGHES: We have been going through relatively an extensive program on the pressurizer heaters.

MR. BAUMAN:: We have B & W qualifying the heater seismicly for us. The qualification program has not been completed as of yet. We don't know the results. That's under way.

MR. HOOD: I don't know if it

gets to your concern or not. We have asked the question about the burnout mode of the heaters and I'm sure there is no concern in that regard.

MR. JENSEN: I wonder if someone could address the processes you would go through in going to Cold Shutdown without the pressurizer heaters? Using other equipment such as the makeup equipment or the ECCS.

MR. AGAR: Well, we haven't looked at that weird scenario for going to Cold Shutdown. We use the available 1-E systems in looking at the various methods and modes of getting to Cold Shutdown, and that includes using a pressurizer heater to maintain pressure to various heaters during the cooldown. We simply haven't looked at that. It probably would be impossible.

MR. GIBSON: I haven't been a plant operator. Also, I don't have a lot of experience with B & W, but from what I have observed, the way to control primary system pressure during the cooldown is with aux feedwater. That may sound weird, but as we discussed at lunch, the impact on system pressure of changes, slight changes in pressurizer level seems to outstrip any effect on the part of heaters, and

having simulated through a couple of cooldowns, I don't ever recall the heaters even being used. That was not the concern. The concern was on the other side, it was even with spray making sure you get enough heat out of that darn thing to keep it up with the cooldown.

I can't -- I guess my estimation would be that it's possible, depending on when you stop and start and all that kind of thing, that you could go through that. Sure, you might need it, but I think if you look at the track record, I don't think people have used those heaters that much. I should -- B & W training people could verify that.

MR. TAYLOR: There have been cooldowns carried out without the heaters, and I think the thing that Terry mentioned is appropriate, that the heater capability is as much a convenience as anything else, and if you run into a situation where you'd have a safety valve leakage that you have to overcome or some reason like that, where you needed extra heat, it would be helpful under those kind of conditions.

MR. BAUMAN: What Terry said was right. The decision to go safety-grade on the heaters was to maintain hot standby. That was the

licensing commitment that Consumers Power Company has always had, and without pressurizer heaters, we could not demonstrate that we could maintain -- it's an unanalyzed situation without heaters, like you can achieve it without heaters, but maintaining hot shutdown without heaters was a nonanalyzed situation. That's long before Three Mile Island. We decided it would be a prudent thing for us to do, upgrade the heaters.

MR. HUGHES: Jim Agar?

MR. AGAR: The only point I wanted to make was that as far as I know right now, B & W does not plan to look at this other case. I just wanted to make sure that was clear to the Board. At this point, we don't intend to look at any scenario, other than using our available 1-E systems for going to Cold Shutdown.

MR. JENSEN: I asked the question because there was a good deal of discussion about another B & W plant as to whether or not they could attain Cold Shutdown without the pressurizer heaters, and I wanted to be sure that there wasn't any need for pressurizer heaters here, that I didn't know about some safety requirement.

MR. AGAR: I think they made that clear, and I certainly agree with the statements made by Terry and Ron, but I just wanted to make the point, make sure the Board agreed that B & W does not plan to do another analysis.

MR. HUGHES: That's the last one; isn't it? I believe that concludes the various positions. Are there any other questions?

MR. SLADE: Yes. I have one, and I guess maybe -- I'm sorry. I'm getting ahead of myself, but are you going to go through the instrumentation separately? The items for instrumentation.

MR. LEWIS: We have not yet covered this. SRP 7.4, compliance. We can do that either as open questions or similar to what we have just done.

MR. HUGHES: Okay. We'll go through that. This one being a little different format, how would you like to go through it? Would you rather go through the tabulation of instruments that we showed and ask questions?

MR. COOK: It's really a pretty

free format, Ed.

MR. HUGHES: What does the Board want to do? We have stated that the instruments are redundant.

MR. COOK: I think any questions the Board may have or the NRC staff may have, I think Jerry, you were the first one up.

MR. SLADE: I have a concern, I guess about the instrumentation that's not available at the auxiliary shutdown panel, and specifically, the lack of a neutron monitor or flux monitor at the remote shutdown panel.

MR. SULLIVAN: I think I can respond to that. I just signed a letter yesterday afternoon to Ron Bauman, which contains a recommendation to add neutron flux indication at the aux shutdown panel, so it's -- that particular modification is in just for background. We have a task after TMI, called plant status indications. We had completed the bulk of that task, except for the indications on the aux shutdown panel. If Jim remembers, it's on the 90 day decision table or whatever, and we just completed that recommendation yesterday and it's

on its way to Ron Bauman, and so I guess that the bottom line is, that the normal process now will allow that to be resolved with the involvement of the Board members and to their satisfaction. I expect the recommendation will carry through.

MR. GIBSON: I have one question of Mike, on his presentation. Again, aux shutdown panel, you allude to controls for component cooling water pumps. Associated with those controls, what kind of indication do you have that your system is functioning?

MR. GERDING: There are pump indicating lights available on that panel and there may be -- just a second.

MR. GIBSON: Is that merely breaker status or is that some other --

MR. GERDING: That is breaker position.

MR. GIBSON: So you could not have a pump and still have a good breaker position?

MR. GERDING: There are also amp meters indicating current to the motors also on the auxiliary shutdown panel.

MR. GIBSON: That's really what I

was looking for. I wasn't sure if you had them.

MR. GERDING: They are there.

MR. GIBSON: Maybe that's my quirk, but I'd much rather see an amp meter next to a light, that not only did I close the circuit, but there is something flowing through it.

MR. GARRICK: Just a few questions along those lines, just for information purposes, and maybe they're trying to get your opinion.

For example, should control rod drive trip breaker position indication be provided in the control room or is it provided?

MR. GERDING: Again, there are nonsafety-grade indications in the control room. Let me clarify a little further.

The indicating light itself is safety-grade; however, it's sensed from a nonsafety-grade source at the control rod drive breaker, so in effect, an indication is not really qualified. That is in the control room; however, with the neutron power indication provided in the control room, there is an indication of -- that the reactor is subcritical and has indeed tripped.

MR. GARRICK: So you have indication, but it's not safety-grade; is that what you're saying?

MR. GERDING: That's correct.

MR. GARRICK: I wanted to know what is the range of the reactor coolant system, hot leg and cold leg temperature indication?

MR. GERDING: These are 50 to 750 degrees Fahrenheit.

MR. GARRICK: Is this valid under natural circulation?

MR. GERDING: What do you mean by valid?

MR. GARRICK: Do you get valid indications under those conditions?

MR. HUGHES: Is your question that you may overrange?

MR. GARRICK: Yes, it might be.

MR. HUGHES: I don't believe we have had any analytical indication of exceeding that range.

MR. GARRICK: I just want to be sure that you get indication during natural circulation

and then there is the range question, yes.

MR. GERDING: Well, the indications will function during that time, and the ranging has been increased. The range was not always up to 750 degrees. The range was increased and it was also done so in agreement with guidance provided in the Reg. Guide 1.97 instrumentation for accident logic.

MR. GIBSON: Could I expend on that question? Not so much the range, but are the sensor design such that they are representative? Can you elaborate a little? On the bottom of the pipe? Top of pipe? Side? Length of probe or anything, again. For circulation intuitively, I don't have a problem with it, but --

MR. GERDING: I really can't answer that myself. Jim?

MR. AGAR: I can't address that. If you really have that concern, I will have to take --

MR. TAYLOR: I can comment on that briefly. There have been about, in excess of ten different instances where the plants have gone into natural circulation cooling and cooled down substantially. Some of them intentional tests and some of them

inadvertent entries, and in all of those tests, there have been a very good agreement between all the TC's, and TH's and no reason to question their validity. They allowed a good heat balance on the system, so I think both the TC's and TH's are very representative under natural circulation conditions.

It's been at different plants both raised loop and lower loop and under different conditions.

MR. GARRICK: I wanted to ask also on the pressurizer liquid and vapor space temperature indication, is that provided in the control room?

MR. GERDING: For which parameter?

MR. GARRICK: Pressurizer liquid and vapor space temperature.

MR. GERDING: Indications are available in the control room; however, they are not safety-grade.

MR. GARRICK: Of course, you want this to get some indication of the subcooling and -- pressurizer subcooling and the margin between RCS and pressurizer. Along those same lines --

MR. HUGHES: Just a second, Tom Ballweg.

MR. BALLWEG: I would hope there is no subcooling in the pressurizer.

MR. GARRICK: No. It's the indication of pressure -- well, okay.

MR. BALLWEG: Maybe you skipped a few words when you were speaking. Pressurizer, by definition is an equilibrium saturated vessel.

MR. GARRICK: That's right, and do you get a PORV position indication in the control room?

MR. GERDING: Yes.

MR. GARRICK: Is that safety-grade?

MR. GERDING: Yes.

MR. SLADE: In reference to Lou's question earlier about length of probes, are the probes for pressurizer vapor space temperature and the pressurizer water phase temperature sufficiently long that they get through the metal of the pressurizer? You are not measuring metal temperatures, but actually vapor and water temperatures?

MR. GERDING: I would have to

refer that to B & W.

MR. TAYLOR: They're inserted into the stream, into the fluid.

MR. COOK: Further questions on this t ic?

MR. HUGHES: Are there any further questions on any topic?

I believe that concludes 7-4; doesn't it?

MR. SLADE: I have one additional question. We discussed a little earlier some of the -- that there were manual actions associated with chemical additional system and I guess I'd like to have a little bit more discussion about the extent of the manual actions to line up the boric acid addition for insertion into the makeup system.

MR. HUGHES: Mike Pratt?

MR. PRATT: What I can do is give you a walk through all of the specific manual actions that would be required for that event.

One thing I would want to point out, though, is we're continuing to evaluate the specific manual actions. Certainly are after today,

but procedures, detailed procedures would be developed and we haven't quite gotten to that point yet.

In particular, what the operator would need to do is first align the suction valve from -- and what -- I have listed all my instrument numbers and whatnot in here.

MR. SLADE: Okay, as you go through, could you indicate whether the manual action is a control room action or whether it requires local. That's really what I'm concerned about.

MR. PRATT: Okay. The operator would need to align the suction valves to 1P70A or B from the boric acid addition tanks, which are 1P70 A, B or C for unit one.

Essentially, line up from the tank and the pump. Local manual action.

MR. GIBSON: Mike, you said align the suction to P70 A or B? Those are the makeup pumps?

MR. PRATT: No. Those are the boric acid addition pumps, which deliver fluid to the makeup tank.

MR. GIBSON: Are we talking about

alignment of EBS?

MR. SLADE: No, no. Chemical addition.

MR. GIBSON: I didn't think I was there.

MR. BAUMAN: This is figure Roman Numeral IV, for the benefit of the people who want to follow this?

MR. PRATT: Well, the detailed valve configuration isn't shown on that.

Now again depending on what the operator is going to be using the boric acid addition tank for, let's say that's auxiliary spray. Then we have a need to open the manual auxiliary spray isolation valve, valve 374, for unit one.

The operator would need to open recirculation valves to recirculate makeup back to the makeup tank solenoid valve 0334 and 0335.

MR. HUGHES: Mike, are those remote or local?

MR. PRATT: That's remote. The operator would need to open a -- there is an air operated valve and discharge for the boric acid

addition pump, and in the event of a loss of air, which we can assume the operator would need to open the bypass valve. Local manual action, valve number 159.

Another action the operator would have to take, this one identified and I'm not -- I have got the valve number indicated and I don't remember specifically what the words are. Let me jump ahead and come back to that one.

Okay. Downstream of the -- now, we have got a flow path established from the boric acid addition tank to the boric acid addition pump. Downstream of that, there are solenoid valves in parallel, and that's what I was just touching on.

The operator will have to open one of these two solenoid valves. Remote -- no, local manual. There is position indication, but local manual. Excuse me, those are remote. 1SV0381 and 03-- 0318 and 0371.

Kind of following the flow path, okay? So you work through the solenoid valve and at this point we're just tying into the makeup purification system line downstream of the three way feed and bleed valve.

Working downstream of that, the operator would have to open a post-filter bypass valve. Valves that align flow through the post-filters are air operated plug valves, and in the event that that was closed, he -- or if it's open and he doesn't want to go through the filter, he'd need to open the bypass valve. Remote manual from the control room. Valve 1SV0366.

In the event of a loss -- now, we're down in the makeup tank. In the event of a loss of offsite power, the motor operated valves downstream of the makeup tank close. 1MO0328 and 0329. The operator would need to open both of those valves to establish a flow path from the makeup tank to the makeup pump, the suction header.

MR. GIBSON: How can those motor operated valves fail to close if they're closed?

MR. PRATT: If they're closed, yes. If they're closed, the operator will have to open them.

MR. COOK: For convenience, where are we taking this discussion?

MR. SLADE: I was just trying to

get an appreciation for the extent of manual control that was required, the extent of operator action, and I think it leads in the same direction as the question that was asked by Jerry earlier about the number of operator actions required in order to assure that you have boric acid addition and you have -- that you are achieving Cold safe Shutdown.

I don't think we probably need to go any farther than this. The operator actions are extensive and from that standpoint, I guess you said you're already reviewing that.

MR. PRATT: These operator actions are only required in the event of the design basis tornado, so that the operator doesn't use the BWST as the source of contraction volume makeup.

MR. HUGHES: The condition you postulated was, Jerry, essentially the chemical addition system. That's only required for going to Cold Shutdown in the event of a design basis tornado. That takes out the -- that takes out the borated water storage tank and that you have lost offsite power, so you're talking a relatively extensive amount of time available in this situation.

MR. GIBSON: I would like to carry on Jerry's conversation a --

MR. SLADE: Does that meet the criteria of number three that you were talking about before? That is, permitting operator action, local operator action?

MR. VAN HOOF: I'd like a clarification here, too. Do all of those operations have to be done or are some of those valves already lined up for normal operation? I think what you're after is what has to be done in that event and you have gone through almost every valve that has to be positioned, and some of those are probably normally lined up already.

MR. PRATT: They may be.

MR. VAN HOOF: So, he went through every valve and the operator would not have to go through every one of those valves.

MR. HUGHES: From a designer standpoint, we presume you'd verify valve lineup before going into that mode. That's up to the operating department, though.

MR. GIBSON: What about the

emergency boration tank? Without going through each valve, how many valves do you position and line up? More than one? More than five?

MR. PRATT: To get to the m[illegible]up header? Two.

MR. GIBSON: Two, t-w-o?

MR. PRATT: Two local manual valves. Downstream of that depends on which makeup pump you are using, and what the configuration of the makeup system valving is.

MR. HUGHES: Would it be fair to say in a normal operating mode, nothing abnormal, that if you wanted to cut into the EBS system, you'd only have to cut in two valves?

MR. PRATT: That's the minimum, right. Well, now wait a minute. That's only to establish the suction path. You still need to isolate recirc. So you got at least one more.

MR. GIBSON: From the control room?

MR. PRATT: That can be done from the control room.

MR. GIBSON: One last question.

For decay heat removal, how many valves do you have to line up outside the control room?

MR. PRATT: Four. You've got to close the valves from the BWST for each train, so you've got to open the comnet. Does someone have a P&ID?

MR. HUGHES: Do we have a P&ID available?

MR. COOK: Let me go back to the overall point.

MR. GRIESE: Let me address this. Nobody asked me to, but that seems to be my forte'. Decay heat removal system requires isolated -- the isloation valves on the pump suction to be opened. It requires the controls to be re-established to the bypass valve around the decay heat removal cooler. It requires manual valves in the auxiliary pressurizer spray to be open from the discharge of the decay heat removal cooler.

Also, we recommend -- B & W recommends that the cross connect between the drop line and the BWST header be closed. Now, that has a check valve in that line, which would be operative; however,

we recommend that it also have a manual valve closed. Now, that takes at least three manual valves open to -- you have to establish control to two motor operated valves, the bypass valves and the other two valves in the suction header are --

MR. PRATT: The power to the bypass valves is electrically locked out. Electrically closed for LPI and you need to restore power back in the breakers for those and open them.

MR. GIBSON: Okay.

MR. COOK: I think, Ed, we're -- what I think we have heard is -- in this review meeting of the Board, is that we have a general question of the adequacy or how much manual action is required, both to understand it from total system operation. I think in the short term we have to address and the Board, I think, has to caucus on this. Generally, how we close the loop on the overall action item. We have some questions of just basic design to respond to the NRC about that we have heard today, but in a much bigger picture, is the question of the overall review and the detailed preparation of procedures to make sure that there is adequate understanding from the operating

folks and feedback of any hard spots they run into in developing their procedures back and forth in the final phases of design, and how we resolve that issue as far as the completion of this Design Review Board.

I think we have to caucus on, but I think we have the action item identified and we have the two general levels of endeavor that are scoped out.

MR. HUGHES: Is it clear to the Board the areas where we were discussing the manual valves are all long term evolutions?

MR. COOK: Yes. I'm not sure if I personally have everyone properly categorized, but I think it would be a group discussion.

MR. SLADE: With the exception of the boric acid addition in the case of the design basis tornado, is that also long term or is that a shorter term?

MR. PRATT: That's long term. That's only required for contraction volume makeup and would not be required in the short term.

MR. COOK: Are there any further questions on any topic from the Board or the NRC staff?

If there are none, I think we now really ought to have two steps left in today's agenda. I think the Design Review Board needs to caucus to clarify and specify for itself and for the record, the action items it expects to get resolved as a result of this meeting.

I think we'd also like to ask the NRC staff to caucus themselves. I'd like to have them give us a reaction, if they would, on just what their observations are in participating with us today in this meeting and then I think we ought to talk about, when we come back together, those two topics and also the followup.

I think as I mentioned in opening the meeting, we have proceeded into this process, basically in an experimental vein. I think we're going to need your feedback as well as our own to determine whether we think this is the most efficient way to carry out the process we have in front of us. I think we are committed to you, as a staff, to do everything we can to support you in the licensing review of the Midland Plant and frankly, we really need to get your feedback in terms of which is the best way

that you can see to get the job done and to let us, you know, assist you in trying to go through that task.

I also think in terms of just the general protocol of this meeting, as we have talked about in terms of the letter that we sent to you in January initiating the process, I think we need to ask you to comment back to us on the -- what our expectations are in the last paragraph of that letter, as to how we close with you the activities, such as completing your review and documenting it in a draft section of an SER on the various topics we're going to address.

I think there is sort of two specific topics, Darl, we need to get response to you. One, how do we close, you know, on the particular items we have addressed today in this Design Review Board with the staff, and then two, that the general evaluation in terms of all the things that you, as the staff, are pursuing with and without us, in terms of the Midland review and how you would suggest that we work together best in the coming months to proceed through the review process.

Ed, do we have a room?

MR. HUGHES: Jim, we have three

rooms. The procurement rooms that are just across the little lobby and down the hall. Not the main lobby, but just the little table out her.. There is a big one at the end, I suspect that will be for the Board, based on the size, and the one next to it for the NRC.

MR. COOK: Do you want to lead us down there?

MR. HUGHES: We had a couple of people keeping track of action items. Do you want to --

MR. SULLIVAN: I have got mine written down. If somebody from Bechtel was keeping track of action items, why don't they just join the Board.

MR. COOK: We will have an adjournment now. Let's -- 20 minutes to a half an hour?

MR. HUGHES: You want to get back here at say ten after five?

MR. COOK: Let's shoot for five, but ten after at the latest.

(Whereupon there was a short recess taken.)

MR. COOK: We're ready to reconvene if the recorder is really to put us on the record.

I think it goes without saying it took just a little longer than we anticipated to get through the considerable amount of discussion we have had during this day, and try and make some organized sense out of it. I think in trying to conclude today's discussion, the first thing I'd like to do is to thank the individual members of the Board and the members of the NRC staff who participated with us. I, for one, it really exceeded my expectations in terms of the amount of information we would get discussed, and the level of discussion; therefore, I think it goes without saying that those who are part of the discussion, had given quite a bit of thought to what was presented to them and raised some very interesting questions.

I think some of the problems we had in getting everything organized to wrap up today's session, is that I find there is a conflict between some of the things that were discussed here today and the context of an individual Design Review

Board, and the functioning of the ongoing project and the way it does its business, both in the licensing arena and in some of the other activities, such as the preparation of the plant procedures and as such, we try to, in going through the stuff that was discussed today, tried to sort out in an appropriate fashion, what should go in what category for ultimate resolution, although obviously I think everybody felt that all the items that we didn't close out today, were worthy of resolution.

As such, we have -- Don Lewis, who is acting as the scribe and recording secretary of the session we just had, who is in charge, with our thanks for getting it committed to paper.

We'd like to have him list the organization of the open items as we recorded them in our notes.

MR. LEWIS: I have 12 action items as follows: First, describe the analysis of the auxiliary spray line and its connection to the existing line. Address temperature, pressure, number of cycles, potential low velocity effects, the effectiveness of the auxiliary spray itself. Address also potential

concern for the fact that many cycles could occur in one usage, and address -- include in the discussion both the spray nozzle and the piping.

Second, provide the basis for sizing of the pressurizer heater bank capacity, the safety-grade heater bank.

Third, the major point of discussion was the interface of the engineering design with the development of normal and emergency procedures, including the design for modifications late in the design. This will be referred to project management for resolution independent of the Design Review Board process.

Fourth --

MR. COOK: Let me just amplify. The specific question was related to Cold Shutdown. The discussion we had today. The thing that I -- as corporate responsible officer for the project, feel that I want to assure myself of -- that we have an ongoing process that's going to make sure that gets taken care of across the board, and as such, I wanted that back in the normal chain of business for the project and we have tracking systems and so forth

in our normal project management meetings, which is the arena in which I propose to resolve that item to my own satisfaction and of course, the rest of the projects.

MR. LEWIS: Fourth, review the manual actions associated with proceeding to Cold Shutdown to determine the cost benefit of potentially automating some of these actions with emphasis on the dominant actions in the risk sequences. That was given to Terry Sullivan and John Garrick of PLG.

Fifth, describe the single loop natural code analysis. State whether potential reverse flow in the idle loop will be addressed. Address the adequacy of sampling for boron and provide the schedule for completion of this analysis.

Six, describe boron mixing under natural circulation conditions. Include the injection to the idle loop for single loop natural circulation, address sample capability, access considerations in sampling, safety grade design of sampling, and discuss also the boron mixing test.

Seven, state the consideration of the need for periodic testing requirements of the

emergency boration system in the design of that system.

Eight, consider a study of the decay heat removal dropline safety valve failure. The probability -- consider the probability of such a failure, whether it can be sensed and how -- if it could be adequately isolated.

Nine, evaluate discharges to the reactor building sump, addressing possible vortex formation.

Ten, demonstrate the acceptability of manual actions in view of the regulatory requirements. A second part of this one is that the plant operations will review the procedures to be able to operate the plant and this is really folded back into action item of three.

MR. PRATT: Clarification. I believe that's action item four, and I don't understand the difference between four and ten.

MR. LEWIS: No. Okay. The second part of that question, ten, the review of plant operations is part of item three, which is the interface of engineering design with development of operating procedures.

MR. PRATT: Okay. Actually, four related to manual actions and risk. Maybe I will wait until you go through all of them.

MR. SULLIVAN: I think, maybe a point of clarification is that the last action item mentioned relates more to the regulatory criteria and then the operating concerns. The previous action item relates to looking at the manual actions that show up in dominant risk sequences, and the two may not be the same, since it may be that none of these manual valves show up in the dominant risk sequence; okay?

MR. COOK: I think we clearly had some items that came up in the section six of the presentation about compliance with regulatory guidance, which revolve around manual actions that we have to directly resolve with the staff and then that's the specific part of number ten.

Then, the generic part was to fold it back into the overall development and review their -- the operation staff.

MR. LEWIS: Item eleven, investigate the concern for intersystem check valve leakage testing as described in the forthcoming NRC

letter.

Item twelve, evaluate natural circulation cooldown testing as to demonstrating cooldown capability and operator training.

That's the extent of the action items.

MR. HUGHES: Is item twelve again related to this recent NRC correspondence?

MR. LEWIS: It's related to it, but it may -- that may be part of the response. It may be in that context.

MR. HUGHES: It's different from -- I can't remember the number that dealt with the natural --

MR. LEWIS: We elected not to state the action items in terms of that letter because there hasn't been enough review on that letter to really be confident that we know what it says.

MR. HUGHES: There was a previous action item whose number I didn't record, which starts off with the natural code and then goes into the testing, and this is different?

MR. SULLIVAN: One is analysis

and one is testing.

MR. HUGHES: Okay.

MR. COOK: I think we ought to put on the record, generally that the complexity of summarizing the action items means that we will have to take an iteration, at least once on trying to review and clarify for our own sanity, exactly what is intended to be done on the -- in specifying the action items.

What we propose to request the design team to do, is to respond to the Board directly on the items that were specifically raised by the Board outside the context of the normal project operational function. Those things that are directly interfacing with the staff and staff positions, would be carried forth in the licensing operation of the project.

The one item concerning the overall project work on translating overall design requirements into operating procedures would go forth as a project item off line of the Design Review Board. Those particular activities will be referenced back to the Board in terms of closing out the action items with regard to this particular Design Review Board,

plus the specific responses to the questions raised in the context of this design review, and as a result of that response, the total list of action items, the Design Review Board will render a conclusion on the adequacy of the action items and respond back to the design team.

MR. BAUMAN: Let me ask, do you have --

MR. COOK: I certainly intend to. I was just trying to specify for his benefit, the way we foresaw our method of proceeding in concluding this particular Design Review Board, and that was really the results of our own caucus, and now I'd like to, you know, ask you to give us any comments you may have as a result of your caucus.

MR. HOOD: I wasn't paying attention to your last comment. You made a statement about the methods by which you intended to conclude the open item. I'm afraid I missed it. I'm going to ask you to repeat it for my benefit.

MR. COOK: Once we have been able to write down with some clarity and specificity, actual action items, we're going to have the design team

respond to each of those items and then direct that response back to the Design Review Board, at which time we will circulate that information and review it among the Design Review Board members and then draw a conclusion as to its adequacy in terms of closing out, in our mind, all of the action items that have been raised.

I think I have made a condition of that response that certain of those action items will be referred to the normal channels of project operations. Specifically, the licensing activities and the operation of -- procedure writing activities.

MR. HOOD: All right, I understand.

MR. COOK: I'd like to now ask you if you'd like to give us any comments from your caucus in reflections on the day's activities?

MR. HOOD: Yes, I do have a few comments. I'm not going to reiterate comments that were given by the staff during the meeting. I'm sure you know what they were. I will just generally highlight what they were under the category of natural circulation test, and I'd like to make a further application with regard to the natural circulation test. Referring now

to the test with respect to RSB 5-1.

Part of this test -- a report should be submitted to the staff which defines the test goals, gives the technical basis for the test, and justifies the acceptance criteria. The report should include calculations of natural circulation flow rate and loop transition times, estimates of expected boron concentrations and should consider the effects of instrument errors sample line transient times, and instrument response times on interpretation of test results.

Another area of frequent staff comment during this meeting was with regard to a manual action, with respect to RSB 5-1. I won't reiterate those, but I'm sure you observed Mr. Mazetis' comment with respect to three categories of manual actions, and his comment that in general, the -- only the third category, category dealing with action after a single failure, is negotiable in the Staff's view - - I believe he did mention the exception in regards to restoring power to a valve, in that regard, and Mr. Jensen, as I recall, made a statement about basis for Cold Shutdown in less than 36 hours. I believe he was after the

analytical basis for why it can reach a Cold Shutdown in less than 36 hours, exactly the where -- of its prior commitments on other matters that relate to this meeting, he referred specifically to our feedback of our position regarding a single fire in the cabinets in the control room.

I'm also aware of the need for feedback with respect to the containment sump test.

I do have a few general comments to make about the observations of the meeting today and its affect, if that would be appropriate at this time.

MR. COOK: We'd appreciate your comment.

MR. HOOD: It's been my impression that this meeting has been very worthwhile. I would characterize it as a very probing type of meeting and its been very helpful to us. I dare say that the meeting was much more probing in certain areas than the staff would have gone. That was also of considerable interest to us.

At the same time, while the meeting has been very helpful in bringing out the issues

that need the action, I would -- I'm also aware that whatfollowup comes out of this meeting is also quite important and in that sense, the true effectiveness of a meeting like this is still in balance, subject to that followup act, but I can say at this point that what has transpired so far has been extremely encouraging.

I'd like to complement Consumers on the composition of the Board as its evidenced here today. That composition has proven to be excellent. I have also seen much evidence in the discussion today that Consumers and all of its consultants, have been very active in making improvements in the system during a period of relatively inactive review on the part of the staff.

I would also like to extend the appreciation on the part of the staff for a very nice tour that we -- was given to us yesterday, and I particularly would like to thank Jim Aldering who acted as our tour guide. I think it was a very well organized tour and no doubt it was very helpful to the staff in today's discussion.

MR. COOK: I think one thing I failed to mention, all of our followup correspondence

will be part of the record in this and made available to the staff.

MR. HOOD: I did want to ask about that, Jim. You know, that one of the -- one of the end products of a meeting like this and one of its measuresof usefulness will be an early SER. I believe that the meeting today, discussion that I have heard today and the followup actions that I anticipate will lead to such an end product.

It will be the staff's goal that within 30 days after the open items are addressed, we would issue a SER. I would anticipate interacting with Consumers in the preparation of that SER, or at least before issuance in its final form.

I am encouraged by your comment that the documentation for resolution of those items would be in the open forum. As you know, I am sure you will appreciate the Commission Department in that regard, and our intent that this meeting serve the surrogate review to the review performed by the staff and in that sense, we are sensitive to our documentation department. Thank you.

MR. COOK: Thank you. I think,

if there are no further comments by any of the members present, this will be the conclusion of the Design Review Board meeting on Cold Shutdown. Thank you very much.

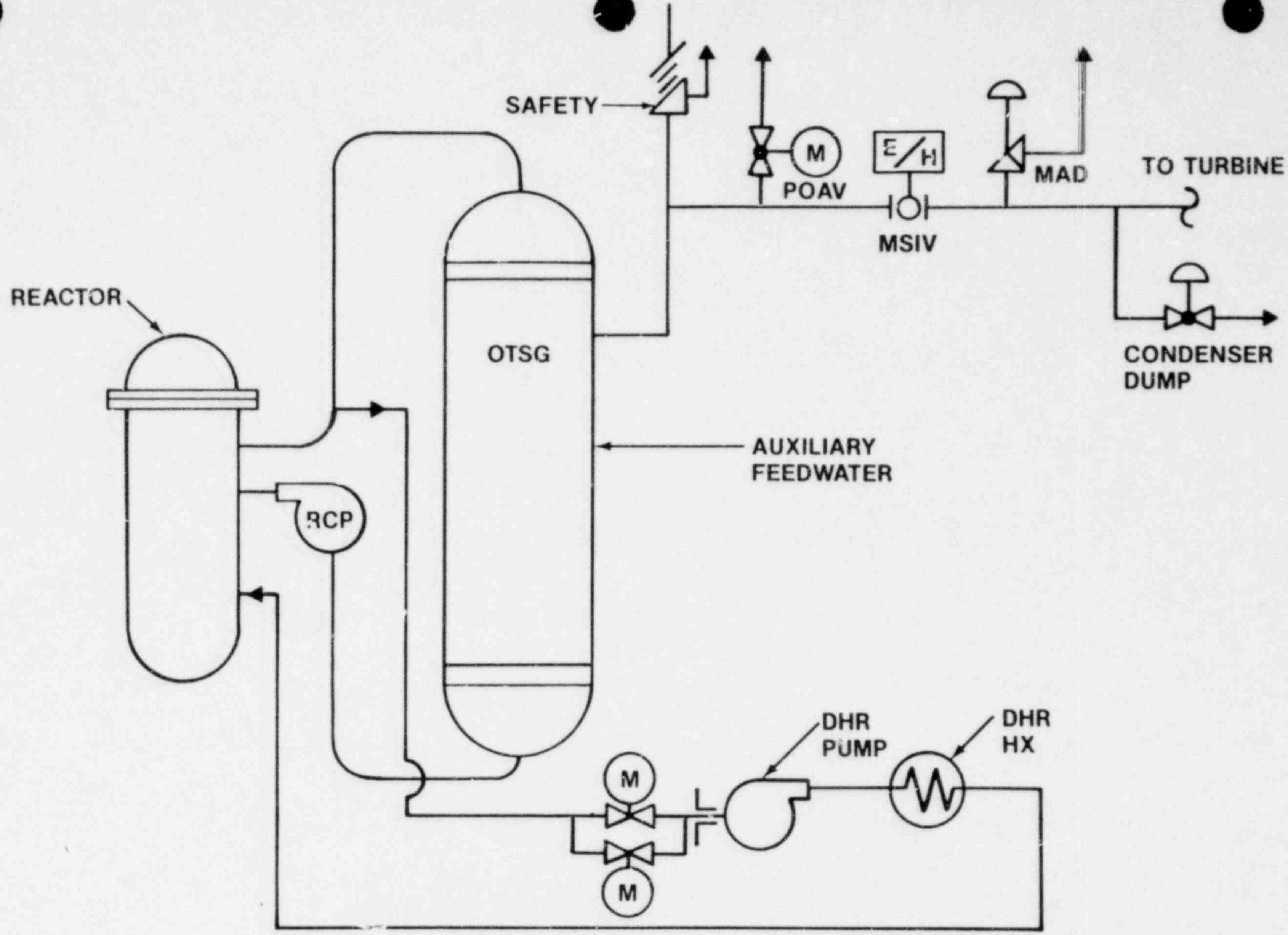
\- - -

CERTIFICATE OF NOTARY PUBLIC

I, Kim Marie Peterson, of the firm of HURON REPORTING SERVICE, a Notary Public within and for the County of Genesee, State of Michigan, do hereby certify that I reported stenographically the foregoing proceedings consisting of (165) typewritten pages and is a full and correct transcript of my stenographic notes so taken.

DATED: May 8, 1981

Kim Marie Peterson
Kim Marie Peterson
Certified Shorthand Reporter



HEAT REJECTION (TEMPERATURE CONTROL)

G-1508-06

ESSENTIAL FUNCTIONS

- REACTIVITY / INVENTORY CONTROL
- PRESSURE CONTROL
- HEAT REJECTION

REACTIVITY/INVENTORY CONTROL

- CONTROL RODS

- BORATION

- RCS MAKEUP

PRESSURE CONTROL

- RCS BOUNDARY
- PRESSURIZER HEATERS
- AUXILIARY PRESSURIZER SPRAY

Cold Shutdown Capability Following Chapter 15 Events

- TRANSIENT FINAL CONDITIONS:
  - TRIPPED - SUBCRITICAL CORE
  - LONG TERM HEAT REMOVAL BY SG's OR HPI
- FINAL CONDITIONS DEPEND ON:
  - TRANSIENT CONSIDERED
  - FAILURES ASSUMED
- MEETING DESIGN OBJECTIVE:
  - CAPABLE FOLLOWING MOST EVENTS
  - SINGLE FAILURES CONSIDERED

FIGURE V-1

- ESSENTIAL CONTROL FUNCTIONS
    - REACTIVITY/INVENTORY CONTROL
    - PRIMARY PRESSURE CONTROL
    - HEAT REJECTION
- REACTIVITY/INVENTORY CONTROL
    - SHORT TERM
        - CONTROL RODS
        - EMERGENCY BORATION SYSTEM
    - LONG TERM/COOLDOWN
        - CHEMICAL ADDITION SYSTEM
        - HIGH PRESSURE INJECTION
- PRESSURE CONTROL
    - AUXILIARY SPRAYS
    - SAFETY GRADE HEATER BANKS

FIGURE V-2

- **TEMPERATURE CONTROL**
  - USE OF ONE OR BOTH STEAM GENERATORS
  - NATURAL CIRCULATION CAPABILITY

- **DESIGN BASIS TORNADO**

  REACTOR TRIP
  - MANUAL
  - LOSS OF POWER

  REACTIVITY/INVENTORY CONTROL - BORATION FROM BWST
EBS
CHEM ADD TANKS

  TEMPERATURE CONTROL
  - MAINTAINED BY STEAM GENERATOR PRESSURE CONTROL

  PRESSURE CONTROL
  - HEATERS OR AUXILIARY SPRAY

- **HOT STANDBY CONDITIONS CAN BE MAINTAINED INDEFINITELY**

FIGURE V-3

Cold Shutdown Capability Following Chapter 15 Events (From Table V-1)

EVENT	COLD SHUTDOWN ACHIEVABLE IN 36 HOURS WITH SAFETY GRADE EQUIPMENT	ASSUMPTIONS	COLD SHUTDOWN LIMITATIONS
STEAM LINE BREAK	NO	LOOP LOSS OF 1 HPI	-ONLY ONE LOOP MAY BE AVAILABLE -TIME > 36 HOURS REQUIRED
LOSS OF NORMAL FEEDWATER	YES	AFW FLOW AVAILABLE TO BOTH STEAM GENERATORS	NONE
CONTROL ROD GROUP WITHDRAWAL	YES	AFW FLOW AVAILABLE TO BOTH STEAM GENERATORS	NONE

FIGURE V-4

DESIGN GUIDANCE TO ACHIEVE / MAINTAIN HOT AND COLD SHUTDOWN

- STANDARD REVIEW PLAN (SRP) 5.4.7, 7.4
- BRANCH TECHNICAL POSITION (BTP) RSB 5-1
- OPEN ITEMS ASSOCIATED WITH NRC STAFF REVIEW
  - RSB-7
  - ASB-8
  - PSB-11
  - RSB-10
  - RSB-20
- REGULATORY GUIDE (RG) 1.139
- NRC QUESTION (QR) 211.35

BWNP-20032A-5 (11-80)

CONTRACT/STANDARD NO. 620-0013/12		APR 08 1981	DOCUMENT RELEASE NOTICE (DRN) ☆
RELEASE DATE MAR 26 1981	PAGE 1 OF 1		

PART-MARK/TASK-GROUP-SEQ.	B&W DOCUMENT NO.	DOCUMENT TITLE	PUL STAT.	RRL.NO.
09-001-001	86-1123880-00	Xenon Dynamics and Shutdown Margin	Y	N/A

FILE COPY

REQUIRED DISTRIBUTION ORGANIZATION OR TE	NO. COPIES CDS	DRN	DOC	INFORMATION COPIES INDIVIDUAL'S NAME	NO. COPIES CDS	DRN	DOC
J. S. Shively	15	15	15	R. G. Griese	1	1	1
J. D. Agar	2	2	2	G. J. Brazill	1	1	1
D. L. Smith	1	1	1	G. E. Hanson	1	1	1
C. W. Tally	1	1	1	J. J. Woods	1	1	1
L. J. Rudy	1	1	1	W. T. Brunson	1	1	1
K. A. Shepherd	1	1	1	J. S. Tulenko	1	1	1
B. J. Delano	1	1	1	J. D. Carlton	1	1	1

RELEASED BY

R R Lange — NAME — 3-10-81 — DATE

REVIEWED BY

C W Tally — NAME — 24 Mar 81 — DATE

RETURN ORIGINAL TO R. R. LANGE

CALCULATION DATA/TRANSMITTAL SHEET

DOCUMENT IDENTIFIER

CALC. 32 - ______ - ______

TRANS. 86 - 1123880 - 00

TYPE: ___RESEARCH & DEVELOPMENT ___SAFETY ANALYSIS REPORT ___NUC. SERV. INPUT ___DESIGN RQMT. ___DESIGN VERIF. ___OTHER

TITLE Xenon Dynamics and Shutdown Margin

PREPARED BY R. R. Lange *RR Lange* REVIEWED BY B. J. Delano *BJ Delano*

TITLE Engineer DATE 3/10/81 TITLE Sr. Engineer DATE 3/10/81

PURPOSE:

The Midland Emergency Boration System (EBS) is designed to provide reactivity control to compensate for the decay of xenon following reactor shutdown. This report will discuss xenon dynamics following reactor trip from a variety of equilibrium and transient conditions. The purpose is to provide technical justification for a two hour EBS availability criterion. That is, the EBS must be designed to permit the operator to inject the contents of the EBS storage tank in two hours. More details on the EBS functional requirements are contained in Reference 2.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

Source calculation file (1) 32-112379-00
(2) 86-1103856-00

Xenon reactivity will not decay to levels below those at reactor trip for at least two hours if the system has been operated at 5-100% power for extended periods.

It was determined that the maximum positive reactivity change due to xenon decay two hours after trip was less than 0.3% $\Delta\rho$. This occurred for a double reactor trip where the reactor was restarted 24 hours after a trip and then tripped a second time after one hour of full power operation.

The ability of the EBS to achieve its design function (long term reactivity control of hot shutdown) with a two hour availability criterion was confirmed.

DISTRIBUTION

XENON DYNAMICS AND
SHUTDOWN MARGIN
(86-1123880-00)

PREPARED BY: R R Lange

DATE: 3-10-81

REVIEWED BY: J D. Elgar

DATE: 3/23/81

APPROVED BY: C W Tally

DATE: 24 Mar 81

INTRODUCTION

This report will discuss xenon dynamics as related to post trip xenon reactivity changes and shutdown margin. In B&W plants, the control rod design accounts for the reactivity deficits between hot full power and 532 F as well as a 1% $\Delta\rho$ shutdown margin with the control rod assembly of greatest worth stuck out of the core. This 1% $\Delta\rho$ shutdown margin is calculated assuming a xenon reactivity corresponding to equilibrium 100% power operation. The xenon level eventually decays to zero if the reactor is shutdown long enough with the resulting reactivity insertion countered by increasing the soluble boron concentration in the reactor coolant system.

The time frame of the xenon decay dictates when the boric acid should be injected into the reactor coolant system to preserve shutdown margin or prevent return to criticality. Post trip xenon dynamics directly impact how soon after reactor trip boric acid addition systems should be functional.

Xenon reactivity following trip from equilibrium conditions and transient conditions will be examined. The purpose is to identify the maximum and expected xenon reactivity decreases that will occur following a reactor trip, particularly those in a two hour time frame.

ASSUMPTIONS

1. Typical iodine-xenon parameters for a 177 FA plant were used. Equilibrium Hot Full Power (HFP) xenon worth was assumed to be 2.7% $\Delta\rho$. These base case parameters were varied $\pm$ 10% for the limiting case of interest.

2. The report deals with hot standby reactivity control. The plant was assumed to be at the Hot Zero Power (HZP) condition for B&W plants (532 F) when shutdown.

3. It is assumed that return to power is accomplished by control rod withdrawal.

4. The operators are assumed to obey Technical Specification rod insertion limits.

5. No additional maneuvering restrictions are imposed.

EQUILIBRIUM CONDITIONS

During steady state operation at power, the levels of iodine and xenon remain essentially constant. Upon reactor trip, xenon burnout (destruction due to neutron absorption) and iodine production (due to fission yield) are no longer occurring. The iodine and xenon inventories begin to decay. However, since iodine is transformed by decay into xenon faster than xenon decays, the xenon inventory increases for some period of time. The result is a temporary increase in the xenon reactivity before its ultimate decay. This post trip phenomenon is illustrated in Figure 1. The values of xenon reactivity at t = 0 are the equilibrium values for infinite irradiation at the power levels indicated. The reactor trips at t = 0, and the xenon levels increase as expected. A curve has been drawn through each of the xenon reactivity traces showing the locus of times when the xenon reactivity has decayed to its value at reactor trip. These are the periods during which the degree of subcriticality of the core is greater than it was at the immediate post trip condition. This assumes that the temperature of the system has not changed. It is noteworthy that as the times to decay to equilibrium xenon decrease with power level, the rate of change decreases as well. Thus for the trips from the lower power levels, the time to decay to equilibrium should be considered in conjunction with the rate of change of xenon reactivity. For example, 1.2 hours after a trip from equilibrium operation at 5% power, the reactivity returns to its value at trip. However, two hours after trip the reactivity has decayed below equilibrium by only 0.003% $\Delta\rho$, an essentially negligible amount.

Also shown are the points in time at which the xenon reactivity has decayed to a value 1% $\Delta\rho$ below the equilibrium value. These correspond, for a core which is shutdown margin limited (i.e., only 1% $\Delta\rho$ subcritical immediately following trip), to the points at which the reactor could return to criticality if no boration operations were undertaken. Figure 1 shows that the minimum time is approximately 27-1/2 hours. The time tends to increase with power at the higher equilibrium pretrip conditions because of increased iodine levels. At the lower power levels, the 1% $\Delta\rho$ xenon decay becomes a larger and larger portion of the equilibrium value. As expected, the curve goes to infinity for the case where the equilibrium power level (between 10 and 15% power) supports just 1% $\Delta\rho$ xenon.

The opposite extreme from operation at equilibrium xenon is operation following a xenon free start-up. Figure 2 shows the xenon reactivity transient for start-up to a number of power levels. Figure 3 shows the xenon transient for trip from a number of power levels one hour after a xenon free start-up. It can be seen that for all power levels xenon returns to its value at the time of trip more than 40 hours after the start-up. Figure 4 shows the xenon transient for a reactor trip three hours following a xenon free start-up. Note that for both Figure 3 and 4 the transient shown begins with the reactor start-up, not the subsequent reactor trip. Note from Figure 4 the times of decay to the value of xenon reactivity at the time of trip. Note that only three hours of full power operation before the reactor trip is sufficient to produce enough iodine to create a considerable xenon transient. In the limit, as the time at power increases, the results will converge to those of Figure 1. The significance of this is that the most limiting cases regarding the time decay of xenon to and below its value at reactor trip following equilibrium operation are represented in Figure 1.

A xenon free start-up implies that the reactor is either in the beginning of Cycle 1 or has been shutdown for several days. It is of interest to observe the xenon transient for a start-up from some sort of post trip condition. Figure 5 compares a xenon free start-up with a reactor start-up following a 40 hour shutdown. The xenon transient for the latter case is based on a recovery at 40 hours from reactor trip from 100% power equilibrium conditions. Start-up is at t = 0 for cases in Figure 5. The curves for start-up to a given power level approach each other faster for higher power levels. For the start-up to 100% power, the curves become indistinguishable between 12 and 15 hours after reactor start-up. Thus as far as the post start-up xenon reactivity trace is concerned, recovery from reactor trip may be considered a xenon free start-up for start-up after a shutdown of at least 40 hours.

DOUBLE REACTOR TRIPS

The logical extension of the above discussion is to examine the effects of tripping the reactor after recovery from a reactor trip. That is, suppose the reactor tripped at t = 1 hour on Figure 5 for both cases. The xenon free case has already been shown on Figure 2. Before showing the effects of a double reactor trip on xenon reactivity for trip after

recovery from a trip, it is useful to list all of the pertinent variables.

The following parameters were investigated for the double reactor trips. The variables are labeled for reference on the Figures.

1. The equilibrium power level of the reactor prior to the first trip (P_0).
2. The number of hours the reactor was shutdown before restart (T_1).
3. The power level to which the reactor was brought following restart (P_1).
4. The number of hours the reactor operated after restart before the second trip occurred (T_2).

Figure 6 shows a reactor trip from 100% power (P_0) with a restart to 100% power (P_1) at 40 hours (T_1). The parameter varied is the duration of the return to power (T_2). As expected, longer periods at power produced more iodine and thus larger increases in xenon reactivity following the second trip. Virtually no increase in xenon reactivity was shown for the case where the return to power lasted but one hour. Thus small values of T_2 lead to earlier xenon decay below equilibrium.

Figures 7 and 8 are similar representations of double reactor trips where the parameter T_1 has been varied to 24 and 18 hours, respectively. The trends are the same if the reactor operates at power for 5-10 hours following the reactor restart. It is seen, however, that upon reactor trip at 25 hours in Figure 7 and 19 hours in Figure 8 the xenon reactivity decreases. There has been insufficient fission to produce enough iodine to overcome the xenon decay even temporarily. Indeed the rate of xenon reactivity change after the second trip is greater for the earlier restart. The earlier the restart, however, the greater the residual iodine from equilibrium power operation prior to the first trip. This may be seen from Figure 9, which shows the restart to 100% power near peak xenon at 10 hours.

The presence of "xenon humps" during the 10 and 40 hour double reactor trip cases and their absence in the 18-24 hour cases implies that a restart exists that produces the maximum xenon reactivity decrease following a second trip. This maximum is observed to be the point at which xenon reactivity decay rate is the greatest following the first trip. It occurs at approximately 19 hours after the initial shutdown.

It is seen that a number of factors govern the rates of reactivity change due to xenon. The greater xenon density tends to increase the rate of xenon reactivity decay. This is seen from Figure 1. During the restart of the double reactor trip, xenon burns out until the second trip. The xenon decay then continues but its rate has been decreased somewhat due to the iodine inventory increase that occurred after the restart. Thus longer operation at power increases the time it takes xenon to decay to some specified value. This is in contrast to the trips following xenon free start-up where more time at power until trip shortened the time to decay to the xenon level at trip. The difference is that in the double reactor trip case the residual xenon inventory decaying from the first trip overrides the tendency of the newly established iodine inventory to increase xenon reactivity following the second trip.

Since it has been observed that less buildup of iodine during the restart leads to faster xenon decay after the second trip, it is logical to expect that the results will be more severe if the second trip occurred after power operation at levels below 100%. This is confirmed from inspection of Figure 10. Shown are restarts at 18 hours to 20 60, and 100% power levels for one hour before the second trip.

The lower the power level to which the reactor is restarted, the less the xenon burnout that occurs and the less the replenishment of the decaying iodine inventory. The profile begins to approach that of no restart at all. The conclusion is that the maximum rate of change of xenon reactivity occurs for the case where the reactor returns to 0% power and then is tripped. The largest theoretical change of xenon reactivity in some time period may then be calculated from the time derivative of the xenon reactivity of a reactor shutdown from 100% equilibrium power conditions. The maximum decrease in reactivity is less than 0.3% $\Delta\rho$ over a two hour period after the second trip of a double reacto trip sequence.

Also investigated is the effect of equilibrium operation at a lower power level (50%) prior to the first trip. For the cases where the reactor is operated at lower and lower equilibrium power levels before the first trip, the situation approaches the xenon free start-up.

UNCERTAINTIES IN DATA

The parameters involved in deriving these results include: equilibrium xenon reactivity, neutron flux, fission and absorption cross sections, and fission yields and decay constants of iodine and xenon. The parameters were varied arbitrarily by ± 10% to assess the impact on the results. The results indicate that if all of the parameters (except the well known decay constants) are increased by 10%, the results are affected by about .06% $\Delta\rho$ for the worst double reactor trip. The two hour reactivity change was still 0.3% $\Delta\rho$ to the nearest 0.1% $\Delta\rho$.

SHUTDOWN MARGIN AND SOLUBLE BORON LEVELS

In the above discussions, the emphasis has been on the examination of xenon changes from the levels at reactor trip. The final result of interest is the post trip shutdown margin. Typical statements of control worth design criteria involve the achievement of the shutdown margin at 532 F at equilibrium xenon. The behavior of the shutdown margin from the nonequilibrium conditions will be discussed in this section. The boration requirements during the double reactor trip sequence as well as other factors will be discussed.

It is important to note that the minimum available shutdown margin occurs at the end of a cycle for a push-pull (feed and bleed to compensate xenon changes during load swings) plant. The critical boron level at this point is approximately 17 ppm.

The case of interest is the double reactor trip at the time in life of minimum shutdown margin. If the trip were to occur after a restart 40 hours after a previous trip, it is clear that since the xenon reactivity is well below equilibrium the boron concentration would be higher than equilibrium. This is equivalent to saying that some of the xenon-boron reactivity swap that must be made has already been accomplished. Since xenon reactivity was above equilibrium after the first trip for approximately 23 hours, no boration was required. Between 23 and 40 hours, the boron

level was raised to compensate xenon decay. The boron level could be raised still further to prevent rod insertion at 100% power during xenon burnout. These factors tend to reduce the amount of xenon reactivity that must be compensated by boron addition after the second trip.

The time of restart that would result in the maximum rate of xenon burnout has been identified as 19 hours. It is of interest to note that the xenon level at this point is above equilibrium. The implication appears to be that the equilibrium value of xenon is not the greatest reactivity insertion that must be compensated via boration. However, it is apparent that the reactor could not be deborated sufficiently at EOL (~ 17 ppm b) to compensate for the added reactivity required during start-up with greater than equilibrium xenon nor could the control rod withdrawal provide enough reactivity as the normal regulating bank position at 100% power and equilibrium xenon is 90% withdrawn. Rod position limits would prevent start-up of a rodded plant at these conditions to 100% power at design ramp rates.

Thus, the double reactor trip with restart no earlier than the decay to equilibrium xenon is the worst case. Equilibrium xenon decay is thus confirmed as the largest post trip reactivity insertion at hot zero power that must be compensated via boration.

It is important to put the 0.3% $\Delta\rho$ xenon reactivity decrease for the worst double reactor trip into proper perspective. Although double reactor trips are quite credible, the decrease in xenon reactivity will only occur if the reactor was restarted between approximately 12 hours and 40 hours after a trip and then tripped again with less than one hour of full power operation. Decrease of shutdown margin below 1% $\Delta\rho$ for a short period would not occur if the minimum shutdown margin provided by the control rods was at least 1.3% $\Delta\rho$.

A review of recent fuel cycles for B&W plants indicated that the average minimum shutdown margin encountered was 1.85% $\Delta\rho$. The lowest recent cycle was 1.6% $\Delta\rho$. No attempt was made to be comprehensive, but the 13 cycles examined are representative. The data was taken from Table 5-2, "Shutdown Margin Calculations" from various reload reports.

SUMMARY AND CONCLUSIONS

1. Long term shutdown margin can be provided without cooldown.

2. Trip from equilibrium power levels between 5% and 100% will not result in xenon reactivity falling below its equilibrium value in two hours.

3. Under very select or improbable circumstances, xenon reactivity could decay 0.3% $\Delta\rho$ below its value at trip in two hours.

4. If the duration of the shutdown period following a reactor trip is at least 24 hours, xenon reactivity will never decrease below 0.3% $\Delta\rho$ in two hours if the reactor trips following restart (provided there has been at least one full power hour of operation following restart).

5. No safety problems exist if up to two hours elapse before boric acid is added to the RCS to compensate xenon decay.

LIST OF FIGURES

Figure 1. REACTOR TRIP FROM EQUILIBRIUM POWER OPERATION P% TO 0% POWER

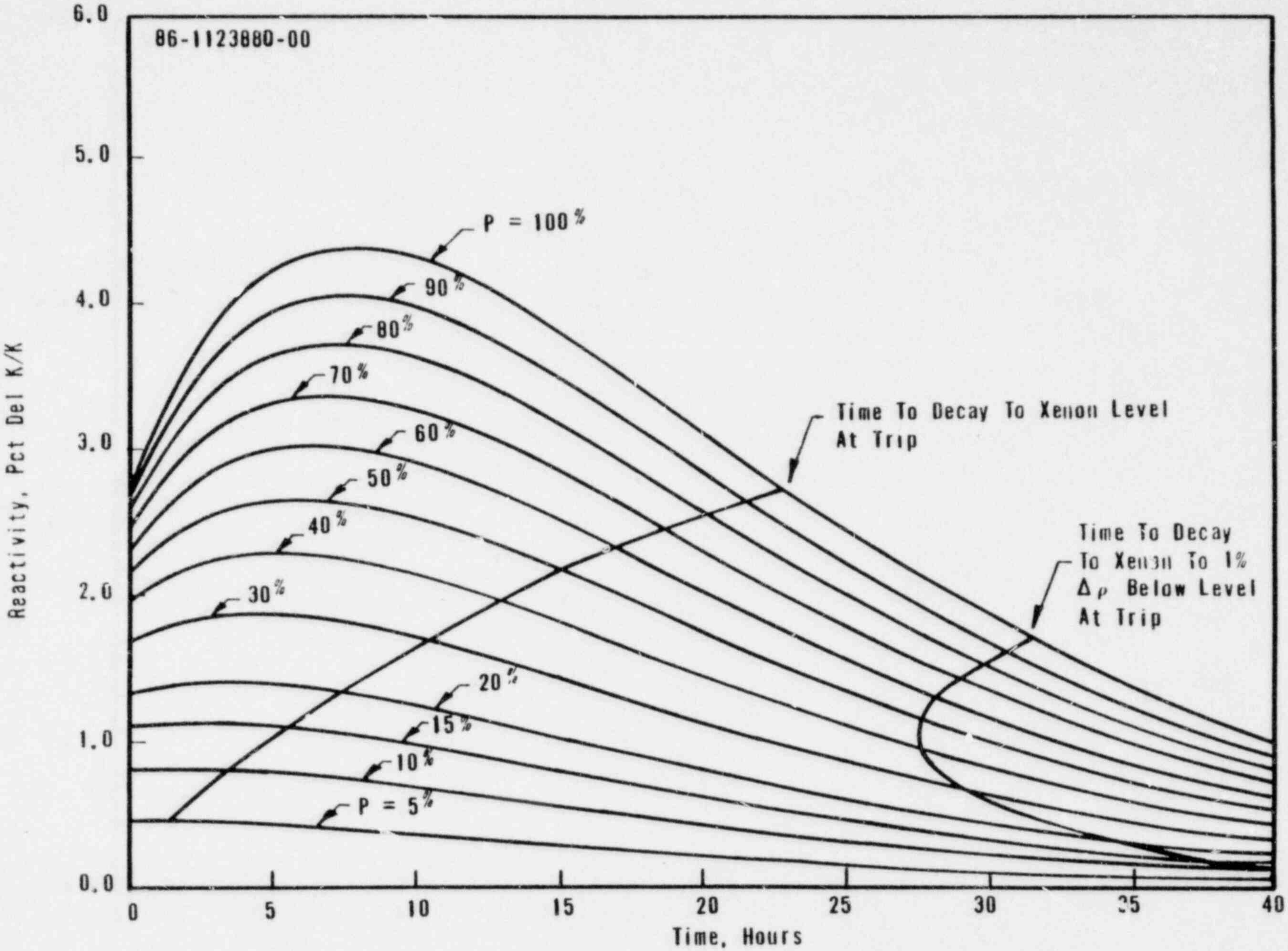


Figure 2. REACTIVITY VS TIME FOR XENON FREE STARTUP TO POWER (P [illegible])

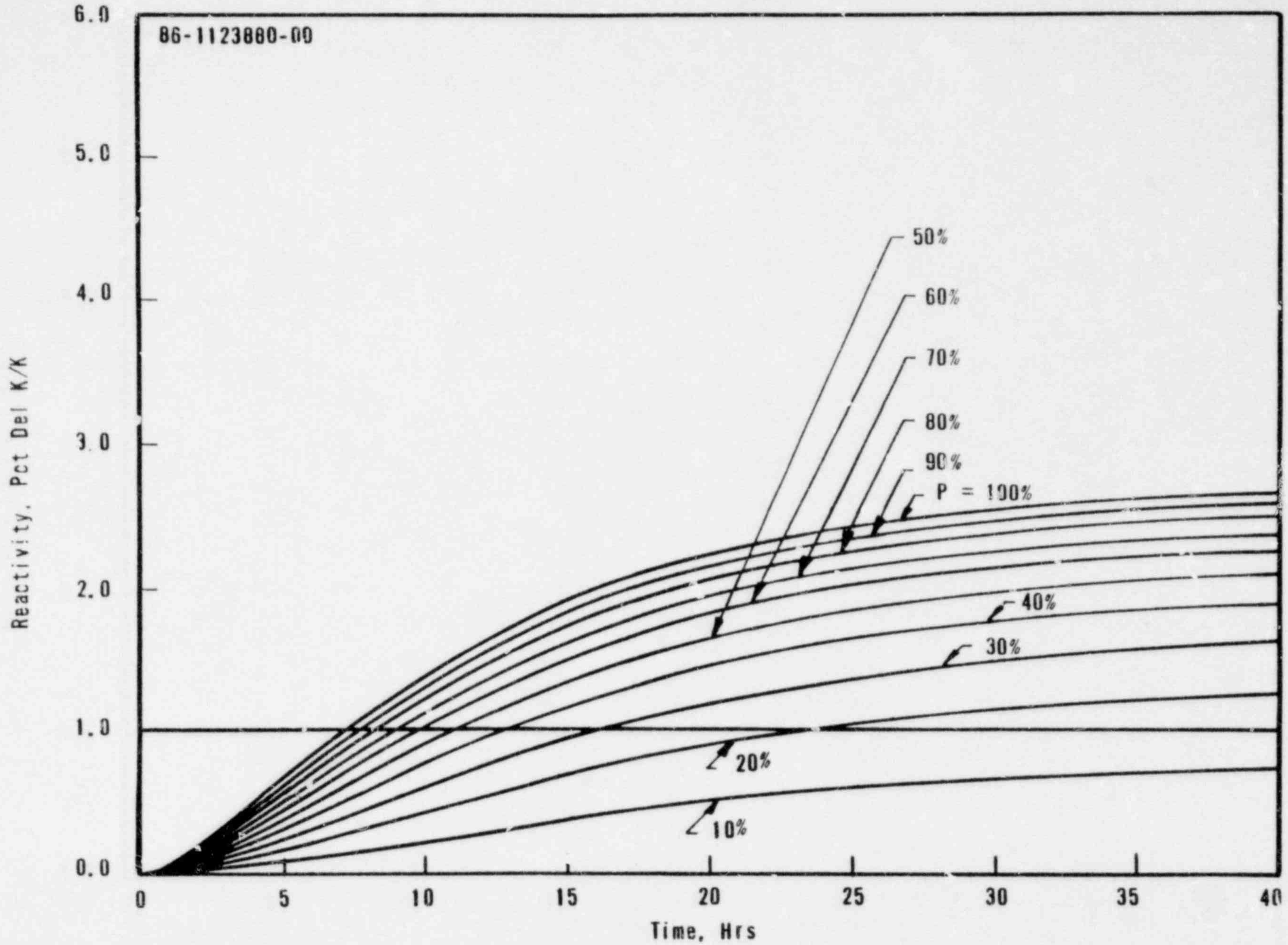


Figure 3. REACTOR TRIP 1 HR AFTER XENON FREE STARTUP TO P% POWER

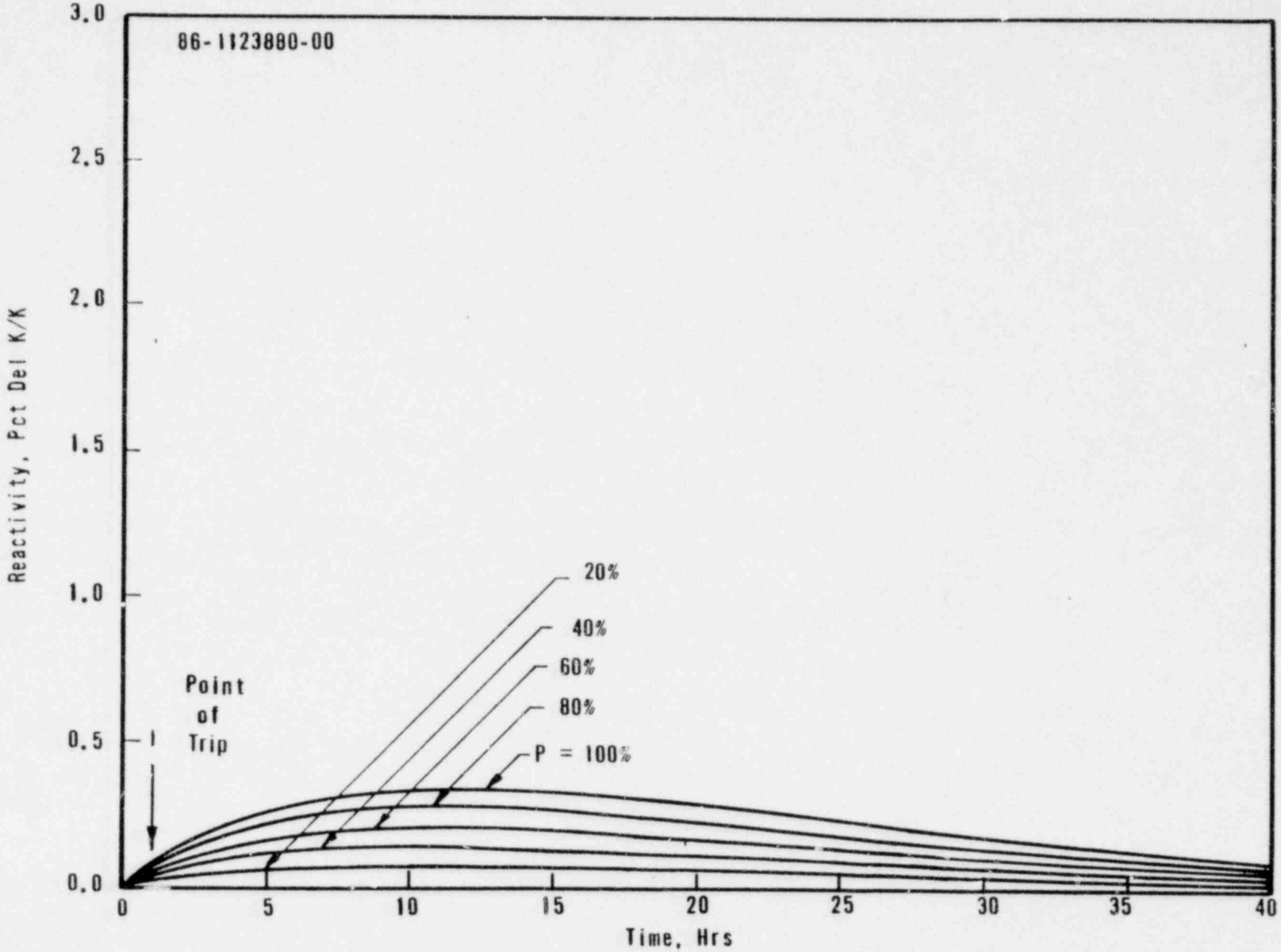


Figure 4. REACTOR TRIP 3 HR AFTER XENON FREE STARTUP TO POWER

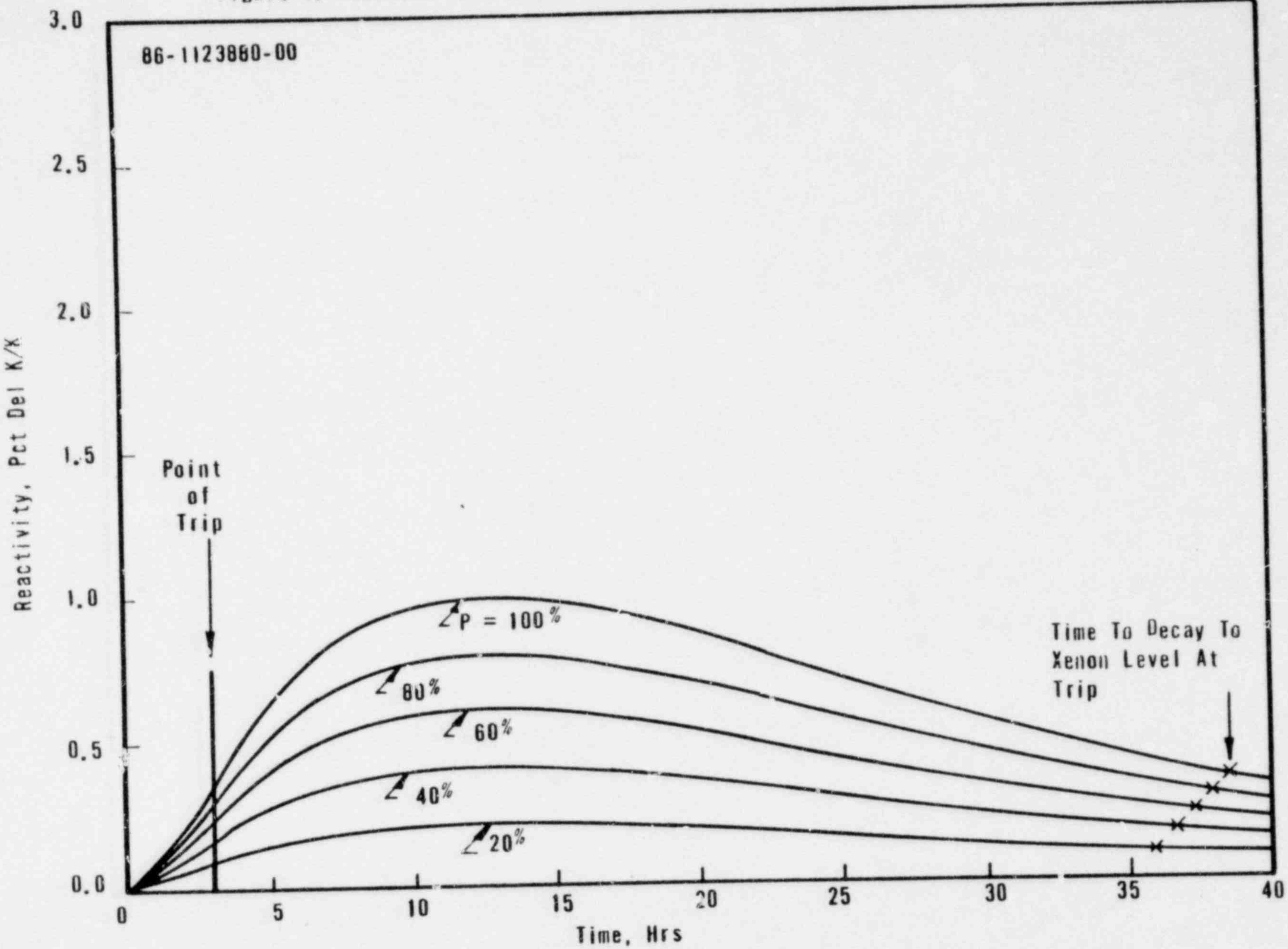


IMAGE EVALUATION
TEST TARGET (MT-3)

6″

Figure 5. COMPARISON OF A XENON FREE STARTUP WITH A STARTUP 40 HRS AFTER TRIP

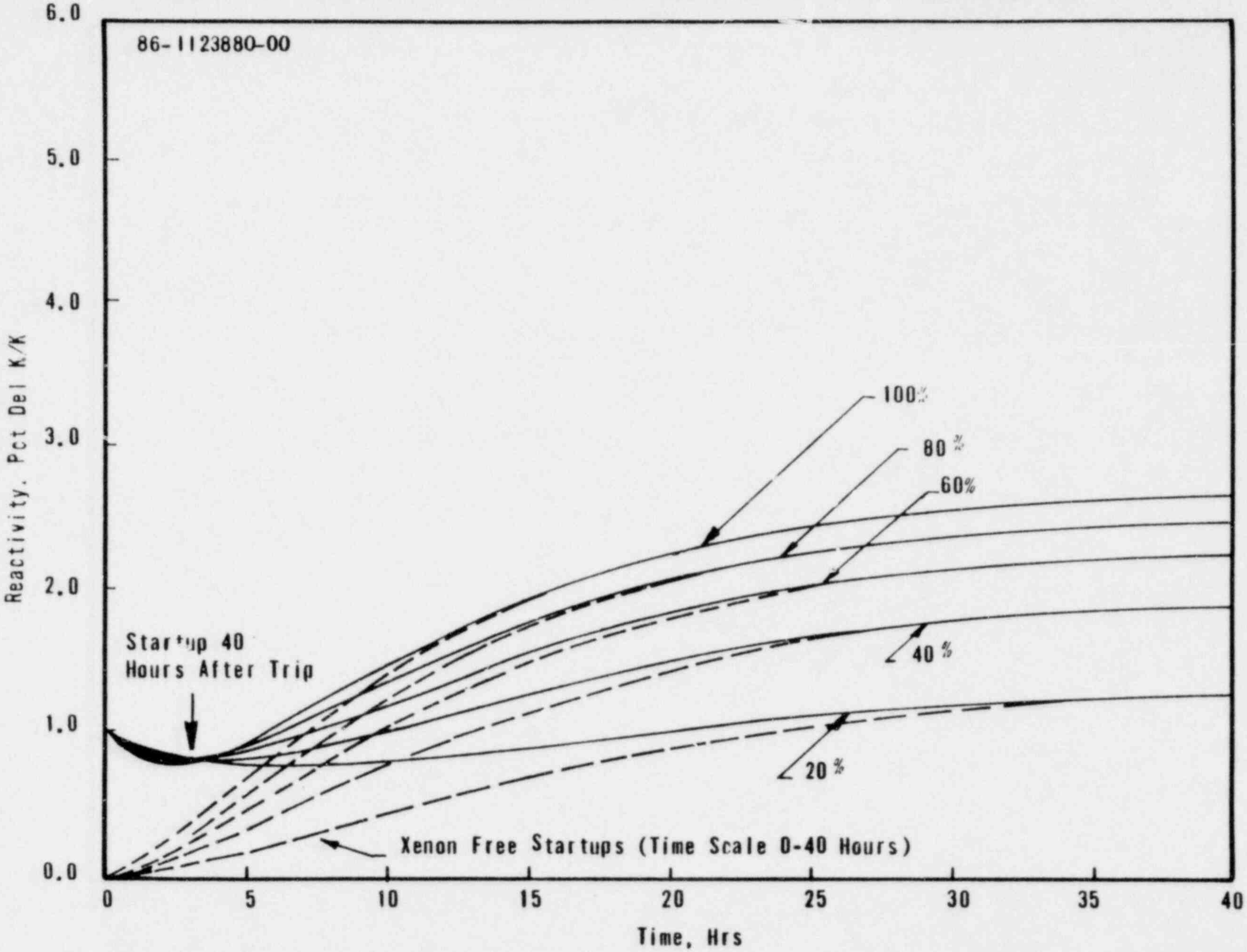


Figure 6. FAMILY OF DOUBLE REACTOR TRIPS

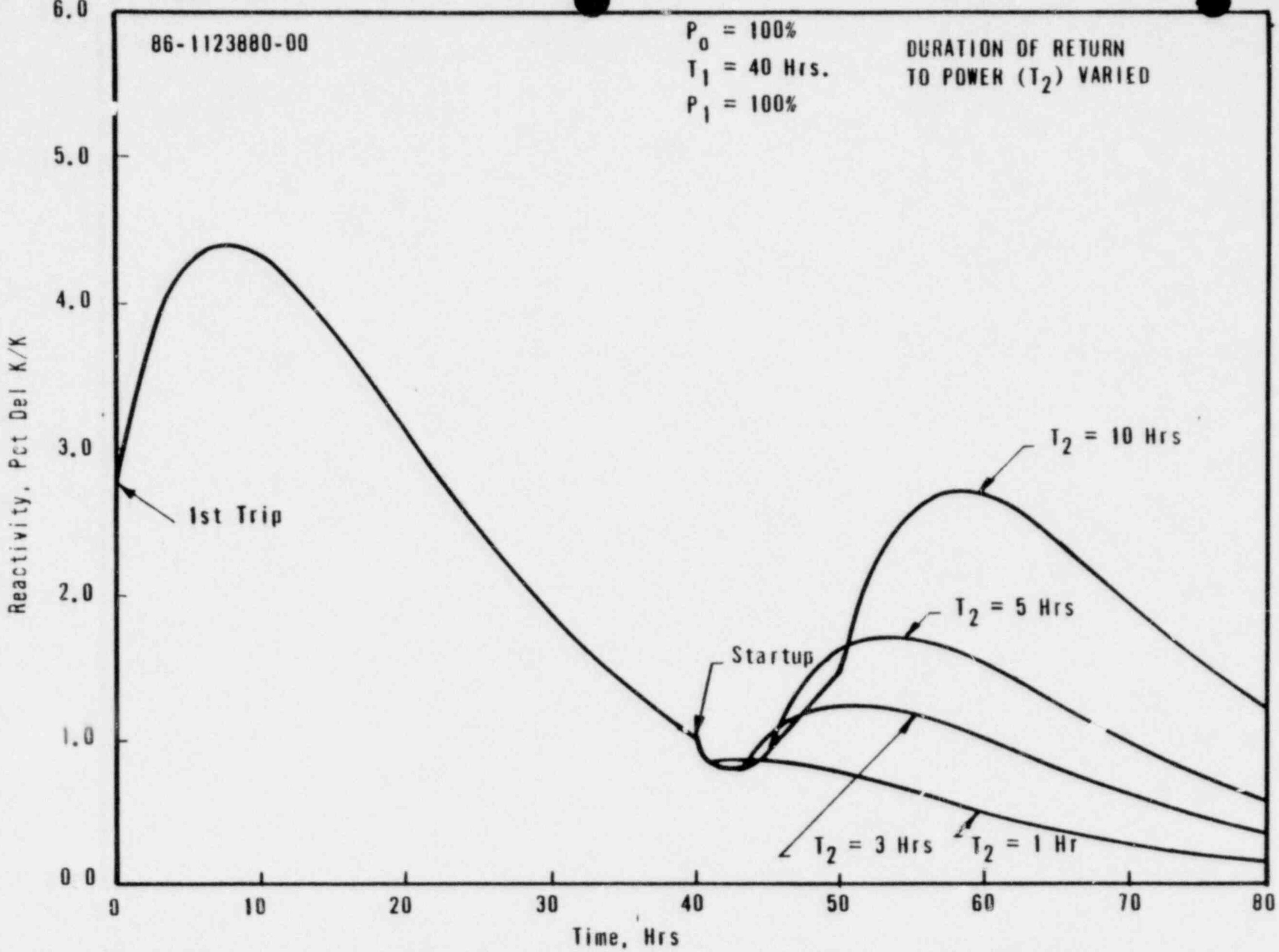


Figure 7. FAMILY OF DOUBLE REACTOR TRIPS

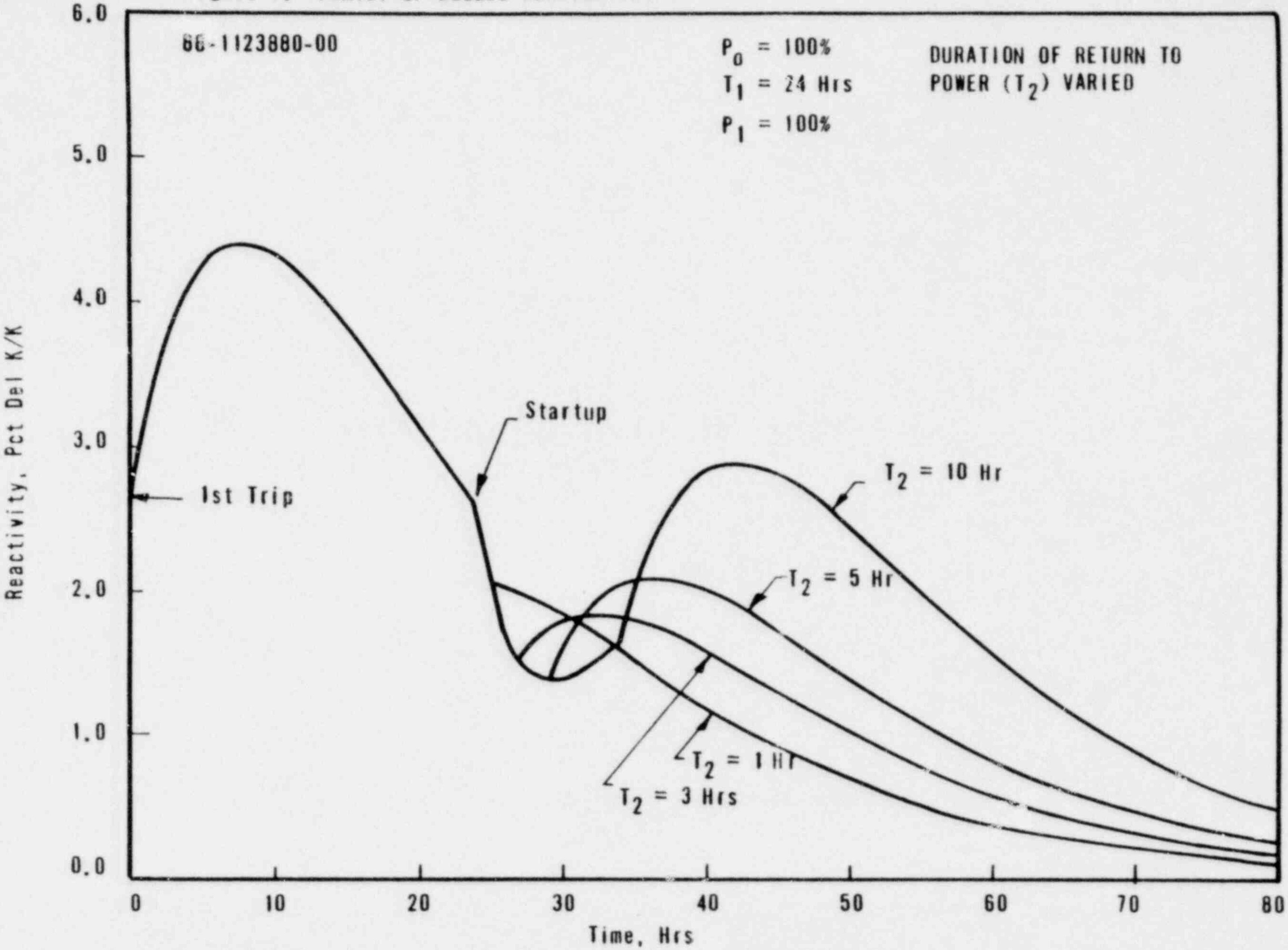


Figure 8. FAMILY OF DOUBLE REACTOR TRIPS

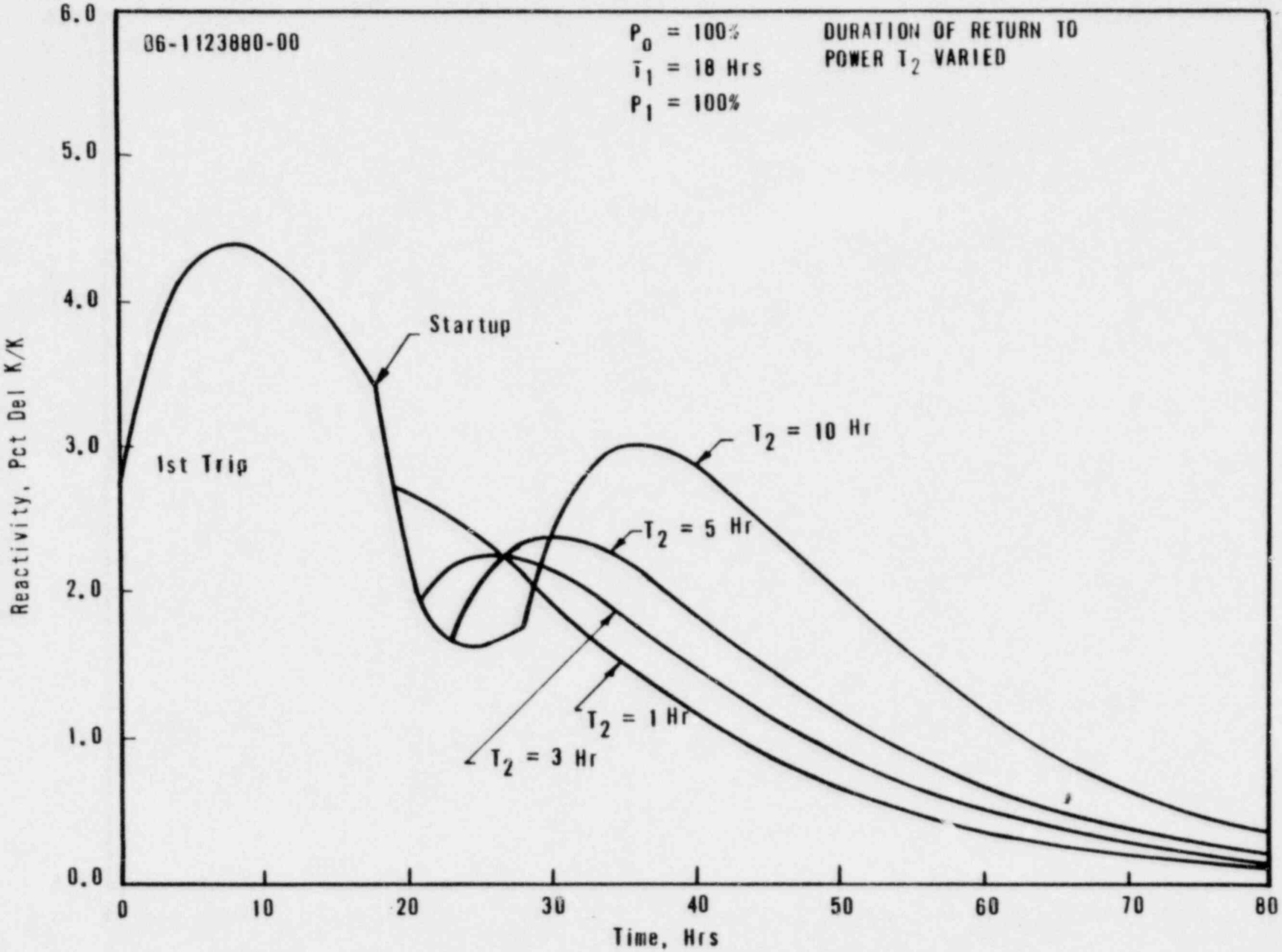


Figure 9. FAMILY OF DOUBLE REACTOR TRIPS

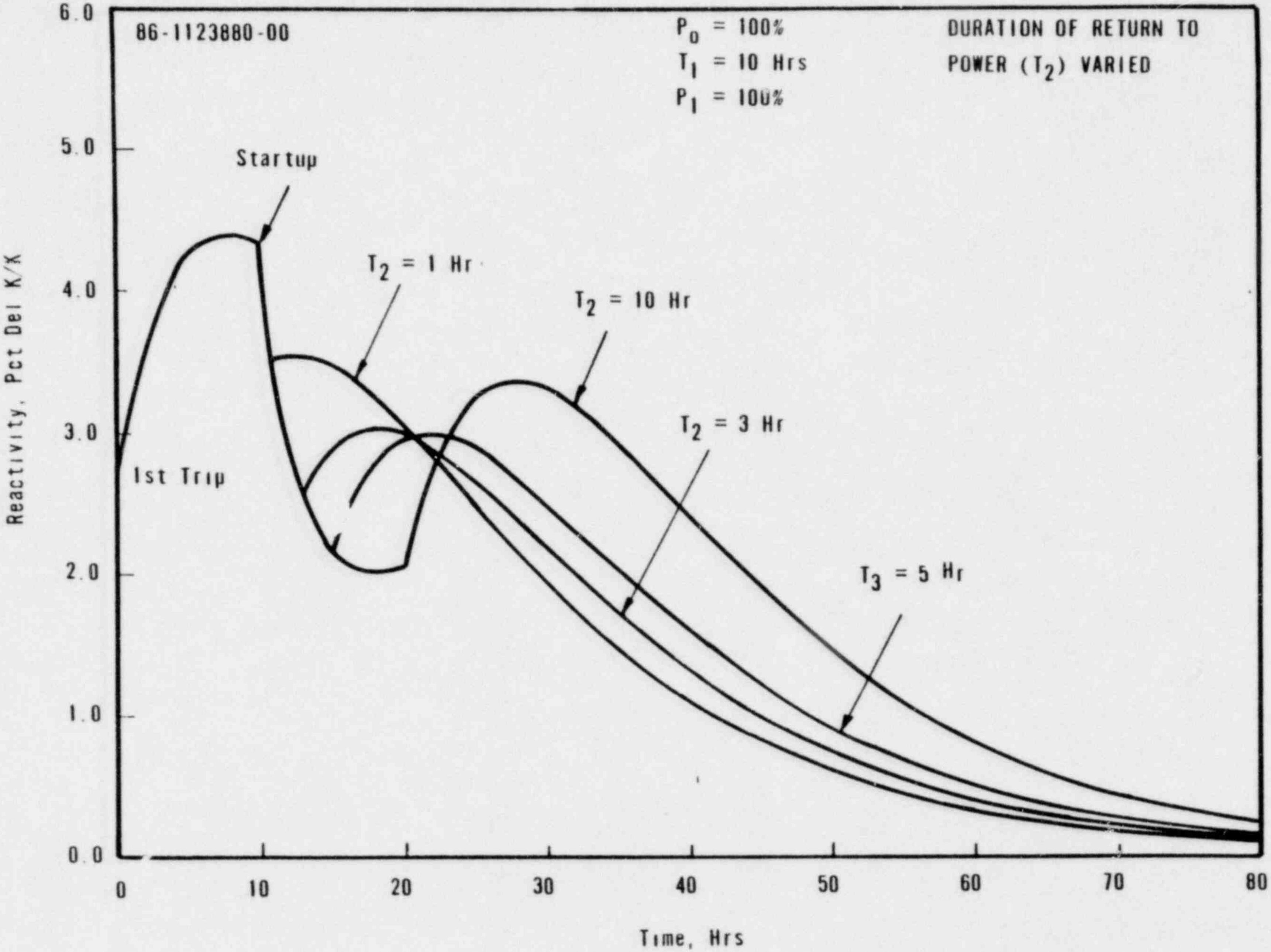
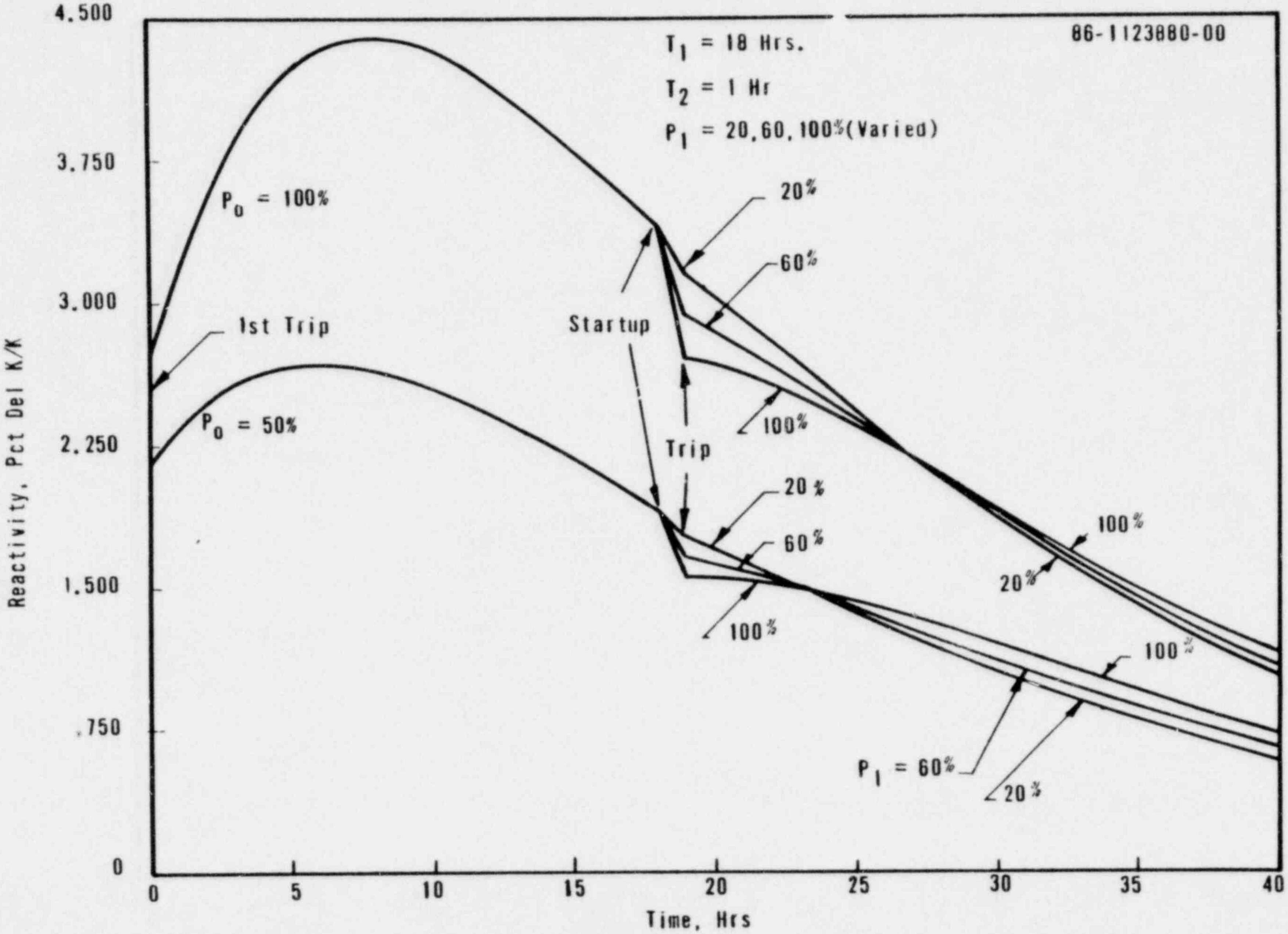


Figure 10. DOUBLE REACTOR TRIPS



SUPPLEMENT TO

PRESENTATION TO THE UTILITY DESIGN AND REVIEW BOARD

DESIGN TO ACHIEVE AND MAINTAIN COLD SHUTDOWN

V. COLD SHUTDOWN CAPABILITY FOLLOWING CHAPTER 15 EVENTS

Va. COLD SHUTDOWN CAPABILITY FOLLOWING A FIRE

A. Purpose

This section describes the ability of the Midland plant design to ensure that at least one means of achieving and maintaining safe shutdown conditions will remain available during and after a postulated fire in the plant.

B. Discussion

The Midland design is presently being reviewed to verify it meets the intent of 10 CFR 50 Appendix R and Branch Technical Position 9.5-1.

The review to verify that the Midland plant will remain safe in case of a fire assumes an exposure fire can occur anywhere in the plant outside the primary containment (biological shield). The review also assumes a fire inside the control room that can disrupt the operation of any single continuous cabinet and result in evacuation of the control room. The goal of the review is to demonstrate that given the fires described, the plant can achieve hot standby immediately and cold shutdown within 72 hours.

The criteria used in the review are as follows:

1. Only one fire occurs.
2. The fire can cause hot shorts, open circuits, and shorts to ground.
3. The only failures considered are those caused by the fire.
4. Offsite power may be available or unavailable.

5. Limited manual action inside the control room is possible for a fire inside the control room. (These actions are assumed possible immediately after discovering the fire and prior to evacuation of the control room if that should become necessary.)

6. Extensive manual action is possible outside the control room.

In the review, the equipment needed to achieve and maintain safe shutdown conditions is determined. The effects of the postulated fire on that equipment are identified. If the identified effects are undesirable, protection will be provided to ensure operation of that equipment.

The systems identified that are required to achieve and maintain safe shutdown conditions are the same as described in other parts of this presentation.

C. Summary

At the conclusion of the present review, the Midland plant will be demonstrably able to achieve and maintain a safe shutdown condition during and after a fire.

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
OBJECTIVE

- ENSURE THAT AT LEAST ONE MEANS OF ACHIEVING AND MAINTAINING SAFE SHUTDOWN CONDITIONS REMAINS AVAILABLE DURING AND AFTER A POSTULATED FIRE

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
REGULATIONS AND GUIDELINES

- 10 CFR 50 APP A, CRITERION 3 (FIRE PROTECTION)

- NRC BRANCH TECHNICAL POSITION ASB 9.5-1 (GUIDELINES FOR FIRE PROTECTION FOR NUCLEAR POWER PLANTS)

- 10 CFR 50 APP R (FIRE PROTECTION PROGRAM FOR OPERATING NUCLEAR POWER PLANTS) (OPERATING LICENSE PRIOR TO JANUARY 1, 1979)

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
ASSUMPTIONS

- EXPOSURE FIRE OUTSIDE PRIMARY CONTAINMENT

- EXPOSURE FIRE INSIDE CONTROL ROOM CAUSING DISRUPTION OF ANY SINGLE CONTINUOUS CABINET

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
GOAL

- ACHIEVE HOT STANDBY IMMEDIATELY

- ACHIEVE COLD SHUTDOWN WITHIN 72 HOURS

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
CRITERIA

- SINGLE FIRE

- HOT SHORTS, OPEN CIRCUITS, SHORTS TO GROUND

- FAILURES CAUSED BY FIRE ONLY

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
CRITERIA (cont'd)

- OFFSITE POWER AVAILABLE OR UNAVAILABLE

- LIMITED MANUAL ACTION INSIDE CONTROL ROOM

- EXTENSIVE MANUAL ACTION OUTSIDE CONTROL ROOM

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS
APPROACH

- IDENTIFY EQUIPMENT NEEDED TO ACHIEVE AND MAINTAIN SAFE SHUTDOWN CONDITIONS

- IDENTIFY POSSIBLE EFFECTS OF FIRE ON THAT EQUIPMENT

- PROVIDE PROTECTION TO ENSURE OPERATION

FIRE PROTECTION - SAFE SHUTDOWN ANALYSIS

- SYSTEMS REQUIRED TO ACHIEVE AND MAINTAIN SAFE SHUTDOWN CONDITIONS
  - Makeup
  - Emergency Boration
  - Pressurizer Heaters, Safety Valves
  - Auxiliary Feedwater
  - Service Water
  - Component Cooling Water
  - Emergency Diesel Generators
  - Chilled Water - Safeguards
  - Reactor Building HVAC
  - Service Water Pump Structure HVAC
  - Control Room HVAC
  - Auxiliary Pressurizer Spray
  - Power-Operated Atmospheric Vent Valves
  - Decay Heat Removal

PRESENTATION TO THE UTILITY DESIGN AND REVIEW BOARD

DESIGN TO ACHIEVE AND MAINTAIN COLD SHUTDOWN

Revision 0
February 26, 1981

PRESENTATION TO THE UTILITY DESIGN AND REVIEW BOARD
DESIGN TO ACHIEVE AND MAINTAIN COLD SHUTDOWN

TABLE OF CONTENTS

PRESENTATION TO THE UTILITY DESIGN
AND REVIEW BOARD

DESIGN TO ACHIEVE AND MAINTAIN COLD SHUTDOWN

I. INTRODUCTION

A. Welcome

B. Purpose of Presentation

C. Outline Format of Talk

II. HISTORY

The ability to establish a stable condition for a nuclear reactor following a normal or emergency shutdown has always been a consideration in plant design. However, the design requirements for pertinent systems and the condition to be established have evolved over the years.

A significant emphasis has traditionally been placed on ensuring a stable condition following a large loss-of-coolant accident (LOCA) event. During a large LOCA, the reactor coolant system (RCS) pressure decreases and a safe shutdown condition is established by the emergency core cooling system. Because of the attention previously given to this event, it is not a current concern and will be addressed only peripherally in this review.

For a non-LOCA event in which RCS integrity is maintained, the stable condition to be achieved is the hot standby condition in which the RCS pressure and temperature remain near their normal operating values. This safe hot standby condition could be achieved without offsite power. The hot standby condition could be maintained until offsite power is restored and further cooldown is desired. Subsequently, emphasis was placed on ensuring that systems necessary to maintain hot standby were safety grade.

More recently, a similar emphasis has been placed on ensuring that systems necessary to achieve cold shutdown are safety grade. This situation evolved from a concern that the safe shutdown condition be cold shutdown. Previously, the safe shutdown condition was considered to be hot standby. Cold shutdown is achieved when the RCS temperature is $\leq$200F, and the reactor is at least 1% $\Delta k/k$ subcritical, assuming the highest worth rod

stuck out, and no xenon. The event useful for evaluating the capability to achieve cold shutdown is the loss of offsite power coincident with a safe shutdown earthquake (SSE). This event is used as a basis to address Sections III (Preceding Design - Hot Standby Capability) and IV (Present Design - Cold Shutdown Capability) of this presentation. Other accident scenarios will be addressed in Section V (Cold Shutdown Following Chapter 15 Type Events).

Subsequent to the Three Mile Island (TMI) accident, the Midland project formed a task force to address some open issues that existed prior to TMI or were raised by the accident. One of the subjects addressed was cold shutdown. During this review, a number of design upgrades were recommended to enhance the hot standby and cold shutdown capability. Most of the design upgrades that have been implemented with respect to shutdown capability have evolved from this effort.

The present Midland design basis is that hot standby is a safe shutdown condition. This design basis is appropriate because hot standby is a safe, stable condition that can be maintained for an extended period of time with a minimal amount of operator action; therefore, it provides additional time to further evaluate the condition of the reactor. In addition, it frequently is preferable to maintain the reactor in this hot stable condition for an extended period of time rather than subjecting the plant to an immediate cooldown transient. The current Midland design provides for the ability to achieve and maintain, by safety-grade means, the hot standby condition following an SSE coincident with loss of offsite power. (Safety-grade systems are seismically designed and capable of being operated with or without offsite power.) Although it is not a design basis, the present Midland design incorporates the ability to be taken to the cold shutdown condition using only safety-grade equipment assuming only onsite or offsite power is available and considering a single failure. In addition, the present Midland plant design can achieve and maintain cold shutdown following a tornado by using equipment that is protected from the effects of a tornado.

III. PRECEDING DESIGN - HOT STANDBY CAPABILITY

This section briefly addresses previous design capabilities of the Midland plant to facilitate an understanding of the design upgrades that have been made. No comparison to the present design is made, because Section IV

(Present Design - Cold Shutdown Capability) addresses current design.

The design prior to the changes of the past 2 years considered hot standby to be the design basis safe shutdown condition. The hot standby condition was considered to be one in which the RCS temperature is in the range from normal operating temperature to the decay heat removal (DHR) cut-in temperature, and the reactor is 1% $\Delta k/k$ subcritical. Initially after the reactor trip, the reactor would be at the high end of the hot standby temperature range and this condition could be maintained for a period of time. During this period, offsite power could be restored, operation of nonsafety-grade equipment could be achieved, and the plant could be taken to cold shutdown. The essential functions to be maintained to ensure this safe and stable hot standby condition were reactivity and inventory control, heat rejection, and pressure control.

A. Reactivity Control/Inventory Control

1. Control Rods

The control rods are designed to bring the reactor at least 1% $\Delta k/k$ subcritical upon reactor scram. Allowance in the design is made for the highest worth control rod assembly sticking out of the core as well as for the temperature effects between hot full power (579F) and hot zero power (532F).

2. Boration

For the limiting control rod design described above, the decay of xenon reactivity and temperature effects below 532F are controlled by boration. Following equilibrium power operation, reactor trip will lead to an increase in xenon reactivity above its equilibrium value for periods up to approximately 23 hours (trip from 100% power). If the equilibrium xenon reactivity is less than or equal to 1% $\Delta k/k$, which corresponds to low power operation of approximately 0-12% power, ensured without operator action. For the case in which equilibrium xenon worth is greater than 1% $\Delta k/k$, which corresponds to equilibrium power operation of approximately

12-100% power, the xenon reactivity is above its equilibrium value for at least 4 hours after a reactor trip. The xenon poison transient permits sufficient time to bleed the RCS and inject water from the BWST.

The boron concentration of the reactor is normally increased by using the makeup system to inject boric acid from the boric acid addition tanks of the chemical addition system. In the event of an accident, the borated water from the borated water storage tank (BWST) is available for injection into the RCS.

3. Inventory control

The makeup system normally controls the RCS inventory. Portions of the makeup system are used for high-pressure injection (HPI) to ensure adequate boron concentration and core cooling. Safety-grade portions of the makeup system are powered by Class 1E onsite power. The makeup water is from the BWST, which is also safety grade.

B. Pressure Control

The pressurizer safety valves prevent overpressurization of the RCS. In the event of loss of offsite power, the thermal inertia of the pressurizer allows it to maintain system pressure for some time after power is removed from the heaters. Thus, sufficient time exists to connect the pressurizer heaters to the emergency diesel generators.

C. Heat Rejection (Temperature Control)

1 Steam generator

a. Main steam isolation valve (MSIV) and main feedwater isolation valve (MFIV) closure

Heat transfer from the RCS to the secondary side of the steam generator must be established for cooldown. In the event of a main steam line break (MSLB), MSIV

and MFIV closure ensure that the heat removal can be controlled. The MSIVs and MFIVs close automatically on low-steam pressure or an emergency core cooling actuation signal (ECCAS), or can be manually closed from the control room.

b. Auxiliary feedwater (AFW) operation

The auxiliary feedwater actuation system (AFWAS) initiates the automatic starting of both the turbine-driven and the motor-driven AFW pumps and the automatic positioning of AFW valves. This mitigates the consequences of the loss of main feedwater or a loss of offsite power accident, and provides feedwater to allow primary heat removal through the steam generators.

A motor-driven and a turbine-driven AFW pump provide redundancy of AFW supply and diversity of motive pumping power. Each pump has a rating of 885 gpm. Discharge piping from both pumps is cross-connected through two normally open valves, permitting each AFW pump to feed both steam generators.

In the safeguards mode, pump suction is normally from the condensate storage tank, with emergency backup provided from the service water system. Steam supply piping to the turbine driver is provided by each of the main steam lines inside the containment. A line from each steam generator, equipped with a normally closed, dc motor-operated isolation valve, supplies steam to a common header.

c. Main steam relief valves

The main steam relief valves lift to remove heat from the secondary system. The hot standby condition can be maintained by cycling of these relief valves. Cooldown to a temperature that corresponds to a pressure below the main steam relief valve setpoint could be

accomplished by opening the modulating atmospheric dump (MAD) valve. If instrument air were unavailable, the MAD valve could be opened by local manual operation.

2. Natural circulation of reactor coolant

Natural circulation characteristics of the RCS have been calculated by Babcock & Wilcox with conservative values for all resistance and form loss factors, and have been found to provide adequate core cooling.

IV. PRESENT DESIGN - COLD SHUTDOWN CAPABILITY

The Midland design provides for the ability to achieve and maintain, by safety-grade means, the hot standby condition following a SSE coincident with loss of offsite power. Although it is not a design basis, the Midland design incorporates the ability to be taken to the cold shutdown condition using only safety-grade equipment, assuming only onsite or offsite power is available and considering a single failure. Therefore, in the unlikely event that a design basis earthquake occurs which results in the need to achieve cold shutdown expeditiously, design features exist to accomplish this evaluation. Reactivity control/inventory control, pressure control, and heat rejection are the essential functions that must be maintained.

Detailed treatment of necessary supporting systems and equipment (such as power and control systems, cooling water, and diesel generators) is not addressed in this presentation. However, plant design ensures that these systems and equipment fulfill the necessary design requirements to achieve cold shutdown.

The loss of offsite power coincident with an SSE is used as a basis for evaluating the capability of achieving cold shutdown.

The NRC design guidance and the guidance followed on the Midland plant to meet the functional requirements necessary to achieve cold shutdown follow.

a. Cold shutdown shall be achieved using safety-grade systems.

b. Systems shall have suitable redundancy in components and features to ensure that the system functions can be accomplished (assuming a single active failure).

c. Systems are capable of being operated from the control room. (Some systems require local manual alignment, but control can be performed from the control room.)

d. The necessary systems can function whether offsite power is available or unavailable.

The essential functions that must be maintained are individually addressed below.

A. Reactivity Control/Inventory Control

1. Control rods

The Midland design (per unit) incorporates 61 control rod drive mechanisms (CRDMs), excluding the axial power shaping rod assemblies (APSRAs), which do not perform a trip function. The CRDMs are the B&W Type C design, which is in use at the Oconee Unit 3 and Davis Besse Unit 1 plants. Rapid control rod insertion is activated by the reactor protection system (RPS), anticipatory reactor trip system (ARTS), loss of power to control rod drive (CRD) motors or a switch in the main control room. The reactivity control capabilities of the control rods are identical to those described in Section III.

2. Boration

For normal shutdown reactivity control, the design of the Midland plant includes two sources of borated water: BWST and the chemical addition system (CAS). With letdown available, either the BWST or the CAS is capable of maintaining the reactor at 1% $\Delta k/k$ subcritical at hot shutdown or during transition to cold shutdown at any time in core life for the most limiting normal fuel cycle, assuming xenon-free conditions and the maximum worth rod stuck out of the core. The use of only

safety-grade equipment to maintain the reactor at 1% $\Delta k/k$ subcritical at hot standby, and the transition to a cold shutdown condition, requires the use of the emergency boration system (EBS).

The EBS is a safety-grade system designed to provide a 6 weight percent boric acid solution to the RCS via the makeup and purification system (MU&PS), in the event of a design basis tornado (DBT) or SSE, in conjunction with the maximum worth stuck control rod. The contents and concentration, in conjunction with the other contraction volume makeup sources, are sized to ensure the ability to maintain a 1% $\Delta k/k$ subcritical margin during hot standby and during the transition to cold shutdown. Adequate shutdown margin is maintained during the transition from hot standby to cold shutdown by using borated water from the BWST or the CAS. These borated water sources provide adequate compensation for reactivity changes that result from the change in moderator temperature.

Following any event which results in the loss of letdown capability and a stuck rod, the 6 weight percent boric acid solution from the EBS storage tank (which contains at least 1,800 gallons), and the contraction makeup from the BWST or CAS can be transferred to the RCS via the MU&PS. One of the three makeup HPI pumps is used to inject this 6 weight percent boric acid into the RCS.

Contraction volume makeup during cooldown is provided by the makeup and EBS tanks and either the BWST, which is designed for an SSE, or the CAS, which is designed to withstand the DBT.

3. Inventory control

As coolant is removed (or let down) from the RCS, this coolant must be replaced (or made up) by additional makeup water that is delivered to the RCS by the makeup portion of the MU&PS.

Even if reactor coolant is not let down, the makeup portion of the MU&PS is still required to ensure a safe shutdown condition. As the RCS cools, the specific volume of water decreases. It is necessary to keep the volume of water in the RCS approximately constant. Therefore, additional water is injected into the RCS via the makeup system.

The safety-grade source of makeup water is the BWST, which contains at least 300,000 gallons of 1.3 wt% boric acid solution. Because the BWST is not required after a design basis tornado, the BWST is not tornado-protected. In addition, three boric acid addition tanks (part of the nonsafety-grade CAS) are also available for makeup addition. These three 10,000 gallon tanks, which contain a total of at least 16,500 gallons of 3.5 wt% boric acid, can provide the required RCS contraction volume in conjunction with other available water sources. These water sources are tornado-protected and can be made available following loss of offsite power.

B. Pressure Control

1. Reactor coolant system pressure boundary [power-operated relief valve (PORV), PORV block valves, and pressurizer safety valves]

   The RCS pressure is controlled by maintaining the RCS pressure boundary and keeping a steam bubble in the pressurizer.

   The PORV is sized to limit the pressure during step load changes, including the maximum design load rejection, to a value less than the high-pressure trip setpoint. While contributing to plant safety by improving operating efficiency, the valve is not required for safety reasons. It may be isolated either manually or automatically upon a coincident signal that the PORV is not closed and a low RCS pressure exists. The isolation is accomplished by either of two Class 1E motor-operated PORV block valves installed upstream of the PORV. Both the PORV and the PORV block valves are Class A

(as defined by Regulatory Guide (RG) 1.26), and, as such, are designed, fabricated, tested, installed, and certified by the requirements of the ASME Code of Class 1 valves.

The pressurizer safety valves ensure that the RCS is protected against overpressure. They are spring-loaded devices, and open automatically by direct action of the fluid pressure in the pressurizer as a result of forces acting against a spring. They are bellows-sealed to make the setpoint independent of backpressure and are equipped with an auxiliary piston to ensure pressure balance in the event of damage to the bellows. These valves are designed, fabricated, tested, installed, and certified in accordance with Article NB-7000, Section III of the ASME Code for Class 1 components. They are Class A components as defined in RG 1.26.

2. Pressurizer heaters

To maintain normal operating RCS pressure for more than a few hours after shutdown, operation of the pressurizer heaters is required.

The pressurizer must be maintained as the hottest point in the RCS to ensure the vapor bubble exists only in the pressurizer.

Power and controls for two banks of pressurizer heaters have been upgraded to safety-grade Class 1E standards. In the event of loss of offsite power, power to the two banks of heaters is controlled by a manual switch in the control room. One bank is sufficient to control RCS pressure via a steam bubble in the pressurizer when the reactor is shut down and the energy input to the RCS is decay heat.

3. Auxiliary pressurizer spray

The auxiliary HPI pressurizer spray is designed to depressurize the RCS from its normal operating pressure to a pressure associated with the emergency DHR system cut-in temperature, and is intended for use

only during emergency cold shutdown. The spray system driving head is derived from the HPI pump discharge. Suction for the HPI pump is normally taken from the BWST. The boric acid addition tanks, via the makeup tanks, serve as an alternative suction source. The spray line discharges to the auxiliary DHR pressurizer spray line upstream of parallel, motor-operated globe valves; these valves permit manual control of flow into the pressurizer. The spray system requires local alignment prior to initiation, but is remotely initiated and controlled from the control room. Once initiated, the spray will be operator-controlled to provide the desired depressurization rate that is determined by the cooldown rate and plant status.

C. Heat Rejection (Temperature Control)

1. Steam generator (at high pressures/temperatures)

To remove heat via the steam generators, a source of water to the secondary side of the steam generators and a steam vent path for energy removal must be provided. The water is provided by the AFW system and steam is vented via the main steam relief valves or the power-operated atmospheric vent (POAV) valves.

a. Auxiliary feedwater

Auxiliary feedwater is automatically supplied at a controlled rate by redundant 100% capacity AFW pumps. One pump is an electric motor-driven pump; the other is a steam turbine driven pump with steam provided by the safety-grade portion of the main steam system. Power and controls to both pumps are safety-grade and Class 1E.

Normally, the 300,000 gallon non-Seismic Category I condensate storage tank serves as the water source for these pumps. The safety-grade service water system provides an alternate source. Because of concern for the quality of steam generator feedwater, automatic transfer is provided only upon coincident AFW actuation signal (AFWAS) and low AFW pump suction pressure.

b. Main steam relief valves

These spring-loaded pressure relief valves cycle to relieve steam, enabling the reactor to remain in the hot standby condition.

c. Power-operated atmospheric vent valves

Steam can be relieved through the POAV valves to maintain the reactor in a hot standby condition without cycling the main steam relief valves; steam can also be relieved to cool the reactor to a temperature where the DHR system can be used.

The POAV valves are safety-grade, motor-operated control valves located upstream of the MSIV. The POAV valves are sized so an inadvertent stuck-open POAV valve will not result in unacceptable consequences to the core.

The POAV valve capacity will permit the RCS to be cooled to the emergency DHR cut-in temperature of 325F within 36 hours assuming one operational POAV valve for each steam generator. The 325F cut-in temperature is discussed in Item 2 below.

Each POAV valve can be jog-controlled from a switch in the control room or the auxiliary shutdown panel. The operator will position the POAV valves until an acceptable temperature is maintained or until an acceptable cooldown rate is established.

Steam relief can also be accomplished by dumping steam to the condenser or opening the MAD valves. These components are downstream of the MSIVs and are not powered or controlled by safety-grade equipment. Thus, to ensure cold shutdown can be achieved using only onsite emergency power and safety-grade systems, credit is taken only for components upstream of the MSIVs.

2. Decay heat removal system

After the RCS pressure and temperature are reduced to approximately 300 psig and 280F (or 325F under emergency conditions), respectively, the DHR system operation may begin.

The previous design directed that the DHR system not be operated until the RCS temperature was 280F. The DHR system was analyzed to determine that operation of the DHR system at 325F is an acceptable, although not normal, mode of operation. The higher DHR cut-in temperature permits operation of the DHR system, within 36 hours assuming operation of one POAV valve on each loop.

Four parallel-series, motor-operated isolation valves are installed on the DHR dropline inside the containment. These are installed so a single failure of a valve to open will not inhibit the flowpath for DHR cooling.

3. Reactor coolant circulation

a. Natural circulation test

The Midland plant has been analyzed to ensure that natural circulation will occur during a cooldown without forced circulation of the reactor coolant. In addition, a natural circulation cooldown test will be referenced if it has been conducted on a plant similar to Midland. If such a test is unavailable, a test will be conducted to verify that operation of the POAV valves under natural circulation will satisfactorily remove heat required to cool down the plant. This test will cool the RCS approximately 50F under natural circulation. The data will be used to verify the adequacy of prior analytical results.

b. Auxiliary feedwater level control

The AFW system will be the subject of another presentation and details of that system operation are not addressed here. However, the system will include safety-grade, automatic control of the steam generator water level. The steam generator water level is normally maintained at a level of 2 feet when two or more reactor coolant pumps (RCPs) are operating. If 0 or 1 RCP is operating, the level is automatically increased to 20 feet; this ensures sufficient feedwater is present in the steam generator to promote natural circulation of the reactor coolant.

The automatic transition from the low-water level to the high-water level in the steam generator is made smoothly by ramping the setpoint between the two values at a controlled rate. This orderly transition prevents overcooling of the primary loop.

V. COLD SHUTDOWN CAPABILITY FOLLOWING CHAPTER 15 TYPE EVENTS

A. Purpose

This section describes the ability of the Midland plant to achieve cold shutdown from the postulated plant conditions and equipment availability that exist following the events addressed in Chapter 15. Previous sections have provided detailed descriptions of the equipment needed to achieve cold shutdown. This section addresses the general post-accident conditions that may exist and assesses the ability to proceed to cold shutdown conditions.

B. Discussion

All of the transients analyzed in Chapter 15, with the exception of anticipated transients without scram events, result in a reactor tripped, subcritical core condition with long-term decay heat removal being provided by one or more intact RC/steam generator loops, or HPI cooling.

The final plant condition and equipment remaining available for use in achieving cold shutdown are dependent on the transient and assumed equipment failures. Equipment failures assumed for Chapter 15 events are based on ensuring a bounding transient response with respect to the established acceptance criteria. This failure may not be the worst one with respect to achieving cold shutdown following the event.

For most events analyzed in Chapter 15, the design objective of achieving cold shutdown within 36 hours can be met. This is true of all transients where no failure of safety-grade instrumentation has been imposed. With the imposition of a single failure of one piece of safety-grade instrumentation equipment, the remaining minimum performance level is still sufficient to achieve cold shutdown.

The transient analyses of Chapter 15 demonstrate that the plant can reach a stable plant condition at hot standby with ensured decay heat removal. An event may rely on an operator action to ensure long-term heat removal or adequate continuous subcritical margin at hot standby. Sufficient time and indication is available to the operator to take the required action in such instances.

Design basis events, such as steam and feedwater line breaks or a LOCA, may result in the loss of forced RC flow and the loss of the use of one steam generator for timely decay heat removal. The essential control functions that must be maintained in order to ensure the capability of achieving cold shutdown are reactivity/inventory control, primary pressure control, and heat rejection. Any accident event, which, in combination with a single failure, results in the complete loss of any one of these functions would preclude cold shutdown with safety-grade equipment. However, the transients analyzed in Chapter 15 do not result in the complete loss of any one of these functions.

1. Reactivity/inventory control

   Short-term reactivity control is provided by the control rods. Upon reactor trip, a 1% $\Delta k/k$ shutdown margin (the control rod assembly of greatest worth is assumed not to

drop into the core) is provided by the rods at hot zero power (532F) temperatures. The EBS provides reactivity control to compensate for the decay of xenon. Replacement of the primary system contraction volume following reactor trip is provided from the makeup tank by the HPI system. The EBS water along with the contents of the makeup tank can be injected prior to cooldown below 532F. Reactivity control for long-term maintenance of hot standby is thus ensured.

Primary system inventory and reactivity control during the cooldown to cold shutdown must be provided by either the CAS or HPI system.

2. Pressure control

Pressure control is provided by auxiliary spray and the safety-grade banks of heaters during the cooldown following non-LOCA events. Letdown from the RCS is not required.

3. Heat rejection (temperature control)

The design method of primary heat removal for both normal and transient conditions is by use of the steam generators. This method requires a source of fluid (AFW) to the steam generators and a mode of steam relief (main steam relief or POAV valves), all of which are safety-grade components or systems for the Midland plant. A secondary system transient such as a steam or feedwater line break may result in the loss of controlled heat removal capability from one steam generator. Heat removal is then provided by the intact loop with AFW flow directed to the intact once-through steam generator (OTSG) by the feed only good generator (FOGG) logic system. After stabilizing plant conditions, the POAV valves on the intact steam generator may be operated to decrease RCS temperature.

If the reactor coolant pumps are not operating, reactor cooling will be maintained by natural circulation. The ability to achieve cold shutdown within a reasonable time frame under the conditions of natural circulation and one

intact loop ~~remains to be evaluated~~. The AFW system will be operated to control the OTSG level to promote natural circulation. Action Item.

The capability to achieve cold shutdown following the design basis tornado (coincident with loss of offsite power) has also been considered. Reactor trip occurs either by manual trip or automatically by loss of onsite and offsite power. Continued reactivity and inventory control are accomplished by injection of borated water from one or more of the three following sources, depending on availability: BWST (not tornado protected), EBS (tornado protected), or chemical addition tanks (tornado protected). Heat rejection is maintained by steam generator pressure control using AFW, main steam safety valves, or by manual operation of the POAV valves. Natural circulation is maintained by proper operation of the AFW system to control OTSG level. Primary pressure control is accomplished by operation of safety-grade heaters or auxiliary pressurizer spray.

Hot standby conditions can be maintained indefinitely unless it becomes desirable to proceed to cold shutdown.

C. Summary

The capability of achieving cold shutdown exists for the conditions following the Chapter 15 events. Various operator actions may be required depending on the transient involved and the assumed equipment failure. Times in excess of 36 hours may be required under the conditions of natural circulation with only one intact loop. It may be desirable to stay at hot standby or cool more slowly if such an action would minimize radiation releases. Table V-I summarizes the capability and limitations relative to achieving cold shutdown for each Chapter 15 event.

VI. COMPARISON OF PRESENT DESIGN TO APPLICABLE REGULATORY GUIDANCE

The Midland design has been compared with the NRC concerns and the design guidance related to the issue of cold shutdown. This section contains the comp

The design guides examined include the Standard Review Plan (SRP) 5.4.7; Branch Technical Position (BTP) RSB 5-1; Open Items Associated with NRC Sstaff Review: RSB-7, ASB-8, PSB-11, RSB-10, RSB-20; SRP 7.4, and RG 1.139. Table VI-1 is a cross index illustrating the origin of the applicable guidance; it also shows which guidance is incorporated into the Midland design.

A. SRP 5.4.7, Residual Heat Removal System

SRP 5.4.7 is primarily directed at review of the residual heat removal system that operates after the RCS has been initially cooled and depressurized. However, the SRP also directs that the chemical volume and control system (CVCS), residual heat removal system, atmospheric dump valves, and source of auxiliary feedwater be reviewed to meet the functional requirements of BTP-RSB 5-1. Therefore, the functional requirements of BTP-RSB 5-1 are examined in more detail. (The SRP and BTP refer to CVCS, residual heat removal (RHR), and atmospheric dump valves. On the Midland plant, the function of these systems is performed by the MU&PS, DHR system, and POAV valves, respectively. Future references are to the latter nomenclature.

B. BTP-RSB 5-1 (Revision 1), Design Requirements of the Decay Heat Removal System

This BTP states the functional requirements to take a reactor from normal operating conditions to cold shutdown. In addition, further guidance is given for the DHR system design, cold shutdown operation procedures, and AFW supply requirements.

Table VI-2 contains a summary of guidance contained in BTP-RSB 5-1. In addition, the far right column of this table contains the design being implemented on the Midland project that is associated with the design guidance of the preceding columns.

The individual positions of the BTP are addressed because they are the main substance of the cold shutdown issue. Most of the subsequent NRC questions and Open Items refer to the issues addressed in this table. A (G) designates the guidance a (D) designates the Midland design. (Note: Midland is a Class 2 plant because the construction permit (CP) was issued before January 1, 1978.)

1. ..ng-term cooling/decay heat removal dropline

   (G) The DHR dropline shall be able to accommodate a single active failure or ensure that manual action is possible to rectify the situation.

   (D) Midland has a single DHR dropline. The line divides into two lines inside the containment and each line has two motor-operated isolation valves inside the containment. The lines rejoin and exit the containment. Thus, a single failure can be accommodated and containment access is not required. The power supplies and controls to the valves are arranged to function with a single failure.

2. Safety-grade steam dump valves

   (G) Provide safety-grade steam dump valves

   (D) The Midland plant has two safety-grade POAV valves associated with each steam generator. These motor-operated valves ensure adequate steam removal from the secondary side coincident with a single failure. This steam removal can be accommodated without manual actions at the location of the valve. These valves are located upstream of the MSIVs.

3. Depressurization

   (G) Review or upgrade RCS depressurization method

   (D) The Midland plant has a safety-grade auxiliary pressurizer spray.

4. Boration for cold shutdown/chemical and volume control system, and boron sampling

   (G) Revise shutdown reactivity requirements to ensure required shutdown margin by safety-grade systems at cold condition

   (D) The Midland plant has the capability to attain a 1% $\Delta k/k$ shutdown margin, assuming the most reactive rod stuck out of the core, no xenon, no letdown, no offsite power, and using only safety-grade systems.

A safety-grade EBS is being added to ensure that an adequate shutdown margin can be accommodated without letdown.

The RCS boron concentration is normally measured with a boronometer that takes samples from the letdown system. A sample line is being installed on the letdown line upstream of the letdown valves to permit RCS samples to be taken with normal letdown isolated. Sample lines in the DHR system permit sample taking after the DHR operation.

The next two requirements are more specific to DHR design and are not cold shutdown concerns. However, they are included in the comparison for completeness.

5. Decay heat removal isolation

(G) Provide sufficient DHR system isolation

(D) The suction side of the DHR system has two parallel lines with two valves on each line, as described in long-term cooling/DHR dropline. These valves have interlocks to prevent opening unless RCS pressure is below DHR design pressure. The valves also have interlocks that close the valve if RCS pressure exceeds approximately 500 psig.

Overpressure protection of DHR system is accomplished by a relief valve that discharges to the reactor building sump.

The discharge side of the DHR system has two check valves in series between the RCS and the DHR system. The system will have provisions to permit periodic leak testing of the valves.

Compliance with the BTP is met, with a clarification required for the isolation valve closure interlock. Overpressure protection of the DHR system is ensured by the DHR system relief valve. This valve also provides one means of overpressure protection of the RCS at low temperature. To maintain this means of overpressure protection, the automatic closure interlock is not actuated

until an RCS pressure of approximately 500 psig is reached; this exceeds the DHR relief valve setpoint (approximately 360 psig).

6. Decay heat removal pressure relief

   (G) Collect and contain DHR pressure relief and discharge

   (D) Relief valve discharge is routed to the containment sump. This fluid is contained and also available for suction from the sump if sump recirculation is necessary.

7. Test requirements

   (G) Develop procedures for cooldown and natural circulation. Meet RG 1.68 and use analysis and testing to confirm adequate mixing and cooldown under natural circulation.

   (D) The Midland plant will reference a natural circulation test if one has been conducted on a plant similar to Midland. If such a test has not been completed, Midland will perform a natural circulation cooldown test for 50F to verify previous calculations. A test to measure mixing is not anticipated. With this clarification, Midland will meet the testing requirements as delineated in the response to RG 1.68 in Appendix 3A of the FSAR.

8. Operational procedures

   (G) Meet RG 1.33 and develop procedures for cooldown under natural circulation.

   (D) Operating procedures for natural circulation cooldown will be written and made available to the operators before initial criticality.

9. Auxiliary feedwater supply

   (G) Ensure that an adequate alternate Seismic Category I source of water is available.

(D) The AFW system has an automatic switchover to safety-grade service water. This volume of water (i.e., the ultimate heat sink and the cooling pond) exceeds any inventory requirements for AFW.

C. Open Items Associated with Staff Review of Midland Plants (NRC Letter, 3/30/79; Meetings of 4/10-11/79 and 4/19-20/79)

1. RSB-7

(G) This open item states that the Midland design does not comply with SRP 5.4.7 and BTP-RSB 5-1 for Class 2 plants (NRC letter, 3/30/79).

(D) A revised response to 211.35 has been provided to respond to this issue. The question in 211.35 closely parallels the issues addressed in BTP-RSB 5-1; the response closely parallels the previous discussion of compliance to BTP-RSB 5-1. The question and response to 211.35 are included in the appendix, but are not addressed further here.

2. ASB-8, Manual operation of MAD valves

(G) This open item required demonstration of manual operation of the MAD valves (Meeting of 4/10-11/79).

(D) The safety function of the MAD valves has been eliminated. The safety function is now accomplished by redundant POAV valves that are operable from the control room. This obviates the need to demonstrate manual operation.

3. PSB-11, Decay heat removal letdown valve

(G) Midland should have motor-operated DHR letdown isolation valves to preclude the need for containment access (Meeting of 4/19-20/79).

(D) Midland meets this requirement as discussed in BTP-RSB 5-1.

4. RSB-10, Pressurizer heaters

(G) Justify the use of nonsafety-grade pressurizer heaters (NRC letter, 3/30/79).

(D) The plant design has been revised to provide safety-grade power and controls to two banks of pressurizer heaters. The power and controls are backed by onsite emergency power systems in the event of loss of offsite power.

5. RSB-20, Long-term cooling after a main steam line break (NRC letter, 3/30/79)

(G) The effects of possible submergence of the DHR dropline valve motor operators inside containment following a main steam line break were questioned.

(D) The response to Question 211.163 addresses this concern. The isolation valve operators are located at the approximate water elevation that would exist if a MSLB were to occur inside the containment and the entire contents of the BWST were also to be injected into the containment. However, the control room operator has safety-grade indication of the reactor containment building water level and has approximately 2 hours to terminate the spray. Thus, operator action will preclude water in the containment from reaching a level to be of a concern with respect to the DHR isolation valve operation.

D. SRP 7.4, Systems Required for Safe Shutdown

1. Purpose

This section of the SRP provides review guidelines for instrumentation and control systems associated with parts of the nuclear steam supply system used to achieve and maintain a safe shutdown condition of the plant.

2. Controls required to achieve and maintain safe shutdown: The following controls are provided in the Midland design to achieve the necessary safety functions:

a. Reactivity control/inventory control

   1) Control rod drive trip circuitry

   2) Safety-grade portion of the MU&PS, BWST, and EBS

b. Heat rejection (temperature control)

   1) Auxiliary feedwater controls - Main steam line and main feedwater line isolation valve controls

   2) Power-operated atmospheric vent valve controls

   3) Necessary service water and component cooling water (CCW) system controls

   4) Control of natural circulation by proper operation of the AFW and POAV valve control systems

   5) During hot shutdown and cold shutdown conditions, DHR system controls are provided.

c. Pressure reduction and control

   1) Pressurizer heater controls for banks 5 and 6

   2) Auxiliary pressurizer spray controls

3. Instrumentation required to achieve and maintain safe shutdown

   The following instrumentation capability exists in the Midland design to monitor the safe shutdown condition:

   a. Reactivity control/inventory control

      1) Control rod drive trip breaker position indication (at the breaker)

      2) Emergency boration system tank level indication

      3) Source range neutron power

b. Heat rejection (temperature control)

1) Reactor coolant system hot and cold leg temperature

2) Decay heat removal heat exchanger outlet temperature (see note below)

3) Auxiliary feedwater flowrate

4) OTSG pressure and level

5) Power-operated atmospheric vent valve position

6) Reactor coolant system flowrate

7) Decay heat removal flowrate (see note below)

c. Pressure reduction and control

1) Reactor coolant system pressure

2) Pressurizer level

Note: Safety-grade indication is provided in the main control room for accident monitoring purposes and is available for safe shutdown monitoring. However, these indications are not immediately required for safe shutdown monitoring. Sufficient time exists to connect portable instruments to line-mounted equipment and, therefore, permanent instruments for these parameters are not provided outside the control room.

4. Conformance to SRP 7.4

Detailed design and procurement of the controls and instrumentation required for safe shutdown are nearing final stages for most items. The SRP acceptance criteria were considered and are being implemented. These criteria are summarized below.

a. Redundancy

(G) All instrumentation and controls essential to achieve and/or maintain the cold shutdown condition are redundant to their intended safety function.

(D) The project is implementing this SRP acceptance criterion.

b. Single failure criterion

(G) All instrumentation and controls essential to the achievement and/or maintenance of the cold shutdown condition meet the single failure criterion.

(D) The project is implementing this SRP acceptance criterion.

c. Capacity and reliability

(G) All instrumentation and controls essential to the achievement and/or maintenance of the cold shutdown condition have the capacity and reliability to perform their intended safety functions whenever necessary.

(D) The project is implementing this SRP acceptance criterion.

d. Qualification

(G) All instrumentation and controls essential to the achievement and/or maintenance of the cold shutdown condition are qualified to function during and after the design basis events for which their operation is essential, including earthquakes and all FSAR Chapter 15 accidents.

(D) The project is implementing this SRP acceptance criterion with the clarification provided in RG 1.97 that instrumentation should continue to read within the required accuracy following but not necessarily during an SSE.

e. Testing

(G) All instrumentation and controls essential to the achievement and/or maintenance of the cold shutdown condition satisfy applicable criteria for preoperational and periodic testing, quality assurance, and design provisions for indicating system availability.

(D) The project is implementing this SRP acceptance criterion.

f. Remote/local station capability

(G) SRP 7.4 states that equipment required for safe shutdown be operable from local control panels and that access to these local control panels should be administratively controlled. Appropriate readouts (such as steam generator level, steam generator pressure, pressurizer pressure, pressurizer level, and AFW flow) to monitor the status of the shutdown should be provided. This equipment should be designed to accommodate a single failure and should be capable of operating independently of the equipment in the main control room. The equipment should also be designed to the same standards as the corresponding equipment in the control room.

(D) The Midland design will comply with this SRP acceptance criterion with the following clarifications:

1) The Midland design provides redundant controls and indications outside the control room on local control panels. These controls and indications outside the control room are designed to operate without the mutual action of those in the control room. No single failure will defeat this capability for safe shutdown at either location. In addition, a study is in progress which responds to fire protection

guidelines. The study evaluates the feasibility of installation of transfer switches, relocation of signal processing equipment, and improved fire protection of safe shutdown control and instrumentation to ensure that the capability exists outside the control room to shut the plant down after a fire.

2) The Midland design provides instrumentation capability at the auxiliary shutdown panel and local control stations beyond the examples provided in SRP 7.4. Instrumentation for monitoring safe shutdown is consistent with the control room capability as described in Section VII.D.3 except as follows:

   a) Source range neutron power for reactivity control monitoring

      Control room: Safety-grade indication is provided.

      Auxiliary shutdown panel: Computer terminal display of isolated safety-grade inputs to the computer is provided.

      Discussion: Complete safety-grade indication of source range neutron power is not available outside the control room. Analysis indicates that in the worst-case scenario, upon completion of EBS injection, the reactor will remain subcritical. Safety-grade EBS tank level indication is provided on the auxiliary shutdown panel and this, together with valve indications, provides sufficient verification of proper EBS injection. Therefore, this precludes the need to monitor source range neutron power.

E. Regulatory Guide 1.139, Guidance for Residual Heat Removal to Achieve and Maintain Cold Shutdown

1.139 has been made available to the industry and is intended to apply to CPs issued after January 1, 1978; therefore, it is not specifically applicable to Midland. The implementation section of the latest available version (Draft 2, Revision 1 transmitted to A.L. Cahn of Bechtel Power Corp. by G.A. Arlotto of the NRC on March 21, 1980) states that the guide will be used for plants docketed after January 1, 1980, and this excludes Midland. This section also states applications docketed before this date will be reviewed against this guide on a case-by-case basis.

Nevertheless, the guidance in RG 1.139 will be compared to the Midland design. This comparison will be made with Section C, Regulatory Position, of the regulatory guide.

1. Functional

   a. (G) The design shall be such that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade equipment.

      (D) Midland has this capability.

   b. (G) The systems utilized are redundant, provide function assuming a single failure, and are capable of operation with onsite or offsite power.

      (D) The systems used satisfy this guidance.

   c. (G) The RCS shall be capable of being cooled and depressurized so DHR initiation can begin in 36 hours.

      (D) The POAV valves that have been added can cool the reactor sufficiently enabling DHR operation to be initiated within 36 hours after shutdown.

   d. (G) Instrumentation and controls conform to IEEE Std 279-1971, 323, 384, and 344; and RG 1.89, 1.75, and 1.100.

(D) All necessary instruments and controls will be safety grade.

e. (G) Safety-related systems should be Seismic Category I and meet RG 1.29.

(D) The Midland design is in accordance with this guidance except for the CAS, which is an alternate system that may be used to provide for RCS contraction volume following a tornado. A seismic event is not assumed to occur simultaneously with a design basis tornado.

2. Reactivity control

(G) A safety-related system shall exist to control and monitor the boron concentration.

(D) Safety-related systems exist to inject sufficient boron to ensure subcriticality. Operation of these systems ensures sufficient boron concentration. Boron concentration can be measured by sampling or by the nonsafety-grade boronometer when letdown is available. A safety-related boron measuring device is not installed.

3. Heat removal

a. Auxiliary feedwater

(G) A safety-related water source should exist to supply water for sufficient time.

(D) Refer to response to BTP RSB 5-1.

b. Steam relief

(G) Provide safety-related atmospheric vent valves.

(D) Refer to response to BTP RSB 5-1.

c. Steam generator inventory

(G) Provide safety-related steam generator water level indication and alarm.

(D) Safety-grade steam generator water level indication is provided. An alarm is provided that is actuated by a Class 1E signal transmitted through an isolation device.

4. Decay heat removal

(G) Provide redundant trains for the RHR system with capability to cool core by 4 hours after shutdown.

(D) The DHR system has redundant trains, but operation of DHR system within 4 hours after shutdown is not a design basis. However, the system will be capable of operation within 36 hours after shutdown.

a. Decay heat removal isolation

Refer to response to BTP-RSB 5-1. The requirements of BTP-RSB 5-1 and this regulatory guide are similar on this issue.

b. Decay heat removal system pressure relief

Refer to the response to BTP-RSB 5-1. The requirements of BTP-RSB 5-1 and this regulatory guide are similar on this issue.

c. Decay heat removal pump protection

(G) Procedures should be such that a single failure or operator error will not result in loss of RHR function due to pump damage.

(D) Operating procedures for the DHR system will be written and made available to the operator before initial criticality. In addition, the present design includes DHR pump protection by a nonsafety-grade low-flow trip. This trip is inhibited during ECCAS actuation.

d. Decay heat removal testing

Refer to the response to BTP-RSB 5-1. The requirements of BTP-RSB 5-1 and this regulatory guide are similar on this issue.

e. Decay heat removal system operation and indication DHR isolation valve position

(G) Provide isolation valve position indication, system pressure and flow, and pump operating status in control room.

(D) These indications are available in the control room.

f. Residual heat removal system integrity

1) Residual heat removal system leakage

(G) Monitor and control DHR system pump and valve leakage.

(D) The DHR pump rooms have floor drains that are normally closed. Safety-grade redundant water level indicators for those rooms are located in the control room. The valves may be opened locally (nonsafety-grade system) and drained to the auxiliary building sumps. The pump rooms are equipped with an engineered safety features (ESF) filtration system to collect airborne radiation after a postulated accident.

2) Shielding of personnel and personnel access

The present design is adequate for all design base scenarios.

3) Engineered safety features filtration system

(G) Service the DHR system, including leakage collection system, by an ESF filtration system

(D) The DHR pump room has an ESF filtration system. Leakage is contained in the pump room by closed drains.

g. Residual heat removal cooling water supply

(G) Provide safety-related cooling water to the DHR heat exhangers and monitor the water for radioactivity at the DHR heat exchanger outlet.

(D) The DHR coolers are serviced by a safety-grade CCW system. Each DHR cooler is serviced by a separate CCW train. Each CCW train is equipped with a nonsafety-grade radiation monitor in the line, but not at the output of the DHR heat exchanger.

5. Natural circulation cooling

(G) Provide redundant emergency power and controls to required number of pressurizer heaters, PORV and PORV block valves, and pressurizer level indicator channels.

(D) Safety-grade power and controls are provided for these instruments and components.

6. Reactor coolant system inventory

(G) Provide capability of supplying makeup and letdown control to accommodate cooldown shrinkage and letdown for boration.

(D) The Midland design can accommodate safety-grade cold shutdown without letdown. Sufficient inventory is available from the BWST. If the BWST is unavailable, RCS makeup can be provided by the tornado-protected, nonsafety-grade, CAS. The letdown system is nonsafety grade, but the letdown isolation is safety grade.

7. Operational procedures

Refer to response to BTP-RSB 5-1.

LIST OF ABBREVIATIONS

AFW	Auxiliary feedwater
AFWAS	Auxiliary feedwater actuation signal
APSRA	Axial power shaping rod assemblies
BTP	Branch Technical Position
BWST	Borated water storage tank
CAS	Chemical addition system
CCW	Component cooling water
CP	Construction permit
CR	Control room
CRD	Control rod drive
CRDM	Control rod drive mechanism
CVCS	Chemical volume and control system
(D)	Design
DBT	Design basis tornado
DHR	Decay heat removal
DHRS	Decay heat removal system
ECCAS	Emergency core cooling actuation system
EBS	Emergency boration system
ESF	Engineered safety features
(G)	Guidance
HPI	High-pressure injection
LOCA	Loss-of-coolant accident
LPI	Low-pressure injection
MAD	Modulating atmospheric dump
MFIV	Main feedwater isolation valve
MSIV	Main steam isolation valve
MSLB	Main steam line break
MU&PS	Makeup and purification system
OTSG	Once-through steam generator
POAV	Power-operated atmospheric vent
PORV	Power-operated relief valve
RCS	Reactor coolant system
RG	Regulatory Guide
RPS	Reactor protection system
RHR	Residual heat removal
SER	Safety Evaluation Report
SF	Single failure
SRP	Standard Review Plan
SSE	Safe shutdown earthquake
TMI	Three Mile Island

TABLES

TABLE V-1

COLD SHUTDOWN CAPABILITY FOLLOWING CHAPTER 15 EVENTS

	Event	Cold Shutdown Achievable in 36 hours with Safety Grade Equipment	Assumptions	Cold Shutdown Limitations
15.1.1	Decrease in feedwater temperature	Yes	AFW available	none
15.1.2	Increase in feedwater flow	Yes	AFW available	none
15.1.3	Steam pressure malfunction resulting in increased steam flow	Yes	AFW available	Intermittent use of both steam generators may be required
15.1.4	Inadvertent opening of an atmospheric pump or safety valve	Yes	AFW available	Intermittent use of both steam generators may be required
15.1.5	Steam line break	No	Loop Loss of 1 HPI Pump	-only one intact loop available -time > 36 hours required
15.2.1	Steam pressure regulator malfunction resulting in decreasing steam flow	Yes	AFW available	none
15.?.2	Loss of external load (turbine trip)	Yes	EBS available even with LOOP	none
15.2.3	Turbine trip	Yes	EBS available	none
15.2.4	Inadvertent MSIV closure	Yes	AFW available to both steam generators	none

TABLE V-1 (Continued)

	Event	Cold Shutdown Achievable in 36 hours with Safety Grade Equipment	Assumptions	Cold Shutdown Limitations
15.2.5	Loss of condenser vacuum	Yes	AFW available to both steam generators	none
15.2.6	Loss of all nonemergency ac power	Yes		none
15.2.7	Loss of normal feedwater	Yes	AFW flow available to both steam generators	none
15.2.8	Main feedwater line break	No	AFW flow available to only one steam generator	With LOOP - natural circulation cooldown may require > 36 hours
15.3.1, 15.3.3, 15.3.4	Decrease in RCS flow rate	Yes	AFW flow to both steam generators following loss of RC flow up to four pumps	none
15.4.1, 15.4.2, 15.4.3, 15.4.4	Reactivity anomolies	Yes		none
15.4.6	Chemical addition system malfunction	Yes	Operator terminates source of dilution	Continued RC inventory increase may result in inability to borate without requiring letdown

TABLE V-1 (Continued)

	Event	Cold Shutdown Achievable in 36 hours with Safety Grade Equipment	Assumptions	Cold Shutdown Limitations
15.4.8	Control rod assembly ejection		Small LOCA	none
15.5.1	Inadvertent operation of ECCS	Yes		none
15.6.1	Inadvertent opening of a pressurizer safety or relief valve	Yes	HPI maintains primary pressure control AFW flow to both steam generators	none
15.6.2	Break in instrument line or line from primary system that panetrates containment	Yes	HPI maintains primary pressure control AFW flow to both steam generators	none
15.6.3	Steam generator tube failure	Yes	HPI maintains primary pressure control	Choosing to use one unaffected steam generator for cooldown may increase time to cold shutdown and ultimately increase radiation released
15.6.5	LOCA	Yes	HPI and LPI available	
15.8	Anticipated transient without scram	No		Time required

TABLE VI-1

LOCATION OF DESIGN REQUIREMENTS TO ACHIEVE/MAINTAIN

SAFE SHUTDOWN

Requirement	Guidance Document							
	BTP RSB 5-1	QR 211.35	ASB-8	PSB-11	RSB-20	RSB-10	RG 1.139	Midland Design
DHR drop line that can accommodate single failure	Yes	Yes		Yes	Yes			Yes
Safety-grade steam dump valves	Yes	Yes	Yes				Yes	Yes
Provide aux. spray or show manual actions are acceptable	Yes	Yes						Yes
Provide safety-related boration system without letdown, or provide safety-grade letdown, or show that manual actions are acceptable	Yes	Yes					Yes	Yes(1)
Provide adequate RHR isolation	Yes						Yes	Yes
Discuss collection of RHR system pressure relief valve discharge	Yes	Yes					Yes	Yes
Conduct borated water mixing test	Yes	Yes						No
Conduct natural circulation test	Yes	Yes						Yes

TABLE VI-1 (Continued)

Requirement	BTP RSB 5-1	QR 211.35	ASB-8	PSB-11	RSB-20	RSB-10	RG 1.139	Midland Design
	Guidance Document							
Provide natural circulation procedures	Yes	Yes					Yes	Yes
Provide Seismic Category I AFW system water supply	Yes	Yes					Yes	Yes
Provide safety-grade means of monitoring boron concentration							Yes	No(2)
Provide safety-grade steam generator level indication and alarm							Yes	Yes(3)
Provide safety-grade makeup and letdown control							Yes	Yes(4)
Provide necessary safety-grade pressurizer heaters with Class 1E power and control						Yes	Yes	Yes

NOTES:
(1)Midland provides safety-grade boration without letdown

(2)Nonsafety-grade sampling is provided

(3)Alarms exist but are not safety-grade

(4)Letdown is safety-grade only for isolation of letdown

TABLE VI-2

DESIGN GUIDANCE OF BTP RSB 5-1 FOR CLASS 2 PLANTS AND COMPARISON TO MIDLAND DESIGN(1)

Design Requirements of BTP RSB 5-1	Process and System or Component	Branch Technical Position Design Guidance for Midland	Midland Design
I. Functional requirement for taking to cold shutdown a. Capability using only safety-grade system b. Capability with either only onsite or only offsite power and with single failure (limited action outside CR to meet SF) c. Reasonable time for cooldown assuming most limiting SF and only offsite or only onsite power	Long-term cooling (RHR drop line)	Compliance will not be required if it can be shown that correction for single failure by manual actions inside or outside of containment, or return to hot standby until manual actions (or repairs) are complete, are found to be acceptable for the individual plant.	Midland complies. Midland has a single DHR dropline that divides into a series/parallel remote motor-operated valve arrangement inside containment; the line then reconverges to exit containment. Local manual actions in the auxiliary building are required for alignment.
	Heat removal and RCS circulation during cooldown to cold shutdown	Provide safety-grade dump valves, operators, and power supplies, etc so that manual actions should not be required after an SSE except to meet single failure.	Midland complies. Remote manual safety-grade POAV valves are provided and are operated by safety-grade power and controls. The single failure criteria is met. Remote manual action is required.
	Depressurization (pressurizer auxiliary spray or power-operated relief valves)	Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure, or b) remaining at hot standby until manual actions or repairs are complete, are found to be acceptable for the individual plant.	Midland complies. A safety-grade auxiliary pressurizer spray is provided. Local manual action in the auxiliary building is required for alignment. Control is accomplished from the control room.
	Boration for cold shutdown (CVCS and boron sampling)	Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure, or b) remaining at hot standby until manual actions or repairs are complete, are found to be acceptable for the individual plant.	Midland complies. Midland has the capability to borate without letdown. A safety-grade emergency boration system provides

Table VI-2 (Continued)

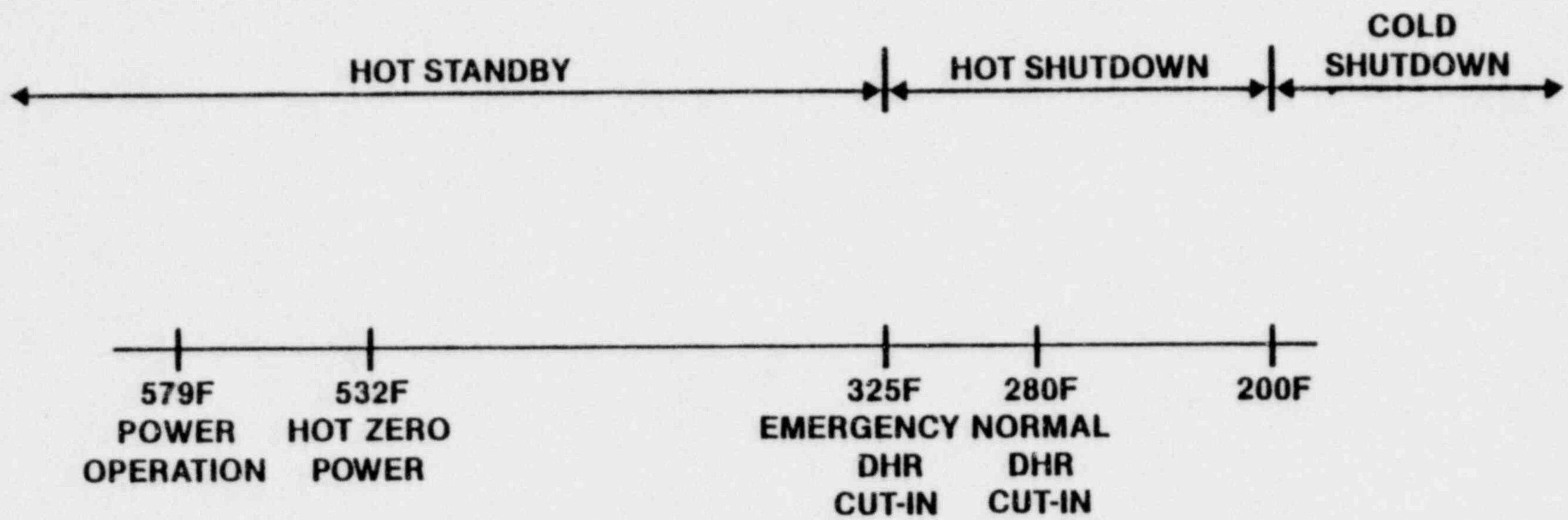
Design Requirements of BTP RSB 5-1	Process and System or Component	Branch Technical Position Design Guidance for Midland	Midland Design
			for boration to hot standby. The BWST or CAS provides for boration to cold shutdown. Local manual alignment is required. Boron concentration is normally measured after being let down. Sampling capability will be added on the cold-loop letdown line upstream of the isolation valve.
II. RHR isolation	RHR system	Comply with one of the allowable arrangements.	Midland complies. The DHR system suction is isolated by two series motor-operated valves on each of two lines. The DHR discharge is isolated by two series check valves on each of two lines.
III. RHR pressure relief			
b. Collect and contain relief discharge	DHR system	Compliance will not be required if it can be shown that adequate methods of disposing of discharge are available.	Midland compiles. The DHR relief valve discharge is routed to the containment sump.
V. Test requirement			
b. Meet RG 1.68 for PWRs test plus analysis for cooldown under natural circulation to confirm adequate mixing and cooldown within limits specified in EOP.		Run tests and confirm analysis to meet the requirement.	Midland complies with clarification for boron mixing test. Midland will use the results of a natural circulation cooldown test on a similar plant to confirm existing calculations if a similar plant is tested before Midland. Otherwise, a 50F cooldown test will be performed on Midland. No separate boron mixing test is presently planned.

Table VI-2 (Continued)

Design Requirements of BTP RSB 5-1	Process and System or Component	Branch Technical Position Design Guidance for Midland	Midland Design
VI. Operational procedure			
a. Meet RG 1.33 for PWRs, include specific procedures and information for cooldown under natural circulation.		Develop procedures and information from tests and analysis.	Midland will comply. Appropriate procedures will be developed.
VII. Auxiliary feedwater supply			
a. Seismic Category I supply for AFW for at least 4 hours at hot shutdown (sic) plus cooldown to RHR cutin based on longest time for only onsite or only off-site power and assumed single failure.	Emergency feedwater supply	Compliance will not be required if it is shown that an adequate alternative Seismic Category I source is available.	Midland complies. An automatic switchover to a safety-grade source of AFW is provided upon low suction to the AFW pumps, coincident with an accident signal.

(1) Midland is a Class 2 plant because the construction permit was issued before January 1, 1978.

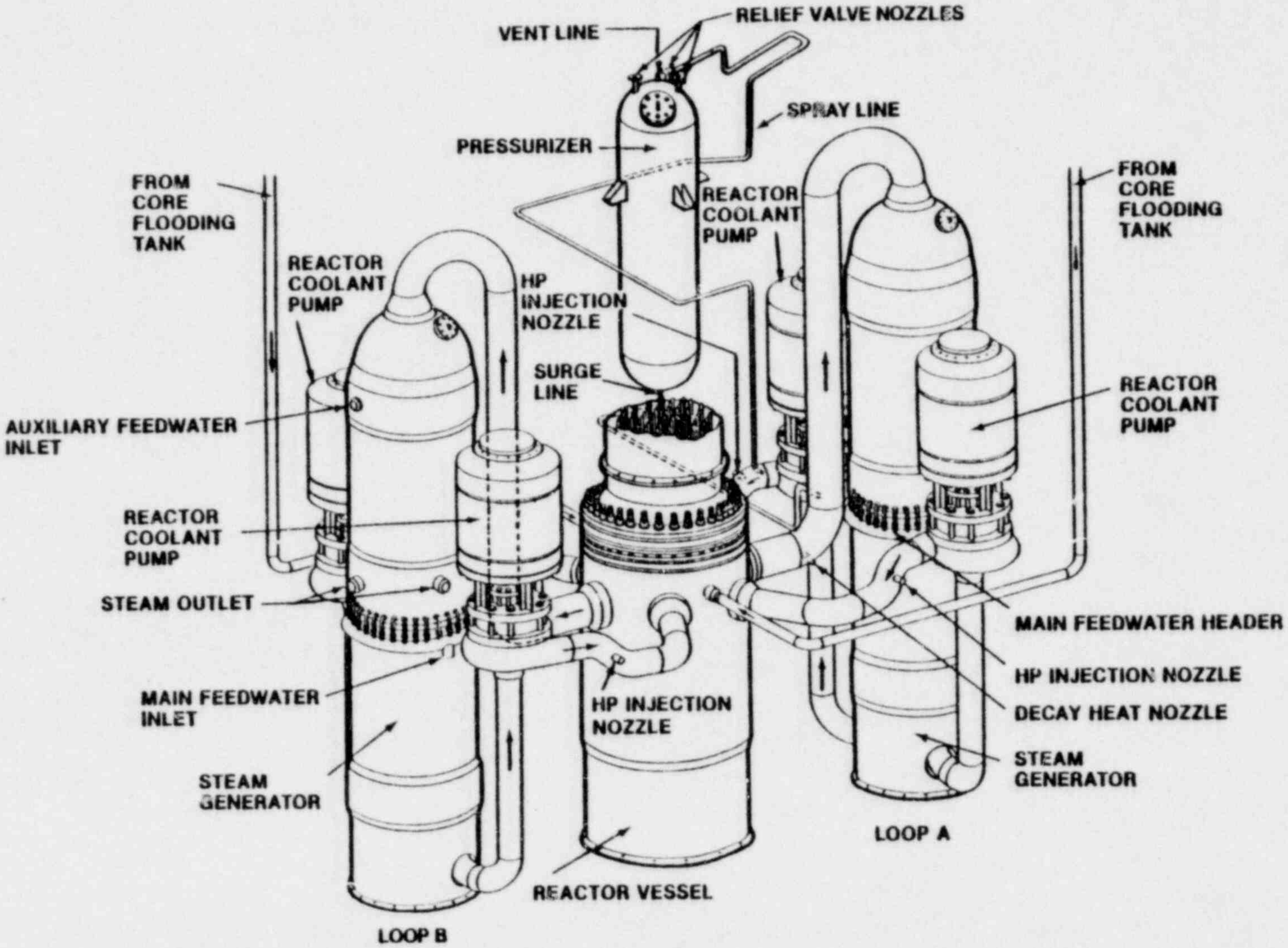
FIGURES



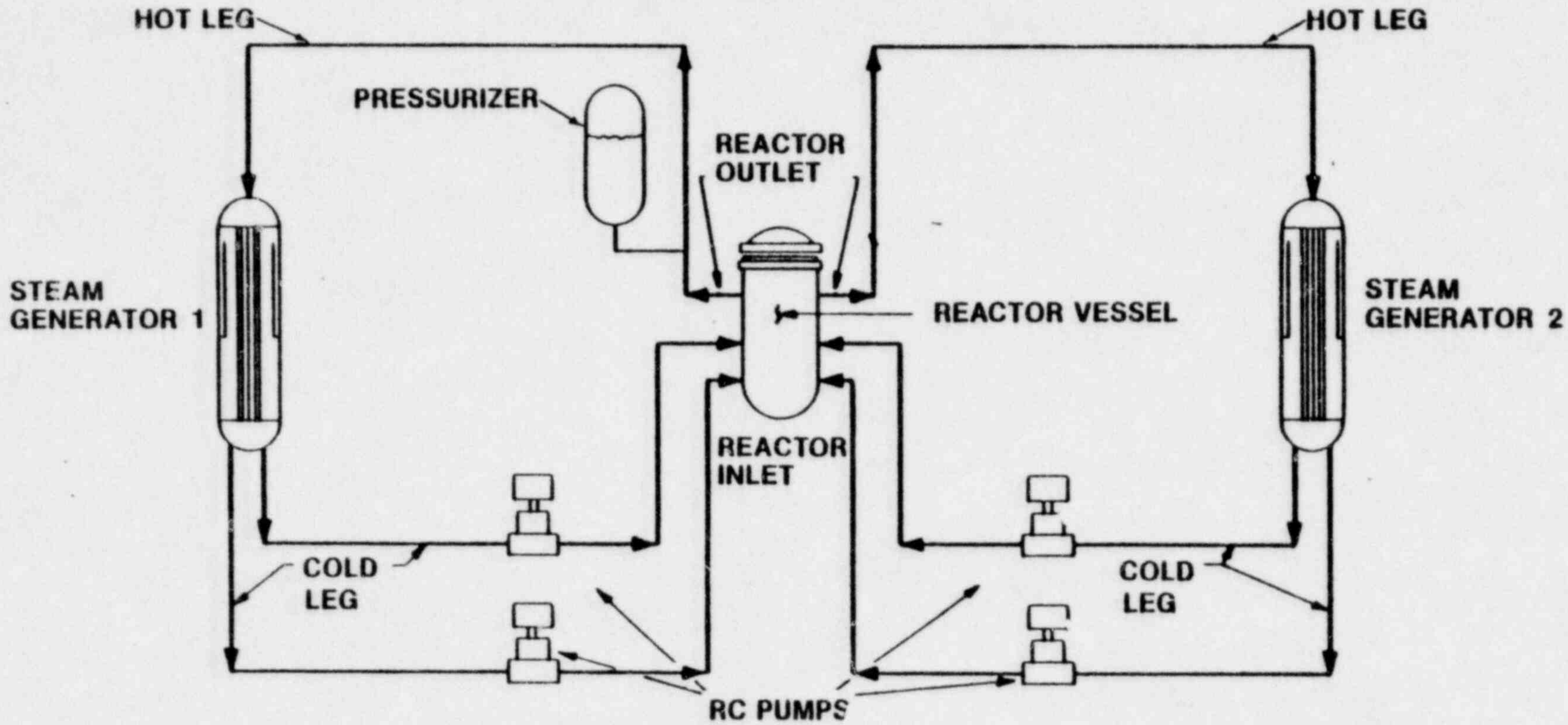
REACTOR OPERATIONAL MODES

G-1508-11

REACTOR COOLANT SYSTEM

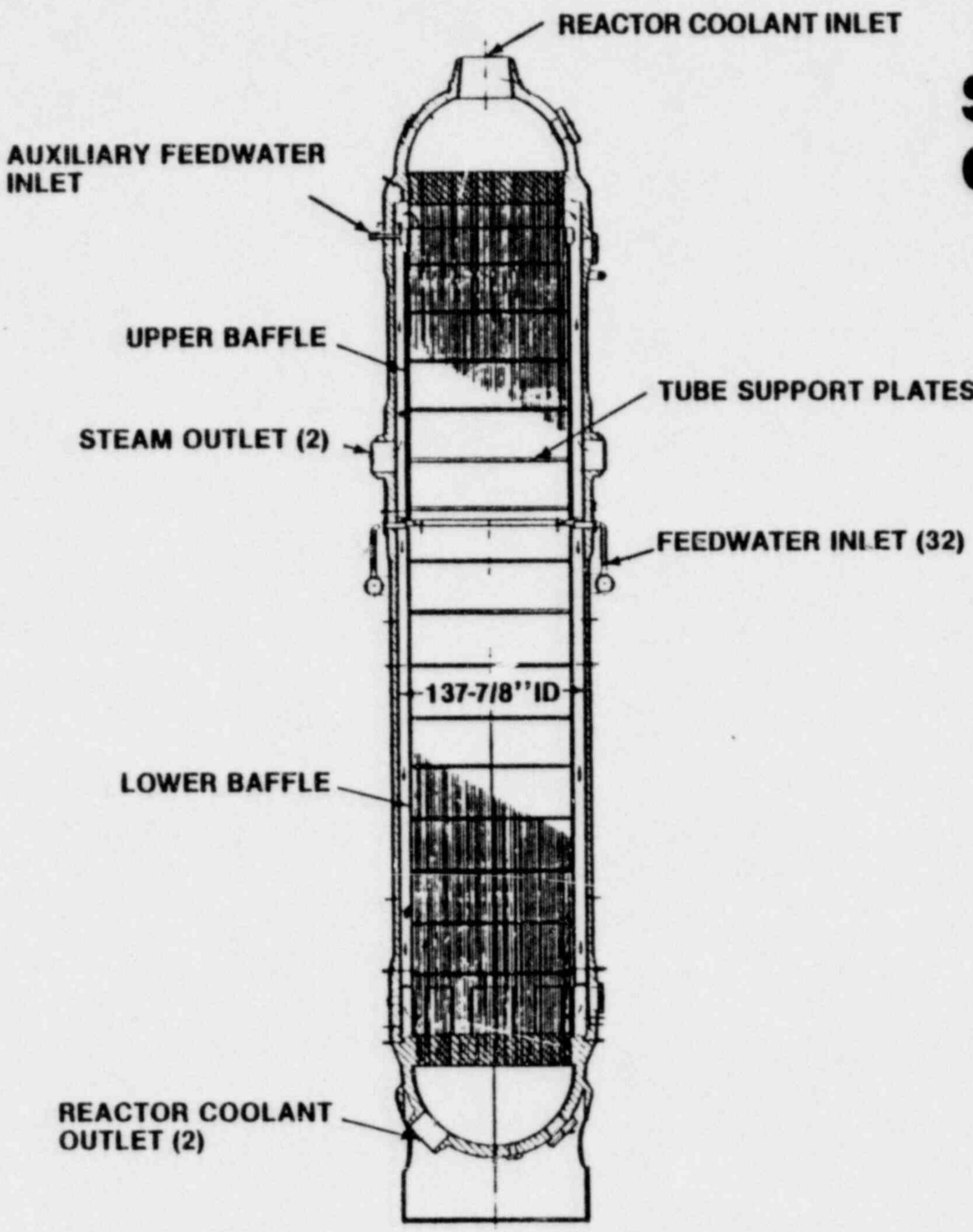


REACTOR COOLANT SYSTEM FLOW DIAGRAM

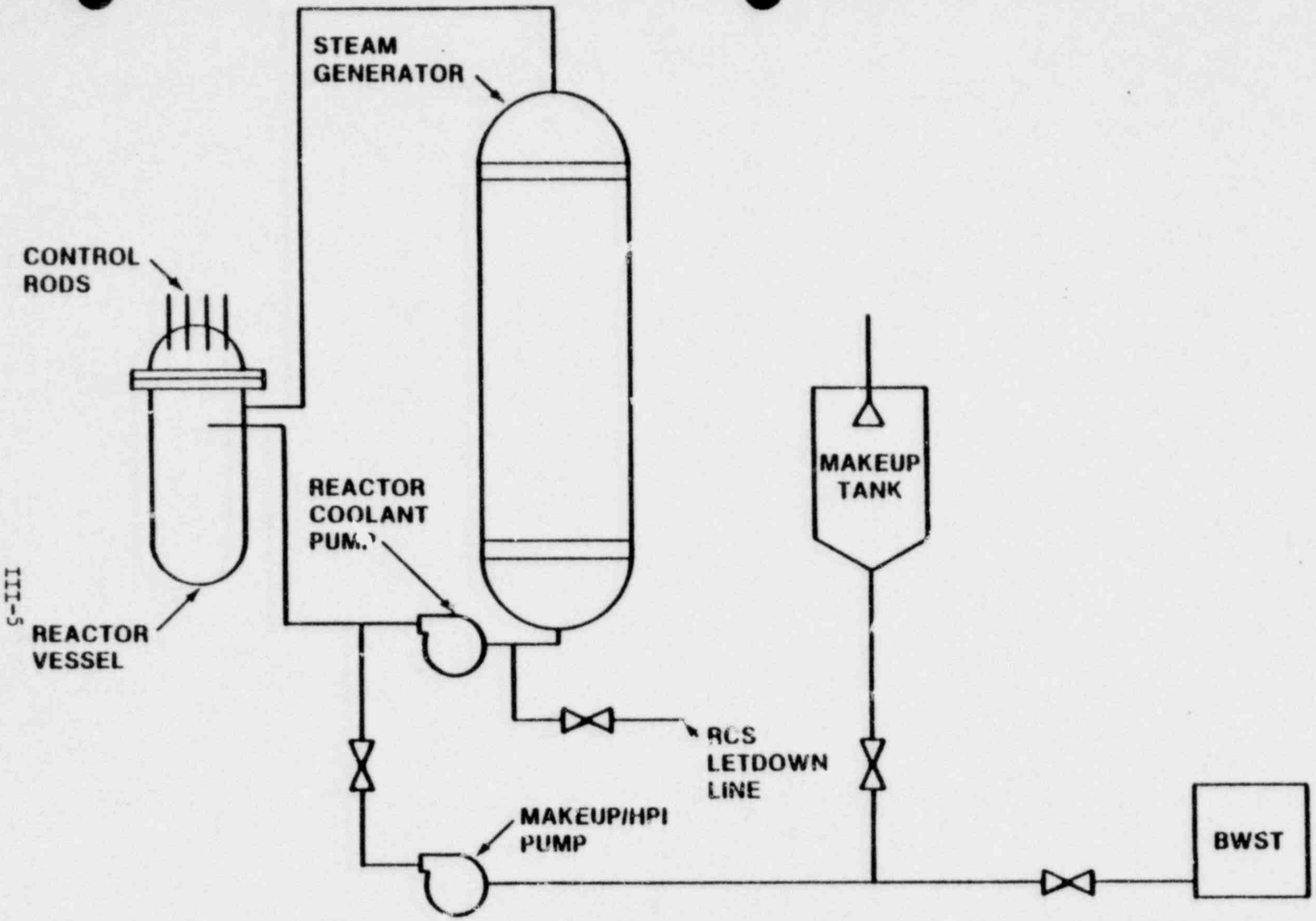


G-1508-02

STEAM GENERATOR

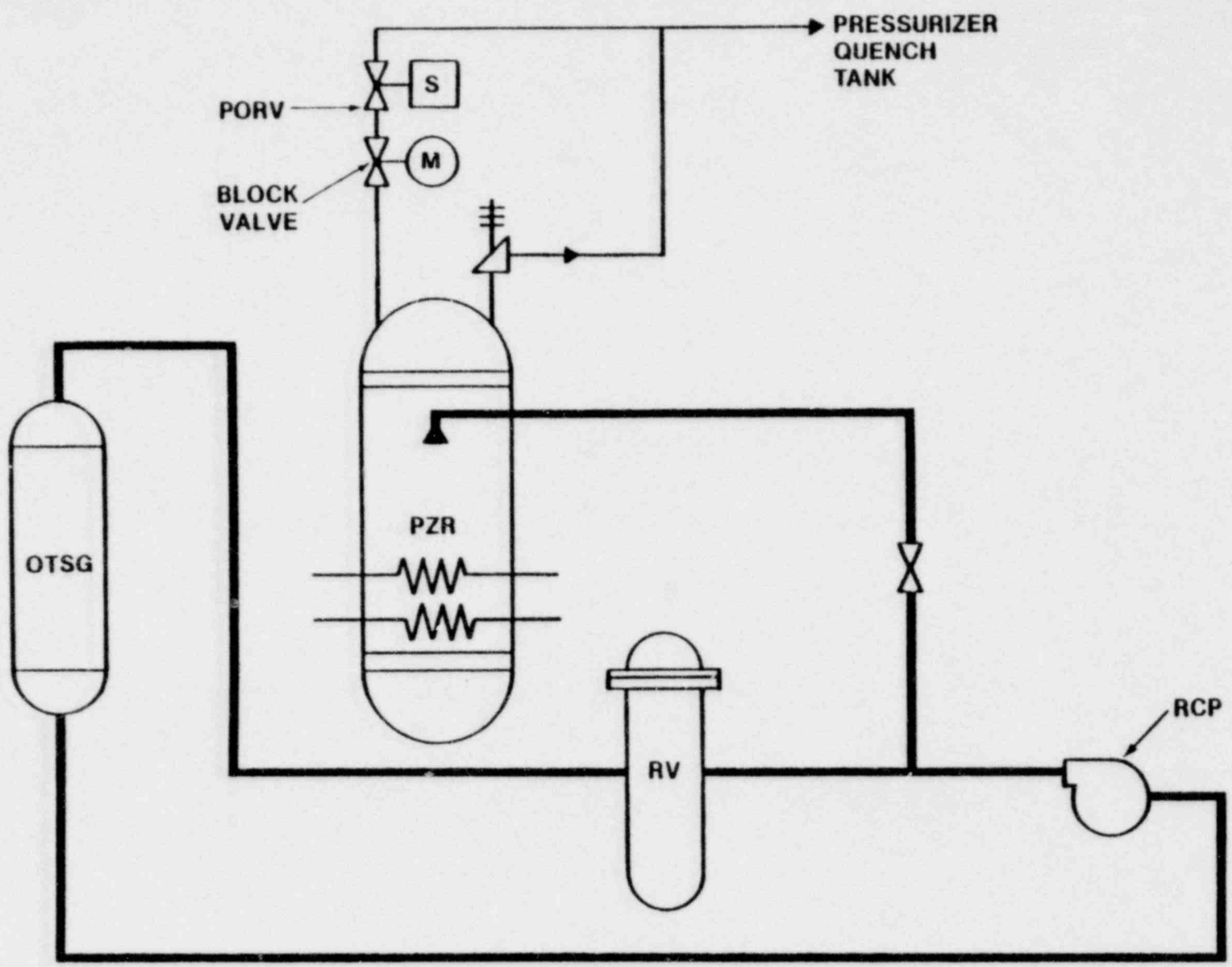


G-1508-01



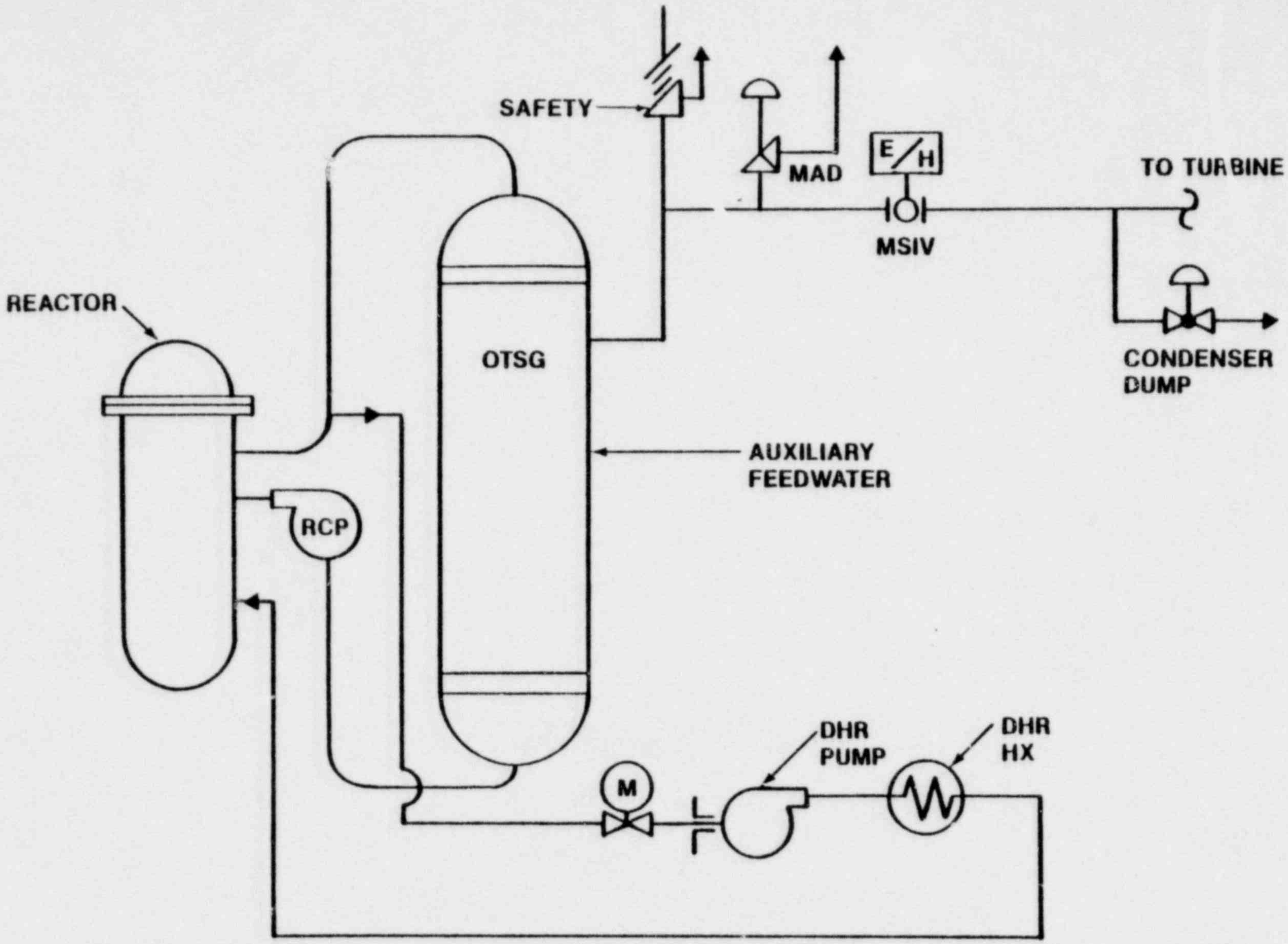
REACTIVITY CONTROL/ INVENTORY CONTROL

G 1508 05



PRESSURE CONTROL

G-1508-04



HEAT REJECTION (TEMPERATURE CONTROL)

G-1508-06

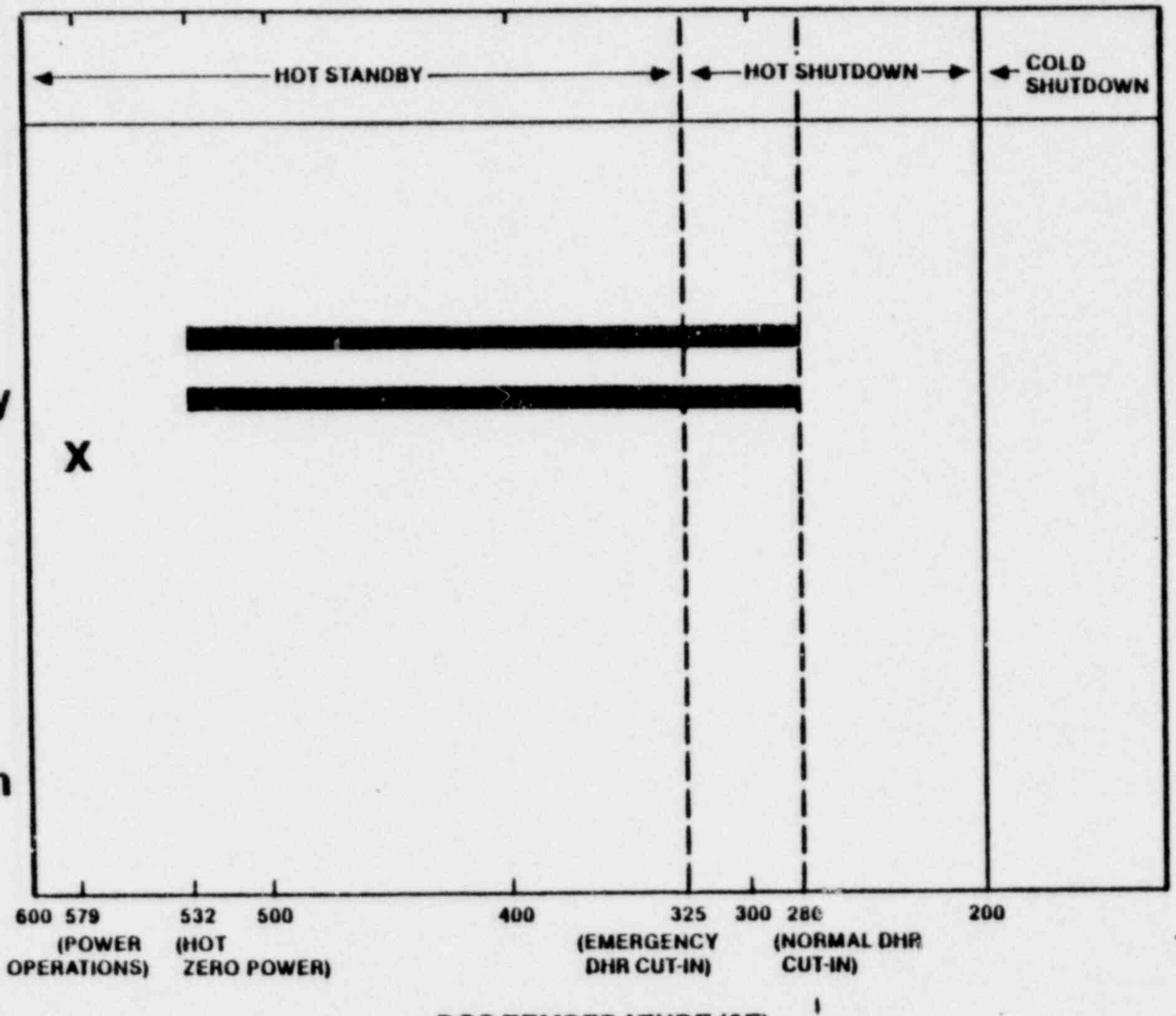
SHUTDOWN SYSTEMS OPERATIONAL RANGE

SHUTDOWN FUNCTIONS AND SYSTEMS

SHUTDOWN STAGE

PRESSURE CONTROL

- Pressurizer Heaters (5&6)
- Auxiliary Pressurizer Spray
- Letdown Isolation Valves
- Pressurizer Safety Valves (Set at 2,500 psig)
- PORV (Set at 2,260 psig)
- PORV Block Valve (Set at 2,100 psig Coincident With PORV not Shut)



NORMAL OPERATING RANGE

AUTOMATIC ACTUATION

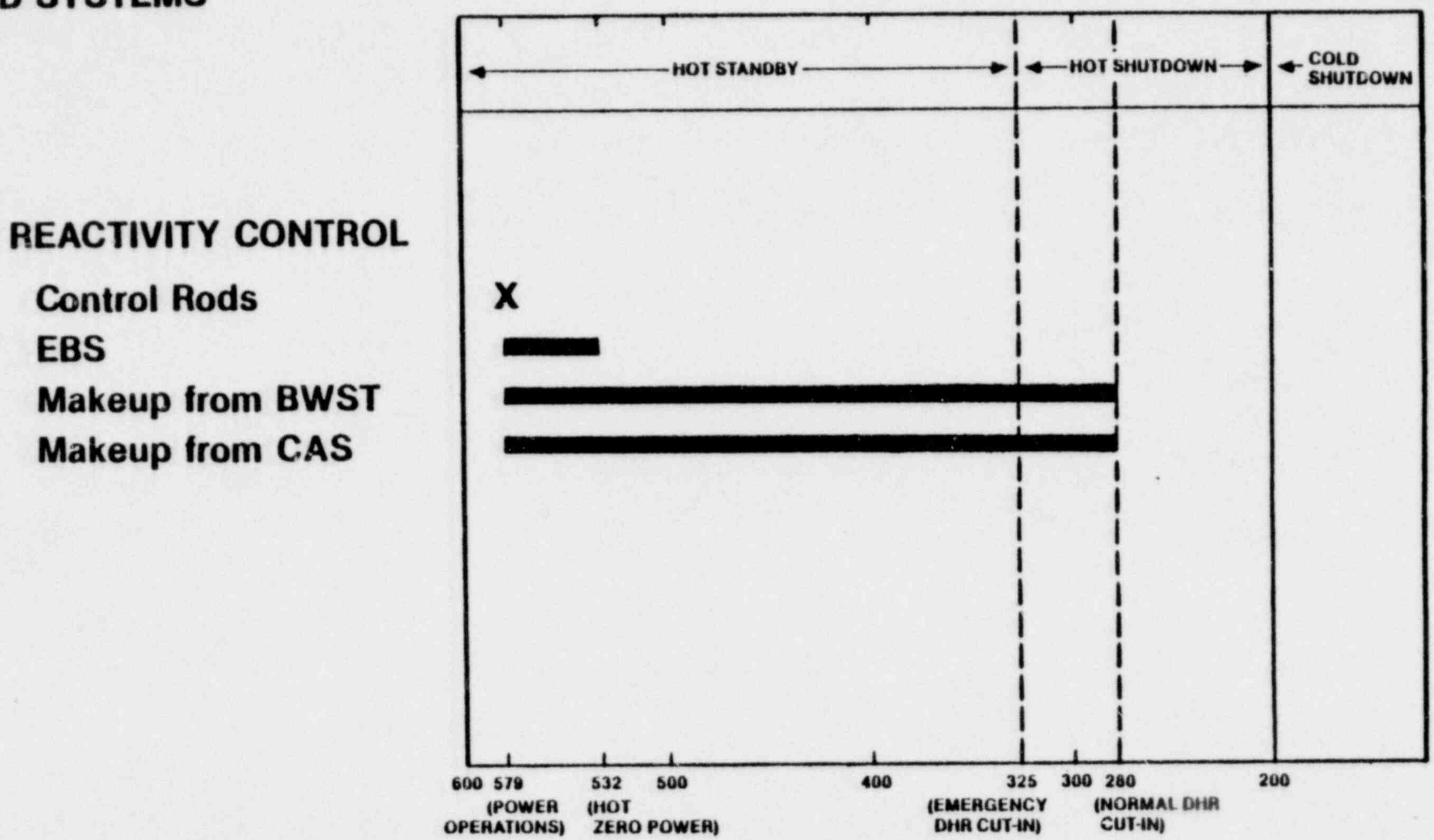
X MANUAL ACTION

G-1610-03

SHUTDOWN SYSTEMS OPERATIONAL RANGE

SHUTDOWN FUNCTIONS AND SYSTEMS

SHUTDOWN STAGE



NORMAL OPERATING RANGE

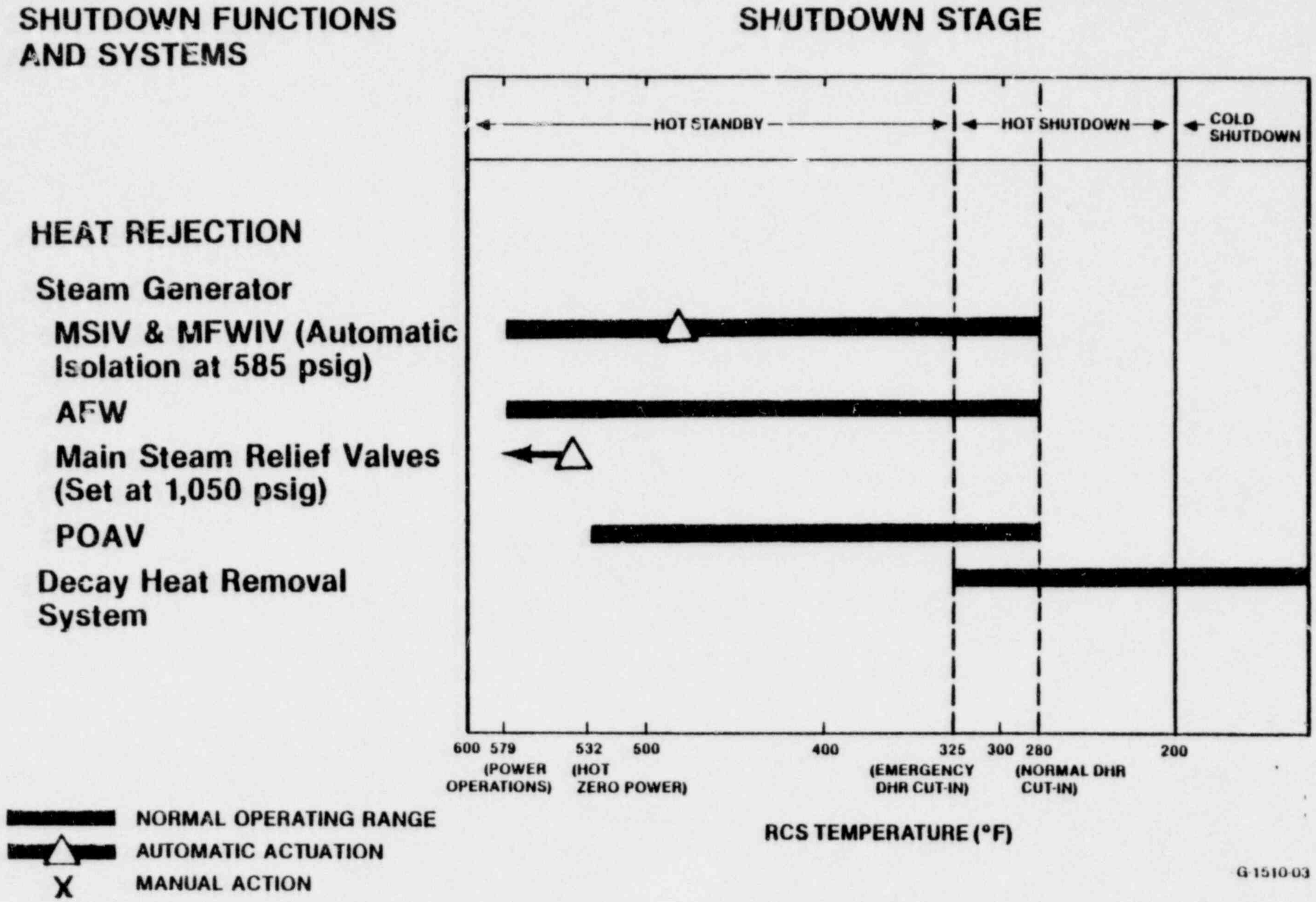
AUTOMATIC ACTUATION

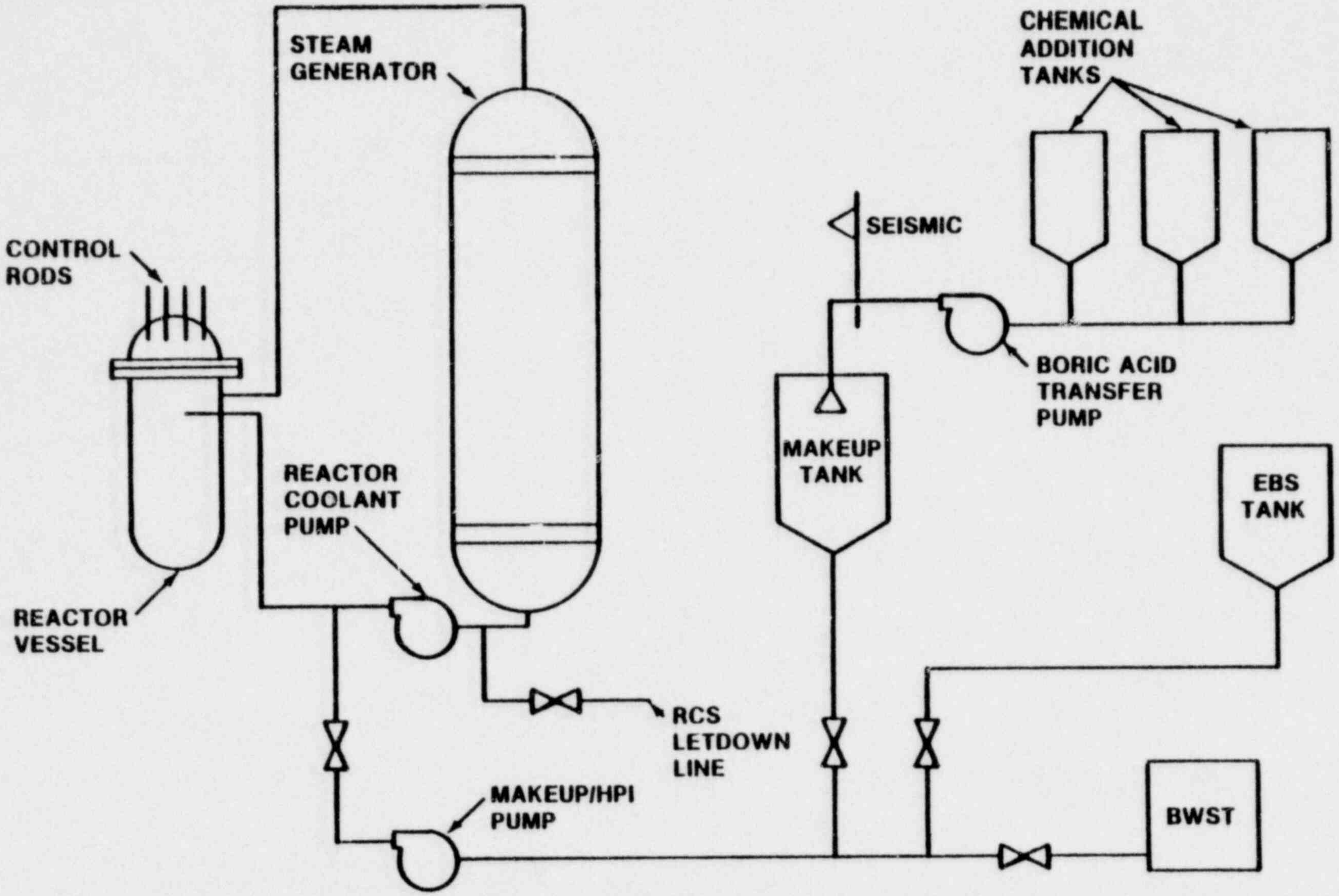
X MANUAL ACTION

G-1510-03

IV-1b

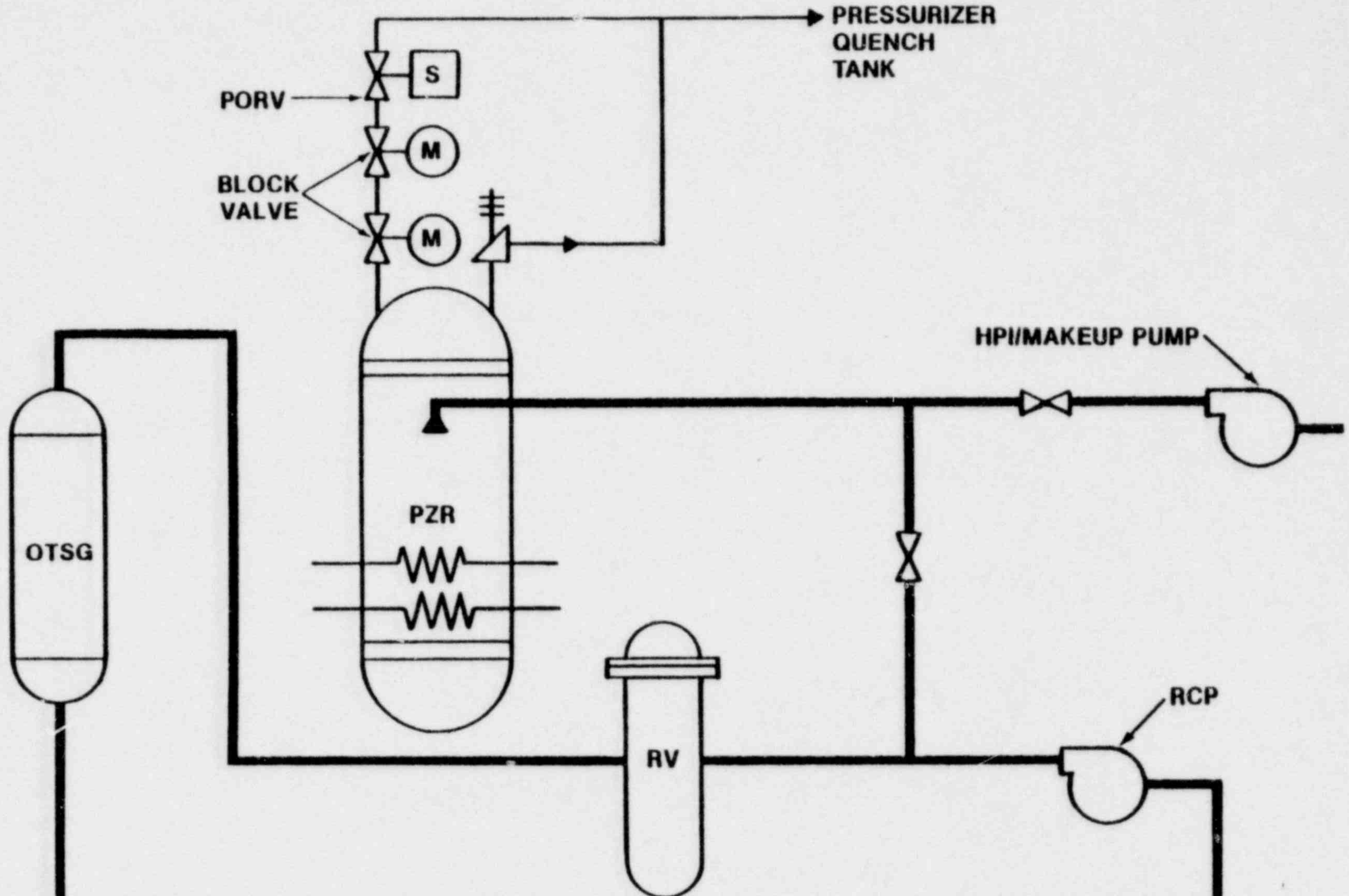
SHUTDOWN SYSTEMS OPERATIONAL RANGE





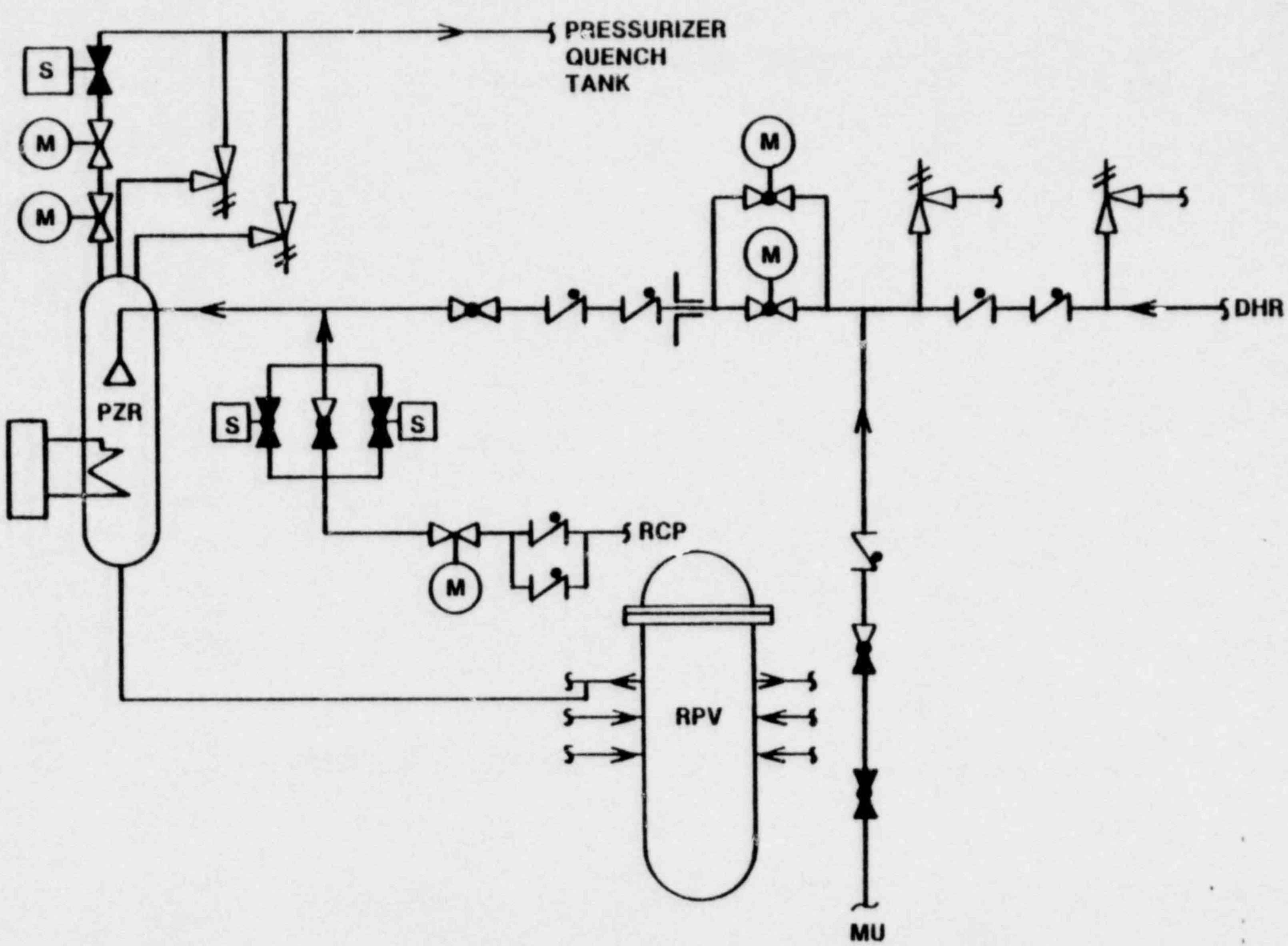
REACTIVITY CONTROL/ INVENTORY CONTROL

G-1508-05



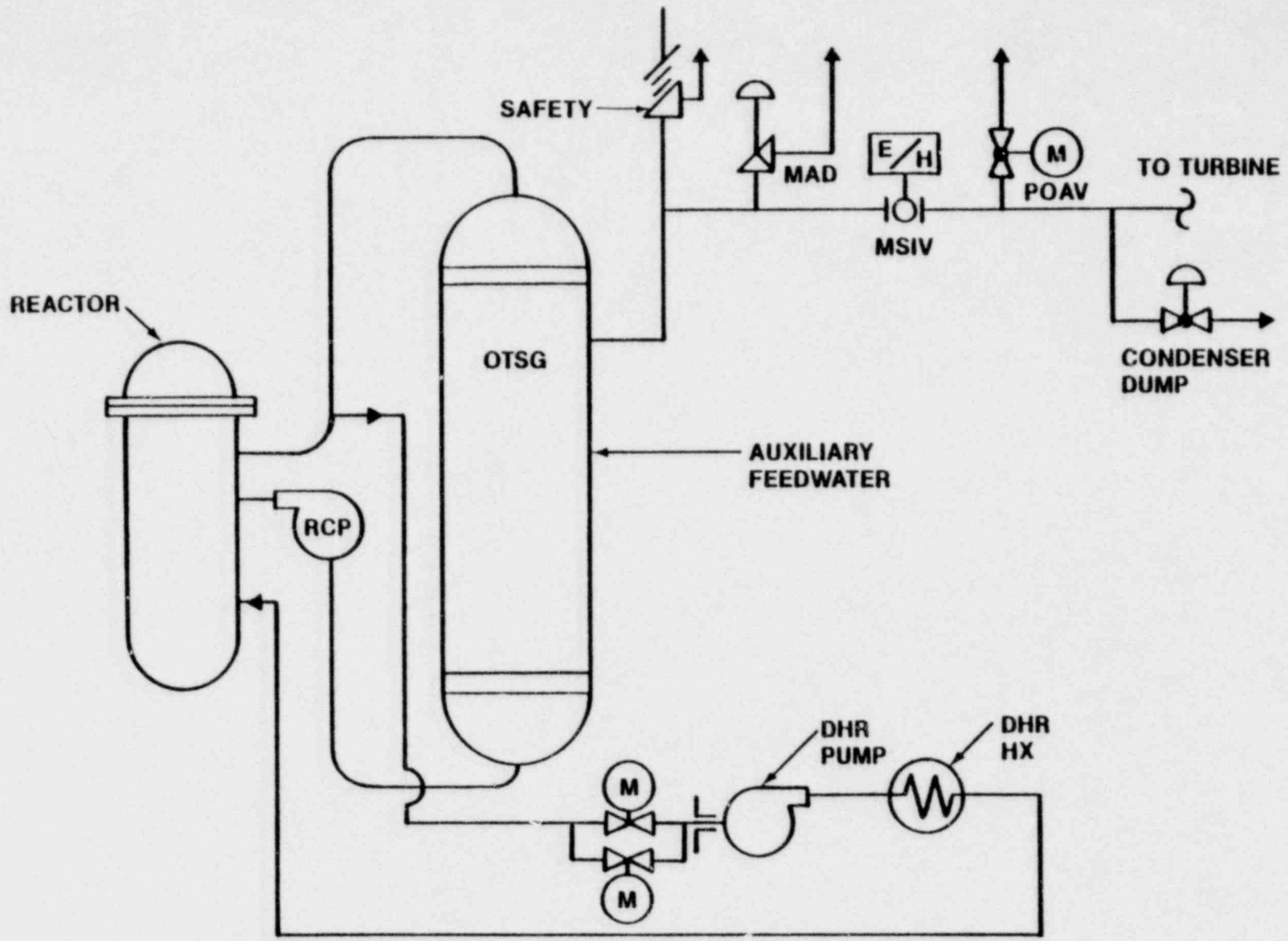
PRESSURE CONTROL

G-1508-04



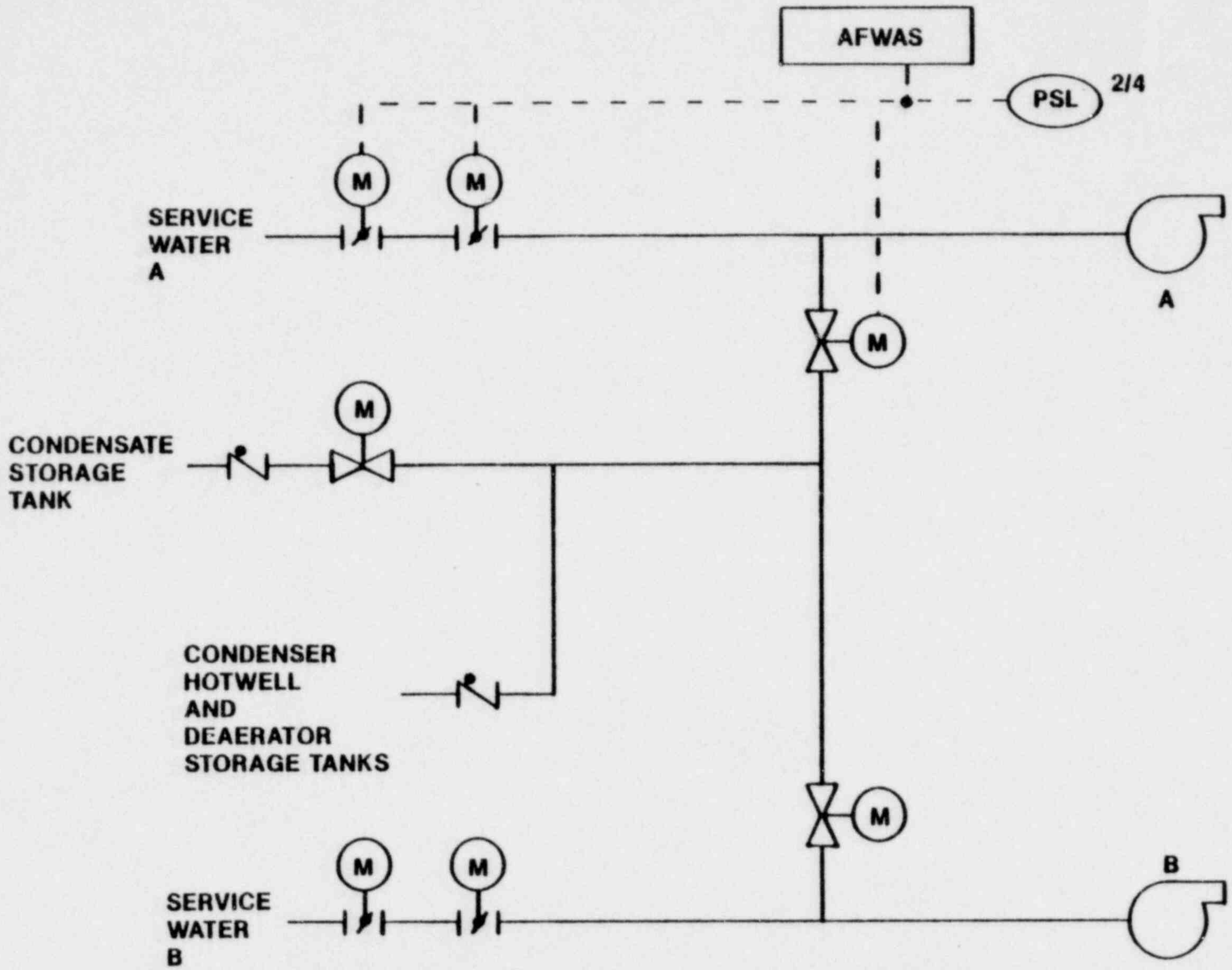
RCS PRESSURE CONTROL

G-1508-07



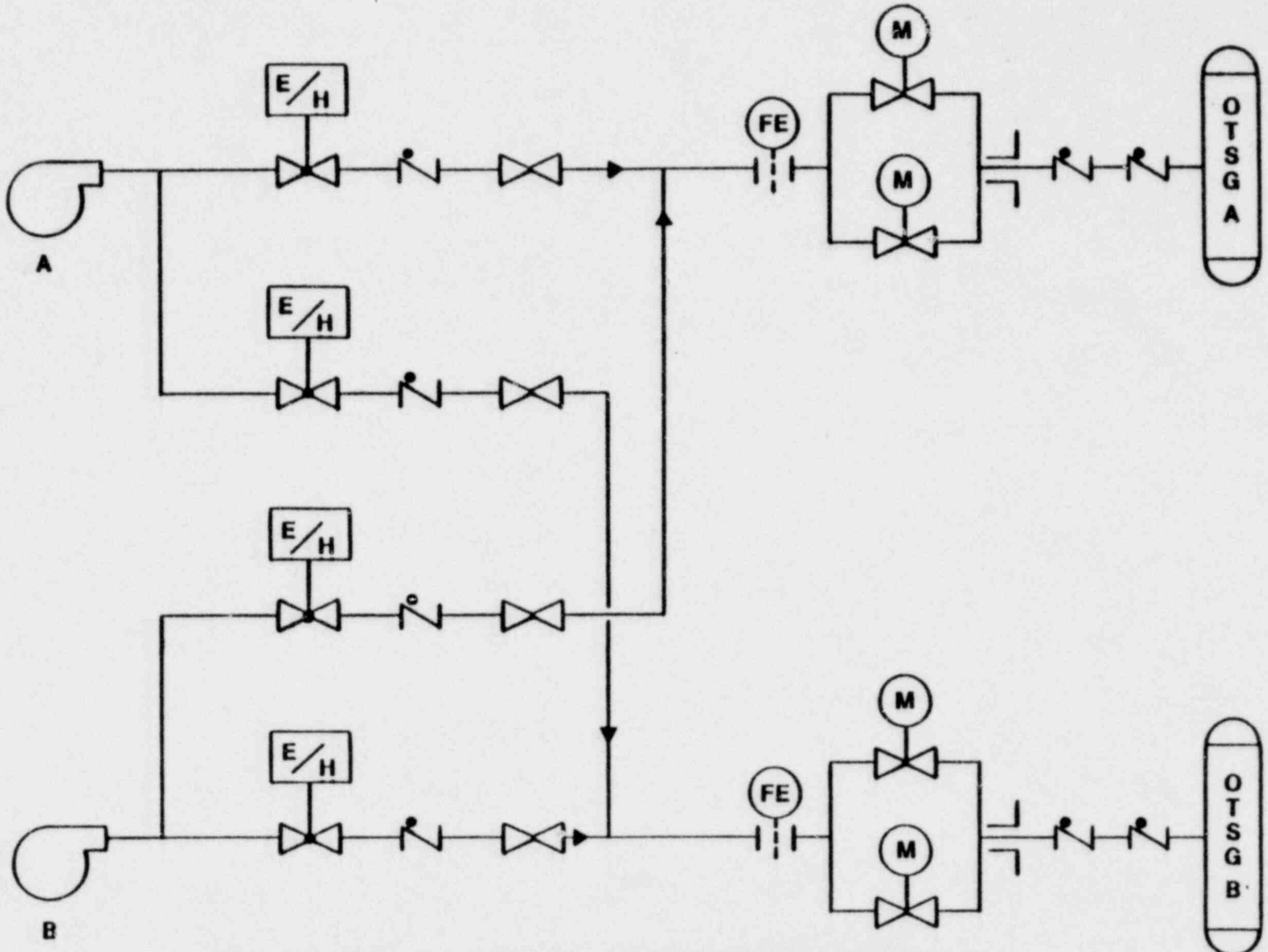
HEAT REJECTION (TEMPERATURE CONTROL)

G-1508-06



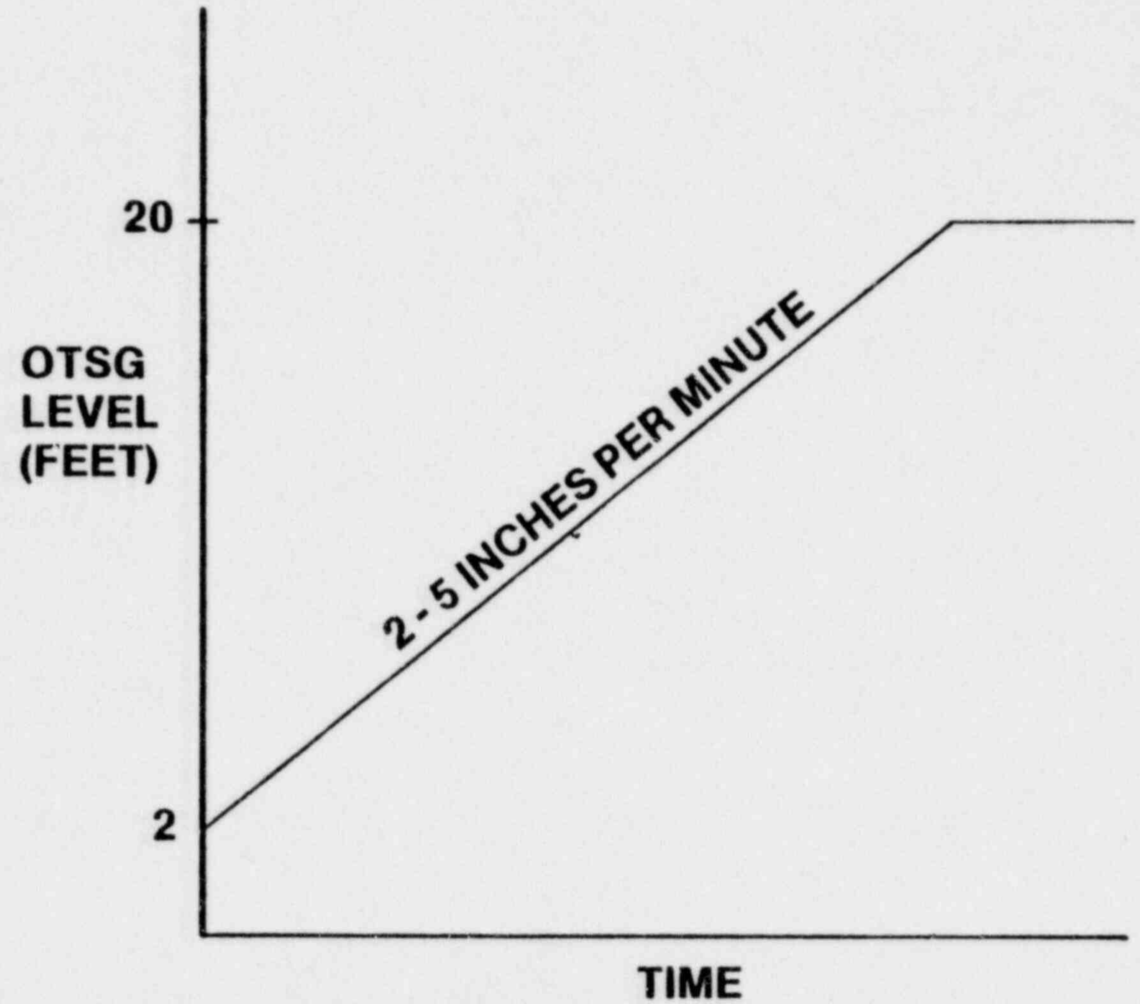
AUXILIARY FEEDWATER SUCTION CONFIGURATION

G-1508-10



AUXILIARY FEEDWATER DISCHARGE CONFIGURATION

G-1508-09



STEAM GENERATOR WATER LEVEL CONTROL

G-1508-08

- **NRC POSITION**
  Provide DHR Dropline Design to Accommodate a Single Failure

- **REFERENCES**
  BTP RSB 5-1, Q211.35, PSB-11, RSB-20

- **MIDLAND DESIGN**
  Complies: Parallel/Series Motor-Operated Valves Provided Inside Containment

- **NRC POSITION**
  Provide Safety-Grade Steam Dump Valves

- **REFERENCE**
  BTP RSB 5-1, Q211.35, ASB-8, RG 1.139

- **MIDLAND DESIGN**
  Complies: Two POAV Valves Provided per Steam Generator

- **NRC POSITION**
  Provide Auxiliary Pressurizer Spray or Show Acceptable Manual Actions

VI-3

- **REFERENCES**
  BTP RSP 5-1, Q211.35

- **MIDLAND DESIGN**
  Complies: Auxiliary Pressurizer Spray Provided

- **NRC POSITION**
  Provide Safety-Grade Boration Capability or Show Acceptable Manual Actions

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139

- **MIDLAND DESIGN**
  Complies: EBS and Other Safety-Grade Borated Water Sources Provide Sufficient Boration

- **NRC POSITION**
  Provide Adequate DHR Isolation

- **REFERENCES**
  BTP RSB 5-1, RG 1.139

- **MIDLAND DESIGN**
  Complies: Suction Isolation by Two Series Motor-Operated Valves; Discharge Isolation by Two Series Check Valves

- **NRC POSITION**
  Collect and Contain DHRS Pressure Relief Valve Discharge

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139

- **MIDLAND DESIGN**
  Complies: Discharge Routed to Containment Sump

- **NRC POSITION**
  Conduct Natural Circulation Cooldown and Borated Water Mixing Test

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139

- **MIDLAND DESIGN**
  Partial Compliance: 50F Natural Circulation Cooldown Test Will Be Conducted or Referenced; No Separate Boron Mixing Test Planned; Safe Boron Mixing Test Infeasible

VI-8

- **NRC POSITION**
  Provide Procedures for Natural Circulation Cooldown

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139

- **MIDLAND DESIGN**
  Complies: Appropriate Procedures to Be Provided

VII-9

- **NRC POSITION**
  Provide Adequate Seismic Category I AFW Supply

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139

- **MIDLAND DESIGN**
  Complies: Normal Supply is Nonsafety-Grade Condensate; Automatic Switchover Provided to Safety-Grade Service Water

- **NRC POSITION**

  Provide Boron Monitoring Capability with Safety-Grade System

- **REFERENCES**

  BTP RSB 5-1, RG 1.139

- **MIDLAND DESIGN**

  - Nonsafety-Grade Boron Monitoring Provided
    - Continuous monitoring by boronometer on letdown
    - Periodic monitoring by manual sampling

- **NRC POSITION**
  Provide Safety-Grade Steam Generator Water Level Indication and Alarm

- **REFERENCES**
  RG 1.139

- **MIDLAND DESIGN**
  Complies with Clarification: Safety-Grade Water Level Indication and Nonsafety-Grade Alarms Provided

- **NRC POSITION**
  Provide Safety-Grade Makeup and Letdown to Accommodate Cooldown Shrinkage and Boration

- **REFERENCES**
  RG 1.139

- **MIDLAND DESIGN**
  Complies with Clarification: Boration and Cooldown Shrinkage Accommodated Using Only Safety-Grade Systems Without Letdown

- **NRC POSITION**
  Address Pressurizer Heaters Required to Maintain Natural Circulation Conditions

- **REFERENCES**
  Open Item RSB-10, RG 1.139

- **MIDLAND DESIGN**
  Complies: Two Banks of Pressurizer Heaters Backed by Safety-Grade Power and Controls

- **NRC POSITION**
  Achieve Cold Shutdown with Safety-Grade Systems

- **REFERENCES**
  BTP RSB 5-1, Q211.35, RG 1.139
  Open Items PSB-11, RSB-10, ASB-8, RSB-7

- **MIDLAND DESIGN**
  Complies with Clarifications:

  - Boration accomplished without letdown
  - Boration monitored and sampled by nonsafety-grade systems
  - No separate boron mixing test planned
  - Steam generator water level alarms are nonsafety-grade
  - One steam generator cooldown will take longer than 36 hours
  - Upgraded nonseismic CAS can provide contraction volume after tornado

VT-14

CONTROL CAPABILITIES OUTSIDE THE CONTROL ROOM

AUXILIARY SHUTDOWN PANEL

MONITORS
- EBS Tank Level
- Pressurizer Level
- T-Hot, T-Cold
- AFW Flow
- OTSG Pressure & Level
- RCS Flow & Pressure
- POAV Position

CONTROLS
- Pressurizer Heaters
- Portions of MU&PS
- CCW Pumps
- POAV Valves
- Pressurizer PORV
- Auxiliary Feedwater

VARIOUS ACTIONS INDICATED IN DISCUSSION (e.g., EBS, DHR)

LOCAL AT EQUIPMENT

LOCAL CONTROL PANELS, MCC, & SWGR

SYSTEMS
- Diesel Generator
- Service Water
- Component Cooling Water
- Chilled Water
- Plant HVAC
- Auxiliary Pressurizer Spray

HOT STANDBY

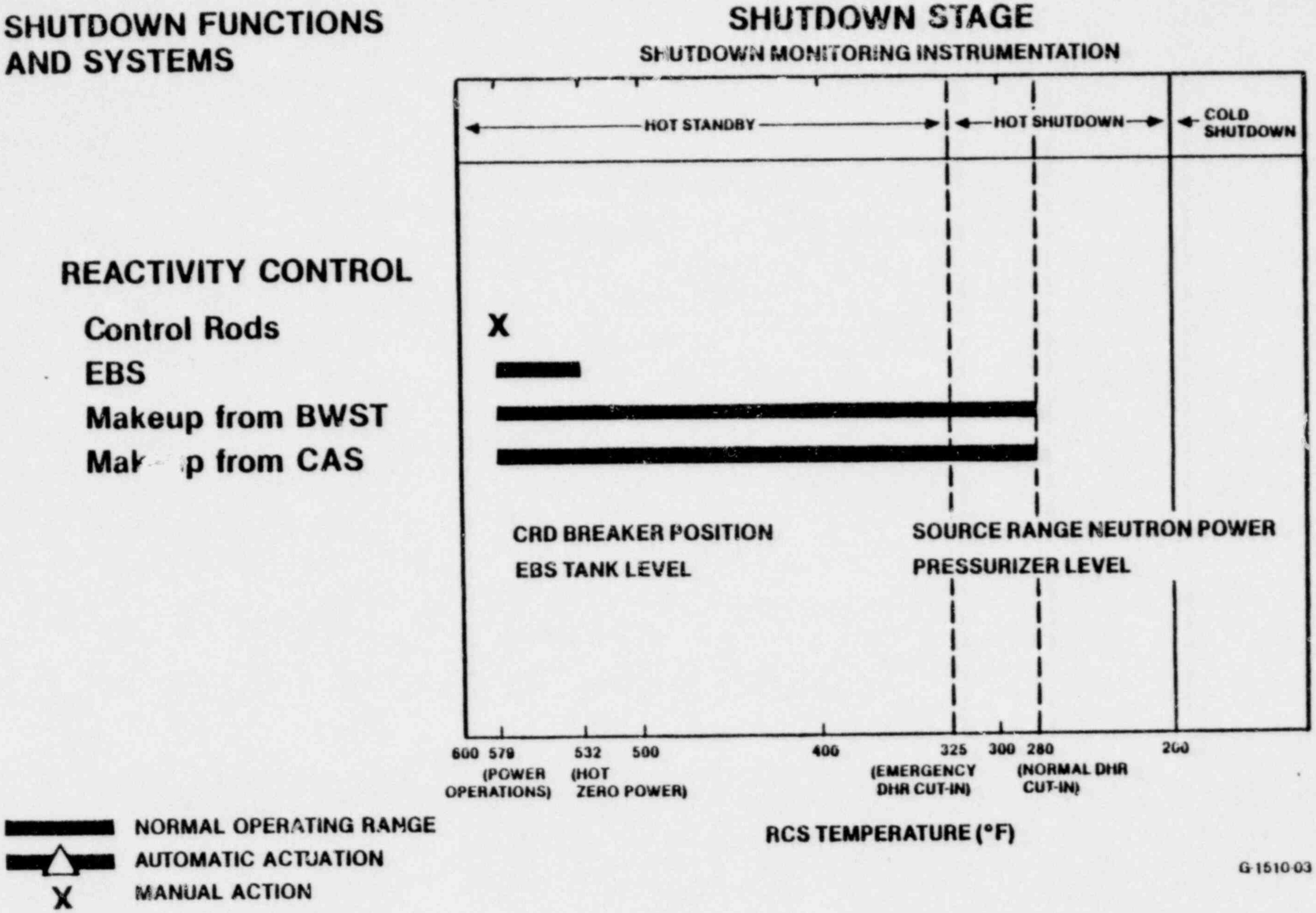
HOT SHUTDOWN

COLD SHUTDOWN

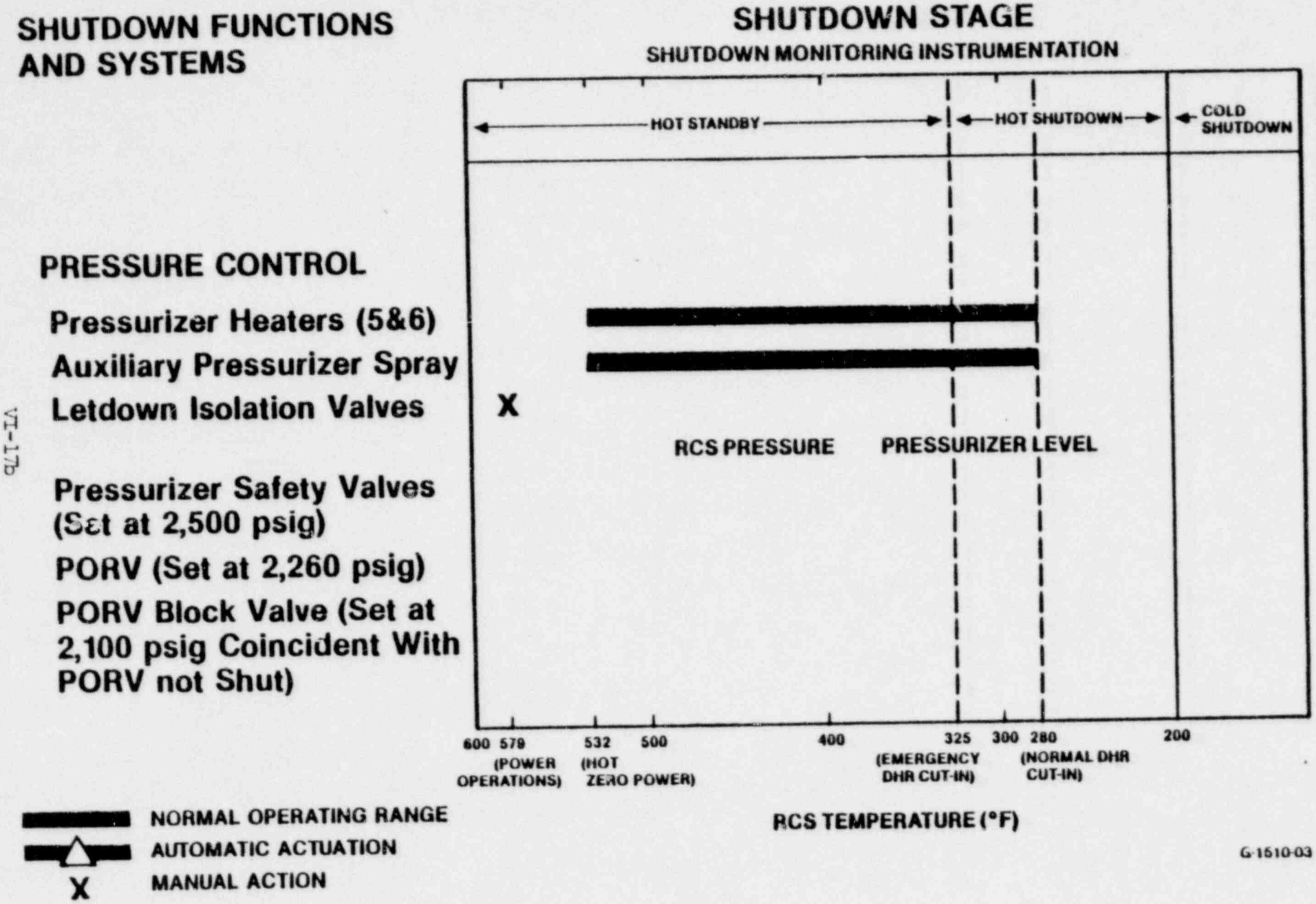
STANDARD REVIEW PLAN
SECTION 7.4 ACCEPTANCE CRITERIA

- ALL INSTRUMENTATION AND CONTROLS ESSENTIAL TO ACHIEVE AND/OR MAINTAIN COLD SHUTDOWN SHALL:
  - BE REDUNDANT in Their Intended Safety Function
  - MEET THE SINGLE-FAILURE CRITERION
  - HAVE CAPACITY AND RELIABILITY to Perform Their Intended Safety Functions Whenever Necessary
  - BE QUALIFIED to Function After the Design Basis Events for Which Their Operation Is Essential, Including Earthquakes and All FSAR Chapter 15 Accidents
  - Satisfy Applicable Criteria for Preoperational and Periodic TESTING, QUALITY Assurance, and Design Provisions for INDICATING SYSTEM AVAILABILITY
  - BE OPERABLE FROM OUTSIDE THE CONTROL ROOM at Local Control Panels with Appropriate Readouts, and Operate Independent of the Control Room

SHUTDOWN SYSTEMS OPERATIONAL RANGE



SHUTDOWN SYSTEMS OPERATIONAL RANGE

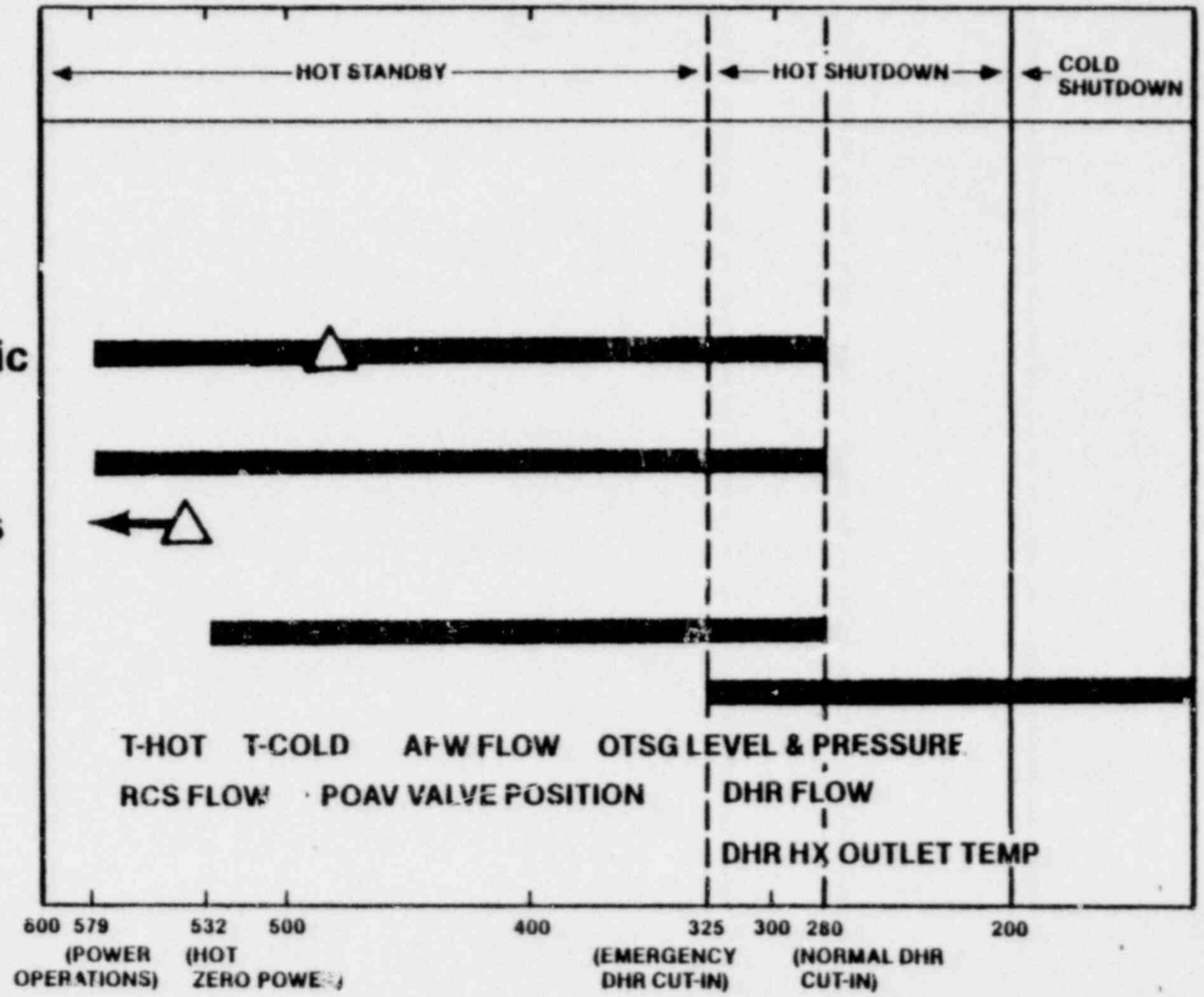


SHUTDOWN SYSTEMS OPERATIONAL RANGE

SHUTDOWN FUNCTIONS AND SYSTEMS

SHUTDOWN STAGE

SHUTDOWN MONITORING INSTRUMENTATION



HEAT REJECTION

Steam Generator

MSIV & MFWIV (Automatic Isolation at 585 psig)

AFW

Main Steam Relief Valves (Set at 1,050 psig)

POAV

Decay Heat Removal System

NORMAL OPERATING RANGE

AUTOMATIC ACTUATION

X MANUAL ACTION

G-1510-03

APPENDIX

Question 211.35 (5.4.7)

Should the Midland plants experience an event that will require eventual cooldown to permit either long-term cooling with the DHR system or going to cold shutdown for inspection and repairs (extended loss of offsite power, steam generator tube rupture, failure of steam generator relief valves to reclose, etc), it is desirable that qualified systems be available to perform the operation safely and in an orderly manner. Discuss the capability of the Midland plants to be taken to a cold shutdown condition using only safety-grade equipment, assuming only onsite or offsite power is available, and considering a single failure. Address each of the following areas of concern in your response:

1. Discuss the capability of the single DHR drop line to provide for the cooldown of the plant assuming a single active failure, including manual actions inside or outside of containment or the return to hot standby until manual actions or maintenance can be performed to correct the failure.

   With regard to the Midland shutdown capability, we note that manual operation outside the control room is required for normal shutdown, and containment entry is required for a failure of a motor-operated DHR suction valve. With regard to reducing the need for such manual actions, address the following areas: 9

   a. Discuss the modifications required to provide the capability to conduct a normal shutdown from the control room.

   b. Justify the viability of the manual actions required after a suction valve failure (i.e., opening cross-connects 093, 094). Address times required, doses expected, and potential for inadvertent opening of cross-connects during high primary side pressure conditions. Compare the Midland cross-connect design to Davis-Besse Unit 1. Provide a reliability analysis for the manual action outside the control room and discuss the incremental increase in reliability expected for various selected design modifications.

2. Provide safety-grade steam generator dump valves, operators, air, and power supplies which meet the single failure criterion.

3. Provide the capability to cool down to cold shutdown assuming the most limiting single failure in less than 36 hours or show that manual actions inside or outside containment or return to hot standby until the manual

actions or maintenance can be performed provides an acceptable alternative.

4. Provide the capability to depressurize the reactor coolant system with only safety grade systems assuming a single failure, or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are complete provides an acceptable alternative.

5. Discuss the capability for boration with only safety-grade systems assuming a single failure or show that manual actions inside or outside containment or remaining at hot standby until manual action or repairs are completed provides an acceptable alternative.

6. Discuss the capability for the collection and containment of DHR system pressure relief valve discharge.

7. Conduct tests to study the mixing of the added borated 9
water and cooldown under natural circulation conditions with and without a single failure of a steam generator atmospheric dump valve.

8. Commit to providing specific procedures for cooling down using natural circulation and submit a summary of these procedures.

9. Provide a Seismic Category I AWF [SIC] supply for at least 4 hours at hot shutdown plus cooldown to the DHR system cut-in based on the longest time (for only onsite or offsite power and assuming the worst single failure), or show that an adequate alternate Seismic Category I source is available.

Response

The Midland design basis provides for the ability to achieve and 30
maintain, by safety grade means, the hot shutdown condition as
described in Section 7.4 of the FSAR. As discussed in the
response to Question 110.16, hot shutdown provides for an 14
extremely stable and safe condition at which the plant can be
maintained until an eventual cooldown can proceed. Although not
a design basis, the Midland design does incorporate the ability 30
to be taken to the cold shutdown condition using only safety 14
grade equipment, assuming only onsite or offsite power is
available and considering a single failure. Therefore, in the
unlikely event that a design basis earthquake occurs which 30
results in the need to achieve cold shutdown expeditiously,
design features exist to accomplish this evolution. This

capability is discussed in the following point-by-point response keyed to the item numbers of NRC Question 211.35: 18

1. The suction side of the decay heat removal (DHR) system inside containment has been upgraded to incorporate motor operators for the previously manual bypass valves. These bypass valves are supplied with redundant Class 1E power (channel E) through manual transfer switches operated outside containment. Therefore, operator action inside containment is not required assuming a 30 single active failure. In addition, the isolation valve outside containment (1MO-1010 or 2MO-1110) is mechanically locked open. Therefore, this valve is not susceptible to an active failure.

   To align the DHR system for cooldown will require limited operator action outside the control room. The operator actions required are: 14

   a. The operator must open the DHR pump suction cross-connect manual valves (Unit 1 valves 009 and 016 or Unit 2 valves 003 and 008) to establish the suction flowpath. 18

   b. The operator must reestablish power to the DHR cooler bypass valve (1MO-1014A, B or 2MO-1114A, B). This valve is electrically locked closed during normal reactor operation.

   To reduce the need for manual actions outside the control room for initiating the normal DHR system cooldown, the DHR system would require:

   a. Replacement of the DHR pump suction cross-connect manual valves with power operated valves

   b. Removal of the electrical lock on the DHR cooler bypass valves. These valves would be ensured 14 closed during normal reactor operation by administrative control.

   The multiple purposes of the DHR system pump suction cross-connect manual isolation valves are given below:

   a. During power operation (DHR system aligned for standby low-pressure injection (LPI) mode), the valves function to separate the suction of the LPI pumps.

   b. During the DHR mode of operation, the valves provide the capability to isolate one DHR train while providing DHR with the other train.

This combination of functions requires manual valves and
operator actions outside the control room, or power 14
operated valves controlled from the control room, to
align the system for decay heat removal operations. 30
Because ample time is available for operator action to
align the system for DHR operation (approximately
6 hours), and because of the cost of equipment 14
considerations, manual valves were selected for the
appplication.

The Davis-Besse Unit 1 DHR suction cross-connect design
is similar to the Midland design. The outstanding
differences are that the Davis-Besse DHR pump suction
valves are provided with motor operators, no containment
isolation valve is provided, and the bypass valves
inside containment are not motorized. Incorporation of
pump suction valve motor operators for Midland would
reduce one of the manual actions outside the control
room required to align the DHR system for plant
cooldowns. However, the operator has at least 6 hours to
perform this action. The valves should be opened after
plant cooldown commences with the steam generator, but
before cooldown commences with the DHR system. Due to
the magnitude of the time available to perform the
action, the modification is not deemed necessary. 30

2,3. To remove heat after a postulated design basis
earthquake, two Class 1E power operated atmospheric vent
(POAV) valves are provided on each steam line between
the once-through steam generator (OTSG) outlet nozzle
and the main steam isolation valve. These valves and
their actuators are qualified as seismic active
components. The POAV valves are capable of being jogged
to any position between full open and full closed by
operator action from the main control room or the
auxiliary shutdown panel. Each valve has individual
manual isolation provisions. The existence of four POAV
valves per unit (two per steam generator) ensures the
capability of conducting a balanced cooldown regardless
of the occurrence of a single active failure. This
cooldown will proceed until the emergency DHR cut-in
temperature of 325F is achieved. Operation of the DHR
system at this temperature is described in Subsection
5.4.7.1.1.1. A detailed description of the POAV valves
and their associated controls can be found in
Subsections 10.3.2 and 7.4.1.2.1.

Water is added to the steam generators by a safety
grade, seismically qualified auxiliary feedwater system.
This system will provide adequate water assuming a loss 14
of offsite power and a single active failure. The steam
produced in the steam generators will be relieved by the
POAV valves as discussed above. 30

4. During normal plant cooldown, the reactor coolant system (RCS) is depressurized through normal pressurizer spray. The driving force for this spray flow is derived from the reactor coolant pump head. Assuming loss of offsite power, reactor coolant pumps stop and are unavailable to provide normal pressurizer spray flow. Under these circumstances, RCS depressurization can be achieved through the operation of the high-pressure auxiliary pressurizer spray system. This system utilizes the discharge of the high-pressure injection (HPI)/makeup pumps to supply spray flow to the pressurizer. Two Class 1E, parallel, motor operated valves are provided that can be jogged by the operator to control the rate of depressurization. The design of this system incorporates a seismic Category I connection from the makeup pump discharge to the auxiliary pressurizer spray line. The system can perform its function assuming a single active failure. A detailed description of this system and its associated controls is presented in FSAR Subsection 9.3.4.2.3.9.

5. The chemical addition system provides the means to borate the RCS to the required shutdown levels during normal plant cooldown. Using this method, boron is added to the RCS while simultaneously creating volume for this addition through primary letdown. Neither the chemical addition nor the letdown systems are qualified to operate after a design basis earthquake and therefore may not be available after this postulated event. Under these circumstances, coincident with a stuck rod, boration to the cold shutdown concentration can be achieved through use of the emergency boration system (EBS). This system stores 6 weight percent boric acid which can be injected into the RCS by the HPI/makeup pumps. If necessary, the operator can add the contents of this system through pump and valve manipulations from the control room after initial manual system alignment. The concentration and storage volume of the EBS, coupled with available excess volume in the pressurizer, ensures that the necessary boric acid required to maintain hot shutdown and achieve cold shutdown concentrations can be injected into the RCS without letdown. 30

   The EBS is a safety grade system capable of performing its design function assuming a single active failure. A detailed description of this system is provided in FSAR Subsection 9.3.10.

6. DHR pressure relief capacity is described in FSAR Subsection 5.4.7.1.1.3. The discharge fluid is directed to the reactor building sump. A further description of 14

relief valve design is contained in the revised FSAR 14
Table 5.4-10.

7. A natural circulation cooldown test will be referenced
if it has been conducted on a plant similar to Midland. 18
If such a test is not available, a test will be
conducted to verify that operation of the POAV valves 30
under natural circulation will satisfactorily remove
heat required to cool down the plant. This test will
demonstrate the ability to cool down approximately 50F 18
under natural circulation conditions and compare the
temperature versus time plot developed with an
analytical plot derived for the entire cooldown process. 30
The test will therefore be used to verify the analytical
results.

8. Operating procedures for natural circulation cooldown 18
will be written and made available to the operators
before initial criticality.

9. As detailed in our response to Question 010.34 and 14
revised Subsection 10.4.9.2.3, an adequate seismic 30
Category I feedwater source is available.

032145

Bechtel Associates Professional Corporation

777 East Eisenhower Parkway
Ann Arbor, Michigan

Mail Address: P.O. Box 1000, Ann Arbor, Michigan 48106

June 4, 1981

BLC- 10938

Consumers Power Company
1945 West Parnall Road
Jackson, Michigan 49201

Attention: [redacted]
Licensing and
Safety Manager

Subject: Midland Plant Units 1 and 2
Consumers Power Company
Bechtel Job 7220
Cold Shutdown Design Review
Board

References: A) BLC-10766, L.H. Curtis
to T.J. Sullivan, 5/6/81
(Com 029370)
B) BLC-10900, L.H. Curtis
to T.J. Sullivan, 5/29/81
(Com 031454)

Action item dispositions (which are listed in Reference A) from the cold shutdown design review board meeting held April 28, 1981 are attached for your use.

The attachment to this letter clarifies the responses provided in Reference B by addressing the comments and concerns expressed by the design review board at its meeting on May 29, 1981. The attachment is a complete statement of the disposition of each action item and further use of Reference B is unnecessary.

Primary input to the attachment has been provided by Consumers Power Company, Babcock & Wilcox, and Bechtel as follows:

Action Item No.	Company
1a	Bechtel
1b	B&W
2	B&W
3	Consumers Power Company
4	Consumers Power Company
5	B&W
6a	Consumers Power Company
6b	Bechtel
7	Bechtel
8	B&W
9	Bechtel
10	Bechtel
11	Bechtel
12	Consumers Power Company

RECEIVED
JUN 06 1981
MIDLAND PROJECT
MANAGEMENT

Bechtel Associates Professional Corporation

032145

June 4, 1981
BLC-10938
Page 2

By copy of this letter, J.W. Cook, chairman of the cold shutdown design review board, is provided with the disposition of the action items.

Very truly yours,

for
L.H. Curtis
Project Engineer

DFL/RJB/jsn(LS)
6/1/1

Attachment: Cold Shutdown Design Review Board Action Item Dispositions

cc: R.C. Bauman w/a
J.W. Cook w/a
D.F. Judd w/a
D.B. Miller w/a

Written Response Requested: No

COLD SHUTDOWN DESIGN REVIEW BOARD

0321 45

Action Item 1a

Describe analysis of auxiliary spray line and connections to existing line. Address temperature, pressure, and number of cycles.

Disposition

The analysis of the auxiliary spray line is being incorporated in the plant stress analysis effort. As described below, the analysis considers the effect of using relatively cold, highpressure spray.

Nuclear Class I piping stress analysis of the auxiliary and normal pressurizer spray system uses data which envelop operating conditions. Four operating modes are considered for the purposes of the analysis and are defined below:

Mode 1: Normal Operation consists of a continuous low-flowrate spray through the bypass valve into the pressurizer from the reactor coolant pump (RCP) discharge. This mode enhances boron mixing in the pressurizer and maintains a constant temperature in the spray line.

Mode 2: Normal Operation - Reactor Coolant System (RCS) Pressure Control and Cooldown Depressurization consists of intermittent actuation of one normal pressurizer spray valve to reduce pressure in the RCS for the following conditions:

a) Normal pressure variations during power operation (2,160 to 2,210 psig)

b) Normal cooldown from power operation to decay heat removal (DHR) cut-in

Mode 3: Decay Heat Removal Cooldown Depressurization consists of intermittent actuation of the auxiliary pressurizer spray valves to reduce pressure in the RCS for normal cooldown from DHR cut-in to cold shutdown.

Mode 4: Emergency Cooldown - High-Pressure Injection (HPI) Depressurization consists of continuous low-flowrate spray into the pressurizer from the HPI system through the auxiliary pressurizer spray valves to reduce pressure in the RCS from power operation to DHR cut-in.

Figure 1 represents the normal and auxiliary spray piping system for Midland Unit 2. Unit 1 is typical. Table 1 describes the valve alignment and cyclic information for the four spray modes.

Figures 2, 3, 4, and 5 are schematic representations of the spray piping system as aligned for operation described in Modes 1, 2, 3, and 4, respectively.

Table 2 delineates the data used in the Nuclear Class I stress analysis, including temperatures, pressures, and flowrates. Node points listed in Table 2 are identified in Figures 2, 3, 4, and 5.

It should be noted that this input data to the analysis is judged to conservatively envelop design conditions transmitted by the NSSS vendor.

The auxiliary pressurizer spray line will be analyzed and supported to acceptable stress levels. The analysis performed, to date, indicates that the stress levels of the normal pressurizer spray lines are acceptable. Finalization of the analysis will be performed as part of the plant stress analysis. This analysis will incorporate information from B&W Functional Specification 1092, Revision 4, and results of the as-built stress walkdown, as appropriate.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 1b

Address low velocity effects of auxiliary spray in terms of the potential for asymmetric stresses caused by steam/water in the spray line. Also, address low velocity effect on spray effectiveness. Address cycle requirements for design of the auxiliary spray line in terms of spray nozzle and piping.

Disposition

The analysis that has been completed by B&W assumed a filled spray line and spray nozzle upstream of the spray head. The spray line piping arrangement will be evaluated to ensure that the lines will be kept full. This evaluation is scheduled to be completed by July 1, 1981. The loop trap between the nozzle and the spray head will remain full after initial filling. The actual stress analysis will be completed by September 1, 1981

Three scheduling dates are required for completion of this test:

a. If the lines are not full, determine whether it is a problem. This will be completed by August 15, 1981.

b. If there is a problem, define conditions for stress analyst by January 15, 1982.

c. Complete new stress analysis by September 15, 1982.

The cycle requirements and design fluid conditions are presented in B&W Functional Specification 1092, Revision 4.

An assessment will be made of low velocity on spray effectiveness. This assessment will be completed by August 15, 1981.

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 2

Provide basis for sizing of safety grade pressurizer heater bank capacity.

Disposition

The 126 kW capacity is sized to replace all pressurizer heat losses during a loss of offsite power with the pressurizer at the normal operating temperature of 650F. Experience and testing has shown that the actual pressurizer heat losses vary significantly, depending on how well the insulation is installed on the pressurizer. The actual heat losses tend to be greater than the calculated value, which is based on the specified pressurizer insulation requirements. For example, the calculated heat losses at Oconee are approximately 35 kW, whereas the actual losses were almost three times higher in one instance. Bechtel has imposed a requirement that insulation be supplied such that the heat flux from the pressurizer will be less than that specified by B&W BOP Criteria 36-1004527-01.

The B&W operating 177 FA plants generally have a 126 kW capacity bank which is continuously energized. This capacity has been demonstrated as being adequate to make up for pressurizer heat losses. Midland has redundant safety-grade pressurizer heater banks, each sized at 126 kW.

In the remote possibility that all insulation is lost from the pressurizer, the installed safety-grade heater capacity may not be adequate to control RCS pressure which will result in a more rapid cooldown. If the depressurization rate becomes excessive during cooldown, the high pressure injection is available as an ultimate backup to assure sufficient inventory to maintain a subcooled core.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 3

The interface of engineering design, including late modification, with the development of normal and emergency procedures will be referred to project management for resolution independent of the Design Review Board.

Disposition

During the Design Review Board Meeting on April 29, 1981, Consumers Power Company management committed to review the interface between engineering design and operating procedure development independent of the Design Review Board. Therefore, this item is considered closed.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 4

Review the manual actions associated with proceeding to cold shutdown utilizing safety grade equipment to determine cost benefit of automating. Emphasis should be on actions in dominant risk sequences.

Disposition

The consultant for the Midland plant PRA has been requested to analyze the manual actions associated with proceeding to cold shutdown to determine the impact on system unavailability. The letter to the consultant, PL&G, is attached. If system unavailability does not change by a significant factor on the assumption that the actions were performed from the control room, the manual actions outside the control room will be considered acceptable. Consideration of risk is implicit with this approach. A reply from the consultant should be received by September 1, 1981 (Consumers Power Company letter Serial 12206 dated May 14, 1981).

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 5

Describe the single loop NATURAL code analysis. State whether potential reverse flow in idle loop will be addressed. Provide schedule for completion.

Disposition

B&W is presently evaluating several options for a mathematical code to evaluate single loop, natural circulation cooldown. This analysis will include the potential for reverse flow in the idle loop. A description of the code can be provided by January 15, 1982. The scheduled completion date for the development of the code and for completion of the cooldown analyses is August 15, 1982.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 6a

Discuss boron mixing under natural circulation conditions with one or two loops. Address injection to idle loop and feasibility of boron mixing test.

Disposition

Natural circulation boron mixing will be addressed in the Natural Circulation Test Program discussed in Action Item No 12.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 6b

Address RCS sampling capability, access requirements, and provisions and requirements for safety grade sampling.

Disposition

a. Sampling Capability

A safety-grade emergency boration system provides the boration necessary to maintain hot standby. The Midland design has the capability to maintain hot standby for an extended period. During normal operation, boron concentration is monitored via samples drawn from the letdown line outside the reactor building, downstream of the letdown line isolation valves. These samples are monitored by either the nonsafety-grade boronometer or the nonsafety-grade reactor plant sampling system (RPSS) (grab sample). Additional boron sampling capability is provided through seismic piping connected to the pressurizer liquid space and the letdown line at the reactor coolant system (RCS) cold leg. The single active failure inside containment will permit sampling from one of these points. The seismic piping is downgraded to nonseismic tubing downstream of the second isolation valve outside the reactor building. Here the sample can be diverted to either the RPSS, described above, or the post-accident sampling system (PASS) which was installed in response to TMI Lessons Learned (NUREG-0578, Section 2.1.8a). The PASS is shielded to allow operators to draw a sample with the potentially high levels of activity in the reactor coolant after an accident and to draw a sample assuming a loss of offsite power. Operator action and/or repairs may be necessary outside containment after a single failure or a seismic event. Sampling lines for the RCS are to be provided from the decay heat removal system to PASS to provide boron sampling capability during cold shutdown conditions.

The sample line connection to the letdown line has not been located. The connection will be located as close as practical to the RCS cold leg. There will be no isolation valves in the letdown line between the cold leg and the sample line connection. Sample system operation will ensure that sufficient liquid is drawn to obtain a representative sample. Sample system design will provide for disposal of purge and sampling fluids.

b. Access Requirements and Provisions of Sampling System

032145 The PASS station area and the pathways to the panel area are accessible after an accident. NUREG-0578 dose guidelines specify that doses due to direct radiation while obtaining and analyzing post-accident samples must not exceed 3 rem to the whole body and 18.75 rem to the extremities. (The Midland design will provide reduced direct radiation doses of 1.75 rem to the whole body and 11 rem to the extremities.)

Provisions are made to transport the grab samples to the sample analysis area and offsite in lead sampling casks. The liquid sample panel area and the onsite analysis laboratory area are provided with a hood type, nonsafety-grade ventilation system which exhausts through high-efficiency particulate air and charcoal filters to control airborne activity levels due to leakage.

c. Requirements for Safety-Grade Sampling

Standard Review Plan (SRP) Section 9.3, Process Sampling System, and Section 11.5, Process and Effluent Radiological Monitoring and Sampling Systems, require reactor coolant system (RCS) sampling provisions. NUREG-0737, II.B.5 requires RCS sampling capability after an accident but does not require a safety-grade sampling system. Nuclear Regulatory Commission Branch Technical Position RSB 5-1 does not specifically require safety-grade sampling. No regulatory requirements currently exist for safety-grade RCS sampling following an accident. Regulatory Guides 1.26 and 1.29 define the regulatory guidance for safety system classification. These regulatory guides do not require a safety-grade sampling system. Regulatory Guide 1.139, a draft which is presently in circulation for comment, requires a safety-grade sampling system. However, the requirements of Regulatory Guide 1.139 (Draft 2) do not apply to Midland design because of its draft status and because the guide stated applicability is only to plants whose construction permit docket dates are later than Midland's.

Regulatory Guide 1.139 Section C.2 states:

> A safety-related system should meet GDC 1-5, 26, and 27 and be capable of controlling and monitoring boron concentration in order to ensure reactor subcriticality from operating conditions through cold shutdown.

The following general design criteria (GDC) are applicable to the boron monitoring system:

GDC-1: Quality Standards and Records

GDC-2: Design Bases for Protection Against Natural Phenomena

GDC-3: Fire Protection

GDC-4: Environmental and Missile Design Bases

GDC-5: Sharing of Structures, Systems, and Components

The PASS design inside the containment meets these criteria. Pass design outside containment does not meet the above GDCs. The PASS does meet applicable existing regulatory requirements and guidance.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 7

State consideration of the need for periodic testing requirements of the EBS in the design.

Disposition

A technical specification will be developed for the emergency boration system as a part of the technical specification generation program which is currently in progress. The technical specification will require the following:

a. Monitor tank level to ensure the required volume of boric acid is maintained

b. Sample boric acid concentration to ensure specified concentration is maintained

c. Verify that the system heat tracing is functional

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 8

Evaluate the failure of a DHR dropline safety valve. Address probability of failure, its consequences, how the failure would be sensed and how it would be isolated.

Disposition

An analysis will be performed by B&W to determine the effects of the failure of the DHR dropline safety valve to reclose and will specifically address the following:

a. Consequences of valve not closing

b. How the failure to close would be sensed

c. How the open valve would be isolated

The analysis is scheduled for completion by August 1, 1981.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 9

Evaluate discharges to reactor building sump addressing possible vortex formation.

Disposition

The discharges to the sump fall in two categories: 1) discharges inside the trash racks and 2) discharges outside the trash racks. The Midland design for vortex prevention includes a trash rack, which provides flow straightening, and a grating cage surrounding the recirculation suction lines. No discharge lines penetrate the grating cage.

The only discharge to the area inside the trash rack is from the decay heat removal relief valve. It is not feasible to discharge from these valves to the sump when in the recirculation mode because the flowpath that includes this relief valve is isolated during the recirculation mode.

The dump-to-sump line discharges outside the trash rack. The trash rack and grating cage effectively prevent vortex formation as verified by the sump model test report by Western Canada Hydraulic Laboratories Ltd. The model test was discussed in response to NRC Question 211.189 (attached), regarding vortex prevention in the sump and the adequacy of the sump model test.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 10

Demonstrate acceptability of manual actions in view of regulatory requirements. (The general concern for the development of plant operations procedures is to be addressed as part of Item 3.)

Disposition

In the April 29, 1981, cold shutdown presentation to the Midland Design Review Board, J. Mazetis defined the NRC position regarding manual actions outside the control room for achieving cold shutdown. This included definition of the following types of manual action:

a. Those required for normal shutdown

b. Those required for emergency shutdown

c. Those required for recovery from a single failure

J. Mazetis further stated that the NRC policy for implementation of Branch Technical Position (BTP) RSB 5-1 is that no credit could be taken for Categories a and b above, and that credit for Category c actions was "a negotiated item."

This policy summarizes the requirements for full compliance with BTP RSB 5-1. However, for the purpose of implementation, this BTP divides plants into three classes. Class 2 plants are defined as "all plants (custom or standard) for which CP or PDA applications are docketed before January 1, 1978 and for which an OL issuance is expected on or after January 1, 1979," and thus include the Midland plant. For such plants, only partial implementation is required. Recommended implementation for Class 2 plants is addressed in Table 1 of the BTP RSB 5-1, which allows local manual actions in cases other than recovery from a single failure if such manual actions are found to be acceptable.

The Midland design requires local manual alignment for portions of three processes within the scope of BTP RSB 5-1: 1) boration [using the makeup and purification system, emergency boration system (EBS), and borated water storage tank or boric acid addition tanks (BAAT)], 2) depressurization (using the auxiliary pressurizer spray), and 3) long-term cooling (using the decay heat removal drop line). As discussed below, these manual actions are performed in accessible areas and within acceptable time frames.

Table 1 of BTP RSB 5-1 does not give any specific system design as a possible solution for full compliance regarding boration. Instead, the BTP requires that boration be performed using only safety-grade systems which can operate with either onsite or offsite power and with a single failure. Boration without letdown is mentioned as an acceptable example of such safety-grade boration. The BTP also requires monitoring the boron concentration. For full compliance, "limited operator action inside or outside containment if justified" is allowed.

The recommended implementation for Class 2 plants states:

> Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure or b) remaining at hot standby until manual actions or repairs are complete are found to be acceptable for the individual plant.

The Midland design provides a safety-grade EBS which can provide sufficient boration for hot standby with onsite or offsite power. Local manual actions are required to align the EBS and for reactor coolant system sampling. These actions are performed in the auxiliary building. The earliest manual action outside the control room is alignment of the EBS. For the scenario requiring the earliest EBS injection, this alignment is required approximately 2 hours after a reactor trip. Thus, relying on operator actions is justified in terms of access and time available, as allowed by the BTP for full compliance. Use of the EBS is required only in the event of a reactor trip with a stuck control rod. In addition, local manual actions are required to align the borated water storage tank or (after a design basis tornado) the BAAT for borated water injection. These actions are long-term and are performed in the auxiliary building. The Midland design exceeds the recommended implementation for Class 2 plants, which allows for nonsafety-grade boration with manual actions in containment.

Table 1 of the BTP provides the following possible solution for full compliance regarding depressurization:

> Provide upgrading and additional valves to ensure operation of auxiliary pressurizer spray using only safety-grade subsystem meeting single failure. Possible alternative may involve using pressurizer power-operated relief valves which have been upgraded. Meet SSE and single failure without manual operation within containment.

The recommended implementation for Class 2 plants states:

> Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure or b) remaining at hot standby until manual actions or repairs are complete are found to be acceptable for the individual plant.

The Midland design provides a safety-grade auxiliary pressurizer spray which requires local manual alignment. This alignment is not required until after EBS injection, thus giving the operator sufficient time to take action. The manual action for the alignment is performed in the auxiliary building. The auxiliary pressurizer spray is required only in the event of a loss of offsite power resulting in the loss of all reactor coolant flow. The Midland design meets the proposed solution for full compliance and exceeds the recommended implementation for Class 2 plants, which could be a nonsafety-grade auxiliary pressurizer spray with manual actions in containment.

For long-term cooling, BTP RSB 5-1 provides the following possible solution for full compliance:

> Provide double drop line (or valves in parallel) to prevent single valve failure from stopping RHR cooling function.

The recommended implementation for Class 2 plants states:

> Compliance will not be required if it can be shown that correction for single failure by manual actions inside or outside of containment or return to hot standby until manual actions (or repairs) are found to be acceptable for the individual plant.

The Midland design provides a single decay heat removal (DHR) drop line which divides into two for a series/parallel motor-operated valve arrangement in containment and then converges to a single line to exit containment. Local manual actions in the auxiliary building are required for alignment. Because the plant can be maintained indefinitely at hot standby, sufficient time is available for the operator to perform these actions. Manual actions are not required outside the control room to recover from single active failures that could stop decay heat removal cooling. The Midland design meets or exceeds the recommended implementation for Class 2 plants, which allows for the possibility of a single drop line inside containment as well as outside.

Thus all of the local manual actions which the Midland design requires for cold shutdown are justified under the recommended implementation of BTP RSB 5-1 provided for plants of Midland's category. To require, in spite of this, that no manual actions be taken outside the control room except in case of a single failure would require major design changes. This was not the intent of the BTP, which specifically states in Note 1 to Table 1,

> The implementation for Class 2 plants does not result in a major impact while providing additional capability to go to cold shutdown.

Therefore, interpretation of BTP RSB 5-1 to mean that local manual actions to achieve and maintain cold shutdown are only allowable after a single failure is not justifiable for Midland.

The existing design uses an appropriate and acceptable combination of local and control room controls that have been, and will continue to be, communicated with Consumers Power Company to provide the opportunity for review by the plant operators to determine proper operating procedures.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 11

Investigate the concern for intersystem check valve leakage testing as described in the forthcoming NRC letter.

Disposition

The leakage concern expressed in the referenced NRC letter was the subject of NRC Question 110.58 (attached). A complete response to this question was supplied in FSAR Revision 33.

032145

COLD SHUTDOWN DESIGN REVIEW BOARD

Action Item 12

Evaluate natural circulation cooldown testing with respect to demonstrating cooldown capability and operating training.

Disposition

A natural circulation cooldown test will be performed which is consistent with the guidance contained in the NRC letter from R.L. Tedesco to J.W. Cook, dated April 22, 1981, and the recent Natural Circulation Test Programs at new license facilities. This NRC letter informed OL applicants of a future requirement for such testing and associated training. The site agrees with the objectives of natural circulation testing and has scheduled time for its performance. The scope of the Natural Circulation Test Program will be documented in Chapter 14 of the FSAR.

032145

Question 211.189 (6.3) 18

During our meeting of January 16, 1979, you described proposed full-scale hydraulic model studies which are planned to assess vortex formation and to determine the trash rack and intake losses for the Midland ECCS intakes (i.e., containment sump) following a LOCA. 19 We have further reviewed related FSAR information and the proposed testing program as to its ability to sufficiently address our concerns and to determine our need for additional information:

1. We note that your proposal does not model the containment structures outside the trash racks and the resultant far field effects. You imply that the trash racks will suppress any vortex generated in the far field and that this effectiveness has been documented for other plants. We are concerned that certain vortices could be formed in the far field particular to the Midland configuration which could penetrate the trash rack. Provide data/justification to show the following: 18

   A. Far field vortex formation is unlikely for the Midland containment configuration considering the low velocities that would exist.

   B. The trash racks would eliminate all vortices produced in the far field which could approach the trash rack at various angles.

2. Provide justification for proposing all tests at the minimum water level since more severe vortices have been known to form at other levels.

3. Discuss more thoroughly the instrumentation and methods used to measure and calculate the sump and intake structure pressure losses during the tests. Address the accuracy and calibration of these instruments.

4. Provide your proposal for the in-plant test which will be 19 used to establish as-built piping losses in the Midland ECCS. Discuss how these tests will be used to confirm that the FSAR npsh calculation is conservative considering the difference between the test conditions (temperature, flows, flow paths, etc) and the worst case pumping modes following a LOCA.

5. Provide the details of your FSAR npsh calculations for which your results are provided in FSAR Table 6.3-10. These calculations should be provided for the high- and low-pressure injection pumps, including the head loss calculated for each section of pipe and the associated L/D, K factors, velocities, Reynolds numbers, etc.

032145

6. Provide an additional test or test data to justify testing for vortex formation at prototype Reynolds number. 19

Response

A series of tests has been performed by Western Canada Hydraulic Laboratories Ltd to evaluate the performance capability of the Midland sump design. A full scale sump model was built and tested to verify vortex control and to determine the head loss associated with the trash rack, grating cage, and inlet piping. 30 Results of the test program have been submitted under separate cover in a letter, dated June 26, 1980, from J.W. Cook to A. Schwencer.

1. Circulation which is essential for vortex formation may be developed in the approaches to the trash rack by two mechanisms:

   A. Eddy shedding from structural members

   B. Configuration of the plant geometry

   The strength of eddy shedding is a function of the velocity past the member which sheds the eddies. Tests were conducted on a full scale model of the J.M. Farley Nuclear Plant Unit 1 in which all structural members, valves, restraints, stairs, etc in the far field were modeled. The approach velocities past these members ranged from 0.02 to 0.5 fps for water depths above the containment floor ranging from 4.8 to 7.4 feet. Eddy shedding was very weak, resulting in only a minor dimpling of the water surface in the eye of the eddy. 18 The maximum postulated approach velocity past far field components in the Midland containment is 0.5 fps.

   Further documentation of the weakness of eddy shedding in approach velocities of 0.5 fps or less was obtained during tests for the San Onofre generating station. Structural members placed in a 2 foot side flume were subjected to approach flow velocities up to 0.5 fps. Eddy shedding was very weak. An additional test was conducted by placing a 1 foot by 1 foot column in the flume such that the maximum velocity past the column was 1 fps. Even with this condition, the eddies shed produced only a dimpling of the surface amidst the general turbulence produced by the member. Other tests were made by placing 2-1/4 inch by 3/16 inch grating bars on 1-3/16 inch centers in the flume at angles up to 60 degrees to the direction of the approach flow. These tests documented that:

   A. The circulation generated by eddies shed from structural members with flow velocities passing them up to 1 fps was completely eliminated by the grating. Even air core

032145

vortexes forced on the upstream side of the grating by a moving paddle were completely eliminated as the flow passed through the grating.

B. Flow exited from the downstream side of the grating in alignment with the grating bars irrespective of approach angle. The grating bars acted as flow straightening vanes.

The trash rack for the Midland recirculation sump will be
2-1/4 inch by 3/16 inch bars on 1-3/16 inch centers. Because
the maximum approach velocity past far field components in 18
the Midland plant will be approximately 0.5 fps at a water
depth of 3.75 feet, eddy shedding will be weak and
circulation associated with these eddies will be totally
removed by the trash rack, irrespective of the approach
angle.

Circulation generated by the plant configuration will be removed by the trash rack. Because circulation is an essential feature of a vortex, no vortex will penetrate the trash rack from the far field.

The effectiveness of the Midland trash rack in eliminating 23
far field vortex formation has been demonstrated by actual 30
induced vortex testing as part of the sump model testing 23
program.

2. The severity of a vortex is primarily a function of the
strength of circulation, the depth of submergence of the 19
intake, and the discharge. Application of the approach given
by Dagget and Keulegan[1] shows that the Reynolds number for
the Midland intake for a discharge of 6,000 gpm and a water
temperature of 227F is 2.4×10^6. 32

For a given discharge, the severity of a vortex will be
reduced with an increased depth of submergence unless the
strength of circulation in the approach flow is increased to
offset the effect of the greater submergence. Situations
where vortexes have been more severe at increased depths of
water have resulted due to change in the planform of the 19
geometry at higher water levels which in turn led to a
stronger circulation.

There is no significant change in planform in the vicinity of the Midland recirculation sump over the 5.55 feet between minimum and maximum postulated water levels (reference FSAR Figures 6.2-58 and 6.2-58A). Because there will be a decrease in the strength of circulation at the higher water levels due to the reduction in approach velocities, there will also be a decrease in vortex potential.

032145

Without any change in planform, the lowest submergence depth
represents the severest potential for vortex formation.
Furthermore, the lowest water depth produces the lowest 19
ambient pressures in the sump and the greatest potential for
the formation of vapor cores associated with vortexes
generated within the trash rack.

3. Trash rack screen losses and intake losses have been 30
determined by measuring the piezometric pressures at the
following locations:

   A. At four points outside of and around the trash rack with 19
   the four piezometer taps interconnected.

   B. At four points within the sump, but outside of the
   grating cage, with the four piezometer taps
   interconnected. These were located near corners where 30
   velocity heads will be negligible. 19

   C. At six points on the intake pipe, 5.23, 8.23, 10.74, 30
   13.24, 15.75, and 18.26 pipe diameters downstream of the
   intake, with each point consisting of two interconnected 19
   piezometer taps.

   The piezometer taps were connected to a bank of water
   manometers. The manometer scales were graduated in 30
   1 foot increments and were readable to less than
   ±0.003 foot. 19

   The trash rack screen loss was determined by subtracting 30
   the piezometric level in the sump from the piezometric
   level outside of the sump plus the approach velocity 19
   head.

   The intake loss was determined by subtracting the 30
   piezometric level measured 18.0 diameters downstream of
   the intake plus the velocity head plus the friction loss 19
   from the piezometric level measured within the sump.

   Discharges were measured through standard orifice plates 30
   with a probable accuracy of ±1%. Differential
   piezometric levels will be measured by water manometers 19
   with a reading accuracy of ±0.003 foot.

4. Refer to the Appendix 3A response to Regulatory Guide 1.79
for a discussion of the in-plant test. 30

5. FSAR Subsection 6.3.2.2.4.1 has been added in response to 20
this question. 26
19

6. Tests were conducted at the prototype Reynolds number for two 30
reasons: 19

A. To develop intake loss coefficients at the correct prototype Reynolds number 32

B. To provide conservatism in the tests to document vortex control

With respect to vortex control, Dagget and Keulegan[1] have shown that above an intake Reynolds number of 5×10^4 the vortex severity is a function of circulation number. Because the 19
discharge will be augmented above prototype flowrates to achieve prototype Reynolds numbers, the strength of circulation and, hence, potential severity of vortex formations will be increased. Such testing thus provides considerable conservatism.

---

[1] Dagget, L.C. and Keulegan, G.H., "Similitude Conditions in Free Surface Vortex Formations," Journal of Hydraulics Division, ASCE, Volume 100, Number HY11, November 1974, pp 1565-1581.

032145

Question 110.58 (3.9.6)

There are several safety systems connected to the reactor coolant system pressure boundary that have design pressures below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suction below RCS pressure. In order to protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high pressure RCS and the low pressure systems. The leak tight integrity of these valves must be ensured by periodic leak testing to prevent exceeding the design pressure of the low pressure systems thus causing an inter-system LOCA.

Provide a list of all pressure isolation valves included in your testing program. Also discuss in detail how your leak testing program will conform to the following staff position:

> It is our position that pressure isolation valves be classified as Category A or AC per IWV-2000 and that they meet the appropriate requirements of IWV-3420 of Section XI of the ASME Code except as discussed below. 32
>
> Limiting Conditions for Operation (LCO) are required to be added to the technical specifications which will require corrective action, i.e., shutdown or system isolation when the final approved leakage limits are not met. Also surveillance requirements, which will state the acceptable leak rate testing frequency, shall be provided in the technical specifications.
>
> Periodic leak testing of each pressure isolation valve is required to be performed at least once each refueling outage, after valve maintenance prior to return to service, and for systems rated at less than 50% of RCS design pressure each time the valve has moved from its fully closed position unless justification is given. The testing interval should average to be approximately one year. Leak testing should also be performed after all disturbances to the valves are complete, prior to reaching power operation following a refueling outage, maintenance and etc.
>
> The staff's present position for the LCO regarding leak rate is that the leak rate must not exceed 1 gallon per minute for each valve.[1] This leak rate is established to ensure the integrity of the valve, demonstrate the adequacy of the redundant pressure isolation function and give an indication of valve degradation over a finite period of time. Significant increases over this limiting value would be an indication of valve degradation from one test to another.

032145

The Class 1 to Class 2 boundary shall be considered the isolation point which must be protected by redundant isolation valves.

In cases where pressure isolation is provided by two valves, both shall be independently leak tested. When three or more valves provide isolation, only two of the valves need be leak tested. 32

[1] Leak rates higher than 1 gpm will be considered by the NRC if the leak rate changes are below 1 gpm above the previous test leak rate or system design precludes measuring 1 gpm with sufficient accuracy. These items will be reviewed by the NRC staff on a case-by-case basis.

Response

The following pressure isolation valves are included in the Midland valve testing program and classified as Category A or AC.

System	P&ID M-	Valve Number	IWV-200 Category
Pressurizer spray	401A	005	AC
Pressurizer spray	401A	075	AC
Pressurizer spray	402A	032	AC
Pressurizer spray	402A	075	AC
Makeup purification	403 Sh 2B	001	AC
Makeup purification	403 Sh 2B	003[1]	A
Makeup purification	403 Sh 2B	004	AC
Makeup purification	403 Sh 2B	006[1]	A
Makeup purification	403 Sh 2B	028[1]	A
Makeup purification	403 Sh 2B	029[1]	A
Makeup purification	403 Sh 2B	030[1]	A
Makeup purification	403 Sh 2B	031[1]	A
Makeup purification	403 Sh 2B	049[1]	A
Makeup purification	403 Sh 2B	051[1]	A
Makeup purification	403 Sh 2B	123	A
Makeup purification	403 Sh 2B	128	A
Makeup purification	403 Sh 2B	130[1]	A
Makeup purification	403 Sh 2B	162	AC
Makeup purification	403 Sh 2B	163	AC
Makeup purification	403 Sh 2B	164	AC
Makeup purification	403 Sh 2B	165	AC
Makeup purification	404 Sh 2B	001	AC
Makeup purification	404 Sh 2B	003[1]	A
Makeup purification	404 Sh 2B	004	AC
Makeup purification	404 Sh 2B	006[1]	A
Makeup purification	404 Sh 2B	028[1]	A
Makeup purification	404 Sh 2B	029[1]	A
Makeup purification	404 Sh 2B	030[1]	A
Makeup purification	404 Sh 2B	031[1]	A

33

Makeup purification	404 Sh 2B	049[1]	A
Makeup purification	404 Sh 2B	051[1]	A
Makeup purification	404 Sh 2B	123	AC
Makeup purification	404 Sh 2B	128	AC
Makeup purification	404 Sh 2B	130[1]	A
Makeup purification	404 Sh 2B	162	AC
Makeup purification	404 Sh 2B	163	AC
Makeup purification	404 Sh 2B	164	AC
Makeup purification	404 Sh 2B	165	AC
Decay heat removal	410	045	A
Decay heat removal	410	046	A
Decay heat removal	410	048	AC
Decay heat removal	410	049	AC
Decay heat removal	410	050	AC
Decay heat removal	410	051	AC
Decay heat removal	410	052	AC
Decay heat removal	410	053	AC
Decay heat removal	410	093	A
Decay heat removal	410	094	A
Decay heat removal	411	046	A
Decay heat removal	411	048	A
Decay heat removal	411	050	AC
Decay heat removal	411	051	AC
Decay heat removal	411	052	AC
Decay heat removal	411	053	AC
Decay heat removal	411	054	AC
Decay heat removal	411	055	AC
Decay heat removal	411	093	A
Decay heat removal	411	094	A

33

[1]These valves are not at the Class 1 to 2 boundary; however, they satisfy the concern of protecting low-pressure system piping.

The valves in the makeup and purification systems will be tested using the appropriate pressurization points and drains each refueling to meet the requirements of IWV-3420 of Section XI of the ASME Code.

Decay heat removal check valves 049 and 052 (P&ID M-410) and 050 and 053 (P&ID M-411) will be tested each disturbance using core flood tank pressure. Upstream observation of leakage will be measured through an appropriate vent or drain, and extrapolated to RCS pressure for comparison with the 1 gpm leak rate.

Decay heat removal check valves 050 and 051 (P&ID M-410) and 052 and 054 (P&ID M-411) will be tested each disturbance using RCS pressure and the leakage measured using the appropriate upstream vent for a leakage not to exceed 1 gpm.

Decay heat removal check valves 048 and 053 (P&ID M-410) and 050 and 053 (P&ID M-411) will be tested each disturbance using the discharge pressure of the decay heat removal pump to seat the

valves and the leakage will be measured using an upstream vent and the leak rate extrapolated to RCS pressure for comparison with the 1 gpm leak rate.

Decay heat removal valves 045, 046, 093, and 094 (P&ID M-420) and 046, 048, 093, and 094 (P&ID M-411) will be tested each disturbance using RCS pressure and the leakage measured using the appropriate downstream vent for a leak rate below 1 gpm.

Auxiliary pressurizer spray line check valves 075 (P&ID M-401A) and 075 (P&ID M-402A) will be tested each disturbance using RCS pressure and the leakage measured using the appropriate upstream vent for a leak rate not to exceed 1 gpm. 33

Auxiliary pressurizer spray line check valves 005 (P&ID M-401A) and 032 (P&ID M-402A) will be tested using the appropriate pressurization points and drains at RCS design pressure for a leak rate of less than 1 gpm.

Technical specifications for these valves will be included by amendment.

Consumers Power Company

030896

Terence J :
Manager, N. ... Licensing
Midland Pr.

General Offices: 1945 West Parnall Road, Jackson, Michigan 49201 • (517) 788-2972

May 14, 1981

JPK 28-81

Mr H F Perla
Pickard, Lowe and Garrick Inc
17840 Skypark Boulevard
Irvine, CA 92714

MIDLAND PROJECT -
COLD SHUTDOWN RISK CONTRIBUTION
FILE 0929.2 UFI 02352(S) SERIAL 12206

During the April 29, 1981 meeting of the Design Review Board on cold shutdown capability with safety grade equipment, an item was discussed concerning manual actions outside the control room. Valves must be positioned manually at different times during the cold shutdown procedure; based on the availability of equipment and plant conditions.

As part of the ongoing probabilistic risk assessment of the Midland Plant, Pickard, Lowe and Garrick, Inc is requested to evaluate the manual actions outside the control room required for cold shutdown in the context of their impact on risk. Initially, the following questions should be answered:

1. What is the contribution to system unavailability of the following manual actions outside the control room which may be required to achieve cold shutdown?

   a. Selection and alignment of alternate borated water sources (BAAT, EBT)
   b. Alignment of the auxiliary pressurizer spray
   c. Alignment of the Decay Heat Removal System

2. How would system availability improve if these actions could be performed from the control room?

These questions were selected to permit utilization of the system failure analysis due to be completed in the near future with little, if any, special effort required. The impact of these manual actions outside the control room on overall risk will be addressed at a later date if this inquiry indicates that meaningful improvement in system availability may be possible by performing these manual actions from the control room.

oc0581-0345a102

Please feel free to criticize this approach and propose a suitable al :native if necessary. A reply is requested as soon as the required informat: : has been developed.

John P Kindinger

John P Kindinger

For Louis S Gibson
Section Head
Nuclear Safety and Analysis Section

CC DFJudd, B&W
DFLewis, Bechtel
DBMiller, Midland
JRWebb, P-24-505

030896

oc0581-0345a102

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

032145

APR 22 1981

cket Nos.: 50-329/330

Mr. J. W. Cook
Vice President
Consumers Power Company
1945 West Parnall Road
Jackson, Michigan 49201

Dear Mr. Cook:

SUBJECT: TMI-2 TASK ACTION PLAN ITEM I.G.1 - SPECIAL LOW POWER TESTING

NUREG-0694 "TMI Related Requirements for New Operating Licenses", Item I.G.1, requires applicants to perform "a special low power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training". To comply with this requirement new PWR applicants have committed to a series of natural circulation tests. To date such tests have been performed at the Sequoyah 1, North Anna 2, and Salem 2 facilities. Based on the success of the programs at these plants, the staff has concluded that augmented natural circulation training should be performed for all future PWR operating licenses. This is to be implemented by including descriptions of natural circulation tests in your FSAR (Chapter 14 - Init ... Test Program). If they are not already included in your FSAR, the natural circulation tests and associated training should be included, either by modifying existing or adding new test descriptions in accordance with Regulatory Guide 1.70 (Paragraph 14.2.12). The tests should fulfill the following objectives:

Training

Each licensed reactor operator (RO or SRO who performs RO or SRO duties, respectively) should participate in the initiation, maintenance and recovery from natural circulation mode. Operators should be able to recognize when natural circulation has stabilized, and should be able to control saturation margin, RCS pressure, and heat removal rate without exceeding specified operating limits.

Testing

The tests should demonstrate the following plant characteristics: length of time required to stabilize natural circulation, core flow distribution, ability to establish and maintain natural circulation with or without onsite and offsite power, the ability to uniformly borate and cool down to hot shutdown conditions using natural circulation, and subcooling monitor performance.

APR 22 1981

0321 45

If these tests have been performed at a comparable prototype plant, they need be repeated only to the extent necessary to accomplish the above training objectives.

Procedure Validation

The tests should make maximum practical use of written plant procedures to validate the completeness and accuracy of the procedures.

The natural circulation tests require a source of actual or simulated decay heat. The tests may be perfromed during initial startup using nuclear heat to simulate decay heat, or may be performed later in the initial fuel cycle when actual decay heat is adequate to permit meaningful testing. If the test objectives are not compromised, pump heat during forced circulation operation could provide an acceptable source of simulated decay heat (e.g., the Loss-of-Onsite and Offsite A/C Test perfromed at North Anna 2).

Applicants who perform a natural circulation boron-mixing and cooldown test to demonstrate compliance with Branch Technical Position RSB BTP 5-1 may use that test to accomplish some or all of the above training and testing objectives.

This guidance is provided for all new PWR OL applicants. Regulatory Guide 1.68 and/or the Standard Review Plan will be revised at a future date to include natural circulation testing and the associated training. OL applicants should submit test descriptions in accordance with Regulatory Guide 1.70 Paragraph 14.2.12 as part of their FSAR or an amendment thereto. Detailed test procedures should be made available for NRC review 60 days prior to scheduled test performance (see Regulatory Guide 1.68 Appendix B). When required by 10 CFR 50.59, a safety analysis must be prepared and distributed in accordance with the requirements stated therein.

Sincerely,

R Tedesco

Robert L. Tedesco, Assistant Director
for Licensing
Division of Licensing

POOR ORIGINAL

Mr. J. W. Cook
Vice President
Consumers Power Company
1945 West Parnall Road
Jackson, Michigan 49201

032145

cc: Michael I. Miller, Esq.
Ronald G. Zamarin, Esq.
Alan S. Farnell, Esq.
Isham, Lincoln & Beale
Suite 4200
1 First National Plaza
Chicago, Illinois 60603

James E. Brunner, Esq.
Consumers Power Company
212 West Michigan Avenue
Jackson, Michigan 49201

Myron M. Cherry, Esq.
1 IBM Plaza
Chicago, Illinois 60611

Ms. Mary Sinclair
5711 Summerset Drive
Midland, Michigan 48640

Frank J. Kelley, Esq.
Attorney General
State of Michigan Environmental
Protection Division
720 Law Building
Lansing, Michigan 48913

Mr. Wendell Marshall
Route 10
Midland, Michigan 48640

Mr. Steve Gadler
2120 Carter Avenue
St. Paul, Minnesota 55108

Mr. Don van Farowe, Chief
Division of Radiological Health
Department of Public Health
P.O. Box 33035
Lansing, Michigan 48909

William J. Scanlon, Esq.
2034 Pauline Boulevard
Ann Arbor, Michigan 48103

U. S. Nuclear Regulatory Commission
Resident Inspectors Office
Route 7
Midland, Michigan 48640

Ms. Barbara Stamiris
5795 N. River
Freeland, Michigan 48623

POOR ORIGINAL