BEFORE THE FACT FINDING TASK FORCE

OF THE NUCLEAR REGULATORY COMMISSION

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Re:

Davis-Besse event :

of June 9, 1985 :

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INTERVIEW OF WALT ROGERS

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Interview of WALT ROGERS by the Nuclear Regulatory Commission Fact Finding Task Force, taken before me, Nicholas A. Marrone, a Registered Professional Reporter and Notary Public in and for the State of Ohio, at the Site Emergeny Operations Center, Davis-Besse Nuclear Plant, Oak Harbor, Ohio, on Thursday, June 20, 1985, commencing at 10:10 o'clock a.m.

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APPEARANCES:

MEMBERS OF THE TEAM:

Wayne Lanning

Larry Bell

J. T. Beard

Ernie Rossi

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Thursday Morning Session

June 20, 1985

10:10 o'clock a.m.

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MR. ROSSI: Okay. Why don't we begin.

Walt, what we are going to do is talk to you about what you remember the day of the event, when you found out about the event, and what observations you made, and we are probably also going to want to ask you about what additional information you have obtained about the event after it occurred, analyses that you have been involved in and so forth of the event.

And we will probably also want to get into some of the more general things you observed about operation of the plant, maintenance of the plant and that kind of thing for the time period you have been here.

Why don't we start out by getting in the transcript -- he has your name. Why don't you tell him -- tell us what your position is and how long have you been here, and also why don't you after that give a brief discussion of what staff you have here?

MR. ROGERS: Okay. Well, I'm Walt Rogers, senior resident inspector at Davis-Besse. I have been the senior about two years now. I have been at Davis-Besse since day one of joining the commission a little over five years ago.

My original position was resident inspector. At this time or prior to the transient, I had one other individual that I supervised full time, which was Donald Kosloff, my resident inspector, and he's been out here for a little over a year, a year maybe four or five months. And also I have a secretarial staff part time, secretary part time.

MR. ROSSI: Okay. Why don't we --

MR. BEARD: I was just going to add, you depended on -- if you need technical support or admin support or other items like that, you would depend on the Region to support you on an as-needed basis?

MR. ROGERS: Yes, on an as-needed basis. We of course are in a little different mode in this facility. Due to their low SALP ratings, we have gone to much -- many more what I call support inspectors, our DRS section has been coming out a

lot.

MR. BEARD: DRS?

MR. ROGERS: Division of reactor safety, I believe is what their title is. They basically provide you with your traveling inspectors that come out of the Region. We are on a much more frequent basis of inspection.

I think our hours out here for the last -- since this began operating, you can see a significant increase in the number of inspectors at this facility versus the other facilities in the Region III. So in terms of what you would normally see in terms of support, you see a lot more support inspectors in the last few months out here than prior to that and at a normal facility.

MR. ROSSI: Okay. Why don't we proceed to the -- do you have another preliminary question?

MR. LANNING: Yes. Would you briefly describe the responsibilities of a resident inspector.

MR. ROGERS: Well, the resident inspector's job is to on a daily basis observe the actions that the licensee is taking in terms of running the plant, control tours, get out in the

plant, make sure that the facility is being run in accordance with the license. That's one -- that is one of the primary functions of the resident inspector.

The other is to communicate what he sees in the field in terms of problems, anything that would be of interest to my management to know, such as the reactor trip, to talk to them about reactor trips, if an unusual event is called. Anything that would be of public interest that would be in the press, you know, we report that back to the Region to keep them abreast of what the real operation of the facility is and how it is being run.

I guess the senior resident and the resident has been -- you know, they are here day in and day out and they are really kind of the scout to say, hey, it's time to bring in some more people to look at this facility. We think there is some problems here, we need some more people out here to be looking at things to get management's attention and say, hey, we are seeing some degradation in performance in these areas and it needs to be addressed.

Those are I think probably the two, is to really inspect for conformance to the license and safe operations, and to communicate that back to the senior management in Region III.

MR. ROSSI: Why don't you give a brief description on your interface with the licensee as it affects, like, what can the resident staff require of the licensee as opposed to areas that you can just observe what they are doing, and are there limitations on areas that you can observe what they are doing? Can you just give us that feel for what your scope is in terms of being able to require the licensee to do specific things as opposed to just being able to say they have done it wrong after they have done it and as opposed to areas that you can observe and report the findings?

MR. ROGERS: Well, I think the main point is that the things that are required by the licensee are required by the law, by their commitments to their standards and by the license, the technical specifications.

The resident inspector doesn't -- is not the law. I mean, we are just here to say, now, this is what the law says, this is what you did.

We don't think you are in conformance or it's apparent, you know, that you have violated the procedure or you haven't performed a procedure.

So it's not like we require. The law requires, and those are the requirements.

In terms of observation, you can pretty much observe anything you want. I guess about the only thing is there would be staff meetings, that type of thing, that the resident inspector would not normally attend, senior staff meetings, that type of thing. We do on a routine basis attend their daily status meeting, their 2:00 -- it used to be 2:00, it's now 1:00 meeting.

We have full roam of the control room, access to the shift supervisor, access to all the lower echelon supervisors, managers, plant manager and also to the assistant VP nuclear and to the VP nuclear if we feel it is necessary to discuss matters with them.

That's about as high as I have ever gone. I never have really needed to push something up to the Chairman of the Board. The Chairman of the Board has more or less set up things with me to come down and talk to me about things or give him a

plant tour. I think that's the last time. So in terms of my initiatives up that high, it's more their initiatives to me than that way.

MR. BEARD: What's your primary contact? If you find something that seems unusual or noncompliant in your mind, would your typical contact be, say, the plant manager or who would that be?

MR. ROGERS: It would depend. If I see what I would consider a tech -- let's say I see a surveillance requirement has just been missed that was needed to be performed, I would bring that to the attention of the shift supervisor at that point, hey, I think this is what I see, just to notify him since he is the one that is supposed to know what's going on in his facility at all times.

I would not necessarily push the point with him in terms of, you know, on day shift with the plant manager there. It's a little different story when it is back shift and you find something since he is then the senior representative for the facility. At that point in time, I get all my ducks in a row and go to the plant manager and say, hey, this is the way it is, this is what the book

says, do you agree or don't agree. And if they agree, then you will have to conform to your license, and I expect them to take the appropriate action at that point in time.

MR. BEARD: So if I understand you then, once all the ballots are counted so to speak, the vote is in and there is an infraction of some degree, you would contact the plant manager. That would be your normal routine?

MR. ROGERS: That would be the normal routine.

MR. LANNING: When do you contact the regional office?

MR. ROGERS: It would depend. If it's a matter -- at least my practice has been if it's a matter that we feel that they have exceeded an action statement, that type of thing, and I feel there is some, you know, if it's just black and white, you go and you tell the plant manager and let him know and then you immediately contact the Region, hey, this is what is going on.

If it is a gray area where you want to make sure that you are right, I normally will discuss that with my management, satisfy myself

talking through with them that this is what it is, and then have my position clear before I talk to the plant manager, that type of thing.

It really depends upon the situation. If you are -- and we are talking about one of the immediate tech spec violations. Now, if we are talking about something a little different, say we have got -- let's take an example, a drawing control break down, that's a good one to take. That doesn't what I would call require you to shut the plant done or something like that.

I normally would discuss it with the, you know, the immediate supervisor in that area about it and then up to his boss at the appropriate division director level here and let the plant manager know that, you know, this is what I see, that this is a problem.

It really depends upon the type of deviation from the law or whatever you want to call it that you see how you deal with it. Basically you do make sure the plant manager knows what you have found.

MR. BEARD: So you keep him informed and work at the appropriate level of supervision or

management that would be the effective place.

MR. ROGERS: Yes.

MR. ROSSI: How about access to the plant records? And I will just give this one example: maintenance records on equipment. Do you have or have you had limitations on what sort of records you have access to? And I'm particularly interested in limitations to safety related versus nonsafety related equipment records.

MR. ROGERS: You have as much access to the records as they do. Now, if it's not filed in the right spot, you don't have access to it, but nobody else does.

MR. ROSSI: Okay. But you haven't been limited to only looking at --

MR. ROGERS: They have not come to me and said, no, you can't do that. They really in this area, they have been very open.

I have my own little computer number. If I want to go into their computer, they can't stop me from getting access because I have my own little access number and I can go in and pick out whatever I want.

MR. ROSSI: So you have access to

drawings also affecting the plant?

MR. ROGERS: I have a set of P&IDs and they are kept up to date. I keep a set of uncontrolled info only, schematic electricals. And it changes so rarely I don't see a need for a control set, but I have access to the control room and the shift supervisor's office if I need to see something immediately, and I have full access to the drawing room.

MR. ROSSI: Okay.

MR. ROGERS: And --

MR. ROSSI: And no limitation of between safety related and nonsafety related?

MR. ROGERS: No.

MR. ROSSI: Okay. Do you have --

MR. BELL: Mr. Rogers, regardless whether the issue is black and white or gray areas, both of those issues are listed in your monthly inspection report, are they not?

MR. YOUNG: Well, whatever you look at you pretty much, if you find a violation -- well, let's say you are out in the water treatment building and you find that they are not using the procedure right or something like that, that wouldn't

necessarily be a violation because it may not be a safety related procedure or that type of thing, especially if it doesn't have really any significance.

It's more an observation then because there is really no requirement if that's what you mean. But in terms of what you found, you document it and say you find this or that.

MR. BELL: But there is several areas in the inspection report like violations, unresolved items that are documented by you?

MR. ROGERS: Oh, yeah. If there is something that I feel that, let's take an example, something that they -- there is a couple of examples I can use. Say there is an LER and they say they are going to do a facility change request, 1988, well, I will continue to control that through an open item. I will follow up and make sure that they do that facility change when they say they are going to do it.

If it is an item that I feel that is not a violation but it's not really a very good situation, say they -- I got one today, they got a 5 DCN rule around here.

MR. BEARD: For the sake of the record, could you be a little more clear, is it 5 DCN?

MR. ROGERS: Oh, yeah. Drawing change notices, they pretty much internally say they are not going to have over five drawing change notices on a drawing and if they exceed that, they will go off and get the drawing revised so -- and they have a time frame in which to do it in.

If you found, say, one drawing that they messed up on and they had six DCNs for over the 90-day period, you would write it up and call it an open item and see them, make sure they realize where the prob'em is and get it taken care of. That's, you know, things that you find that are not very good, you track as open items, important items, like one FCR is to change out the governors on the auxiliary feedpump. That's an open item. They changed one of them out and they still have got one to go. Things you think are significant facility changes, that type of stuff, or management initiatives.

MR. BEARD: Let me ask you about something that is less specific. You know, you are talking about situations where a procedure says do

something and they may or may not have done it.

Explain to me how a general situation where a specific case by itself is not terribly significant but when taken as a collection of specifics, then the bigger picture begins to form maybe in your mind of some perception of a general degradation, and I will pick purely as an example that the maintenance is not of some quality or timeliness or something like that. How would a resident inspector or a senior resident inspector address this issue in terms of dealing with a utility and dealing with a region and other people?

MR. ROGERS: I think in something like that when you can see something going downhill, you -- there is a couple of things you do.

No. 1, it goes in the SALP report. It starts building up. Those are starting to be the cornerstones of some of the things that will be set in the SALP report for your trending and also to give you a good perception of where you really do stand in terms of categories. You let your management know, hey, you start -- I'm starting to feel things aren't going quite right, start to give them -- what you are giving are the small examples,

and you say, hey, it's what I'm seeing, I'm not getting a good feel.

And that has to be factored into your management's concern, like when something does happen, say this particular incident, it was a violation which though on the onset may not be very significant to a plant, that it's just an isolated instance, but if you can feel that it's being built up, then you have got to look at it in a different light.

And especially in light of the type of corrective actions the licensee takes. Here you can see that we have over the last years, we have been intensifying NRC concern and NRC management overview in this -- on the facility. It really started with the CCAP or what we call comprehensive corrective action program which dealt with drawing control areas, the maintenance area and what we call -- I call it the design bases area. And it has pretty much built itself through seeing the -- you know, a couple of other things in the same area that they tended you to believe the root cause hasn't been taken care of, that is built then into what was initiated in the regulatory improvement

program, started with the interim regulatory improvement program after, you know, we say, you know, commit to it or, you know, they acceded to our wishes to -- and based upon our observations they said, yeah, we understand your observations and we agree we are seeing some overall degradation throughout the mission.

They took -- they came back with long-term programs to deal, you know, starting to see it, and we say, well, it's apparent you see some areas that you are not going to be able to address for years. What are you going to do in the interim? And then they came back and gave us some interim actions to be done.

MR. ROSSI: They? When you say they in this discussion, are you referring specifically to Davis-Besse or --

MR. ROGERS: The licensee.

MR. ROSSI: -- are you referring to licensees in general?

MR. ROGERS: No. The licensee, this licensee.

MR. ROSSI: I just wanted to clarify that.

MR. ROGERS: And then built up to the

regulatory improvement program, and even after that the SALP ratings came out and they were pretty poor for this facility and from what I understand in comparison to other facilities, it was pretty poor. A lot of category 3s.

They embarked then upon another program called their SALP improvement program I guess, I guess their SALP improvement task force to deal with some of these areas that were not directly addressed by their own licensee problem identification program under the regulatory improvement program.

I guess I should say, that regulatory improvement program is something that the licensee does and it's basically a chance for them to say look at themselves, determine what their problems are, and take care of them before, you know, the commission has to really get involved and have to deal with their -- how they deal with their problems. It gives them a lot more flexibility, basically.

MR. BEARD: Since you brought it up, the SALP rating as I have been told on maintenance at this facility was given the lowest rating of three?

MR. ROGERS: The last three years running.

MR. BEARD: Can you give me some flavor of the characteristics of the maintenance program that you find are a problem.

MR. ROSSI: Could we delay -- you know, I would like to go, after we finish with his description of the scope of his job here and what a resident does and doesn't do, I would like to go on and get the description of the event and then come back to the specific question that you just asked --

MR. BEARD: Fine.

MR. ROSSI: -- after that. Does anybody have any more questions on just the scope of the job?

MR. LANNING: Yes. When you identify a potential safety concern, whether it be a site specific concern or a concern that may be generic to other operating plants, how do you communicate that concern to other NRC offices, if you do?

MR. ROGERS: Other NRC offices, you mean NRR and AEOD, that type of thing? Anything I think is pretty much kind of a big thing, sometimes I will talk to Al DeAgazio about it. I try to keep Al abreast of what's going on in the plant

operation, you know, what's actually happening out at the plant.

If I think it's something that, like I say, NRR can help with, I definitely talk to Al and Al -- I think we have a pretty good relationship, a good dialogue back and forth in terms of, you know, communication and discussing issues and that type of thing. If I think I got a generic issue, we have, I don't know if the sheet is still in existence, but I still use it, in terms of a potential generic concern, you ship those into the Region. You can also write a potential information notice type thing or write up something you feel might be generic for the industry in the info notice type situation.

But most of your correspondence and dealings is really with the regional office and then some of the other resident inspector offices. Occasionally if you think you got something, you call around, get some of the other plants and Region III and see what they think. And if you think it is only for a B & W unit, I'll call Tom Steka down at Crystal or call SMUD or something like that and check it out to see if they get the same thing.

Their primary site system is pretty much the same. Their secondary site, that's where there is some modifications, but sometimes you can get a handle on what's going on that way.

MR. LANNING: How about changes to approve design in the plant?

MR. ROGERS: You mean when they go out to a license amendment or something like that?

MR. LANNING: I'm really thinking more in the context of once the plant has received an operating license, in your review of the operation of the plant or whatever you find system designs that could be improved or could be changed to improve safety or required for safety, how would you handle an issue like that?

MR. ROGERS: When you don't think the system is working as well as it should? Well, I think probably the first thing you have got to do, you have got to address it to the licensee and say, hey, the thing really doesn't seem to be working as well as you want it to be working here fellows, you are still meeting -- I'm going to assume you still meet your surveillance requirements, your tech spec requirements all right, but things aren't working

quite right. I think you better, you know, take a look at it.

Usually it would be something like an exit or maybe some meeting before -- not meeting but just say, boy, you know, what is going on here that maybe you ought to be taking some initiatives in this area.

Hopefully they are appreciative that you are on base and that they come up with some type of facility change which you can track as an open item, something like that. Those are the types of things you see what happens. If not, then you just kind of got to pass it up to your management and say, you know, this is what -- I see some problems, maybe if something happens later on, then we can get some momentum to get something done about it if they don't seem to be taking the initiative.

Those are the type things that really get pretty tricky. You got to know how to handle them in the best way. It's really a case-by-case basis. There is no cookbook on that.

You talk to NRR, you talk to Al and say, hey, Al, next time you talk license amendments or something to these people or what type of

initiatives do we have in the commission right now in this area and try to give him some field data to back him up to say, you know, give him a good warm feeling whether, you know, you are getting what you want out of him.

MR. LANNING: Based on your experience, has this been an effective method for doing this?

MR. ROGERS: I think you get some things -- it's a mixed bag. It always seems that things are never as -- you know, once you think you see what it is, to get it completely fixed it always seems to take another refueling outage or something like that. It's just a fact of life, sometimes it's difficult to get it that day or whatever. So I guess in that respect, time seems to be the biggest thing.

I don't know how to phrase it quite right, what I'm trying to say, but --

MR. ROSSI: Well, let me ask you. You have got an area where there are flat out requirements, there are the technical specifications, there is the FSAR commitments, there are the license requirements, and in those areas it's very clear what you do. The licensee

has to follow them. If he doesn't, you might -- rather than nod your head.

MR. ROGERS: That's right. You got the hammer.

MR. ROSSI: You have got the hammer you need. You have another area where you observe things not being done perhaps in the optimum way but they aren't in violation of license requirements, technical specifications or regulations, and in those areas you are involved by discussing them with the licensee, pointing them out to him, you don't have a hammer, but you can point them out and they would probably also come into the SALP rating?

MR. ROGERS: They come into the SALP rating. I think you are getting into what I call the batting average. You say, hey, that doesn't look quite right, that one doesn't look quite right, and down the road, you know, what you say comes true, you have a lot higher credence and batting average and the licensee listening to you about what you are saying than if you go in there and say, well, this is going to happen and that's going to happen and you are off in left field.

And I think this is where you are dealing in the area of -- into a certain amount I think your personality, your ability to present an adequate and a good technical argument to the licensee. I think that you probably have mixed results depending upon the personality, the licensing personnel and the resident inspector.

There are other methods you can use, you know, where you think there is problems and that deals with through your SALP rating and also through your discussions with NRR and with your management.

MR. LANNING: I guess I would like to come back to this area after we get through the discussion of the event.

MR. ROSSI: I wanted to get kind of a general definition of the scope of your job, what things you can do and what things you can't do. And I think we have gotten that. Why don't we go on to the day of the event now.

MR. ROGERS: Okay. You can't backfit them. That's one thing you can't do.

MR. ROSSI: I understand that. That's another limitation that you have in terms of what

you can and can't require. You cannot -- you cannot require nor can the Region require you to go out and actually change something without going through a formal procedure.

MR. ROGERS: Yes.

MR. ROSSI: Why don't we go to the morning of the event, June 9th, and why don't you start by telling us when you first found out that there was a problem and then just describe what you did after that and your observations and actions and so forth?

MR. ROGERS: Okay. Well, I was woken up by Rebecca Osborn at what I think is probably around 2:30, 2:20, 2:30, something like that in the morning, and Rebecca started talking to me and finally -- I had a little difficulty because she just said this is Rebecca.

MR. ROSSI: Rebecca is in the control room?

MR. ROGERS: She's the admin assistant. She says Teddy Lee wants to talk to you, who is the shift supervisor. Then I said, oh, this is the plant talking to me now.

Then Teddy Lee came on the line and said

they had a loss of feedwater, total loss of feedwater, they had gotten auxiliary speed pumps back. I said basically at that point, after his first statement, I knew that I was going to be going to the plant very directly because I knew it was not a good situation if they had actually lost both main feedpumps and the auxiliary feedpumps, even if it was for a limited period of time.

I at that point in time asked a couple of questions, you know, is the plant stable, I think there was a few words about that. I believe at that time I asked Teddy Lee whether they popped the PORV, he said yes, they popped the PORV. And that was something I would have expected to have happen at that point, given the type of training --

MR. BELL: Excuse me. Teddy Lee is Teddy Lehman?

MR. ROGERS: Yes. Ted Lehman, the shift supervisor that was signed in the book that night.

I hung up the phone and Don Kosloff called me and said that Steve Quennoz had called him and said something had happened at the plant and evidently Steve Quennoz, the plant manager, had given Don a rundown.

I cut him off fairly short and said, yeah, you know, go to the plant. And I think it was pretty -- there wasn't much discussed other than that, you know, why don't you go out to the plant, I'm coming out now. I hung up the phone, went downstairs, pulled out my little book, got Nick Jackiw's telephone number.

MR. BELL: Nick Jackiw?

MR. ROGERS: Is my section chief and my immediate supervisor.

MR. BEARD: He's regional office?

MR. ROGERS: Yeah, he's back in Glen Ellyn. Went back downstairs, called him. Informed him there had been a loss of main feedwater and loss of auxiliary feedwater and that I was and Don was going to the facility.

And then I got in my car -- I had gotten my pants on and all that beforehand -- and it takes about an hour for me to drive out to the plant. And so I would guess it was somewhere in the time frame of about 3:50, I would say 3:45 to 4:00 that I probably got to the plant. I can check the card file when I actually logged in, but that's an estimate about when I got to the plant.

Went up to the control room, walked in, looked, first thing I saw was subcool meters, saw they were reading right, they had not lost subcool margin, so I knew that was a good sign. There were a lot of senior --

MR. ROSSI: When you say you read the subcool meter and found they hadn't lost subcooling margin, was that an instantaneous reading or did you look at a recorder over the term of the event?

MR. ROGERS: When you walk into the control room, as you walk in, probably the most prominent thing you see because you are actually walking into the side of the control room is the STA panel or the postaccident monitoring panel, and it has two digital display meters on it that are red, that have red indication on them and they are good size. And then there is a little light there too, so when you walk in and see the numbers, you know right then whether you got subcool. It's instantaneous, you just -- that's what you look at.

MR. ROSSI: So it was the subcooling value at that time?

MR. ROGERS: Yes, at that time. I could tell there were a lot of senior reactor operator

licensees in the control room and, you know, management personnel, had the reactor operator's licenses.

MR. BEARD: Walt, how many people were in the control room roughly when you arrived, just a number?

MR. ROGERS: I would say, as I recollect, Quennoz, O'Connor, Louis Simon, Dick Crouse, Scott Wise I believe was already there. I'm not sure whether I can recollect Scott's face right that instant. I know it was pretty soon, you know, in that first hour that I saw Scott, the ROs, shift sup, Feasel, I would say -- I think there were a couple of equipment operators running around plus Rebecca, so I would say let's call it eleven for right now.

MR. BEARD: So roughly a dozen people?

MR. ROGERS: Okay, a dozen. I didn't count heads, but I would say that's about right.

MR. BEARD: I just wanted to get a feel, that's all.

MR. ROGERS: Okay. I could see -- I just kind of stood back to see what was going on. Saw the MSIVs were closed, saw the guy was on the

atmospheric vents.

MR. BEARD: Excuse me, Walt. When you saw the MSIVs closed, was this something you would expect to see or was it unusual?

MR. ROGERS: I would expect to see it because on a total loss of -- well, a loss of the main feedwater pumps tells me that they had a steam feed rupture control actuation which would close the Main Steam Isolation Valves. So I would have expected the MSIVs to be closed.

MR. BEARD: This would be on the parameter of low level in the generators?

MR. ROGERS: Yes. Low level is what I would have expected it to be on. I saw that they had atmospheric vent valves and were working those. Went over, checked pressurizer level and pressure, make sure they were reading okay. Then I just, you know, things looked like it was the way it should be. Looked like they had steam generator level where they wanted, startup feedpump was on. So things looked normal.

MR. ROSSI: Were the auxiliary feedwater pumps on too or just the startup feedpumps?

MR. ROGERS: I'm going to -- at my

initial look there, I'm going to say that I wasn't sure that the auxiliary feedpumps were actually on at that original look. I knew they had level and startup feedwater pumps were on, you know, a minute or two later. You know, I was able to look and see the auxiliary feedpumps were, you know, on.

MR. ROSSI: Okay. So they were on a couple of minutes later?

MR. ROGERS: They were in manual.

MR. BEARD: What about ECCS equipment?

MR. ROGERS: At that point HPI and LPI were off. So -- I looked there, Quennoz started talking to me, giving me a rundown on what had happened, I went okay, and I basically did what I call my normal panel walkdown. I started on the back and just started looking.

Saw the reactor coolant pumps were on, went over, looked and saw where that SFRCS, you know, some of the valves that were -- that was probably the first time I saw what I would call something abnormal in that both the steam valves to both auxiliary feedpumps were open.

MR. ROSSI: By both steam valves, you mean all four segregation valves were open. There

is four of them?

MR. ROGERS: 160, 106-A, 107 and 107-A.

MR. BEARD: And these are the four valves that are between the steam generators and the turbines for the aux feed?

MR. ROGERS: Yes. And I would not have expected to see all four valves open. I would have expected to see 106 open and feeding the No. 1 turbine, and 107 open feeding the No. 2 turbine. Looked at the ECCS schematic, looked okay, took a good hard look at the four RCS pressure indicators, you have all four of the SFAS parameters and each of them have four indicators that indicate their condition at that point. And I looked at all four of those and made sure -- that's BWST level, containment radiation, containment pressure, and RCS pressure -- and they were all reading normal. So I would not have expected to see SFAS actuated given those conditions.

Then I went over and looked at the electrical. Also I guess when I looked -- you look at TSat meters and then probably something else, I knew they had NNI because there is four little lights on the back of the right-hand panels that

give you DC, AC, X and Y indication. They were all on.

Went over and looked at that, everything was the way you would have expected it. They were on the startup transformers and that the diesels weren't on. Things looked normal there. Pretty much came back around and I don't remember -- I think they already had the RCS pressure recorder pulled out of -- on the front panel. I'm not really sure whether it was actually then or if they pulled it out for me. But I was able to get a good line on seeing what RCS pressure was. I could see that seventeen hundred was low, and high was --

MR. ROSSI: That pressure recording was during the event that you are speaking of now?

MR. ROGERS: Yes. I had already looked and saw that it was okay by indication prior to that, that it was all right. But this is what I was looking at was -- maybe I was looking at the tracing. Anyhow, I verified in my mind that pressure was okay. And I was just kind of getting a feel for what pressure had done during the transient. So it went down to seventeen hundred. I said that shouldn't have actuated SFAS. That's

good.

Also I got a feel it went high. I think I saw 24 -- I don't know. I ended up actually drawing that trace for my own personal knowledge. I am pretty sure that Tave was around 555, 550 as I remember it. It may have been a little lower. But I guess I shouldn't say, it's not so much you remember numbers as much if it looks normal. It's almost like the number that pops in your head is the one that isn't normal. So I guess maybe I should not say what the exact numbers were I was looking at because I guess I don't have a real perception on saying that was the number.

MR. BEARD: Normal post-trip Tave would be something like 555?

MR. ROGERS: 550, 555.

MR. ROSSI: But it was in that range?

MR. ROGERS: Yeah. Something like that.

MR. BEARD: What about the secondary site parameters? Did you look at any of those? I'm particularly interested in which secondary site parameters had recorder tracers so you could determine what had the plant been through?

MR. ROGERS: Un-hun. Well, in terms of

recorder traces for secondary side pressure, you don't really have that good a deal because all you really got is throttle pressure and that's it. The actual pressure in the steam generators are -- in each generator are nothing but an indication.

MR. ROSSI: No recorders for steam generator pressure?

MR. ROGERS: That's right.

MR. BELL: Throttle pressure would have been reading zero because the MSIVs had gone closed earlier in the incident?

MR. ROGERS: That should be the case.

MR. BEARD: So they really don't have a recording --

MR. ROGERS: I can't tell you for sure that it was reading zero because I didn't look at it.

MR. BELL: Not zero, but at the low end.

MR. ROGERS: Low end, whatever. Yeah, whatever the low setpoint for that thing is.

MR. BEARD: So what I'm trying to understand, Walt, is in terms of your assessment of where the plant had been, you were really not able to get an assessment of steam generator pressure.

Is that what you are saying?

MR. ROGERS: Yeah. You don't know where it had gone. All you know is where it is. Pretty much about that time --

MR. BEARD: Excuse me. If you are getting ready to shift, I would like you to also address the same question for steam generator level.

MR. ROGERS: Okay. Level is a little different because you have got recorders for level. You have also got -- I guess in terms of level, I wasn't maybe -- I knew they had gotten SFRCS. I didn't really go and look at the level indication because I knew it had gotten down low. I didn't need them to tell me it went low from what they were telling me. They had lost main feedwater, they had lost aux, they had been out for about twelve, fifteen minutes, whatever the time. I knew it was not like a minute or something like that. So I knew levels had dropped down.

MR. ROSSI: Do they have recorders for steam generator levels?

MR. ROGERS: Yes.

MR. ROSSI: They do have recorders?

MR. ROGERS: They do have recorders.

MR. ROSSI: Can you tell us how accurately they can determine the level from those recorders? I mean, you know, what sort of resolution do you have from the recorders in terms of being able to tell what the level is, especially when it gets low?

MR. ROGERS: Well, that's the thing. When it gets low, I mean, you are dealing with -- I think like operating level, you are dealing with a pretty large vertical distance that you are actually measuring. Now you are measuring, you know, a couple of inches here and that's -- it's the best guess. What you really got a key on, the closest thing you have got to really see level of all of them is startup level which is what SFRCS is really looking at, but even that is, you know, it's not like you got zero, one, two, three, four, five, six, seven, eight, nine, ten. You got zero to ten and you just kind of -- you make your best guess where your level is.

MR. ROSSI: Can you give us your own description of how easy it is to tell the difference between, say, twelve inches of level, ten inches of level, and eight inches of level, just your description of that? And if you don't

know, say you don't know.

MR. ROGERS: I guess you look at the meter. I guess it really depends how tall you are how easy, given the directions you look at it. You can tell whether you are above the carrot and below the carrot.

MR. ROSSI: And the carrot is ten?

MR. ROGERS: Ten.

MR. ROSSI: So you can tell if you are above ten or below ten?

MR. ROGERS: At that point. The thing is going to be wiggling a little bit, so to actually draw it out yourself, I think you can call which side of the carrot you are on. But what the indicator reads and what you really got in the generator aren't necessarily the same thing.

MR. BEARD: Why is that, Walt?

MR. ROGERS: Because you have got a certain amount of instrument error associated there. And when you are talking about this type of cutting hairs, let's say, you know, instrument error is definitely involved in something like that.

MR. BEARD: Can you give us a feel for the magnitude of the error that one could

reasonably or typically expect on the level change of this type? Are we talking a couple inches, a foot or what?

MR. ROGERS: I would say a couple of inches. More than just a couple inches, calling a couple two. I sometimes use couple for more than that. I would say it's not like you are talking three feet here, but we are talking three or four, five inches, in there for probably a difference. You can see it on -- you can see it on -- even on SFRCS setpoint during the event.

You are talking a difference of six seconds between actuation channel one and -- or eight seconds. You can see there is a time frame between Actuation Channel 1 and Actuation Channel 2. Even though both actuation channels are reading the same generator level, they are just different transmitters to get their set points and all that. So there is a certain amount of inaccuracy that goes into all this.

MR. BEARD: Well, Walt, you brought up a subject I heard alluded to many times in these interviews and I would like to pursue that a bit. The operators that we have talked to that alluded

to, yeah, the instrument reads this but really what's out there is something else?

MR. ROGERS: Oh, yeah.

MR. BEARD: And I would like to understand a little better than I do now why the operators don't take the other approach, which is to say, yeah, it's a little different, we all recognize nothing is perfect or absolutly accurate, but my best information is I'm above ten inches on level, for example, and it's not important to know that it might really be eleven or might really be nine. I'm curious about this philosophical approach.

MR. ROGERS: That's something you know about the instrumentation. You always believe your indication until your indication is proved wrong.

MR. BEARD: Now, are you talking about your personal philosophy or what you observed with the operators in this control room?

MR. ROGERS: I think that's my personal philosophy. I would say that it is the perception of the operators, that it's their philosophy too that they rely on their indication that that is an accurate indication unless, you know, they have

enough preponderance of information to disallow that.

MR. BEARD: All right.

MR. ROGERS: But that also means that they have to believe if something is out of service, it's out of service.

MR. BEARD: Right.

MR. ROGERS: Like in that instance, there was source range come on. Both source ranges weren't dead. There is one reading something, but they didn't look at that source range and say that source range says that, I'm going to believe that source range, because they knew it was out of service.

MR. BEARD: It had been declared out of service?

MR. ROGERS: That's right. So there was no doubt in my mind what they did.

MR. BEARD: What I'm trying to get a handle on, Walt, is this. I'm fishing trying to understand what happened during this event and being able to analyze what happened.

But could it be that the knowledge that the actual level is somewhat different may be from

the indicated level by whatever inaccuracy is involved, that an instrument say reads eight or ten inches and an operator concludes, well, but the real level out there might be fifteen inches or some value like that because of the uncertainties associated with the instrument? Could that -- could you describe for me to what extent that type of thinking could or you have seen exist in the control room before?

MR. ROGERS: Well, I guess I am just going to give my opinion here. You would have to talk -- and you all have talked to the operators themselves and they can tell you what they do. I would assume they would use their indication and believe their indication. Even though they, you know, they know what's going on there, they still have got to believe that indication and rely on it to perform safe operations of the facility. If they see it's reading, you know, 20 inches and they look up and see SFRCS is in trip, they would go trip SFRCS.

MR. BEARD: That's because the setpoint is 26 and a half, so there is a significant difference?

MR. ROGERS: Yes. And they have done that in the past. They will look and see those indicators and know it is close and they will go ahead and say I know by my indication what the plant response is and if it's not responding as it should, then they take that, what they consider the automatic action. Sometimes the automatic action does it before they do.

MR. ROSSI: Well, in terms of instrument errors that might be there, they wouldn't have any way of knowing whether or not the level indication is reading high or low. I mean, if it's reading ten inches, it might just as easily be off, actually higher than that as lower. So they wouldn't know which way it's off.

MR. ROGERS: That's true. But you would never take the nonconservative approach when you make an assumption. If you are going to do anything, you always err on the side of the angels.

MR. ROSSI: So in this case, they saw given the level of ten inches, it would certainly be improper to assume it was above that.

MR. ROGERS: That's right.

MR. ROSSI: It might be proper to assume

it was below that and begin the action based on it being below that, that being the conservative assumption?

MR. ROGERS: That's my personal perception, and I think I have seen that's the way they normally handle themselves. I can't think of any glaring instance where they haven't done that.

MR. ROSSI: Larry, you have a question?

MR. BELL: One more question on the level and then hopefully we can get back to the incident. Are there level recorders installed on the startup level transmitters?

MR. ROGERS: Are there level recorders? You mean on the startup, the steam generator level?

MR. BELL: Yes, sir.

MR. ROGERS: I know they are normally there or they were stuck in as a result of -- that would be in the back panels?

MR. BELL: That are normally available for control room operator use.

MR. ROGERS: That is operating level. Startup level I don't think so. I would have to look at the prints, but just right now I don't think so.

MR. BELL: That was unclear to me. I thought that only the operating range had level recorders.

MR. ROGERS: I would have to look at the drawings myself or go back to the control room, but my perception is right now that the indication you have, you have wide range, you have got startup, you have got operating level, but what you have got on the recorder is operating, not startup which is what SFRCS works off of.

Now, there is in the back panels, there is also indication of level that's I think very close to startup. There has at times been discrepancies between what is on the SFRCS in the back and what is on the back panel -- on the front panels, but I think they finally got that squared away. There used to be an inch or two difference or something.

MR. BEARD: Okay.

MR. LANNING: With regard to indication, how would one define dried out steam generator?

MR. ROGERS: Dried out is anybody's term. There is no official definition of what dried out is from what I know of.

Now, I guess a lot of what is canned around here as No. 1 level is not really level. Level is differential pressure across that generator. If you flip-flop some pressures around there, you can make the level look like it does anything.

By the time that water that comes in by feedwater gets down to the tube sheet, it's a combined net mixture of steam and feedwater because of the aspirating steam ports. So in terms of you thinking you have got water in that steam generator, it's really a combination of steam and water, if not almost all steam.

Now, if you are dried out, there is some statement that eight inches, some people say that's dried out because then there is no -- I would guess what they are saying there is no saturated, there is no water in there. It's all steam.

In terms of the thermal nature of the beast, I don't think it really makes that much difference in terms technically. The big thing here is if you depressurize this thing, and that's when you get yourself into trouble is, whether you have got steam or water in here, is if you

depressurize and then you come in with saturated water, then you have got to watch it because you may fracture your tube sheet and your tubes.

That may be a little bit more than what you are really saying. I guess if you want to really get down to what dried out would be, it would be I guess when there is no saturated water at all in there. The term really doesn't have much -- it's just a nice thing to talk about as far as I know. It doesn't have any legal bases or any legal requirement.

If you get below eight inches, it does mean you have got to take a hit in tech specs, though. I think that's pretty much what everybody has come to the conclusion, I think TAP and B & W makes them do that if they get below eight inches.

MR. ROSSI: What do you mean a hit on their tech specs?

MR. ROGERS: You are only allowed so many things. You can have so many heatups, cooldowns, reactor trips, so many times --

MR. ROSSI: Go below eight inches?

MR. ROGERS: Yeah.

MR. ROSSI: So you have to count the

number of times you go below eight inches?

MR. ROGERS: That's what I mean by taking a hit. And after that, I guess from what my understanding of the way they do it is they take the ASME code and design the pressure vessel or the generator and then they design in so many thermocycles into what they do, and then you can take that many thermocycles and be okay given that you can have all your thermocycles taken and then have a significant design -- the design basis accident against that component, and it still in fact performs its safety function. And it may not perform its function afterwards but it will at least get the plant down to a safe condition and cool down, long-term cool and all that. And everything supposedly is analyzed. That's my perception. That may not be the way it really is, but that's kind of the way I always looked at it.

MR. BEARD: Walt, I would like to understand a little bit better. In terms of your response to Wayne's question about dried out, what that means, was your answer your perception?

MR. ROGERS: My perception.

MR. BEARD: Personally? And how might

that compare with what you think the operators view that as or ATOG procedures or things of this nature?

MR. ROGERS: Well, dried out could mean it's the point in time where you are below eight inches and you actually see some type of -- you actually do a depressurization of the generators, so now you don't have anything in the generator, whether it be steam or water. That could be one.

It could be the point at which when you start to see the curves, your pressure temperature curves start to peel off, that says you don't really think you have got anything in there in terms of saturated condition. In terms of ATOG, maybe I just don't know if they actually use the word dried out in ATOG itself. I just have given what I would guess some people think it is. I don't think there is a real definition for it.

MR. BEARD: I'm particularly interested in your comment to the general effect that levels are not an important variable as much as I think you said the depressurization is really the big thing. Is that your opinion or do you think that's generally the opinion of the operators?

MR. ROGERS: That's my opinion. I could

not speak to the operators, per se. Some of the senior people I think would probably agree with me, that depressurization -- some of the senior licensee people. I'm not so sure I could really speak in terms of some of the younger ROs and SROs.

MR. LANNING: What do you mean when you say depressurization in the steam generator?

MR. ROGERS: That you get a situation where let's say you open turbine bypass valves, all steam goes away, you got a stuck open safety valve, all the steam goes away, that your pressure actually starts to go away.

I guess if you left it there long enough, that you could get -- that steam in there would, in fact, condense and return back to water because you don't have a completely closed system. Then you could depressurize that way if you were decoupled.

MR. LANNING: Are you talking about pressures below the post-trip steam pressures or what?

MR. ROGERS: Yeah. That and pressures that would take you down towards atmospheric pressure.

MR. BEARD: Just as information, what

would be a nominal post-trip pressure level, just to give me a numerical feel for it?

MR. ROGERS: Well, I guess the way things go, you are running along there and all of the sudden, especially anything above I guess 50 percent power, you are going to be starting to pull safeties. By that I mean you are going to be opening up the code safeties on the secondary side.

MR. ROSSI: That is for any reactor trip, you would normally expect to lift the code safeties if you are above 50 percent power?

MR. ROGERS: Would be my guess. That's just a gut feel. So I would say your original response is you would see pressure jump up to 1150, maybe up to -- I mean, 1050 and then maybe all the way up to 1150, something in there. That's where you would expect pressure to go. They would reseat. Eventually you would get control. Assuming you don't get SFRCS, you would be controlling atmospheric vent valves and they would try to modulate pressure. And let me think, what is that, I'm going to say 890 plus 125. I think that's about right.

MR. BELL: Around 1010?

MR. ROGERS: I think that's it. 1010. I just can't add right now.

MR. BEARD: In terms of those values, what do you mean by an abnormal pressure on the depressurization?

MR. ROGERS: When you start to drop below 1010. Say you are getting down in the 900s, that's not that unusual here, then it recovers because you have had cases where you will get some excessive blowdown on the secondary side safeties. When you are starting to get down below 900, you are getting in your eight and seven hundreds, then you are starting to get into some problems. And then the next thing you know, you are down where you are going to get SFRCS which is going to try to bottle you up and then you are really in trouble in terms of pressurization because that means you probably got a -- that is an indication of a steamline break or, well, that's what it is really there for.

That steamline break can come through a number of sources. It could really be the turbine bypass valve is coming open, it could be the atmospheric vent valve is sticking on you, it could be the code safety sticking on you. It doesn't

necessarily mean a pipe is in rupture. It could mean a valve failure.

MR. BEARD: You are saying normally you would expect to see it under a thousand pounds, you have seen it in the 900s, but somewhere in the 800s you would say, okay, I think we have got something you need to deal with?

MR. ROGERS: You are starting to listen then, because then you are saying is that code safety going to seat now. Because you can hear -- that's one of the things, you have got your indication, but there is another indication in the control room and that's your ears. And you have got a lot of things that you can actually hear going on.

Like the shift sup, let's say the plant hasn't really tripped yet, but he can hear something starting going on because he can actually hear something rolling down the steamlines that's abnormal. He can hear MS, some of these steam supply valves for the auxiliary feedpumps opening up, he can hear CCW switch over, if there is something like that, an abnormal thing there, code safety blows. There is a definite difference

between the secondary side safeties opening up and the atmospheric vent valve opening up and you can -- and also when the, I forget, the 235 header blows on the aux boiler, you can tell kind of what's going on with your steam and what's really happening. You hear the MSIVs slam close.

MR. ROSSI: Let's see. I wanted to go back and talk about the auxiliary feedwater pumps and what you observed when you got to the plant. You told us you observed all four steam supply valves to the auxiliary feedwater pumps open. Could you tell us, were the pumps -- I think you mentioned they were in manual at one point in time.

MR. ROGERS: Yeah.

MR. ROSSI: Could you expand on whether they were being manually controlled from the control room or whether they were being controlled locally or what did you observe about that? And if you don't remember or didn't observe it, which is probably a more likely situation, just say that.

MR. ROGERS: I guess I can say some things about that because at some point in time I went down into the auxiliary feedpump room because there has been some concerns and these people have

experienced it since their last refueling outage, they did some modification in that system, water hammering in the steamlines and they have found some steamline hangers deformed and snubbers busted.

Anyhow, at that point in time I really wasn't terribly focusing in on the auxiliary feedwater pumps at that time because of steam generator level being the way it was. It's just my perception at that point that both of them were in manual. As you go through --

MR. ROSSI: Both in manual from in the control room?

MR. ROGERS: Yes. As you go through it later on, it became apparent that one of them was being controlled down in the room itself.

MR. ROSSI: One was being controlled down in the room, and you observed that after you had been there.

MR. ROGERS: Yes.

MR. ROSSI: Which one?

MR. ROGERS: Well, based upon the one I was looking at, I couldn't tell you because there was the guy with the headset on and he had the door open and looking at both of them, I can't right now

tell you which one it actually was. I think Steve had told me some things about the auxiliary feedwater system originally that may have tended, I think -- I think they were both in manual. I'm just going to say that was my perception. I just have a visual image --

MR. ROSSI: In any event, you are not too sure what the control was based on your observations when you got to the control room?

MR. ROGERS: Right. The main point was that steam generator level was where I would expect it to be. At that point in time, it was all over but the shouting, really, because you are down low enough the startup feedpump can hack it and the startup feedpump was on, so that was the one really controlling level.

MR. ROSSI: I want to ask one more question and then we can take a break. Did you observe anything about the auxiliary feedwater pump -- feedwater valves? Were they what you would expect?

MR. ROGERS: They were what I would have expected to see.

MR. ROSSI: There are four of those also?

MR. ROGERS: Well, no. There is four --

what I call the four digit valves and they are actually on the front panel and they are right up -- right below the CRTs, and then there is two other valves that are discharge valves, that are containment isolation valves.

MR. ROSSI: That's the 599 and 608 are the last two?

MR. ROGERS: And then there are another two discharge valves that are always open on the -- by the pump along with the suction valves for the pump. I do know at some point in the event I came over and I looked at those valves, and I do have a visual image that those valves were in fact opened, all four, the suction and the immediate discharge valves. In terms of the others, I don't remember anything abnormal with them.

MR. ROSSI: It's not like the steam valves where you remember all four being open?

MR. ROGERS: That's right.

MR. ROSSI: Well, normally, the normal thing to have expected would be the valve feeding Steam Generator 1 from aux feed one being open?

MR. ROGERS: That's correct.

MR. ROSSI: The one that feeds Steam

Generator 2 from auxiliary feedwater pump being closed?

MR. ROGERS: Right.

MR. ROSSI: And vice versa for the other pump?

MR. ROGERS: What you would expect to see is two green lights and two red lights.

MR. ROSSI: And you don't recall seeing anything different from that, but you don't specifically remember noting that they were normal?

MR. ROGERS: Right. You know, it's one of those things as far as finding 599 and 608, they were in the position they were expected to be. At some point during that night, I do know the operator said they had to hand crank at least one of them and crack it off the seat before the limitorque can take it all the way open.

MR. ROSSI: I'm ready to take a break. Why don't we take a ten-minute break.

(Thereupon, a brief recess was taken.)

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MR. ROSSI: We are back again to continue the interview. I guess the next question I wanted to ask was about the source range instrumentation.

MR. ROGERS: Yeah. When I did that first walkdown of the back panel, the recorder, that's not right. You know, it wasn't reading right. I think they had already identified that from, you know, when I said this one looks like it's busted, it looked like they already identified that themselves.

MR. ROSSI: What do you mean by busted?

MR. ROGERS: You could sit there and you saw the recorder and you saw the way the paper was not laying flat, it was back out and you look at the reading, it was zero. You would expect to see a few counts.

MR. ROSSI: Was it the pen that didn't read what you would expect, or was it the paper wasn't working right or --

MR. ROGERS: The first thing I noticed, because you are going, as you are walking, I just looked and I saw the paper wasn't laying right before I could actually see the indication. I looked a little closer, okay, that's not right. The first indication was the paper, though.

MR. ROSSI: Okay. That's one of the two channels. What about the other one?

MR. ROGERS: Well, the other one was out of service, so I wouldn't --

MR. ROSSI: It was out of service before the start of the event?

MR. ROGERS: Right. It has been out of service off and on for --

MR. ROSSI: For how long?

MR. ROGERS: Before I went off training, because I had -- the week before the incident, I was actually in Chattanooga, had flown home that Friday night and was actually Sunday night there at home. I really wasn't supposed to be there.

I was there for a management meeting with some of my people that were going to be in on Sunday. I told Steve that, and fortunately a lot of times that does happen, they will continue using the call list even though I'm not there and call my wife. Just by happenstance I was there. There is no doubt in my mind I wouldn't have got a call, because obviously Don Kosloff called me after I talked to the shift sup. He knew where I was.

I lost my train of thought there.

MR. ROSSI: You were telling us about the channel that had been inoperable in the source

range.

MR. ROGERS: So before I had left -- it's had a history of problems. It was doing something, but you can just take it with a grain of salt.

MR. ROSSI: It was technically inoperable from a tech spec standpoint?

MR. ROGERS: It was technically inoperable, so you don't count that. As I went around I said, Don, did you check the shutdown margin. He said -- I don't know if he actually checked it, but I know I glanced at the paper to make sure they had adequate shutdown margin and later on, I don't think that night, that we -- I actually confirmed they did emergency borate, but if you --

MR. ROSSI: That night being June 9th?

MR. ROGERS: Yeah. If you got the shutdown margin, whether they did emergency borate or not doesn't matter as long as you got shutdown margin, and that's what really counts. Of course, one of the things you check when I walk around the back panel is -- one of the main things is all the rods are in circuit, which is what I would have expected to see, groups one through seven inserted

and group eight at somewhere around 28 to 25 percent from being inserted. Group eight is APSR; they don't trip.

MR. BEARD: Okay.

MR. ROSSI: Can you remember anything else that you noticed when you were walking around that appeared abnormal to you that we ought to know about from your initial review of things when you got to the plant?

MR. ROGERS: No. I know the PORV block was where they were supposed to be.

MR. ROSSI: The PORV block was open at this time?

MR. ROGERS: Yeah. Red/green, it was red/green. That's what I expected to see. At that point in time, about the only ones that really I could say that were a perceived problem by looking at the control boards were the PORV valves open on the steam supply to the turbine and the source range.

They had by that time when Steve, you know, Steve started going through talking to me there at the very beginning, it was apparent there were some other problems, but at that point in time

on the boards themselves they were the only two.

MR. ROSSI: Do you know why the four steam valves were open? What reason -- I mean, including things that you have learned subsequent to that night, do you know why they were all four open?

MR. ROGERS: Well, yeah, to a certain extent I do. I still would like to go through a little more of the SFRCS in my mind to understand that. How they got the original open signal, I understand that.

They had SFRCS and those four steam supply valves used to work one way. They went through an outage and then modified those things so that both steam supply valves to each turbine came open on a low level.

Well, when they did that they went in and I believe stuck in the eight hundred, nine hundred series logic modules. Well, that was one of the suspects for the water hammer because this is something -- they don't see water hammer in the steamlines, then all of the sudden they make this modification along with the governor and along with opening up the four digit valve, and so they started

putting everything back the way it was originally, but when they put it back originally, they didn't quite put it back exactly physically the same because they leave in the eight hundred and nine hundred series logic modules, which I'm not quite certain what type of check close and check open signals it gives.

It did physically change the SFRCS. It made it so on low level and DP and loss of feedpumps you only have one supply valve feeding the generator, but the way in which it does it changed and I can't tell you how. I just haven't looked at it enough to really tell you. I don't know if they can even tell you all the story.

MR. BEARD: Are you saying they made a design mod and put some equipment in, and when they decided that wasn't what they wanted and they went to restore it to the original, they didn't physically restore it to the original but maybe they intended to restore it to something that was equivalent?

MR. ROGERS: That's right.

MR. BEARD: And that's your concern or your area --

MR. ROGERS: Yeah. It's supposedly equivalent, but there is some other things. There is some check closes that gets in there, and then there is some check close signals that you also get that I'm not sure that are there or now they are there and they weren't there.

So at that point in time, I just said that's abnormal, they say, yeah, that's abnormal and they put it on their little list and say, well, when we go through all the SFRCS, because it was apparent to them that they had had some different enterations, you know, they knew they already hit the SFRCS low pressure buttons and that wasn't quite right, and that not only that, that instead of hitting it -- even when they hit it, if you were to hit low pressure, you would hit it cater-corner and they hit it straight on, so basically it totally gave the logic signals to SFRCS something it had never seen before.

MR. ROSSI: You have talked about water hammer problems that they had at the time that they had done modifications to the logic for these steam supply valves to the auxiliary feedwater pumps?

MR. ROGERS: Right.

MR. ROSSI: What were the results of that water hammer? You talked about hanger problems.

MR. ROGERS: Hanger problems. Well, they started off, it looked like it was a line off the auxiliary boiler that was feeding the auxiliary feedpumps and they found a hanger problem. Basically what we are talking about is bolts backed off so they are a little loose in some instances. There is a couple instances where -- boy, I don't know what they are called. Maybe you all can help me out. It's like a metal piece that's welded on to the pipe that's used and then you have like a steel box around it and then you have these metal pieces around the sides so that when -- if the pipe were to move, it doesn't hit the pipe directly into the box, it actually hits this little metal piece.

MR. BEARD: I know what you are talking about. It looks like leaves on a daisy in shape?

MR. ROGERS: That's right.

MR. BEARD: And I don't know the name of it.

MR. ROGERS: But they had found at least one of those crushed so it didn't look like a daisy any more, it was flat.

And this was kind of a progression thing. They found one and they thought they knew what it was, and the more they got involved in it and the more they looked, the more they found. So they found bolts backing off.

And what really I guess started it was they found the snubber was physically broken. And if you want to look at it, it's over in engineering, I believe. I think that's the one. But the rod was broke off so it was just kind of dangling there, and that's probably -- I think that was the original indication they had a problem.

And they found out the reason for that is because it was seeing a tight motion that the snubber was not designed for, because the hanger that was supposed to restrain it had been pulled out of the wall. So instead of it restraining it from moving this way, it couldn't, so the pipe would move this way and the snubber will take something directly on its piston. But if you take it with any bending moment, you get enough in there and it will break, and that's what they saw.

So they have -- we had them under a confirmation action letter, we had Esa out here to

take a look at it, they walked the system down, done different testing on it to try to determine where the water hammer is coming from a couple of times. But --

MR. ROSSI: Did the water hammer problem ever to your knowledge interfere with the operation or startup of the auxiliary feedwater pumps themselves?

MR. ROGERS: Actual startup of them?

MR. BEARD: During this event.

MR. ROSSI: No, not during this event. I'm talking about --

MR. BEARD: More in general.

MR. ROSSI: Prior to this event, are you aware of any cases where the water hammer problem caused the tripping or malfunctioning of the auxiliary feedwater pump turbines?

MR. ROGERS: No. I have heard some words that the first time -- and this is just perception in my mind. I don't even know who I was talking to. But I think they may have seen a little more water. I think they may have seen some water out of the sentinel valve or somehow or another they saw a little more water rolling on the turbine that first

time. The turbine still worked properly, but that was the only -- they had some problems with that. There was a little more water rolling out of the turbine than they normally would expect or they did see water versus that --

MR. ROSSI: What do you mean by water rolling out of the turbine?

MR. ROGERS: You blow some out of the sentinel valve. You could see it. That would be the main point.

MR. LANNING: What's the source of the water?

MR. ROGERS: Well, that's the million dollar question or whatever. That's what people have been trying to figure out. There are some theories that what it is is that there is some steam that gets trapped or it's a long run of pipe and for some reason there is some steam that would be trapped from a previous run or something, and then that water condenses and then it doesn't drain out one of the drains for some reason.

There are a lot -- at one point in time, they thought it might have been some water carrying over from the aux boiler line, that that wasn't

draining properly. In terms of where the water source actually is, I think you would probably have to talk to Wood. I think they probably have the best up to date engineering evaluation on what -- where the water is coming from.

MR. LANNING: Is this something that would be an open item under an inspection report?

MR. ROGERS: Well, it's not an open item. We have got them on our confirmation action letter. That's a lot more significant than -- I'm not an expert on seismic restraints. We do have a gentleman in the Region named Mr. Yin that comes out and we -- that's one of these where the residents say, hey, this is outside of my capabilities, let's bring in somebody that knows a little bit more, and this is the case.

And that area, the water hammer and the diagnostics of that situation and what they have been doing with the hangers and all, is really in a part of Mr. Danielson and -- I think it's Mr. Danielson's group with Mr. Yin under him dealing with that area of it.

We have something, I guess the licensee has been responsive to help out in one way. The

trick with the hangers is that you have a safety factor associated with the hangers, and if you go below that safety factor, which, okay, the plant is built to a safety factor. However they found out back in 1979 -- and I'm going to say 7914 - maybe you all remember which it is, but there is a bulletin that starts with 7902, you start talking about hanger problems and people finding problems with hangers and not built to the -- what it is -- I'm not just talking about Davis-Besse, I'm talking about it's a generic deal because it was a bulletin in this case that went out to all of them, that the hangers may not have -- because they are not built exactly to the as-built condition, you may not have the safety factors you expect it to have.

However there was a position drawn that there is an interim criteria that you can drop below this original safety factor and you are still okay. Now, if you drop below the interim, then you can -- given a determination of whether it's accessible or inaccessible, you have got to fix the hanger. You have got to fix the hanger to come up with a better mod basically to find out what happened in the hanger, but you have got to do it

either at your next refueling outage or whenever it is next accessible or you have got to work on it as expeditiously as necessary if it is accessible.

So every time they get one of these hangers to drop down below into the interim criteria, John Wood calls me and lets me know because it's all dealing with this auxiliary feedwater. ESA knows about it and we talk back and forth on that type of thing on occasion about it when he's out here, make sure we all have all the information available.

The only time this thing has caused any problem is one time the hangers gapped when it got hit or whatever happened to it, it was one of the key hangers in the line, let's say, such that it drops below the interim criteria and they had to declare that system inoperable once they determined that it was not in accordance with their interim criteria.

MR. LANNING: What in your opinion is the consequences of a water hammer in the steam supply to the auxiliary feedwater pumps?

MR. ROGERS: It's like it says, it's a water hammer. What it is is water condensing back

into the vacuum and it's like a hammer. I mean, you physically rattle the pipes. You can damage these things.

MR. ROSSI: Have you seen damage down the pumps itself, the inlet to the pump or the trip throttle valve?

MR. ROGERS: There doesn't seem to be damage in that area. It seems to be a little higher up is my perception, but I have the actual hanger. If you all want to see it, I have which hangers were damaged on the drawing.

MR. ROSSI: Is it in the pump room or do you know?

MR. ROGERS: It's a little bit of everywhere. There is one in No. 2 mechanical and there is some up in No. 4 mechanical. Then there is over in auxiliary feedpump rooms themselves, some of the damages to snubbers breaking I believe is in the pump room.

MR. ROSSI: I'm sure we can get the details of where those hangers are from the licensee.

MR. BEARD: I was going to ask a quick availability question. I realize I'm interrupting

Wayne. Do you know if the plant has isometric drawings of the pipe runs of the aux feedwater system?

MR. ROGERS: Oh, yeah.

MR. BEARD: I mean, something if we wanted to know or refresh our memories with regard to the way the pipes are laid out in those rooms, that something is available, if we should ask for it?

MR. ROGERS: Sure. It's in the FSAR. I have color-coded pictures if you want to see them.

MR. BEARD: I think I would.

MR. ROGERS: I will get Don to go get them.

MR. LANNING: As I understand your answer, the consequences of the water hammer can result in damage to the piping itself and to its -- the hangers for the piping.

MR. ROGERS: Well, yeah, if you get a big enough water hammer. I don't know how you put it, what limited thing I have on it, the water hammer. It depends upon a lot of different things, but you could have water hammer on a line and it not damage anything, but you can also have one that, you know, you are putting a lot of stress in one particular

area.

MR. LANNING: Now, what precautions had been taken to preclude a water hammer in this system while the plant continues to operate?

MR. ROGERS: Well, No. 1, the water hammer itself had not from my understanding, that was part of it, the water hammer wasn't a big serious water hammer that on the hit it makes everything inoperable. It seems that they would be doing testing to determine, you know, what the water sources were, what the real impact on the system was in terms of long-term degradation.

MR. LANNING: That was the thrust of the confirmatory action letter?

MR. ROGERS: I'm not going to say that's the thrust. I would rather go ahead and if you all want to see the confirmatory action letter and put that in the record, I'm not going to sit here and try to second guess what that thing says because it says a lot. There is a lot of steps in there and it talks on a lot more sophisticated basis that I think I'm going -- I would rather fall back and actually put a copy in the record of the confirmatory action letter on what it does do.

It's not just -- it's not a little hokey-pokey document or something. It's pretty good size.

MR. ROSSI: Larry I think had a question.

MR. BELL: Are low point drains installed in this piping?

MR. ROGERS: Yeah.

MR. BELL: Did the utility make any commitment to blow the water out those drains? It seems that's the quick and easy fix, to manually blow the water out of the piping while they are investigating.

MR. ROGERS: There are drains in the lines, but whether the drains are in the right spot or not, that's another -- that's a different animal.

MR. BEARD: Have you had any experience or information regarding whether or not the drain valves work properly regardless of their locations?

MR. ROGERS: I have no knowledge that any of them were working improperly.

MR. BEARD: Okay. I would like to follow up Wayne's question with one on the water hammer in a little bit different vein. I would like to understand a little bit better the effect of water in the steam supply on the turbine itself, neglecting

the physical damage the hammer might have. I have heard a lot of different stories and I'm curious about your assessment because I respect your judgment.

What do you think the effect of water in that line would have on the turbine, especially with regard to its speed and consideration of the possibility some of that could flash?

MR. ROGERS: I guess I have heard that kicked around a little. In terms of actually having water on that turbine, and this is more just not actually going through the manuals but people's perception, that that Terry Turbine will run on water. I mean, it's a water wheel if it has to be.

MR. BEARD: I've heard that stated.

MR. ROGERS: And that's at least my perception. So those things seem to have a pretty good industry reputation in terms of being able to take water.

If in terms of a potential water flashing back to steam and that energy assessment overspeeds the turbine, I say that is a physical phenomena. Yes, it could happen. I think people would have to sit down and give me some calculations on what --

how much water you got versus how much is flashing to steam and, I mean, do some engineering calculations to prove to me that's what could cause that turbine to overspeed. I guess I would go in upfront saying show me. I have a little Missouri in me there. That's about the way I would look at it.

MR. BEARD: I hear your answer as being like my own position. That is, I heard this hypothesis stated, but I haven't looked into it enough to be convinced myself.

MR. ROGERS: That's a good assessment.

MR. BEARD: All right.

MR. ROSSI: I wonder if we could proceed on to -- I think we learned, you know, what Walt found out when he first got in the control room, which is basically the status of the plant when he got there. I wonder if he could describe, you know, what involvement that you may have had in analyzing what happened during the event, the sequence of events, analyses that you have been involved in or results of reviews of either the licensee's sequence of events or our sequence of events at this point in time to see if there is anything we

can learn from your personal knowledge of those?

MR. ROGERS: Okay. Well, I guess to really start to get into the analysis side, we are getting a little later on Sunday in terms of they are already out of the unusual event and they are starting to do their tests of one of the auxiliary speed pumps, and kind of now I guess we are talking -- I can't -- I guess very late in the morning after everything looks normal, the turbine bypass valve yoke is already busted and they have taken care of that. So they are in a very safe condition at that point.

Of course I guess really -- and then I went over to the tech section because that's where the computer printouts are really starting to come out and started looking. And I guess the first indication that they -- I knew the PORV would have had to have popped. For some reason I knew it had popped a couple of times. Whether I expected that or whether I actually saw that on some of the printouts or just what, but when I finally was given the pressure trace, the RCS pressure trace, it's a graph and I say -- I don't know if it's Stan or Jacque Lingenfelter or Jim Marley was in at that

time, someone gave that because they know what they are supposed -- that after every trip, I'm going to come ask them for a package, I have been doing it for years. So I don't even ask them any more, they just know Rogers is going to want this so they have it ready.

Part of it is the alarm printer, part of that is the computer traces and all that. So at least they had one of the graph traces, and Don and I were there together at that time. I said, well, there is PORV, there is PORV. I said, okay, that's third on the PORV. I said there is something wrong with PORV.

I knew that, it was obvious that the PORV didn't close as fast as it should have closed because it's a three-five, I would call it closer to three, some people say five to make it go closed, but you can tell from pressure because it's like a little half moon curve you will see on it and you know that's what it is, but this one just kind of keeps on going. You can tell that, you know, it closed, the pressure returns, so you knew that either they shut the block or the PORV reseated itself at some point in time. Knowing what I knew

about the control room, I knew the PORV had to have reseated itself at some point in time and said, Don, now, that's --

MR. ROSSI: Why do you say you knew the -- oh, because the block valve was open when you were there. That's the way you knew the PORV had reseated?

MR. ROGERS: Yep. So, you know, I said we are going to have to add that to the list. So we started looking at a few things. Did they inject, I guess I can't tell you how -- through that point it had come up it had been on piggyback. Did they inject on piggyback, we looked at that. They have been saying fifteen gallons but I think they are just being conservative in saying that. They may have pumped in fifteen gallons, but it doesn't really matter. You took a hit on it. I say hit, you give a thermal shock to the HPI nozzle, and that's really what counts. So then they have to take a hit for that.

Just started to get a feel for some of the things, knowing then what had happened to SFRCS, you really can't start to guess what's going on at that point in time. I guess at that point in time,

we were kind of starting to get -- we are going to need to brief our management who are flying in, Nick and Wayne, Nick Jackiw and Wayne Shafer who were flying in, and we really hadn't had much sleep at that point in time.

We had looked at some of it basically. We knew they weren't going anywhere and they were out of the unusual event already. They had -- and by the time we made that decision, they had already tested auxiliary feedpumps. I talked to Steve Quennoz on the Gaitronics and he said they passed okay. And they had performed their -- they had done their surveillance test and it worked okay.

MR. ROSSI: So the auxiliary feedwater pumps at that point had been tested to come up to speed and not trip again. They just worked properly?

MR. ROGERS: Right. At that point in time, you didn't need auxiliary feedwater from about an hour, hour and a half after the trip. The startup feedpump would hack it without any problem.

So we -- I went -- I guess this was in the early afternoon, really didn't have a good chance to sit down and look through all the traces,

but just enough you knew SFAS wasn't going to actuate, it hadn't actuated, that type of thing, reactor protection system hadn't functioned properly. SFRCS, you couldn't make a guess on that because I already knew they had thrown some different glitches into that and it was going to take a long time to figure out what was going on there.

MR. BEARD: What do you mean by that, result on the Rupture Control System since they have thrown some different glitches?

MR. ROGERS: By pressing the buttons, they had given it a real weird logic. See, when they press the button, they pressed and they told actuation, they told the No. 1 channel, hey, one of the generators is busted and then -- which I believe it says -- I believe it was telling that the No. 1 generator is busted, feed the No. 2 generator. At the same time on Actuation Channel 2, they are saying, hey, the No. 2 generator is busted, go feed the No. 1 generator.

That's what when they hit those manual buttons there, that's what they told the logic, which is -- you should never -- you could say that,

hey, you could tell the logic -- you could tell the two channels this generator is busted or you can tell the logic that generator is busted, but it told each channel a different generator is busted. By busted, I mean it has got a low pressure.

MR. BEARD: I understand. If you had a real situation where one generator was busted and you wanted to tell your Rupture Control System that manually, could you describe what buttons would be the appropriate ones to push in terms of their physical location, because it seemed like the top two in each column are low pressure on some generator?

MR. ROGERS: Yes.

MR. BEARD: What would you do if you wanted to manually tell the system that No. 1 generator was busted?

MR. ROGERS: Okay. You would press the -- you have got two columns of buttons with the top button being the one that you would tell actuation channel No. 1 you are busted, that's in the first column. Then you would go down on the second column and you would go down to the second button from the top and you would press that one.

MR. BEARD: So you press a cater-corner combination?

MR. ROGERS: It's cater-corner, that's right. And if you want to tell the other one, it's cater-corner that way.

MR. BEARD: You mean the other generator?

MR. ROGERS: The other generator, it would be just a different cater-corner, and then down below you got low DP or DP, and then you got loss of reactor coolant pumps, and then at the very bottom I believe it is, I think it's very bottom you have got low level. I can't tell you for certain. I know they are in some order. If you look at them, the way you tell them is not so much the position, but the little red buttons are the low level -- not red. There is a little piece of red tape on the ones that are low level.

MR. BEARD: Are you saying in your mind the ones that the person would have probably wanted to use were identified by a red marker?

MR. ROGERS: Yeah. Now, that red marker is not to identify to the operator that during -- that if you want to manually press SFRCS, let's say, the MSIVs go closed or for some reason you want to

press the buttons for low level for other than the smart fire or a control room fire, they have little red pieces of tape throughout the plant and the control room that identify those buttons or controllers that are to be used in what is generally known as the smart fire. And that's what it is there for. It's not to tell the operator on a normal day-to-day basis these are the low levels. So they pressed them and it's cater-corner, so that kind of doesn't help, but that happens.

MR. ROSSI: At this plant, do they normally manually actuate safety systems in anticipation of the automatic actuation? Is that a normal thing that they do?

MR. ROGERS: Well, I have seen them and they have done it before as to punch out SFRCS on low level manually. I don't remember any time where they have manually punched out reactor protection system. I know of at least one instance where they were -- they perceived a problem and tried to punch her out, but in reality the automatic system beat them to it.

SFAS, as far as I know, there has not been any manual initiation of SFAS. The real

system that you are getting involved in is going to be SFRCS, and that's where it really gets involved. I believe you even see it in some of the procedures. If possible, they will try to, like if you get a low pressure and you have got -- you can see it is drifting down and heading towards its trip setpoint, they will want to manually go ahead and do it.

MR. ROSSI: This is low pressure in what?

MR. ROGERS: The steam generator lines. The steamlines. They will if they know they have lost their main feedpumps, I think it's probably reasonable to assume that they are going to try to go ahead and get on auxiliary feedwater, which is what's going to be your supply source. And the fastest and easiest way to do that is go ahead and hit low level on SFRCS.

MR. ROSSI: Have they had other occasions where they have manually initiated the SFRCS on low pressure that you know of?

MR. ROGERS: If it was -- I would have to go back and review the March 2nd event for exactly what the sequence of events was there.

MR. ROSSI: The March 2nd event was from March 1984 when they had the stuck open safety

valve?

MR. ROGERS: Safety valve. I don't believe they manually hit the buttons there but that would be the only time -- I'm just thinking of all the times I've been here, that's the only time I can think of that would have even been a possibility. If I remember right, I think it went --

MR. ROSSI: Well, you don't need to search your memory. Some of these things where you can't remember, especially where there is some records someplace presumably that we can go look at if we are interested?

MR. ROGERS: That would be the only thing. I think it went low level first and then it went out on low pressure.

MR. BEARD: Ernie, let me ask you a question. Before this interview, I jotted down a few topics I did want to ask Walt's opinion on or get some answers from him. And I had three or four about the Steam and Feedwater Rupture Control system in terms of how it works and what equipment would respond to it. Would this be an appropriate time to ask this?

MR. ROSSI: I would like to continue to

find out what he knows about the analyses and sequence of events and then we will go on to these other areas at that point.

MR. BELL: Fine.

MR. ROGERS: Okay. After I left the site on Sunday and briefed Wayne Shafer and Nick Jackiw on the situation, I guess there was a time frame where I believe I went home, got an hour or two -- it wasn't much, I think I got a little sleep there, took a shower and then met Wayne and Nick. I believe that's the way it went. I was to catch a plane that afternoon to go back to Chattanooga, which turned out I didn't make, and ended up -- Monday morning I ended up back in Chattanooga at that time. I think I had some -- I may have had the alarm printer or portions of the alarm printer with me at that time. I think I had some data that I had jotted down.

I talked to Don that Monday. We were on the phone I don't know how long Monday night because during the event, there had been two things that I wanted to talk to him a little more fully about and he had the data, so we were on the phone talking and I was in my motel room because we wanted

to make sure we had as good a sequence of events and briefing for the Fact Finding Team as we could come up with.

And we centered it on the PORV to make sure that we were on sinque on the PORV and went through that and what the pressure got to and when the block valve went closed and all that so we would have a good frame of reference for that.

I think at that point in time, I was interested in whether the HPI injection was due to the PORV blow-down or not. And I think based upon running through the numbers back and forth, it looked like auxiliary feed is actually what knocked pressure down enough to do HPI injection. That was kind of interesting.

The other thing was I wanted to see when the switchover to service water took place, and that looked a little strange. It looked like the thing had come up -- auxiliary feedpump turbine had come up to speed and it had switched over later on. It wouldn't have been unusual to me to see that when the turbine actually got its blast to go -- by that time it was apparent they had some problems with the turbine, I wasn't really sure what it was,

but when they wanted to get water to the auxiliary -- from the auxiliary feedpumps into the steam generators, that it could have seen a low suction pressure which would have been sensed in that line and cause a switchover from the CST to the service water, but that did not look to be the case. So I told Don to highlight that for you all.

MR. ROSSI: Do you know anything more now about why that might have occurred?

MR. ROGERS: Not yet. Basically you can look at some things, but other than the chart recordings -- and we are waiting for them to come up with their maintenance plan in this area. A lot of these were -- I guess we kind of, I guess due to the liaison here, that we are not definitely born -- not born in, but asking the licensee a lot of different questions right up front but letting them do their analysis and come to their conclusions, and then we can inspect on what they are doing and verifying that's going along right, realizing you all are the ones that are who they are presenting the maintenance plans to. We don't want to inhibit you all.

MR. ROSSI: Do you happen to know

anything about the analyses of the startup feed flow during the initial recovery of the startup feed as to indications that might be available to tell whether the startup feed actually got to a steam generator before an auxiliary feed or not?

MR. ROGERS: Oh, yeah. Startup feed got to the steam generator before auxiliary feed did.

MR. ROSSI: Both steam generators or just one?

MR. ROGERS: I'm saying No. 1 right now. I'm not sure whether No. 2 got it or not.

MR. ROSSI: What would be your basis for saying that the startup feed got there first?

MR. ROGERS: Oh, you look at the main feedwater flow, startup feedwater flow indication. The feedwater goes through the main feedwater line. Auxiliary feedwater flow goes through its own auxiliary feedwater line which is a different connection in the steam generator.

So if you look and see no auxiliary feedwater flow going into the steam generator but you do see feedwater flow here on the startup range and you also see steam generator level starting to increase or no longer decrease, that's the only

place you are going to get water with the main control valves shut.

I mean, you have got the main isolated, the main -- of course, you know the main feedwater pumps aren't pumping it and you know what the pressure in the steam generator is, so you know the condensate pumps aren't pumping any in.

MR. BEARD: Do you know, is there a specific data point in one of these sources of hard data that is available that would tell you the flow versus say the control valve -- startup control valve's position?

MR. ROGERS: There is a computer readout that will give you startup feedwater valve position.

MR. BEARD: I know, I have that one in front of me. I'm really trying to focus on --

MR. ROGERS: Whether there is a startup feedwater flow indication?

MR. BEARD: Yes.

MR. ROGERS: Boy, I don't think there is. You know, you may have to go to main feedwater flow. I would have to go back and look at it. I was thinking -- I could have sworn I saw something on -- somehow or another I got to the conclusion that

startup feedwater got there and it was a combination of level coming up and also some flow picking up.

MR. BELL: But can you read four hundred gallons per minute on the startup feed flow detector?

MR. ROGERS: Oh, I don't think so.

MR. BEARD: I think my glance of the curves that the licensee gave us indicates that, maybe it's my imagination, but there does seem to be a slight increase on the flow of the main feed, the composite flow I guess it's identified as, and at a particular point there is beginning to be a turnaround of the level signal.

MR. ROSSI: Before the auxiliary feedwater.

MR. BEARD: Yes, before. And it's roughly, if I had to estimate, I would say one and three-quarter minutes prior to when No. 2 aux feedwater flow came on. And I'm looking at generator one traces. We had some discussions that the possibility that the secondary system operator in the control room may have gone ahead and opened the startup control valve in anticipation, that Mr.

Feasel got the pump available and he was ready to inject because they were trying to get feed in the worse sort of way.

MR. ROGERS: Yeah.

MR. BEARD: But in fact, we heard at one of the meetings where we discussed this point I guess in regard to our sequence of events that we presented to the licensee, this would be Rev 0 when we were trying to make sure we had the factual information correct and not misunderstood, someone if I remember correctly stated that they had hard data that indicated the startup valve was open, there was flow through it to both steam generators, and I haven't had a chance to look into that area myself, but I'm wondering if you knew, that's all?

MR. ROGERS: No, I know there is some question about SP7B, and I kind of have been holding off.

MR. ROSSI: 7A, wasn't it?

MR. BEARD: The one to Steam Generator 2 at this plant is A rather than B, and I think it's the one to Steam Generator 2 that was identified to us as apparently -- there were indications at least that it did not open.

MR. ROGERS: See, evidently that's what the licensee -- I haven't looked too fully in that. I figured they are going to come back and talk to us there.

MR. ROSSI: You know, if you can't shed significant light on these questions, it's probably not worth our discussing it. I think what we ought to do is make a list of questions like this for the licensee for our sequence of events meeting tomorrow afternoon and give it to the licensee well in advance of the meeting in the hopes he will come prepared to answer them. That's probably the best thing to do.

MR. BEARD: My intent in asking Walt about it is to find out if he knew there was a specific data point on flow versus valve position.

MR. ROSSI: I also had those questions on my list, but I think we found out everything that Walt knows on that issue.

MR. ROGERS: Yeah. The only thing I knew maybe different is I know there was some problem with the reset lights in the back on the west wall for the startup feed valves, that there was some lights that were blown and there was also some

lights blown on the main steam -- I mean, MSIV solenoids they had to replace at some point during the night.

MR. ROSSI: I wonder if this is a good place to stop for lunch?

MR. BEARD: I have been holding off a number of questions so we get through this line that you are pursuing now of I guess Walt's assessment of analysis of the event. Are you finished with that?

MR. ROSSI: You know, if you have got more questions on Walt's assessment of the analyses, maybe we can finish those if it doesn't run too long and then we will break for lunch.

MR. BEARD: In that area, I only had really one question and this I'm asking for just an overall assessment on your part, Walt, and you may not want to do it. But you are the man that is the eyes and the ears for the NRC and you are close to this plant and you know the people and et cetera; it would be valuable at least for me to know.

I'm curious about your overall assessment of the severity of this incident in the sense of I would like to term near miss; okay?

MR. ROGERS: Yes.

MR. BEARD: We wrote that in some NRC manual chapters and I like it. If you wanted to use the term this is a near miss, how would you assess this in terms of how close the plant was to a problem? That's what I'm trying to get for us, some overall assessment of the severity of the event.

MR. ROSSI: And you might approach that by giving us your opinion of how close they were to severe plant damage which is one thing, and then another assessment of public safety issue. Because they may have been close to one and not the other or close to both, so you might as well give us your assessment of that.

MR. ROGERS: I guess I would start with severe plant damage. I don't think they were close. And it's a combination of things that makes me say that.

One is past experience in watching the operators during transient performance. And from what I see, their capability in getting what they needed in service when they needed it in service, realizing they had a number of multiple equipment

failures in this situation, they still overcame those and did in fact their job. They kept the core covered. They maintained a very significant saturation margin or subcool margin, and they went and -- went to a number of areas they had available to get water into those steam generators.

In terms of what this does, obviously you are not supposed to lose two auxiliary feedwater pumps. This is not analyzed for in the license, it is outside single failure criteria. This is not supposed to happen. You are not supposed to have to make your man/machine interface work at this high level in this type of time frame to maintain the core cover.

So in terms of a near miss per se, I think these people were able to do it, and I think just about any of the operating shifts they had out there would have been able to do it. But it's not the type of thing that you want to do on a day in, day out basis. Sooner or later you are not going to be able to do it.

That would be my assessment, that you have to have your operators trained, properly qualified to a high enough level that they

understand not only the design basis of their facility but have a lot of good common sense understanding of the engineering fundamentals you need to know and what it takes to get water in a generator or when to put water in a generator, that type of thing.

MR. BEARD: Let me see if I can follow up and focus my question a little better, Walt. I have heard numbers batted around, comments batted around in these rooms that we have had these interviews where people were talking and saying things like the important thing in their mind is that if we know from our training or something that we need to get 450 gallons per minute within thirty minutes --

MR. ROGERS: Okay. That's --

MR. BEARD: -- now, with that kind of a comment in the back of your mind, how close would you assess this situation?

MR. ROGERS: Well, it took them 12 minutes.

MR. ROSSI: Well, this 450 gallons per minute, perhaps you might say where. Is that makeup to the primary system or water to the steam

generators? Which did you mean?

MR. BEARD: We are talking feed.

MR. ROSSI: Feed to the steam generator?

MR. ROGERS: I guess from what I have seen of the analyses, and I guess what they pretty much have been saying, you have got a half hour, you have to get water to those steam generators in a half hour is what it really comes down to. Whether it's 450 gallons, I think it's always assumed it's going to be more than 450 gallons.

MR. BEARD: Some significant flow, at least?

MR. ROGERS: Some significant flow. And that you have got to do it in a half hour, assuming you don't use HPI coolant in the piggyback methodology. I think you will probably find the analyses are going to push you out to a core damage of probably somewhere in the 60 minute time frame if you go ahead and put piggyback in service without secondary side coolant.

MR. BEARD: Are you saying that if at the 30 minute point they can't regain some feedwater, aux feedwater, startup, whatever, and you enter the PORV cooling mode, that the analysis would show

that somewhere around 60 minutes then you would get into some sort of core damage situation?

MR. ROGERS: I think that's probably where you would probably be headed. That's just based upon looking at some data to the addenda to that May 1979, I believe it's an addenda to it, I think that goes with the numbers used.

Taking into account the numbers used in two different decay heat loads and I think the more realistic decay heat load, there are some points in times that I have heard it batted around you might be able to get around on just HPI coolant but it gets real hairy there to about three cycles. You are just sitting there watching the PORV stay open for about fifteen, twenty minutes and just -- it's not a good situation to be in.

But as far as I know, I have yet to ever see analysis that says that you can hack it without some secondary site cooling.

MR. BEARD: Okay. The last aspect of that -- maybe we will delay that one, but would it be your professional judgment they were in at least for a period of time what's classified as a site emergency during this transient?

MR. ROGERS: That is an interesting point. I guess there is some flexibility in the law that gives you fifteen minutes to make a good judgment on where you actually stand, and I have always taken that fifteen minutes is for the operator and the shift supervisor, basically, to assure himself that he maintains that his primary safety goal at that point is to keep the core covered.

MR. ROSSI: Where does that fifteen minutes come from?

MR. ROGERS: That's just something I believe -- I can't even remember where in the law it is or in the regulations, but I think that's pretty much the stuff, talking to the EP guys, you try to make your determination in fifteen minutes. And given that your first response, like you look at it, your immediate response is not -- let's say the plant does something abnormally. You don't look in the emergency plan and then trip the reactor. You trip the reactor, you look at your primary indicators before you look at your emergency plan.

And given that light, I don't know whether -- I know what their EAL says because they

even talked to me about it that night. They say, Walt, look, this is what our EAL says. It says we lost main feedwater and auxiliary and that says it is site emergency. However, by the time we got here and looked at this, we already had our auxiliary feedpumps back.

I said, okay. We consider ourselves in an unusual event right now. I said, yeah, okay, given your parameters and everything, that's right. I think you have got to take things and look at them in terms of who is going to make that decision, and that's that shift supervisor on where you are in this action plan.

MR. BEARD: Let me clarify just for the sake of time. I'm not trying to investigate the area of whether or not they called it properly when they phoned it in or later or whether or not they called it on the basis of their condition at the plant at that point in time or what they had been through. I'm trying to just learn from your personal assessment overall of the event, what is it at the severity level? Had they been through a site emergency? That's the severity level that you believe is the significance of this event?

MR. ROGERS: Oh, I see what you mean. You mean if you were sitting there, you know, a half hour later and you didn't have auxiliary feedwater or main feedwater, would you think that the proper classification is a site emergency?

MR. BEARD: Well, I'm just saying independent of reporting and those kinds of things, had they been through the conditions that you normally associate with site emergency in your mind? Maybe they weren't there then because they had recovered, but had they been through that severe of an overall incident?

MR. ROGERS: Had they been through? I don't know if I can say they had been through. If that condition had continued for a period of time, you know, longer than twelve minutes or whatever, fifteen minutes, that it would mandate a site emergency.

MR. BEARD: But you are talking -- I perceive now that you are thinking in terms of activation of emergency plans?

MR. ROGERS: Yeah.

MR. BEARD: If I'm looking at it at continuous points of time, neglecting what I would

have to do if I called it that, would the severity of the incident the plant went through at some point in time be what you would consider to be a site emergency? I'm trying to get your overall assessment of how severe this incident was or how close to a near miss it was, just your overall feel.

MR. ROGERS: I guess I feel that it would be proper to call it a site emergency if you had a loss of main feedpumps and loss of auxiliary feedpumps.

MR. BEARD: So at some point they were at that status?

MR. ROGERS: Yes.

MR. BEARD: That's all I'm trying to get to.

MR. ROGERS: Whether they called it or not, I think -- I think I understand what you are saying. I think that type of situation is significant enough that it should be considered a site emergency.

MR. BEARD: That's all I was trying to get at.

MR. ROSSI: Can we break for lunch now?

MR. BEARD: That's the end of my

questions.

MR. ROSSI: Why don't we break for lunch and convene back in an hour.

(Thereupon, a luncheon recess was taken.)

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Thursday Afternoon Session

June 20, 1985

2:00 o'clock p.m.

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MR. ROSSI: Why don't we start.

MR. BEARD: We covered the overall assessment analysis of the event, I think. And I think that's the point that we stopped at the end of the morning section.

MR. ROSSI: We had also gotten everything that you know about what happened after the event because I think you told us everything that you observed when you got here and so forth.

MR. ROGERS: Okay.

MR. BEARD: I don't know how you want to do this. Everyone has a few questions.

MR. ROSSI: Why don't we let Larry go with his questions.

MR. BELL: It's my understanding at the time of the event that the startup feedwater pump was isolated?

MR. ROGERS: Yes.

MR. BELL: It's also my understanding that that is a recent range to plant operating

procedures, in March of '85 time frame?

MR. ROGERS: That's wrong.

MR. BELL: When was that change made?

MR. ROGERS: That change was made I'm going to say in the July time frame of 1984.

MR. BELL: Why was this mode of operation changed?

MR. ROGERS: The startup feedwater suction line discharge line was not properly analyzed under the license. The line actually goes through the auxiliary feedpump rooms, and as such, if you considered its -- I'm not going to call it -- it was either the high energy break or moderate energy break, there is certain criteria that was supposed to have been met to allow you to use these lines so they do not impact upon safety related equipment.

Well, they stuck -- they changed the position of the suction valve at one point in time. It was originally closed; okay? And when it was -- the way they had the valves at one point in time was okay, but when they opened the valves, a couple of years ago they didn't do a proper analysis of that line in terms of what the ramifications were.

And as such, they did not meet the requirements associated with that system and the piping system such as they had to isolate it.

Also there is some problem with turbine plant cooling water to cool the startup feedpump. It also falls in the situation that it is not adequately protected from the high energy plant breaks. This is pretty well documented in a couple of inspection reports and was part of an escalated enforcement action against the licensee last year.

MR. BEARD: Let me see if I understand here. You are saying this whole issue arose out of one of your inspections?

MR. ROGERS: Well, they actually identified it themselves, but as a result of them identifying it and looking into it, the event, and what happened when we went back or I went back and looked at what they did in the facility change package is you run across where they changed the position of that startup feedwater valve.

MR. ROSSI: When you say they changed the position of the startup feedwater valve, you mean they changed its actual valve position, not where it was located?

MR. ROGERS: No. What they did, they changed it on the drawings. See, what they had was the drawing, the P&ID originally had the valves being closed. Well, they were never aligning the system with the valves closed.

My understanding is their policy is that if you have the suction valve of a pump closed, that they pull the control power fuses or they disable the pump from starting electrically, and that is a company policy associated with their pumps.

Now, the P&ID originally showed the line as being closed, but they were never running like that because they never pulled the control power fuses, and the operators identified it and had a facility change. They wouldn't want the valve open like they were really running.

Well, when they did that, no one caught on with what that meant in terms of the analysis as stated -- words in the FSAR talk about it in a very limited respect for the turbine plant cooling water valves, which were also being left open.

So basically, yeah, they ended up getting into -- they got a licensed condition that we let

them use the startup feedpump provided they only used it to startup, and then when they did use it, that they kept a man in the room to monitor the line for a potential high energy or moderate energy break. And that was to go anyway, I believe, as part of their 1986 modifications, that startup feedpump system or whatever you want to call it, the third pump.

MR. BELL: The higher moderate energy break, is that associated with any particular phenomenon such as a seismic event or is this independent of a seismic event?

MR. ROGERS: It is my recollection on that that this is independent of a seismic event.

MR. ROSSI: Did the licensed condition go back through NRR? Was it a NRR licensed condition?

MR. ROGERS: Yes.

MR. ROSSI: So NRR was involved in the decision to isolate the pump and so forth; is that right?

MR. ROGERS: Yes. Well, NRR is the only people that deal with licensed conditions. I & E doesn't do that. That's NRR's function.

Now, I'm not sure what the license says

completely, if it calls out specific valves for isolation or just what. I would have to go get the text -- I mean, go get the license itself, and that would be the easiest way to do that.

MR. ROSSI: Okay. But the decision to do all this came from -- it came to you for making sure they did it and not -- and it may have started from you just finding a problem with it being run not in accordance with the FSAR?

MR. ROGERS: Well, see, they wrote the LER and they provided the corrective action themselves. The original LER says what they are going to do and they say they are going to pull the control power fuses and shut the valves. They knew they were not in compliance with their license.

MR. ROSSI: So they identified the problem, the licensee identified the problem of the high energy line break?

MR. ROGERS: Right.

MR. ROSSI: They wrote an LER on it, and then they in that LER identified or proposed the corrective action?

MR. ROGERS: Yeah.

MR. ROSSI: That's the way it occurred.

It wasn't that the NRC found the problem and told them to do this. The corrective action for it came from them?

MR. ROGERS: I believe that is true. And in the original onset, there is some things that get -- there is some iterations in this that once they say, you know, we got to do this for high energy line breaks, there was an instance where they ended up opening the valve and they left it open, the suction valve, for so long, and that was part of the escalated enforcement package also. There was a lot of things that went into that escalated enforcement package with the valve.

But, you know, eventually the license, they settled on that for the licensed condition that was -- I think it was essentially nothing more than the LER.

MR. ROSSI: Now, I would assume that you can help us find the LER and the escalated enforcement documentation, that we can get that material and trace through the history of that from the paper?

MR. ROGERS: Yes.

MR. ROSSI: Which is probably the best

way to do it rather than try to get it in the interview.

MR. ROGERS: I guess the main thing is the line should have either been protected properly to start off with, given their conditions. If it had been done right to start off with, they wouldn't have had this problem.

MR. BELL: When you got to the control room, what was the attitude of the operators? Were they nervous or had they calmed down by now?

MR. ROGERS: They seemed to be relatively calm at that time. I think about the only time I really saw -- it sounded like Teddy Lee was kind of pumped up on the phone when he was telling me about it, but that's understandable given the duration and the proximity of the event. But by the time I got in the control room, it was a calm atmosphere.

MR. BELL: Okay. I've got a series of questions on the SALP report. There has been a complaint of the utilities when they receive a bad SALP report that the Region assigns a bad reputation to that utility and it's very difficult for the utility to turn the SALP reports around regardless of his performance. Do you think that

perhaps is the case at Davis-Besse?

MR. ROGERS: I'm not going to speak in the areas that I do not have direct input. In the areas of operations, maintenance, quality activities, surveillance and tests, I'll say their reputation is not involved. It is based upon pure fact as identified in inspection reports and LERs that they report.

MR. BELL: All right. I guess that answers that question. Do you -- unless somebody else has follow-up question on that, we can get the report.

MR. ROSSI: Yeah. I don't have a follow-up on that.

MR. ROGERS: Let me write that down, if you want to see that escalated enforcement stuff.

MR. ROSSI: Let's see. Larry, you have more?

MR. BELL: I have two small questions.

MR. ROGERS: Okay. Go ahead.

MR. ROSSI: Are there any NRC regulations that in your opinion have a negative impact on safety and would have influenced this event?

MR. ROGERS: Regulations?

MR. ROSSI: Well, that can be expanded to regulations, practices.

MR. BELL: Practices.

MR. ROSSI: Procedures, you know, anything that the NRC has required of the licensee that would have -- that you think is a significant problem, first, related to this event and then just in general aside from this event.

MR. ROGERS: Well, I think given the condition of the startup feedpump system at the point in time, it's kind of like what do you defense against? Obviously I'm sure some of the operations people here probably are under the opinion that, boy, it would have been nice if all we had to do is turn that startup feedpump on, boy, you know, why did we have to shut all this and pull these control power fuses and all that. And given its condition, yeah, it would have been a lot easier to get water to the steam generator.

However, there is another side to that story too. And that's very simply that the plant is supposed to be designed to a certain design bases and they didn't design it to that, and that at some point in time they have got to ask

themselves a question. They knew what the ramifications of that startup feedpump were and just what was going on with that. So in that respect, it's a two-sided story.

There is a lot of other things. You protect it against one thing, but you did increase the time frame in another event, but an event that was not a part of the license and was not supposed to happen and not a part of the design basis was to occur. Now, it's a two-sided edge there. In terms of some of the other things --

MR. BELL: Technical specifications, is there any ambiguity in the technical specifications for this unit that have given you problems or give the licensee problems?

MR. ROGERS: I don't know if it's given the licensee problems, but I know there is a tech spec here that's given me problems and it has to do with a definition of what is a steamline break or a feedwater break in the tech specs on steam generator.

When you look at the event as I have seen it so far, I'm not terribly concerned about what the transient was on the primary side from the

standpoint of what actually happened, I'm not looking at the what-ifs; I'm saying what really did happen. I'm more interested based upon seeing what I have seen on the secondary side and specifically the generator.

If you look at a steam generator, to a tech spec it says, well, thou shall establish an inspection frequency on a steam generator, on the tubes, a special inspection based upon these particular events.

Well, I mean, in reality a total loss of feedwater produces -- the generator doesn't care why it doesn't get water if it is upstream of the check valve. If you break the check valve, that's one thing.

I guess I better back up and try to explain what I'm saying. In the main feedwater line you have got a pump, there is a lot of valves, but basically we are talking a pump, a check valve and a steam generator. If you break upstream of that check valve, that is basically a feedwater line break or for some reason you don't get water through that pipe to the steam generator, he sees it, no matter what.

If you break downstream of that check valve, in essence even though you are putting water through there, in reality it is nothing more than a steamline break because you are going to blow everything down. This would be a blow-down. This would be a depressurization event.

The main point is a loss of main feedwater, is it in fact -- does it do the same characteristics that they look at in a main feedwater line break because you are basically not putting water to the steam generator. And in that term, I would guess there is some questions there.

It's just like the one on -- say you have a turbine bypass valve failure without a main steam isolation valve or you do have a main steam isolation valve closure and you get a main steam side safety stick open or you get an atmospheric valve stick open. To the generator itself it doesn't care why; all it knows is it sees a steamline hole. Now, how big these holes have to be, how much of a feedwater line loss do you have to have before you invoke this tech spec --

MR. ROSSI: What does the tech spec specifically say, that it sounds as a cycle or they

have to do additional analyses or additional inspection?

MR. ROGERS: They have to do a special 80 current tube inspection is what it amounts to. I guess when we did have the depressurization event on the one generator, part of the CAL called for them to do detailed analyses that covered and also had them do tube inspections later on because of another problem.

I guess that one kind of gives me some difficulty in terms of how do you read that tech spec and what are they really trying to get at. Even when I read the regular guide on it, it still doesn't give me the type of clarification I guess I would like to see.

MR. BELL: Have you asked this question of any other people or brought this up in any other -- with any other NRC group other than this Fact Finding Team?

MR. ROGERS: I am pretty sure I sent a memo in to talk about it, say, what's the size. If not, I think I mentioned it to my supervision. I will check my memo file to see if I haven't put something in memoranda.

There was a couple of things I put in after that steamline -- when the safety opened up that deals with the way that tech spec reads because of the way you have got to look at the curves. This is really more than another event.

I know I said maybe they ought to take a look at it because at some point in time your cooldown curve in the very upper limits as I understand it is really limited by the tubes and not so much by beltline or the reactor pressure vessel. But when you actually get into reading the words, it really only has you doing analysis of the reactor vessel and not necessarily an analysis on the more pertinent pieces of equipment of the steam generator and the tubes.

MR. ROSSI: But this is a question really of a tech spec that affects, you know, that there is some time in which to go back to NRR or back to the Region and get an interpretation of it. It's not a tech spec. It has to be acted on like that?

MR. ROGERS: No.

MR. ROSSI: So even though it may be unclear, it doesn't create an immediate safety problem?

MR. ROGERS: Yeah.

MR. ROSSI: I think we are more interested in things that might cause the operator a problem during an event that might make the event worse than would otherwise be.

MR. BELL: The reason I asked about technical specifications is that if I read the specification correctly, there is some limit -- minimum feedwater temperature limit for using the main feedwater nozzles, and I was wondering if maybe that technical specification was in the minds of the operators when they made the decision to either go with auxiliary feedwater to the steam generator or startup feedwater to the steam generator.

MR. ROGERS: Yeah. There is another tech spec, and that one deals in using the main feedwater nozzles and it basically, it gives you only a maximum -- you have to be I believe it's greater than 110 degrees feedwater to the steam generator. It has to be greater than 110 degrees if you are greater than 235 pounds in the generator. I would almost like to refer -- is that a problem for me to break and just get the tech specs and

actually read that just for a second?

MR. ROSSI: Why don't we go off the record while he gets the tech specs.

(Discussion held off the record.)

MR. ROSSI: We'll go back on the record.

MR. ROGERS: Tech spec 3.7.2.1 states the temperature of the secondary coolant in the steam generator shall be greater than 110 degrees Fahrenheit when the pressure of the secondary coolant in the steam generator is greater than 237 psig.

I guess that was the one that I was kind of wondering about in terms of how this is applicable, if in fact they had injected via the startup feedpump CST water which is around 90 degrees through the main feedwater nozzles into the steam generator.

It's kind of a strange tech spec in that even though, I mean, like you actually end up sticking auxiliary feedwater into the steam generator during a steam feed rupture control actuation and that water is CST water also, I guess I have some wondering as to whether, you know, the words here are just quite what they want. You can read the

bases and I kind of doubt that, given the condition they are in, the bases really is -- it's appropriate at this time that this tech spec would be invoked.

MR. BELL: My point of asking you that question, do you think that the operators had that in mind when they were feeding the steam generators or they decided that either pump they could get in service to the steam generators would be good enough to provide plant cooling features?

MR. ROGERS: Well, I guess, No. 1, I'm going to take a best guess because I had not talked to the operators. I would guess that the technical specification itself probably was not in the back of their minds. My guess is that they and from what little I do understand, I think I know who the individual that was doing this --

MR. BELL: It was Mr. Feasel.

MR. ROGERS: Okay. That he is no dummy. He's a pretty smart cookie. I don't know if, No. 1, the valve to open to get on off of the deaerators is the closer valve. I'm sure, you know, that's one thing. Whether he also in the back of his mind knows at that point in time it's probably better

from a thermal shock standpoint to feed using the deaerators which is significantly higher, couple hundred degrees temperature higher into the steam generator at that time, I know that at least it's my perception then that it is pretty dangerous, that if it was a depressurized steam generator and they were trying to hit that cold water, that they could do some substantial damage to the generator itself.

But I would have to guess that even though he may have been going for the closest valve, it may be in the back of his mind he also was thinking that's the best thing for that generator at that time.

MR. BELL: Okay.

MR. ROGERS: But that is speculation and you all probably --

MR. BELL: I understand. And we will review the transcripts and see if we have any amplifying information. My final question has to do with the training that was provided to you by the NRC. Do you feel the NRC provided you adequate training in properly performing inspections and monitoring transients in modern plants?

MR. ROGERS: I think training and inspection, your training for the most part is training for systems. That's your formalized sit down across the table type training, your classroom training.

What you do to understand how to be an inspector is really -- it's more an apprentice program type thing, I think. That's my perception. You in the classroom, they can give you some basis of inspection, but to really do inspection and understand what you are doing, it is more an apprentice type deal.

In terms of transient behavior, I guess in one way I'm kind of -- I have had a lot more experience at this facility than other people. It this transient had happened to someone else who had not been here for a long time frame, I think that his assessment of the transient would have been probably fairly severely hampered. Transient analysis on this particular facility is not like any other facility. This is -- and I'm going to use some slang here. This is the raised loop plan, and it's probably the only raised loop plant that's probably ever going to get built of the 177 vintage.

The other plants are droop loops, so the design basis of the droop loop plan and the design basis of the raised loop plan are not the same because of the nature of things. It deals with the high fresh injection pumps, it deals with the capability and natural circulation here, it deals with the necessity to have the auxiliary feedpumps in what appears to be small break LOCA considerations that in other places you probably don't need. So in terms of really understanding that and trying to do what's going on in transient analysis against this facility or the Bellefont facility which I have been trained on in the simulator, it is rather -- there is some things there, but it would be greatly enhanced if you had site specific training.

MR. BELL: That's my questions.

MR. ROSSI: Wayne?

MR. LANNING: Do you know of any efforts by the licensee to improve the reliability of the auxiliary feedwater system?

MR. ROGERS: Yeah. In terms of what I think they have been doing, reading some of their FCRs. No. 1, they started out -- and I'm not talking so much just TMI auxiliary feedwater availability

study here. I'm going to kind of talk about all of this stuff and maybe not being able to tell you which one they are claiming for TMI and which ones they are not, take that into account.

The auxiliary feedpump governors around here, the original design wasn't too good, to put it politely. They went and they modified -- what they did is they took a governor that's normally run on air, they went to the manual speed knob and they took the knob off of it and they put a Bodine DC motor on it that would do the same thing that the air system would do. And that caused some problems. And then they --

MR. ROSSI: Who had that done? Was that through the vendor for the governor?

MR. ROGERS: That was the way it originally came. That's the way they designed it originally. I don't know if that was Bechtel or TECO or just who it was, but that's the way it came.

It wasn't exactly what I would call your run of the mill governor to start off with. They had some problems with it. So they took out part of the guts of the governor to make it respond a little bit better.

Well, part of the problem is it does a couple of things. One, it seems like the history is that the thing would hang up on his high speed and low speed stop because what is really happening with the auxiliary feedwater system is it's got a level control system in, but it's kind of sloppy in that what you are really doing is you are putting slug flow in. You don't have a nice constant flow of auxiliary feedwater to these generators.

Basically you have got it up on your high speed stops to start off with, so it feeds it till it gets to a certain level and then it cuts off and then it boils off, and then all of the sudden it feeds it so you keep slugging it in there.

Well, that puts a lot of movement on that governor so it's going from its high speed to its low speed stop back and forth and back and forth. And they have had instances where that roll pin will hang up either on its high speed or low speed stop inside the governor.

Also they got a clutch assembly that's a piece of plastic and some aluminum. I shouldn't -- it's a system by which there is a slip clutch in there, and that's what it is, it's a set of teeth

on the plastic and the aluminum couplings that also have some affect in here to work properly. If the slip clutch slips too early, then you don't get the signal from the Bodine motor to the governor to actually get it up to speed or back it back down. So once that slip clutch starts sliping in there, things go away.

Well, they had gotten the slip clutch problem it looks like taken care of. The history -- you got a fairly long history. These are the things they saw.

They went in, they have been doing for a couple of years now preventive maintenance on the slip clutch to make sure it is at the right torque. So they kept that up to speed. Then they went in and they finally just took one of their governors out because that was kind of long term. They eventually got around to do that, decided we would just get rid of these things. They threw -- well, they didn't throw away, they replaced one of them and they went to one of these hydraulic governors. They had some problems with that when they installed it.

They had the right size time delay

pushing in there, so they had to replace that and they got that taken care of. I wish I could have analyzed this one a little closer. Maybe you could help me out to tell me how did that hydraulic governor work at this time, but evidently there is some problem with this event. I think it hung up on its high speed stop and probably when they get inside, they are going to find that roll pin bent.

So with the governors there has been some problems. I guess you can say -- I don't think it's been terribly thrilling for this slug flow to the generator because here a couple years ago they found the auxiliary feedwater header deformed and I think they found this at Crystal and I want to say SMUD, and that was internal auxiliary feedwater headers. They were getting water into these headers and something was going on. I don't know if they even fully understand the dynamics and stress curves in there, that was actually deforming the headers. So they eventually pulled it out and now they have an external header. So that was a problem.

Also the limitorque valves haven't been -- and I'm not going to say it just was in the aux

feedwater system. There are probably a lot of problems industry wide here with the limitorques. I think seeing some of the information notices that we have been coming out with, the limitorque valves were a problem.

MR. ROSSI: The limitorque valves, that would apply to the 599, 608 valves; is that correct?

MR. ROGERS: That would apply to the MS 106, 106-A, 107, 107-A, 3872, 71, 70, 69, 599, 608, those valves were problems, or at least those valves are limitorque valves it's my understanding.

You are also talking it used to be, they don't seem to be a problem now, but the very first discharge valves on the pump, they are now set so they don't have to go open on the signal -- and it's like a 399 number, I think. I can't tell you right now what those numbers are. Anyhow, the limitorque valves there has been problems with.

So they ended up doing a Torrey Pines study. Torrey Pines is a consultant and they worked up a way in which they can evaluate, because what they originally got on torque switch settings was Bechtel had given them a one, like a one number. Well, that's one for opening and one for closing.

well, that's fine, only it's not really what you want. You want something a little different between opening and closing. So Torrey Pines went through and did a study and said, if you are having trouble with valves and the things don't seem to be working right, here is a way in which we will give you what we think is a good engineering judgment on where you ought to set your torque switches, but you got to couple that with your maintenance histories, you know. If you don't have trouble with the valve, don't use this thing, you know. There is no reason to fix something that doesn't need to be fixed.

So there has been problems with the limitorque valves which they -- we ended up writing them up in one of the SALP reports because they weren't keeping the management overview they should have at least I guess what I consider on that type study and getting them implemented, and they have since put the type of management attention appropriate to it and I think they have gotten at least all the safety related ones and I think almost all of the nonsafety related valves under the Torrey Pines study that they felt needed to be

implemented implemented.

MR. LANNING: Do you know if the Torrey Pines study included the opening of these valves when there is a large differential pressure across these valves?

MR. ROGERS: I don't think so. I'm not going to say that. I don't know. I just don't know so I'm not going to speak to it.

MR. LANNING: All right.

MR. ROSSI: To what extent had they tested like valves 599 and 608 for the hot conditions, you know, like cycled them and opened them again? Is that something they would do?

MR. ROGERS: I don't know of any time they have ever done them in a hot condition. As far as I know, they have only been tested -- a stroke time test done on them in a cold condition. Boy, I think they are even listed as passive in the IST testing. I can check that. I think they are passives. I don't think they can get a stroke signal when they are running.

MR. ROSSI: They are listed as passive because they are normally open and they are at the position where they would serve their safety

function?

MR. ROGERS: Yes.

MR. ROSSI: Never expected they would be cycled closed and have to open again?

MR. ROGERS: The analysis says they have got to be -- you know, if you look at the analysis, they would be cycled to close and then have to come open at some point.

MR. ROSSI: The analysis does say that?

MR. ROGERS: Well, the FSAR, that's the reason the system is built. It gets into SFRCS design.

See, if you get a steamline break, a big one, what will happen is you will actually depressurize both generators at the same time so everything basically goes down, bottles up, shut down, nothing happens. One of them repressurizes. When that one repressurizes, the two auxiliary feedpumps both feed that good generator that repressurizes.

MR. ROSSI: So for a real steamline break without the operator error that occurred here, for a real steamline break, 599 and 608 would be expected to close early in the transient and then reopen --

MR. ROGERS: One of them would reopen.

MR. SIMON: One of them would reopen. So you go through something not terribly different than what occurred in this transient?

MR. ROGERS: You are right.

MR. ROSSI: So those valves to serve their actual safety function under some events would have to have gone through the cycle that they did here?

MR. ROGERS: Yes.

MR. BELL: Is the close time critical on those valves following that steamline break? Because if it is, then there should be Section 11 testing on those valves to determine close times, shouldn't there?

MR. ROGERS: Well, I would think so. I also think that would be called out in tech specs too.

MR. BELL: If I remember technical specifications, they are so general, under spec 404 they have to test safety related equipment under the ASME Section 11 code.

MR. ROGERS: That's true. There is some words in tech specs -- and this gets to some other

things -- is that your response on the Steam and Feedwater Rupture Control system doesn't specifically call out response times for valves. What they do is they call out a response time in seconds for the auxiliary feedpump to be it says actuated equipment at less than 40 seconds. It says it has to be less than or equal to 40 seconds.

That means, or at least the real intent behind that is that the valves have to be open and the pump has to be up to the discharge pressure that is called out in the surveillance requirements for the auxiliary feedpumps, so those valves have to be opened in that time frame or they are normally opened, but they also have to go closed.

Now, the closing time I believe you will find is because they are containment isolation valves. But in terms of this other function, I don't think it's addressed in any technical specifications.

MR. ROSSI: Can you tell me whether they had a problem with either 599 or 608 during the event that occurred in March of 1984 where they had a stuck open safety valve and blew one steam generator dry during the recovery?

MR. ROGERS: It's my understanding I believe it was 599 that went closed and then they could not get it open pretty much. I think they had to get it open by hand crank, and I don't know if it was another instance where they had to crack it off the seat and limitorque would take care of it from there or whether they hand cranked it all the way open. That was -- to my best recollection, that was 599.

My understanding on the maintenance activity was that this was one of the things that brought to light the Torrey Pines study because that valve had been identified as one of the Torrey Pines valves and had not in fact had its torque switch settings changed. And it did, in fact, change the torque switch settings at that time under facility change request and then the valve stroked and was declared inoperable.

MR. ROSSI: We can check and find the details of that possible 599 problem during the March '84 event. That's something I guess that can be chased down.

MR. ROGERS: I know it is one of the two discharge valves and I'm pretty sure it's 599. But

I can have that checked.

MR. LANNING: It was.

MR. ROSSI: You know it was?

MR. LANNING: Yes, it was.

MR. ROSSI: Okay.

MR. LANNING: During your five years at this plant, have you identified any safety concerns associated -- potential safety concerns associated with the aux feedwater system?

MR. ROGERS: I think the governors are something that we have mentioned on occasion to them.

MR. LANNING: Mentioned how?

MR. ROGERS: I think it has come up in a couple of management meetings and in that respect it is an open item that I carry on the books still for the changeout of the governors.

The -- I'm trying to think if there is anything else that would be on that that would be documentation files. There may be something in the SALP report that says, I think maybe at least a plus that, hey, did you finally changeout one of the governors I think was maybe an example. I would have to check the SALP reports to be absolutely

certain of that.

The Torrey Pines study, I think you will find some words in -- that was carried as an open item by me in terms of implementation after the March 2nd event for them to make a timely resolution to it. And I followed that up, verified they did do it. Is that the type of thing you are talking about?

MR. LANNING: Yes. Besides having that as an open item in the inspection reports, did you communicate those concerns to other NRC offices?

MR. ROGERS: I have talked to Al DeAgazio about them.

MR. LANNING: He's the project manager for Davis-Besse?

MR. ROGERS: Yes. I showed him some drawings of them, this is what it looks like, it doesn't seem to be really doing its thing, to kind of help out. And his discussions, I think he's been -- I don't want to talk about what Al has been doing, but I think you can see some of the correspondence that has been trying to get this pump installed and I'm sure that's part of it. The reliability study talks about it and it's pretty

clear in the reliability study, I think that's part of the problem is governors and limitorque valves. I'm not going -- I am just drawing on memory right now on some of the conclusions on that reliability study.

MR. LANNING: Are you aware of an NRC requirement or any licensee initiated activities with regard to a third auxiliary feedwater pump?

MR. ROGERS: That's been subject of a lot of discussion over the years. I am aware of it. I know they originally wanted to try to upgrade the startup feedpump, the existing one down in No. 2's auxiliary feedpump room, and they wanted to do some work there, and that eventually was considered not viable. And then it was a question, well, let's go to a third nonsafety grade -- basically a pump that has the same capacity as an auxiliary feedpump, and that was pretty much what was decided to be done, you know, this next out, something along those lines.

MR. LANNING: Is this an NRC requirement for the third pump?

MR. ROGERS: No. It's not an NR -- it's not a requirement of law it's my understanding

originally. I think it is a condition of the license now and now it's an NRC requirement. But I have to check that to be sure that it is now part of the license, but I believe it is a part of the license.

MR. LANNING: If it's part of the license, it makes it a requirement.

MR. ROGERS: Yes. Originally, I'm saying. I think it is a part of the license now and is now a requirement. I think that it was, you know, they originally discussed and decided this is what we will do and then it wasn't a requirement then. They said, okay, that's what you are going to do, it's a requirement for you to do it now.

MR. ROSSI: By a certain time.

MR. ROGERS: By a certain time.

MR. LANNING: And what is that time frame?

MR. ROGERS: I believe it's this next refueling outage.

MR. BEARD: Can I interject, Wayne, do you have any remembrance of when that licensed condition was established, roughly?

MR. ROGERS: I can go back and pull that -- I am pretty sure it's a licensed condition and I

can have that verified.

MR. BEARD: I think you are right on that point. I'm just wondering if it was established six months ago, a year ago, four years ago. I'm not trying to pin you down.

MR. ROGERS: We are talking less than a year.

MR. BEARD: It isn't last year when the licensed condition was established?

MR. ROGERS: Yes. It's one of the more recent licensed conditions. In fact, it's about the only licensed condition, because you don't get many licensed conditions at this stage of a facility. It's very rare, in fact.

MR. ROSSI: I wanted to ask a question about human factors, problems that may have been identified with three things. One of them is steam generator level indicators and recorders in the control room, another is steam generator pressure indicators and lack of recorders I guess in the control room, and the third one would be SFRCS manual actuation buttons. Could you just tell us whether you know of human factors, problems in control room reviews with any or all of those three

items?

MR. ROGERS: Well, I guess my main thing -- I'm going to talk just previous to reading over the human factors study or portions of it in the last couple of days -- I do know it's a high level thing on the SFRCS push buttons to get them changed so they are not cater-corner.

MR. ROSSI: That was the change, make it so they are not cater-corner?

MR. ROGERS: Right.

MR. ROSSI: Not make it so the level is more distinguishable from the pressure?

MR. ROGERS: That's true. As far as I know, that's the high level thing is to just get the push buttons switch set up so they are one and one and two and two.

Really, my biggest perception is the operations people have always had a real problem with SFRCS from the standpoint it's so spread out in the control room. They have -- basically you got the pumps on the front panel, you have got what I'm going to call the four digit discharge valves on the front panel to get control -- I mean, the valves -- the main feedwater block valves and those

type valves are on the back panel and the SFAS panel, and then the manual push buttons are on the other side of the control room on the back panel, so -- and then the startup level is really on your steam generator and your turbine panel.

So it's all just spread out all over the place. And I know they have been wanting to get SFRCS kind of as a schematic like the ECCS is so they can have a better understanding of the whole system. That seems to be the thing. I'm not going to say I know every little detail of these particular things, other than I knew there was a general discontent with SFRCS as a whole.

MR. BEARD: Was the SFRCS system part of the original plant design or was it added some point in the design process?

MR. ROGERS: It was added at some point in the design process, but it was a part of the design prior to the plant being licensed in terms of its operating license. What happened was the high energy break letter came out that talks about having to protect -- you have got to protect against a pipe break in a high energy line, irregardless of its position in the plant. So

anything in the auxiliary building or in the turbine building to a certain extent has got to be protected against a high energy line break. And when that came out, that brought SFRCS, it's my understanding, into being.

And that is pretty much where it got its roots, which I think is probably in the '74-75 time frame versus the other stuff that was probably in the '69 and '70 vintages, early '70 vintages.

MR. ROSSI: Before we leave that, I still wanted to know about any human factors problems that you knew of that had been identified with steam generator level indicators or recorders or steam generator pressure indicators?

MR. ROGERS: Not as specific items.

MR. ROSSI: Okay.

MR. LANNING: Is this a human factor study that was performed by the licensee?

MR. ROGERS: Yes. I believe so. If it is not by the licensee -- I think it is the licensee. I do not know if there were or are any consultants involved at this point. But it is the licensee's study.

MR. LANNING: Do you know if there has

been a report on the results of the study?

MR. ROGERS: Well, there is a couple of volumes that talk about it in terms of we just had NRR I think it was or someone -- I shouldn't say it was NRR, but someone came out from Washington to take a look at that study and see how things were going. It's a TMI item and has a certain time frame associated with it, and if you look at the correspondence between NRR, on it will give you a much more detailed history on when some of this stuff has to be done.

MR. BEARD: But is it correct that the human factors efficiency was the criss-cross on the high pressure side of the thing as contrasted to the location of all the switches or the indication of the low level switches?

MR. ROGERS: I think there are a lot of things on SFRCS that are indicated on the human factor study. One that was high was the position of the switches. I think there are other things in the human factor study which discuss the other specific items of SFRCS. I can get copies of it.

MR. BEARD: That's not necessary.

MR. ROGERS: That's just my perception.

I may be totally off base on what all that -- the high level portion of that is.

MR. ROSSI: Well, if the operator had pushed the correct low pressure combination of SFRCS, in other words, if he pushed the buttons cater-corner rather than right across, or rather if I can put it another way, if the human factors problem had been corrected so the top two buttons are what is now cater-corner, then that change would not have isolated both steam generators. Is that your understanding?

MR. ROGERS: Okay. Let me just think for a second what you are doing. Let's just pick one. You would be telling both actuation channels that steam generator No. 1 is bad. It would not have isolated both steam generators, that is correct. No. 2 generator then would have been fed from both auxiliary feedpumps.

MR. ROSSI: Okay.

MR. ROGERS: Looking at all this, it's apparent that if there had been indication, if the guy had already known that SFRCS was gone, he probably would never have pressed buttons in the first place.

MR. ROSSI: Or if he pushed even the correct combination of pressure buttons, at least he would have gotten water to one of the steam generators except for the fact that the pump also failed?

MR. ROGERS: Yeah.

MR. ROSSI: The valves would have been aligned.

MR. ROSSI: The valves would have been aligned so that one steam generator would have gotten flow, but with the pump failures you still would have gotten flow to the other steam generator?

MR. ROGERS: That's correct.

MR. LANNING: Have you identified any potential safety concerns associated with the SFRCS?

MR. ROGERS: I don't know -- well, the potential safety concern, I got some questions about SFRCS in terms of the main steam isolation valve. That is something that I've talked about even with some of the individuals prior to you becoming part of the Fact Finding Team in some conference calls dealing with the Main Steam Isolation Valves gives a signal to close -- this gets rather complicated.

Basically the Main Steam Isolation Valves can get a signal to close from one of two safety systems, SFAS, there is a containment isolation valve under that function, or under SFRCS. And what you have got up there are five solenoid files that control the air to the valve, and it would really help to show you some drawings, but basically if you get A and B solenoid deenergized, you will shut the valve. If you get C, D and E solenoid, you will shut the valve.

And if you get A and E, you won't do anything. It has got to be these particular combinations. And the thing is the way the testing sequence is on it, they would test it in such a manner that all five solenoids get a closed signal at the same time. So, boom, all five. So you don't know whether A and B or C, D and E get closed; okay?

Now, they have done some testing and they have been able in their surveillance test, it just happens -- it's one of those it just happens to be the way that they can show the A and B solenoids will close the valves with the C, D and E energized. It deals with their ASME testing and the push

button and what the SFAS portion would do. However they have yet to show me the C, D, and E solenoid in and of themselves will close the valve.

Now, this gets into a question of design and what is legal and what is not legal -- or I shouldn't say so much legal, but what was the original intent behind the LER that was written in terms of the MSIVs and whether you had to have the C, D and E solenoids to deenergize to close the valves. It's very complicated in terms of the way you get there, but basically I had pointed this out to the licensee and they have acceded to testing the C, D and E solenoids exclusively and have written a procedure to do that.

I cannot say that it is at this point in time a violation of the regulations or the requirements associated with testing, but at least from a prudent engineering judgment call, it is prudent to test those three solenoids to close the valve.

MR. LANNING: So it sounds like your concern was not a failure of the system so much as it was a testing of a part of the system to insure its function?

MR. ROGERS: That's true. In terms of the testing frequency -- I mean, of what you are testing up there. Now, this also goes to the startup feed valves also because you get yourself in a consideration of what the design was.

See, in tech specs you are taking credit for the main feedwater control valves, the startup feedwater valves, and the block valve which are not necessarily in the turbine building -- I mean, not in the auxiliary building. They are in the turbine building. And it took me a couple of months to figure out what you can have and where you can have on the high energy break spectrum and it looks like it's okay, but these valves are, quote-unquote, not in the Q boundary, but they are tech spec valves and as such they have to be tested and assured okay and you have got to make sure that the quality of the maintenance of them are okay. But it gets into the design of them, could you take a credit for these, and I think I resolved that in my mind.

MR. LANNING: At this point in time, does the issue that you have raised concerning the MSIVs, have anything to do with this event that you are aware of?

MR. ROGERS: I cannot say concretely that it does have anything to do with it for the simple fact that they have not performed trouble-shooting on the MSIVs. I am not at this point in time satisfied as to -- the explanation yet is I think the licensee agrees -- they did yesterday when we talked or whenever it was -- on the SOE about what actually closed the Main Steam Isolation Valves. Until they get in there and people see what exactly happened, I'm not going to say yea or nay on whether this has anything to do with it.

MR. BEARD: Can I ask one --

MR. LANNING: Let me finish mine. Was inadvertent closure of the MSIV part of your concern?

MR. ROGERS: Actually it's more the MSIVs not closing I think is probably my biggest safety concern.

MR. BEARD: That was the question I was going to raise.

MR. LANNING: About what period of time or how long ago did you initiate this conversation with the licensee?

MR. ROGERS: About I'm going to try to

say a month ago. Is that about the right time?

MR. BEARD: That's my remembrance is about a month ago.

MR. ROGERS: A month ago. I think I've been away from the site and it was a couple of weeks before I left the site.

MR. ROSSI: Can we go off the record.

(Discussion held off the record.)

MR. ROSSI: Why don't we go back on the record. JT, why don't you go ahead and ask your questions.

MR. BEARD: Walt, I realize we can talk about this for hours and hours and hours, but I would like to ask you some questions about your knowledge and experience at the plant, how some of the key pieces of equipment are performed just in a short synopsis. Are you aware of any history or knowledge of spurious actuations, either half trips or full trips of the Steam and Feedwater Rupture Control System in the recent past?

MR. ROGERS: Yes.

MR. BEARD: Would you say the frequency of these is very frequent, rare, how would you classify this?

MR. ROGERS: In the last -- since they started up from this refueling outage, I have seen at least two and looks like maybe this time also, maybe three spurious half trips of SFRCS looking like as a result of the post-trip response of the facility.

MR. BEARD: You say since the last outage, can you give me a month, how long are we talking about?

MR. ROGERS: December of this year, January 1st, somewhere around that time.

MR. BEARD: We are talking about six months?

MR. ROGERS: The last six months.

MR. BEARD: Would you consider that an extraordinary amount, typical amount, or when you talk to the guys from the other B & W plants unusual or how would you classify it?

MR. ROGERS: You can't really talk to the other B & W units or anybody else about SFRCS because these are the only people that have got this animal.

MR. BEARD: I understand, but they have an analogous system. It may be called a SLBIC or

some other name, but they have a system.

MR. ROGERS: But it's nowhere near the complicated nature. It's very hard to compare. From what I can see, though, I don't think these people get that much spurious problems.

MR. ROSSI: These people being the other people?

MR. ROGERS: Yeah, the other plants.

MR. ROSSI: So you are saying Davis-Besse in your belief has more spurious problems than other plants would have?

MR. ROGERS: I think that would be my guess.

MR. BEARD: I guess one other thing if I hear you I judge to be significant in your opinion is that Steam Feed Rupture Control System is a very complex system?

MR. ROGERS: Extremely complex.

MR. BEARD: Let me change to the second question, basically the same type of question. Do you have any knowledge in the recent past of overspeed trip problems on the aux speed water turbines?

MR. ROGERS: No recent knowledge of any

overspeed problems. The only time I can remember they lost a trip throttle valve was a while back and it wasn't an overspeed problem. It was --

MR. BELL: Latch?

MR. ROGERS: A latch problem. Trip throttle valve latch problem.

MR. BEARD: I gather from what I remember the general tone of some earlier discussions, they had had governor problems but none -- that was more of a control nature than an overspeed I gather?

MR. ROGERS: Yeah. The overspeed, when it locked up on its overspeed stop or high speed stop, it still wouldn't trip out on overspeed.

MR. BEARD: This is my last question. I have got a very general question. When we and NRR try to require something of a licensee, we realize that we may not know the plant as well as the licensee and the options that may be available for working the problems through some alternatives, so we put in typically a statement that says this is what we think we want or suitable alternative as you may propose.

And my question is in this effort to try to provide flexibility and not overregulate, do you

think this has allowed maybe too much room for delays and circumvention of the intent, just a token addressing of the intent?

MR. ROGERS: I think it depends upon the utility.

MR. BEARD: Well, let's talk about this utility. You have been here a pretty good number of years.

MR. ROGERS: I think if you look at some of the big changes, you say -- well, I guess I have a little frustration on why it took so long to get the new auxiliary feedpump governor in. That's not so much something NRR would see, but I think a judgment on what you are saying is going to be made almost in the public domain with regard to the startup feedpump, and that will be the real telltale on that.

MR. BEARD: That may be and you may choose not to answer. I'm just curious from your perspective, the eyes and ears of the agency at Davis-Besse, do you have an opinion you would like to express?

MR. ROGERS: In terms of like the TMI mods, they seem to move in a fairly -- from what I

understand on a lot of the other units, they were very quick in getting their modifications in. In that respect, almost some of the other bigger problems, it seems like they haven't moved in the speed they probably could have, but it may be just that they were moving on these other things that caused them some problems. It's hard to judge, to be really honest.

MR. BEARD: Okay. That's -- I had some other questions about the operational experience on the Rupture Control System, but I understand we are going to have a discussion on that as a separate item just to get me better educated on the local design here, so I won't bring those up at this time.

MR. ROSSI: Okay. Then why don't we end the interview then.

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Thereupon, the interview was concluded at 3:10 o'clock p.m.

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CERTIFICATE

I, Nicholas Marrone, a Registered Professional Reporter and Notary Public in and for the State of Ohio, do hereby certify that I took the aforementioned interview and that the foregoing transcript of such proceedings is a full, true and correct transcript of my stenotypy notes as so taken.

I do further certify that I was called there in the capacity of a Registered Professional Reporter, and am not otherwise interested in this proceeding.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal of office at Columbus, Ohio, on this 22nd day of June, 1985.

Nicholas A. Marrone

NICHOLAS A. MARRONE, Registered Professional Reporter, Notary Public in and for the State of Ohio.

My Commission expires November 1, 1987.

DIRECTIONS FOR MAKING CORRECTIONS

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Page	Line	Correction or change and reason therefor

Page No. _____ DATE _____ SIGNATURE _____

Page	Line	Correction or change and reason therefor
5	24	add 'room" after touus for clarification
4	12	delete "secretaiial staff part time" for clarification
7	21	add "and" in front of the for clarification
9	3	Δ "that way" to "mine to them". for clarification
9	10	to tech Δ to "technical specification violation"
9	18	after of add "management action" and delete
		"you know" for clarification
9	21	Δ he to "the shift supervisor" for clarification
9	24	Delete "hey" for clarification
10	16	Δ we to "I" for proper sentence structure
10	21	Δ hey to "stating" for clarification
11	1	add "by" in front of talking for clarification

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