ORIGINAL

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of:

COMMISSION MEETING

Briefing on Davis Besse

(Public Meeting)

Docket No. 50-346

Location: Washington, D. C.
Date: Wednesday, July 24, 1985

Pages: 1 - 84

50-346

ANN RILEY & ASSOCIATES
Court Reporters
1625 I St., N.W.
Suite 921
Washington, D.C. 20006
(202) 293-3950

D I S C L A I M E R

This is an unofficial transcript of a meeting of the United States Nuclear Regulatory Commission held on Wednesday, July 24, 1985 in the Commission's office at 1717 H Street, N.W., Washington, D.C. The meeting was open to public attendance and observation. This transcript has not been reviewed, corrected, or edited, and it may contain inaccuracies.

The transcript is intended solely for general informational purposes. As provided by 10 CFR 9.103, it is not part of the formal or informal record of decision of the matters discussed. Expressions of opinion in this transcript do not necessarily reflect final determination or beliefs. No pleading or other paper may be filed with the Commission in any proceeding as the result of or addressed to any statement or argument contained herein, except as the Commission may authorize.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

- - -

BRIEFING ON DAVIS BESSE

- - -

PUBLIC MEETING

Room 1130

1717 H Street, N.W.

Washington, D.C.

Wednesday, July 24, 1985

The Commission met, pursuant to notice, at 1:35 p.m.

COMMISSIONERS PRESENT:

NUNZIO J. PALLADINO, Chairman of the Commission

THOMAS M. ROBERTS, Commissioner

FREDERICK M. BERNTHAL, Commissioner

JAMES K. ASSELSTINE, Commissioner

LANDO W. ZECH, JR., Commissioner

STAFF AND PRESENTERS SEATED AT COMMISSION TABLE:

S. CHILK	H. PLAINE
W. DIRCKS	E. ROSSI
J.T. BEARD	W. LANNING
L. BELL	J. HELTEMES

P R O C E E D I N G S

CHAIRMAN PALLADINO: Good afternoon, ladies and gentlemen. The purpose of today's meeting is for the Commission to receive a briefing by the NRC Staff on the event which took place on June 9, 1985 at the Davis Besse Nuclear Power Plant.

On that date, the Davis Besse plant experienced a complete loss of all feedwater which led to a turbine and a reactor trip. Subsequently, equipment malfunctions and operator errors resulted in the steam generator boiling dry before feedwater from any source could be restored. Nevertheless, operators were successful in bringing the the plant to a stable shutdown and in preventing any abnormal releases of radioactivity or apparent major damage to the plant.

On the day following the event and in conformance with the Staff's proposed incident investigation program, the NRC Executive Director for Operations, Mr. Dircks, sent a team of technical experts to the site. That team was composed of four Staff experts who, one, are to determine what happened; two, identify the probable cause or causes; and three, make appropriate findings and conclusions to form the basis for possible follow-on actions.

On July 22, the NRC Team forwarded its Davis Besse report and today will brief the Commission on its findings.

At this time, I would like to commend the EDO for taking the action necessary to accomplish this important investigation. In addition, I would like to express my appreciation to Mr. Rossi, the Task Force Team Leader, for directing the effort, as well as the other three Team members who spent many long hours necessary to produce the report that we have before us today.

This morning, we received the briefing slides for today's presentation and it appears that we could easily consume two hours on these slides alone. Therefore, I would like to suggest that we allow the Staff to make their presentation without interruption except for questions of understanding and to hold other questions until completion of the presentation.

Do any of my fellow Commissioners have other opening remarks?

COMMISSIONER ASSELSTINE: I might make just a couple of comments, Joe. I would agree with the comments you made about the appreciation to the Team, and we have only had the report for about a day but at least from everything that I have read so far, it looks like they did a very good job. The report is clear, it's understandable and pitched to my level. It was great.

[Laughter.]

And I found it very useful. It looked to me like a

very good job, and I'm looking forward to hearing some of the further discussion on it.

I have to say, though, -- and I don't want to take anything away from the Team or its report -- that I think that the focus on the events that occurred, their root causes, while it was appropriate for this Team, doesn't answer all the questions that I think we have to answer related to the Davis Besse event on June 9th.

And it does seem to me that there are at least three broader questions that we need to look at and I would emphasize not from the standpoint of finding fault or attributing blame within our own organization, but from the standpoint of learning from the past and assuring that our own programs are truly effective in preventing this kind of an event from occurring in the future.

And I would suggest, although it doesn't have to be discussed at this meeting, that we consider a further review to look at the adequacy of our own program in insuring the upgrading and reliability of the auxiliary feedwater systems. It's quite apparent to me from some of the documents that we've already provided to the Congress that there was fairly extensive consideration of that issue within the agency, and I think we really need to get to the bottom of how well we did in assuring a reliable auxiliary feedwater system at this plant and, for that matter, at the other Babcock & Wilcox

plants.

And I think that goes to how well we have done in both setting the post-TMI requirements and in assuring that they are properly implemented.

Second, I think we need to look at the adequacy of our inspection and enforcement program. It's quite clear to me and to, I think, most people that we knew that there were deep-rooted problems at this plant for quite a while, and yet, we didn't seem to be able to bring about the changes that need to be brought about to prevent this kind of event from occurring.

I also find it interesting that this particular plant seems to have had a better than average history in terms of violations, and that leads me to wonder whether we are looking at the right things; whether we're really focusing on all of the right problems. I think that's another area that we need to look at and do a fairly critical self-evaluation of how well we have done.

And the third area I think is the vulnerabilities of the Babcock & Wilcox plants in general and how well we have done in making our previous judgments on the acceptability of those plants.

I also think that the same kind of approach that we took here in having an independent group that is not in any way involved with those previous decisions, having that kind

of a review is the approach we ought to take in looking at those three issues.

I realize that goes beyond the context of this particular meeting, but I think until we answer those questions we really haven't finished the job on understanding the implications of the June 9th Davis Besse event.

One last comment, and I don't want to make a big issue of this but I have to say I know we have received a request from one of the local members of Congress to address the Commission briefly at this meeting, and I realize the majority of the Commission has decided not to allow her to speak to the Commission.

For myself, I have to say I think that was a big mistake. I went up with the Staff to appear before Mr. Markey's subcommittee, and I have to say that while I think that the members of the Staff who made the presentations there did a good job, we did not do a very good job of explaining the adequacy of our past performance and our understanding of the problems that came to light by the June 9th event.

I think we've got a long way to go in convincing those people that we really are doing a good job, and I think that the way to do that is to open up communications and not to close them off.

CHAIRMAN PALLADINO: Thank you for your comments. I

think, speaking for the majority, we felt this was a factfinding session, and it was appropriate to stick primarily to the factfinding.

COMMISSIONER BERNTHAL: I guess I should say that I agree with Jim on I'm sure more than that element of what he said, but at least I agree that we ought to take five minutes to listen to a member of Congress in this circumstance, and I would have done so as well.

CHAIRMAN PALLADINO: Well, let me repeat again that we do listen to people from Congress and we do have them appear at meetings where other issues and factfinding are involved.

Any other comments?

COMMISSIONER ZECH: Well, I would just like to agree with the Chairman. We haven't had ourselves a factfinding briefing until today from the Staff on what happened. It seems to me that's the purpose of this meeting, and certainly we're willing to listen to members of Congress at any time. But today is our time to be briefed on the facts, and I think it's important that we do that without any other sessions going on.

So to me, it's important that we get the facts first so that we can speak with some kind of confidence in this area.

CHAIRMAN PALLADINO: Any other comments?

[No response.]

All right, then. Let me turn the meeting over to Mr. Dircks.

MR. DIRCKS: I was just going to say a few words to again emphasize the purpose of this mission today. First of all, I do want to say that in addition to the Team at the site, Jack Heltemes back at Headquarters was the chief production man here, so he deserves a good deal of credit, too for keeping the thing moving.

But I want to emphasize a couple other points. The Team's activities were conducted in accordance with the concepts and principles we laid down in the SECY 85-208 that we sent to you on the Incident Investigation Program. We wanted to give that a practical run, and this incident did serve to highlight the usefulness of the concept.

You did mention the three purposes of the Team, and that's to describe as factually as possible what happened at that incident on June 9th. We're going into probable causes, and the Team will make appropriate findings and conclusions.

While the study was to identify and understand the implications, consequences and significance of the event, the Team was not to and did not identify and analyze all the "what if" questions of this event. We wanted to just keep attention focused on the event and not get into the "what if" questions.

The Team was also not to get into the issues of, or

review the design or regulatory base of the plant, and it was not to determine possible violations of NRC requirements. I think these are other issues, and we wanted to keep the Team's attention focused, again, on the factfinding mission.

The Team's report will be now reviewed for items requiring attention, actio or close-out. I am going to ask the office directors and Jack Heltemes to work with me to make out specific assignments to specific offices for follow-up action, and we will be getting on with that activity next week.

The Team has one more important function, Ernie, before you disappear, and that is we want the Team to review the process that we have used in this event, in this factfinding event. We want the Team to identify what worked well, what were the problems, where is guidance needed. We want them to comment on the Team's composition, resources, the time that we made available to it, what additional support is needed and so on.

I hope the Team will spend Thursday and Friday identifying some lessons learned, just from the process that we followed in this matter.

The advance copies of the Team's report have been distributed here and we have made it publicly available. We expect to issue the report next week as a NUREG document, NUREG-1154, and that will be available next week. All the

reference documents used by the Team, including the interviews, the equipment action plan, had been placed in the PDR so there are no documents that have been withheld in this matter as a result of the Team's activities.

I guess finally, I want to emphasize that the Team has worked very hard, long hours, weekends, over the past several weeks to understand this event. Their report, as a result, was pulled together in a very short period of time, but due to their activities, their attention, their emphasis, their motivation, they met the schedule that we established several weeks ago. We said July 22nd and the Team did meet the July 22nd date. Thank you.

MR. ROSSI: Could I please have the first viewgraph?

[Slide.]

As Mr. Dircks indicated, an advance copy of NUREG-1154 containing the Team's report was provided to you yesterday. The report is entitled, "Loss of Main and Auxiliary Feedwater Event at the Davis Besse Plant on June 9, 1985."

In addition to me, the Team included three others. We have J.T. Beard from the Operating Reactors Assessment Branch in NRR who is to the left of Mr. Dircks; beside Mr. Beard we have Wayne Lanning from the Office for Analysis and Evaluation of Operational Data; and there on the end we have Larry Bell from the I&E Technical Training Section in

Chattanooga. I am from the Events Analysis Branch in the Office of Inspection and Enforcement.

It should be noted that Larry Bell, one of the members of the Team, was previously licensed as a senior reactor operator at a B&W plant, so he brought that perspective to the Team.

[Slide.]

What I'd like to cover this afternoon is the contents of the report. I'd like to go through briefly with you the highlights of the sequence of events that occurred on June 9th. I want to discuss the equipment problems that occurred during the event, and I'd like to make a point right now that many of those equipment problems, the causes for them, have still not been finally established. And Toledo Edison has not as yet submitted reports that summarize the findings on the ones where they do feel that they have actually identified the cause.

So the causes of the equipment problems in many cases, the troubleshooting to identify those in ongoing, and that's a very important issue, of course, that has to be tied up.

I will also talk about the human factors considerations associated with the event, and will spend a moderate amount of time discussing the Team's findings and conclusions.

[Slide.]

The introduction of the report covers an overview of the event, it discusses the Executive Director for Operations' June 10th directive establishing the Team, and it also gives a brief overview of the report's scope indicating what sort of things you can expect to see in each of the sections of the report.

Section 2 of the report contains a description of the factfinding efforts and methodology used by the Team. We feel that this is a very important section because the methodology that was used was intended to be very systematic all the way through, leaving a clear record of what we did do and what we did not do.

Section 2 discusses the interviews and meetings that were conducted by the Team. These interviews and meetings were all recorded by a stenographer and there are typed transcripts that were prepared. A list of those meetings and interviews is contained in Section 2.

The source of the plant data used by the Team in developing the sequence of events is briefly summarized. The handling of the quarantined equipment is also covered in Section 2. The troubleshooting on the equipment is being and has been performed using general guidelines agreed to between the Team and Toledo Edison. The guidelines are contained in Appendix B of the report, and these guidelines are intended to

insure that the root cause determination is systematically carried out, and careful records are kept of everything that's done.

The guidelines basically require the licensee to develop an action plan for the troubleshooting of each piece of equipment which malfunctioned. The key features included in these action plans are summaries of past problems that the licensee has had with the equipment, the kind of maintenance activities that have occurred and the reasons for them. And of course, the action plans contain the plans for testing the failure hypotheses that the licensee came up with to explain the malfunction of each piece of equipment.

Section 3 of the report is a description of the event. Section 3 includes a narrative description of the event that was written basically from the operators' perspective. That narrative is based upon a composite of the operator interviews. As you can see from the list in Section 2, we did a large number of interviews with the operators. We found them very interesting and very useful, and we thought that others would find things from those interviews that would be useful to them.

So Section 3 describes the event in terms of what the various operators did during the event.

Section 3 also contains a table with a chronological sequence of events. That table has all of the factual

information on what occurred at various times during the event, and it is primarily based on automatically reported plant data that was taken during the event. Alarm printouts and that kind of thing.

We have also included things that we were able to learn from interviews with the operators in portions of that, but it has basically been prepared from the automatically-recorded plant data records.

Section 4 contains a description of the plant systems that are important to understanding the event, so they are brief and are intended to cover those things that people need to know or need to refer to in order to have a good understanding of the event.

Section 5 discusses the equipment performance from the event. Section 5 is divided into preexisting conditions and equipment problems that were there and equipment problems that occurred during the event. For each piece of equipment there is a discussion of the problem which occurred during the event.

That is then followed for each piece of equipment by a summary of the trouble-shooting efforts that had been completed or were completed at the time the report was written and the information that was available at that time on the root causes.

And again, a lot of that effort is still ongoing.

Some of that effort cannot be completed fully until the plant is heated up.

Last, for each piece of equipment there is a discussion of the maintenance, surveillance and testing history for each piece of malfunctioning equipment, and that is based on summaries that were provided to the team by the licensee in his action plans, and also information that we obtained in discussions with the licensee in meetings.

The equipment histories were, as I said, primarily obtained from the action plans for troubleshooting. Section 5 also contains a summary table of the equipment troubleshooting results obtained up to the time the report was prepared, and indicates, where it is known, what the likely cause of malfunction was.

In some cases we have provided comments there to provide a perspective on where things stand.

Section 6 of the report evaluates the human factors considerations of the event. It covers operator performance as well as some man-machine interface issues that were noted from our evaluation of the event.

Section 7 is entitled "Safety Significance." It is for the purpose of providing a perspective on loss of feedwater events at Davis-Besse to give some feel for the kinds of analyses that had been performed in the past and what those analyses showed in terms of ability to handle loss of

feedwater events with various pieces of equipment used in mitigation.

Section 8 contains the Team's findings and conclusions, and as I indicated earlier, I will discuss those in some detail. I will run through each of them, time permitting, later on.

[Slide]

What I would like to do now is to briefly go over the highlights of the sequence of events. I think you probably in the last few weeks heard these a number of times. Again, the complete sequence of events is contained in a table in Chapter 3. What I'm going to do is just review the highlights.

As you know, the plant was initially at 90 percent power, operating in steady state. At 1:35 a.m., which is considered for these Vu-graphs to be time zero, a main feedwater pump tripped. It was main feedwater pump No. 1, and it tripped on overspeed.

That constituted a partial loss of main feed. A reactor runback in power then ensued, but about a half-minute later, the reactor and turbine tripped on high reactor coolant pressure. Soon after, the main steam isolation valves were spuriously closed, and this caused interruption of steam to the turbine of main feewater pump No. 2.

At five minutes into the event, the once-through

steam generator levels began to fall, indicating a complete loss of feedwater. This was at the time where the second feedwater pump had coasted down and was no longer able to supply feed to the steam generators.

At six minutes, the reactor operator assigned to the secondary side mistakenly initiated the steam and feedwater rupture control system on low steam pressure.

Now, at this point that basically isolated the auxiliary feedwater system and constituted a complete loss of auxliary feed.

[Slide]

This Vu-graph shows the steam and feedwater rupture control system switches that the operator used. The low pressure actuation switches which were actually initiated are the two top buttons. It's the top one in each column. These switches are not frequently used. The correct buttons that the operator should have initiated are four buttons down on each column, so he should have initiated the fourth button down on each of the two columns.

Had low pressure actuation actually been the intended operator action, because of what is considered to be a human factors deficiency in the layout of these buttons, actuated the steam and feedwater rupture control system on low pressure would have required pushing the buttons on a diagonal.

For example, the operator would have had to push the first button in one column and the second button down in another column in order to correctly actuate it on low steam line pressure. Again, what he actually did was he pushed the top two, which was in error, which basically indicated to the system that both steam generators had a steam line rupture and it shut off the auxiliary feed to the two steam generators.

[Slide]

COMMISSIONER ASSELSTINE: I understand the buttons are going to be realigned and then there will be caps or covers on those two. That's what I heard last week.

MR. ROSSI: Our team has very carefully not involved itself in the corrective actions. We have collected the information on what happened. I understand that the corrective actions are being looked at by others, but we have not really gotten into that.

COMMISSIONER ZECH: But it's something you are going to follow through on, I presume, becuause it seems to me a pretty logical thing to look into very carefully.

MR. ROSSI: Well, that will not be the Team's scope.

MR. DIRCKS: I think that's something I referred to that we are going to have in something like this the NRR people to take a look at.

COMMISSIONER ZECH: Oh, yes. The Staff in some capacity will look at it and follow through.

COMMISSIONER ASSELSTINE: But we won't have the Team's advice on your view.

MR. DIRCKS: No, we will not have the Team's advice. I think we made it clear that the Team just went out to look at the fact-finding aspect of it. The actual delegation of responsibilities now will pass through the responsible offices.

MR. ROSSI: We were at the point where the operator had pushed the wrong two buttons. At 6.75 minutes into the event, not exactly simultaneously but very close together, the two auxiliary feedwater pump turbines both tripped on overspeed. Now, the tripping of the two auxiliary feedwater pumps, of course, in itself would have defeated the function of the auxiliary feedwater system had later operator actions not been taken.

At 7 minutes into the event, the operator error in pushing the wrong buttons was recognized in the control room and it was corrected by resetting the low pressure trips and tripping on low level. That was recognized relatively quickly and that part of it was corrected relatively easily.

However, the auxiliary feedwater valves failed to reopen. These are the valves that are shown in the next Vu-graph. Why don't you put that next Vu-graph up.

[Slide]

COMMISSIONER ZECH: Excuse me. Again, I understand,

Bill, that your people are going to be looking into some of these things. in other words, why certain things happened and why a certain thing didn't happen. That's what you are telling us. That will be looked into by the Staff. It looks to me like that is very obvious that some of these things -- why did it fail to reopen and so forth -- that that has got to be looked into, and I presume that's what you are telling us you are going to be doing.

MR. ROSSI: Well, some of that was covered by the Team because we are involved in looking for the causes of the equipment malfunctions up until the time we prepared our report, and we do have some information later on the probable causes of some of these things, and it will have to be carried on, of course.

COMMISSIONER ZECH: Sure. I presume you will have, perhaps, recommendations or things like that, but I presume somebody will follow through --

MR. DIRCKS: We will follow through to make sure corrective actions are taken, not only here but at any other plant that requires it. That's why I have asked Jack Heltemes in his responsibility in the follow-up of operational data now to pick up a heavy responsibility of this thing and make sure the offices are tracking this.

COMMISSIONER ZECH: Thank you.

MR. ROSSI: This figure 4.4, which is out of the

report, shows the auxiliary feedwater system in the detail that we feel it is necessary to show in order to understand the event. The two valves that closed as a result of the operator actuating the incorrect buttons are marked there as AF-608 and AF-599. Those closed, and then when they corrected the error, what should have happened was the valve should have reopened, and they did not reopen.

There were then some subsequent actions taken within the control room to try to open those and the valves could not be opened from the control room.

[Slide]

At 9 minutes into the transient, several equipment operators were dispatched to go to the auxiliary feedwater valves that we were just discussing and open them locally, and also to go to the auxiliary feedwater pumps and to attempt to return those pumps to service.

At essentially the same time or very close to it, the assistant shift supervisor left the control room in order to make the electric motor-driven startup feedwater pump available for service.

[Slide]

At 12.75 minutes, the auxiliary feedwater isolation valve for steam generator No. 2 was opened locally by the equipment operators, and a couple of minutes later, the valve associated with the other steam generator was opened.

At 14 minutes into the event, both steam generators at this point had dried out according to the criteria in the emergency procedures for steam generators being dry. Now, that criterion is either that the level is indicated as being less than 8 inches in the steam generator or that the steam generator has a pressure below 960 psig and decreasing. And if you have either of those conditions and you don't have feedwater, that is the definition for steam generator being dried out.

In our report I think we have referred to this as essentially being dried out, but in fact, the procedures say to meet that criterion, the steam generator is dry from the standpoint of the criterion in the procedure.

Now, the procedure at this point calls for initiating makeup high pressure injection cooling, and I will come back to that later on.

At 16.25 minutes, the pressurizer pilot-operated relief valve failed to close. This was actually the third time that it had lifted during the transient, and this time it failed to close. The associated block valve, however, was closed by the operator within about a half-minute of that.

[Slide.]

At 16-1/2 minutes, flow was obtained from the electric driven start-up feedwater pump to once-through steam generator No. 1, and this was 10 minutes after the complete

loss of main and auxiliary feed, and three minutes after the steam generators met the dried-out condition.

At 18-1/2 minutes, flow was obtained from auxiliary feedwater pump 2. This turned the temperature in the plant around with the peak reactor coolant temperature reached being 592 degrees F.

CHAIRMAN PALLADINO: In order to start those pumps, did you not need steam aside from the electrical one?

MR. ROSSI: Well, they do indeed need steam. The turbine driven auxiliary feedwater pumps need steam. In this particular transient, it appears that they got start-up feedwater pump back a little before they started the turbine driven pumps.

There is a calculation that indicates that the pumps can be started with the steam remaining in a dry steam generator. I would be very hesitant to say that that was a hypothesis or calculation that is verified here, because the start-up feedwater pump was returned to service. But, nonetheless, they did indeed require steam and when they put them in service, obviously steam was available, and by the end of 19-3/4 minutes into the transient, they again had flow from both of the auxiliary feedwater pumps.

[Slide.]

CHAIRMAN PALLADINO: Are you saying there is enough steam in the dried-out steam generator to --

MR. ROSSI: Well, that was not my statement. There is a calculation that's referred to and referenced in our report, I believe it is in Section 8. There was a letter submitted by Toledo Edison, and it's in here. I could look it up for you, but it is there.

CHAIRMAN PALLADINO: All right.

MR. ROSSI: Where they had indicated that the steam in a dry steam generator at 1000 psig would be sufficient. There would be sufficient mass left to start the auxiliary feedwater pumps. And that also had, I think, reference to a transient that they felt substantiated that. That is not a team conclusion, however. We did not look at that and try to conclude whether you could or could not.

CHAIRMAN PALLADINO: Well, if the steam didn't come from there, where else could it have come from?

MR. ROSSI: Well, it could have come from the start-up feedwater pump. That's also possible because that's an electric-driven pump.

CHAIRMAN PALLADINO: No, I was talking about where did the steam come from the steam-driven --

COMMISSIONER ASSELSTINE: You could only be getting water into the steam generators and making new steam.

MR. ROSSI: Yes, that is correct.

Okay. Around 22 minutes, there was a cooldown of reactor coolant system, and it cooled down relatively rapidly

because of the introduction of feedwater into the steam generators.

As a result of that, the high pressure injection system was operated in the piggy-back mode to maintain pressurizer and pressure level as it dropped during the cooldown.

At 23 minutes, the minimum reactor coolant system pressure reached was 1716 psig and then, of course, things recovered, and by 29 minutes the plant was essentially stable. That's 29 minutes from the time that the main feedwater pump No. 1 had tripped on overspeed.

There were a number of additional complications that occurred during the 29 or -- well, during and even after the 29 minutes, in some cases. There was some difficulty in steam pressure control which could have been due either to problems with the safety valve either leaking or not reseating or problems in controlling atmospheric vent valves. But, nonetheless, there were some problems with steam pressure control.

There was an indicator lamp for one start-up feedwater valve that had burned out and as a result of that, the operators didn't recognize that that valve was usable. So there was little flow fed to one of the two steam generators because apparently they didn't know that that valve could indeed be used.

The source range nuclear instrumentation, one channel had been out of service prior to the event, and when they got down under the source range after the reactor trip, the other one had failed and so they had both of their source range instrumentations out, and as a result of that, had to borate in accordance with the procedures.

They had difficulties with the turbine going on the turbine gear, and later that morning there was one turbine bypass valve which was fractured by water hammer which occurred during the portion of the -- I think it was during the time when they opened up the main steamline isolation valves.

If I could have the next viewgraph, please.

[Slide.]

There were a number of operator actions outside the control room which occurred, which were relatively difficult, and these are discussed in some detail in Section 3 of the report. But these actions outside the control room required passing through key-locked doors. They required the unlocking of valves, and they also required actions at several different locations in the plant.

CHAIRMAN PALLADINO: Was there great difficulty in getting through the locked doors?

MR. ROSSI: I wouldn't say there was great difficulty, but from our interviews with the operators, it was

something that at the time it concerned them. They in some cases needed these key cards that are commonly used to get through doors, and there was a concern that they might break off, and had they broken off, they would either have to go back to the control room for a key, or they would have to call a guard to get through the door.

So we have referred to that as a -- well, why don't I wait till we get to our -- it is covered in our findings and conclusions, because it was an important point.

COMMISSIONER ASSELSTINE: I am not sure you get the full flavor from those three statements of some of the difficulties of those things. I hope you are, because having seen it last week, those cages with the grates and the locked doors and the big door between the auxiliary feedwater rooms, that has a history of not working properly. I hope you can convey the real flavor, how difficult some of these things were, and some of the obstacles that these guys had to overcome.

MR. ROSSI: Well, I hadn't intended to get into that in great detail here, but that is one of the things that is discussed in the narrative in Section 3. Again, I pointed out earlier that that narrative was written from the standpoint of what the operators were doing during the event, and it is indeed discussed, and we tried to discuss it in a way that would present the difficulties that they encountered in a

balanced way, and they were not simple things. You read in reports that they look local action outside of the control room. That was somewhat a difficulty. And I am going to talk about it a little bit more.

CHAIRMAN PALLADINO: These are important things to get to the Staff, because they may indicate some generic action needed, not only at this plant, but possibly other plants.

MR. ROSSI: Yes. And we have included that in our findings and conclusions.

CHAIRMAN PALLADINO: Yes, I've heard some of the stories. That's why I raise the question.

Similarly with regard to unlocking of valves, I gather there were chains and whatnot.

COMMISSIONER ASSELSTINE: That's right. In this case they remembered the keys, and they were in good shape. If they hadn't remembered those keys, it would have been tough to get those valves opened.

MR. ROSSI: That is correct.

Well, in terms of the start-up feedwater pump, that required opening four valves outside of the control room, and it also required inserting fuses in the breaker controlled circuits of the circuit breaker used for the pump motor. These actions were at four different locations.

CHAIRMAN PALLADINO: Could you refresh my memory on

those fuses? I remember raising the question once before, but I forgot the answer. Why do they have to insert fuses?

MR. ROSSI: Well, the company policy is that when you have suction valves and discharge valves, when the pump is valved out, basically, in order to ensure no pump damage, the fuses are removed from the circuit breakers so that they can't be inadvertently started.

MR. BEARD: It is purely for the protection of the equipment. You wouldn't want to inadvertently energize the motor and cause some damage if the thing is valved out.

CHAIRMAN PALLADINO: And were the fuses handily available?

MR. BEARD: Yes. They were right inside the switch gear door.

COMMISSIONER ASSELSTINE: But that was the fifth location he had to go to.

MR. BEARD: There were a total of -- for the start-up pump, he had to go to -- he had to make five operations, four locations. It turns out that the two -- two of the valves were right beside each other, so we called that four different locations.

CHAIRMAN PALLADINO: Okay. Thank you.

MR. ROSSI: The effort to obtain auxiliary feedwater required opening the two isolation valves that I showed you on the sketch before, and those valves were indeed locked. They

are locked valves. They had chains, so they had to unlock them. And they are also not located side by side. They were separated, so they were in two places.

CHAIRMAN PALLADINO: When were these isolation valves opened? Do you know the time?

MR. ROSSI: That was in my sequence of events. The first one was opened at 12-3/4 minutes into the event, and I believe the second one was about two minutes later. Resetting the auxiliary feedwater pump turbine trip throttle valves was also relatively difficult. And after they got them reset, they controlled the pumps locally for some period of time with communications over a Gatronics phone system with instructions from the control room.

And in the case of one pump, the instructions came from the control room to a guy in one of the two adjacent auxiliary feedwater pump rooms, and the guy on the telephone then would give hand signals to the guy that was actually controlling the pump, because it was noisy enough that they couldn't just verbally communicate.

So these were not real easy operations. And again, we tried to give that flavor in the narrative that's in Section 3, because we had the opportunity of hearing it all firsthand from the interviews with the operators.

[Slide.]

The next viewgraph shows the grate. It's a hatch

that you have to go through in order to get to the two auxiliary feedwater pump rooms.

Now, remember, the auxiliary feedwater pumps had tripped on overspeed. To reset the overspeed trips, you have to go to the pumps locally and do some manipulations with the trip throttle valve.

The two auxiliary feedwater pump rooms are located -- there is a padlock there. You have to unlock the padlock, and that is a sliding grate, and it basically is pulled back towards the front of the picture, and then there is a steep ladder that you go down into auxiliary feedwater pump No. 2, the room for it.

Now that ladder is not the kind of ladder that you have to go down backwards. You can go down it frontwards, but it is a steep ladder. It's the kind, I guess, that I think you would see on a ship where you go down a relatively steep ladder.

CHAIRMAN PALLADINO: How far down do they have to go?

MR. ROSSI: Well, it was just basically one flight. But, nonetheless, you had to have the key for the padlock, you had to roll that back, and then you went down into the first auxiliary feedwater pump room.

The second auxiliary feedwater pump room is adjacent to that through a watertight door that then was opened up.

COMMISSIONER ASSELSTINE: Which sometimes doesn't work. It worked this time, but sometimes it doesn't.

MR. ROSSI: That is a piece of information we have not been told.

COMMISSIONER ASSELSTINE: I was told that then you have to go down through a ventilation shaft on a rope to get into the second one.

MR. ROSSI: That is a piece of information that we perhaps didn't ask the right question, but we did not hear that from the operators that we had talked to.

COMMISSIONER BERNTHAL: Just as a matter of curiosity, it seems, of course, under the circumstances like that whole set-up is very unfortunate and ill-advised, perhaps. Why is it that way? I presume there is a security argument for it. Is that the reason for having this sort of arrangement?

For example, just a simple matter of a padlock. Do we tell them to do that for security reasons, or why is it a locked-up grate that's tough to get into?

MR. ROSSI: We didn't look at the reason for each one of these specifically, you know. We were there to find the facts of what occurred and report them back, and I think our finding on this particular item was a simple statement that the locked doors and valves in the plant had the potential for significantly hampering operator actions taken

to compensate for equipment malfunctions during the event. And they were of significant concern to the equipment operators.

COMMISSIONER BERNTHAL: Well, that's obvious, but what's the other side of the story? That's what I'm asking.

MR. DIRCKS: I think that is the second shoe that must drop here. We've got to go back and find out why these things were done.

CHAIRMAN PALLADINO: But I suspect it was part of the security system?

MR. ROSSI: That's right, it is.

CHAIRMAN PALLADINO: And we don't design the security system, but we do approve them, and maybe we have some insight now that would help us.

MR. DIRCKS: Yes. Now we have just gotten the report and we have not gotten into why these things happened. So I think if you will give us some time, we can come back with the answers.

Somebody said it was security, and it could be the security plan. These are vital areas, so that may be part of the answer.

COMMISSIONER ASSELSTINE: Yes. I know, Fred, on that point some of the company representatives expressed the view to me last week that if your concern is just making sure that nobody has tampered with a valve, opened it or closed it

when it should be in the other position, you can do that with a wire and a seal which can then be easily broken if you've got an emergency situation like this, as opposed to putting a big heavy chain like these were, with a padlock, where if you don't have the key, you're out of luck, you've got to run back upstairs and get the key.

I think that's one area that does need to be looked at. To what extent are we trying to protect against inadvertent or intentional tampering with these things. And what you want to do is verify the valve is in the right position as opposed to providing an absolute lock on the thing to prevent it from being moved.

MR. ROSSI: Well, you know, we identified this as one of our findings, and the corrective actions were outside of our scope. If we had gotten into that, it would have been an extremely lengthy process.

CHAIRMAN PALLADINO: However, I don't think it's wrong for us to ask those questions. When we get some insight, that helps.

MR. ROSSI: Well, one other thing I might point out is that this grate -- I believe the grate itself -- or was it the rooms that were three levels below?

MR. BEARD: The grate, I believe, is three levels below the room. This is where the operator was.

MR. ROSSI: So you have to go down three levels of

stairs and so forth within the plant in order to get to the grate, and then you unlock the grate and you go down to the pumps, and then there were some, you know, as I say, complications in getting the turbine trip throttle valves reset.

Well, I will get to that later.

CHAIRMAN PALLADINO: Apparently, though, the employees knew their plant well enough to know where they had to go.

MR. ROSSI: They were successful in most of what they did, so, yes, I'd have to say that they knew how to do things in general.

COMMISSIONER ASSELSTINE: And this is where all three pumps were, the start-up pump as well?

MR. ROSSI: The start-up pump as well, but the actions to put the start-up pump in service were performed elsewhere. Those valves were located in other places. We could go on now to viewgraph No. 15.

[Slide.]

I am going to talk a little bit about the equipment problems and the causes for them.

I would like to point out that each of the following problems were common mode failures and that without corrective operator actions in the cases of these two here, those actions had to be taken outside of the control room with the

difficulties that I have just explained, that either one of them, in and by itself, makes the auxiliary feedwater system unavailable.

The first one of those is the failure of the two redundant containment isolation valves to reopen after their inadvertent closure. That in itself, without corrective actions, defeats the safety function of that system.

Again, the overspeed tripping of the auxiliary feedwater pumps, both of them, the redundant pumps, that by itself would indeed defeat the safety function of the system.

CHAIRMAN PALLADINO: Why did these overspeed?

MR. ROSSI: I'll get to that in a minute.

That is not -- it has not been verified that the cause on that is known, but I do have a table here that I will run through rather briefly and try to discuss where some of the causes for this are.

CHAIRMAN PALLADINO: I gather, though, it wasn't just a simple operator action. Wasn't there a sequence that had to go --

MR. ROSSI: My understanding is that that was done within a minute relatively easily, that they just corrected and reset two of the buttons and repushed the other two.

MR. BEARD: But if all the equipment had worked properly as it is designed to, our understanding, if he had pushed the two reset buttons and all the equipment worked,

these valves should have automatically reopened at that point. But now, because they did not, the operators did run around and try manual controls and resets and various other activities in order to get them to reopen. But they should have reopened automatically --

CHAIRMAN PALLADINO: Oh, I guess I misunderstood something that was said to me earlier.

COMMISSIONER ASSELSTINE: Yes. The way the system was designed, it should have been possibly to fairly quickly correct those actions and realign the valves, and the actions they took would have done that if the equipment would have worked properly.

MR. BEARD: It should have done that.

MR. ROSSI: Let's go on to Vu-graph No. 16.

[Slide]

This is a table that is reproduced from NUREG-1154, and it gives a summary of the status of the trouble-shooting efforts that had been completed basically at the time the report was published. We left the site, I guess, about a week ago Friday, so they could proceeded somewhat further, I guess, in that time, but this is basically where they were at the time we left the site, which was a little more than a week ago.

As I indicated previously, we spent a lot of time when we were at the site talking to the licensee about their

trouble-shooting efforts and working with them to make sure that they were using procedures that were systematic in going about finding the root causes for the equipment.

They did the work, but we looked at the general procedures that they were going to use for doing that, and we are convinced that if they did it in accordance with what we had agreed on, that that would be systematically done. And while there are a number of different counts of how much equipment didn't work here -- I hate to just try to summarize it with one number because it depends on how you do the counting, and in some cases you may count two things as one failure or that sort of thing, or one system caused something else to do something -- but this table has 14 different things.

Obviously, they aren't all of equal significance, and I could go through a few of these and just give you a flavor of the kind of things that we found.

The first thing is the main feedwater pump, which started the whole event off. It tripped on overspeed. At the time we left the site, the licensee had determined that that was a control system electronic circuit card failure. However, they had had a number of control system problems with both feedwater pumps during this year.

They had had a trip of the No. 1 pump on April 24th. They had had a trip of both pumps on June 2nd, and the

No. 1 pump tripped again on June 5th when they tried to start the plant up, and they had not found those general control problems at that time. And it is not at all clear at this time that those problems have yet been resolved.

Now, they did find an electronic circuit card failure that they have identified as the cause of the particular overspeed trip that occurred on June 9th.

CHAIRMAN PALLADINO: So you are saying it really wasn't an overspeed, it was --

MR. ROSSI: No, no. The turbine really overspeed. It was part of the control system that caused it to overspeed. It was a card failure that caused it to increase speed. You know, you control the speed of the pump, and an electronic card within the system that controls that speed had failed and caused a demand for an increase in feed which was a false demand, basically, and just went right up and tripped.

The main steam isolation valves both closed. The licensee at the time we left the site had not begun the trouble-shooting activities in this area. He had a hypothesis on it that that was caused by a spurious actuation of the steam and feedwater rupture control system, and in turn, that spurious actuation was hypothesized to be due to a pressure transient that is very rapid and oscillatory that possibly occurs after the turbine was tripped that just was picked up by the instrumentation and gave a false indication for a need

to trip the main steam line isolation valves.

Again, that trouble-shooting had not begun and, as far as I know, has not been carried on very far as yet. I'm not going to go through every one of these because I don't see any purpose in that, but I will go through some of the more interesting ones.

The auxiliary feedwater pump turbines that tripped on overspeed, the hypothesis for the reason for that is that because of the actuation of the system on low pressure, it lined the auxiliary feedwater pump turbines up to the opposite steam generator from the way it normally works, so the steam flow going to the auxiliary feedwater pumps on June 9th came from a different steam generator than is normally used and it came through piping lines that are not the same as normally used.

And Toledo Edison's hypothesis of the cause of the tripping of the turbines is that when the steam came through these lines that were not used very often, the lines were cold and condensate was formed and they got slugs of hot condensate going through the pump turbines at the time they were trying to start up the turbine, and that that hot condensate imparted more energy into the turbine because it was masses of water that was hot and it flashed in the turbine, and that caused both of the turbines to overspeed.

Nw, that is their hypothesis. They have discussed

it with the turbine vendor. The turbine vendor believes that that is a likely thing, but this is one that they have not -- you know, they feel very confident that that is the cause of the problem, but the only way you are going to be able to know for sure is you have to go up with the plant hot and try it over again and see if it does, indeed, happen when you open the lines that were used on June 9th.

So that's one that can't be verified until the plant is taken hot.

COMMISSIONER ASSELSTINE: In fact, that configuration had never been tested before, had it?

MR. ROSSI: It is our understanding that even though this configuration is a configuration that would be used under certain design basis accidents, that that had not been tested before at this plant. And when we get to the findings and conclusions, there are some discussions of that. The phenomena, if true, really depends on the steam going down these different lines. It didn't have anything to do with the valves or any what you would consider to be active equipment that is on either end of the line.

It was simply that on June 9th, the steam to the turbines went down different sections of pipe that were longer and colder than what was normally used for the turbines, and because of that, according to the hypothesis, the steam condensed. They got slugs of water into the turbine and they

both went up and tripped on overspeed.

Now again, I want to reemphasize that can only be verified by testing, and it is very important that they be able be reproduce it because if they can't reproduce it, you really can't tell that it has been fixed.

CHAIRMAN PALLADINO: Well, in my experience on turbines, it says this is a very plausible explanation because I have seen similar circumstances happen in long lines that hadn't been used.

MR. ROSSI: Well, I believe this is plausible and it's a reasonable hypothesis.

CHAIRMAN PALLADINO: Yes, but I agree you have to check it.

MR. ROSSI: Their auxiliary feedwater containment isolation valves, the reason they would not reopen, it appears in this one they were pretty far along with their trouble-shooting on it, but it has to do with the fact that these valves have torque switches that turn off the motors if you try to open the valve with too much torque.

Now, those torque switches are generally bypassed by another set of contacts in order that you can apply enough torque to start to open the valve, and the bottom line of the hypothesis is that the bypass switch settings were, first of all, actually determined to be the wrong settings. So I mean they had specified settings that didn't take into account the

fact that the valves might have to open with a differential pressure across the valve.

In addition to that, the settings, first of all, were wrong because they didn't include the fact that they might have to open with differential pressure. It is also correct that the settings for one of the valves were pretty far off from what it had been specified as being, so that was a contributing problem.

But the bigger problem is the one that the settings had not been specified in a way that took account of the differential pressure, and then the valves when they are tested and cycled are cycled without differential pressure across the valve, so that would have never been picked up in testing.

Before we left the site, Toledo Edison had done testing of the valves with differential pressure across them, and they had been able to reproduce the failures with that differential pressure across the valves. They reproduced the failures that occurred on June 9th when you had the differential pressure, and when you didn't have the differential pressure, the valves worked.

So that one, they have probably found the root cause.

Now, they are in the process of tying up the loose ends even where they feel they found the problems, you know,

preparing a report and so forth to justify that they know what happened.

CHAIRMAN PALLADINO: That's another generic area that the Staff will want to look into, whether valves are so designed that they have enough torque to open with the differential pressure on them.

MR. ROSSI: There was an I&E information notice that has been issued on the general aspects of this event that I believe at least makes this fact know, and this one is clearly one that is already being looked at within the Staff for possible generic implications.

I won't run through all of these. I would like to mention, however, the pilot-operated relief valve because that one did not close. That one didn't have a big effect on the event, but it clearly was one that got a lot of attention.

They have disassembled the valve and looked at it and have not been able to find anything wrong with it. The valve worked the first two times properly, and it was the third time that it failed to reclose. So at this point in time, they don't know what caused that failure, and they were basically relooking at their plant to try to determine where to go next, and that is one that -- you know, all of these items on the equipment are basically at this time not closed out and will be presumably considered by the rest of the staff.

CHAIRMAN PALLADINO: It may be worth looking at the impact of heating up. I presume when they blow, there is steam going or hot water going through, at least, and whether the cycling in itself brings about expansion problems or possible interferences.

MR. ROSSI: That is the major hypthesis at this time of the cause, and of course, that's something that you wouldn't see by simply taking it apart.

COMMISSIONER ASSELSTINE: Yes. And in fact, I think experience tends to show, doesn't it, that when you cycle these things repeatedly, and particularly the last time when they got water through it as opposed to just the steam, that that is when they tend not to work.

COMMISSIONER ZECH: Yes, that's a pretty obvious thing to look at, if it closed properly twice and didn't again. So just that fact may have something to do with it. I'm sure you will look at that.

COMMISSIONER ASSELSTINE: Yes. It's a fairly key question because that's one of the things that was supposed to have been fixed after TMI, and EPRI had this big testing program that was supposed to provide the assurance that these things were going to work.

MR. BEARD: Excuse me. Let me see if I can speak to that question for a minute because we do bring it up in a finding later, but we did look back at the EPRI testing and

there is some information, I think, that's worth picking up. One is that it probably was the scope of the EPRI testing not to show reliability in terms of repeated operations but rather to show could it handle two-phase flow or water, and it probably did a pretty good job of that objective.

I don't think it was its objective to show repeated cycle things.

But the other thing that is more interesting is each of the tests while they were under various conditions were a single lift of the valve, a single lift of the valve.

CHAIRMAN PALLADINO: Was that the test at EPRI?

MR. BEARD: The EPRI test. That is what I'm referring to. And of course, if your objective is to show that it can handle certain phenomena like, say, two-phased flow, that's fine. If your objective is to show reliability in the type o situation a transient might produce, which would probably involve multiple lifts, then that test should be looked at or its results should be used carefully.

COMMISSIONER ASSELSTINE: In other words, the testing program didn't accurately fit the real life situations for what these things would have to go through.

MR. BEARD: I think it probably met its intended objectives, but I think the reason I am bringing this up is that we need to understand what the objectives were before we start using the information because I don't think its

reliability of repeated operations was one of the objectives.

CHAIRMAN PALLADINO. Is it still possible to do some of this test work at EPRI, on cycling, I mean?

MR. BEARD: I'm not sure that we are the best ones to answer that.

CHAIRMAN PALLADINO: I will leave that to the EDO to look at.

MR. ROSSI: Okay. Why don't we skip on over to Vu-graph 18.

[Slide]

I don't think it's worthwhile to talk about any of the other equipment --

COMMISSIONER ASSELSTINE: One last question on that Vu-graph before you leave it. Is it possible to further characterize the probable root causes? Is it possible to reach at least a preliminary conclusion on did some of these things involve poor maintenance practices, did some of them involve lack of procedures on how to do maintenance on some of this equipment, did some of these things involve possible design questions like this routing of the pipe, the steam along this one pipe path? Is it possible to get to that level --

MR. ROSSI: Well, we have findings and conclusions that I think speak to those questions.

COMMISSIONER ASSELSTINE. Is it fair to say all of

those things are mixed up in this?

MR. ROSSI: We will get to that in a minute. We have tried to cover that in our findings and conclusions.

COMMISSIONER ASSELSTINE: Okay.

MR. ROSSI: Our report and our evaluation did look at some of the human factors considerations coming out of the event. There is, of course, the question of the operator pushing the wrong steam feedwater rupture control system buttons early on in the transient, and that has to do primarily with the arrangement of the buttons, which I already discussed, the poor labeling of the buttons.

It appears that the particular operator involved, that this was the first time he had ever done that operation and he really lacked training in how to do it properly.

The next item --

CHAIRMAN PALLADINO: Do they have something like that at a simulator? You don't put those kind of things --

MR. ROSSI: Well, this is a Davis-Besse-unique design, so simulator training -- this is an area that that would not pick it up for this particular thing.

COMMISSIONER ASSELSTINE: Well, if they had a plant-referenced simulator it would, but --

CHAIRMAN PALLADINO: I'm not sure how far they would go on some of these auxiliary details.

COMMISSIONER ZECH: Most of them are pretty

detailed. Dedicated simulators are very much the same as the control room.

COMMISSIONER ASSELSTINE: That is on the main panel, so I would think that that would be replicated on a plant-specific simulator.

MR. ROSSI: On a plant-specific simulator, there is no question in my mind that would be covered.

CHAIRMAN PALLADINO: Was this on the front of the panel or on the back?

COMMISSIONER ASSELSTINE: It's on the front of one of the main panels, the back panels that are in front of the operators. It's not behind.

MR. ROSSI: You can see it from where you normally are.

As I indicated when I was talking about sequence of events, the steam generators did reach the criterion where by the emergency procedures they would be considered to be dry. AT that point, the emergency procedures instruct that you are to initiate makeup, high pressure injection cooling. That was not done.

Now, there are a number of reasons why it apparently was not done. One of the reasons is that the instrumentation in the control room that was available on that day did not very clearly indicate that they were at the point where they had dry steam generators. In the case of the level, you had

to read 8 inches off of a scale where you are right down at the very bottom. In the case of the steam pressure, the criterion is that you be below a certain value and that the pressure is decreasing.

They didn't have anything that would trend it for them that was available in the control room on that day.

Now, both redundant channels of the safety parameter display system were out of service that day. Had those been in service, it appears they would have had that information more readily and clearly available to them, but the SPDS was not in service. As our report discusses, that is a piece of equipment that, while it is redudant, it is actually even diverse in some ways. But there have been, apparently, reliability problems with it at the plant.

CHAIRMAN PALLADINO: But you say you need the SPDS, really, to make that determination?

MR. ROSSI: Well, I wouldn't say you have to have it to make that determination, but the instrumentation that was available appears not to be terribly clear that they had reached the criterion. They recognized the fact, however, that they were on the verge of the point where they were going to have to go to make up high pressure injection or feed-and-bleed cooling. They knew they were there, and there were discussions about doing it.

And the other aspect of why they didn't do it had to

do with the fact that the shift supervisor believed that they were imminently going to get the auxiliary feedwater back, and indeed they did get it back, and there were no consequences because of any delay in going to the feed-and-bleed.

The other thing, in talking to the operators, that is apparent is that they had an apparent reluctance to rush into the feed-and-bleed mode because when they went into that, that would mean releasing reactor coolant to the containment, and they considered that to be not a very significant step, and they waited a period of time to reconsider it and look for alternatives before they went to that.

And obviously, on June 9th, that had no effect. But it is one of our findings, that operators for these kinds of actions that they perceive as being relatively severe, that there is going to likely be a reluctance to do them immediately without thinking a little bit and reconsidering and looking for the alternatives, and there can be at least a few minutes delay.

CHAIRMAN PALLADINO: Bill, are you going to look at the level instrumentation for possible faults?

MR. DIRCKS: Well, we are going to go through the whole report and pick up all of these items.

CHAIRMAN PALLADINO: And I wasn't thinking only for this plant --

MR. DIRCKS: No.

CHAIRMAN PALLADINO: -- but maybe it's a --

MR. DIRCKS: To the extent we can, we've -- or any point now, we are picking up generic items on an immediate basis, and if it's necessary, we issue bulletins on them, but every item that Ernie's mentioned, we picked up, and Jack, as I mentioned, will be working to get the appropriate offices assigned to the task.

COMMISSIONER BERNTHAL: I am still unclear on exactly what you are implying here about the safety parameter display system. Are you suggesting that had it been available and working the way it's supposed to, that this sequence would have been arrested at an earlier stage?

MR. ROSSI: No, I'm not really suggesting that. What I am saying is that it's a fact that when they got to the point in the procedures that required initiation of make-up high pressure injection and cooling, they didn't do it.

Now it wasn't needed on June 9th because a few minutes later they got back the auxiliary feedwater, but nonetheless, you know, we talked to them. They didn't do this immediately, and we tried to assess why they didn't do it immediately, and they didn't recognize that they were at the criterion -- they didn't recognize that they were really at the criterion where the emergency procedures say do it now.

They did indeed recognize that they were on the verge of having to do it, and all indications are -- and

there's no way of knowing what they would have done had things gone on, but all indications are that if things had gone on without auxiliary feedwater much longer, that they would indeed have gone to it.

So, you know, all we're doing is pointing out the facts and what we know about the possible reasons for the delay.

COMMISSIONER BERNTHAL: But your point is that this would have been a hypothetical branch that may have been additionally delayed because of this uncertainty over instrumentation? I guess that's what you're saying.

COMMISSIONER ASSELSTINE: And the SPDS would have given them a clear indication of what they needed to do.

MR. ROSSI: That's right.

Now I would like to --

CHAIRMAN PALLADINO: But we have never figured the SPDS to be an operational type information.

MR. ROSSI: In terms of addressing that particular point on that, I would like to remind everybody that the particular event that occurred at Davis-Besse on June 9th is one that goes beyond the design basis of the plant. The design basis of the plant is to cover transients with single failures and safety systems.

This one here had multiple failures in the key safety system, which was the auxiliary feedwater system, so

it's outside of that envelope that's normally used in design.

CHAIRMAN PALLADINO: Well, maybe they have to look at the envelope also. Excuse me. You might cross out "maybe." Cross out "maybe." We should look at the envelope.

COMMISSIONER ASSELSTINE: And also single failures.

CHAIRMAN PALLADINO: Well, I was including that in my envelope.

MR. ROSSI: Let me go on. There were some difficulties. A couple of the equipment operators, it turns out the ones that got to the auxiliary feedwater pump trip throttle valves first had difficulty in getting them reset. They didn't fully reset them and then when they tried to open the valves, they apparently thought they were opened when they had just removed the slack by turning the wheel.

CHAIRMAN PALLADINO: Which valves are these?

MR. ROSSI: These are the auxiliary feedwater pump trip throttle valves.

There were -- the assistant shift supervisor and a more experienced equipment operator arrived on the scene shortly after the first two operators had had the difficulty, and they knew exactly what to do. But there was a problem with the first two ones in terms of not knowing exactly how to set the overspeed trips, not how to reset them, and also there was difficulty in the feel for what it took to turn the valve. It had to do with the fact that they had apparently

never done it with high pressure steam at the inlet when they had to try to open it --

COMMISSIONER ASSELSTINE: The pressure differential across the valve?

MR. ROSSI: Pressure differential across the valve, and it was difficult to open. So these are discussed in our report on human factors.

COMMISSIONER ASSELSTINE: On that one in particular, did you look at the procedures? Because the company made the point to me last week that there was apparently some ambiguity in the procedure. It didn't make it clear that on that throttle you have really got to give that thing a tug to get it reset.

MR. ROSSI: That was our understanding, that they also needed a procedural thing, too. So it's training and procedure.

There's a couple of other things there that are covered in the report. The shift technical adviser really wasn't used during this for anything, but it was a fast transient that was basically well along before he got to the control room.

The shift technical adviser is not required to be in the control room at all times, so he's called when he's needed. And, of course, by the time he got there, they were into the middle somewhere in the transient, and in order for

him to have done anything, he would have had to update himself on the situation, and he wasn't needed. And I guess he wasn't needed and wasn't used.

CHAIRMAN PALLADINO: Yes, but that doesn't mean there might not be a circumstance where he might be needed.

MR. ROSSI: That's true.

CHAIRMAN PALLADINO: How far away was he and how long did it take him to get there, and what was he doing?

MR. ROSSI: Well, he was outside of the protected area in the administrative building that's there, and there is a short drive from there to the protected area. And it appears from what we know that he got there about 15 minutes into the transient. And the requirement is that he is supposed to be able to get there within 10 minutes, I guess, from when he's called.

MR. BEARD: I think that's correct. And I think one thing that we need to make clear is that we had no information that this shift technical adviser did not comply with the 10-minute requirement. It's just that when he got there, as best the story can be pieced together, it looks to be about 15 minutes into the event.

CHAIRMAN PALLADINO: Yes. I wasn't criticizing what he was doing. I was just looking to see whether or not we should look at the requirements for the STA any differently.

MR. BEARD: I think for B&W plants, you might want

to reconsider that.

COMMISSIONER BERNTHAL: For this plant, it seems to me that you might want to treat the STA a little differently.

CHAIRMAN PALLADINO: That's where I was going.

COMMISSIONER ASSELSTINE: Well, I think the point about the B&W plant, the speed with which you have to react, is a valid one. Is this where the STA is normally stationed, at an administrative area?

MR. BEARD: At this plant, that's the way the utility set it up. He has like an apartment over there, and he works like 24 hours on before he takes a break, so he has, you know, a rest area. He has telephone communication, and if the control room feels like they need the assistance or the function of a technical adviser, they pick up the phone and solicit his help. He gets in the car or gets his clothes back on if it's in the middle of the night and he's asleep. But he gets to the plant and goes in the control room and provides assistance.

CHAIRMAN PALLADINO: I never figured an STA having to use a car to get to the control room. This is a new feature in my thinking.

COMMISSIONER ASSELSTINE: Yes. And this approach to the STA I'm not a big fan of. The ones where they work with the shift and they are right there with the shift and they train with the shift, I think is a much better approach.

I know this approach is used at several plants where the STA works 24-hour shifts and he's really sort of independent and off doing other things. But that always sort of bothers me. I think it's something that deserves a fresh look.

MR. DIRCKS: I don't want to reopen fresh wounds or old wounds, I should say, but at one time we were talking about having the qualifications of the STA comply with the shift supervisor, to have something equivalent to the engineering officer on watch.

CHAIRMAN PALLADINO: It's still an option, I think. It's interesting.

MR. BEARD: I think it should be noted here in passing that the Team got absolutely no indication that the crew that was on this night lacked technical expertise in understanding the transient they were trying to cope with. So that we are not trying to make the point that a technical adviser function should have been provided and wasn't. It's just that these are the facts.

COMMISSIONER ASSELSTINE: Yes.

CHAIRMAN PALLADINO: Yes, I wasn't criticizing people for what they did. As a matter of fact, I am rather impressed with what they did, except for the button part. But I was just thinking, suppose, though, they needed him and they needed him fast. Having to get into the car to get over there

seems like not really being close enough to help.

MR. DIRCKS: Well, we will take a look at that.

MR. ROSSI: Okay. I think we ought to skip over to viewgraph No. 20 now.

COMMISSIONER ASSELSTINE: Well, on emergency notification, before you leave that, do you have any information on what level this event was?

MR. ROSSI: During the time that they were without any feedwater, it was a site area emergency.

COMMISSIONER ASSELSTINE: And was that declared?

MR. ROSSI: That was not declared. Well, they didn't call it in to the NRC Operations Center until after the plant was stable, and at that time a site area emergency or any other emergency action level didn't exist. But, you know, they didn't call it in while the transient was underway. They did not have the people available to call it in at that point. I think that is pretty clear from everything that was going on.

They called it in fairly soon after they were stabilized, and at that time they just called it in and they reported it. It was reported in a way that you wouldn't really, if picked up, know how significant the transient was. And then some time later they phoned in and declared an unusual event which is the lowest emergency action level. That was done based on our interviews primarily from the

standpoint of getting them into a level where additional personnel would be brought to the site to help them handle the situation, rather than to inform offsite people that they had a problem. And, you know, that is discussed in here.

COMMISSIONER ASSELSTINE: Okay. The site area emergency is one notch up from that or two?

MR. ROSSI: The site area emergency is two notches. There is an alert in between the site area -- after the site area emergency. But, you know, at the time they called it in, the plant was stable. There had been no damage, other than -- well, damage to the bypass valve occurred even later than that, as I understand it.

So there was no emergency at that point in time.

[Slide.]

This is the major conclusion that the Team had, based on its review of the event, and this is reproduced here on this viewgraph verbatim out of our report, because it is fairly important, and it was the Team conclusion. We thought it ought to be produced verbatim.

Basically the Team concluded that the underlying cause of the loss of main and auxiliary feedwater event was the Licensee's lack of attention to detail in the care of plant equipment. The Licensee has a history of performing troubleshooting maintenance and testing of equipment and of evaluating operating experience related to equipment in a

superficial manner and, as a result, root causes of problems are not always being found and corrected.

CHAIRMAN PALLADINO: I was going to ask you whether you felt the majority of equipment inadequacies were due to faulty design or were they due more to maintenance?

MR. ROSSI: Well, you know, it's the way all of those are tied together, you know. It's the relation between looking at the problem to make sure you know what it is, and then taking aggressive action to fix it.

So we were very reluctant to tie it to just one thing, you know. There's a whole way of going at looking at equipment problems in a coordinated way, between making good use of their operating experience, making good use of engineering evaluations of problems, and then carrying that through in terms of fixing the problem. And it is really how those are intertied.

I guess one good example is the valves that wouldn't open. There is a case where even had they used the settings that had been given to the people to do the maintenance, they would have still probably had the problems because the settings were specified right. The setting is an engineering thing, you know.

CHAIRMAN PALLADINO: Yes. Well, I use the word "maintenance," I guess more broadly. Okay. Thank you.

COMMISSIONER ASSELSTINE: What does all that do to

the operators? Doesn't all that mean that basically the operators end up being the remedy for all of these things?

MR. ROSSI: Well, that is clearly the case on June 9th, that they were. Yes, the operators, when there is difficulty with the equipment, more of a burden is placed on them.

Now, in support of this major conclusion, you know, just a large number of failures, and I discussed the kind of things that were causing them, particularly the failures that were in redundant safety systems.

The number of failures that occurred during the single event itself we feel supports this conclusion.

We had also looked at their action plans and past histories and things like the testing of the piping to the turbines that had never been done, and those all went into our coming to this finding.

Could I have the next slide.

CHAIRMAN PALLADINO: Could I ask you a question? If it is not appropriate at this point, tell me and I will wait.

To what extent would you say an underlying cause was the lack of an electric driven auxiliary feed pump?

MR. ROSSI: There is a finding related to that, but why don't we wait and talk about that, if we could, till we get there.

[Slide.]

I had not fully finished reading the major conclusion, but I think I covered it significantly.

Okay. Since I think time is going on, why don't we go on to the next one.

These are the other findings and conclusions. The Team had 18 what we call principal findings and conclusions over and above our conclusion on the underlying cause.

I would like to point out that within our report we think that in reading the report the Staff will find a number of things that are in there that didn't rise to the level of being included in the findings and conclusions. But these are the principal findings and conclusions.

The first one is key safety significance of the event is that multiple equipment failures occurred, resulting in a transient that is beyond the design basis of the plant, and that the failures that occurred included several common mode failures that affected redundant safety-related equipment.

Specifically the valve's failure to open and the pump trips were both common mode failures in redundant pieces of safety equipment. And we feel that that is of key safety significance of this particular event.

COMMISSIONER ASSELSTINE: Were you-all surprised at the number of things that failed, that didn't work, o that appeared not to have been operational?

MR. ROSSI: I would say we were surprised by the number of things, particularly within the safety-related equipment.

The next finding and conclusion is that if the failure of only the safety-related equipment could have been prevented, then the event would not have been nearly as serious or complicated. So if the proper attention had been given to keeping just the safety-related stuff working, then things would have been considerably better.

Obviously, the auxiliary feedwater system would have worked in that case. Even if it had only undergone one single failure, it would have worked.

The next one is that if the safety-related auxiliary feedwater equipment had functioned in accordance with the system design requirement, the operator error in initiating the steam and feedwater rupture control system on low steam pressure, rather than low level, would have been corrected in less than a minute and would not have had a significant effect on the course of the transient.

So had the equipment worked, and had they dealt with the operator error promptly and quickly, and if it hadn't been for the equipment problems, that operator error would not have been particularly significant.

[Slide.]

COMMISSIONER ASSELSTINE: I think that's a very

useful point, because I think, in some quarters, the operator error thing has been emphasized as a fairly significant contributor on this. I think that's a very important point of what you all did.

MR. ROSSI: Based on the Licensee's current hypotheses for the causes of the auxiliary feedwater system containment valve and pump malfunctions, the cause could have been detected and corrected prior to the event by straightforward tests, and such tests had apparently never been run during the life of the plant. And assuming that their hypothesis on why the auxiliary feedwater pump turbines oversped is correct, that's one where had they run a test using those lines, they would have found that one.

The valves, had they run tests to verify operability of the valves with the differential pressure across them that they might see during real events, they would have found that one.

The Licensee's lack of effective engineering for determining the proper settings for the valve torque switch bypass contacts and improper implementation of the specified settings were the probable causes of the auxiliary feedwater system containment isolation valve malfunctions.

Furthermore, this problem likely exists with other valves at Davis-Besse and could exist at other plants. That one, we talked about as I've gone through, so I won't go into

it anymore.

In our review, we determined that the steam and feedwater rupture control system and the auxiliary feedwater system does not meet the single-failure criterion for all design-basis accidents. There is a design-basis steamline break in the plant accident analyses where both of the valves that were involved in this event would be called upon to close, and only the one associated with the good steam generator would then have to reopen. And since there's only one valve there that would have to reopen to deal with it, that does not meet the single-failure criterion.

COMMISSIONER ASSELSTINE: Did you look at why that wasn't picked up before, either in our reviews or the Licensee's analysis?

MR. ROSSI: I do not know the reason. The Licensee appeared to assume that the valves would never be closed, and this event drew attention to the fact that, gee, maybe they may be. And we looked at and discussed it with Toledo Edison, and there is, indeed, an analysis where it appears that valves would close as part of the accident sequence, and then only one of them, the one going to the good steam generator, would be required to reopen.

MR. BEARD: I think it's fair also to point out that the mechanical pipes and valve-type part of the system has a single component that can fail. Also, the safety actuation

system that would give the signals to the valves, given a single failure, could fail to give the valve a signal to open, and hence it may never try.

COMMISSIONER ASSELSTINE: So it may be more than one single failure.

MR. BEARD: I think the team's conclusion is that neither system meets the single-failure.

COMMISSIONER ASSELSTINE: Okay.

[Slide.]

MR. ROSSI: The availability of the electric motor-driven startup feedwater pump significantly improved the safety margin for the plant during the vent, and the capability to promptly place an electric pump and associated valves for supplying auxiliary feedwater in service from the control room would have significantly increased the safety margin for the plant during the event.

Now it has been point out that the turbine-driven pumps need steam. One of the things that an electric pump will do for you is that if there is a delay after you empty the steam generators in correcting a problem, that you have a source of power for an electric pump, in general, whereas on a plant with empty steam generators, you wouldn't have anything for the turbines. And that's the reason we came to this conclusion.

In addition, the electric pump, from the analyses

that were presented to us, could be used to advantage with feed-and-bleed cooling.

Now somebody asked a question earlier on on the electric pump --

CHAIRMAN PALLADINO: No. I was waiting -- I was struck by the nature of the first major conclusion, and it made me think about the electric pump, and so I wanted to know whether you were going to discuss it.

Well, you say the steam-drive pumps need steam, and the electric-drive pumps need electricity.

MR. ROSSI: If you have both, there is obviously a certain diversity, which I think has been known for some time.

Well, I described what the operators did during the event in some detail, and it's clear that the operators' understanding of procedures, the plant's system designs, and specific equipment operations and the operator training all played a crucial role in their success in mitigating the consequences of the event.

They had a knowledge of what they had to do, and as a team, they were able to get it done successfully, and that was clearly crucial in dealing with the event, particularly in view of the actions that were taken outside of the control room.

CHAIRMAN PALLADINO: Had they given any particular attention to training since, let's say, Three Mile Island?

MR. ROSSI: I believe that's covered in one of our other findings.

CHAIRMAN PALLADINO: Well, reference was made earlier to things which haven't been done. I was thinking of some things that maybe had been done that benefitted from Three Mile Island.

MR. ROSSI: That was probably the big benefit from the Three Mile Island items, was the training on transient behavior, and that's in one of our findings later on, that the training on transient behavior was the most important of the post-TMI improvements.

COMMISSIONER ASSELSTINE: But that's training for operators, as distinguished from training for other plant personnel like maintenance people.

MR. ROSSI: That could very well be, but they knew what they had to do, and who to send where, and that kind of thing.

CHAIRMAN PALLADINO: The people who run around and close the valves, are they control room operators?

COMMISSIONER ASSELSTINE: They're auxiliary operators and equipment operators.

CHAIRMAN PALLADINO: Oh. So that some training apparently brushed off on the auxiliary operators as well.

MR. ROSSI: Well, one of the ones who did a lot of these actions and supervised a lot of them outside of the

control room was actually the Assistant Shift Supervisor, and he is a licensed operator. So he was involved in the actions outside.

COMMISSIONER ASSELSTINE: He did the startup pump, right?

MR. ROSSI: He did the startup pump, and in addition to that, he helped in auxiliary feedwater pump turbine throttle reset. So he was involved. And as I say, you know, we have talked about some problems in various areas that -- where the operators may not have done things quite as quickly as they should have, but in general, as a team, they very clearly were crucial, and they were able to turn the situation around that was caused by the equipment problems.

The locked doors and valves in the plant have the potential for significantly hampering operator actions taken to compensate for equipment malfunctions during the event, and they were, as I explained earlier, a significant concern to the equipment operators.

This was very clear from the interviews with them, that they were concerned that night about not having the key or not being able to get through the doors, and what they would do if they couldn't.

We have already talked about -- one of our findings is that the operators did not initiate makeup high-pressure injection immediately upon reaching the conditions where it's

required by the emergency procedures. I don't see any reason to go into that anymore, because I think I talked about that enough already.

[Slide.]

With respect to the switches in the steam and feedwater rupture control system, if the manual switches had originally been properly designed with regard to human factor considerations, such as labeling and the way they were arranged, it's likely that no operator error in the initiation would have occurred.

Furthermore, if only the previously identified deficiency regarding the placement of the switches had been corrected prior to this event, and then had the operator actuated the system on low pressure, rather than on low level, the consequences would have only been that one steam generator would have been affected rather than both.

CHAIRMAN PALLADINO: You say previously identified problems?

MR. ROSSI: Yes. That has to do with the fact that they had already identified the fact that if the operator was intending to actuate the system on low pressure, he had to push the switches diagonally, and that had already been identified as a deficiency.

Had that been corrected, so that he had to push the switches horizontally, then the consequences of his actuating

the system on pressure rather than level would have simply been to have fed auxiliary feed to one steam generator, rather than both, and they wouldn't have had a total loss of auxiliary feed.

COMMISSIONER ASSELSTINE: Had there been a decision made to change the switches, and they just hadn't gotten around to it, or was it that they identified the problem, and nobody followed through on it?

MR. BEARD: They had identified the problem in their detailed control room design review. They had identified a number of deficiencies in the control room. This particular one was recognized and given a high priority.

What the Toledo Edison folks told us was that they, I believe, had designed a fix, an improvement if you will, and were planning to implement that, if my memory serves me, in 1986. And the point of our finding is, had that been done prior to June 9th of 1985, it would have made the operator's mistake even less significant than it probably was.

MR. ROSSI: The reporting to the operations center, I think we already talked about that. We do have a finding and conclusion on that.

We talked about the pilot-operated relief valve testing, and we have a finding and conclusion on that. I won't go through those again.

CHAIRMAN PALLADINO: What did you have to say about

reporting?

MR. ROSSI: Well, the event was not reported in a manner reflecting the safety significance, and the remaining part of our finding is that the more serious an event is, the more operator involvement there is going to be required to maintain plant safety. And so there is a concern about whether people are available to maintain an open telephone line during a very serious event, with the NRC, and that's basically the finding.

CHAIRMAN PALLADINO: When did they notify us?

MR. ROSSI: They notified us at -- I believe it was at 2:11; 2:11 was the first telephone call, and then there were a number of other telephone calls after that. But the first one, I'm sure, was at 2:11.

CHAIRMAN PALLADINO: Yes. And I don't think it was recognized to be very serious.

COMMISSIONER ASSELSTINE: It was an unusual event.

MR. ROSSI: Yes. It was not called in in a way that would have led people on this end of the telephone line to recognize the seriousness. That was recognized in the follow-up that occurred over the remaining part of the day and additional telephone calls and looking at it primary from the Region's standpoint.

COMMISSIONER ASSELSTINE: That's an interesting point you make, though, that the more serious the event gets,

presumably, then, the more interested we are in knowing about it, and the less able the utility is to tell us about it, because everybody is busy running around trying to deal with it.

MR. ROSSI: That's precisely the point we were trying to make. And this one is a clear one, because here you have an event that was basically all over in 29 minutes, and the most serious part of it was somewhere in the ten to fifteen minute area.

CHAIRMAN PALLADINO: But even so, the seriousness of it should have been apparent to them, even at that time, and even though they were too busy to call us. But when they did call us, it should have been quite clear that this was a significant event.

MR. BEARD: I think that one of the things that ought to be brought out as a result of our interviews was, the gentleman in the control room who was responsible for this reporting, who is responsible for classifying and reporting the event, and some others -- and I don't mean to pick anyone out -- but the general feeling was, it's not clear that you are required to call a site emergency "a site emergency" if you do not have any longer a site emergency. In other words, you transitioned into that stage, now you're back out, what is the required reporting?

So I think the area might use some more thought.

COMMISSIONER ASSELSTINE: As I understand it also, they had more than the minimum required complement of people on duty that night. So presumably, if they had had the minimum complement required by, I guess, their FSAR --

MR. BEARD: I think we have to bear in mind, my understanding is --

COMMISSIONER ASSELSTINE: They had nine people, right?

MR. BEARD: Yes. But the point that's important in my mind -- and the Senior Resident Inspector is sitting in the room, so we can get a correction if I make a mistake -- but the number of licensed individuals was the required number. Where they had an excess was in the non-licensed equipment operators in the plant.

Let me check.

COMMISSIONER ASSELSTINE: I think that's right.

MR. BEARD: The Resident says that is correct.

COMMISSIONER ASSELSTINE: In fact, I think they had two extra, from what they told me last week.

MR. ROSSI: The post-TMI improvements, the temperature saturation meters, the additional training on transient behavior, and the abnormal transient operational guideline emergency procedures, we found made a positive contribution to the mitigation of the event, and of these, training on transient behavior was the most important.

The pilot-operated relief valve flow and acoustic monitor was not used by the operators to determine if the valve was opened. As a matter of fact, from the interviews, it was clear that the operators did not recognize at the time the valve was stuck open, that it was stuck open. He closed the block valve as a precautionary measure, and then he opened it up again two minutes later, and he apparently did not recognize that it had stuck. And that only came out when they did the post-trip analyses of the event and looked at the traces and so forth.

CHAIRMAN PALLADINO: You mean he closed it once, and then he opened it? Did he leave it open?

MR. ROSSI: He closed the block valve, and then he apparently had a feeling that things weren't going just right, and he did that as a precautionary measure, and then he opened it up again a couple minutes later, so that he would have it if it needed to be used.

CHAIRMAN PALLADINO: And he didn't know that the PORV was leaking or opened, was stuck?

MR. ROSSI: He did not know at the time that it was stuck.

CHAIRMAN PALLADINO: Well, then, did he close it again?

MR. ROSSI: No. It reseated during the time -- I'm sorry -- during the time that the block valve was closed, it

reseated.

Well, we have talked about the fact that the shift technical adviser was not used.

[Slide.]

Well, most of these have come up during our discussion, but I will run through them rather quickly.

The first one there is on the importance of integrated system testing, to whatever degree is practicable in detecting common mode design deficiencies, and the one I would like to point out that is the best illustration of this is the problem with heating the turbines through the lines where they had never been tested.

It is likely that they had tested the valves and the things on both ends of the steam line, but what apparently had not been done was to actually run the turbines with steam going through the lines, and that integrated testing, assuming that their hypothesis on the failure is correct, would have picked that problem up.

We have talked about -- well, the next one is a generalization on events that are outside the plant design basis, and the fact that operator training and operator understanding of systems and equipment are the key to the success of mitigating actions that might be taken when you go beyond the design basis, that when you are outside of the events that you have used in the design of the plant, that it

is not practical to rely on detailed step-by-step procedures for those, because there would be no end to how many procedures you would have to have to cover them.

So you are really dependent at that point on the operators knowing what to do and their training on what to do.

We have talked about the question of the delay in feed-and-bleed initiation and we had a finding that operators at other plants may be reluctant to initiate makeup high pressure injection cooling or similar actions without a delay to reconfirm the need and to consider less severe alternatives.

And the last item we had already talked about, instrumentation available in the control room during the event was not adequate to clearly inform the operators that the criterion for makeup high pressure injection cooling had been reached. And the only practical alternative would have been the safety parameter display system, which wasn't available and it was not required to be available.

And that brings to a conclusion our presentation.

CHAIRMAN PALLADINO: Well, thank you very much. That was very well done, and I think we got a very good picture.

Now before I open it to questions, let me note that Commissioner Zech will be leaving at precisely 4:15. We still have affirmation and agenda planning to do before that, so I

guess I'll say I would like to defer as many question as we can.

I guess the main question I had is where do we go from here on some of the things that you're still looking at? And then where do we go from here on corrective action? But that might be the subject of another meeting.

Are there any other burning questions that we ought to deal with?

COMMISSIONER ZECH: Well, I would just like to make one quick point:

First of all, the major conclusion, I think, which you didn't go into great detail on, but it was very critical of the Licensee in a number of areas, the casualty, as I understand it, certainly involved multiple failures. And I can just envision that control room with alarms going off and a lot of noise, and the operators moving around and going in and out of the control room and trying to do what they could to handle that casualty, you know. And all the operators made mistakes, there's no question about that.

It seems to me that they really did a very commendable job. And as you pointed out, I think, perhaps with all those failures, the operators should get great credit for handling that casualty like they did.

At least my experience would show me, from what I can tell from what you've told me, that they did quite a good

job under the circumstances.

It seems to me that there's a lot of lessons to be learned, though, from all this, and you pointed out a number that the Licensee should learn. And I think there are some the NRC should learn, too, there's no question about it. I think we have to take the next step and evaluate what this Team has given us.

I think the Team has done a very fine job in evaluating the facts. They have laid out the facts to us, but now the next step, I think, is for us to look at those facts very carefully and to see what steps the Licensee should take, and what steps NRC should take.

So I think that lies ahead of us.

COMMISSIONER ASSELSTINE: Joe, I had a couple of points as well.

I agree with Lando's comments and, in fact, I wanted to see if Larry Bell shared those views since he was a licensed SRO.

My impression, certainly, from what you said today, and also from what I heard out at the plant last week, was that apart from a couple of the operator errors that occurred, it doesn't sound like significantly contributed to the seriousness of the event, but these guys really did a heck of a job in the way they functioned, and particularly having to run around and turning all those valves and getting the pumps

and valves opened on the auxiliary feedwater system, that those guys were real heroes in this thing.

Larry, I would be interested in your perception, since you were an operator.

MR. BELL: I share your opinion and Commissioner Zech's opinion. I think the operators performed admirably.

COMMISSIONER ASSELSTINE: It also seems to me that the thrust of what you were saying in your conclusions was that the support system that those guys had to depend upon, the maintenance program for the plant, the engineering support organization, the supplies -- all of those kinds of things -- that's where there was essentially a widespread breakdown in this operation.

Is that a fair characterization?

MR. ROSSI: Yes, I think it is a fair characterization that the June 9th event was primarily one that involved the care of equipment, and, you know, those things were all just waiting there, and combined altogether to get them on June 9th. That's the way I see it. It was the equipment failures that did it.

COMMISSIONER ASSELSTINE: It also sounds like the condition of the equipment in this plant is, to a very large degree, somewhat indeterminate now. I mean these are the things you have looked at specifically in relation to the June 9th event.

I guess one of the questions in my mind is, if you saw that in this widespread range of equipment, doesn't that call into question some of the other safety-related equipment in the plant, and the need for a pretty thorough going-over?

CHAIRMAN PALLADINO: Okay, I'm going to suggest that agenda planning might talk briefly about when we might hear more about the action that's needed.

COMMISSIONER BERNTHAL: I did have a comment I wanted to make. But it looks like you're winding up there, Joe.

[Laughter.]

CHAIRMAN PALLADINO: Well, I'm just looking at the clock. But we've got to do affirmation and I think we ought to have a three-minute break, anyhow.

COMMISSIONER BERNTHAL: I just want to emphasize that this is only the first of a three-step process here. We just heard what went wrong, and I would like to hear soon now from the Staff on their appraisal of why it went wrong, and then we have to figure out what to do about it.

But peripheral to that, I think is something that we also need to face up to, and that is whether we can find part of the fault by looking in the mirror on this thing, and I would urge again that the Commission not take a thing away from the Staff performance. And I agree that this investigation and, in fact, the way I think you, Bill, and

Harold Denton have organized this particular investigation shows you have made a lot of progress there.

I still believe that it behooves us to look very carefully at the concept of an independent Commission level safety investigatory branch that would have the kind of independence and credibility that we need if, in fact, we are part of the problem here.

COMMISSIONER ASSELSTINE: I agree with that very much. In fact, I think this is an ideal case to try that concept out and see how it works.

CHAIRMAN PALLADINO: Well, I think we have learned some lessons.

COMMISSIONER ASSELSTINE: Yes, and Fred mapped out a good approach to try and do that, and I think we ought to focus attention on it.

CHAIRMAN PALLADINO: I would also note that the budget has some provisions for this.

COMMISSIONER ASSELSTINE: Well, we can't wait for the budget for '87 on something like this.

CHAIRMAN PALLADINO: Well, no. It also says we are going to implement it starting now.

COMMISSIONER ZECH: Well, I don't think that should detract from what this Team has done. They have done a very, very fine job. I really appreciate what they have done. I think we all should appreciate it.

CHAIRMAN PALLADINO: Let me repeat the commendation I made in the opening remarks, and thank you very much for your yeoman efforts.

We stand adjourned.

[Whereupon, at 3:38 p.m., the meeting was adjourned.]

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of: Commission Meeting

Name of Proceeding: Briefing on Davis Besse (Public Meeting)

Docket No.:

Place: Washington, D. C.

Date: Wednesday, July 24, 1985

were held as herein appears and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission.

(Signature) Suzanne B. Young

(Typed Name of Reporter) Suzanne B. Young

Ann Riley & Associates, Ltd.

NRC TEAM REPORT

ON

LOSS OF MAIN AND AUXILIARY FEEDWATER EVENT

AT

THE DAVIS-BESSE PLANT ON JUNE 9, 1985

CHARLES E. ROSSI, TEAM LEADER

J. T. BEARD

T. LARRY BELL

WAYNE D. LANNING

C. E. ROSSI, X24193

JULY 23, 1985

Order of Presentation

- Report Contents
- Sequence of Events
- Equipment Problems
- Human Factors Considerations
- Findings and Conclusions

C. E. Rossi, X24193

July 23, 1985

Contents of the Report

C. E. Rossi, X24193

July 23, 1985

Sequence of Events

- T = 0 min. (1:35:00) — Main Feedwater Pump No. 1 Trips (Partial Loss of Main Feed)
- T = 1/2 — Reactor Trip and Turbine Trip
- T = 1/2 — Main Steam Isolation Valves Close
- T = 5 — OTSG Levels Begin to Fall (Complete Loss of Main Feed)
- T = 6 — Secondary Side Reactor Operator Initiated Steam and Feedwater Rupture Control System (SFRCS) on Low Steam Pressure (Complete Loss of Auxiliary Feed)

C. E. Rossi, X24193

July 23, 1985

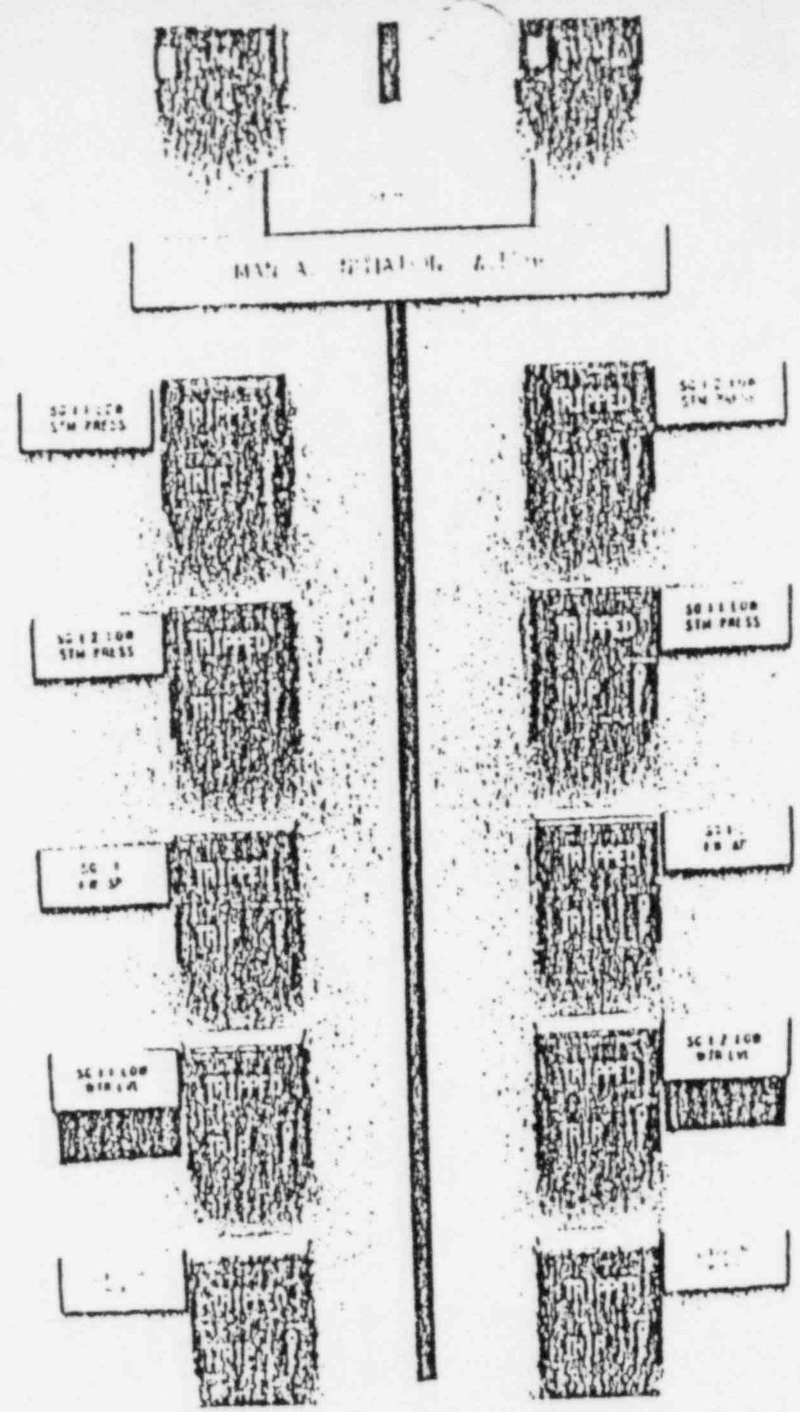


Figure 3.6 Manual Initiation Switches for SFRCS

SEQUENCE OF EVENTS (CONTINUED)

- T = 6 3/4 MIN. AUXILIARY FEEDWATER PUMP TURBINES TRIP ON OVERSPEED
- T = 7 OPERATOR ERROR IN SFRCS CORRECTED
- T = 7 AUXILIARY FEEDWATER VALVES FAIL TO RE-OPEN

C. E. ROSSI, X24193

JULY 23, 1985

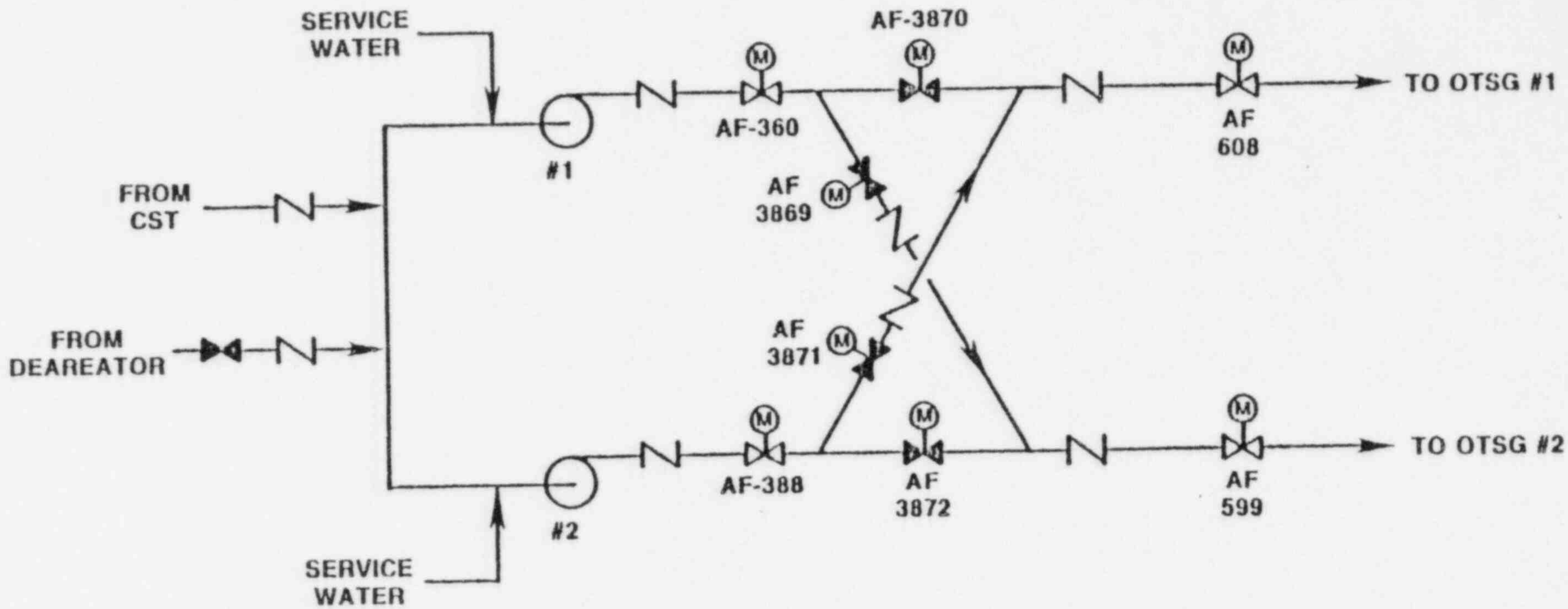


Figure 4.4 Auxiliary Feedwater System

SEQUENCE OF EVENTS (CONTINUED)

- T = 9 MIN. EQUIPMENT OPERATORS DISPATCHED TO:
  - -- OPEN AUXILIARY FEEDWATER VALVES
  - -- RESTORE AUXILIARY FEEDWATER PUMPS TO SERVICE
- T = 9 ASSISTANT SHIFT SUPERVISOR LEFT CONTROL ROOM TO MAKE STARTUP FEED PUMP AVAILABLE FOR SERVICE

C. E. ROSSI, X24193

JULY 23, 1985

SEQUENCE OF EVENTS (CONTINUED)

- T = 12 3/4 MIN. AUXILIARY FEEDWATER ISOLATION VALVE FOR OTSG NO. 2 OPENED BY EQUIPMENT OPERATORS
- T = 14 BOTH STEAM GENERATORS "DRIED OUT" - EMERGENCY PROCEDURE CRITERION FOR INITIATING MAKE UP/HIGH PRESSURE INJECTION COOLING
- T = 16 1/4 PRESSURIZER PILOT OPERATED RELIEF VALVE (PORV) FAILS TO CLOSE AFTER THIRD ACTUATION - PORV BLOCK VALVE CLOSED 1/2 MINUTE LATER

C. E. ROSSI, X24193

JULY 23, 1985

Sequence of Events (Continued)

- T = 16 1/2 MIN. — Flow Obtained from Startup Feed Pump to OTSG No. 1
- T = 18 1/2 — Flow Obtained from Auxiliary Feed Pump No. 2
- T = 18 1/2 — Peak Reactor Coolant Temperature 592°F (Normal Post-Trip 550°F)
- T = 19 3/4 — Flow Obtained from Auxiliary Feed Pump No. 1

C. E. Rossi, X24193

July 23, 1985

SEQUENCE OF EVENTS (CONTINUED)

- T = 22 MIN. COOLDOWN OF REACTOR COOLANT SYSTEM FROM RAPID FEED OF STEAM GENERATORS
- T = 23 HIGH PRESSURE INJECTION IN PIGGYBACK MODE TO MAINTAIN PRESSURIZER PRESSURE AND LEVEL
- T = 23 MINIMUM REACTOR COOLANT SYSTEM PRESSURE 1716 PSIG (NORMAL PRESSURE 2150 PSIG)
- T = 29 PLANT ESSENTIALLY STABLE

C. E. ROSSI, X24193

JULY 23, 1985

Operator Actions Outside Control Room

- Required Passing Through Locked Doors

- Required Unlocking of Valves

- Required Actions at Several Locations

C. E. Rossi, X24193

July 23, 1985

Operator Actions Outside Control Room (Continued)

- Startup Feedwater Pump
  - -- Required Opening 4 Valves
  - -- Required Inserting Fuses in Breaker Control Circuit
- Auxiliary Feedwater
  - -- Required Opening Isolation Valves
  - -- Required Resetting of Pump Turbine Trip Throttle Valves (Difficulties Were Encountered)

C. E. Rossi, X24193

July 23, 1985

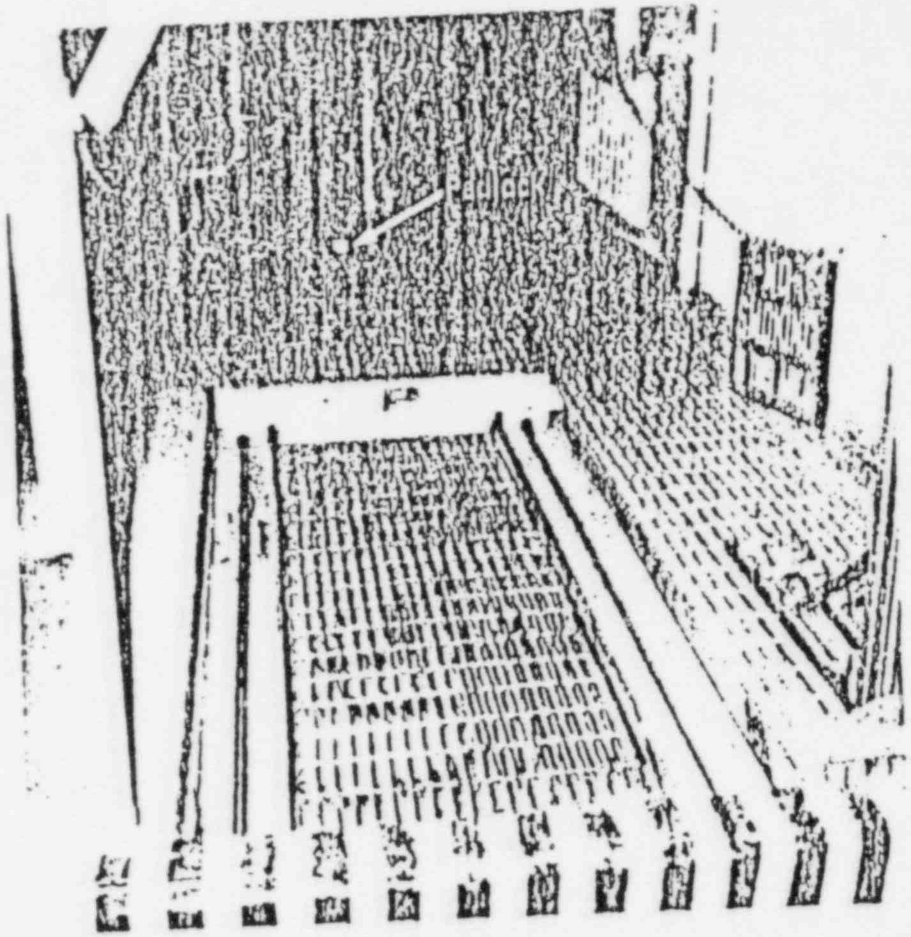


Figure 3.7 Grate Leading to Auxiliary Feedwater Pump Room

Equipment Problems

- Each of the Following Common Mode Failures, without Corrective Operator Actions, would have Defeated Operation of the Safety-related Auxiliary Feedwater System:

  -- The Failure of the Auxiliary Feedwater System Containment Isolation Valves to Reopen After Their Inadvertent Closure

  -- The Overspeed Tripping of the Auxiliary Feedwater Pumps

C. E. Rossi, X24193

July 23, 1985

Table 5.1 Summary of Equipment Troubleshooting Results

	ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
1.	Main Feedwater Turbine	Overspeed	Control System Electronic Circuit Card Failure	Pre-existing Control System Problems Have Not Been Resolved
2.	Closure of MSIVs	Spurious Actuation of SFRCS	Not Identified	Troubleshooting Activities Have Not Yet Begun
3.	Steam Safeties, Atmos. Vents	Abnormal Pressure Control	Not Identified	
4.	Aux. Feedwater Turbines	Overspeed	Condensate Flow to Turbines From Steam Supply Lines During Turbine Start	Testing with Plant Hot Needed to Verify Cause
5.	AFW Containment Isolation Valves	Would Not Re-Open	Improper Settings for Torque Switch Bypass Contacts	
6.	Steam Supply Valve to AFPT #1	Short Cycle	Not Identified	Failure Could Not Be Reproduced Improper Torque Switch Bypass Contacts Could Be Problem
7.	Source Range NI	Failed, Low	Not Identified	Failure of One of Two Channels Could Not Be Reproduced
8.	PORV	Did Not Close	Disassembly of Valve and Testing of Control System Failed to Reveal Cause	Cause May Never Be Identified
9.	S/U Feedwater Control Valve	Did Not "Reset"	Indication Problem Only - Indicator Lamp	
10.	Recovery of AFP Turbine	Trip-Throttle Valve Operational Difficulties	Lack of Operator Training	Not a Hardware Problem

Table 5.1 Summary of Equipment Troubleshooting Results (Continued)

	ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
11.	AFP #1 Suction Transfer	Transfer to Service Water	Not Identified	
12.	Turbine Turning Gear	Did not Engage		Troubleshooting Not Reviewed by Team
13.	Control Room HVAC	Spurious Transfer to Emergency Mode		Troubleshooting Not Reviewed by Team
14.	Turbine Bypass Valve	Structured	Water Hammer, Valve Mis-Assembly	Cause of Water Hammer Not Yet Known

Human Factors Considerations

- Operator Errors
  - -- Pushed Wrong SFRCS Buttons
  - -- Did not Follow Emergency Procedure
  - -- Difficulty in Resetting AFW Pump Overspeed Trips (2 Errors)
- STA Not Required
- Emergency Notification

C. E. Rossi, X24193

July 23, 1985

MAN-MACHINE INTERFACES

- ACOUSTIC MONITOR NOT USED
- SAFETY PARAMETER DISPLAY SYSTEM INOPERABLE
- PLANT COMMUNICATIONS SIGNIFICANT BENEFIT

C. E. ROSSI, X24193

JULY 23, 1985

Major Conclusion

The Team has concluded that the underlying cause of the loss of main and auxiliary feedwater event of June 9, 1985, was the licensee's lack of attention to detail in the care of plant equipment. The licensee has a history of performing troubleshooting, maintenance and testing of equipment, and of evaluating operating experience related to equipment in a superficial manner and, as a result, the root causes of problems are not always found and corrected. Engineering design and analysis effort to address equipment problems has frequently either not been utilized or has not been effective. Furthermore, operator interviews made clear that equipment problems were not aggressively addressed and resolved beyond compliance with NRC regulatory requirements.

C. E. Rossi, X24193

July 23, 1985

Findings and Conclusions

- Key Safety Significance is that Multiple Equipment Failures Occurred
- Prevention of Only the Failures in Safety Related Equipment Would Have Made Event Significantly Less Serious
- If Safety-Related Auxiliary Feedwater System Equipment Had Functioned, Operator Error Would Not Have Had Significant Effect

C. E. Rossi, X24193

July 23, 1985

Findings and Conclusions (Cont.)

- Testing is Likely to Have Detected Causes of Auxiliary Feedwater System Pump and Valve Malfunctions

- Improperly Specified and Improperly Implemented Torque Switch Bypass Contact Settings Probable Causes of Valve Malfunctions

- Neither SFRCS Nor Auxiliary Feedwater System Meet Single Failure Criterion for All Design Basis Accidents

C. E. Rossi, X24193

July 23, 1985

Findings and Conclusions (Cont.)

- Electric Motor-Driven Startup Feedwater Pump Availability Improved Safety Margin
- Operator Understanding of Procedures, Designs, and Equipment Operation and Operator Training Played Crucial Role
- Locked Doors and Valves Were Potential Impediment
- Operators Did Not Initiate Make Up/High Pressure Injection Cooling When Called for By Procedures

C. E. Rossi, X24193

July 23, 1985

Advance Copy

NUREG-1154

Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985

U.S. Nuclear Regulatory Commission

ABSTRACT

On June 9, 1985, Toledo Edison Company's Davis-Besse Nuclear Power Plant, located in Ottawa County, Ohio, experienced a loss of all feedwater event while the plant was operating at 90% power. The event involved a number of equipment malfunctions and extensive operator actions, including operator actions outside the control room. A number of operator errors also occurred during the event. This report documents the findings of an NRC Team sent to Davis-Besse by the NRC Executive Director for Operations in conformance with the staff-proposed Incident Investigation Program.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

Appendices

THE NRC TEAM FOR THE DAVIS-BESSE EVENT OF JUNE 9, 1985

Charles E. Rossi, Team Leader

J. T. Beard

T. Larry Bell

Wayne D. Lanning

TEAM SUPPORT STAFF

Stephen Burns, Office of the Executive Legal Director

Walter E. Oliu, Division of Technical Information and Document Control

ACRONYMS

AFPT	Auxiliary Feedwater Pump Turbine
AFWS	Auxiliary Feedwater System
ARTS	Anticipatory Reactor Trip System
ASME	American Society of Mechanical Engineers
ATOG	Anticipated Transient Operator Guidelines
B&W	Babcock & Wilcox
BWST	Borated Water Storage Tank
CRAM	Count Rate Amplifier Module
CST	Condensate Storage Tank
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EDO	Emergency Duty Officer
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
F/V	Frequency-to-Voltage
HED	Human Engineering Deciciency
HPI	High Pressure Injection
HVAC	Heating, Ventilating, and Air Conditioning
I&C	Instrumentation and Control
ICS	Integrated Control System
LPI	Low Pressure Injection
MFP	Main Feed Pump
MFW	Main Feedwater
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valve
MU/HPI	Makeup/High Pressure Injection
NI	Nuclear Instrumentation
NPSH	Net Positive Suction Head
NSSS	Nuclear Steam Supply System
OTSG	Once-Through Steam Generator
PORV	Pilot Operated Relief Valve
PWR	Pressurized Water Reactor
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
SFAS	Safety Features Actuation System
SFRCS	Steam and Feedwater Rupture Control System
S/G	Steam Generator
SPDS	Safety Parameter Display System
STA	Shift Technical Advisor
S/U	Startup
SUFP	Startup Feedwater Pump
USAR	Updated Safety Analysis Report

1 INTRODUCTION

The Davis-Besse Nuclear Power Station, Unit 1, operated by the Toledo Edison Company, is located on Lake Erie in Ottawa, County, Ohio, approximately six miles northeast of Oak Harbor, Ohio. At 1:35 a.m., on June 9, 1985, one of the two main feedwater pumps at Davis-Besse tripped (i.e., stopped) on overspeed while the plant was operating at 90% power. Thirty seconds later the reactor and turbine were automatically tripped on high reactor coolant system pressure. Soon after the reactor tripped, both main steam isolation valves spuriously closed, resulting in a loss of steam to the second main feedwater pump. Subsequent to this complete loss of main feedwater, an operator error, malfunctions of two redundant valves in the safety-related auxiliary feedwater system, and overspeed trips of the two redundant, steam turbine-driven auxiliary feedwater pumps resulted in loss of all sources of feedwater to the steam generators.

Separate actions by operators were required to (1) correct the initial operator error, (2) open the valves which malfunctioned, and (3) reset the overspeed trips of the turbine-driven auxiliary feedwater pumps. Actions outside the control room were required to open the valves and place the pumps in operation. While operators acted to restart the safety-related auxiliary feedwater system, operator actions outside the control room were also taken to place a nonsafety-related, electric motor-driven, startup feedwater pump in service. The plant's two steam generators had essentially boiled dry before feedwater from any source became available to them. Further, a number of additional equipment problems complicated the event. Nevertheless, operators were successful in bringing the plant to a stable shutdown and in preventing any abnormal releases of radioactivity and any major damage to the plant.

On the day following the event, and in conformance with the staff-proposed Incident Investigation Program, the NRC Executive Director for Operations sent an NRC Team of technical experts to the site. (For the directive establishing the Team, see Appendix A.) The Team, composed of four staff members, was selected because of its broad experience in operating plant event analyses, with individual Team members having specific knowledge and experience in operations, instrumentation and controls, and reactor systems. The Team was to (1) fact-find as to what happened; (2) identify the probable cause as to why it happened; and (3) make appropriate findings and conclusions to form the basis for possible follow-on actions. This report documents the Team's efforts in identifying the circumstances and causes of the event together with its findings, and conclusions.

The scope of this fact-finding effort was limited to the circumstances concerning the event of June 9, 1985, including operator actions and equipment malfunctions. Section 2 describes the methodology used by the team to collect and evaluate information about the event.

Sections 3 and 6 of this report discuss what was learned about operator performance. Through interviews with the operators on duty at the time of the event, the Team obtained a considerable amount of information about operator performance and capabilities during circumstances that required an extensive

range of operator actions in a relatively short period of time to bring the plant to a safe, stable condition. A number of the findings and conclusions in Section 8 are based on the Team's evaluation of operator response to the event.

Section 4 provides an overview of how the reactor systems function and interact, as well as a description of the safety systems involved in this event.

Section 5 discusses the Team's review of Toledo Edison Company's efforts to determine the causes of the equipment malfunctions as well as summaries of their maintenance experience related to that equipment. The Team did not, however, extensively review Toledo Edison's management performance record, quality assurance program, maintenance procedures, or history of regulatory compliance. A number of significant pieces of equipment were either not in service prior to the event or malfunctioned during the event. The Team used summaries provided by Toledo Edison of their past evaluations, troubleshooting, testing, and maintenance related to the equipment that malfunctioned in reaching a number of the findings and conclusions discussed in Section 8.

Section 7 contains a discussion of the safety significance of the event, including a summary of information on the consequences of loss of feedwater events at Davis-Besse as a function of mitigating systems available. Section 8 presents the Team's findings and conclusions.

Based on this report, it is expected that the NRC Executive Director for Operations will identify and assign specific NRC offices the responsibility for subsequent actions related to this event.

2 DESCRIPTION OF FACT FINDING EFFORTS

2.1 General

The Team collected and evaluated information to determine the sequence of operator, plant, and equipment responses during the event and the causes of equipment malfunctions. The sequence of these responses was determined primarily by interviewing personnel who were at the plant during the event and by reviewing plant data for the period immediately preceding and during the event. The Team also toured the plant to examine the equipment which malfunctioned, the equipment that was key to mitigating the transient, and the control room instrumentation and controls. The Team also interviewed plant management personnel and NRC Region III personnel who arrived at the site soon after the plant was stabilized about their knowledge of the plant response and operator actions. The root causes of equipment malfunctions in most cases have yet to be definitively determined. The root causes are being established through systematic troubleshooting performed by Toledo Edison personnel and equipment vendors using procedures agreed upon by the Team.

As with all commercial nuclear power plants, a considerable amount of information on plant response and specific equipment actuation can be obtained from records automatically generated in the form of analog recordings and digital printouts. These records accurately indicate the chronological sequence for such things as the starting and stopping of pumps and the opening and closing of valves, as well as the time response of key plant parameters. By correlating plant records with personnel statements on their actions and observations, the Team was able to compile a picture of the key aspects of the event.

The equipment which malfunctioned was quarantined so that troubleshooting and corrective actions could be performed systematically. This ensured that information on the root causes of each malfunction could be obtained.

2.2 Interviews and Meetings

The Team placed a high priority on interviewing personnel on duty at the time of the event to learn about the actions they took and the observations they made. It was recognized that the quicker these interviews could be held, the more information those being interviewed would remember. The Team held meetings with Toledo Edison and NRC Region III personnel to obtain an overview of the sequence of events from their analyses and evaluations of plant data. The Team also met with Toledo Edison and Region III staff members to agree upon a course of action for troubleshooting the equipment which malfunctioned and to discuss the results of the troubleshooting efforts. The root causes for equipment malfunctions cannot be determined until the troubleshooting efforts are completed.

All interviews and meetings about the sequence of events during the plant transient, the course of action for troubleshooting equipment which had malfunctioned, and the cause for the equipment malfunctions were recorded by stenographers and

typed transcripts were prepared. The Team also took pictures of key plant equipment and made tape recordings of pertinent discussions during the tour of the control room and plant. A record was not made of discussions between the Team and Toledo Edison or Region III personnel about obtaining documents relating to the Davis-Besse plant design/operation or pertaining to schedules. Nor did the Team record the first meeting with Toledo Edison and Region III staff members on the morning of June 11, 1985 to explain the Team's objectives and plans.

The formal fact-finding effort began in the afternoon of June 11 when the Team met with Toledo Edison personnel to obtain an overview of their understanding of the event. The Team then met with Toledo Edison and Region III staffs to learn about specific design features of the Davis-Besse plant important to understanding the event. The Team was given an overview of the design of the Davis-Besse main steam system, main feedwater system, auxiliary feedwater system, and steam and feedwater rupture control system. Questions concerning the plant design were answered.

Following these overview meetings on the sequence of events and plant systems, the first of a number of meetings was held on the course of action to be taken with the equipment which malfunctioned. The decisions and actions taken are discussed in Section 2.4.

Although the highest priority was given to interviews with the personnel on duty during the event, shift scheduling made it more convenient to interview available NRC Region III staff first. On June 11, the Team discussed the event with Region III personnel to obtain their overview from observations and evaluations made when they arrived at the site following the event. The NRC Resident Inspector was the first NRC representative to arrive at the site at approximately 3:20 a.m. on June 9. He described his observations of the plant status when he arrived and discussed a sequence of events which he had prepared from plant records.

Interviews with operating personnel began on the morning of June 12. The general approach for scheduling interviews was to talk to personnel in decreasing order of their seniority within the shift, beginning with the shift supervisor and proceeding to those less senior. The rationale for this sequence was to move from general to specific information. Thus, the Team obtained information on the overall plant operation and then obtained information on the detailed actions of specific operators. The scheduling of interviews and meetings was also based on the availability of personnel and the progress of Toledo Edison in developing plans for troubleshooting the equipment.

The interviews with the plant personnel generally covered the following areas. The interviewee was asked to describe his position in the plant organization and to discuss his background and experience. The interviewee was then asked to describe the event beginning from the time he first realized that an abnormal plant condition existed. The interviewee was questioned on the actions he personally took during the event, his observations of plant responses during the event, and his observations of the actions of others. Following a "walk-through" of actions and observations made during the event, the team asked the interviewee questions on the use of procedures, the value of training, perceptions of the adequacy of plant maintenance, and whether NRC regulations or procedures interfered with maintaining plant safety during this event or at other times.

The shift supervisor, assistant shift supervisor, the two licensed reactor operators, the shift technical advisor, and the administrative assistant to the shift supervisor were interviewed individually. The four non-licensed equipment operators who performed key actions outside the control room during the event were interviewed as a group. Those being interviewed in some cases had either a supervisor or an attorney (or both) present during the interview. Except in rare cases, only the interviewee responded to questions during the interview.

Plant management and NRC Region III personnel who went to the site soon after the event were interviewed in the same general manner as plant operating personnel. In addition to the NRC Resident Inspector discussed above, those interviewed included the NRC Senior Resident Inspector, the Plant Manager, the Operations Superintendent, and the Operations Supervisor. Specific questions related to the plant organization, maintenance, and other issues not directly related to the sequence of events varied, depending upon the particular experience and position of the individual being interviewed.

Some personnel were interviewed more than one time when the Team needed to obtain additional clarifying information. Table 2-1 contains a listing of the interviews and meetings conducted by the Team.

2.3 Plant Data

The following plant records were used in determining the times at which key events occurred during the transient:

(1) Sequence of Events Monitor Printout
(2) Alarm Printout
(3) Data Acquisition Display System Printout
(4) Analog curves generated from the digital information from the Data Acquisition Display System

The Sequence of Events Monitor and the Alarm Printout are both functions of the Plant Process Computer. The Sequence of Events Monitor records the change of state of the major digital inputs, such as equipment and key system trips. The Sequence of Events Monitor records events to the nearest five milliseconds and provides the most accurate time recording of all available plant records. The Alarm Printout lists both digital and analog information when parameters reach a predetermined alarm state. The digital points are scanned once per second and analog points are scanned at varying intervals (either at 1-, 5-, 15-, 30-, or 60-second intervals). The Alarm Printout indicates the time that a parameter either exceeds the alarm limit or returns to within the limit. The time resolution, however, is determined by the scanning interval.

The Data Acquisition and Display System is part of the Technical Support Center equipment and maintains a 24-hour record of plant parameters for event analyses. Key plant variables are recorded with a scan rate of once per second. Data from this system were available to the Team both in tabular form and, for selected variables, in the form of graphs. The times for the various events in the sequence of events were taken from the above plant records.

2.4 Quarantined Equipment

On June 10, 1985, NRC Region III issued a Confirmatory Action Letter indicating, among other things, that Toledo Edison would not perform any additional work

on equipment that malfunctioned during the event until the Team could review the proposed actions. The Team met with Toledo Edison and Region III representatives on the afternoon of June 11 to ensure agreement on the quarantined equipment list and to establish a course of action for determining the root causes of the equipment malfunctions. Toledo Edison was asked to develop plans for performing the troubleshooting in a systematic, controlled manner. A primary concern was to ensure that adequate records would be maintained on the "as-found" condition of equipment. In this meeting, any item that had failed during the June 9 event was placed on the quarantine list, except where Toledo Edison was able to justify removal on the basis of not being related to the safety concerns of the event.

In subsequent meetings, Toledo Edison and the Team agreed upon the list of equipment which should be handled under the procedures for quarantined equipment. As the evaluation of the event evolved, the list was modified. For example, steam line traps and drains thought to have malfunctioned and caused water buildup in the steam lines upstream of one set of turbine bypass valves were included. The malfunctioning of the traps and drains then became a possible root cause for water hammer damage to the turbine bypass valve. The steam generator atmospheric vent valves were also added to the list when a question arose regarding their potential malfunctioning or improper use during the event.

In a meeting on June 14, Toledo Edison presented plans for controlling the equipment troubleshooting. They provided "Guidelines to Follow When Troubleshooting or Performing Investigative Actions Into the Root Causes Surrounding the June 9, 1985 Reactor Trip," which delineated the general procedures to be followed for troubleshooting each piece of equipment. Toledo Edison's original document was revised as a result of discussions at this and subsequent meetings. The procedures agreed upon required maintenance work orders to be based upon a specific action plan for each piece of equipment. The action plans were to contain hypotheses and probable causes of failure or abnormal operation for each piece of equipment. The action plans were to include an analysis of information concerning the operation of the equipment during the event, a review of the maintenance, surveillance and testing history for the equipment, and plans for determining the probable causes for the equipment malfunctions observed. Specific statements indicating where equipment vendor representatives were to be used in the troubleshooting also were to be provided in the action plans.

The troubleshooting procedures required that all as-found conditions, such as damaged components or setpoint adjustments, be documented. Retention and complete traceability for components and equipment requiring replacement were to be maintained. Toledo Edison agreed to notify the NRC when the determination of the root cause of the malfunction or failure of a piece of equipment was made. It was agreed that the results of the troubleshooting process, root cause determinations, and supporting justification were to be presented to the NRC as soon as practical.

The Team did not approve the individual action plans, but did review and comment on the plans for the most significant equipment which malfunctioned during the event. Region III personnel monitored Toledo Edison troubleshooting efforts to ensure that the general guidelines for the troubleshooting and the specific equipment action plans were followed.

On July 11 and 12, 1985, the Team met with Toledo Edison personnel to discuss the status of the troubleshooting efforts. The information available on the equipment malfunctions at the time this report was prepared is discussed in Section 5.

The "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip" with the attached list of quarantined equipment ("Equipment Freeze" list) appears as Appendix A.

Table 2.1 List of Interviews and Meetings Conducted by the Davis-Besse Team

Date	Time	Meeting/Interview
6/11/85	12:30 pm	Briefing by Licensee on Event
6/11/85	3:20 pm	Meeting on Davis-Besse Design Features Related to Event
6/11/85	4:55 pm	Meeting on Status of Equipment Which Malfunctioned
6/11/85	5:55 pm	Interview of NRC Region III Resident Inspector
6/12/85	9:08 am	Interview of Shift Supervisor
6/12/85	11:22 am	Interview of Assistant Shift Supervisor
6/12/85	12:30 pm	Meeting on Status of Equipment Which Malfunctioned
6/12/85	1:45 pm	Interview of Operations Superintendent
6/13/85	9:10 am	Interview of Reactor Operator (Secondary Side)
6/14/85	9:12 am	Interview of Reactor Operator (Primary Side)
6/14/85	2:53 pm	Meeting on Troubleshooting of Equipment
6/15/85	9:15 am	Interview of Plant Manager and Operations Supervisor
6/15/85		Plant Tour
6/15/85	4:30 pm	Meeting on Troubleshooting of Equipment
6/17/85	9:10 am	Interview of Four Equipment Operators
6/18/85	9:26 am	Interview of Shift Technical Advisor
6/18/85	1:19 pm	Meeting on Troubleshooting for the Main Feedwater Pump Control System
6/18/85	4:26 pm	Meeting on Sequence of Events
6/19/85	9:55 am	Meeting on Troubleshooting for the Nuclear Instrumentation Source Range Channels
6/19/85	11:22 am	Meeting on Troubleshooting for the Turbine Bypass Valve
6/19/85	1:05 pm	Interview of the Shift Supervisor and Assistant Shift Supervisor

*Transcripts were made of all meetings and interviews listed.

6/20/85	10:10 am	Interview of NRC Region III Senior Resident Inspector
6/20/85	5:30 pm	Meeting on Troubleshooting for the Auxiliary Feed Pumps Overspeed Trips
6/21/85	9:00 am	Interview of Plant Manager and Operations Superintendent
6/21/85	10:30 am	Meeting on Valves AF 599 and AF 608; Troubleshooting for the AFPT Overspeed Trip Throttle Valve Problem; and Sequence of Events
6/21/85	2:00 pm	Interview of Administrative Assistant to the Shift Supervisor
6/21/85	5:30 pm	Interview of NRC Region III Senior Resident Inspector
6/27/85	10:35 am	Meeting on Troubleshooting for the Auxiliary Feed Pumps Overspeed Trips, the PORV, Spurious Closure of the MSIVs, and the Startup Feed Valve SP-7A.
7/9/85	9:30 am	Meeting on Design and Operation of the Steam and Feedwater Rupture Control System
7/9/85	11:20 am	Meeting on Miscellaneous Plant Design Details and Equipment Capacities
7/9/85	1:25 pm	Interview of Operations Superintendent on Availability of Selected Procedures and Actions Required to Regain Main Feedwater Flow
7/9/85	2:40 pm	Meeting on Pilot Operated Relief Valve Controls
7/10/85	9:10 am	Meeting on Design and Operation of the Steam and Feedwater Rupture Control System
7/10/85	1:12 pm	Meeting on Sequence of Events
7/11/85	9:22 am	Meeting on Design and Operation of the Steam and Feedwater Rupture Control System
7/11/85	12:00 pm	Meeting on Operator Training Related to Steam and Feedwater Rupture Control System Manual Actuation
7/11/85	4:25 pm	Meeting on Status of Troubleshooting Activities
7/12/85	9:10 am	Meeting on Status of Troubleshooting Activities

3 NARRATIVE OF THE EVENT

This detailed description of the Davis-Besse loss-of-feedwater event focuses attention on the operator actions which prevented a potentially serious event, both in terms of safety and economics, from occurring. From their normal operating routine, the operators were plunged abruptly into a high stress situation requiring complicated responses outside the control room. Furthermore, these activities unfolded early on a Sunday morning when additional technical expertise from either onsite or offsite was at a minimum.

In view of the importance of the operator actions, the narrative of the event which follows is based upon a composite of the operator interviews performed by the Team. The narrative is written to reflect the operators' descriptions of their actions, observations, and thoughts during the event. The team decided that this would best convey the effects of stress, training, experience, teamwork, and impediments on operator performance. There are undoubtedly lessons to be learned about what operators are likely to do during a serious event which are not easily summarized, but which perhaps can be inferred from the descriptions of what occurred during this particular event.

The sequence of events listed in Table 3.1 is based on the plant process computer printouts (alarm and sequence of events) and the data acquisition display system (DADS) computer printouts. The trends of important primary and secondary coolant system parameters are shown in Figures 3.1 through 3.3 as a function of time. Figure 3.1 shows the reactor coolant system pressure, average temperature, and the pressurizer level. Figures 3.2 and 3.3 show the pressure, level and flow for each of the two steam generators.

3.1 Shift Change

On June 9, 1985, the midnight shift of operators assumed control of the Davis-Besse nuclear power plant. The oncoming shift included four licensed operators, four equipment operators, an auxiliary operator, and an administrative assistant. The shift supervisor and the assistant shift supervisor are licensed senior reactor operators and the most experienced members of the operating crew. Both were at the plant before it was issued an operating license in April 1977. The two reactor operators, who were responsible for the control room, had decided between themselves who would be responsible for the primary-side and who would take the secondary-side work stations. The secondary-side operator has been a licensed reactor operator for about two years; the primary-side operator was licensed in January 1985. He had previous nuclear Navy experience and was an equipment operator before being licensed. Prior to the morning of June 9, neither reactor operator had been at the controls during a reactor trip at Davis-Besse.

The four equipment operators are a close-knit group, three of whom had been operators in the nuclear Navy. Their experience at the plant ranges from three to nine years, averaging six-and-one-half years per operator. Equipment operators receive directions from the control room operators to manipulate and troubleshoot equipment in the reactor auxiliary building and the turbine

building. Generally, equipment operators occupy this position temporarily as they participate in a development program leading to the position of licensed operator. However, two equipment operators did not intend to become licensed operators.

The shift turnover on June 9 was easy--there were no ongoing tests or planned changes to plant status. The plant was operating at 90 percent of the full power authorized in the license granted by the NRC in April 1977, to minimize the potential for an inadvertent reactor trip (i.e., shutdown) due to noise on primary coolant flow instrumentation.

All the major equipment control stations were running on automatic except the No. 2 main feedwater pump. As a result, the integrated control system instruments were monitoring and controlling the balance between the plant's reactor coolant system and the secondary coolant system.

Since April 1985, there had been control problems with both main feedwater pumps. Troubleshooting had not identified nor resolved the problems. In fact, a week earlier, on June 2, 1985, both feedwater pumps tripped unexpectedly after a reactor trip. After some additional troubleshooting, the decision was made to not delay startup any longer, but to put instrumentation on the pumps to help diagnose the cause of a pump trip, if it occurred again. As a precaution, the number two main feedwater pump was operating in manual control to prevent it from tripping and to ensure that all main feedwater would not be lost should the reactor trip.

Some operators were uneasy about going up to power with problems in the feedwater pumps, but they complied with the decisions made by their management.

During the first hour of the shift, the operators' attention and thoughts were directed to examining the control panels and alarm panels, and performing instrument checks and routine surveillances associated with shift turnover. Thus, at 1:35 in the morning, the plant generator was providing electricity to the Ohio countryside. The secondary-side operator had gone to the kitchen where he joined an equipment operator for a snack. The other reactor operator was at the operator's desk studying procedures for requalification examinations. The assistant shift supervisor had just left the kitchen on his way back to the control room after a break. The shift supervisor was in his office outside the control room performing administrative duties.

3.2 Reactor Trip - Turbine Trip

The assistant shift supervisor entered the control room (shown in Figure 3.4) and was examining one of the consoles when he noticed that main feedwater flow was decreasing and that the No. 1 main feedwater pump had tripped. Since the No. 2 feedwater pump was in manual control, it could not respond to the integrated control system demand automatically to increase feedwater flow.

The "winding down" sound of the feedwater pump turbine was heard by the reactor operator in the kitchen, and by the administrative assistant and the shift supervisor, both of whom were in their respective offices immediately outside the control room. They headed immediately for the control room--the event had begun.

The secondary-side reactor operator ran to his station and immediately increased the speed of the No. 2 main feedwater pump to compensate for the decrease of feedwater flow from the No. 1 pump. The primary-side operator had already opened the pressurizer spray valve in an attempt to reduce the pressure surge resulting from the heatup of the reactor coolant system due to a decrease in feedwater flow.

The plant's integrated control system attempted automatically to reduce reactor/turbine power in accordance with the reduced feedwater flow. The control rods were being inserted into the core and reactor power had been reduced to about 80 percent. At the same time the primary-side reactor operator held open the pressurizer spray valve in an attempt to keep the reactor coolant pressure below the high pressure reactor trip set point of 2300 psig (normal pressure is 2150 psig). However, the reduction of feedwater and subsequent degradation of heat removal from the primary coolant system caused the reactor to trip on high reactor coolant pressure. The operators had done all they could do to prevent the trip, but the safety systems had acted automatically to shut down the nuclear reaction.

The primary-side operator acted in accordance with the immediate post-trip actions specified in the emergency procedure that he had memorized. Among other things, he checked that all control rod bottom lights were on, hit the reactor trip (shutdown) button, isolated letdown from the reactor coolant system, and started a second makeup pump to anticipate a reduced pressurizer inventory after a normal reactor trip. Then he waited, and watched the reactor coolant pressure to see how it behaved.

The secondary-side operator heard the turbine stop valves slamming shut and knew the reactor had tripped. This "thud" was heard by most of the equipment operators who also recognized its meaning and two of them headed for the control room. Almost simultaneously, the secondary-side operator heard the loud roar of main steam safety valves opening, a sound providing further proof that the reactor had tripped. The lifting of safety valves after a high-power reactor trip was normal. Everything was going as expected as he waited and watched the steam generator water levels boil down--each should reach the normal post-trip low level limit of 35 inches on the startup level instrumentation and hold steady.

The shift supervisor joined the operator at the secondary-side control console and watched the rapid decrease of the steam generator levels. The rapid feed-water reduction system (a subsystem of the integrated control system) had closed the startup feedwater valves, but as the level approached the low level limits, the startup valves opened to hold the level steady. The main steam safety valves closed as expected. The system response was looking "real good" to the shift supervisor.

The assistant shift supervisor in the meantime opened the plant's looseleaf emergency procedure book. (It is about two inches thick, with tabs for quick reference. The operators refer to it as emergency procedure 1202:01; the NRC refers to it as the ATOG procedure - Abnormal Transient Operating Guidelines.) As he read aloud the immediate actions specified, the reactor operators were responding in the affirmative. After phoning the shift technical advisor (STA) to come to the control room, the administrative assistant began writing down what the operators were saying, although they were speaking faster then she could write.

The STA was working a 24-hour shift and was asleep when awakened by a telephone call from the shift supervisor, which was followed immediately by the call from the administrative assistant. (The STAs are provided an apartment-type room in the administrative building, which is outside the protected area about one-half mile from the plant. According to procedures, they must be able to get to the control room within 10 minutes of being called.) He had detected a sense of urgency in the telephone calls and so he ran out of the building to his car for the drive to the site. He was anxious himself--this was his first reactor trip since becoming a shift technical advisor in January 1985.

3.3 Loss of Main Feedwater

Although the assistant shift supervisor was loudly reading the supplementary actions from the emergency procedure book, the shift supervisor heard the main steam safety valves open again. He knew from experience that something was unusual and instinctively surveyed the control console and panels for a clue. He discovered that both main steam isolation valves (MSIVs) had closed--the first and second of a list of unexpected equipment performances and failures that occurred during the event.

The secondary-side operator was also aware that something was wrong because he noticed that the speed of the only operating main feedwater pump was decreasing. After verifying that the status of the main feedwater pump turbine was normal, he concluded that the turbine was losing steam pressure at about the same time that the shift supervisor shouted that the MSIVs were closed. All eyes then turned up to the annunciators at the top of the back panel. They saw nothing abnormal in the kind or number of annunciators lit after the reactor trip. The operators expected to find an alarm indicating that the Steam Feedwater Rupture Control System (SFRCS, pronounced S-FARSE) had activated. Based on their knowledge of previous events at the plant, they believed that either a partial or full actuation of the SFRCS had closed the MSIVs. However, the SFRCS annunciator lights shown in Figure 3.5 were dark. The MSIVs had closed at 1:36 a.m. and they were going to stay closed. It normally takes at least one-half hour to prepare the steam system for reopening the valves.

The No. 2 main feedwater pump turbine, deprived of steam, was slowly winding down. Since the MSIVs were closed and there was limited steam inventory in the moisture separator reheaters, there was inadequate motive power to pump feedwater to the steam generators. At about 1:40 a.m. the discharge pressure of the pump had dropped below the steam pressure which terminated main feedwater flow.

3.4 Loss of Emergency Feedwater

The secondary-side operator watched the levels in both steam generators boil down; he had also heard the main steam safety valves lifting. Without feedwater, he knew that an SFRCS actuation on low steam generator level was imminent. The SFRCS should actuate the auxiliary feedwater system (AFWS) which in turn should provide emergency feedwater to the steam generators. He was trained to trip manually any system that he felt was going to trip automatically. He requested and received permission from the shift supervisor to trip the SFRCS on low level to conserve steam generator inventory, i.e., the AFWS would be initiated before the steam generator low-level setpoint was reached.

He went to the manual initiation switches at the back panel and pushed two buttons to trip the SFRCS. (The SFRCS control panel is shown in Figure 3.6.) He inadvertently pushed the wrong two buttons and, as a result, both steam generators were isolated from the emergency feedwater supply. He had activated the SFRCS on low pressure (the top pair of buttons in Figure 3.6) for each steam generator instead of on low level (the fourth pair of buttons from the top). By manually actuating the SFRCS on low pressure, the SFRCS was signalled that both generators had experienced a steamline break or leak and the system responded, as designed, to isolate both steam generators. The operator's anticipatory action defeated the safety function of the auxiliary feedwater system--a common-mode failure and the third abnormality to occur within 6 minutes after the reactor trip.

The operator returned to the auxiliary feedwater station expecting the AFWS to actuate and provide the much-needed feedwater to the steam generators that were boiling dry. Instead, he first saw the No. 1 AFW pump, followed by the No. 2 AFW pump trip on overspeed--a second common-mode failure of the auxiliary feedwater system and abnormalities four and five. He returned to the SFRCS panel to find that he had pushed the wrong two buttons.

The operator knew what he was supposed to do. In fact, most knowledgeable people in the nuclear power industry, even control room designers, know that the once-through steam generators in Babcock & Wilcox-designed plants can boil dry in as little as 5 minutes; consequently, it is vital for an operator to be able to quickly start the AFWS. There could have been a button labeled simply "AFWS--Push to Start." But instead, the operator had to do a mental exercise to first identify a signal in the SFRCS that would indirectly start the AFW system, find the correct set of buttons from a selection of five identical sets located knee-high from the floor on the back panel, and then push them without being distracted by the numerous alarms and loud exchanges of information between operators.

The shift supervisor quickly determined that the valves in the AFWS were improperly aligned. He reset the SFRCS, tripped it on low level, and corrected the operator's error about one minute after it occurred. This action commanded the SFRCS to realign itself such that each AFW pump delivered flow to its associated steam generator. Thus, had both systems (the AFWS and SFRCS) operated properly, the operator's mistake would have had no significant consequences on plant safety.

The assistant shift supervisor, meanwhile, continued reading aloud from the emergency procedure. He had reached the point in the supplementary actions that require verification that feedwater flow was available. However, there was no feedwater, not even from the AFWS, a safety system designed to provide feedwater in the situation that existed. (The Davis-Besse emergency plan identifies such a situation as a Site Area Emergency.) Given this condition, the procedure directs the operator to the section entitled, "Lack of Heat Transfer." He opened the procedure at the tab corresponding to this condition, but left the desk and the procedure at this point, to diagnose why the AFWS had failed. He performed a valve alignment verification and found that the isolation valve in each AFW train had closed. Both valves (AF-599 and AF-608) had failed to reopen automatically after the shift supervisor had reset the SFRCS. He tried unsuccessfully to open the valves by the push buttons on the back panel. He went to the SFRCS cabinets in the back of the back panel to clear any trips

in the system and block them so that the isolation valves could open. However, there were no signals keeping the valves closed. He concluded that the torque switches in the valve operators must have tripped. The AFW system had now suffered its third common-mode failure, thus increasing the number of malfunctions to seven within 7 minutes after the reactor trip (1:42 a.m.).

3.5 Reactor Coolant System Heatup

Meanwhile, about 1:40 a.m., the levels in both steam generators began to decrease below the normal post-reactor-trip limits (about 35 inches on the startup range). The feedwater flow provided by the No. 1 main feedwater pump had terminated. The flow from the No. 2 main feedwater pump was decreasing because the MSIVs were closed, which isolated the main steam supply to the pump. With decreasing feedwater flow, the effectiveness of the steam generators as a heat sink for removing decay (i.e., residual) heat from the reactor coolant system rapidly decreased. As the levels boiled down through the low level setpoints (the auxiliary feedwater should automatically initiate at about 27 inches), the average temperature of the reactor coolant system began to increase, indicating a lack of heat transfer from the primary to the secondary coolant systems. When the operator incorrectly initiated SFRCS on low pressure, all feedwater was isolated to both steam generators. The reactor coolant system began to heat up because heat transfer to the steam generators was essentially lost due to loss of steam generator water level.

The average reactor coolant temperature increased at the rate of about 4 degrees Farenheit per minute for about 12 minutes. The system pressure also increased steadily until the operator fully opened the pressurizer spray valve (at about 1:42 a.m.). The spray reduced the steam volume in the pressurizer and temporarily interrupted the pressure increase. The pressurizer level increased rapidly but the pressurizer did not completely fill with water. As the indicated level exceeded the normal value of 200 inches, the control valve for makeup flow automatically closed.

At this point, things in the control room were hectic. The plant had lost all feedwater; reactor pressure and temperature were increasing; and a number of unexpected equipment problems had occurred. The seriousness of the situation was fully appreciated.

3.6 Operator Actions

By 1:44 a.m., the licensed operators had exhausted every option available in the control room to restore feedwater to the steam generators. The main feedwater pumps no longer had a steam supply. Even if the MSIVs could be opened, the steam generators had essentially boiled dry, and sufficient steam for the main feedwater pump turbines would likely not have been available. The turbines for the AFW pumps had tripped on overspeed, and the trip throttle valves could not be reset from the control room. Even if the AFW pumps had been operable, the isolation valves between the pumps and steam generators could not be opened from the control room, which also inhibited the AFWS from performing its safety function. The likelihood of providing emergency feedwater was not certain, even if the AFW pump overspeed trips could be reset and the flow path established; for example there was a question as to whether there was enough steam remaining in the steam generators to start the steam-driven pumps. Unknown to

the operators, the steam inventory was further decreased because of problems controlling main steam pressure. The number of malfunctions had now reached eight.

Three equipment operators had been in the control room since shortly after the reactor tripped. They had come to the control room to receive directions and to assist the licensed operators as necessary. They were on the sidelines watching their fellow operators trying to gain control of the situation.

The safety-related AFW equipment needed to restore water to the steam generators had failed in a manner that could only be remedied at the equipment location and not from the control room. The affected pumps and valves are located in locked compartments deep in the plant.

The primary-side reactor operator directed two of the equipment operators to go to the auxiliary feedwater pump room to determine what was wrong--and hurry.

The pump room, located three levels below the control room, has only one entrance: a sliding grate hatch that is locked with a safety padlock (Figure 3.7). One of the operators carried the key ring with the padlock key in his hand as they left the control room. They violated the company's "no running" policy as they raced down the stairs. The first operator was about 10 feet ahead of the other operator who tossed him the keys so as not to delay unlocking the auxiliary feedwater pump room. The operator ran as fast as he could and had unlocked the padlock by the time the other operator arrived to help slide the hatch open.

The operators descended the steep stairs resembling a ladder into the No. 2 AFW pump room. They recognized immediately that the trip throttle valve had tripped (see Figure 3.8). One operator started to remove the lock wire on the handwheel while the other operator opened the water-tight door to the No. 1 AFW pump. He also found the trip throttle valve tripped and began to remove the lock wire from the handwheel.

The shift supervisor had just dispatched a third equipment operator to open AFW isolation valves AF-599 and AF-608. These are chained and locked valves, as shown in Figure 3.9, and the shift supervisor gave the lock-valve key to the operator before he left the control room. He paged a fourth equipment operator over the plant communications systems and directed him also to open valves AF-599 and AF-608. Although the operators had to go to different rooms for each valve, they opened both valves in about 3½ minutes. They were then directed to the AFW pump room.

As the operators ran to the equipment, a variety of troubling thoughts ran through their minds. One operator was uncertain if he would be able to carry out the task that he had been directed to do. He knew that the valves he had to open were locked valves, and they could not be operated manually without a key. He did not have a key and that concerned him. As he moved through the turbine building, he knew there were numerous locked doors that he would have to go through to reach the valves. He had a plastic card to get through the card readers, but they had been known to break and fail. He did not have a set of door keys and he would not gain access if his key card broke and that concerned him too.

The assistant shift supervisor came back into the control console area after having cleared the logic for the SFRCS and he tried again, unsuccessfully, to open the AFWS isolation valves. At this point, the assistant shift supervisor made the important decision to attempt to place the startup feedwater pump (SUFP) in service to supply feedwater to the steam generators. He went to the key locker for the key required to perform one of the five operations required to get the pump running.

The SUFP is a motor-driven pump, usually more reliable than a turbine-driven pump, and more importantly, it does not require steam from the steam generators to operate. The SUFP is located in the same compartment as the No. 2 AFW pump. But since the refueling outage in January 1985, the SUFP had been isolated by closing four manual valves and its fuses were removed from the motor control circuit. This isolation was believed necessary because of the consequences of a high energy break of the non-seismic grade piping which passes through the two seismic-qualified AFW pump rooms. Prior to January 1985, the SUFP could be initiated from the control room by the operation of a single switch.

The assistant shift supervisor headed for the turbine building where he opened the four valves and placed fuses in the pump electrical switchgear. This equipment is located at four different places; in fact, other operators had walked through the procedure of placing the SUFP in operation and required 15 to 20 minutes to do it. The assistant shift supervisor took about 4 minutes to perform these activities. He then paged the control room from the AFW pump room and instructed the secondary-side operator to start the pump and align it with the No. 1 steam generator.

The two equipment operators in the AFW pump rooms had been working about 5 minutes to reset the trip throttle valves when the assistant shift supervisor entered the room to check the SUFP. The equipment operators thought that they had latched and opened the valves. However, neither operator was initially successful in getting the pumps operational. Finally, after one equipment operator had tried everything that he knew to get the No. 1 AFW pump operating, he left it and went to the No. 2 AFW pump where the other operator was having the same problem of getting steam to the turbine. Neither operator had previously performed the task that he was attempting.

The assistant shift supervisor went over to assist the equipment operators and noticed immediately that the trip throttle valves were still closed. Apparently, the equipment operators had only removed the slack in attempting to open the valve. The valve was still closed and the differential pressure on the wedge disk made it difficult to turn the handwheel after the slack was removed, thus necessitating the use of the valve wrench. A third, more experienced operator had entered the pump room and used a valve wrench to open the trip throttle valve on AFW pump No. 2. Without the benefit of such assistance the equipment operators may well have failed to open the trip throttle valves to admit steam to the pump turbines.

The third equipment operator then proceeded to the No. 1 AFW pump trip throttle valve. The valve had not been reset properly and he experienced great difficulty in relatching and opening it because he had to hold the trip mechanism in the latched position and open the valve with the valve wrench. Because the trip mechanism was not reset properly, the valve shut twice before he finally opened the valve and got the pump operating.

3.7 PORV Failure

Prior to being informed by the assistant shift supervisor that the SUFP was available, the secondary-side operator requested the primary-side operator to reset the isolation signal to the startup feedwater valves in preparation for starting the SUFP. In order to perform this task, the operator left the control console and went to the SFRCS cabinets in back of the control room. As he re-entered the control panel area, he was requested to reset the atmospheric vent valves. As a result of these activities the primary side operator estimated that he was away from his station for 20 to 30 seconds. (In fact, he was away for about two minutes.)

While the operator was away from the primary-side control station, the pressurizer PORV opened and closed twice without his knowledge. The pressure had increased because of the continued heatup of the reactor coolant system that resulted when both steam generators had essentially boiled dry.

According to the emergency procedure, a steam generator is considered "dry" when its pressure falls below 960 psig and is decreasing, or when its level is below 8 inches on the startup range (normal post-trip pressure is 1010 psig and post-trip level is 35 inches). The instrumentation in the control room is inadequate for the operator to determine with certainty if these conditions exist in a steam generator. The lack of a trend recorder for steam generator pressure makes it difficult to determine if the steam pressure is 960 psig and decreasing. The range of the steam generator level indicator (Figure 3.10) in the control room is 0-250 inches, a scale which makes determining the 8-inch level difficult. The safety parameter display system (SPDS) was intended to provide the operators with these critical data, but both channels of the SPDS were inoperable prior to and during this event. Thus, the operators did not know that the conditions in the steam generators beginning at about 1:47 a.m. were indicative of a "dry" steam generator, or subsequently, that both steam generators were essentially dry.

When both steam generators are dry, the procedure requires the initiation of make-up/high pressure injection (MU/HPI) cooling, or what is called the "feed-and-bleed" method for decay heat removal. Even before conditions in the steam generators met these criteria, the shift supervisor was fully aware that MU/HPI cooling might be necessary. When the hot-leg temperature reached 591°F (normal post-trip temperature is about 550°F), the secondary-side operator recommended to the shift supervisor that MU/HPI cooling be initiated. At about the same time, the operations superintendent told the shift supervisor in a telephone discussion that if an auxiliary feedwater pump was not providing cooling to one steam generator within one minute, to prepare for MU/HPI cooling. However, the shift supervisor did not initiate MU/HPI cooling. He waited for the equipment operators to recover the auxiliary feedwater system.

The shift supervisor appreciated the economic consequences of initiating MU/HPI cooling. One operator described it as a drastic action. During MU/HPI, the PORV and the high point vents on the reactor coolant system are locked open, which breaches one of the plant's radiological barriers. Consequently, radioactive reactor coolant is released inside the containment building. The plant would have to be shut down for days for cleanup even if MU/HPI cooling was successful. In addition, achieving cold shutdown could be delayed. Despite his delay, the shift supervisor acknowledged having confidence in this mode of core

cooling based on his simulator training; he would have initiated MU/HPI cooling if "it comes to that."

The primary-side operator returned to his station and began monitoring the pressure in the pressurizer, which was near the PORV setpoint (2425 psig). The PORV then opened and he watched the pressure decrease. The indicator in front of him signaled that there was a closed signal to the PORV and that it should be closed (Figure 3.11). The acoustic monitor installed after the TMI accident was available to him to verify that the PORV was closed, but he did not look at it. Instead, he looked at the indicated pressurizer level, which appeared steady, and based on simulator training, he concluded that the PORV was closed.

In fact, the PORV had not completely closed and, as a result, the pressure decreased at a rapid rate for about 30 seconds.

The operator did not know that the PORV had failed. He believed the RCS depressurization was due either to the fully open pressurizer spray valve or to the feedwater flow to the steam generators. He closed the spray valve and the PORV block valve as precautionary measures. But subsequent analyses showed that the failed PORV was responsible for the rapid RCS depressurization. Two minutes later, the reactor operator opened the PORV block valve to ensure that the PORV was available. Fortunately, the PORV had closed by itself during the time the block valve was closed. The failed PORV was the ninth abnormality that had occurred within 15 minutes after reactor trip.

3.8 Steam Generator Refill

At about 1:50 a.m. the No. 1 atmospheric vent valve opened and depressurized the No. 1 steam generator to about 750 psig when the SFRCS signal was reset by the primary-side operator. The vent valve for the No. 2 steam generator had been closed by the secondary-side operator before the SFRCS signal was reset. The indicated No. 1 steam generator level was less than 8 inches. The corresponding pressure and indicated level in No. 2 steam generator were about 928 psig and 10 inches, respectively. The indicated levels continued to decrease until the secondary-side operator started the SUFP after being informed by the assistant shift supervisor that it was available and after the other operator had reset the isolation signal to startup feedwater valves.

Although the flow capacity of the SUFP is somewhat greater, approximately 150 gallons per minute (gpm) were fed to the steam generators because the startup valves were not fully opened. Essentially all the feedwater from the SUFP was directed to the No. 1 steam generator. At about 1:52 a.m., the pressure in the No. 1 steam generator increased sharply while the indicated water level stopped decreasing and began slowly to increase. Since there was little feedwater sent to the No. 2 steam generator, its condition did not change significantly.

The trip throttle valve for No. 2 AFW pump was opened by the equipment operators at about 1:53 a.m. After the SFRCS was reset and tripped on low level by the shift supervisor, the AFWS aligned itself so that each AFW pump would feed only its associated steam generator, i.e., the No. 2 AFW pump would feed the No. 2 steam generator. Thus, the No. 2 AFW pump refilled the No. 2 steam generator and its pressure increased abruptly to the atmospheric vent valve relief set point. The turbine governor valve was fully open when the trip throttle valve

was opened and the pump delivered full flow for about 30 seconds until the operator throttled the flow down.

The No. 1 trip throttle valve was opened by the equipment operator about 1:55 a.m. and feedwater from the AFWS flowed to the No. 1 steam generator. However, the No. 1 AFW pump was not controlled from the control room but controlled locally by the equipment operators.

The equipment operators controlled the pump locally using the trip throttle valve. One operator manipulated the valve based on hand signals from the operator who was outside the No. 1 AFW pump room communicating with the control room operator. For two hours the AFW pump was controlled in this manner by the operators. Their task was made more difficult from the time they first entered the AFW pump room by the intermittent failures of the plant communication station in the room.

With feedwater flow to the steam generators, the heatup of the reactor coolant system ended. At about 1:53 a.m. the average reactor coolant temperature peaked at about 592°F and then decreased sharply to 540°F in approximately 6 minutes (normal post-trip average temperature is 550°F). Thus, the reactor coolant system experienced an overcooling transient caused by an excessive AFW flow from the condensate storage tank. The overfill of the steam generators caused the reactor coolant system pressure to decrease towards the safety features actuation system (SFAS) setpoint of 1650 psig. To compensate for the pressure decrease, and to avoid an automatic SFAS actuation, at approximately 1:58 a.m., the primary-side operator aligned one train of the emergency core cooling system (ECCS) in the piggyback configuration. In this configuration the discharge of the low pressure injection pump is aligned to the suction of the high pressure injection pump to increase its shutoff head pressure to about 1830 psig. At about the time the train was actuated, the combination of pressurizer heaters, makeup flow, and reduction of the AFW flow increased the reactor coolant pressure above 1830 psig. As a result, only a limited amount (an estimated 50 gallons) of borated water was injected into the primary system from the ECCS.

At 1:58 a.m., the No. 1 AFW pump suction transferred spuriously from the condensate storage tank to the service water system (malfunction number 10). This action was not significant, but it had occurred before and had not been corrected. Similarly, a source range nuclear instrument because inoperable after the reactor trip (malfunction number 11) and the operators initiated emergency boration pursuant to procedures. (Note: One channel had been inoperable prior to the event.) The source range instrumentation had malfunctioned previously and apparently had not been properly repaired. Also, the control room ventilation system tripped into its emergency recirculation mode (malfunction number 12), which had also occurred prior to this event.

The steam generator water levels soon exceeded the normal post-trip level and the operator terminated AFW flow to the steam generators. The subcooling margin remained adequate throughout this event. The event ended at about 2 o'clock in the morning, twelve malfunctions and approximately 30 minutes after it began.

3.9 Emergency Plan

The shift technical advisor (STA) entered the control room about 15 minutes after the reactor trip and at about the time the SUFP was started. The STA was not required during this event in the manner that was envisioned, i.e., to provide technical advice and independent oversight. Instead, he provided administrative assistance to the shift supervisor by consulting the emergency plan. He also made the initial call to the NRC Operations Center at 2:11 a.m., after the plant was stable.

At that time, no emergency class was declared. In the telephone call to NRC, the fact that all feedwater had been lost during the event was reported. However, the fact that the steam generators had essentially emptied and that no sources of feedwater had been available for nearly 12 minutes was not reported. The STA had not been in the control room at the start of the event and did not have a total understanding of what had occurred. It is likely that had the plant not been brought to a stable condition quickly, and had plant safety further degraded, knowledgeable personnel in the control room would be focused on recovery efforts and would not want to take time to discuss the plant status with the NRC Operations Center.

At 2:26 a.m., the STA telephoned the NRC Operations Center to indicate that an Unusual Event had been declared. From questions asked by the NRC Operations Officer, he learned that either an alert or site area emergency had existed during the event. Plant conditions did not warrant any emergency classification at that time, although the shift supervisor had declared an Unusual Event primarily to ensure that additional personnel were made available at the plant to aid in evaluating the event and to maintain stable plant conditions.

From the interviews of those on duty during the event, it appears that all knowledgeable personnel were occupied in stabilizing the plant and, thus, not available to quickly and adequately inform the NRC Operations Center during the period that the plant had no feedwater. Although there appears to have been no intent to withhold information from the NRC Operations Center, there also was no appreciation that prompt, clear notification of the severity of an event to the NRC is essential for the NRC to perform its required functions. It should also be noted that plant management was informed of the event, including its severity, much more rapidly than the NRC. However, lengthy continued conversations with plant management did not occur as would be the case when an open telephone line is maintained with the NRC Operations Center.

Table 3.1 Chronological Sequence of Events

Initial Conditions

- Unit operating at 90% power
- Number One Main Feedpump (MFP) in automatic control
- Number Two Main Feedpump in manual control
- One Source Range Nuclear Instrumentation Channel inoperable
- Safety Parameter Display System (SPDS) inoperable, both channels

Transient Initiator

*01:35:00	#1 MFP Trips Control system causes MFP flow increase; MFP turbine trips on overspeed.

Systems Response/Operator Actions to Partial Loss of Main Feedwater

01:35:01	Unit runback initiated toward 55% at 50%/min.
01:35:21	Operator increases the speed of #2 MFP turbine. Pressurizer (Prz) spray valve manually opened to 100%.
01:35:30	Reactor Trip & Turbine Trip--RCS High Pressure (2300 psig) from 80% power.**
*01:35:31	Computer recorded Steam and Feedwater Rupture Control System (SFRCS), full trip on low level, actuation channel 2.
*01:35:31	Both Main Steam Isolation Valves (MSIVs) start to close.
01:35:34	SFRCS actuation signal automatically clears.
*01:35:36	MSIV #2 has closed.
*01:35:37	MSIV #1 has closed. With both MSIVs closed, the source of steam for #2 MFP turbine is isolated. Steam from main steam piping and moisture separator reheaters allowed #2 MFP to provide adequate flow for about 4½ minutes.
01:35:45	Pressurizer spray valve closed.
01:35:56	Once Through Steam Generator (OTSG) levels at normal post-trip level (35 inches).
*01:40:00	OTSG levels begin to fall from the normal post-trip level.

*Unexpected or off-normal response.

**As part of normal reactor trip procedure, operator isolated RCS letdown and started second RCS makeup pump, to maintain pressurizer level.

Table 3.1 Chronological Sequence of Events (continued)

System Response/Operator Actions to Complete Loss of Main Feedwater

01:41:04 SFRCS OTSG #1 low level (26.5 in.) full trip, actuation channel 1; this actuation causes Auxiliary Feedwater Pump (AFP) #1 to be aligned to draw steam from, and provide feed to, OTSG #1.

*01:41:08 The control room operator attempted to manually initiate SFRCS; however, he incorrectly actuated the SFRCS on low steam pressure instead of the desired low steam generator level. He performed the manual actuation by depressing the top switch in each column of manual actuation switches for the two SFRCS actuation channels.

Therefore, each SFRCS actuation channel sensed that its associated steam generator was inoperable and that the opposite OTSG was intact. SFRCS actuation channel 1 then attempted to align its associated AFW train (#1) to draw steam from only, and to provide feed only to, OSTG #2. SFRCS actuation channel 2 attempted to align its associated AFW train (#2) to draw steam from only, and to provide feed only to, OTSG #1. Both SFRCS actuation channels also closed their associated OTSG/AFW containment isolation valves. That is, SFRCS actuation channel 1 isolated OTSG #1 by closing valve AF-608; actuation channel 2 isolated OTSG #2 by closing valve AF-599. These OTSG/AFW isolation actions prevented any auxiliary feed flow from reaching either OTSG.

Per the SFRCS design, valves that had been positioned by the low level trip on SFRCS channel 1 were repositioned by the higher priority low pressure trip. The AFP 1 steam supply valve from OTSG #1, MS-106 had started open in response to the SFRCS actuation channel 1 low level trip. Following the low pressure trip, the valve should have continued opening to its full open position before it cycled closed. The entire open/close stroke time should have been about 50 seconds. *MS-106, however, returned to its closed position in about 18 seconds.

01:41:13 SFRCS actuation channel 2 tripped on OTSG #2 low level. Since the low pressure trip already present had priority, no change in component actuation occurred.

*01:41:31 Auxiliary Feedwater Pump Turbine (AFPT) #1 tripped on overspeed.

*01:41:44 AFPT #2 tripped on overspeed.

System Response/Operator Actions to Complete Loss of All Feedwater

01:42:00 Manual reset of SFRCS OTSG low pressure actuation.

*AF-599, AF-608 should have reopened automatically, but did not

*An attempt was made to reopen AF-599 and AF-608 from the main control panel, but the valves did not respond.

Table 3.1 Chronological Sequence of Events (continued)

01:42:00	Pzr. Spray valve opened.
01:43:55	Assistant Shift Supervisor went to SFRCS cabinets (behind the control room area), opened the doors, and operated the "operating bypass" for the SFRCS ("Initiate Reset and Block," used for normal plant cooldowns) in an attempt to reset any automatic safety signals to AF-599 and AF-608. *The valves remained closed.
*01:44	Equipment Operators were dispatched into the plant to operate the following equipment: (1) Two Equipment Operators were sent to the Auxiliary Feedwater Pump turbines to manually restore the AFW pump to service. (2) The Assistant Shift Supervisor left the control room to make the startup feed pump available for service. This required opening the pump suction valve, the pump discharge valve, and two cooling water valves. In addition, the control fuses for the 4160-volt pump motor circuit breaker were required to be installed. (3) Two equipment operators were sent to open OTSG Auxiliary Feedwater Isolation Valves AF-599 and AF-608. These valves are the containment isolations for the AFW system. The operators moved the valves from the closed position, and the motor operators opened the valves.
01:44:50	RCS Makeup flow decreases as the makeup flow control valve, MU-32, modulates closed based on pzr. level being above setpoint (200 inches).
01:45:50	AFPT #2 overspeed trip reset locally.
01:46:29	OTSG#1 Atmospheric Vent Valve opened.
01:46:30	AFPT #1 trip throttle valve re-latched and valve opened (overspeed trip not cleared). Speed controlled locally throughout event.
01:47:33	OTSG #1 below 960 psig and decreasing.
01:47:48	OTSG #2/AFW isolation valve, AF-599, opened locally.
01:48:08	OTSG #1 atmospheric vent valve closed.
01:48:49	Pzr. PORV opens (first time) at 2433 psig (2425 setpoint).
*01:48:51	OTSG #2 below 960 psig and decreasing. (Both OTSGs now "dried out," according to criteria in plant emergency procedures related to MU/HPI cooling.)

Table 3.1 Chronological Sequence of Events (continued)

01:48:52	Pzr. PORV has closed at 2377 psig (2375 setpoint).
01:49:28	OTSG #1/AFW isolation valve, AF-608, opened locally.
01:50:09	Pzr. PORV opens (second time) at 2434 psig.
01:50:12	Pzr. PORV has closed at 2369 psig.
01:50:13	OTSG #1 Atmospheric Vent Valve opened; OTSG #1 pressure decreases rapidly toward about 750 psig.
01:51:17	OTSG #1 level falls below eight inches (MU/HPI cooling criterion).
*01:51:18	Pzr. PORV opens (third time) at 2435 psig; did not close.
01:51:23	Startup feed pump motor started.
01:51:30	Obtained flow from startup feed pump to OTSG #1.
01:51:42	Operator started to close Pzr. PORV block valve as RCS pressure fell through 2140 psig.
01:51:42	RCS Loop #1 reaches a minimum pressure of 2081 psig. Loop #1: T-hot = 588.6°F; Tave = 587.5°F.
01:51:43	Pzr spray valve closed.
01:51:49	Acoustic monitor indicates less than 20% flow through PORV/block valves.
01:53:00	RCS loop #1 T-hot reaches peak value of 593.5°F.
01:53:22	AFW Train #2 has significant flow, with control locally via the trip-throttle valve.
01:53:25	RCS Tave reaches peak value of 592.3°F.
01:53:35	OTSG #2 returns to above 960 psig.
01:53:56	PORV Block Valve reopened by operator.
01:54:45	OTSG #1 returns to above 960 psig.
01:54:46	AFW Train #1 has significant flow, with control locally via the trip throttle valve.
01:56:58	OTSG #2 Atmospheric vent open; OTSG #2 below 960 psig and decreasing.
01:57:05	OTSG #1 below 960 psig and decreasing.

Table 3.1 Chronological Sequence of Events (continued)

*01:57:53	Low suction pressure developed on AFP #1; 34 seconds later (01:58:27), suction pressure was recovered.
01:58	Tave passed through the normal post-trip temperature. The cooldown had lowered RCS pressure to about 1720 psig. Operators manually started the HPI pump #1 in the piggyback mode (LPI pump 1 supplying the suction to the HPI pump 1) to maintain pressurizer pressure and level. A slight amount of water (about 50 gallons) was injected.
01:58:08	RCS loop #1 reaches a minimum pressure of 1716 psig. Loop #1: T-hot = 546.6°F; Tave = 546.2°F.
01:58:28	OTSG #1 Atmospheric vent closed.
01:58:33	AFW Train #1 flow reduced to control OTSG level.
*01:58:40	AFP #1 suction automatically transferred from the condensate storage tank (CST) to the service water system. The operator realigned to CST.
01:58:57	AFPT#1 overspeed trip reset.
02:01	When AFPT #2 was returned to service, the control room operator controlled the pump in manual rather than returning it to Automatic.
02:01:13	AFW Train #2 flow reduced.
02:02:27	OTSG #1 returns to above 960 psig.
02:02:30	OTSG #2 returns to above 960 psig.
02:04	Plant conditions essentially stable.

Additional Complications

1. Control Room HVAC system spuriously tripped to its emergency mode.
2. The operator attempted to override/reset the automatic close signal to the OTSG #2 startup feed control valve SP-7A. The reset light for this valve did not come on, indicating that control of the valve had not been regained. The control room operators therefore believed that flow from the S/U feed-pump went only through SP-7B to OSTG #1 and not through SP-7A to OTSG #2.
3. Upon energization the remaining source range nuclear instrumentation channel failed off-scale low. All control rods were verified to be fully inserted, and emergency boration was initiated.
4. The main turbine did not go into its turning gear.
5. When vacuum was restored and the MSIVs opened, a water slug damaged one of the main turbine bypass valves.

Table 3.1 Chronological Sequence of Events (continued)

Notes

1. The above sequence of events is based upon combining information obtained from plant computer printouts and operator interviews.

2. Adequate subcooled margin was available throughout the transient. The Reactor Coolant Pumps remained in operation. The Quench Tank contained the discharges from the PORV.

3. There is a question regarding the operation of the atmospheric vent valves.

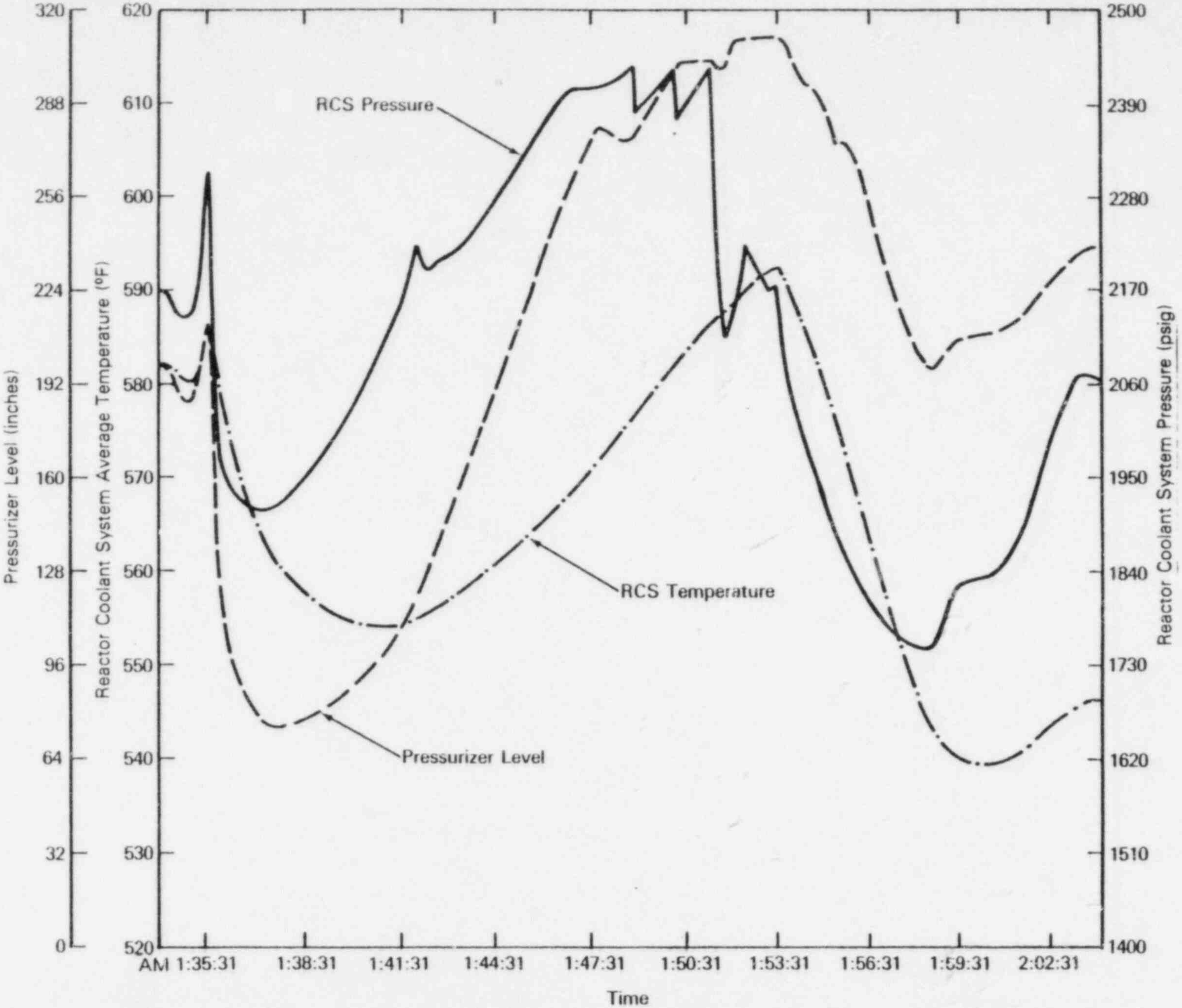


Figure 3.1 Reactor Coolant System and Pressurizer Response as a Function of Time, June 9, 1985

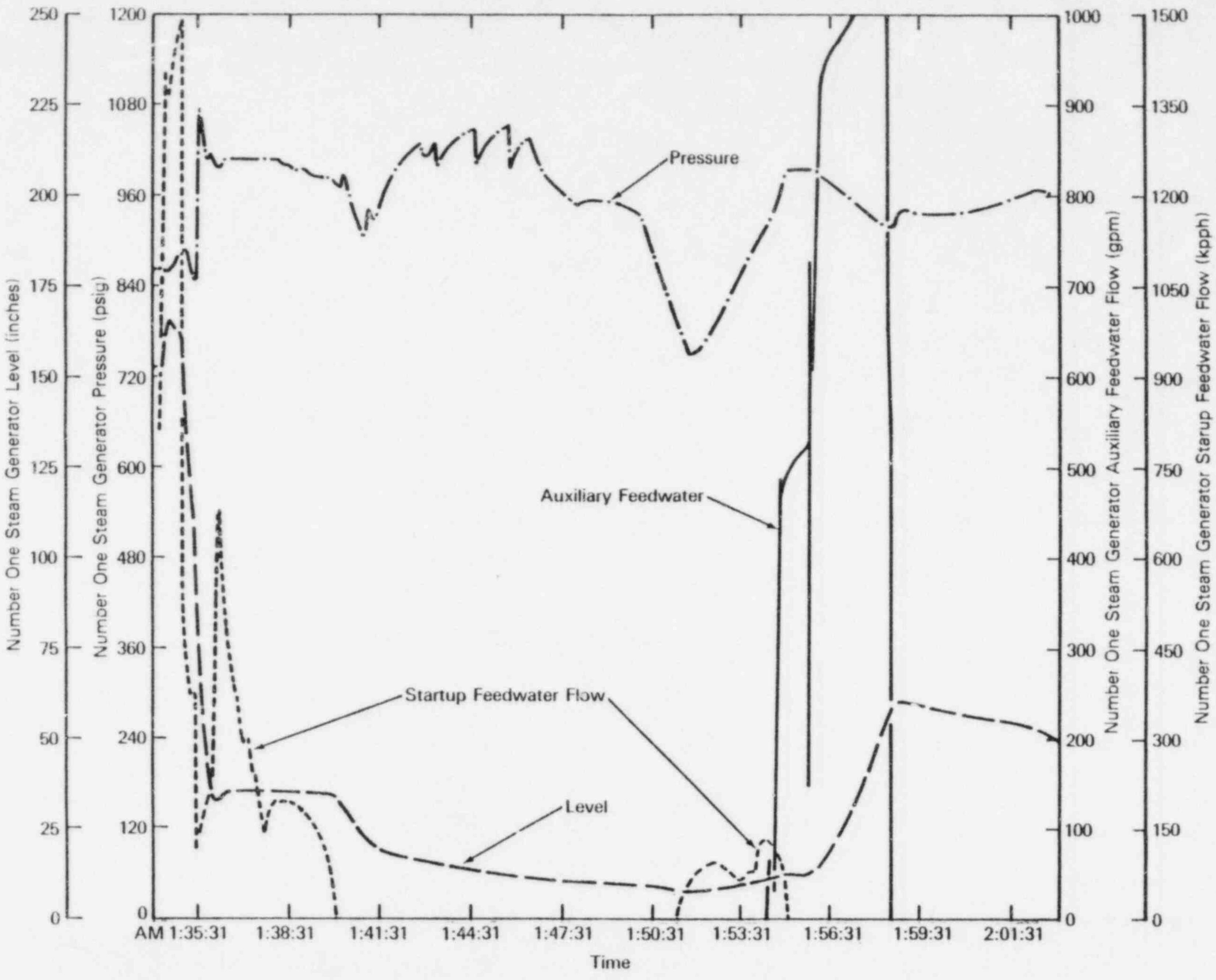


Figure 3.2 Number One Steam Generator Pressure, Level and Flow as a Function of Time, June 9, 1985

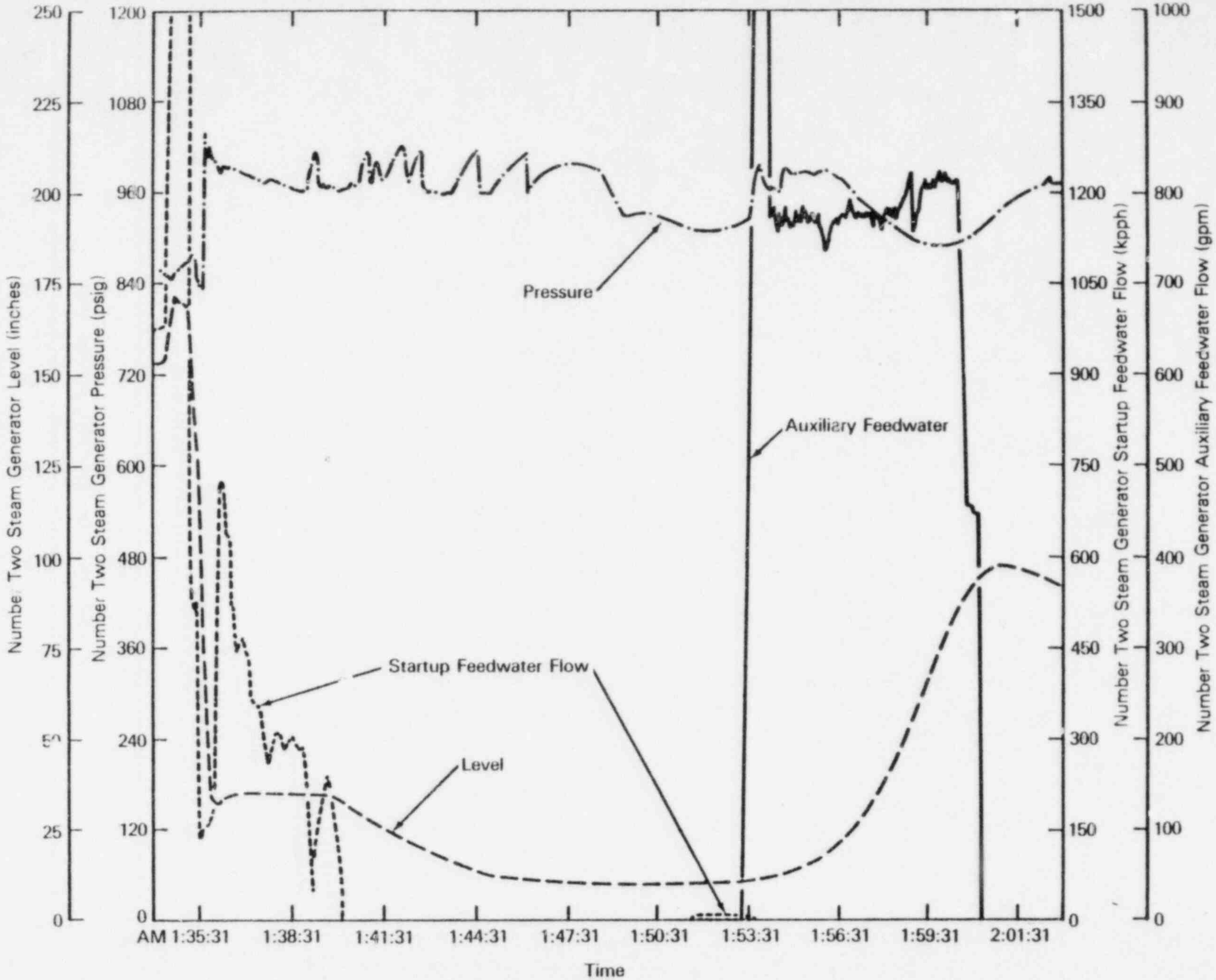


Figure 3.3 Number Two Steam Generator Pressure, Level and Flow as a Function of Time, June 9, 1985

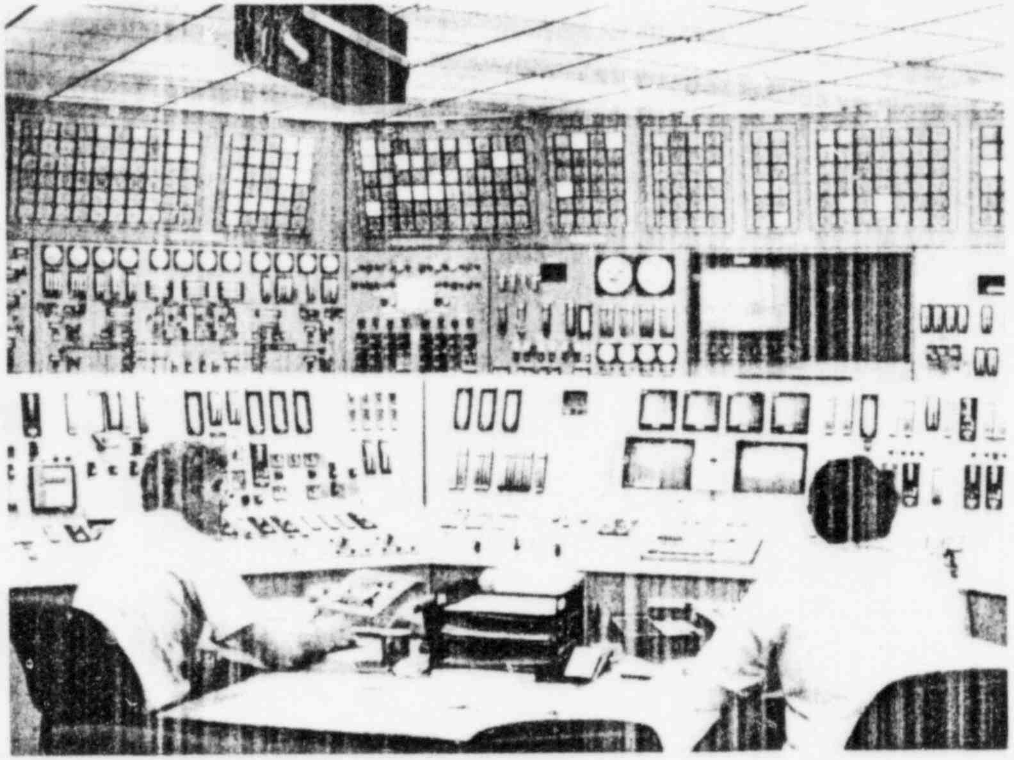


Figure 3.4 Davis-Besse Control Room

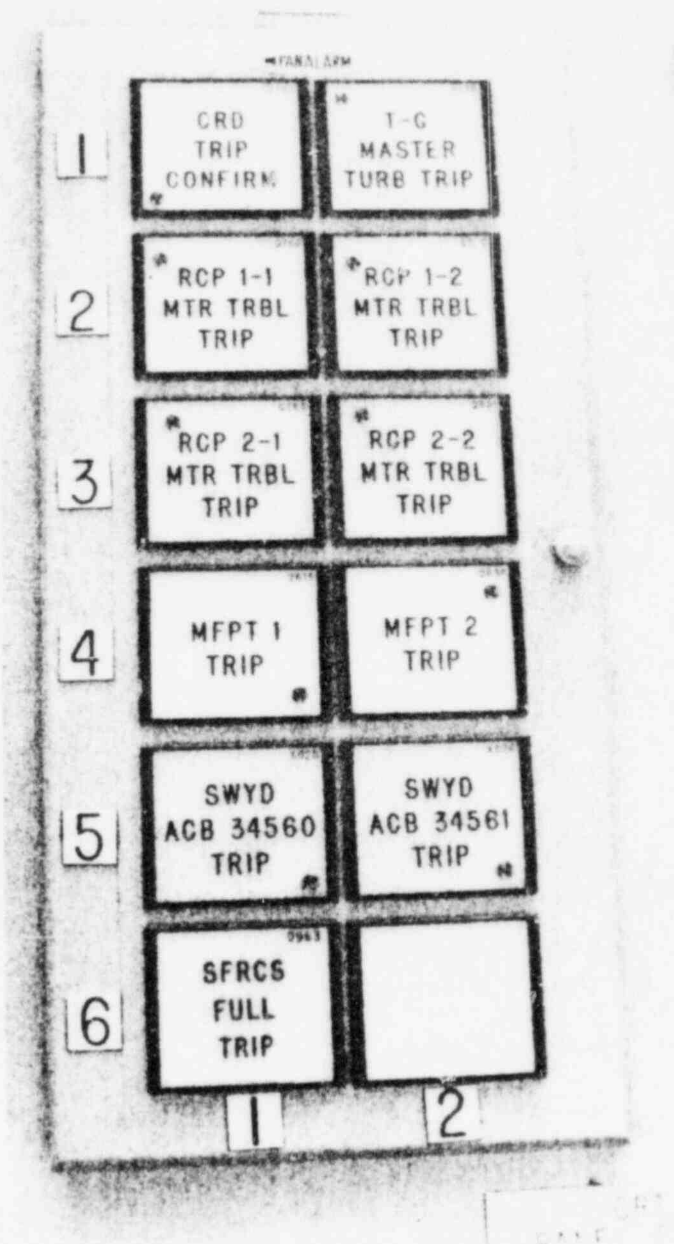


Figure 3.5 Annunciator Panel

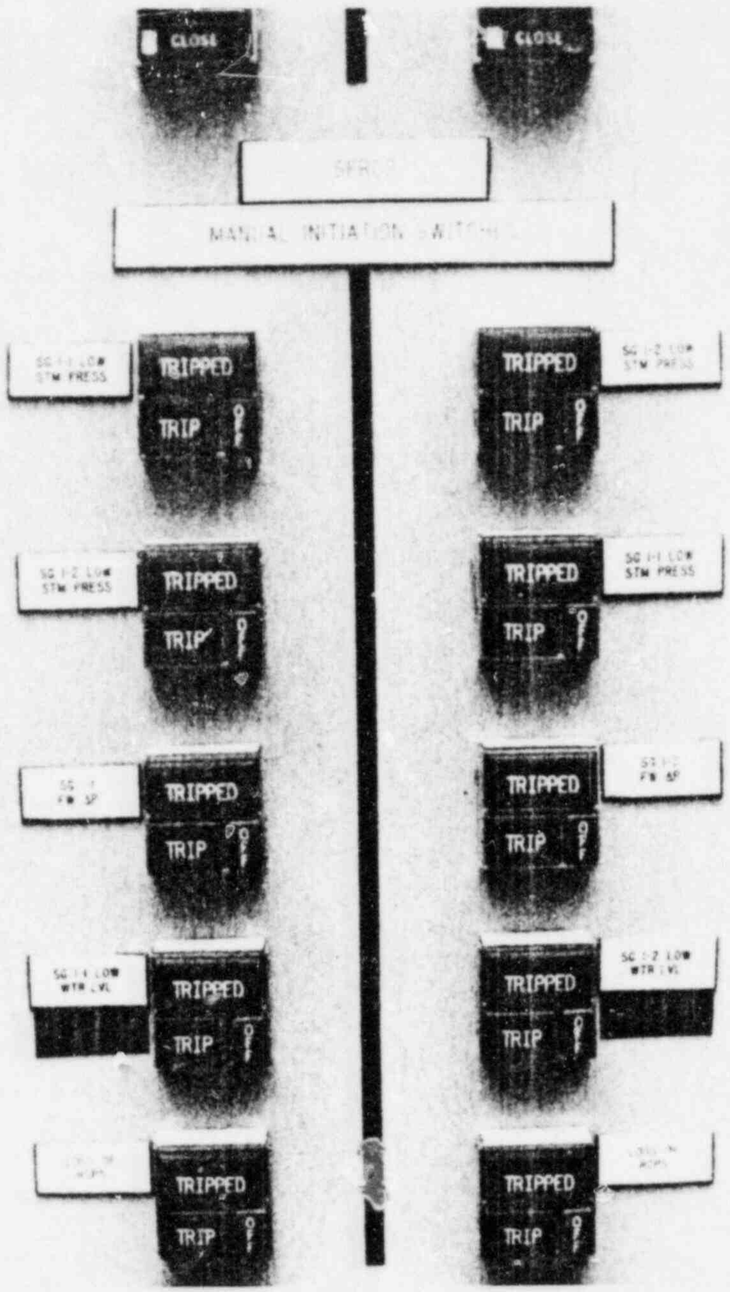


Figure 3.6 Manual Initiation Switches for SFRCS

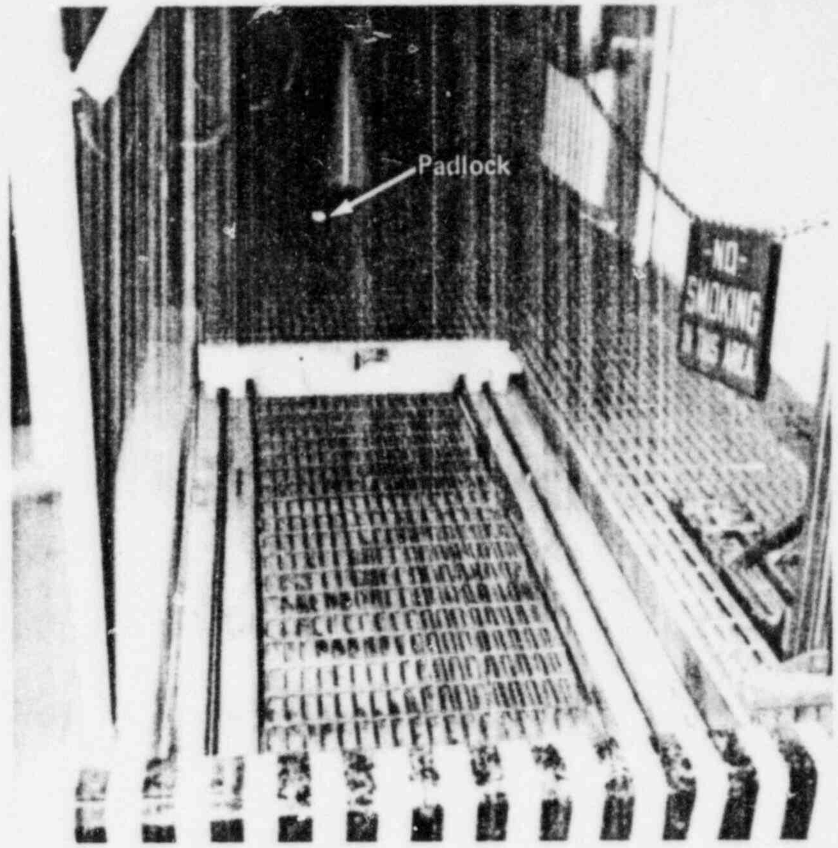


Figure 3.7 Grate Leading to Auxiliary Feedwater Pump Room

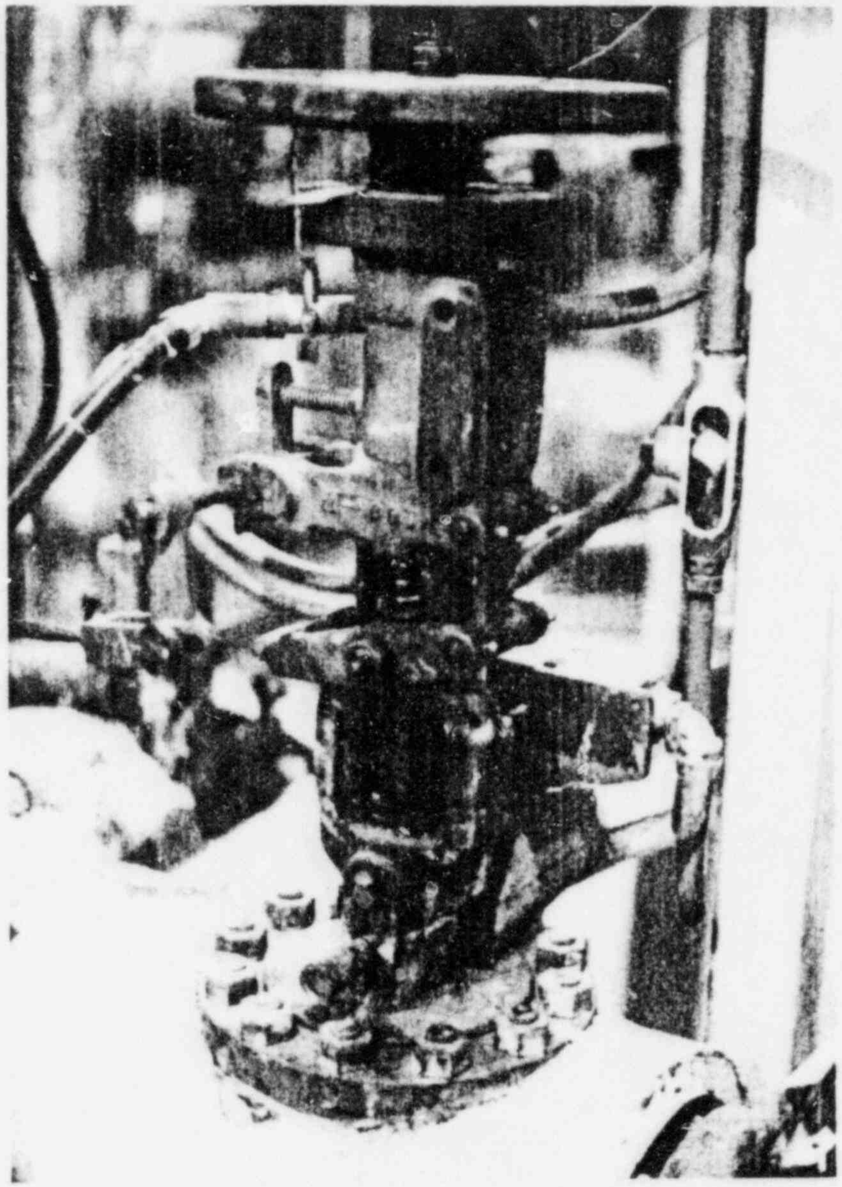


Figure 3.8 Trip Throttle Valve

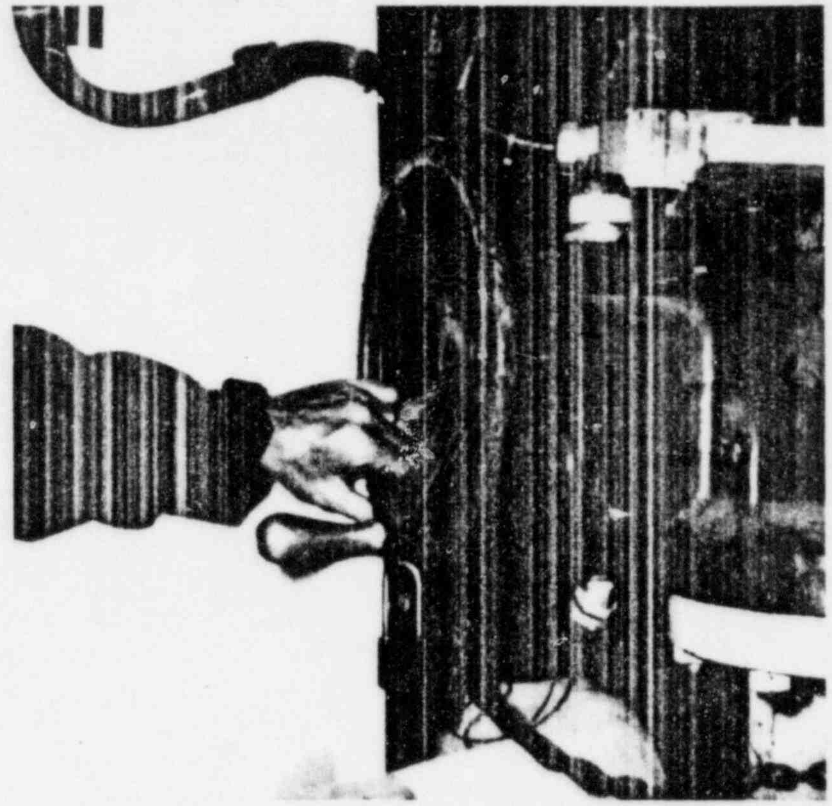


Figure 3.9 Chained and Locked AF-608 Valve

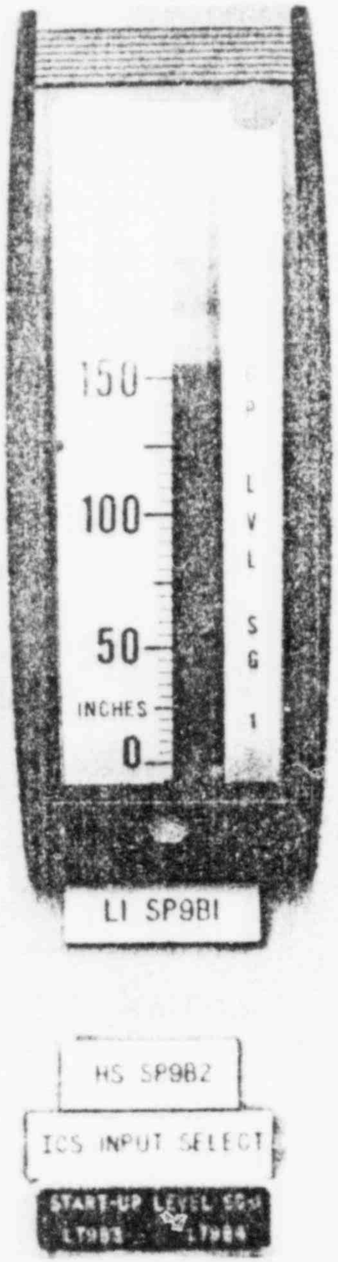


Figure 3.10 Control Room Indication of Steam Generator Level

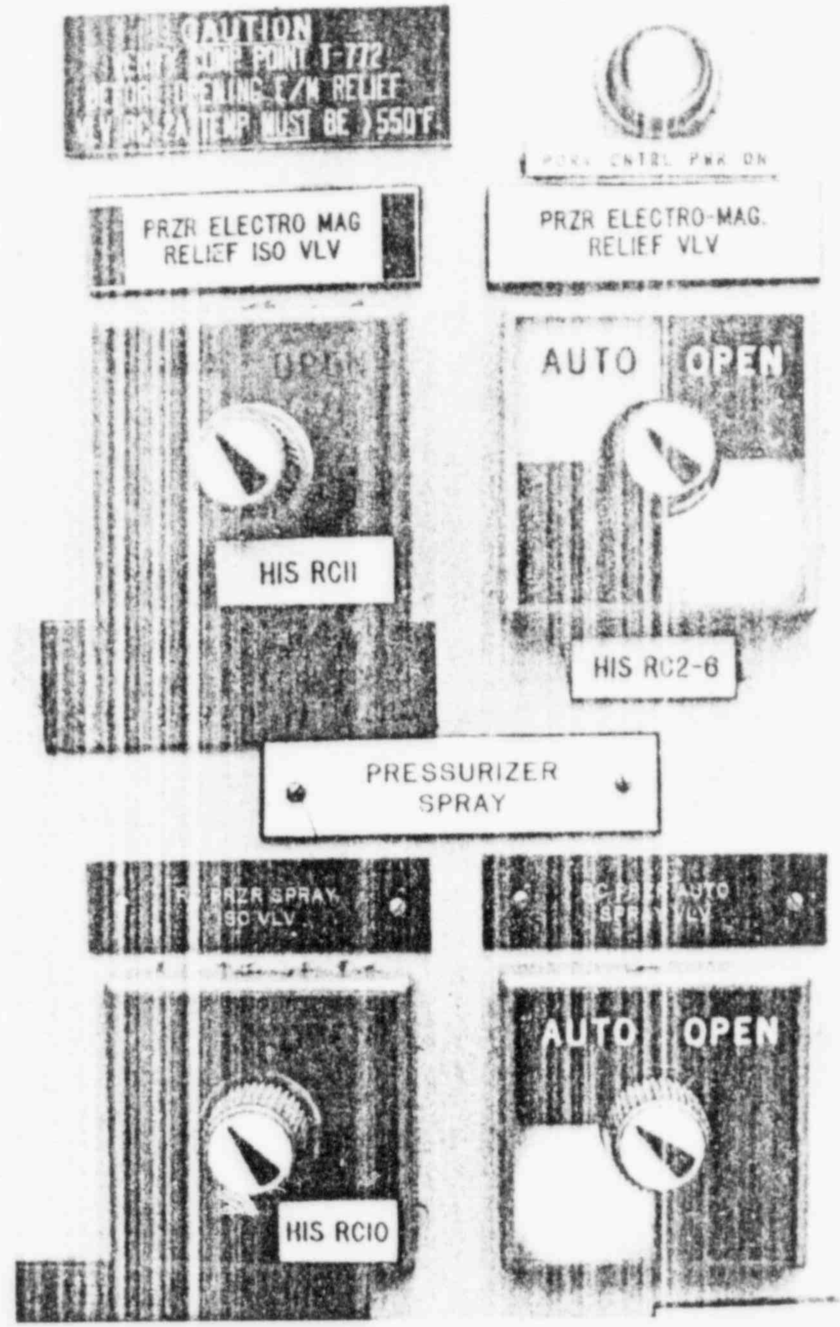


Figure 3.11 Control Station for Pressurizer PORV

4 DESCRIPTION OF PLANT SYSTEMS

4.1 General Design

The Nuclear Steam Supply System (NSSS) for the Davis-Besse plant was supplied by the Babcock & Wilcox Company. The NSSS, shown in Figure 4.1, consists of two heat transport loops with each containing a hot leg, a once-through steam generator (OTSG), and two cold legs. Water from the OTSG is returned to the reactor vessel by the reactor coolant pumps, with one pump located in each cold leg. Reactor coolant system (RCS) pressure is maintained by an electrically heated pressurizer that is connected to one of the hot legs. During normal operations, the pressurizer contains a 700-cubic foot steam bubble that exerts a pressure of approximately 2150 psig on the RCS. Protection against overpressurization is provided by the pilot operated relief valve (PORV) and two code safety valves. The pilot operated relief valve discharges to a quench tank. The two code safety valves discharge directly to the containment building.

The reactor design power level is 2,772 MW(t), which is also the design power level for the station and all components. At a power level of 2,772 MW(t), the net station electrical output is 906 MW(e).

4.2 Main Steam System

The main steam system functions to deliver superheated steam from the steam generators (OTSGs) to the main turbine and required plant auxiliaries. As shown in Figure 4.2, the system begins with the outlet piping from the steam generators and passes through the containment building to the main steam isolation valves (MSIVs). Protection against overpressurization for the steam generators is provided by 18 code safety valves (9 per steam generator) located on the system piping upstream of the MSIVs, and two atmospheric vent valves (one per steam generator) which act as relief valves. The atmospheric vent valves are controlled by the integrated control system (ICS) and aid in controlling steam pressure if a large transient occurs when the unit is in service, if condenser vacuum is lost, or if the MSIVs are closed. Connections upstream of each main steam isolation valve supply steam to the redundant turbine-driven auxiliary feedwater pumps. Either system header is capable of supplying either turbine; however, the auxiliary feedwater pump turbine normally receives steam from its associated steam header.

The piping downstream of the MSIVs contains non-return valves that prevent reverse flow when steam generator pressures are not equal. From the non-return valves, steam flows to the high pressure turbine and secondary systems, such as the air ejectors.

During normal operations, the main steam system valves are not required to change position; however, reactor trips and steam and feedwater rupture control system actuations cause changes in valve position. When the reactor trips, OTSG pressure rises rapidly resulting in the actuation of the steamline safety valves. The integrated control system (ICS) biases the steam generator pressure control setpoint to a value higher than the normal steam header pressure control value

to minimize the cooldown of the reactor coolant system. Once the ICS gains control of the steam pressure, the safety valves should close.

The steam and feedwater rupture control system (SFRCS) also changes the position of the main steam system valves. If a SFRCS actuation signal is received, the following changes can occur in the system:

1. The MSIVs close.
2. The atmospheric vent valves close
3. The steam supply valves open to supply steam to the auxiliary feedwater pump turbines.

4.3 Main Feedwater System

The main feedwater system, Figure 4.3, begins with the cross-connected deareator storage tanks. Each of these tanks has a capacity of 64,000 gallons and provides the required net positive suction head (NPSH), i.e. pressure, for the booster feedwater pumps. The booster feedwater pumps are driven through a gear reducer by the main feedwater pump turbines and function to increase system pressure to satisfy the suction requirements for the main feedwater pumps. The direct-driven main feedwater pumps increase feedwater pressure to a value greater than steam generator pressure and discharge through the high pressure feedwater heaters to the feedwater regulating valves.

Two parallel valves are used to govern the flow of feedwater to each OTSG. The first of the two valves is called the startup control valve and regulates feedwater flow from 0% power to approximately 15% power. Startup control valve SP-7B supplies the #1 OTSG, and startup control valve SP-7A supplies the #2 OTSG. When the startup control valves reach the 80% open position, the main feedwater regulating block valves open, and flow is also controlled by the main feedwater regulating valves. The main feedwater regulating valves control feedwater flow during the power escalation from 15% to 100%. The pressure drop across the valve network is monitored and used to control main feedwater pump turbine speed. From the outlet of the feedwater regulating valves, the feedwater travels to the OTSGs via a motor-operated main feedwater isolation valve. Main feedwater is added to the OTSG through the external main feedwater ring and the main feedwater nozzles.

A separate auxiliary feedwater ring is used for the addition of auxiliary feedwater flow. After entering the steam generator, auxiliary feedwater is sprayed on the tubes to enhance natural circulation when reactor coolant pumps are not running and to minimize thermal shock to the steam generator.

When the plant is in mode 3 (Hot Standby), a motor-driven startup feedwater pump is used to maintain steam generator level. The startup feedwater pump receives its suction from the deareator storage tanks and discharges to the steam generator main feed rings via the high pressure feedwater heaters, the feedwater regulating valves, and the main feedwater isolation valves. After reactor criticality is achieved, power is escalated to about 1% and a main feedwater pump is placed in service. When the main feedwater pump is in service, the startup feedwater pump is shutdown and isolated from the main feedwater system. Startup feedwater pump isolation includes the closing of the suction, discharge, and the cooling water isolation valves. All of these valves are located in the turbine building and must be locally operated. In addition

to the manual operation of the pump isolation valves, the breaker control power fuses are removed as a safety precaution. This prevents the operation of the pump with its suction supply isolated.

The startup feedwater pump is designed to deliver feedwater flow at approximately 200 gpm with a steam generator pressure of 1050 psig. Electrical power is supplied to the pump motor from the non-Class 1E distribution; however, the pump power supply may be manually transferred to the diesel generator busses if required. Operation of the startup feedwater pump in off-normal situations requires the manual opening of the suction, discharge, cooling water inlet and outlet valves, and the installation of the breaker control power fuses.

If the reactor trips, the feedwater system is controlled by the rapid feedwater reduction system which closes the main feedwater regulating valves and positions the startup control valves to a position that allows proper OTSG level control. These actions are taken to prevent excessive cooling of the RCS caused by overfeeding the steam generators. This system also increases the speed of the operating main feedpump turbine(s) from a normal value of 4400 rpm to 4600 rpm.

In addition to the control actions described above, the steam and feedwater rupture control system (SFRCS) closes the main feedwater regulating valves, the startup regulating valves, and the main feedwater isolation valves when certain abnormal plant conditions are detected.

4.4 Auxiliary Feedwater System

The auxiliary feedwater system (AFW), Figure 4.4, is designed to remove the core's decay heat by the addition of feedwater to the steam generators following a reactor trip, if main feedwater is not available. The system consists of redundant turbine-driven auxiliary feedwater pumps and associated piping. Three suction sources are available to the AFW pumps: the deareator storage tanks, the condensate storage tank (CST), and the service water system. The CST serves as the normal suction source for the system; however, if a low suction pressure condition is sensed, the AFW suction will automatically transfer to the service water system. Manual action would be required to transfer suction to the deareator storage tanks.

When the AFW system is actuated by the steam and feedwater rupture control system (SFRCS) on signals other than low steam generator pressure, the steam to drive the AFW pump turbine and the discharge of each pump are aligned with the associated steam generator. Each of the AFW pumps is rated at 1050 gallons per minute (gpm) when pumping against a steam generator pressure of 1050 psig; 250 gpm of the 1050 gpm is used for recirculation flow.

The #1 pump supplies the #1 OTSG via motor-operated valves AF-360, AF-3870, and AF-608. The feedwater supply for #2 OTSG is from the #2 pump through valves AF-388, AF-3872, and AF-599. However, if the SFRCS is actuated on low OTSG pressure, the flow path of the system is altered to prevent the feeding of a ruptured steam generator. The isolation of feedwater to the faulted steam generator is accomplished by closing the AFW containment isolation valve (AF-599 or AF-608). Feedwater to the intact steam generator is supplied by both pumps through the appropriate cross-connect valve (AF-3869 or AF-3871). The steam supply valves for the turbine-driven pumps are also realigned to provide steam for both pumps from the intact steam generator. The following listing gives the position of the AFW system valves during various SFRCS actuations:

NORMAL SYSTEM ALIGNMENT

Open valves - AF-360, AF-388, AF-599, AF-608
Closed valves - AF-3869, AF-3870, AF-3871, AF-3872, MS-106, MS-106A, MS-107, MS-107A

SFRCS LOW LEVEL ACTUATION

Open valves - AF-360, AF-388, AF-3870, AF-3872, AF-599, AF-608, MS-106, MS-107
Closed valves - AF-3869, AF-3871, MS-106A, MS-107A

SFRCS ACTUATION #1 OTSG LOW PRESSURE

Open valves - AF-360, AF-388, AF-3869, AF-3872, AF-599, MS-106A, MS-107
Closed valves - AF-608, AF-3871, MS-106, MS-107A

SFRCS ACTUATION #2 OTSG LOW PRESSURE

Open valves - AF-360, AF-388, AF-3870, AF-3871, AF-608, MS-106, MS-107A
Closed valves - AF-3869, AF-3872, AF-599, MS-106A, MS-107

The SFRCS is also described in section 4.6.

4.5 MU/HPI Cooling Systems

Makeup/High Pressure Injection (MU/HPI) core cooling (also called PORV cooling or feed and bleed core cooling) involves the use of the makeup and purification system, the high pressure injection system and, at the operator's discretion, the low pressure injection system. These three systems are shown in Figure 4.5. The system contains two multistage centrifugal makeup pumps rated at 150 gpm, with a discharge pressure of approximately 2500 psig. Two suction sources are available to the pumps; the makeup tank and the borated water storage tank (BWST). During normal operations, the makeup pumps supply seal injection and control pressurizer level by discharging into the RCS via the makeup flow control valve (MU-32). The discharge of the makeup pumps enters the RCS through one of the high pressure injection penetrations. When feed and bleed operations are required, plant procedures require the positioning of the three-way suction valve (MU-3971) to the BWST suction source, fully opening the makeup flow control valve, and the starting of both makeup pumps.

The high pressure injection pumps (HPI) are a part of the emergency core cooling system and are not in service during normal operations. The system consists of redundant pumps and four injection paths into the cold legs of the RCS. The pumps receive their suction from the BWST and have a shutoff head of 1630 psig. When these pumps are used in the feed and bleed mode of core cooling, both pumps are started and the discharge paths into the RCS are opened. However, in order to supply a flow of cooling water to the core, RCS pressure must be less than the shutoff head of the HPI pumps or the pumps must be "piggy-backed" to the discharge of the low pressure injection pumps as described below.

The low pressure injection (LPI) pumps are also a part of the emergency core cooling systems. The LPI pumps receive a suction from the BWST and discharge via the decay heat removal coolers (not shown in Figure 4.5) into the reactor

vessel. The pumps are rated at 3000 gpm with a discharge pressure of approximately 150 psig. The shutoff head of the pumps is about 200 psig. Plant procedures allow the discharge of the LPI pumps to be aligned to the suction of the HPI pumps by opening valves DH-62 and DH-63. This alignment increases the discharge pressure of the HPI pumps from 1630 psig to approximately 1830 psig and allows HPI flow at a higher RCS pressure.

When the feed and bleed mode of core cooling is required, plant procedures call for starting the makeup pumps and the high pressure injection pumps. After the pumps are in service, the pressurizer pilot-operated relief valve, the pressurizer vent, and the hot leg vents are opened. The HPI/LPI piggy-back mode of operation is not specifically addressed in the loss of subcooling margin or the overheating sections of plant procedures but may be aligned at the discretion of the operator. All the required bleed and feed alignments are performed in the control room.

4.6 Steam and Feedwater Rupture Control System (SFRCS)

The steam and feedwater rupture control system (SFRCS) is provided in the plant design as an engineered safety features actuation system for postulated transient or accident conditions arising generally from the secondary (steam generation) side of the plant, because the OTSGs serve as the heat sinks for the reactor power. The SFRCS senses loss of main feedwater (MFW) flow, rupture of an MFW line, and rupture of a main steamline. It also senses loss of all forced coolant flow in the primary system.

The safety function of the SFRCS is to provide safety actuation signals to equipment that will: isolate the steam flow from the OTSGs, isolate the MFW flow, and start and align the AFW system. The SFRCS also provides output signals to the turbine trip system and to the Anticipatory Reactor Trip System (ARTS).

In the event of loss of MFW pumps or a main feedwater line rupture, the OTSGs would start to boil dry, and, if action is not initiated promptly, there would be no motive steam available for the turbine-driven AFW system and the OTSGs would be lost as a heat sinks. As soon as the MFW pump discharge pressure falls below the pressure in the OTSG (i.e., reverse differential pressure across a check valve) by a predetermined value, the SFRCS provides safety actuation signals to close the main steam isolation valves (MSIVs), close the MFW stop and control valves, and start AFW. The SFRCS also receives OTSG low level signals which are diverse from the reverse differential pressure signals.

In the event of steamline pipe ruptures, when the main steam pressure drops, the SFRCS will close both MSIVs and the MFW stop and control valves. The description of the SFRCS in the Updated Safety Analysis Report (USAR) Section 7.4.1.3 does not mention the SFRCS closure (or re-opening) of the AFW containment isolation valves (AF-608 and AF-599), although the design does include such features. The AFW is also initiated and both AFW trains are aligned to draw steam only from, and to provide feed only to, the unaffected "intact" OTSG.

In the event of loss of all four reactor coolant pumps (RCPs), forced cooling flow of the reactor coolant system would be lost and AFW flow is needed to enhance natural circulation flow. Therefore, the SFRCS senses the loss of four RCPs and automatically initiates AFW.

Figure 4.6 depicts the channelization of the SFRCS. There are two Actuation Channels, each of which contains two identical logic channels. Within each Actuation Channel, one logic channel is ac powered and the other logic channel is dc powered. The field wiring at the actuated equipment is such that generally both logic channels must "trip" (i.e., a two-out-of-two AND logical arrangement) to actuate most equipment, which is referred to as a "full trip." However, some equipment is actuated by a "half trip" (i.e., only one logic channel of an actuation channel has tripped). For example, the atmospheric steam vent valves are closed by "half trips."

4.7 Pressurizer Pilot Operated Relief Valve (PORV)

At the top of the pressurizer as shown in Figure 4.1, there are two code safety valves which vent directly to the containment atmosphere, a high-point vent line, and the pilot operated relief valve (PORV) with its associated upstream block valve.

The PORV block valve is a manually-controlled motor-operated valve, equipped with position instrumentation including a position alarm.

The PORV is a style HPV-SN solenoid-controlled pilot-operated pressure relief valve manufactured by the Crosby Valve and Gage Company. It is the Team's understanding that Davis-Besse is the only B&W-designed PWR that has a Crosby PORV. The Crosby PORV is operated by the reactor coolant system pressure via a solenoid-operated pilot valve and therefore does not involve any pneumatic power (instrument air or nitrogen). Electric power is used for the solenoid control device. To actuate the PORV, the solenoid is energized. This action allows the use of reactor coolant system pressure to open the main disc of the valve.

The controls for the PORV include features for automatic operation, manual open, manual close, and lock open. All operations to open the PORV involve energizing a control relay which in turn energizes the PORV solenoid. In automatic, the pressure channel's bistable would close one set of contacts above the high pressure setpoint (2425 psig) and would close another set of contacts below the low pressure setpoint (2375 psig). When the high pressure setpoint is reached, the control relay is energized and an electrical seal-in circuit is energized. When the low setpoint is reached, an auxiliary relay is operated which in turn interrupts the valve-open seal-in circuit.

In manual control, the circuit is designed for momentary-only operation of the switch to the valve-open position. The seal-in circuit will hold the valve open if the pressure is above the low pressure setpoint. To lock open the PORV (as would be done for MU/HPI cooling), manual control switch would be rotated to the "lock open" position. The control circuitry would maintain the PORV solenoid energized regardless of RCS pressure. To manually close the PORV, the control switch must be rotated to the "auto" position and the control switch pushed inward. This action causes both control relays to be de-energized and the seal-in circuit to be de-energized, which in-turn causes the PORV solenoid to be de-energized.

Shown in Figure 3.11, the indicators for the PORV include: control power available light (blue), automatic (white), PORV open (red), PORV close (green), lock open (amber). The PORV open/close lights are operated by a limit switch operated by the PORV solenoid plunger (i.e., the output of the electric solenoid; the

mechanical input to the PORV). All of these position lights are PORV command indicators, in that they indicate only the position that the electric controls have commanded for the PORV. Only the acoustic monitor is a direct indicator of the flow condition through the PORV/block valve path.

The acoustic monitor for the PORV was installed as one of the post-TMI safety improvements. Two redundant accelerometer sensors are mounted on the discharge piping. Each sensor channel provides a signal to drive the remote 0-100% (open) PORV position meter on the post-accident monitoring (PAM) panel, and an adjustable position signal switch to drive the remote PORV open/closed lights on the PAM panel. The Team was told that the adjustable switch was set such that the red (open) light would be energized if the flow signal is greater than 22% of the full flow value.

If PORV/block valve flow is less than 22%, the red (open) light would be turned off and the green (closed) light would be energized. The meter could be used to obtain more precise position/flow information. The PAM panel is a separate panel mounted about 7 feet to the left of where the reactor operator assigned to the primary system would be standing. Both redundant red/green PORV indicating lights are easily visible to the operator if he turns his head. However, the 0-100% meters are relatively small, i.e., about a 3-inch tall vertical edge-mounted meters. To read this meter, the operator would have to step a pace or two toward the PAM panel.

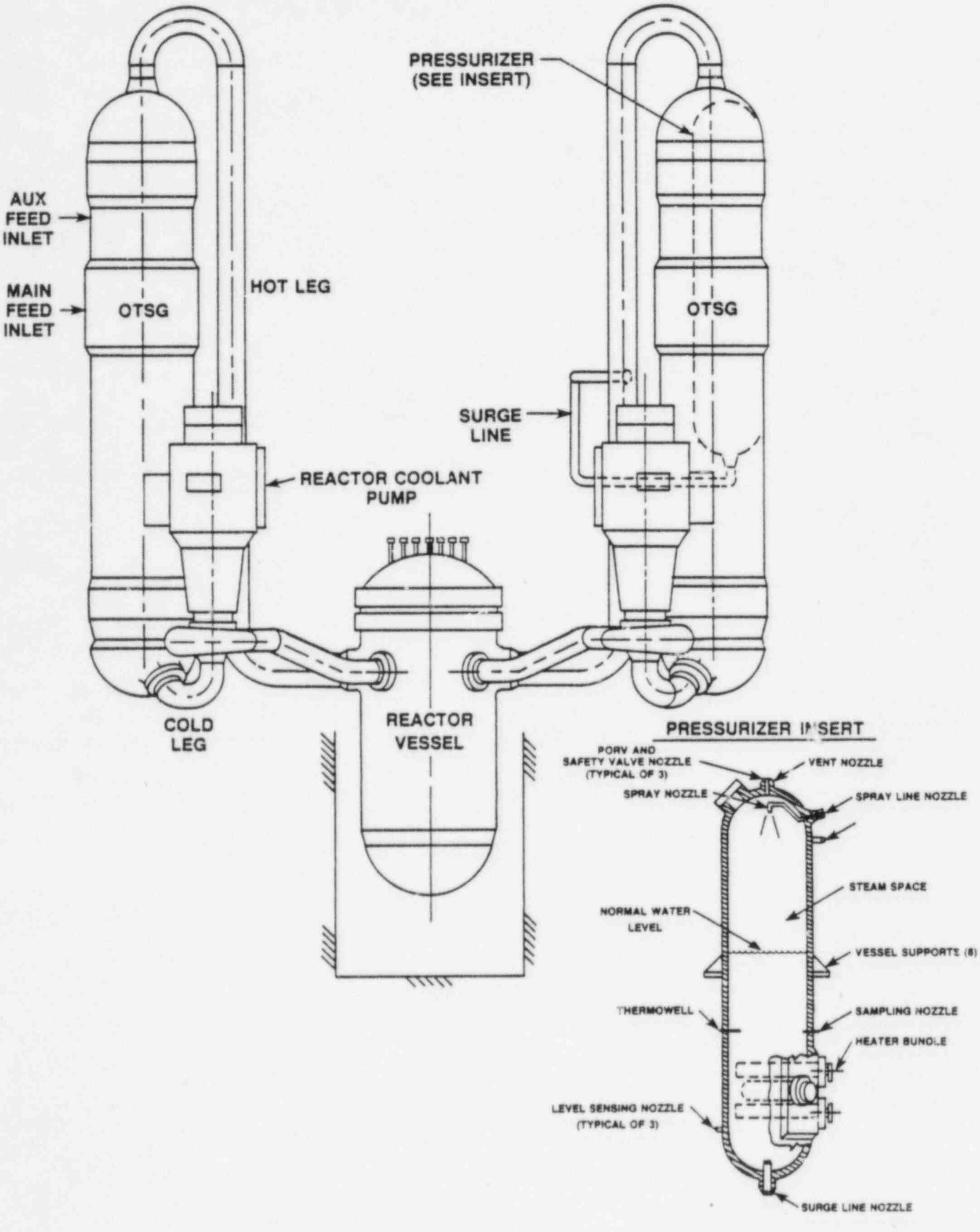


Figure 4.1 Davis-Besse Nuclear Steam Supply System

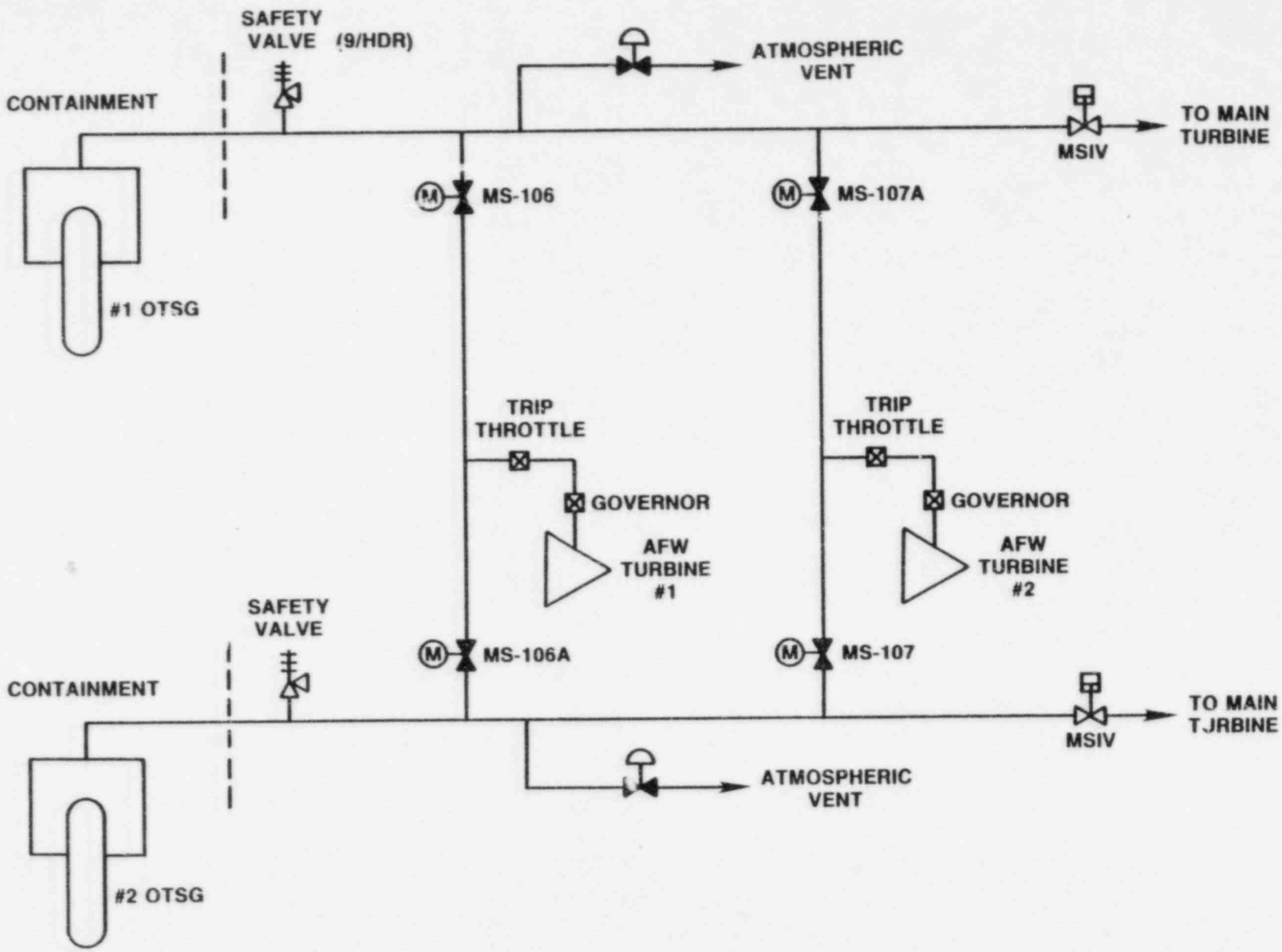
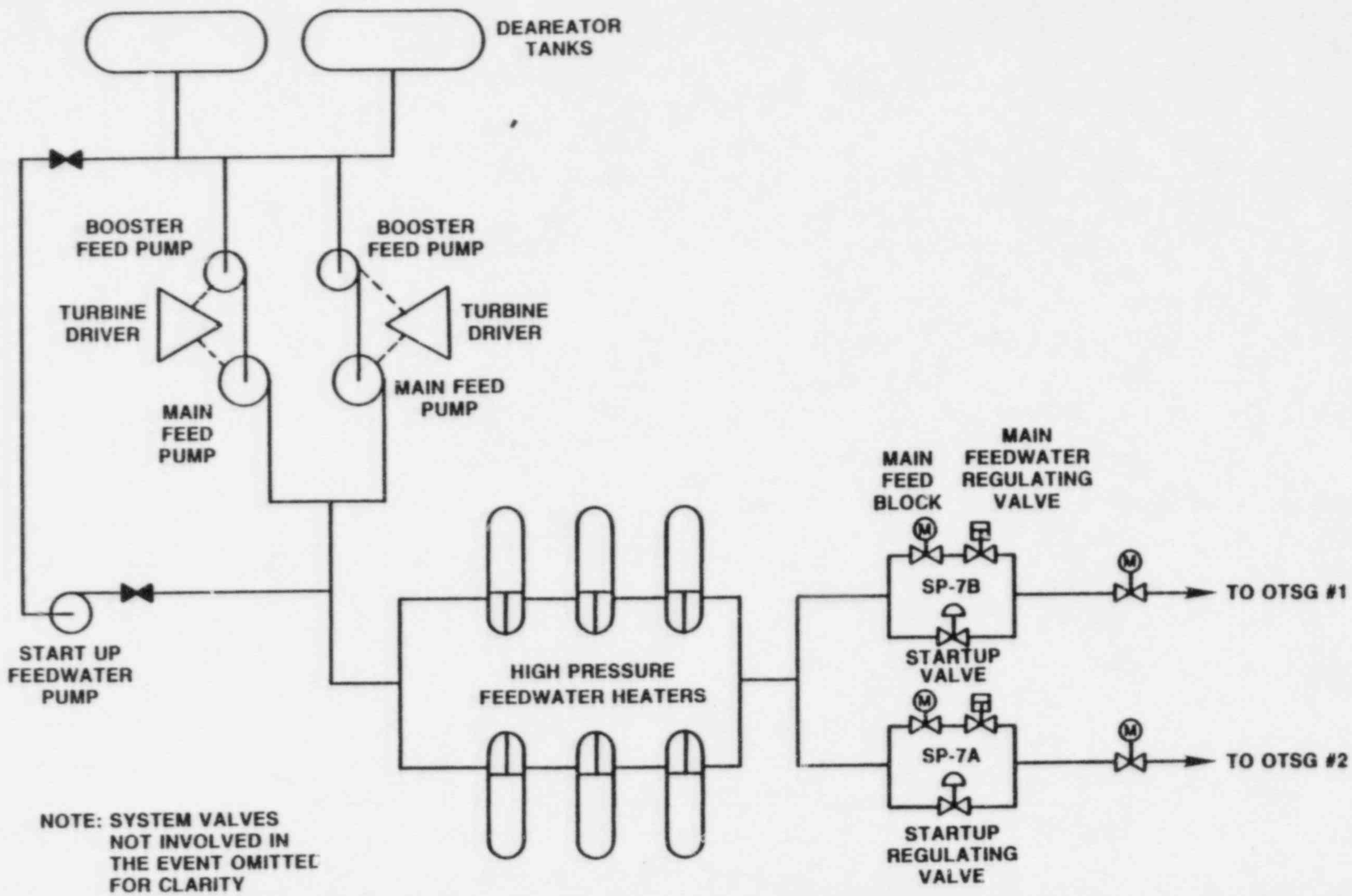


Figure 4.2 Main Steam System



NOTE: SYSTEM VALVES NOT INVOLVED IN THE EVENT OMITTED FOR CLARITY

Figure 4.3 Main Feedwater System

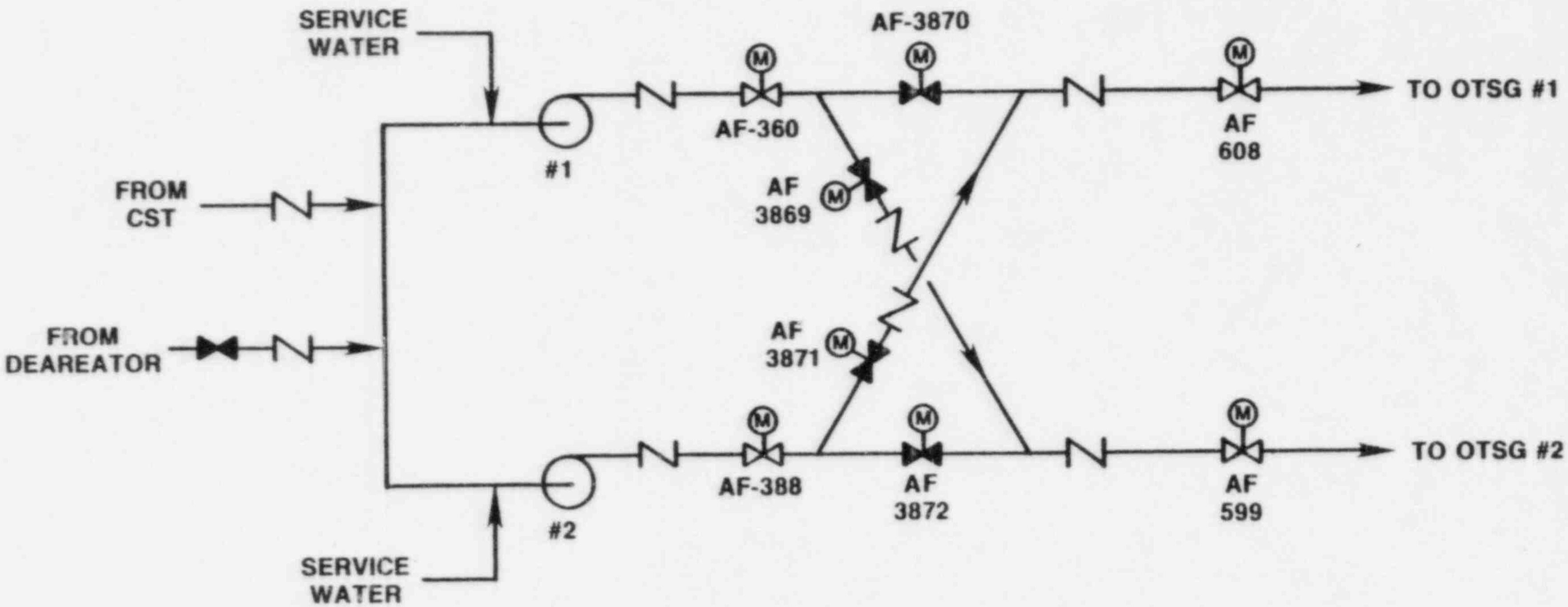


Figure 4.4 Auxiliary Feedwater System

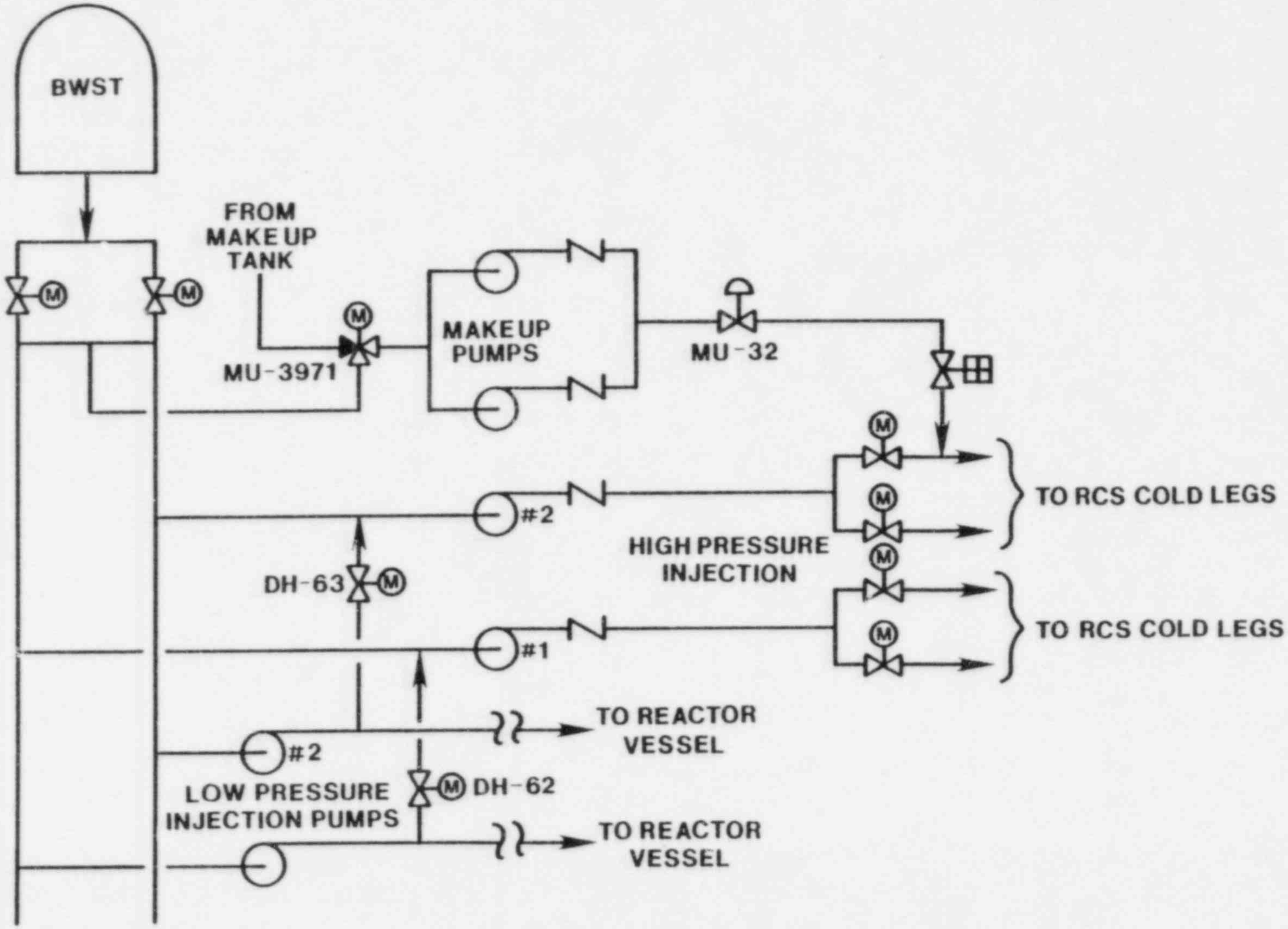


Figure 4.5 Makeup/HPI Cooling System

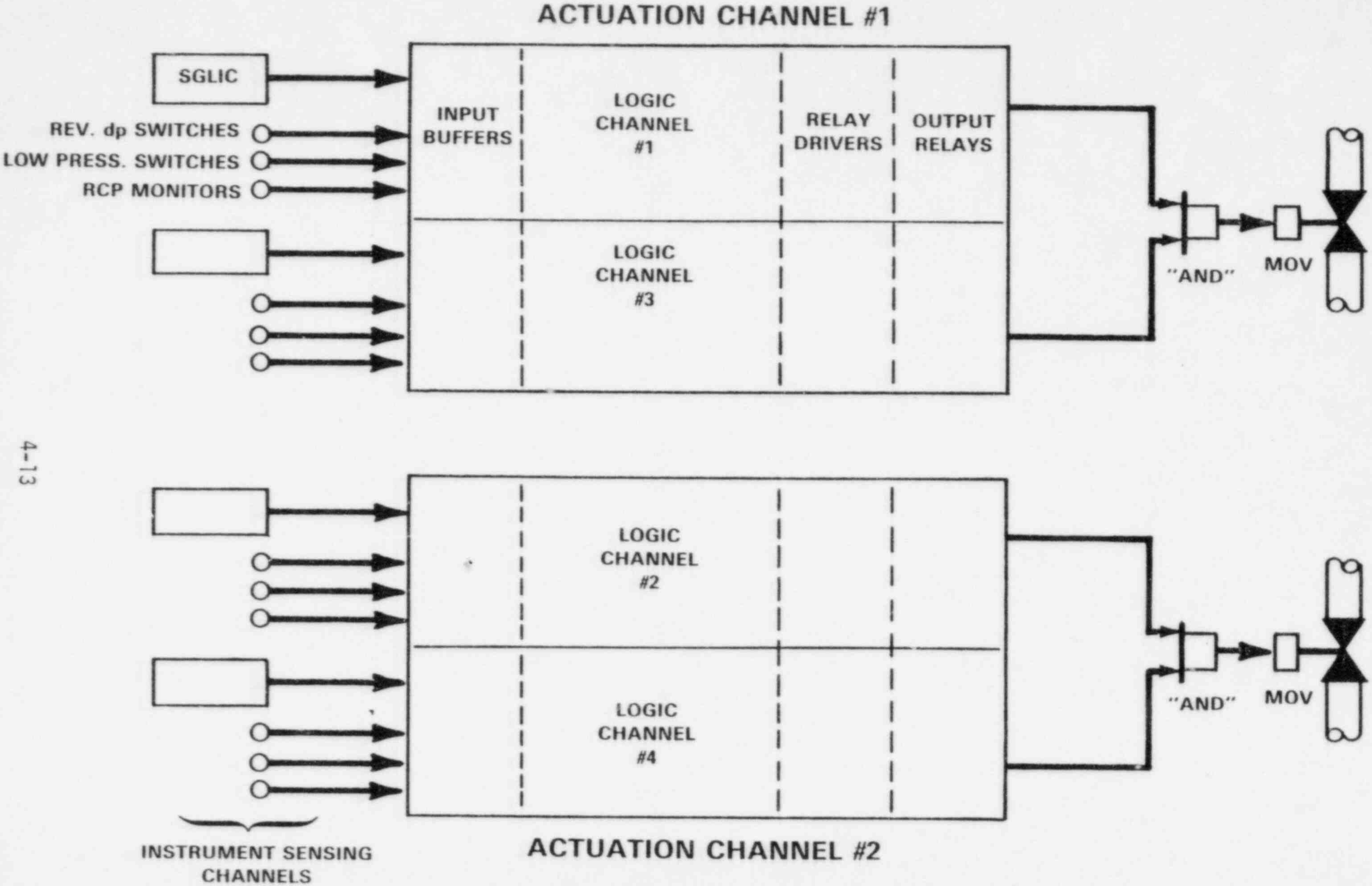


Figure 4.6 SFRCS Block Diagram

5 EQUIPMENT PERFORMANCE

This section identifies and discusses the equipment problems related to the June 9, 1985 event. The section is divided into two parts: pre-existing conditions, and problems that occurred during the event. The fact that such a large number of failures occurred and that several common mode failures occurred during this event are major concerns. Effective evaluation of operating experience related to the equipment performance and effective troubleshooting, maintenance, and test'ng of the equipment would likely have prevented many of these failures.

5.1 Pre-existing Conditions

This section discusses equipment conditions known to have existed prior to the onset of the June 9 event.

5.1.1 Safety Parameter Display System (SPDS)

At Davis-P the safety parameter display system (SPDS), also referred to as the "ATOG ay" (for Abnormal Transient Operating Guidelines which were developed b, the Babcock & Wilcox (B&W) Owners' Group). This display system summarizes the most safety-significant plant variables on TV-screen displays in real-time.

The SPDS was inoperable prior to, and remained out of service throughout the event. Both independent SPDS display units were inoperable due to separate but similar problems in the data transmission system between the control room terminals and their respective computer processors. The failures were intermittent in nature. The diversity of the SPDS display sources (Ramtek and Chromatics display devices) has often allowed at least one display to remain operable. However, it is the Team's understanding that the SPDS at Davis-Besse has not proven reliable; Toledo Edison indicated that the failure rate of these units is higher than is acceptable.

5.1.2 Source Range Nuclear Instrumentation

The Davis-Besse design includes redundant nuclear instrumentation channels (NIs) for each of the overlapping regions: power range, intermediate range, and source range. For the source range, two channels are provided. For a plant restart, the Technical Specifications require that both source range NIs be operable. If, after startup, a source range NI is lost, power operations may continue.

Problems with NI-1 (source range channel 2) have existed prior to the initial plant startup in 1977. On June 4, 1985, NI-1 was declared inoperable because (even with its detector high voltage supply turned off) it read a steady 1½ decades (counts per second) greater than the redundant channel. Further, the NI-1 channel seemed to be experiencing intermittent count rate spiking problems whether its detector high voltage was on or off.

Since January 1985, five maintenance work orders had been initiated for NI-1 due to these two problems. In each case, the Technical Specifications surveillance test was performed and the channel was declared operable. The cause of the problems was not definitively identified.

The other source range nuclear channel (NI-2, channel 1) has also had a history of unresolved intermittent problems. For example, on March 25, 1985, NI-2 failed off-scale low (less than 1 X 10^{-1} counts per second). When the reactor protection system cabinet door was opened, the count rate level indication returned to normal. The Technical Specification surveillance test was then performed and the channel declared to be operable without any troubleshooting effort. Similarly, on April 13, 1985, NI-2 failed off-scale low. Prior to performing any troubleshooting, the instrumentation and control (I&C) technician tapped on the front of a module in the cabinet and the count rate returned to normal. After a visual inspection, the Technical Specification surveillance test was performed and the channel was declared again to be operable. No additional troubleshooting was performed.

5.1.3 Startup Feedwater Pump

At the Davis-Besse plant, the steam turbine-driven AFW system is not used normally for plant startup or shutdown. Instead a separate, non-safety-related electric motor-driven startup (S/U) feedwater pump was provided as part of the original plant design. The availability of the S/U feedwater pump has been an important consideration in Toledo Edison's assessment of the AFW system reliability and in assessing equipment which could be used to mitigate events involving loss of main feedwater. In October 1984, Toledo Edison advised the NRC of a previously unanalyzed condition regarding the S/U feed pump. The associated piping had not been designed or analyzed for a postulated high (or moderate) energy line break. Since the non-safety-related S/U feed pump is in the same room as one of the safety-related AFW pump turbines, and the associated S/U feedwater piping runs through both AFW pump rooms, Toledo Edison proposed certain compensatory actions. These actions included stationing an operator in the room during operation of the S/U pump and closing certain manual isolation valves. In January 1985 the NRC found the proposed compensatory actions acceptable and Toledo Edison implemented them, as well as the removal of fuses in the control circuit for the breaker.

Thus, making the S/U pump available for service involves five separate manual actions at four different locations in the plant: (1) a pump suction valve must be opened; (2) the pump discharge valve must be opened; (3) two pump cooling water valves must be opened; and (4) the control fuses for the 4160-volt circuit breaker for the pump motor must be re-installed.

5.1.4 Control of Main Feedwater Pumps

During the 1984 refueling of the plant (plant restart took place in January 1985), replacement control equipment for the main feed pumps (MFPs) was installed to improve plant performance following a plant trip.

During a previous event on April 24, 1985, when operating at 98% power, a flux/delta flux to flow automatic reactor trip occurred. Approximately 8 seconds later, MFP No. 1 turbine tripped unexpectedly. The cause of the MFP trip was

never positively identified. Additionally, several MFP instruments were recalibrated. (Note: there have been difficulties in obtaining proper speeds for rapid feedwater reductions. For example, prior to April 24, 1985, the target speed was thought to be set to 4800 rpm, when in fact it was actually set to 5150 rpm. Following the April 24, 1985 trip, the target speed was thought to have been readjusted to 4600 rpm, when in fact it was actually set to 5000 rpm.)

During a plant trip on June 2, 1985, both MFPs tripped unexpectedly 4 seconds after the plant trip. Several possible failure causes were postulated by Toledo Edison's staff; however, troubleshooting was not able to substantiate any of these. Following the June 2, 1985 trip, further adjustments were made to the target speed voltage for the rapid feedwater reduction control system.

Although some of Toledo Edison's staff expressed reservations, Toledo Edison's senior management decided not to delay the plant startup to resolve the MFP control problem. It was decided that one MFP would be operated in automatic and the other MFP would be operated in manual. During the plant startup with the plant at 56% power and increasing, the No. 1 MFP (in automatic control) tripped causing a plant runback. As a result, additional testing was performed on June 5 and 6, 1985.

5.1.5 Flux/Delta Flux to Flow Reactor Trip Instrumentation

At Davis-Besse, the reactor protection system design includes a reactor trip on the ratio of reactor coolant flow to neutron flux/delta flux. The flow portion of this instrumentation had been experiencing some "noise" problems. The magnitude of this noise was sufficient to reach the trip setpoint if the reactor was operated at 100% power (as had occurred on April 24, 1985); however, the instrumentation was considered to be "operable."

It is the Team's understanding that this "noise" problem has existed since new flow instrumentation was installed during the 1984 refueling outage. Toledo Edison's efforts to resolve this problem had not been effective. As a result, it was decided that the reactor would be operated at 90% power to avoid further reactor trips due to the "noise." Had this problem been resolved, the plant would have most likely been much closer to 100% power at the onset of the June 9, 1985 event.

5.2 Equipment Problems That Occurred During the Event

This section discusses the equipment problems that occurred during the June 9, 1985 event. Each problem is described, followed by the results to date of Toledo Edison's root cause determination. Related background information is also given. A couple of the problems are not of major safety significance but are included in order to convey the overall situation with respect to the problems that the operators faced during the event. A brief summary of these equipment failures is provided in Table 5.1.

5.2.1 Control of Main Feedwater Pumps (MFPs)

While the Davis-Besse plant was operating at a steady 90% power level on June 9, 1985, the transient was initiated by a spontaneous and substantial speed increase of the No. 1 MFP and the subsequent MFP trip on overspeed.

Toledo Edison's troubleshooting plan for this item was "Action Plan for Main-feed Pump Control System," Action Plan No. 8, dated June 18, 1985. Prior to the initiation of troubleshooting activity, Toledo Edison's hypothesis was that the root cause for this failure involved one or more of the following conditions:

1. Loose connections associated with the electrical circuitry for the MDT-20 control system.

2. A circuit board malfunction.

3. Hydraulic/mechanical control problem.

During a meeting on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. The frequency-to-voltage converter (F/V) module on circuit board number 4 was found to be faulty.

The circuit board was sent to the General Electric (GE) factory in Fitchburg, MA. The factory confirmed that the F/V converter had failed in a manner which GE classified as a "random failure." However, Toledo Edison has not presented an engineering report to support the conclusion that the circuit board failure was the root cause for the overspeed of MFP No. 1.

5.2.2 Closure of Both MSIVs, Spurious SFRCS Actuation

Early in the June 9, 1985 event, both main steam isolation valves (MSIVs) closed, causing the loss of the main steam source for operating the second MFP.

The MSIVs are tripped closed automatically by the safety features actuation system (SFAS) and by the steam and feedwater rupture control system (SFRCS). During the June 9, 1985 event, there was no annunciator indication in the control room of either a partial or full actuation of the SFAS or the SFRCS at the time of MSIV closure. Initially, Toledo Edison believed that both MSIVs had failed due to causes unrelated to other systems. Currently, Toledo Edison believes that the MSIVs were responding to a spurious full trip of SFRCS Actuation Channel #2 on OTSG low level which the alarm print shows occurred a few seconds earlier.

Toledo Edison's troubleshooting plan for this item was "Low Steam Generator Level Trip of SFRCS," Action Plan Nos. 5, 6, and 7, dated June 22, 1985. Toledo Edison's hypothesis, based upon information from the nuclear system vendor Babcock & Wilcox, was that the SFRCS trip was caused by the OTSG level transmitter's response to a rapid oscillatory pressure wave phenomenon that occurs in the OTSGs subsequent to the closure of the main turbine stop valves.

During a meeting with the Team on July 11, 1985, Toledo Edison indicated that no actual troubleshooting had started on this item. Thus, Toledo Edison has not presented an engineering report to support the results of the root-cause determination.

During the 1984 refueling outage, the OTSG level transmitters providing level control and level indication on the main control panel were changed from B&W/Bailey Model BY transmitters to Rosemont model 1153 transmitters. These transmitters share OTSG taps and sensing lines with the level transmitters which provide the OTSG level input signals to the SFRCS.

The Bailey Model BY transmitters require a volume displacement to operate the bellows. Toledo Edison believes that this volume displacement served to absorb (dampen) some of the oscillatory pressure phenomenon in the instrument sensing lines. The replacement Rosemont transmitters require no significant volume displacement for their operation. Toledo Edison believes that the resultant loss of damping in the sensing lines due to the new transmitters may have caused the SFRCS level transmitters to sense the pressure phenomenon to a degree that spurious trip signals were generated.

The modifications completed during the refueling outage that may affect this equipment include:

a. replacement of the amplifier and calibration boards within the level transmitters for the SFRCS to meet equipment qualification needs,

b. replacement of the low level bistable modules for the SFRCS level input channels with dual high/low bistables,

c. opening of auxiliary feedwater pump turbine (AFPT) steam crossover valves on all AFW system actuations; this modification was later functionally removed after water hammers were experienced, and

d. modification of the OTSG blowdown valves.

Toledo Edison stated that prior to the 1984 refueling outage there had not been any spurious actuations of the SFRCS on level, but that during the five months between the January 1985 restart and the June 9, 1985 event, the plant experienced two spurious partial actuations of the SFRCS on OTSG low level following turbine trips. These actuations were made more difficult to analyze because the SFRCS seemed to automatically reset itself after a few seconds. The SFRCS design does not include seal-in features to maintain the safety actuation signal until deliberate reset action is taken by the reactor operator.

The time delays associated with the main annunciators in the control room may not have indicated the actuation and reset times accurately. Further, the alarm printer apparently does not distinguish well between a partial and a full actuation of an SFRCS logic actuation channel, and the sequence of events monitor might print "full trip" for either a partial or full actuation.

Following the first of these spurious actuations (on April 24, 1985), the maintenance work order called for running the monthly Technical Specification surveillance test while checking for anomalies; none were found. Following the second spurious actuation (on June 2, 1985), the maintenance work order called for testing the alarm logic to determine why a full-trip alarm occurred when only a half-trip existed. In the process of re-connecting a connection opened for troubleshooting, the problem cleared, and no further effort was made to troubleshoot the equipment.

5.2.3 Main Steam Safety Valves, Atmospheric Vent Valves

After the reactor trip on June 9, 1985, all 18 of the main steam safety valves apparently lifted. This determination is based upon the fact that all the canvas exhaust hoods were later found to be missing; they apparently were forced

off by the exhausts during the event. Subsequent to the trip, repeated lifts of one or more of the safeties on each steam header were experienced intermittently for several minutes, resulting in pressure swings of approximately 50 psi. There were also several periods when steam header pressure swung over 100-250 psi for several minutes. Toledo Edison believes that this degree of pressure change was abnormal.

The Toledo Edison's troubleshooting plan for this item was "Report on Main Steam Header Pressure" Action Plan No. 16, dated June 25, 1985. Toledo Edison's hypotheses were that the unexpected header pressure swings could have been caused by an extended blowdown of one or more safety valves on each steam header, by leakage steam flow past the safety valves, by malfunction of the atmospheric vent valves, or by malfunction of the controls for the atmospheric vent valves.

During a meeting on July 11, 1985, Toledo Edison discussed the status of the troubleshooting of this item. Two ICS modules were found to be out of calibration. These discrepancies would have caused the atmospheric vent valves to have opened at about 1030 psig instead of 1015 psig, which is the ICS setpoint for vent valve control in a post-trip situation when the turbine bypass system is not available. Further, the bore size of the inlet piping to the main steam safety valves was found to be smaller than the manufacturer (Dresser) stated. However, neither of these results is believed to explain the conditions observed on June 9, 1985, and the troubleshooting is continuing.

As of this time, Toledo Edison has not presented an engineering report to support the root cause determination for the pressure change.

5.2.4 AFW Trains No. 1 and No. 2 Turbine Overspeed Trips

During the initial acceleration of the AFW pump turbines (AFPTs), both tripped on overspeed. This caused a complete loss of auxiliary feedwater.

Toledo Edison's troubleshooting plan for this item was "Auxiliary Feed Pumps Overspeed Trips," Action Plan Nos. 1A and 1B, dated June 20, 1985.

Toledo Edison's primary hypothesis is that steam, which had condensed in the supply lines, formed saturated water slugs which went through the turbine governors, flashed in the nozzles of the turbines and caused overspeed. Alternate or contributing hypotheses included: "double start" of AFPT #1 in that it was rolling on steam from OTSG #1 via valve MS-106 prior to receiving steam from OTSG #2 via valve MS-106A, a sudden decrease in pump loads due to an abrupt closing of AFW containment isolation valves AF-608 and AF-599, governor problems, and loss of pump suction.

During a meeting on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. Both AFPT governors were inspected by the manufacturer (Woodward); no problems were found. Analysis shows that large amounts of steam would condense in the steam supply pipes to the AFPTs, especially in the crossover lines (e.g., OTSG #2 to AFPT #1).

Toledo Edison has discussed the possibility of condensate causing turbine overspeed with the vendor (Terry Turbine). Tests apparently had been conducted several years ago. In one test case, after steam was flowing and the turbine

was running, the injection of 50-600 lbm (pounds mass) of water caused the turbine to bog down. In another test, when water was injected into the steam during the starting of the turbine, the water went through the governor, causing it to open further and allowing more water to pass. At the turbine nozzles, the water flashed and caused the speed to increase significantly. The tests were terminated prior to reaching the overspeed trip setpoint. Toledo Edison's discussions add credibility to the primary hypothesis. Toledo Edison stated that a search of the manufacturer's technical manual and the vendor service letters yielded no suggestion of this overspeed potential or a minimum steam quality (dryness) specification.

Although the troubleshooting is not complete because of the need for hot functional tests (plant Mode 3), Toledo Edison believes that the root cause has been determined to be the primary hypothesis. The Mode 3 tests are expected to be confirmatory. As of this time, Toledo Edison has not presented an engineering report to support this root cause determination.

In an effort to improve AFW system reliability, Toledo Edison modified the actuation logics such that, for all AFW actuations, each AFW turbine would draw steam through redundant parallel valves (i.e., from both OTSGs via valves MS-106, MS-106A for AFPT #1 and valves MS-107, MS-107A for AFPT #2, as shown on Figure 4.2, rather than only from its associated OTSG). This modification, however, resulted in the occurrences of some water hammer events. Toledo Edison then re-modified the actuation logics so that they would be functionally similar to the previous configuration. The water hammer events are consistent with the hypothesis that hot water collects in the lines to the pump turbines. However, Toledo Edison did not address potential adverse affects of operating on the steam crossover lines alone.

The review of the AFW design indicates that the AFW steam crossover lines (i.e., those associated with the opposite OTSG for each AFW turbine and steam admission valves MS-106A and MS-107A) have long horizontal runs. Toledo Edison believes that these conditions are likely to have resulted in several hundred pounds of saturated hot water.

When Toledo Edison initially explained the June 9, 1985 event to the vendor of the AFW turbines, the vendor indicated that the overspeed trips could have been caused by hot (saturated) water entering the AFW governors/turbines, flashing to steam, and causing the turbine to overspeed. Toledo Edison has stated that overspeed trips at four different plants appear to have been caused by this phenomenon. While it appears that the vendor had been aware of this overspeed susceptibility, it is not clear whether the vendor had advised Toledo Edison or any other nuclear users of the turbines.

For a postulated break of one main steamline, the steam crossover valves (MS-106A and MS-107A) and lines are provided in the design so that the AFP turbines can draw steam from the OTSG not affected by the break. Toledo Edison stated that the AFW system had never been tested in this configuration, i.e., AFPT #1 drawing steam only from OTSG #2 via MS-106A, or AFPT #2 drawing steam only from OTSG #1 via MS-107A. Testing of the AFW system in this accident configuration would be expected to have revealed the steam condensation problems and the overspeed tripping prior to an actual operating event.

5.2.5 AFW Containment Isolation Valves

During the June 9, 1985 event, AFW containment isolation valves AF-608 and AF-599 could not be reopened from the control room, either automatically or manually, following their inadvertent closure. This caused the complete loss of the AFW safety function by blocking the flow of both AFW trains to either OTSG.

Toledo Edison's troubleshooting plan for this item is "Auxiliary Feedwater System Valve Problem Analysis (AF-599 and AF-608)" Action Plan No. 12, dated June 14, 1985. Toledo Edison's hypotheses for this problem included: improperly adjusted torque switch bypass contacts, improper torque switch settings, improper torque switch setting calculation, improper torque switch installation, wrong or improperly adjusted spring packs, and failure of motor brakes to release.

On June 21, 1985, during a meeting with NRC, Toledo Edison reported the results of the root cause determination. The number of handwheel turns to the point where the bypass contacts for the torque switches are opened were found to be improper for both valves. For one valve (AF-608), the bypass contact was set at nearly the value in the procedure (8 turns vs. 9 turns), but the specified setting is believed to be too early in the opening cycle. Premature opening of the bypass contacts can result in torque switch actuation which trips the valve motor (i.e., the load on the motor is greater than the torque switch setting). This load may be higher because of the high differential pressure (dp) across the valve at the time the torque switch bypass contact opened. For the second valve (AF-599), the bypass contact was grossly misadjusted from the value specified in the procedure. Toledo Edison stated that the procedure was "bulky and difficult" and, therefore, such an error should not be unexpected.

Toledo Edison stated that the bypass switch settings had been increased in the past few years based upon a Torrey Pines study. Toledo Edison's current consultant, retained for the troubleshooting activities (MOVATS, Inc.), suggested that a higher bypass switch setting (at least 10%) is necessary to overcome the high differential pressure across the valve, and even a higher value should be considered if more margin is needed.

The Team expressed concern that this root cause determination was primarily based upon analysis and did not involve tests that reproduced the failure. Because of the implications on other motor-operated valves at the Davis-Besse plant and other plants, the Team suggested also that Toledo Edison confer with the valve designer/manufacturers (Limitorque and Velan) to determine if they concur with this root cause.

Toledo Edison issued Revision 2 of the troubleshooting plan, dated June 26, 1985, to provide testing with a differential pressure across the valve.

During a meeting on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. They had discussed the preliminary root cause with both the valve operator manufacturer (Limitorque) and the valve manufacturer (Velan). Neither disagreed with the possibility that the opening torque switch bypass contacts had been specified at too small a value.

Toledo Edison has now conducted tests with about 1000 psid across the valves (AFW pump side high) to attempt to reproduce the failure. The AF-608 valve failed one of three tests at 1050 psid. The AF-599 valve passed a test at 350 psid, just barely passed at 750 psid, and failed to open twice successively at 1050 psid.

Discussions revealed that Torrey Pines had specified settings from the start of valve stem motion, whereas MOVATS specifies settings from valve disc movement. Due to the gap between the stem and the disc, the difference between these two motions could be as great as 10% of total valve travel.

Toledo Edison has also completed calculations and confirmed that the valve operator has sufficient force to open the valve against high differential pressures of 1050 psid (2.9 hp vs. 4.0 hp available).

Toledo Edison also found that for AF-599 the spring-pack locknut was installed backwards and that no setscrew was installed. For AF-608, the spring pack was lightly pre-loaded. Toledo Edison believes that these discrepancies were not significant with regard to the June 9 failures.

Toledo Edison believes that the root cause of the AF-608 and AF-599 valve malfunctions has wide applicability at the Davis-Besse Plant and could affect other plants also. They are currently considering specifying the setpoint for the open torque switch bypass contact at 90% of the full-open position for all valves at the plant.

As of this time, Toledo Edison has not presented an engineering report to support the final result of the root cause determination.

During the discussion Toledo Edison stated that the safety function for the valve had been incorrectly specified as only to close, not to open or reopen. For a postulated main steamline break upstream of the MSIV, both OTSGs would initially depressurize. This is shown in Figure 15.4.4-3 of the USAR. Low OTSG pressure would actuate the SFRCS and cause both MSIVs and both AFW containment isolation valves (AF-608 for OTSG #1 and AF-599 for OTSG #2) to close. Because the MSIV would close, the "intact" OTSG would repressurize. The repressurization should reset the SFRCS actuation and cause the automatic re-opening of the associated AFW containment isolation valve to allow AFW flow so that the OTSG could be used as a heat sink. Thus, valves AF-608 and AF-599 and the associated SFRCS have two safety functions: to close to isolate the affected OTSG and to open to allow use of the unaffected OTSG. Review of the auxiliary feedwater system and the SFRCS designs revealed, and discussions with Toledo Edison confirmed, that neither the SFRCS nor the auxiliary feedwater system meet the single failure criterion with respect to opening an AFW containment isolation valve to feed an intact steam generator.

The valves had never been tested with a differential pressure across the valve which is likely to be the condition for certain postulated accidents. With no differential pressure present, the tests may not reveal an improper setting of the bypass contacts around the torque switches, an improper torque switch setting, or an improperly sized motor. It should be noted that testing of valves with differential pressure is not generally done within the industry.

During a previous event on March 2, 1984 at Davis-Besse, the AF-599 valve automatically closed and later could not be re-opened with the controls provided for the valve in the control room. The valve had be to handcranked open locally during the recovery phase of that event (as was also the case on June 9, 1985). In March 1984, Toledo Edison's corporate engineering staff decided that, although the valve inspection found no causes, and no attempt had been made to reproduce the failure by a test, the valve must have driven itself too far closed and could not re-open. Therefore, the specified closing torque switch setting for the valve must be improper. On this basis, the specified closing torque switch was changed to cut off the motor at a smaller closing torque value. Subsequent testing of the valve (without a differential pressure across the valve) did not show any problems but likewise did not demonstrate that the problem had been corrected. No further action was pursued, and the valve was returned to service and declared to be "operable."

5.2.6 Main Steam Supply Valve to AFPT No. 1

Valve MS-106 is the main steam supply valve from OTSG #1 to auxiliary feed pump turbine (AFPT) #1. It was in its normally closed position just prior to the June 9, 1985 event. Six minutes into the event (at 01:41:04) Actuation Channel #1 of the SFRCS actuated on low level and initiated the start of AFPT #1 on steam from OTSG #1. That is, MS-106 started to open. Four seconds later, the SFRCS was actuated manually on low pressure. Such an actuation (low pressure on OTSG #1) has priority and would signal MS-106 to re-close. The design of the valve control circuitry is such that the valve should have completed its opening stroke (25 seconds) and then returned to the closed position (another 25 seconds). Review of the plant data after the event revealed that MS-106 was fully closed at 19 seconds after it started to open. This value suggests that the valve stopped and/or switched direction in mid-stroke, contrary to the design intent.

Toledo Edison's troubleshooting plan for this item was "Auxiliary Feed Pump Turbine Main Steam Inlet Isolation Valve (MS-106) Problem Analysis," Action Plan No. 27, dated June 25, 1985. Toledo Edison developed six hypotheses which included: an open motor field circuit which could have caused the motor operator to overspeed; and five different open-circuit malfunctions of seal-in circuits, pressure switches, control relays, torque switches, or limit switches which could have caused the valve to reverse direction at some intermediate position.

Toledo Edison issued Revision 1 to the troubleshooting plan, dated July 3, 1985, to reflect the possibility of wiring errors associated with the SFRCS modifications, improper AFP low suction pressure switch operation, improper steam supply low pressure relays, and torque switch or bypass contact misadjustments.

During a meeting on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. The actual troubleshooting is complete except for testing under reactor system operating conditions. The troubleshooting found:

1. A loose wiring connection.

2. A wiring discrepancy in the MS-106 controls.

3. A wiring discrepancy in the motor starter.

4. An unnecessary gap between the spring pack locknut and the outer thrust washer.

5. A cocked packing gland flange.

6. The opening torque switch bypass contact set to open too early.

7. Inoperable MS-106A position alarms in the control room.

At this time, the troubleshooting has not produced a conclusive root cause for the June 9, 1985 malfunction, and thus, a Toledo Edison engineering report to support the results of the root cause determination is not available.

5.2.7 Source Range Nuclear Instrumentation

One of the two redundant source range nuclear instrumentation channels (NIs) (Channel 2, NI-1) was inoperable prior to and throughout the June 9, 1985, event. About 16 minutes into the event, the neutron level had decreased to the top of the source range. Upon energization, the second source range NI (Channel 1, NI-2) failed; it went off-scale low (i.e., less than 1 X 10^{-1} counts per second).

Toledo Edison's troubleshooting plans for this item were "Action Plan Report for NI-1 Source Range Channel," Plan No. 15A-1, 15A-2, dated June 17, 1985 and "NI-2 Count Rate Level Indication Failure Analysis," Plan No. 15B, dated June 17, 1985. Toledo Edison's hypotheses for the failure of NI-1 are: an intermittent problem within the Count Rate Amplifier Module (CRAM), extraneous counts being introduced from various external sources, and resonant cable lengths. The hypothesis for NI-2 is that the detector high voltage or the input signal to the CRAM is being interrupted by a bad relay contact, loose wiring, and/or loose components.

At a meeting on July 11, 1985, Toledo Edison discussed the status of the troubleshooting of this item. For NI-1 (inoperable prior to the event), Toledo Edison has observed periods of elevated count rates that seemed to come and go, and Toledo Edison has obtained some baseline data. Technical assistance on noise problems with pulse-type instrumentation is being obtained from Ohio State University. No root cause has been identified and troubleshooting is continuing. For NI-2 (failed low during event), Toledo Edison's efforts have not reproduced the failure. No root cause has been identified and troubleshooting is continuing. Toledo Edison is considering revising the troubleshooting plan.

As of this time, Toledo Edison has not presented an engineering report to support the results of the root cause determination.

The problems with the source range NIs which occurred prior to the event are discussed in Section 5.1.2.

5.2.8 Pilot Operated Relief Valve (PORV)

During the June 9, 1985, event, the pilot operated relief valve (PORV) operated automatically three times. In the first operation, the valve opened at about

the proper pressure (the setpoint is 2425 psig), was open for about 3 seconds, and re-closed at about the proper pressure (2375 psig). The second operation was similar except that the closing pressure was slightly lower. In the third operation of the PORV, it did not re-close. Review of the data for the quench tank pressure and level indicates that the flow was not terminated until the block valve was closed. The PORV block valve was closed by the operator when system pressure had fallen to about 2140 psig, 24 seconds after the PORV had opened. The operator re-opened the block valve a little over 2 minutes later. At this time, it appeared that the PORV was closed.

Toledo Edison's troubleshooting plan for this item was "Review of the Operation of the PORV," Action Plan No. 10, dated June 22, 1985. It appears that Toledo Edison's primary hypothesis is that differential thermal expansion of the valve disc and the body caused the PORV to become stuck. Other hypotheses are: valve mechanical malfunction, solenoid linkage broken or corrosion buildup, and sticking caused by foreign material.

Toledo Edison approved Revision 1 to the troubleshooting plan on July 3, 1985. A major change was the addition of a summary of the operating experiences with PORVs sticking open at six other PWRs (i.e., pressurized water reactors, the same type reactor as Davis-Besse) due to a wide variety of causes. These PORVs were manufactured by vendors different from that for Davis-Besse.

During a meeting with NRC on July 11, 1985, Toledo Edison discussed the status of the troubleshooting of this item. The plan has virtually been completed, including disassembly and inspection of the valve, without identification of the root cause for failure.

When the Team inquired as to what the manufacturer advised, Toledo Edison replied that Crosby had recommended additional tests in two areas: (1) the PORV control circuits, and (2) functional PORV tests at 600 psi and full RCS pressure. Toledo Edison stated that the PORV manufacturer is not surprised that no cause has been found. During the Electric Power Research Institute's (EPRI) PORV valve testing, tests were conducted under a variety of conditions, but each test consisted of only a single operation of the PORV. Toledo Edison states that during the EPRI testing there were one or more failures of the PORV to close and, although investigation(s) were conducted, no cause was ever determined. During the June 9, 1985 event, the PORV did not fail until the third operation. During a 1977 event at Davis-Besse, the PORV operated nine times and then failed. These points suggest that the EPRI test results may not be representative of PORV operation and that the results should be used with caution. Further, the apparent situation that the causes of some PORV failures may not ever be known raises again the question of the need for better protection against PORV failures, i.e., automatic block valve closure.

Toledo Edison is currently reviewing Revision 2 to the PORV troubleshooting plan to provide for checking the controls and actual PORV lifts. Toledo Edison is also considering that if a failure cause for this PORV cannot be identified, a new PORV may be procured that would be tested prior to installation.

As of this time, Toledo Edison has not presented an engineering report to support the results of the root cause determination.

The review of the PORV maintenance and operating history reveals that the mechanical operation valve had not been tested or otherwise operated for over 2 years, 9 months prior to the June 9, 1985 event.

5.2.9 Startup Feed Control Valve for OTSG No. 2

During full power operation, the startup (S/U) feed control valves (SP-7B and SP-7A) are fully open. Upon SFRCS actuation, the S/U feed control valve to each OTSG is automatically closed. This action occurred inadvertently 5½ minutes after the plant trip on June 9.

In anticipation of returning the startup feed pump to service, the operator attempted to override/reset the SFRCS so that the S/U feed control valves could be re-opened. However, the reset light for SP-7A did not come on, indicating that the operator had not regained control of the valve. Based upon the apparent lack of reset for SP-7A, the control room operators believed at the time that flow from the startup feed pump went through SP-7B to OTSG #1 only and not through SP-7A to OTSG #2.

Toledo Edison's troubleshooting plan for this item was "Startup Feed Valve SP-7A Problem Analysis," Action Plan No. 18, dated June 22, 1985. Their hypothesis is that the valve actually functioned properly, but the indication of SFRCS reset for this valve was not available due to a burned out indicator bulb. The alternative hypothesis, i.e., that the valve did not respond correctly, would be addressed by the collection of plant data to show if there was flow through the valve.

During a meeting with NRC on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. The actual troubleshooting has been completed, and Toledo Edison believes that a final conclusion regarding this valve has been reached. Simulated SFRCS output signals show that the S/U feed control valve SP-7A closed on demand, that the override/reset features functioned properly, and that the valve re-opened when operated from the control room. Plant data shows that during the June 9, 1985 event, SP-7A actually opened to about 12% and the measured flow was about 1.5% of full S/U flow.

Therefore, Toledo Edison has concluded that the valve performed properly during the event, and that only the reset indicator failed due to a burned out bulb. However, as of this time, Toledo Edison has not presented an engineering report to support the results of this root cause determination.

5.2.10 Recovery and Control of Both AFW Turbines

During the June 9, 1985, event, equipment operators were dispatched to restore both AFW trains. The equipment operators had difficulty resetting the turbine trip-throttle valves which had tripped due to overspeed. Further, there was difficulty restoring proper speed control. The control room operator attempted to regain control repeatedly. The efforts were not successful. During the event, the AFW #1 turbine increased to about 2200 rpm, which is well below full speed and was insufficient to pump feedwater into the pressurized OTSG. The equipment operators continued to operate the trip-throttle to control speed, and encountered difficulties. The linkage for the trip-throttle valve for

AFPT #1 apparently disengaged twice, causing the valve to slam shut. Control of both AFW turbines was performed locally throughout the event.

Toledo Edison's troubleshooting plans for this item were "AFPT Overspeed Trip Throttle Valve Problem," Action Plan 1D, dated June 20, 1985 and "AFPT Manual/Auto-Essential Control Problem," Action Plan 1C, dated June 24, 1985. Toledo Edison's hypotheses regarding the difficulty in re-latching the overspeed trip throttle included: (1) the tappet of the turbine trip mechanism malfunctioned, (2) the trip hook relatching spring was inadequate, and (3) there were mechanical difficulties related to the trip hook pivot point or to the linkage mechanism. Toledo Edison's hypotheses regarding difficulty opening the trip throttle valve included the possibility that the valve may not be correctly balanced or adjusted for opening against the steam generator pressure. Toledo Edison's hypothesis regarding the difficulty that the control room operator experienced in regaining AFPT control was directly attributable to the inability to re-latch the trip-throttle valve linkage properly and the difficulty and delay in opening the trip-throttle valve.

During a meeting with NRC on July 11, 1985, Toledo Edison discussed the status of the troubleshooting under plan No. 1D, which covers the re-latching of the turbine overspeed trip mechanism and difficulties in opening the turbine trip-throttle valve. Figure 5.1, from Toledo Edison's action plan, illustrates the pertinent aspects related to this problem. Except for some tests to be done under full steam pressure (plant mode 3), the actual troubleshooting has been completed. Toledo Edison believes the root cause for this item has been determined. All mechanisms have been checked and found to be properly adjusted, with all mechanism pivot points and components free to operate. The equipment operators who were involved during the June 9, 1985, event have been involved in every step of this troubleshooting activity. Toledo Edison stated that these equipment operators now believe that there was no mechanical problem with the mechanism, but rather that they did not know how to perform the necessary actions.

It is physically possible to pull the connecting arm sufficiently far (to the left in Figure 5.1) to be able to barely re-engage the trip hook at the trip-throttle valve but not reset the overspeed trip back at the other end, where the overspeed tappet and manual trip lever are located. This end of the connecting arm is behind the governor and is not easy to see.

The equipment operators had been trained and certified in all the specified areas related to the AFW systems. The overspeed trips are tested monthly and have to be reset each time; however, the test is conducted with low pressure auxiliary steam (235 psig), and the procedure emphasizes getting the trip hook and latchup lever at the trip-throttle valve together. Since the Technical Specification surveillance test is performed by one out of six operating shifts on a rotating basis, it is possible that these equipment operators had not had sufficient hands-on experience, even at the lower auxiliary steam pressure.

During the event, when a more experienced individual arrived later at AFPT #1, the trip was immediately relatched properly, the trip-throttle re-opened, and the AFP made operable. Had this operation been performed originally by a more experienced operator, the AFP would have been available when the isolation valve (AF-608) was re-opened, i.e., about 5 minutes before flow was actually acquired. For the #2 AFPT, the equipment operator reset the overspeed trip mechanism

properly and in a timely manner. However, some resistance was experienced as the trip-throttle valve was being opened. The equipment operator seemed not to know what to do at that point. After a more experienced operator arrived some minutes later and used a valve wrench to open the trip-throttle valve fully, the AFP #2 was operable.

In summary, the delay in recovering both AFW trains following the overspeed trips is attributed to less-than-adequate hands-on training under full steam pressure conditions.

As of this time, Toledo Edison has not presented an engineering report to support the results of the root cause determination.

Problems had been experienced previously with resetting the trip-throttle valves properly.

5.2.11 AFW No. 1 Suction Transfer

During the June 9, 1985, event, AFW train #1 provided significant flow (>400 gpm) for about a 3½-minute period between about 01:55 and 01:59 a.m. At about the end of this period, the operator reported that the low suction pressure alarm had come on and the suction source was being automatically transferred from the condensate storage tank to the service water system. The plant traces also show a sharp speed reduction (nearly all the way to zero rpm) at about the same time, suggesting a spurious closure of the trip-throttle valve. Just after this time (01:59), the overspeed trip was properly reset, and the trip-throttle valve re-opened. The control room operator manually returned the suction to the condensate storage tank.

Prior to this transfer (i.e., at 01:58), the alarm data shows an actual low suction condition had developed, had lasted for 34 seconds, and cleared itself.

Toledo Edison's troubleshooting plan for this item was "Inadvertent Auxiliary Feedwater Pump #1 Suction Supply Transfer from Condensate Storage Tank to Service Water Supply," Action Plan No. 26, dated June 26, 1985. Toledo Edison's primary hypotheses include: suction pressure switches associated with AFW #1 setpoints were out of specification, suction pressure switches actuated due to vibration, the low suction pressure alarm was out of specification, the common AFW strainer was clogged, the AFW #2 low pressure switches were out of specification, or an actual low suction pressure situation was induced. Other hypotheses include: momentary loss of power to suction valves AF-786 and SW-1382, suction strainer S-201 was clogged, and manual suction transfer to the service water system.

During a meeting with NRC on July 11, 1985, Toledo Edison discussed the status of the troubleshooting on this item. Some of the troubleshooting steps have been completed but none of the findings establish the cause of the suction transfer. Troubleshooting is continuing.

As of this time, Toledo Edison has not presented an engineering report to support the results of the root cause determination.

5.2.12 Turbine Turning Gear

After the plant had stabilized from the June 9, 1985, event, it was noticed that the main turbine had not gone onto its turning gear. Since the same problem had been experienced recently and blown fuses had been found then, the shift supervisor dispatched a worker to replace these same fuses. As the Team understands it, the fuse replacement alleviated the immediate problem.

The Team agreed with Toledo Edison that it was not necessary to have this item on the quarantine list or to develop a special troubleshooting plan.

5.2.13 Control Room HVAC System

Toledo Edison stated that during the event the control room heating, ventilation, and air conditioning (HVAC) system tripped spuriously and went into its emergency mode of operation. This type of actuation had occurred on previous occasions and did not appear to be unique to this event.

The Team agreed that it was not necessary to have this item on the quarantine list or to develop a special troubleshooting plan.

5.2.14 Turbine Bypass Valve

About 5 hours after the reactor trip on June 9, 1985, the condenser vacuum was re-established and MSIVs were re-opened. At this time one of the turbine bypass valves was damaged severely. The control room operators heard a loud cracking sound like that heard typically from a water hammer. Subsequent inspection showed that both the valve yoke and housing were cracked. Additionally, the valve stem thread dimension was questionable and the pin connector was found in contact with the sleeve assembly.

Toledo Edison's troubleshooting plan for this item was "Turbine Bypass Valve 2-2 (SP13A2) Problem Analysis," Action Plan Nos. 9a and 9b, dated June 18, 1985. Toledo Edison's hypothesis is that the damage was most likely caused by a combination of a water hammer and mis-assembly of certain valve internals. An alternate hypothesis is that the valve positioner malfunctioned.

During a meeting on July 12, 1985, Toledo Edison discussed the status of the troubleshooting of this item. It has been determined that, while all the turbine bypass valves had been rebuilt in 1980 under the supervision of the manufacturer, only this valve was rebuilt again in 1982 (and without the benefit of supervision by the manufacturer). Further, this is the only bypass valve found to have a modified valve stem with a cotter pin. The inspection results identified 11 discrepancies:

1. Clogged strainer (ST3).

2. Deformed strainer (ST3A) and failed steam trap.

3. Short piston actuator travel length, 1 9/32 inches vs. the design valve of 1 9/16 inches.

4. Discoloration of the yoke at the break location.

5. Broken positioner linkage.

6. Valve stem previously scored seriously in a vise.

7. Valve Activator stem extension piece bent.

8. Main plug separated from stem, found in bottom of valve body.

9. Belleville springs and spacers found jammed together on pilot plug.

10. Cotter pin and washer for main plug missing.

11. Three inches of water in bottom of valve.

Toledo Edison re-confirmed that there is no program at Davis-Besse for periodic maintenance or testing of the turbine bypass valves. The valve parts have been sent to Fisher for destructive testing and evaluation of possible failure causes.

Investigation into the temperature (about 140°F) difference between the two steam lines downstream of the MSIVs is continuing to determine how much steam condensed. The associated steam traps and drains are also being investigated for proper operation.

Toledo Edison maintains that the root cause of this failure is a combination of a water hammer and valve misassembly.

As of this date, Toledo Edison has not presented an engineering report to support the results of the root cause determinations.

Table 5.1 Summary of Equipment Troubleshooting Results

	ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
1.	Main Feedwater Turbine	Overspeed	Control System Electronic Circuit Card Failure	Pre-existing Control System Problems Have Not Been Resolved
2.	Closure of MSIVs	Spurious Actuation of SFRCS	Not Identified	Troubleshooting Activities Have Not Yet Begun
3.	Steam Safeties, Atmos. Vents	Abnormal Pressure Control	Not Identified	
4.	Aux. Feedwater Turbines	Overspeed	Condensate Flow to Turbines From Steam Supply Lines During Turbine Start	Testing with Plant Hot Needed to Verify Cause
5.	AFW Containment Isolation Valves	Would Not Re-Open	Improper Settings for Torque Switch Bypass Contacts	
6.	Steam Supply Valve to AFPT #1	Short Cycle	Not Identified	Failure Could Not Be Reproduced. Improper Torque Switch Bypass Contacts Could Be Problem
7.	Source Range NI	Failed, Low	Not Identified	Failure of One of Two Channels Could Not Be Reproduced
8.	PORV	Did Not Close	Disassembly of Valve and Testing of Control System Failed to Reveal Cause	Cause May Never Be Identified
9.	S/U Feedwater Control Valve	Did Not "Reset"	Indication Problem Only - Indicator Lamp	
10.	Recovery of AFP Turbine	Trip-Throttle Valve Operational Difficulties	Lack of Operator Training	Not a Hardware Problem

Table 5.1 Summary of Equipment Troubleshooting Results (Continued)

	ITEM	NATURE OF FAILURE	PROBABLE ROOT CAUSE	COMMENTS
11.	AFP #1 Suction Transfer	Transfer to Service Water	Not Identified	
12.	Turbine Turning Gear	Did not Engage		Troubleshooting Not Reviewed by Team
13.	Control Room HVAC	Spurious Transfer to Emergency Mode		Troubleshooting Not Reviewed by Team
14.	Turbine Bypass Valve	Structured	Water Hammer, Valve Mis-Assembly	Cause of Water Hammer Not Yet Known

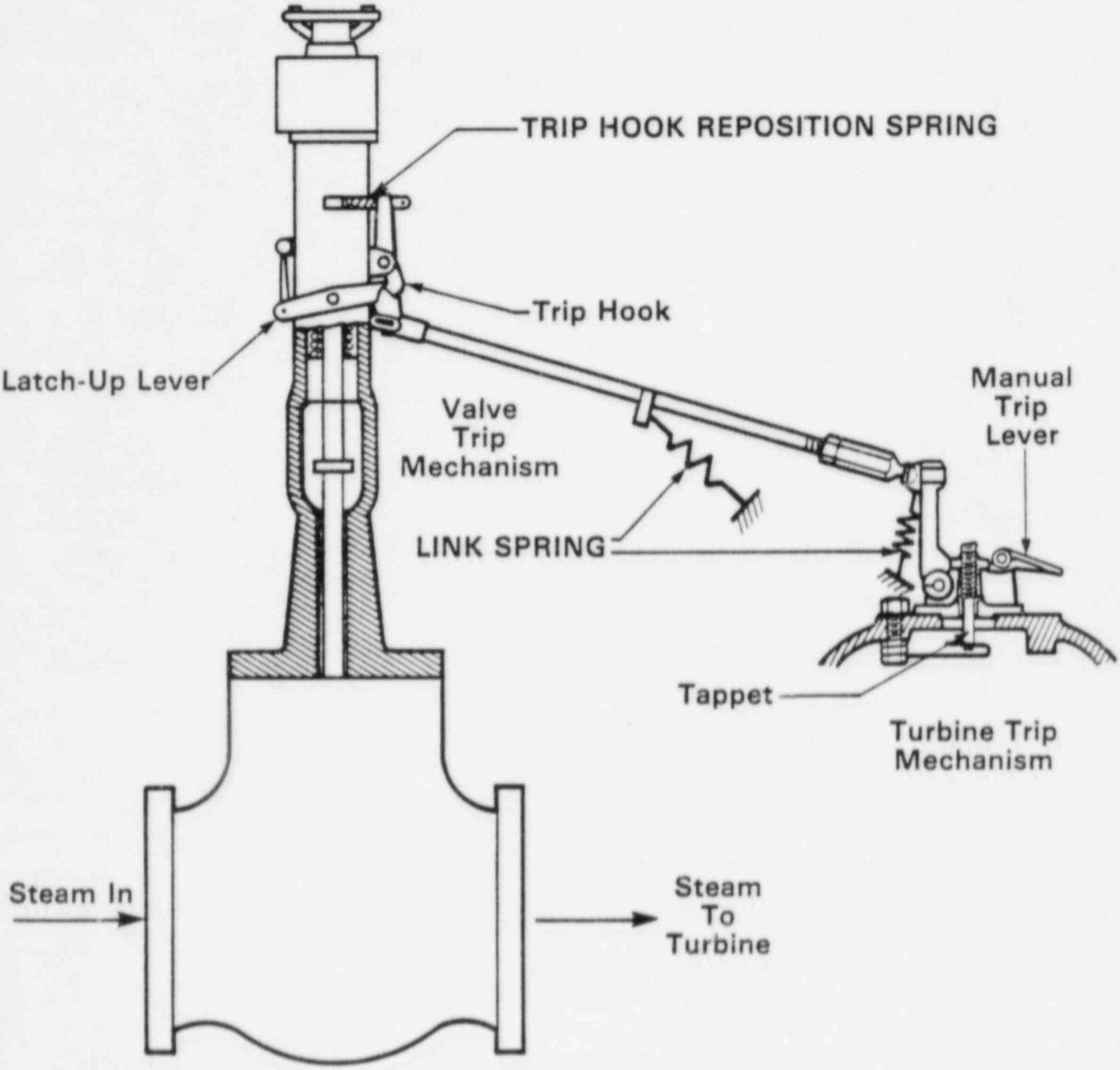


Figure 5.1 AFPT Trip-Throttle Valve

6.0 HUMAN FACTORS CONSIDERATIONS OF THE DAVIS-BESSE EVENT

This section discusses the human factors aspects of the June 9 event. The following discussion of personnel performance and man-machine interfaces are related to how these human factors considerations affected the event. When appropriate, potentially adverse effects are described that could have affected the event. The information was obtained through interviews with plant operators and their management, and by a walk-through of the control room and other parts of the plant where relevant equipment is located.

6.1 Operator Performance

Based on the details of operator actions described in Section 3, it should be evident that both the licensed (control room) and non-licensed (equipment) operators performed well as a coordinated group to mitigate a complex event involving multiple malfunctions. The operators, particularly the assistant shift supervisor and senior equipment operator, performed timely corrective actions from outside the control room and prevented a potentially more serious event. However, noteworthy operator errors also occurred. Two were made by licensed operators and two were made by equipment operators.

6.1.1 Licensed Operators

The actions taken by the licensed operators during the event indicated that they were generally cognizant of plant conditions and responded to them in a deliberate manner. For example, the first operator error involving manual initiation of the steam and feedwater rupture control system (SFRCS) occurred only after the reactor operator had requested and received permission from the shift supervisor to initiate the SFRCS system. The second operator error occurred when the shift supervisor did not initiate MU/HPI cooling at the point required by the emergency procedure. The shift supervisor believed that initiating MU/HPI cooling was not needed nor required because restoration of auxiliary feedwater flow was imminent and he did not recognize that the criteria in the procedure for initiating MU/HPI cooling existed.

The operator's attempt to initiate SFRCS manually was anticipatory. He tried to initiate the SFRCS before it automatically initiated on low steam generator water level. Instead he inadvertently pushed the two buttons labeled low steam pressure. A Davis-Besse operator described such anticipatory actions as a kind of preventive medicine. That is, if the safety system is going to trip, manually tripping it earlier would provide its benefit sooner. For this event, manual initiation of the SFRCS would initiate the AFWS before the steam generator low water level set point was reached. Hence, less inventory would be lost and the AFWS would restore the steam generator inventory to normal levels faster.

Operators at some other utilities are also trained to manually initiate safety systems when automatic actuation is imminent. While this practice is normally conservative and proper, this event indicates that it introduces an opportunity for incorrect operator actions either because of a lack of knowledge of plant conditions or through mistakes in implementation. In this case, the layout of

the control panel contributed to the event, but had the equipment worked properly, this operator error would not have had a major effect on the seriousness or consequences of the event.

As noted above, the layout of the SFRCS buttons contributed to the operator error. The SFRCS manual switches, shown in Figure 3.6, are arranged in two columns of five switches. Each column represents one actuation channel of the SFRCS and each button represents a different parameter; for example, low steam pressure or low water level. During recovery activities on June 9, the operator should have pushed the fourth button from the top of each column to initiate SFRCS on low water level in both steam generators rather than the two top buttons (which initiates the SFRCS on low steam pressure).

Further, it should be noted that to initiate SFRCS for a depressurized steam generator, the operator currently has to operate pushbuttons on a diagonal rather than a horizontal line. For example, to manually initiate SFRCS on low pressure in one steam generator using the push buttons in Figure 3.6, the operator must push the top button in one column and the second button from the top of the other column, depending on which steam generator had the low pressure. Toledo Edison was considering a revised layout in which the pushbuttons for low pressure actuation for either steam generator would be in a horizontal line. Had this high-priority deficiency been corrected in this manner prior to the June 9 event, the operator's error would have isolated only one steam generator and the other steam generator would have been available as a heat sink.

In addition to the diagonally aligned buttons, other human factors considerations of concern are the location of the SFRCS panel and the labels identifying the buttons. The SFRCS panel is located on the back panel--behind and below the main control console shown in Figure 3.4. It is not easily visible from the operator's normal work station and the operators must walk around the main control console to manipulate the switches. The pushbuttons are small and their labels do not clearly describe their function. For examples, the label "SG 1-1 LOW STM PRESS" means that pushing the button initiates SFRCS channel 1, which isolates the feedwater to No. 1 steam generator because it has low pressure (e.g., steamline break or leak). (See Figure 3.6.) Similarly, the button labelled "SG 1-1 LOW WTR LVL" means to initiate SFRCS channel 1 on low level in No. 1 steam generator and start the No. 1 AFW pump to feed the steam generator because it has low water level (e.g., loss of feedwater). The labelling of controls for manually initiating one of the most important systems at Davis-Besse should have been unambiguous.

In January 1985, Toledo Edison advised the NRC that the SFRCS manual initiation pushbuttons had been identified as one of the principal items needing human engineering improvements.* A design change of these pushbuttons was expected to be completed by the end of the fifth refueling outage, scheduled in late 1986. Toledo Edison had given a high safety significance to the correction of this deficiency because it was recognized that an operator error could inadvertently block any SFRCS actuation. The operator error postulated in the Toledo Edison analyses had the same result as the operator error that occurred during the June 9 event, i.e., feedwater was not supplied to both steam generators. During

---

*Letter from R. Crouse, Toledo Edison Company, to J. F. Stolz, NRC, Docket 50-346, January 31, 1985.

a meeting with the Team, Toledo Edison informed the Team that current control room operator training emphasized the proper technique for manual initiation of SFRCS but did not emphasize the potential consequences of an incorrect initiation.

The operator on duty during the event, however, who pushed the wrong buttons indicated that this was the first time that he had manually actuated the SFRCS or had ever been at the control panel during an SFRCS actuation. Further, he indicated that he had received no specialized classroom or simulator training on correctly initiating the SFRCS. Furthermore, the simulator at the Babcock & Wilcox facility where the reactor operator received training did not include the SFRCS. This situation indicates a lack of thoroughness of training and provides a further incentive for plant-specific simulators.

The operations superintendent indicated that during the event he directed the shift supervisor by telephone to prepare for MU/HPI cooling within 1 minute if the shift supervisor was unable to establish feedwater flow with an AFW pump. This instruction was based on the operations superintendent's knowledge that analyses showed that if make-up cooling was established within half an hour, there was a good probability that the core would not become uncovered, and that a serious situation would be avoided, even with only the startup feedwater pump (SUFP) operating.

During the time that the shift supervisor was discussing the initiation of MU/HPI cooling with the operations superintendent, the secondary-side operator twice suggested this mode of cooling to the shift supervisor. In addition, emergency procedure 1202.01 specified that MU/HPI cooling be initiated if (and when) both steam generators were "dry" and there was no feedwater. However, as noted previously, the shift supervisor did not initiate MU/HPI cooling because he believed that restoration of auxiliary feedwater flow was imminent. During this period he was on the telephone and, as a result, a delay in a decision regarding this mode of core cooling occurred and time was made available for the equipment operators to restore auxiliary feedwater flow. The decision by the shift supervisor was also influenced by a reluctance to release reactor coolant into the containment because of the cleanup and extended shutdown associated with it. In this regard, when the shift supervisor was asked why he did not initiate MU/HPI cooling, he noted:

> Well, it's a pretty drastic step. And I wanted to wait until I was -- well, I didn't want to do it prematurely. I wanted to wait until I was at the point that was required by the procedures to do that.

6.1.2 Procedural Compliance

Emergency Procedure 1202.01 is the Davis-Besse version of the B&W Owners Group's Abnormal Transient Operating Guidelines (ATOG) and had been implemented in January 1985. From interviews conducted by the Team, the operators have confidence in this procedure to help them mitigate the consequences of plant events. For example, when asked how this procedure compared with pre-TMI procedures, the shift supervisor replied,

> Before we would have to be in maybe two, three, four procedures. This is the only document that we have to pull out. And it will

lead you step by step through the procedure until you do discover your fault.

This procedure was followed during the event. The Team believes it was implemented correctly until the decision point was reached in the section entitled "Lack of Heat Transfer" regarding the initiation of MU/HPI cooling. With both steam generators dry, i.e., pressure is below 960 psig and decreasing or water level is less than 8 inches and with no feedwater, the procedure indicates that MU/HPI cooling is to be initiated. However, based on the operator interviews, it appears that none of the control room operators were fully aware that both steam generators were "dry" as defined by the emergency procedure.

At Davis-Besse, the available instrumentation did not provide clear information to the operator that the steam generators were dry. For example, steam generator pressure is not recorded in the control room for trending purposes. As a result, when the steam generator pressure reaches 960 psig, the operator must remember whether the pressure has been decreasing or whether a sudden depressurization has occurred. Further, steam generator levels are indicated in the control room on a scale of 0 to 250 inches on the startup level instrumentation shown in Figure 3.10. Given this scale, the operator cannot read "8 inches" on the instrument accurately, even if the instrument is accurate at the low range of its scale.

Both the steam generator pressure and water level can be trended using the safety parameter display system (SPDS); however, it was inoperable prior to the June 9 event. The inoperability of the SPDS and the lack of adequate indication of steam generator conditions contributed to the control room operators not knowing that the steam generators were dry, which resulted in their failure to follow the emergency procedure.

Further, because the equipment operators restored auxiliary feedwater flow to the steam generators in approximately 12 minutes, the shift supervisor's delay in implementing MU/HPI cooling did not lead to adverse consequences. However, the time to restore the feedwater is a critical factor regarding the seriousness of this event, and further delays in restoring feedwater could have had potentially serious safety consequences, as discussed in Section 7.

This event points out a natural reluctance on the part of operators to initiate any action which could result in long plant shutdowns or other major economic consequences. That is, the operator can be expected to explore and discuss all available options and to take the time to assure the need before initiating a "drastic" action. This consideration should be recognized and reflected through precise and clear instructions in any procedure which addresses the need for such "actions."

6.1.3 Operator/STA Interaction

Neither the shift supervisor nor any of the other licensed operators requested the assistance of the shift technical advisor (STA) during the event. One reason for not doing so is the fact that the STA was not in the control room when the event occurred. (Note: He is allowed 10 minutes to reach the control room after being called.) Moreover, the event occurred so rapidly that it was essentially over when he did arrive. In summary having the STA available

was a post-TMI improvement to provide the shift supervisor with additional technical expertise, but his potential assistance and guidance were not available nor required during this event.

6.1.4 Emergency Notification

After the plant was stabilized, the shift supervisor's attention turned toward the actions specified in the emergency plan, such as notifying the NRC, and the local sheriff. He requested that the STA perform the notifications, which was the only responsibility that the STA was assigned during the event. The transcribed telephone discussions with the NRC operations officer, indicate that in the initial call, the STA did not provide an adequate description of the event because of lack of sufficient knowledge. Subsequently, additional calls were made. During the third telephone call, at 2:26 a.m., the STA informed the NRC that an Unusual Event had been declared.

The shift supervisor, who is also the emergency duty officer (EDO) on this shift, declared an Unusual Event. Although he recognized that the emergency plan identified the total loss of feedwater event as a Site Area Emergency, the plant was no longer in this emergency action level, and he concluded that it was not an appropriate emergency class. He declared an Unusual Event primarily to assure that sufficient technical and maintenance support personnel would come to the site for event analyses and to ensure that the plant remained stable. The shift supervisor indicated there was some confusion as to the correct classification or if any classification was required because the emergency plan was silent on how to determine the emergency action level if it changed during the event.

At Davis-Besse, the emergency plan is initially implemented by the shift supervisor, who also has primary responsibility for ensuring that the plant is maintained in a safe condition. Thus, because of the competing priorities of directing attention to necessary recovery actions to obtain a safe and stable plant or of reviewing the emergency plan and initiation of its actions, there could be a substantial delay in implementing the emergency plan. This delay, in turn, may affect the timely identification of the proper emergency action level and appropriate notifications. If the June 9 event had been more complex and continued longer, it is likely that the emergency classification and notification would have been substantially delayed and would have lacked accurate details because knowledgeable personnel during this shift were involved with activities to obtain a safe and stable plant condition.

6.1.5 Equipment Operators

The control room operators dispatched two equipment operators to reset the overspeed trip for each AFW pump, and accordingly, to restore this equipment to service. The recovery from an overspeed trip is a two-step process. First, the overspeed trip must be reset, and then the trip throttle valve must be latched. The trip throttle valve may be latched without resetting the overspeed trip; however, overspeed trip protection would then not be available. One equipment operator went to the No. 1 AFWP turbine, while the other operator went to the No. 2 AFWP turbine.

One operator had successfully reset the overspeed trip and had latched the No. 2 trip throttle valve. However, he had not turned the handwheel the required number of revolutions to unseat the valve and admit steam to the turbine. The

fact that there was steam pressure of about 900 psig at the valve made the valve difficult to open. Furthermore, the operator was extremely cautious in attempting to open the valve. In attempting to avoid any potentially damaging or adverse actions, he failed to apply enough force to the handwheel to open the valve.

The other operator latched the No. 1 trip throttle valve but failed to properly reset the trip. Again, a large differential pressure existed across the trip throttle valve, but the operator partially opened the valve and, as a result, the turbine speed increased to about two-thirds its normal speed. At this speed, the discharge pressure of the pump was not high enough to feed the steam generators. After several unsuccessful attempts to increase the pump speed, he went to assist the other operator at the No. 2 AFW pump.

The assistant shift supervisor, who had come to the AFW pump rooms to start the startup feedwater pump, told the equipment operators that the No. 2 trip throttle valve was still closed and it had to be opened to admit steam to the No. 2 AFW pump turbine. Meanwhile, after having opened the AFWS isolation valves (See Section 3) a third, more experienced, senior equipment operator entered the AFW pump room and used a valve wrench to open the trip throttle valve. He then proceeded to the No. 1 turbine, and again using the valve wrench, fully opened the trip throttle valve. As noted previously, at this point the No. 1 trip throttle valve had not been reset. The senior equipment operator correctly reset the overspeed trip and latched the trip throttle valve. The No. 1 AFW pump turbine was then returned to service.

The experience of the assistant shift supervisor and the senior equipment operator were instrumental in their returning the AFW system to service. The failure of the equipment operators to initially reset the overspeed trips and open the trip throttle valves was due to their lack of knowledge and experience. (Note: The Training Coordinator stated that the equipment operators had been trained on how to reset and latch the trip throttle valves.) If the equipment operators had been able to quickly reset and had opened the trip throttle valves, auxiliary feedwater flow would have been available approximately 5 minutes earlier.

6.2 Other Man-Machine Interface Considerations

This section discusses other relevant man-machine interfaces that were important to ensuring that the control room operators could properly operate the systems during the event.

6.2.1 PORV Position Indication

The PORV control station (shown in Figure 3.11) indicated to the operator that the PORV had closed after the third opening, when in fact the PORV had failed to close. The indication showed PORV solenoid plunger position and control signal status. However, these indications are indirect and are not necessarily representative of actual PORV positions. As a result, the operator did not know that the PORV had failed to close when he closed the PORV block valve as a precautionary action. Thus, proper operator action was taken and the PORV position instrumentation was not an important factor in mitigating this event.

One of the post-TMI requirements was installation of acoustic monitors for detecting a failed-open PORV. Although this monitoring system was available in

the control room, the operator did not use it, even after he reopened the PORV block valve. One important reason for not referring to this instrument is believed to be the fact that the acoustic monitors are located on the post-accident panel which is about 7 feet away from the PORV control station. The 3-inch high and ½-inch wide meters cannot be read from this distance. Thus, the operator has to leave his control station to read the acoustical instrumentation and he did not do this.

6.2.2 Safety Parameter Display System

The safety parameter display system (SPDS) at Davis-Besse was also a post-TMI improvement to provide the operator unambiguous information on the status of the plant. The system has the capability of displaying a full range of relevant plant parameters and trends on demand by the operator. Although the SPDS has two channels or trains, both were inoperable prior to the event. At Davis-Besse, the system has a reputation for being so unreliable that the operators do not depend upon it.

There are specific references in the "Lack of Heat Transfer" section of the emergency procedure that require the SPDS or hand plots (which are not practical) to be used during an event. However, the SPDS is not required to be operable by the Davis-Besse technical specifications.

The SPDS was needed during the event to trend RCS pressure and temperature and OTSG pressure and level because the corresponding steam generator instrumentation in the control room was inadequate to properly implement the plant procedures required. The SPDS, as noted previously, was not available nor was it required to be available by NRC requirements.

6.2.3 Plant Communications

The plant communication system was a significant contributor to the proper and prompt mitigation of the event. The control room operators used the Gaitronics System to direct the equipment operators to various places in the plant to correct and operate equipment. Without the communications system, a number of operator actions would have been delayed or prevented, such as when: (a) the assistant shift supervisor informed the control room operator that the SUFP was available after he had made the SUFP system operable; (b) the more experienced senior equipment operator was paged and directed to go to the AFW pump room where he opened the trip throttle valves and started the AFW pumps; and (c) after the AFW pumps were running, they had to be controlled manually at the pumps by the equipment operators in response to directions communicated from the control room.

6.2.4 AFW Pump Turbine Overspeed Trip

The AFW pump turbine overspeed trips could not be reset in the control room; action had to be taken at the equipment. The trip throttle valve is a manual valve and the associated linkages must be manually manipulated at the AFW pump by an operator. If, for example, the AFW pump room became uninhabitable, overspeed trips of the AFW pump turbines could not be reset and the AFWS would remain unavailable.

6.3 Personnel Issues

There are a number of management-labor situations affecting personnel morale at Davis-Besse--the most talked about being ongoing contract negotiations. Further, some licensed operators resent a Toledo Edison dress code requiring that they wear uniforms. According to the operators' interviews, neither plant morale nor contract negotiations have had any adverse impact on plant operations and maintenance. A good deal of mutual respect exists among the people working at the plant. "They have worked many years in nuclear power, so everybody is competent," according to one operator. They are concerned about losing their jobs, for example, if the NRC recommended that the plant not go back on line. In general, the operators were skittish towards NRC. As one operator put it, "I am more uncomfortable in this room this morning than I was in the auxiliary feedpump room Sunday morning and I had the whole plant on top of me Sunday morning."

Throughout the course of its fact-finding efforts, the Team met with and interviewed Toledo Edison managers, operators and support personnel. The Team could not infer from their comments or from their actions on June 9 that management-labor issues at Davis-Besse adversely affected operator performance.

7 SAFETY SIGNIFICANCE

A total loss of feedwater is a significant event. It can have severe consequences if actions to ensure prompt and effective recovery are not taken. The consequences and significance of the June 9 event could have been far different had additional equipment failed, had additional personnel errors been made, or had recovery otherwise been delayed. Thus, there are many possibilities and differing sequences which could have affected the safety significance of this transient.

The time margins and consequences of alternate sequences remain under study by the NRC. However, based upon what happened during the event, and on the analyses of the consequences of loss of feedwater events provided by Toledo Edison, the Team was able to gain a perspective on the safety significance of the event, on the time available for its mitigation, and on the effects of various combinations of equipment available for mitigation.

When a reactor trips, decay heat must be removed. The preferred heat removal path is through the steam generators. If this path is not available, direct core cooling must be initiated. If decay heat is not removed from the reactor coolant system more rapidly than it is produced, temperature and pressure will increase. The pressure rise would be limited by the PORV and primary safety valves, but when the pressure rise is limited or reduced by these valves, reactor coolant is lost. If this loss continues and the inventory is not made up from external sources, eventually the core will become uncovered and fuel damage will result. Thus, the parameters which assume importance in this mode of cooling are the system pressure and the pressure capabilities (and flow) of the systems available to provide makeup cooling water to the reactor coolant system.

In reality, over a period of approximately 15 minutes, the Davis-Besse steam generators boiled essentially dry. As a result, the reactor heat sink was lost and reactor temperature and pressure increased. Eventually a reactor coolant temperature of 594°F was reached, which corresponds to a saturation pressure of 1460 psig. (that is, if the system pressure decreased to or below 1460 psig, bulk boiling of the core would result). The high pressure injection (HPI) pumps at Davis-Besse have a pressure capability of approximately 1630 psig. When operated in the piggy-back mode with the low pressure injection pumps, the HPI pumps have a maximum pressure of approximately 1830 psig. This higher pressure corresponds to a reactor coolant saturation temperature of 623°F. Had feedwater not been restored or other mitigative actions taken, extrapolations indicate that the reactor coolant temperature would have reached 623°F about 20 minutes after the loss of feedwater, or approximately 13 minutes after the steam generators essentially boiled dry.

As previously indicated, decay heat can be removed in two ways: (1) through the boiling action in the steam generators and (2) through release of coolant through the PORV and safety valves with makeup water (MU/HPI cooling mode). Feedwater to the steam generators can be supplied by the main feedwater system,

two steam-turbine driven AFW pumps or by the electric-motor driven startup feedwater pump. Pumps available for use in the MU/HPI cooling mode include the two reactor makeup pumps and the two high pressure injection pumps discussed above. In fact, the two makeup pumps can provide flow to the primary system even when the primary system pressure is at the safety valve setting. The HPI pump, however, as previously discussed, cannot.

On June 9, flow from the auxiliary feedwater pumps promptly reversed the temperature rise in the reactor coolant system. However, these pumps require steam for their operation. In this particular event, the motor-driven startup feedwater pump was available, thus steam availability for the AFW pump turbines was assured. Even if this pump were not available, the auxiliary feedwater pump turbines could possibly be started with the high pressure steam stored in dry steam generators. Calculations have indicated that stored steam at a pressure of 1000 psig would be sufficient to start the pumps (Ref. 1).

Another factor influencing the ability to start the AFW pumps is leakage of steam, if the startup feedwater pump is not available. Leakage of steam through leaking steam line safety valves or release of steam by misoperation or leakage of the steam line atmospheric vent valves could have affected steam availability for restarting the auxiliary feedwater pump turbines. It should be noted that subsequent to a reactor trip which occurred on June 2, 1985, seven main steam safety valves and one atmospheric vent valve were found to be leaking. In the June 9 event, steam header pressure swung over 100 to 250 psi for several minutes for unknown reasons after closure of the main steam isolation valves (MSIV). Since the main steam safety valves routinely lift for reactor trips at high power at Davis-Besse, valve leakage or failure to fully reseat is not unlikely.

The Team considered available analyses of loss of feedwater events. Among these was a report prepared for Toledo Edison by EDS Nuclear Inc., "Davis Besse Unit No. 1 Auxiliary Feedwater System Reliability Analysis Final Report," dated December, 1981 (Ref. 2). This report asserts that adequate core cooling and the prevention of fuel damage at Davis-Besse can be accomplished in the following two ways whenever the main feedwater flow or the reactor coolant system forced circulation has been interrupted:

1. Availability of full flow from at least one of the redundant AFWS turbine-driven pumps to one steam generator within 10 minutes of the initial loss of main feedwater or loss of forced circulation.

2. Availability of main feedwater startup pump flow to one steam generator, combined with availability of primary coolant makeup flow from at least one makeup pump, manual opening of the pressurizer pilot operated relief valve, and isolation of reactor coolant system letdown within 30 minutes of the loss of feedwater.

During the fact-finding effort, Toledo Edison provided the Team with a report dated June 22, 1981, entitled "Engineering Summary Report of a Complete Loss of Feedwater Transient Analyses for Davis Besse, Unit 1" (Ref. 3), prepared by Babcock & Wilcox (B&W) Company. It was marked as a "Draft" with a note that "This Document is Presented as Preliminary and For Information Only. This Document Does not Serve as a Licensing/Procedure Base Document For Davis-Besse." The Team reviewed the analyses contained in the document in an effort to assess the capability of systems at Davis-Besse to mitigate a loss of feedwater event

with failures in the systems needed for mitigation. It should be noted that such events are beyond the design basis for the plant. Following is a discussion of the results from the B&W report.

Using normal conservative licensing assumptions, and assuming neither operator actions nor AFW, the core begins to be uncovered at approximately 37 minutes and is completely uncovered by 41 minutes following complete loss of feedwater. With the assumption of a "realistic" decay heat curve, opening the PORV and manual initiation of both makeup pumps by the operator at 30 minutes extends the time for beginning to uncover the core from 37 minutes to over 1 hour. Operator action at 30 minutes to open the PORV, to manually initiate one makeup pump and to place the startup feedwater pump in operation would prevent the core from becoming uncovered. Initiating both makeup pumps and the startup feedwater pump at 30 minutes without opening the PORV would also prevent the core from becoming uncovered.

Tables 7-1 and 7-2, reproduced from the B&W report (Ref. 3), summarize the consequences of loss of all feedwater with various equipment used for mitigation. Loss of offsite power is also assumed in these analyses. It should be noted that the tables show that the startup feedwater pump was assumed available for all cases in which analyses showed the mitigative actions to be successful. It should also be noted that in the June 9 event, the plant was initially at 90% power and not, as assumed in the tables, at full power, and main feedwater from main feedpump 2 continued for approximately 5 minutes after reactor trip. Also, both auxiliary feedwater pumps were returned to service and the startup feedwater pump was placed in service in less than 20 minutes.

Toledo Edison submitted a report to NRC entitled "Analysis of a Complete Loss of Feedwater Transient for the Davis-Besse Nuclear Power Station Unit 1" (Ref. 4). This report analyzed a complete loss of feedwater under two circumstances: (1) no operator actions and (2) operator actions at 30 minutes to open the PORV, to manually initiate one makeup pump and to place the startup feedwater pump in operation. The conclusions were the same as those in the June 22, 1981, Babcock & Wilcox report (Ref. 3) discussed above.

In assessing the safety significance of the June 9 event, a review of the analyses of loss of feedwater transients indicates that loss of feedwater is an event where mitigation is required within approximately 30 minutes to 1 hour. On June 9, ample equipment was available to fully mitigate the transient in less than 20 minutes. Both safety-related auxiliary feedwater trains were available, the startup feedwater pump was available, both reactor coolant makeup pumps were available, and the operator had the capability to open the PORV and makeup flow-control valve from the control room. The equipment of most value for the event, however, had been placed in service only through relatively complex actions outside the control room. The startup feedwater pump appears to have been particularly important in that it is capable of ensuring steam availability for the turbine-driven auxiliary feedwater pumps even after the steam generators are dry, and according to the previously discussed analyses, it can be used in combination with one reactor coolant makeup pump to prevent the core from being uncovered even without the safety-related auxiliary feedwater pumps.

The key safety significance of the event, however, is the fact that multiple equipment failures occurred, initiating a transient beyond the design

basis of the plant. Each of the following, without corrective operator actions, would have defeated operation of the safety-related auxiliary feedwater system:

1. The operator error in SFRCS actuation on low pressure.

2. The failure of the auxiliary feedwater system containment isolation valves to reopen after their inadvertent closure.

3. The overspeed tripping of the auxiliary feedwater pumps.

The event demonstrates the susceptibility of redundant equipment to common mode failures and reiterates the importance of "defense in depth" to reactor safety. Excellence in equipment maintenance, thoroughness in identifying the basic causes for system malfunctions, thoroughness in testing systems under conditions for which they may have to perform, and excellence in operator training are all required to ensure safety. The value of diversity and prompt and effective operator action in accomplishing key safety functions are particularly evident from this event.

Table 7.1 Alternate Operator Actions at Davis-Besse for Loss of All Feedwater and Offsite Power Transient

Operator action required at 30 minutes	1.2 ANS decay heat	1.0 ANS decay heat (realistic cases)			
Number of makeup pumps actuated at 30 minutes	2	2	1	2	1
PORV opened at 30 minutes	Yes	No	No	Yes	Yes
Electric startup feedwater pump actuated at 30 minutes	Yes	Yes	Yes	Yes	Yes
Success of action to mitigate accident	50%*	Yes	50%*	Yes	Yes

*Chance of success.

Table 7.2 Summary of Alternate Operator Actions at Davis Besse for Loss of all Feedwater and Offsite Power

Operator action required at 30 minutes	1.2 ANS decay heat						1.0 ANS decay heat (realistic cases)						
Number of makeup pumps actuated at 30 minutes	2	1	2	1	1	2	2	1	2	1	1	2	2
PORV opened at 30 minutes	No	No	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	No
Electric startup feedwater pump actuated at 30 minutes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	No	No	No
Success of action to mitigate accident	No	No	50%*	No	No	No	Yes	50%*	Yes	Yes	No	No	No

*Chance of success.

References

1. L. E. Roe, Toledo Edison to R. N. Reid, NRC, transmitting "An analysis on the capability of a dry and isolated steam generator to start an auxiliary feedwater pump 30 minutes after the loss of all main and auxiliary feedwater." June 23, 1979.

2. R. P. Crouse, Toledo Edison to T. N. Novak, NRC, Transmitting "Davis-Besse No. 1 Auxiliary Feedwater System Reliability Analysis Final Report." Docket 50-346. December 31, 1981.

3. Draft "Engineering Summary Report of a Complete Loss of Feedwater Transient Analysis for Davis-Besse Unit 1," Babcock & Wilcox Company (582-7151-14-00). Docket 50-346. June 22, 1981.

4. L. E. Roe, Toledo Edison, to H. R. Denton, NRC, Transmitting "Analysis of a Complete Loss of Feedwater Transient for the Davis-Besse Nuclear Power Station, Unit 1." Docket 50-346. June 15, 1979.

8 PRINCIPAL FINDINGS AND CONCLUSIONS

The Team's findings and conclusions are based upon an evaluation of the following:

1. Information from interviews of Toledo Edison (licensee) and NRC Region III personnel;
2. Plant data recorded during the event;
3. Information from meetings with the licensee and Region III personnel;
4. The licensee's troubleshooting action plans for equipment that malfunctioned;
5. Information obtained from the equipment troubleshooting activities; and
6. Available analyses of the consequences of loss of feedwater events at Davis-Besse.

It must be recognized that the root cause determination process is critically important and is not yet completed by the licensee. Table 5.1 summarizes the results to date for each equipment problem. The final results could, of course, revise the information in this report and perhaps raise important additional aspects or issues.

The Team has concluded that the underlying cause of the loss of main and auxiliary feedwater event of June 9, 1985, was the licensee's lack of attention to detail in the care of plant equipment. The licensee has a history of performing troubleshooting, maintenance and testing of equipment, and of evaluating operating experience related to equipment in a superficial manner and, as a result, the root causes of problems are not always found and corrected. Engineering design and analysis effort to address equipment problems has frequently either not been utilized or has not been effective. Furthermore, operator interviews made clear that equipment problems were not aggressively addressed and resolved beyond compliance with NRC regulatory requirements.

In addition to this major conclusion on the underlying cause of the event, the Team has made the following findings and conclusions. There is no significance to the order in which they are presented.

(1) The key safety significance of the event is that multiple equipment failures occurred, resulting in a transient beyond the design basis of the plant. These failures included several common-mode failures affecting redundant safety-related equipment.

(2) If the failure of only the safety-related equipment could have been prevented, the event would not have been so serious or so complicated.

(3) If the safety-related auxiliary feedwater system equipment had functioned in accordance with system design requirements, the operator error in initiating the steam and feedwater rupture control system on low steam pressure rather than low steam generator level would have been corrected in less than a minute and would not have had a significant effect on the course of the plant transient.

(4) Based on the licensee's current hypotheses for the causes of the auxiliary feedwater system containment isolation valve and pump malfunctions, the causes could have been detected and corrected prior to the event by straightforward tests. Such tests had apparently never been run during the life of the plant.

(5) The licensee's lack of effective engineering for determining the proper settings for valve torque switch bypass contacts and improper implementation of specified settings were the probable causes of the auxiliary feedwater system containment isolation valve malfunctions. Furthermore, this problem likely exists with other valves at Davis-Besse and could exist at other plants.

(6) Neither the SFRCS system nor the auxiliary feedwater system at the Davis-Besse plant meet the single-failure criterion for all design basis accidents.

(7) The availability of the electric motor-driven startup feedwater pump significantly improved the safety margin for the plant during the event. The capability to promptly place an electric motor-driven pump and associated valves for supplying auxiliary feedwater in service from the control room would have significantly increased the safety margin for the plant during the event.

(8) The operators' understanding of procedures, plant system designs, and specific equipment operation, and operator training all played a crucial role in their success in mitigating the consequences of the event. However, if the equipment operators had been more familiar with the operation of the auxiliary feedwater pump turbine trip-throttle valve, auxiliary feedwater could have been restored several minutes sooner.

(9) The locked doors and valves in the plant had the potential for significantly hampering operator actions taken to compensate for equipment malfunctions during the event and were a significant concern to the equipment operators.

(10) The operators did not initiate MU/HPI cooling (feed and bleed) immediately upon reaching plant conditions where MU/HPI cooling is required by the emergency procedures. MU/HPI cooling was delayed because of the belief that restoration of feedwater was imminent and a reluctance to release reactor coolant to the containment structure. The operators and plant management believed that analyses for Davis-Besse indicated that 30 minutes was available before actions were required to prevent the core from beginning to uncover.

(11) If the manual initiation features of the SFRCS had originally been properly designed with regard to human factors considerations, such as labeling and placement, it is likely that no operator error in this initiation would have occurred. Further, if only the previously identified human engineering deficiency regarding SFRCS manual initiation on low pressure had been corrected prior to this event, the operator's erroneous initiation would likely have resulted in isolation of only one steam generator from auxiliary feedwater.

(12) The event was not reported to the NRC Operations Center in a manner reflecting the safety significance of the event. The more serious the event, the more operator involvement required to maintain plant safety. For example, if the June 9 event had been protracted, knowledgeable personnel would not have been available to maintain an open telephone line with the NRC.

(13) Although the PORV is involved in the recovery from certain plant transients, its reliable operation has not been established by a suitable test program nor is its operational readiness verified by a periodic surveillance test.

(14) The post-TMI improvements: Temperature-saturation meters, additional training on transient behavior, and ATOG emergency procedures made a positive contribution to the mitigation of the event. Of these, training on transient behavior was the most important. The PORV flow acoustic monitor was not used by the operators. Because the shift technical advisor was not in the control room at the time the event began, and because the transient occurred so rapidly, he did not provide technical advice to the shift supervisor.

(15) Thorough integrated system testing under various system configurations and plant conditions as near as practicable to those for which the system is required to function during an accident is essential for timely detection and correction of common mode design deficiencies.

(16) For plant events involving conditions outside the plant design basis, operator training and operator understanding of systems and equipment are key to the success of mitigating actions taken by the operators. It is not practical to rely on detailed step-by-step procedures for such events.

(17) Operators at other plants may be reluctant to initiate MU/HPI cooling (feed and bleed) or similar actions without a delay to reconfirm the need and to consider less severe alternatives.

(18) The instrumentation available in the control room during the event was not adequate to clearly inform the operators that the criteria for MU/HPI cooling had been reached. The only practical alternative was the SPDS, which was not available, nor was it required to be available.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Appendix A

JUN 10 1985

MEMORANDUM FOR: Chairman Palladino
Commissioner Roberts
Commissioner Asselstine
Commissioner Bernthal
Commissioner Zech

FROM: William J. Dircks
Executive Director for Operations

SUBJECT: INVESTIGATION OF JUNE 9, 1985 EVENT AT DAVIS BESSE WILL BE CONDUCTED BY NRC TEAM

About 1:30am on June 9, 1985, a loss of feedwater transient occurred at Davis Besse. The reactor tripped from 90% power on the loss of a main feedwater pump; the other feedwater pump was lost because of an inadvertent MSIV isolation. Both turbine-driven auxiliary feedwater pumps failed to operate as designed. It is understood at this time that the steam generators reached a "dry-out" condition and that the pressurizer PORV actuated. Feedwater was restored within approximately 12 minutes. Instrumentation indicated that adequate subcooling was maintained at all times.

Because this event has potential safety implications worthy of further study, I have requested AEOD to take the necessary action to send a small (4 member) team of technical experts to the site to: (a) fact-find as to what happened; (b) identify the probable cause as to why it happened; and (c) make appropriate findings and conclusions which will form the basis for possible follow-on actions. The team will report directly to me and is composed of: Dr. Ernie Rossi, Team Leader (IE), Mr. Wayne Lanning (AEOD), Mr. J. T. Beard (NRR), and Mr. Larry Bell (Reactor Training Center, Chattanooga). This team was selected on the basis of their knowledge and experience in the fields of operations, instrumentation and control, and reactor systems. Because the team has not completed incident investigation training, OI is providing assistance regarding investigation techniques and support. The team will leave in the evening of June 10, 1985 and will be onsite early June 11, 1985.

The licensee has been requested, to the extent practical, to preserve the equipment in an "as-found" state and to have personnel and records available.

They have agreed to this request to the Regional Administrator. The team's report will constitute the single fact-finding investigation report. It is expected that the team's report will be issued no later than 30 days from now.

(Signed) William J. Dircks

William J. Dircks
Executive Director for Operations

cc: SECY
OPE
OGC
ACRS

INTRA-COMPANY MEMORANDUM
ED 6214-2

DATE
June 13, 1985
June 15, 1985, Rev. 1
June 15, 1985, Rev. 2
June 19, 1985, Rev. 3
June 21, 1985, Rev. 4

TO
Action Item Lead Individuals

FROM
J. K. Wood

SUBJECT
Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip

For each item on the Equipment Freeze list (Attachment 1), an action plan shall be developed for investigative or troubleshooting work which
1 provides the basis for the Maintenance Work Order. Personnel (lead and/ or support) developing the action plan shall have knowledge of the design criteria of the specific area being considered. Vendor engineering support will be utilized as necessary to accomplish this requirement. When used, vendor assistance shall be documented.

Troubleshooting and investigative activity shall be preceded by event evaluation and analysis to determine hypothesis(ses) and probable causes of failure or abnormal operation. Analysis and evaluation shall proceed as follows:

a. Collect and analyze known information/operational data for conditions prior to, during and after the transient.

2 b. Review maintenance and surveillance/testing history.

c. Develop a summary of data including a and b above that support any proposed probable cause of failure or abnormal operation.

d. Conduct a change analysis (i.e., what has changed since the last known successful operation of the system or equipment).

e. Based on above Items a-d, develop primary and alternate hypothesis(ses) for the root cause of the problem.

f. Develop plans for testing the probable causes/hypothesis (i.e., checks, verifications, inspections, troubleshooting, etc.). In developing inspection and troubleshooting plans, care must be taken to insure when possible that the less likely causes/hypotheses(ses) remain testable. When planning troubleshooting activity try to simulate as closely as practical the actual conditions under which the system or component failed to operate properly on June 9, 1985.

g. Document the above in a report.

It is very important that the performance of our investigations do not in any way result in the loss of any information due to disturbances of components or systems. Investigations need to be conducted in a logical, well thought-out and documented manner. To avoid the <u>loss</u> of information

and to assure the capture of reliable information, the following guidelines in addition to the requirements of AD 1844.00 need to be addressed and followed when initiating and implementing an MWO.

1 1. All action plans for troubleshooting and investigative work shall be reviewed with NRC personnel prior to implementation.

2. All MWOs relating to the 6/9/85 trip investigation shall be handled as NSR.

3. Troubleshooting and repair shall be accomplished on separate MWOs.

4. MWO's are to be approved by the Action Item Lead individual and reviewed by QC prior to their implementation. Copies of MWOs, when approved by the Action Item Lead Individual, shall be forwarded to D. J. Mominee (Stop 3070). It is the Lead Individual's responsibility to assure that the investigative actions are appropriate,
1 sufficient, properly defined, documented, and data is preserved.

5. Only those MWO's approved by the Action Item Lead Individual and QC may be worked on any of the "frozen systems" identified on the attached list.

6. Assure that only current drawings and controlled vendor manuals are used.

7. Consider the need for vendor representatives. Vendor representatives should be used to assist in troubleshooting if appropriate expertise is not available in-house. The representatives will need to be given specific guidance for what they are and are not to do. Vendor representatives must follow the guidelines of this memorandum and
1 requirements of the Maintenance Work Order.

8. The MWO must clearly document the scope, affected equipment, and the desired objective of the investigative activity.

9. The sequence of activity needs to be documented on the MWO or procedures specified in the MWO. If the sequence can be determined prior to the activity being performed, define that sequence and provide a checkoff for each step. If the desired sequence cannot be determined prior to the activity, as a minimum define the fundamental sequence to be taken and document each specific step as it is performed.

10. Document on the MWO all as found conditions. Visual inspect and document any missing, loose or damaged components, note positions
1 (open, closed, up, down, knob settings, switch positions, setpoints, etc.) abnormal environmental conditions, operation of cooling devices, water leaks, oil leaks, loose fittings, cracks, evidence of overheating or water damage, cleanliness, bent tubing, fluid levels,
1 jumpers, lifted wires, etc. Describe the overall condition or

appearance. Whenever possible, use photographs to document as found conditions. When considered necessary, retain a sample of fluids or their residue for further analysis.

11. When discrepancies are noted during the investigation, <u>stop work</u> and notify the Action Item Lead Individual. Document the deficiency. The Lead individual must sign off on the discrepancy prior to continuing the investigation.

12. Document the results of the investigation on the MWO.

13. Prior to starting any repair activities the Action Item Lead Individual must document that all investigations have been properly completed.

14. No equipment is to be shipped off site without prior approval of
1 Nuclear Facility Engineering and Quality Engineering for including appropriate hold and witness points. Use the "Q" purchase order process to obtain these approvals.

NOTE: In all cases, applicable procedure must be followed. The requirements of this memorandum must be communicated to craft personnel to avoid any confusion or misunderstandings during this investigative period.

15. All failed or removed components/equipment shall be retained for ongoing review and examination. Complete traceability shall be maintained.

The NRC shall be notified when the determination of the root cause of the
1 malfunction/failure has been made. As soon as practical, the results of the troubleshooting process, root cause determinations and justification will be presented to the NRC (e.g., next day in a meeting).

The NRC shall be advised as soon as practical of plans and schedules for corrective action work, prior to the work being performed.

NOTE: Any communication with the NRC personnel will be coordinated through John Wood.

JKW/SGW/bjs

Attachment

EQUIPMENT FREEZE

The following list of items is the licensee's proposal for continued quarantine:

1. MFP's Turbine and Controls
2. SFRCS and Associated Instrument Channels
3. Aux Feed Pump Turbines and Controls
4. MSIV's Including Controls - Actuating Circuits, Pneumatic Supplies
5. S/U Feed Valve SP-7A - and Controls
6. Source Range Instrument Channels
7. Turbine Bypass Valve (TBV) SP-13A2 - Any other components for which there is found an indication of water hammer damage

   2 Traps and drains associated #2 TBV header: MS 2575, MS 737, MS 739, ST 3, ST 3A
8. PORV and Controls and Actuation System
9. 4 Main Steam Safety Valves and Atmospheric Vent Valves
10. AF 599 and AF 608 Valves, Actuators and Controls
11. 1 MS 106 and Controls

3

This item was released by the Fact-Finding Team:

1. SPDS

This item was added by the Fact-Finding Team:

1. SW Valve and Controls on AFW Alternate Supply

It is agreed that no work will be done in the proximity of, or on, this equipment.

The licensee agreed to complete a walkdown outside Containment of the Main Steam System by appropriate personnel to identify any additional damage that may have been caused by water hammer.

The Fact-Finding Team stated that:

a. If required for safety, work shall proceed.

b. Surveillance Requirements of the Technical Specifications should be satisfied.

c. The team should be advised of any actions taken in the two areas above.

SGW/bjs

12/82

TRANSMITTAL TO: [X] Document Control Desk, 016 Phillips

ADVANCED COPY TO: [ ] The Public Document Room

DATE: 7/29/85

cc: OPS File

C&R (Natalie)

FROM: SECY OPS BRANCH

Attached are copies of a Commission meeting transcript(s) and related meeting document(s). They are being forwarded for entry on the Daily Accession List and placement in the Public Document Room. No other distribution is requested or required. Existing DCS identification numbers are listed on the individual documents wherever known.

Meeting Title: Briefing on Davis-Besse

Meeting Date: 7/24/85 Open X Closed ___

Item Description:	Copies Advanced To PDR	DCS Copies (1 of each checked) Original Document	May be Dup*	Duplicate Copy*
1. TRANSCRIPT ___ When checked, DCS should send a copy of this transcript to the LPDR for: ___ w/viewgraphs	1	1	___	___
2. Nureg-1154 Advance copy	1	___	1	___
3. ___	___	___	___	___
4. ___	___	___	___	___

(PDR is advanced one copy of each document, two of each SECY paper.)

*Verify if in DCS, and Change to "PDR Available."