INDEPENDENT DESIGN REVIEW

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Before the

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I N D E X

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8:05 a.m.

MR. ALLEN: The first thing we will start off this morning with is we will ask Bechtel to report on the open items they were able to resolve last night and then we will get into the subject matter. Hopefully, we will be done by noon.

MR. BINGHAM: Dennis, would you go over the open items we want to answer at this time?

MR. KEITH: Yes. The first one that we were asked was the criteria for routing of the sensing lines for instruments that were concerned with the high-energy line break. We have done extensive high-energy line break analysis. It has been particularly related to piping and large components. We are now in the process of performing that analysis as related to instrument lines, conduit. Those are the two key things, instrument lines and conduit, the things which get routed last. We will be applying the same criteria to the instrument lines and the conduit that we apply to the rest of the analysis, and that is if a system is required to mitigate the accident, then we can not lose redundancy. If it is required for other safety concerns, then we can lose redundancy, but not lose function. Interpreting that for our instrument lines, since we have four of them, for those

1 lines which are required to mitigate the accident and bring
2 the plant to a safe shutdown, we will allow a loss of one
3 of the four of those instrument lines. Then for the systems
4 that are safety systems and can't lose redundancy, we will
5 allow the loss of two of the four of those instrument lines.
6 Those are our criteria.
7 MR. ALLEN: Any questions from the Board on the
8 response?
9 Any questions from the NRC?
10 MR. ROSENTHAL: At some point in the plant, you may
11 have to bring impulse lines fairly close together, in which
12 case I assume that you will put them in raceways of some sort.
13 MR. KEITH: We will have to do something to protect
14 them, you know, put things that are considered a barrier in
15 front of them or a guard pipe around the break.
16 MR. ROSENTHAL: Have you reached conclusions about
17 that yet?
18 MR. KEITH: We have not completed that analysis and we
19 have not implemented any design for that.
20 The concern was raised on MSIV testing. We do
21 have a test switch on our main steam isolation valves on
22 the main control boards in the main control room, and going
23 to test, we will stroke the valves 10%, so we can do that
24 at power.
25 MR. ROGERS: That was my question. I had asked that

1 with regard to the main steam isolation system and whether
2 that met the criteria that were listed in 2A1. That also
3 applied to the auxiliary feedwater system and containment
4 isolation system, Dennis. Specifically, Dennis, Figure 2A-1
5 gives a list of what is called on that figure balance of
6 plant systems. Section 2.A.1. does not include discussions on
7 several of the systems listed. We were wondering where
8 those systems would be discussed criteria-wise and test-wise.
9 MR. KEITH: We just addressed main steam isolation.
10 MR. ROGERS: Yes, that was one of them, and I used
11 that as an example because later on, and I have lost the
12 reference for the exhibit, but someplace you have indicated
13 that for the balance of plant systems, you can test them all
14 on line, and I was concerned as to whether the main steam
15 isolation system could be tested on line, and I hear your
16 answer. You are saying that you only stroke the valve 10%;
17 therefore, the test can be conducted on line I assume
18 without lowering the output mode of the plant or disrupting
19 normal plant operation. I am also wondering whether that
20 applies to the auxiliary feedwater system, whether that can
21 be tested or how it is tested on line or off line, and
22 containment isolation. Those may have been addressed at
23 another system review.
24 MR. KEITH: Yes, you have hit it exactly. Containment
25 isolation was hit at the last IDR. Auxiliary feedwater was

1 hit at an earlier IDR for testing of that. Then containment
2 combustible gas control was discussed at the last IDR.
3 MR. ROGERS: Well, you discussed containment combustible
4 gas control at this IDR and the design criteria and the
5 testing was considered I believe during the discussion of
6 2.A.
7 MR. KEITH: Well, the logic as I recall. I think so
8 far as the testing of the system itself, that was discussed
9 at the last IDR.
10 MR. ROGERS: Right. What I am saying is where are the
11 logic for these other balance of plant systems considered?
12 Are they considered in this IDR or are they considered
13 someplace else, and the evident one was the main steam
14 isolation. You have answered at least part of the question.
15 I think you might want to put up Exhibit 2A1-24.
16 MR. KEITH: The sensor checks, the trip bistable test?
17 MR. ROGERS: No, that is not the first paragraph.
18 Actuation of the ESF systems controlled by the one-out-of-two
19 ESFAS does not disturb normal plant operating conditions.
20 This is all listed under balance of plant Engineered Safety
21 Features Actuation System. I believe we are talking about
22 the systems listed under BOP over on the right-hand side.
23 MRS. MORETON: We are talking about the first bullet.
24 MR. ROGERS: The first bullet there, but not the rest
25 of them.

1 MR. KEITH: That's correct.

2 MR. ROGERS: Where are the rest of them covered?

3 MR. KEITH: Carter, what has been listed here and
4 what is really discussed at this IDR is the actuation system,
5 this first bullet, as Mary just pointed out. These others
6 are balance of plant ESF systems and testing of those is
7 really part of a separate subject. I think that is what
8 has confused me for a minute here. In the case of contain-
9 ment isolation, auxiliary feedwater, and containment
10 combustible gas control, those systems have all been
11 discussed at previous IDR's. I think, let's see, containment
12 purge isolation was also discussed at the last IDR. The
13 other items we do not have scheduled to discuss at an IDR,
14 but they will be reviewed at least in terms of the NRC in
15 terms of a working meeting or however. Those are the systems
16 themselves, and in this review, from here down (indicating),
17 we are talking about the ESF systems themselves, but this
18 review is really to cover the actuation systems. I think
19 that is where the confusion has arisen.

20 MR. KOPCHINSKI: Is that closed?

21 MR. ROGERS: Let's continue on. I want to think about
22 that a little bit. If I have a problem with that, I will
23 get back to you.

24 MR. BESSETTE: Maybe I can shed a little light on
25 this. The MSIS, the aux feedwater, containment isolation

1 signal, the logic for that is developed in the RPS and it
2 is tested and was discussed at the last IDR about the RPS
3 testing scheme. I think, Carter, if I understand, your
4 question is once you get past the actuation relay where we
5 provide you with a contact closure of MSIV, can you test
6 during operation the circuitry from the point of actuation
7 relay downstream to the motor controllers, valve operators,
8 whatever, downstream of the actuation relays in the reactor
9 protection system. If you say you have a manual switch on
10 the MSIV's for 10% stroke, then is that switch that goes
11 into the motor controller an actual portion of the circuitry
12 or does that in fact have some input signals downstream so
13 that I have a complete test of the actuated device circuitry?
14 I think that is the scope of your question.
15 MR. ROGERS: Bernie, you are getting at what I am
16 concerned about and presenting it in a much better way than
17 I can ask. I think that we ought to proceed on that particular
18 line.
19 MR. HELMAN: You mentioned a test switch. Does this
20 test switch go into the specific logic of the MSIS or does
21 the test switch go into the specific logic of the motor
22 control center for the valve?
23 MRS. MORETON: The exercise switch on the main control
24 board for the main steam isolation valves goes into the
25 main steam isolation valve logic, but it does not simulate an

1 MSIS. It is simply an exercise to lift the valve off its
2 seat and close 10%.
3 MR. HELMAN: Is this typical of the other ESFAS
4 testing devices?
5 MRS. MORETON: No, that is unique for the MSIV's.
6 MR. HELMAN: So in the other devices that are tested
7 during their specific ESFAS channel, they are tested during
8 the time the ESFAS channel is tested, which is manually
9 simulated by pressing a test button.
10 MR. KEITH: If we can talk about, say, the LPSI pump,
11 you do channel checks, you do logic checks, which you do
12 without ever starting the component. I think I will defer
13 to APS Operations as far as when they line up the system.
14 You have to open the bypass valve, since you are not actually
15 going to be injecting into the reactor coolant system when
16 you test the pump. When they do that, whether they actually
17 press a button to simulate an SIAS, I don't know just what
18 is done as far as the testing on those pumps, but there is
19 a required frequency of testing the pumps and the valves that
20 is all supplied in ASME Section 11 and really part of a
21 separate review, but if you want to get into that here --
22 MR. HELMAN: No, I understand. The question is based
23 on do you test the continuity, shall we say, between the
24 ESFAS actuated relay that Combustion provides and the
25 actuated device?

1 MR. KEITH: I guess it would be our understanding that
2 would be how it would be tested. In order to get that part
3 of the circuit when you are testing the pump, you should
4 simulate an SIAS and, therefore, check that part of the
5 circuit.
6 MRS. MORETON: On the NSSS ESFAS cabinet, which is
7 where these signals are coming from that actuate, even though
8 they are BOP ESF systems, they are actuated by NSSS ESFAS,
9 there are test relays and you can individually test by
10 dropping out contacts on an individual relay to test a pump
11 or a valve or a collective group of valves.
12 MR. HELMAN: Simultaneously when you test the ESFAS
13 channel?
14 MRS. MORETON: The testing of the NSSS ESFAS, which
15 was discussed at the CESSAR IDR, is an overlapping piece-wise
16 test. It is up to Operations if it is simultaneous or not.
17 MR. ALLEN: Does the Board feel that Bechtel should
18 take an open item to dwell a little bit more deeply into the
19 testing of these systems or reference where they are discussed?
20 MR. MINNICKS: I think so, John. I don't know that
21 Carter's question has ever been adequately answered whether
22 these systems are designed to be tested at power. I think
23 that was Carter's question. In other words, CE has designed
24 a system to test the logic up to the actuating relay. Now
25 we are concerned with from the actuating relay contact out

1 to the device itself, is that portion of the system designed
2 to be tested at power as our criterion says it is?
3 MRS. MORETON: The criterion you are reading is for
4 the one-out-of-two ESFAS that controls selected balance of
5 plant ESF systems. The fuel building essential ventilation,
6 control room essential ventilation, containment purge
7 isolation, and containment combustible gas control (manual),
8 that criterion is met.
9 MR. HELMAN: But you also stated interface criteria,
10 that the ESFAS systems meet the CESSAR design criteria as
11 an interface. Was that one of the ones that was in the
12 first few exhibits?
13 MRS. MORETON: Yes, we meet the CESSAR interface
14 test.
15 MR. ROGERS: John, I think it is appropriate that we
16 take an open item here and just list as the open item where
17 the complete system criteria are discussed. I am not
18 particularly hung up in the idea that you have to test all
19 of these systems at power, but I think it is important that
20 we know when each system can be tested completely, and
21 especially those systems that are partly Combustion and
22 partly designed by Bechtel, that we are sure of the interface
23 and we are sure that we can test that interface at an
24 appropriate time. I would like to see the list on the
25 figure, just a listing next to that as to where the testing

1 requirements are discussed in an IDR or in the FSAR. I
2 think you are covered, but I am still a little unclear as
3 to how to draw the complete line on the steam line isolation
4 signal, how that complete line is tested. Am I clear,
5 Dennis?
6 MR. KEITH: I guess I can relate it a little bit
7 better if we relate it to Norm's concern, mainly that for
8 the balance of plant ESF systems, which are primarily the
9 ventilation systems, those we can test at power.
10 MR. ROGERS: Yes, there is no problem there.
11 MR. HELMAN: What I am more concerned about is the
12 NSSS systems that are actuated by the NSSS ESFAS and how
13 do we get from the actuation relay to the device in the
14 MSIV area, also?
15 MR. KEITH: That falls into that, yes.
16 MR. HELMAN: I understand from you that you have a
17 test switch on the Combustion-supplied ESFAS box, module,
18 whatever, that will provide a contact that goes directly to
19 the specific actuated device for closing or opening or
20 starting or stopping in the test mode. Is that what I heard
21 you say?
22 MRS. MORETON: That is correct.
23 MR. HELMAN: But in the balance of plant, this is not
24 so. Is that what I am hearing?
25 MRS. MORETON: In the balance of plant, testing is

1 done by complete system actuation unlike the NSSS ESFAS where
2 testing is done in an overlapping piece-wise test.
3 MR. HELMAN: But it is unique to test the MSIV's?
4 MRS. MORETON: The MSIV's are unique, yes.
5 MR. HELMAN: With this little pushbutton that doesn't
6 test continuity of the circuit.
7 MRS. MORETON: Right.
8 MR. STERLING: In the CESSAR IDR, they went through
9 an extensive review of the testing features on their correc-
10 tion system and the ESFAS, and so forth, and when you are
11 running at power, you test your actuation systems and you
12 are in bypass, since you don't actuate your final piece of
13 equipment. When you are in shutdown, periodically you do
14 go in and you test the complete circuit. I think maybe it
15 should be tempered with that. Your response should be
16 tempered by that facility in that requirement that CE places.
17 MR. KEITH: That is what we basically stated was done
18 about 10 or 15 minutes ago, but I guess, Carter, now the
19 question is to just tie the two together on where this is
20 all covered.
21 MR. ROGERS: Yes. On Exhibit 2A1-27, you start with
22 a list of actuated systems and those systems are at least
23 part of the listing of systems on Figure 2A-1. Just to
24 restate what I said a few times, where are the missing systems
25 covered?

1 MR. BESSETTE: May I add a little more clarity to
2 it? I think the piece that is missing in this discussion
3 is the function of the auxiliary relay cabinet and the group
4 relay assignments of components to certain actuated relays.
5 What I am not familiar with is the actual testing scheme,
6 and I think we need to leave this open just to prove this
7 out. There are components assigned certain actuated relays
8 so that you can actuate valves without pumps running and
9 actuate pumps without valves open by the nature of the
10 assignment of components to these actuation relays, and this
11 I believe can be done at power. But, again, I think that
12 we ought to just verify that, which I think will answer your
13 question. We go from our actuation relay to the ECF actuation
14 relay cabinet where the components are assigned to group
15 relays and then that does permit the actuation of components
16 and starting pumps without completely actuating the train
17 by a partial actuation. Then there is overlap there.
18 MR. HELMAN: So during the channel test, you are
19 actually not energizing the group relay?
20 MR. BESSETTE: No.
21 MR. HELMAN: You are just bypassing at that point and
22 testing the upstream portion, is that correct?
23 MR. BESSETTE: I believe that's correct. I think
24 the balance of that is a manual test for the group relay
25 test, but we should verify that.

MR. ALLEN: Do you understand the open item now?

MR. KEITH: Yes.

MR. ALLEN: Do you have another one you want to close out?

MR. KEITH: The next concern that was brought up was missile protection of the control room outside air intake, the concern being specifically the sensors that we have in the control room air intake. We have two intakes for the control ventilation system. They are located on either side of the control building and these intakes join together. The air comes in horizontally and then the intakes join together into a vertical chase and then all the instruments are located in the vertial chase, so it is highly unlikely that a missile could affect the instruments, since they are in a vertical chase and there is a long horizontal run before we get to the vertical chase.

MR. BARNOSKI: Does that mean you are providing line-of-sight protection?

MR. KEITH: Yes.

MR. ALLEN: That was my question. I am satisfied on that.

MR. KEITH: A question was brought up whether the safety injection tank interlocks receive a signal from the same sensors as the Class IE alarm system which we discussed yesterday, and they do.

1 That's all we have to close out.

2 MR. ALLEN: Are there any further questions on these

3 open items?

4 If not, Bill, why don't you go ahead with your

5 presentation?

6 MR. BINGHAM: Let's continue then with Section 3.A,

7 Compliance With Regulatory Requirements, the SRP's.

8 MRS. MORETON: Figure 3-1 provides a summary of the

9 regulatory requirements that will be discussed, regulatory

10 requirements that come from Standard Review Plans 7.1

11 through 7.7, Rev. 1, through General Design Criteria,

12 Regulatory Guides, IEEE Standards, and Branch Technical

13 Positions defined per SRP Table 7-1, which defines the

14 applicable criteria, guides, standards, and positions for

15 the subsystems discussed in 7.2 through 7.7. We will also

16 be addressing the I&E Bulletins, Circulars, and Information

17 Notices and compliance with NUREG-0737.

18 Starting with Standard Review Plans, Figure 3A-1,

19 Standard Review Plan 7.1 does provide a Compliance Table

20 7-1, which defines the applicable criteria for the Engineered

21 Safety Features Systems as defined in SRP 7.3, safe shutdown

22 systems as defined in SRP 7.4, safety-related display

23 instrumentation as defined in SRP 7.5, and all other safety-

24 related instrumentation per SRP 7.6, and the nonsafety-

25 related control systems per SRP 7.7. We will be discussing

compliance with the NSSS requirements per SRP 7.2 as well as all the other sections and compliance as applicable to the balance of plant systems.

Exhibit 3A-1. SRP Section 7.3, SRP Acceptance Criteria. The requirement is to meet the General Design Criteria and IEEE 279. In compliance.

Exhibit 3A-2, SRP Section 7.4, redundancy required per GDC 26, 33, and 34 and IEEE Standard 279. In compliance.

Conformance with the single failure criterion as defined in IEEE 279, 379, and Reg. Guide 1.53. In compliance.

Exhibit 3A-3, identification of cables, cable trays, and instrument panels as defined in Reg. Guide 1.75. In compliance.

Vital supporting systems required for safe shutdown should meet the same acceptance criteria as for the systems they support. In compliance.

Exhibit 3A-4, continuing with the SRP 7.4 criteria. System testing, quality assurance, and surveillance in accordance with GDC 1 and 21, IEEE Standard 279, 336, and Reg. Guides 1.22, 1.47, and 1.68. In compliance.

Exhibit 3A-5, SRP Section 7.5. The safety-related display instrumentation should cover appropriate variables consistent with the assumptions for accident analyses and with the information needs of the operator and shall meet Reg. Guide 1.97. In compliance.

All monitoring channels should be redundant to assure that wrong indication due to device malfunction will not cause false action. In compliance.

Exhibit 3A-6, continuing with SRP 7.5. Requirement: Redundant channels of safety-related display instrumentation should be isolated physically and electrically to comply with single failure criteria. In compliance.

Exhibit 3A-7, continuing with SRP 7.5 criteria. Capability should be provided for checking. In compliance.

Exhibit 3A-8, SRP 7.5 continued. An indication system should be provided to cover bypass or deliberately inoperable conditions per Reg. Guide 1.47 and Branch Technical Position ICSB 21. In compliance.

Cables, cable trays, components, modules, and interconnecting wiring shall be identified per Reg. Guide 1.75. In compliance.

Components and modules shall be of a quality consistent with reliability requirements for safety-related systems. In compliance.

Exhibit 3A-9, continuing with SRP 7.5 criteria. In order to assure that the requirements of GDC 1 are met, the quality assurance program must satisfy the requirements of IEEE 336 and Reg. Guide 1.30. In compliance.

Exhibit 3A-10, SRP requirement as stated in 7.6, system redundancy shall meet General Design Criteria 26 and

33 and IEEE Standard 279. In compliance.

Exhibit 3A-11, conformance with the single failure criterion shall meet IEEE Standard 279, 379, and Reg. Guide 1.53. In compliance.

Identification of cables and raceways per Reg. Guide 1.75. In compliance.

Exhibit 3A-12, continuing with SRP 7.6. Requirement for vital supporting systems. In compliance.

Testing, quality assurance, and system availability surveillance per GDC 1 and 21, IEEE standards 279, 336, and 338, and Regulatory Guides 1.22, 1.47, 1.68, and 1.118. In compliance.

Exhibit 3A-13 provides the SRP requirement stated in Section 7.7, conformance with GDC 13 for instrumentation and control systems. In compliance.

Conformance with GDC 24 for separation of control systems from protection systems. In compliance.

Exhibit 3A-14, SRP Section 7.7 continued. Conformance to IEEE Standard 279, Section 4.7, for control and protection system interaction. In compliance.

Exhibit 3A-15 provides a key to the acceptance criteria. We will be going through all of Table 7-1 for compliance. The tables have been annotated to identify the applicable sections as defined in 7.1. If they are not applicable in 7.1, they are keyed in the table as not

1 applicable. In compliance, with clarification or without
2 clarification, is noted by a C. If the item is totally
3 within CESSAR scope, it is noted by NSSS. If it is a CESSAR
4 interface requirement, if PVNGS is in compliance, it is
5 noted with an I. If it is both a CESSAR interface require-
6 ment for NSSS scope and we are in compliance for BOP scope,
7 it is noted with an I/C.
8 To cover very briefly the first criterion identified
9 in SRP 7-1 on Exhibit 3A-16, requirement provided in
10 10CFR50.34, Contents of Application. In compliance.
11 10CFR50.36, requirement for Technical Specifica-
12 tions. In compliance.
13 10CFR50.55A, Codes and Standards. In compliance.
14 Compliance with IEEE 279. In compliance.
15 MR. BINGHAM: Are there any questions from the Board?
16 MR. MINNICKS: I've got one on Exhibit 3A-5, the
17 requirement there on the SRDI, the accuracy and range of
18 indicating instrumentation should be consistent with the
19 assumptions of the accident analyses. I am curious as to
20 where those accuracy and range values are stated.
21 MRS. MORETON: The range values we covered when we
22 covered post-accident monitoring yesterday. Accuracy will
23 be provided when it is available.
24 MR. MINNICKS: But in a permanent documentation,
25 where would that be found? In the instrument index?

MRS. MORETON: Data sheets.

MR. MINNICKS: It is my understanding that the data sheets were just a procurement document and weren't part of the formal package. Instrument data sheets you are talking about?

MR. BINGHAM: You will have instrument data sheets as part of the permanent records.

MR. MINNICKS: So then each data sheet that identifies an instrument should have an accuracy on that data sheet?

MR. BINGHAM: Yes.

MR. MINNICKS: That should be an open item, then, because there are many data sheets that do not have accuracies for instrumentation items identified on them.

MR. BINGHAM: If I might, John, I think it would be inappropriate to have an open item with the Board here. That is just completion of the engineering information. There will be sheets on modifications yet to come that will be all pulled together at the final conference.

MR. ALLEN: I guess it should be an open item to the effect to indicate to the Board where the accuracies can be found, whether it be on data sheets or another document.

MR. MINNICKS: It gets a little more complicated, because some of these are in CE's scope of supply.

MR. STERLING: In the CE IDR, Combustion did provide some documents that showed where they provide these

1 accuracies, and that will appear in their transcript. What
2 I would suggest is that we take some sample data sheets
3 and show where these things will appear and add them as part
4 of this transcript so we would have a complete picture of
5 where this information is going to be found.
6 MR. BINGHAM: May I clarify what I think you are
7 after again? There are many accuracies. When a system
8 designer generates his accuracies related in the NSSS scope,
9 what we call a measurement channel requirement, that is
10 converted to an instrument specification sheet for procurement,
11 as you referred to. Are you looking for that description
12 of the accuracy or are you looking at what the final vendor's
13 product accuracy is and where that is specified? That may
14 be, for example, a technical manual.
15 MR. MINNICKS: I am looking for the formals. In
16 other words, the requirement here is that the accuracy has
17 to be consistent with the assumptions in the accident
18 analyses, so that should be the accuracy that we are concerned
19 with. The vendor may supply something that is better than
20 that, but we have to know what was assumed in the accident
21 analyses.
22 MR. BINGHAM: Let me see if I understand. You want
23 to know what was assumed in the accident analyses, and I can
24 x
25 x

1 understand that, from CE. You may have an instrument that
2 is more accurate, and I believe you also want to know that,
3 do you not?
4 MR. MINNICKS: True.
5 MR. BINGHAM: What piece of information is it that
6 you want as part of the transcript?
7 MR. ALLEN: I think Ed said to make it consistent
8 with Combustion Engineering IDR, and that was to provide
9 samples of documentation and reference to documents where
10 they could find the accuracy of the instrumentation.
11 MR. STERLING: Combustion provided, correct me if I
12 am wrong, the interface documents, the detailed interface
13 documents that they send to us that we design our support
14 systems to, which had all the detailed information about
15 their requirements, and they also went through how they take
16 the accuracies of the equipment and define setpoints and
17 that sort of thing, errors.
18 In response to Jim's question, we maybe could have a
19 sample of those documents that provide the accuracies that
20 we use.
21 MR. BINGHAM: I guess what is confusing me, Ed, is
22 the fact that all of the interface information does come
23 from CE, comes to us, becomes part of the permanent record,
24 as well as information developed for balance of plant.
25 That is all one stash of information that you will have for

1 the particular plant when you get ready to start it up.
2 Certainly we can provide all of those examples.
3 MR. STERLING: Couldn't you just provide a sample
4 of a data sheet and show us where the accuracy is?
5 MR. BINGHAM: Sure. Here is a sample of a data sheet
6 here. Is that what you had in mind?
7 MR. MINNICKS: I guess the question would be what
8 assurance do you have that -- I am familiar with the data
9 sheet. What assurance do you have that every instrument has
10 an accuracy value in these data sheets?
11 MR. BINGHAM: That's a different question. Just one
12 moment.
13 Regarding the question of how do we assure that
14 those data sheets that require accuracies have been, that
15 is done by review by Bechtel, particularly by the controls
16 discipline in looking at each data sheet to assure that
17 that information is available.
18 MR. MINNICKS: I guess to expand that, Bill, would
19 that accuracy be the value assumed in the accident analyses
20 or would that value be what the vendor supplied?
21 MR. BINGHAM: I would assume that that would be what
22 the vendor supplies.
23 MR. MARSH: Can I interject something here? I think
24 there are two different questions that we need to address.
25 One is how do we know that the instrument is performing its

1 function within its design limits, and the second question
2 is how do we know that the design is adequate in terms of
3 the accident analyses. The question of the design accuracy
4 really goes to the system design consideration. It is a
5 lot more than just an instrument. It has to do with the
6 tolerance that is built into the analyses as well as the
7 instrument accuracy and other system factors that the
8 instrument itself interconnects with. It is my understanding
9 that that system consideration is documented on a separate
10 data sheet separate from the procurement data sheet that you
11 are speaking of and that that data sheet is completed for
12 every safety-related functional instrument, and I suspect
13 that many of those documents haven't yet been completed for
14 this project. Maybe Mary or Dino can indicate to us whether
15 they have been completed for this project.
16 MR. BINGHAM: Fred, were you discussing with the
17 Board on a generic basis of how these things are handled
18 or were you trying to be plant specific?
19 MR. MARSH: On the basis of what I have seen before,
20 that's correct.
21 MR. BINGHAM: Not all the work is complete and, as
22 you know, we talked about the instruments. As a result of
23 Reg. Guide 1.97, we have two that we are still in the process
24 of developing and purchasing, so they would not be there.
25 The other point I wanted to mention to the Board is that we

1 do rely on Combustion Engineering to specify the requirements
2 properly and we go and procure instruments to meet those
3 requirements. We do send that information back to them for
4 them to verify. So when it comes to assumptions for accident
5 analyses, Chapter 15 work, we would, of course, rely on
6 Combustion Engineering to specify right and we would buy
7 right.
8 MR. MINNICKS: That leads me to two questions. One,
9 Mr. Marsh identified a very exact method of determining where
10 the accuracies are acceptable to the accident analyses. I
11 don't know that I heard a response whether that was what
12 Bechtel was using on this project or not. I am looking for
13 that. Is that the method that Bechtel is using on this
14 project, a separate data sheet other than the procurement
15 data sheet?
16 MR. BINGHAM: Excuse me, maybe Mr. Marsh would clarify
17 that. Did you talk about two data sheets?
18 MR. MARSH: That's correct.
19 MR. BINGHAM: I don't believe we have a document of
20 that type you described on Palo Verde. We will check and
21 see and confirm.
22 MR. PHELPS: Maybe I can clarify what I predict will
23 happen on Palo Verde based on what has happened on San Onofre
24 The setpoints that they use in the safety analyses in the
25 FSAR are called analysis setpoints. The way you get from

[illegible] [illegible] the requirements properly and we do not provide legal remedies to those requirements. We do not [illegible] such documentation such to them for them to review. [illegible] we can [illegible] responsibility for accident analyses, whether it is [illegible] working of reactors, rely on commission directives to apparently right and we would buy right.

Mr. MARKEY. Mr. Lewis, I have two questions. One, Mr. Marsh mentioned a very exact method of determining where the [illegible] are equal to the accident analyses. I don't know that I [illegible] a response whether that was what happened [illegible] exactly at [illegible]. I'm looking for [illegible] there the [illegible] to review of this project, a [illegible] other other than the [illegible] data about?

[illegible]

Mr. MARSH. [illegible]

Mr. [illegible]

[illegible] and conditions.

[illegible]

1 that analysis setpoint back to an instrument setpoint is
2 through a specific document which usually Combustion
3 Engineering creates and they would factor in the instrument
4 accuracies that have been specified on the data sheets along
5 with all the other accuracies that combine in that particular
6 protection channel, so in that way, you are assured that the
7 instrumentation that you have procurred is set with a setpoint
8 that is consistent with the accident analysis, and Palo Verde
9 should eventually get the same document.
10 MR. BINGHAM: That's correct. We have a commitment
11 from CE for a setpoint document. I wasn't aware that that
12 was where the Board was headed with the question.
13 MR. STERLING: At the CE IDR, they went through a
14 very detailed explanation of how they got those setpoints.
15 What I understand the question to be is how do we handle our
16 portion, the BOP.
17 MR. BINGHAM: So the question is how do we determine
18 the setpoints? Is that the question?
19 MR. STERLING: You could expand it to that.
20 MR. BINGHAM: What is the question?
21 MR. MINNICKS: We kind of mixed apples and oranges
22 here. Setpoints and accuracy are two very distinct differences
23 and they have been handled differently both by CE and
24 Bechtel with setpoint indexes. The question I had was
25 relative to accuracy, how does Bechtel document that the

1 accuracies assumed in the accident analyses are carried
2 through the procurement system through sensor to signal
3 converter to indicator -- the indicator is what is discussed
4 in this requirement -- and that that total loop accuracy is
5 within what was assumed in the accident analyses. Mr. Marsh
6 described a method that he had seen at other plants, but
7 what you responded is that is not used here, so I am wondering
8 what is used for Palo Verde.
9 MR. BINGHAM: We will caucus at the break and come
10 back and tell you.
11 MR. ALLEN: That then is an open item?
12 MR. BINGHAM: Yes.
13 MR. ALLEN: Norm, have you got a further comment?
14 MR. HELMAN: No, I have another question whenever you
15 close that out on something different.
16 MR. STERLING: I think then we should carry that on
17 to how we determine our setpoints in our portion of the
18 instrumentation, also.
19 MR. ALLEN: Just expand it to include both accuracy
20 and setpoints.
21 MR. BINGHAM: All right.
22 MR. ALLEN: Norm, have you got another question?
23 MR. HELMAN: I had a question on Exhibit 3A-4, SRP
24 7.4. SRP 7.4.11 requires that a specific interlock for
25 bypassing of Channel A or Channel B ESFAS instrumentation be

1 provided. It appears on an earlier drawing that we covered
2 yesterday, Figure 2A1-6, this interlock is provided. They
3 also require that with the failure of this interlock that
4 there is no capability for bypassing both channels at one
5 time. Could you clarify that for me, please?
6 MRS. MORETON: BOP ESFAS interlocks are isolated such
7 that if the logic senses that both channels are in interlock,
8 they both revert back to a non-bypass mode, and it does
9 meet the single failure criterion. We really need a logic
10 diagram. This is Figure 2A1-6 on the CPIAS. If this
11 interlock (indicating) fails and the operator attempts to
12 put this in bypass, this interlock (indicating) will
13 immediately throw that one out of bypass.
14 MR. HELMAN: I see.
15 MR. ALLEN: Further questions? Carter.
16 MR. ROGERS: On Figure 3A-12, this pertains to
17 Standard Review Plan 7.6. Review of that Standard Review
18 Plan indicates that there are six acceptance criteria. The
19 last one, the number six one, which does not appear here,
20 pertains to the fire protection system. I believe that the
21 fire protection system requirements are covered elsewhere,
22 but I think if that's true that there should be a note to
23 that so that it doesn't confuse other readers of this
24 transcript. Is that correct?
25 MRS. MORETON: For clarification, there was a note

1 on the introduction slide, the Other Systems Required for
2 Safety slide, that excluded fire protection. A note can be
3 added here.
4 MR. ROGERS: I missed that before, but if it is
5 already there, then nothing needs to be changed.
6 MR. ALLEN: Any further questions from the Board?
7 MR. STERLING: Exhibit 3A-13, Item 1). I will ask
8 the same question I asked at the CE IDR. Is this a case that
9 all the instrumentation that is provided currently for
10 Palo Verde is designed to be on range throughout the anticipated
11 normal and abnormal plant occurrences?
12 MRS. MORETON: All instrumentation?
13 MR. STERLING: Yes. You say there you are in
14 compliance.
15 MRS. MORETON: Instrumentation is provided to cover
16 all anticipated occurrences per Reg. Guide 1.97. It does not
17 cover all anticipated ranges. There are overlapping
18 instrumentation to cover all anticipated ranges per Reg.
19 Guide 1.97, Rev. 2.
20 MR. STERLING: Prior to Reg. Guide 1.97, Rev. 2, did
21 we have cases where instrument ranges were designed to
22 fall short of anticipated trends?
23 MR. BINGHAM: May I ask why we are going back into
24 the history? We have been asked by APS to upgrade the
25 system to respond to Reg. Guide 1.97, Rev. 2. John, if you

1 want, we can go back and research the answer.
2 MR. ALLEN: Well, I think you know the answer.
3 MR. BINGHAM: We'll see if we can't answer that
4 properly.
5 MR. KEITH: Prior to 1.97, Rev. 2, we were still
6 designed such that all our instruments covered the anticipated
7 ranges. Since 1.97, Rev. 2, came out, some of the anticipated
8 ranges changed, and that is why we are changing some
9 instruments.
10 MR. ALLEN: Any other questions of the Board?
11 MR. SIMKO: I've got one. On Exhibit 3A-11, on
12 Number 2, you talked about single failure criterion for
13 electrically operated valves. Does that cover the contain-
14 ment purge butterfly valves, the isolation valves?
15 MRS. MORETON: ICSB 18? No. ICSB 18 applies to the
16 safety injection tank isolation valves and other valves
17 where only one valve is provided in the field house to meet
18 the single failure criterion. The containment purge isolation
19 valves are two valves in series.
20 MR. SIMKO: Is there a single failure criterion for
21 isolation valves? One is on Train A and one is on Train B,
22 I believe. What I am driving at is on the containment
23 purge system, is it credible to have both of those isolation
24 valves fail open and you could blow out the filter train
25 going to the plant vent. I guess the question is is the

1 plant vent designed for a Delta P of about 50 psig?
2 MR. KEITH: As you stated, we have one valve off
3 Train A, one valve off Train B, and that is designed to that.
4 We have that designed so that we don't have to design for
5 full containment pressure out beyond those valves and we have
6 not designed that purge ducting for the 50 psi.
7 MR. ALLEN: Anybody else on the Board?
8 Does NRC have any questions?
9 MISS KERRIGAN: I just have a comment that the NRC
10 audit of the assertions will not be made until our drawing
11 review, the assertions about compliance with different
12 Reg. Guides and other NRC criteria.
13 MR. BINGHAM: As you recall, about the second IDR
14 we had, we decided that it was appropriate for us to go
15 through and give a first cut, if you would, at how we stack
16 up against the SRP's as a convenience for the licensing
17 process.
18 Are there any other questions, John?
19 MR. ALLEN: Go ahead.
20 MR. BINGHAM: The next section we would like to cover
21 is 3B, Compliance With Regulatory Requirements, General
22 Design Criteria.
23 MRS. MORETON: Throughout SRP Table 7-1, we will be
24 using the compliance statements as stated on Exhibit 3A-15.
25 On Exhibit 3B-1, we start with the General Design

1 Criteria as defined in SRP Table 7-1.

2 GDC 1, Quality Standards and Records. In

3 compliance.

4 GDC 2, Design Bases for Protection Against

5 Natural Phenomena. In compliance.

6 Exhibit 3B-2, GDC 3, Fire Protection. In

7 compliance.

8 GDC 4, Environmental and Missile Design Bases.

9 In compliance.

10 Exhibit 3B-3. GDC 5, Sharing of Structures,

11 Systems and Components. In compliance.

12 GDC 10, Reactor Design, NSSS scope.

13 Exhibit 3B-4, GDC 12, Suppression of Reactor

14 Power Oscillations, NSSS scope.

15 Exhibit 3B-5, GDC 13, Instrumentation and Control.

16 In compliance.

17 Exhibit 3B-6, GDC 15, Reactor Coolant System Design,

18 NSSS scope.

19 GDC 19, Control Room. In compliance.

20 Exhibit 3B-7. GDC 20, Protection System Functions.

21 In compliance with a clarification that the containment

22 combustible gas control system is manually initiated.

23 Exhibit 3B-8. GDC 21, Protecton System Reliability

24 and Testability. In compliance with a clarification about

25 the one-out-of-two ESFAS. They do not meet the single failure

criterion during channel bypass, but the bypass time interval as discussed before, is a very short interval and is for maintenance only.

Exhibit 3B-9. GDC 22, Protection System Independence. In compliance.

GDC 25, Protection System Failure Modes. In compliance.

Exhibit 3B-10. GDC 24, Separation of Protection and Control Systems. In compliance.

Exhibit 3B-11. GDC 25, Protection System Requirement for Reactivity Control Malfunctions, NSSS scope.

GDC 26, Reactivity Control System Redundancy and Capability, NSSS scope.

Exhibit 3B-12. GDC 27, Combined Reactivity Control Systems Capability, NSSS scope.

GDC 28, Reactivity Limits, NSSS scope.

Exhibit 3B-13. GDC 29, Protection Against Anticipated Operational Changes. In compliance.

GDC 33, Reactor Coolant Makeup, NSSS scope.

Exhibit 3B-14. GDC 34, Residual Heat Removal. In compliance.

Exhibit 3B-15. GDC 35, Emergency Core Cooling, NSSS scope.

GDC 37, Testing of Emergency Core Cooling System, NSSS scope.

1 Exhibit 3B-16. GDC 38, Containment Heat Removal,
2 NSSS scope.
3 GDC 40, Testing of the Containment Heat Removal
4 System, NSSS scope.
5 Exhibit 3B-17. GDC 41, Containment Atmosphere
6 Cleanup. In compliance.
7 Exhibit 3B-18. GDC 43, Testing of Containment
8 Atmosphere Cleanup Systems. In compliance.
9 GDC 44, Cooling Water. In compliance.
10 Exhibit 3B-19. GDC 46, Testing of Cooling Water
11 System. In compliance.
12 GDC 50, Containment Design Bases. In compliance.
13 Exhibit 3B-20. GDC 54, Piping Systems Penetrating
14 Containment. In compliance.
15 GDC 55, Reactor Coolant Pressure Boundary
16 Penetrating Containment. In compliance.
17 Exhibit 3B-21. GDC 56, Primary Containment
18 Isolation. In compliance.
19 GDC 57, Closed System Isolation Valves. In
20 compliance.
21 MR. BINGHAM: Are there any questions from the Board?
22 MR. STERLING: On Exhibit 3B-2, what does the little
23 I under 7.2 mean?
24 MR. BINGHAM: Excuse me, your question was what does
25 "I" mean? It is on Exhibit 3A-15, Ed.

1 MR. STERLING: All right. On Criterions 3 and 4
2 for the Engineered Safety Features System, which is
3 Column 7.3, Combustion also provided interface requirements.
4 You don't indicate that. I think you should have an I/C
5 under 7.3 if that is the case.
6 MRS. MORETON: An I/C can be added to all the sections
7 MR. ALLEN: Any further questions from the Board?
8 I've got one, Mary. Do we have any third of a kind
9 type instrumentation in our scope like off the charging
10 pumps or anything like that that may not meet the same
11 requirements as the rest of our ESFAS systems in regard to
12 marking, maybe?
13 MRS. MORETON: The third charging pump receives power
14 from Train A and from Train B, but the control circuit for
15 that is redundant instrumentation.
16 MR. ALLEN: Completely redundant?
17 MRS. MORETON: The pressure switch instrumentation
18 for the charging pumps is redundant. A Train A pressure
19 switch controls the Train A switchgear and B controls the
20 Train B switchgear.
21 MR. STERLING: Exhibit 3B-6. Combustion Engineering
22 in their IDR indicated Criteria 17 and 18, which are the
23 electrical power requirements, they provided us an interface
24 requirement. I think it would be appropriate, I believe that
25 was covered in the IDR's for the power system electrical,

1 that reference should be made to that IDR to close that loop.
2 MR. BINGHAM: I guess the point here is that, since
3 it isn't in 7 in the table, we didn't put it on the chart.
4 MR. STERLING: In the CE IDR, they provided an
5 interface requirement, but there is nothing to tie that
6 interface requirement to something.
7 MR. BINGHAM: I understand. Let me try to explain
8 again. What we did was take what is in the SRP's, reproduce
9 it to the best of our ability, and respond to it. If there
10 is other information, for example, that CE said that wasn't
11 in the SRP, you wouldn't find it on these charts. We could
12 annotate the charts or add some information as clarification
13 in addition, but the purpose of this review was to take the
14 SRP as it is written and respond to it.
15 MR. STERLING: I guess just for the record that will
16 be found in the power IDR's, the AC and the DC IDR's.
17 MR. BINGHAM: Yes, that's correct. The GDC responses
18 are in there.
19 MR. ALLEN: Any further questions from the Board?
20 NRC?
21 MR. ROSENTHAL: Yes, please. Exhibit 3B-15. I just
22 want a clarification of the scope of supply. I understand
23 that HPSI's are within CE's scope of supply. Are the LPSI's
24 and the containment heat removal system Bechtel or CE?
25 MR. BINGHAM: Combustion Engineering's scope.

1 MR. ROSENTHAL: On 3B-16, to what extent is the
2 containment spray system downstream of CSAS Bechtel or
3 Combustion?
4 MR. BINGHAM: The pumps are provided by Combustion
5 Engineering. The supports for the pumps are provided as
6 balance of plant. It includes piping.
7 MR. ROSENTHAL: Piping, spray headers?
8 MR. BINGHAM: Yes.
9 MR. ROSENTHAL: And the electrical connections
10 between the power and between the auxiliary relay cabinet,
11 the ESF auxiliary relay cabinet and --
12 MR. BINGHAM: The hard wires, yes.
13 MR. ROSENTHAL: The wires to start those?
14 MR. BINGHAM: That's correct.
15 MR. KEITH: Jack, I think we should clarify it is the
16 same scope as to the containment spray pump as it is on the
17 HPSI and LPSI. There is no difference between the Bechtel
18 and CE scope.
19 MR. ROSENTHAL: But you also have tanks to take
20 hydrogen.
21 MR. KEITH: CE scope.
22 MR. ROSENTHAL: Those pumps and the tanks are yours?
23 MRS. MORETON: No.
24 MR. ROSENTHAL: Are CE's?
25 MRS. MORETON: Yes, Combustion Engineering scope.

1 MR. KEITH: The system will be designed by CE. There
2 may be some individual components, but the containment spray
3 system is completely within the CESSAR scope. When we get
4 to the next slide, which is containment atmosphere cleanup,
5 the iodine removal system, although provided by CE, is not
6 covered in CESSAR, it is covered in our FSAR, so that is
7 why you see a difference. We don't say NSSS scope here
8 even though as a point of fact as far as components provided,
9 it is the same as the containment spray system and the
10 HPSI and LPSI.
11 MR. ALLEN: Any further questions?
12 MR. ROSENTHAL: Thank you.
13 MR. ALLEN: Go ahead, Bill.
14 MR. BINGHAM: Let's move on to 3C, Compliance With
15 Regulatory Guides.
16 MRS. MORETON: Continuing on with SRP Table 7-1,
17 Acceptance Criteria for Regulatory Guides.
18 Exhibit 3C-1. Reg. Guide 1.6 requiring an
19 acceptable degree of independence between the redundant
20 standby power sources and their distribution systems. In
21 compliance.
22 Reg. Guide 1.7 requiring a containment combustible
23 gas control system. In compliance.
24 Exhibit 3C-2. Reg. Guide 1.11 regarding instrument
25 lines penetrating containment. In compliance with the

clarification that there are four instrument lines that are a part of the containment pressure boundary and part of the protection system and are provided with isolation facilities that meet the requirements for redundancy, independence, and testability of that redundant system.

Exhibit 3C-3, Reg. Guide 1.12, Instrumentation for Earthquakes. In compliance with the clarification that the strong motion accelerometers are used inside containment rather than the peak recording accelerographs required by Reg. Guide 1.12. Time-history strong motion accelerometers provide data for response spectra analysis rather than response spectrum recorders. Thirty-minute battery power is provided for continuous operation in the event of a loss of external power. Seismic monitoring instrumentation has a response essentially flat or equivalently correctible by computational techniques over the range of 1 to 30 Hertz. Damping values are applicable to the overall strong motion accelerometer. Seismic triggers are adjustable over a minimum range of 0.01 to 0.03 G on the base slab.

Exhibit 3C-4. Reg. Guide 1.22, Periodic Testing of Protection System Actuation Functions. In compliance.

Reg. Guide 1.29 requiring a seismic design classification. In compliance.

Exhibit 3C-5. Reg. Guide 1.30, Quality Assurance Requirements. In compliance.

1 Reg. Guide 1.32, Criteria for Safety-Related
2 Power Systems. In compliance.
3 Exhibit 3C-6. Reg. Guide 1.45 addressing reactor
4 coolant pressure boundary leakage detection. In compliance.
5 Reg. Guide 1.47 identifying the requirements for
6 bypassed and inoperable status indication. In compliance.
7 Exhibit 3C-7. Reg. Guide 1.53 addressing the
8 single failure criterion. In compliance.
9 Reg. Guide 1.62 requiring manual initiation of
10 protective actions.. In compliance.
11 Exhibit 3C-8. Reg. Guide 1.63 addressing
12 electrical penetrations. In compliance.
13 Reg. Guide 1.67 addressing overpressure protection
14 devices. In compliance.
15 Exhibit 3C-9. Reg. Guide 1.68 on the initial
16 test program. In compliance.
17 Reg. Guide 1.70 on the standard format and content
18 of the Safety Analysis Report. In compliance.
19 Exhibit 3C-10. Reg. Guide 1.75 addressing physical
20 independence of electric systems. In compliance.
21 Reg. Guide 1.78 addressing control room habitability.
22 In compliance.
23 Exhibit 3C-11. Reg. Guide 1.80 addressing pro-op.
24 testing of instrument air. In compliance.
25 Reg. Guide 1.89, Qualification of Class IE Equipment.

1 In compliance.

2 Exhibit 3C-12. Reg. Guide 1.95, Protection Against

3 Chlorine Release. In compliance.

4 Reg. Guide 1.97, which we have addressed earlier,

5 the Rev. 2 will be in compliance.

6 Exhibit 3C-13. Reg. Guide 1.100, Seismic

7 Qualification of Electrical Equipment. In compliance.

8 Reg. Guide 1.105 on instrument setpoints. In

9 compliance.

10 Exhibit 3C-14. Reg. Guide 1.118 addressing

11 requirements for periodic testing. In compliance.

12 Reg. Guide 1.120 on fire protection. This subject

13 was covered in the fire protection IDR.

14 MR. BINGHAM: Any questions from the Board?

15 MR. BARNOSKI: I just have one request. I think it

16 would be appropriate that in the transcript you identify

17 what revisions of these you are using as a basis for saying

18 you are in compliance. There is a number of these where I

19 have questions on which revision you are using. I believe

20 that needs to be added for completeness.

21 MR. ALLEN: That's a good idea.

22 MR. BINGHAM: We will add it.

23 MR. PHELPS: Exhibit 3C-10, Protection of the Control

24 Room From Toxic Gases. I know you addressed the chlorine

25 monitors. Do you have monitors for any other toxic gases to

1 isolate the control room?

2 MR. BINGHAM: Not to my knowledge.

3 MR. MARSH: Is there a threat to the control room

4 from release of any other toxic gases?

5 MR. BINGHAM: No.

6 MR. ALLEN: Jim, did you have a question?

7 MR. MINNICKS: On 3C-13, Reg. Guide 1.105, this kind

8 of falls into what we were talking about before on the

9 accuracy and setpoints. The requirement says instrument

10 setpoints in systems important to safety initially are within

11 and remain within the specified limits. The same question,

12 I guess. The specified limits are documented where?

13 MR. BINGHAM: It is in the setpoint index or list.

14 MR. MINNICKS: So in the setpoint index, is that

15 setpoint required to meet the accident analyses? That is

16 the setpoint that is in the index.

17 MR. BINGHAM: At least that much, yes.

18 MR. MINNICKS: Well, is it that or is it some

19 conservative number thrown in there with it?

20 MR. BINGHAM: Excuse me, I confused you. What I meant

21 was there will be other setpoints other than those related

22 to accident analyses in the list.

23 MR. MINNICKS: In this setpoint document, which is

24 out in Rev. 0, will the CE setpoints be included in that or

25 will we have a separate setpoint document for CE setpoints?

1 MR. BINGHAM: I believe we will start with two
2 setpoint lists, one from CE and one for the balance of
3 plant, and eventually they will be combined.
4 MR. JOHNSON: On Exhibit 3C-7 on Reg. Guide 1.53,
5 can you briefly explain to me how the Failure Modes and
6 Effects Analysis for the balance of plant system are properly
7 dovetailed into the Failure Modes and Effects Analysis
8 performed by Combustion Engineering on the plant protection
9 system to ensure that you meet the regulatory requirements
10 of 1.53 to meld those Failure Modes and Effects Analyses
11 together?
12 MR. BINGHAM: Maybe you could help us a little bit
13 and indicate what Failure Modes and Effects Analysis CE
14 has done.
15 MR. JOHNSON: If you will read the FSAR, it is about
16 an inch thick in CESSAR. There are assumptions made in
17 there on the balance of plant. A Failure Modes and Effects
18 Analysis is required by the SRP's to be performed in the
19 balance of plant area, also. Reg. Guide 1.53 is highlighting
20 that they should not be done completely independent, they
21 should be melded together to assure a uniform analysis.
22 MR. BINGHAM: Let me see if we can get to responding
23 to the issue, Larry. When Combustion Engineering does their
24 Failure Modes and Effects Analysis, they look at what happens
25 outside their systems and they document any requirements in

1 the interface information that they send to Bechtel for
2 designing the balance of plant. I believe that is the way
3 that the two are integrated.
4 MR. JOHNSON: The Section 7.2 Failure Modes and Effects
5 Analysis summary tables are quite extensive. Do you have
6 similar tables for the balance of plant portion?
7 MR. KEITH: CE looks at the detailed component level
8 failures, we look more at the system level failures, so ours
9 are not in the same level of detail as Combustion Engineering s.
10 MR. JOHNSON: Do you provide a summary table of
11 those failures?
12 MR. KEITH: We provide a table showing what we looked
13 at in our analysis.
14 MR. JOHNSON: In Section 7?
15 MR. KEITH: Yes.
16 MR. STERLING: Just for reference, it is Table 7.3-14.
17 MR. JOHNSON: I notice them in Section 7.3. I don't
18 notice them in Section 7.4 where you will find the systems
19 that are really supporting a lot of the CE other than
20 ventilation systems, which are in 7.3.
21 MR. BINGHAM: Give us just a minute, John. We will
22 try to find it.
23 (Thereupon a brief off-the-record discussion ensued,
24 after which proceedings were resumed as follows:)
25 MR. BINGHAM: Could I ask that Larry Johnson restate

1 the question to make sure we have the proper response?
2 MR. JOHNSON: How do you demonstrate that you have
3 summarized your Failure Modes and Effects Analysis in the
4 support systems for the CE plant protection system?
5 MR. BINGHAM: Thank you.
6 MR. ALLEN: Any further Board questions on this?
7 I have one, just a clarification. On Exhibit 3C-3
8 where we talk about the seismic trigger range, .01 to .03
9 or .01 to .3 G, which one?
10 MRS. MORETON: The slide is correct.
11 MR. ALLEN: Further questions from the Board or the
12 NRC? Jack.
13 MR. ROSENTHAL: Yes. You stop at Reg. Guide 1.105.
14 Will you make comments about conformance to Reg. Guide 1.06
15 and Reg. Guide 1.118? Okay, 1.106. What is the thermal
16 overload protection for electric motors on motor-operated
17 valves?
18 MRS. MORETON: We will take it as an open item, but
19 for information today, thermal overloads are bypassed by
20 the ESFAS signals on motor-operated valves.
21 MR. ROSENTHAL: Let me get back to Reg. Guide 1.118,
22 and I will need your help on this. 1.118, which was issued
23 after the date of your CP, endorses IEEE 338-1977, which was
24 also issued after your CP. I believe that you are telling
25 me that you are in conformance with 338-77 by listing

1 Reg. Guide 1.118, and, if so, that's terrific.
2 MR. KEITH: Well, there are different versions of
3 1.118, also. I believe one of the references is 338-75.
4 MISS KERRIGAN: I believe one of your open items was
5 to provide a table of which revision you are meeting for
6 all these.
7 MR. KEITH: Yes, that would be part of that. We will
8 tell you what revision and confirm that we are in compliance.
9 MR. ROSENTHAL: Now, just the last part. I believe
10 that the CE scope of supply is in conformance with IEEE
11 338-1971. Should the Bechtel scope of supply be in
12 conformance with 338-75 or 338-77, then does this represent
13 an interface problem? I would like to explore that. Is
14 there conflict?
15 MR. KEITH: Would it matter if one part of the plant
16 were tested to one version and one part to another?
17 MR. ROSENTHAL: You can always do more, and that's
18 fantastic. I am not clear that unless there is careful
19 review that conflicts don't necessarily come up and I am
20 not clear on what the conflicts would be.
21 MR. BINGHAM: Let's see if we can understand. As
22 Gerry Kopchinski said, in the SAR, we are talking about
23 Rev. 1 to Reg. Guide 1.118, which I believe is the one you
24 were referring to.
25 MR. ROSENTHAL: Well, for instance, Rev. 1 I believe

1 endorses the 1975 version of 338 which requires, as an
2 example, periodic testing, and 338-71 did not. I am asking
3 if the interfaces have been satisfied between the BOP and the
4 CE scope of supply such that you can in fact conform to
5 338-1975 given that the CE system was built to 338-71. I
6 would like you to identify where there are conflicts between
7 trying to conform to standards which have been revised.
8 MR. BINGHAM: We will take that as an open item for
9 this Reg. Guide 1.118.
10 MR. ALLEN: Further questions?
11 MR. ROSENTHAL: There are regulations which were
12 in force as of the date of your CP or were backfit. There
13 are many other regulations or revisions of those regulations
14 which are post your CP date and to which you need not conform,
15 but for those latter situations, I think we would like to
16 understand where you conform to the Reg. Guide that is in
17 force by virtue of the date of the CP, but not with the
18 new requirements.
19 MISS KERRIGAN: I think I would like to kind of expand
20 his question. Would you confirm that there are, first of
21 all, for all the Reg. Guides, regulations, SRP's that you
22 are discussing here, confirm either that CE and balance of
23 plant are using the same revision and, if they are not,
24 confirm that there are no interface problems caused by using
25 different revisions of the SRP or Reg. Guide or all the NRC

requirements in this area?

MR. BINGHAM: All right. I think we can handle that, Janis. I also wanted to indicate that there was an amendment to the PSAR, Amendment 4, I believe, that did clarify some later updates on requirements of the revision numbers to Reg. Guide and General Design Criteria.

MISS KERRIGAN: Did you say PSAR?

MR. BINGHAM: Yes.

MR. KEITH: That is all now reflected in the FSAR.

MR. BINGHAM: It is now in the FSAR.

MR. BESSETTE: For clarification on this item, you can refer to CESSAR Appendix A for the revisions of the Regulatory Guides and standards that CE complies with, and then for project specific cases where we may actually exceed what is in CESSAR, you can refer to your System 80 and Palo Verde project specific specifications and interface documents, and you have to look through all those references in order to identify where there is some nonequality in the regulations that were used.

MR. KEITH: That is the open item.

MISS KERRIGAN: Yes. We just want you to confirm that no interface problems resulted from perhaps using different revisions.

MR. ALLEN: Any further questions before we move along? Okay, Bill.

1 MR. BINGHAM: The next section is 3.D., Compliance
2 With Regulatory Requirements, IEEE Standards.
3 MRS. MORETON: Continuing on with SRP Table 7-1
4 Acceptance Criteria.
5 Exhibit 3D-1. IEEE Standard 279 identifies
6 criteria for protection systems for nuclear power generating
7 stations. The criteria in Section 4 will be addressed.
8 Section 4.1, General Functional Requirements. In
9 compliance with a clarification that the containment
10 combustible gas control system is to be a manually initiated
11 system.
12 Exhibit 3D-2, continuing on with IEEE Standard
13 279. Section 4.2 on the single failure criterion. In
14 compliance with the clarification that has been stated
15 earlier about single failure in the BOP ESFAS will defeat
16 more than one of the two protective channels. A single
17 failure may cause spurious actuation. However, this
18 spurious actuation is allowable, since it does not create
19 plant conditions requiring protective action nor does it
20 interfere with normal reactor operations.
21 Exhibit 3D-3, continuing with IEEE Standard 279.
22 Section 4.3 on quality of components and modules. In
23 compliance.
24 Section 4.4 on equipment qualification. In
25 compliance.

Section 4.5 on channel integrity. In compliance.

Exhibit 3D-4, continuing with IEEE Standard 279. Section 4.6, Channel Independence. In compliance.

Exhibit 3D-5. Section 4.7, Control and Protection System Interaction. In compliance.

Subsections 4.7.1 on Classification of Equipment, 4.7.2 on Isolation Devices. 4.7.3 shown on Exhibit 3D-6 on the Single Random Failures, Section 4.7.4 on Multiple Failures Resulting From a Credible Single Event shown on Exhibit 3D-7.

Continuing on with IEEE 279. Section 4.8 on Exhibit 3D-8, Derivation of System Inputs. In compliance.

4.9, Capability for Sensor Checks. In compliance.

Exhibit 3D-9. Section 4.10 requiring capability for test and calibration. In compliance.

Exhibit 3D-10. IEEE Standard 279, Section 4.11 requiring channel bypass or removal from operation. In compliance. The one-out-of-two systems, however, do violate the single failure criterion during channel bypass for maintenance.

Exhibit 3D-11. Section 4.11 continued at the top of this. Testing of the ESFAS is done by channel actuation. Either one of the two channels may be calibrated or repaired without detrimental effects on the system. Individual trip channels may be bypassed to effect a single channel logic

during maintenance mode.

Exhibit 3D-12, continuing with IEEE Standard 279, Section 4.11 at the top of the slide.

4.12 on Operating Bypasses. The BOP has no operating bypasses.

Exhibit 3D-13, IEEE Standard 279. Section 4.13 on Indication of Bypasses. In compliance.

Section 4.14, Access to Means for Bypassing. In compliance.

Exhibit 3D-14, IEEE 279. Section 4.15 on Multiple Setpoints. In compliance.

Exhibit 3D-15 continuing with IEEE Standard 279. Section 4.16, Completion of Protective Action Once It Is Initiated. In compliance.

Section 4.17 addressing manual initiation. In compliance.

Exhibit 3D-16 continuing with IEEE Standard 279. Section 4.18 addressing access to setpoint adjustments, calibration, and test points. In compliance.

Section 4.19 requiring identification of protective actions. In compliance.

Exhibit 3D-17 continuing with IEEE Standard 279. Section 4.20, Information Read Out. In compliance.

Exhibit 3D-18 continuing IEEE Standard 279. Section 4.22 on Identification. In compliance.

1 Exhibit 3D-19. IEEE Standard 308, Criteria for
2 Class IE Power Systems. Requirement is for power systems
3 to meet the functional requirements. In compliance.
4 IEEE Standard 317 on Electrical Penetrating
5 Assemblies in Containment Structures. In compliance.
6 Exhibit 3D-20. IEEE Standard 336 on Installation,
7 Inspection, and Testing Requirements for Instrumentation and
8 Electric Equipment During Construction. In compliance.
9 IEEE Standard 338, Criteria for Periodic Testing.
10 In compliance.
11 Exhibit 3D-21. IEEE Standard 344 addressing
12 seismic qualification of Class IE equipment. In compliance.
13 IEEE Standard 379 addressing the application of
14 single failure criteria. In compliance.
15 Exhibit 3D-22. IEEE Standard 384, Criteria for
16 Separation of Class IE Equipment and Circuits. In compliance
17 per Reg. Guide 1.75.
18 MR. BINGHAM: Are there any questions?
19 MR. STERLING: On Exhibit 3D-16, Section 4.18, the
20 control access, was it designed in the controls? Is that a
21 key lock or are you depending upon administrative procedures,
22 or what?
23 MRS. MORETON: ESFAS setpoints are controlled by key
24 lock. Other setpoints are adjustable in the control room
25 and they are controlled by administrative procedures.

1 MR. HELMAN: Exhibit 3D-11, Section 4.11. In your
2 clarification, you are talking about a short time interval
3 with maintenance and calibration of the bypass panel. Can
4 you shed some more light on that, please?
5 MR. BINGHAM: Excuse me just a minute. Was that an
6 open item we had from yesterday?
7 MR. ALLEN: It seems like it was.
8 MR. BINGHAM: Maybe Gerry or Terry could help us on
9 that point.
10 MR. KOPCHINSKI: There was a question on time allowed
11 for bypass.
12 MR. ALLEN: It was Jack's question. I think it was
13 how can you justify a short interval, what justifies it.
14 MR. BINGHAM: Is that the same question?
15 MR. HELMAN: Yes.
16 MR. BINGHAM: All right. Do you have any other
17 questions?
18 MR. HELMAN: No.
19 MR. BINGHAM: I think Ralph's got one.
20 MR. PHELPS: It is a followup on the question that
21 was just asked and you might take it into consideration when
22 you come up with your justification that when you look at
23 that time interval, you might have to look at it not only
24 on a per event observance, but on an integrated time out of
25 service to make your argument. You might want to look at

1 that very carefully, because it might prove to be restrictive
2 and would have to go in the Tech. Specs.
3 MR. ALLEN: I've got a question on 3D-2. On the
4 clarification, it says spurious actuation is allowable since
5 it does not create plant conditions requiring protective
6 action nor does it interfere with normal reactor operations.
7 I was trying to figure out in my own mind how we could say
8 that a spurious actuation of the sequencer full power is
9 not going to interfere with normal reactor operation.
10 MRS. MORETON: The sequencer is designed to only
11 actuate pumps and does not control any valves. The pumps
12 would go on recirc and no injection would be initiated.
13 MR. ALLEN: So in no way would it interfere with
14 normal reactor operations?
15 MR. BINGHAM: Could you define normal reactor
16 operations to us?
17 MR. ALLEN: Operating the system at all, just continue
18 on if you were operating at 75% power.
19 MR. BINGHAM: It shouldn't perturbate the system. I
20 am sure the operators will be busy putting the safety systems
21 back in order.
22 MR. ALLEN: Along the same line, I guess, I was
23 wondering how we justified making that statement. Was there
24 an analysis done?
25 MR. BINGHAM: John, in order to make sure we respond

1 correctly, we will caucus at break time and pick this up
2 right after.
3 MR. KONDIC: Just to add to Mr. Allen's question,
4 is there an event tree analysis to confirm this statement
5 which we are discussing now?
6 MR. BINGHAM: Event tree like fault tree?
7 MR. KONDIC: Event tree analysis.
8 MR. BINGHAM: Fault tree analysis?
9 MR. KONDIC: Well, event tree is slightly different,
10 but this will really be able to confirm such a statement,
11 an event tree analysis.
12 MR. ALLEN: It is just an addition to the question.
13 MR. BINGHAM: Yes. Are there any further questions?
14 MR. MINNICKS: On 3D-9, I would like some clarification.
15 In the last sentence there, you talk about less than normal
16 time interval between generating station shutdowns. I
17 would like to know what that is defined as. Is that a
18 refueling outage, or what is the intent of that generating
19 station shutdown?
20 MR. ALLEN: That probably should be clarified, because
21 generating station shutdowns could be anything from spurious
22 trips to whatever.
23 MR. BINGHAM: We will clarify it.
24 MR. MINNICKS: To go on with that, when you clarify,
25 that should be whether that is 12 months, 18 months, what you

1 are talking about.

2 Above that, there is a statement "Where the

3 required interval between testing," and I'm curious as to

4 where that is documented, where those required intervals

5 between testing are. Are we talking about surveillance

6 requirements there?

7 MRS. MORETON: The shutdown is required by the Tech.

8 Spec. at periodic testing intervals.

9 MR. MINNICKS: So that is the Tech. Spec. surveillance

10 requirements. Those are the required intervals between

11 testing as defined in this statement?

12 MRS. MORETON: Yes.

13 MR. ROSENTHAL: Deciding on what a proper periodic

14 test interval is is the applicant's responsibility and,

15 having decided what are appropriate test intervals, the NRC

16 staff may put them into the Technical Specifications of a

17 plant, but it is your responsibility based on your knowledge

18 of equipment reliability to decide what would be a proper

19 test interval.

20 MR. MINNICKS: I guess using that, we have heard

21 discussions that for some of these systems or some of these

22 instrumentations that have been post-TMI, requirements aren't

23 designed yet, so I am curious as to how you can say that

24 you are complying with these requirements when the instru-

25 mentation isn't designed. Therefore, the required interval

1 for testing can't be defined, either.

2 MR. BINGHAM: John, we may be getting tangled up in

3 what compliance means. At the other IDR's, we have indicated

4 that if we have not yet procurred an instrument, for example,

5 that it would be our intent to comply once we have procurred

6 it and determined the parameters that were appropriate for

7 testing. While we say we are in compliance, we really have

8 that one exception.

9 MR. MINNICKS: So that is compliance with systems

10 as designed as of the writing of this document.

11 MR. BINGHAM: Yes.

12 MR. KEITH: And the systems which are yet to be

13 designed, we intend them to be in compliance.

14 MR. ROSENTHAL: IEEE 338-1977, Section 6.5, talks

15 about test intervals and defines initial test interval

16 frequency and changes of test interval lengths, and I believe

17 it would be appropriate for you to consider these stipulations

18 or criteria in the selection of test intervals for equipment,

19 especially those that are new.

20 MR. ALLEN: Any further questions?

21 Is this a good time to break?

22 MR. BINGHAM: Yes.

23 MR. ALLEN: Why don't we take about a 15-minute

24 break.

25 (Thereupon a brief recess was taken, after which

1 proceedings were resumed as follows:)

2 MR. ALLEN: Jack, I believe you had a question before

3 we recessed.

4 MR. ROSENTHAL: Yes. Exhibit 3D-8, Section 4.9 of

5 IEEE 279, do you employ pressure or temperature switches

6 as well as analog devices for bistables?

7 MRS. MORETON: We have no pressure switches in

8 safety-related systems. We would have to check on temperature

9 systems for the HVAC system.

10 MR. ROSENTHAL: Exhibit 3D-5, Isolation Devices.

11 I would appreciate on a programmatic basis a statement of

12 the criteria that you use in the selection of isolation

13 devices and link that with your cable routing criteria

14 downstream of those isolation devices.

15 MR. BINGHAM: We will take that as an open item.

16 MR. ALLEN: You touched on that yesterday.

17 MR. KEITH: I was going to ask how that was different

18 from what we stated yesterday, Jack.

19 MR. ROSENTHAL: We have before us a set of statements

20 by Bechtel and I was hoping to appropriately insert in the

21 transcript some programmatic statements which would serve

22 as confirmation of your statements.

23 MR. ALLEN: Do you want to take that as an open item

24 or do you want to address it now?

25 MISS KERRIGAN: Maybe we can help the Board if Jack

1 can kind of tell you the type of statements that he is
2 looking for.
3 MR. BINGHAM: All right.
4 MR. ROSENTHAL: I would hope that you had purchased
5 all your isolation devices for at least, let's say, 480 volts
6 AC and some DC voltage, applied it to that terminal, and
7 that, having done that, you ensure that all cables downstream
8 of isolation buffers are run in cable trays where you don't
9 have 2,160 volts. Some general statement of that sort I
10 think would clear it up. If you've got a mix-and-match
11 situation, it may be more difficult.
12 MR. BINGHAM: I think that was the same area that we
13 discussed yesterday.
14 MR. ROSENTHAL: Can you make a definitive statement.
15 MR. BINGHAM: Let's see if we can do that.
16 MRS. MORETON: All analog isolation devices are bought
17 at 600 volts AC isolation capability. Digital isolation
18 devices are bought at 1,500 volts DC isolation capability.
19 All downstream cables are routed per the EE580 program in
20 cable trays at voltage levels much lower than those rated
21 isolation voltage levels.
22 MR. BINGHAM: Is that the statement you were looking
23 for?
24 MR. ROSENTHAL: Thank you.
25 MR. ALLEN: Does that close that item, then? It

closes the item.

Any further questions?

Go ahead, Bill.

MR. BINGHAM: The next section we will do is 3.E., Compliance With Regulatory Requirements, Branch Technical Positions.

MRS. MORETON: Continuing on with SRP Acceptance Criteria Table 7-1 on the Branch Technical Positions starting on Exhibit 3E-1. Branch Technical Position ICSB 1 requiring instrumentation and electric equipment essential to safety to function in an accident environment, requiring protection circuits to meet single failure criterion, and that DC power be provided for single failure criterion, in compliance.

ICSB 1 is continued on Exhibit 3E-2 requiring redundant sources of onsite AC power. Also in compliance.

Exhibit 3E-3. Branch Technical Position ICSB 3 requiring the design of interfaces between low pressure systems and high pressure systems. In compliance.

Exhibit 3E-4, continuing with Branch Technical Position 3 at the top of the slide.

At the bottom of the slide, Branch Technical Position ICSB 4 requiring that features be incorporated in the design of MOI valve systems to meet the intent of IEEE Standard 279. In compliance.

Exhibit 3E-5 provides more specific information on

1 Branch Technical Position 4.

2 Branch Technical Position 4 is continued again

3 on Exhibit 3E-6.

4 Also identified is Branch Technical Position ICSB

5 5 requiring control rod drive trip breakers be tested monthly

6 which is in NSSS scope.

7 Exhibit 3E-7 continues with Branch Technical

8 Position ICSB 9 requiring daily adjustment to fulfill the

9 requirements of calibration procedures to remain as a daily

10 requirement, but be deleted from the channel calibration

11 category in the Technical Specifications. In compliance.

12 Branch Technical Position ICSB 12 requiring a

13 change to the more restrictive setpoints be accomplished

14 automatically when required. In compliance.

15 Exhibit 3E-8, continuing with Branch Technical

16 Position 12 at the top of the slide.

17 Branch Technical Position ICSB 13 on the auxiliary

18 feedwater system. In compliance.

19 Exhibit 3E-9, Branch Technical Position ICSB 14,

20 requirement to demonstrate compliance with the requirements

21 of GDC 20 to 25 with regard to spurious withdrawal of single

22 control rods. NSSS scope.

23 Exhibit 3E-10. Branch Technical Position ICSB 16.

24 Interlocks are considered safety-related and should meet

25 the requirements of IEEE 279 for the shutdown CEA's and more

1 than two groups of CEA's. All these are in the NSSS scope.
2 Exhibit 3E-11. ICSB 18. Where a single failure
3 in an electrical system can result in loss of capability to
4 perform a safety function, the effect on the plant safety
5 must be evaluated. In compliance.
6 Branch Technical Position ICSB 20. A manual
7 initiation of the transfer to the recirculation mode. In
8 compliance.
9 Exhibit 3E-12 continues with Branch Technical
10 Position 20 and is also directed to Branch Technical Position
11 ICSB 21 on bypass indicators. In compliance.
12 On Exhibit 3E-13, Branch Technical Position 21
13 is continued, and on Exhibit 3E-14.
14 Exhibit 3E-15. Branch Technical Position ICSB 22
15 on testing of the protection systems. In compliance.
16 Branch Technical Position ICSB 25 requires compliance
17 with GDC 37. In compliance.
18 Branch Technical Position ICSB 26 on reactor trips
19 is NSSS scope.
20 MR. BINGHAM: Are there any questions from the Board?
21 MR. PHELPS: I have a question on Exhibit 3E-4. On
22 Branch Technical Position ICSB 4, the first statement is
23 automatic opening of the valves. Would you just explain
24 your clarification to that position for me, please, the
25 clarification on 3E-6, and how it relates to Item No. 1.

1 MR. BINGHAM: I'm sorry, I didn't hear the last part
2 of that question.
3 MR. PHELPS: I would like to just have you explain
4 to me how your clarification relates to Item 1. Do the
5 valves automatically open when the reactor coolant pressure
6 reaches a certain value and then the operator manually locks
7 them open? Is that what you mean to say?
8 MRS. MORETON: That's correct. That was discussed in
9 the CESSAR IDR, the interlocks on the safety injection tank
10 isolation valves. The valve motor centers are also opened
11 and locked.
12 MR. STERLING: On that same Exhibit 3E-4, the indica-
13 tions for the safety injection tanks on the main board are
14 safety-related. Why is not 7.5 applicable in this case?
15 MRS. MORETON: The nonapplicable identified in this
16 table would be because it was not checked in SRP Table 7-1,
17 but your statement is correct. They are identified on the
18 main control board.
19 MR. STERLING: It is the case that the safety-related
20 displays for the safety injection systems do meet the
21 requirements of a safety-related display system that would
22 have been set down if they were inapplicable under 7.5?
23 MRS. MORETON: Yes.
24 MR. ALLEN: Further questions from the Board? Ned.
25 MR. KONDIC: A formal question. On Exhibit 3E-7 under

1, you said setpoints. It is written trip points. Is it a typo or is it setpoints or trip points?

MRS. MORETON: I think it is the same thing.

MR. KONDIC: You have setpoints without any trip.

MRS. MORETON: The only requirement is on the reactor trip system as an interface.

MR. KONDIC: Then it is trip points?

MRS. MORETON: It is trip points.

MR. KONDIC: Thank you.

MR. ALLEN: Further questions?

MR. MECH: On Exhibit 3E-11, I have a specific question in this case on the shutdown cooling system interlocks and the safety injection tank interlocks. If I understand it properly, the system design is such that all the power can be lost on all the interlocks at one time on a loss of power incident. Are the interlocks such that they will change state under a loss of power or suffer a common mode failure on more than one interlock?

MRS. MORETON: Would you clarify that on loss of power? Loss of power to more than one channel?

MR. MECH: Yes.

MRS. MORETON: More than one channel?

MR. MECH: Right.

MR. BINGHAM: I believe we are still just a little confused on the question.

1 MR. ROSENTHAL: Are the interlocks supplied by vital
2 power?
3 MR. BINGHAM: Yes, they are.
4 MR. MECH: Well, that conflicts with my understanding
5 of the FSAR, then.
6 MRS. MORETON: The interlocks are addressed in CESSAR
7 Section 7.6.
8 MR. MECH: They are also addressed in Palo Verde, too.
9 Maybe it is a question of the wording or the accuracy of the
10 writing.
11 MRS. MORETON: The Class IE alarms are addressed in
12 the Palo Verde FSAR.
13 MR. BINGHAM: Perhaps, John, if the Board or NRC
14 could provide us with a reference, we could look at that and
15 clarify the issue.
16 MR. ALLEN: Do you have a reference we could look at?
17 MISS KERRIGAN: Why don't you give us a couple minutes?
18 If you could give him Section 7 of the Palo Verde FSAR, a
19 copy of that, so that he can find the reference, we will go
20 on while he is looking at that.
21 MR. BINGHAM: We can do that.
22 MR. ALLEN: We will come back to it, then.
23 MR. ROSENTHAL: I would like to insert into the
24 transcript at this point that implementation of Branch
25 Technical Position Reactor Safety Branch 5.1 with respect to

1 the ability to perform a cold shutdown from the control room
2 may require interpretation of Branch Technical Positions
3 ICSB 4 and 18, interpretations that are different from those
4 that are now employed.
5 MISS KERRIGAN: That was an open item from yesterday.
6 I just wanted to draw your attention again to that.
7 MR. ALLEN: Do you have any further questions? Do
8 you have your reference yet?
9 MR. BINGHAM: Would it be appropriate to continue
10 while they are looking for the reference?
11 MR. ALLEN: I think we can continue.
12 MR. BINGHAM: The next section is 3.F., Compliance
13 With Regulatory Requirements, IE Bulletins, Circulars, and
14 Information Notices.
15 MRS. MORETON: Referring back to Figure 3-1. We have
16 completed the Standard Review Plans and will now address the
17 IE Bulletins, Circulars, and Information Notices.
18 Exhibit 3F-1 starts off with IE Bulletins beginning
19 with 78-01 on Flammable Contact-Arm Retainers in GE CR120A
20 Relays. These are not used in the PVNGS design.
21 78-02 on Terminal Block Qualification has been
22 covered on another Review Board is per IEEE 323 and NUREG-
23 0588.
24 78-04 on Environmental Qualification of Certain
25 Stem-Mounted Limit Switches Inside Reactor Containment will

1 also be qualified per NUREG-0588 to meet the requirements of
2 Reg. Guide 1.97. This slide will be corrected.
3 78-05, Malfunctioning of Circuit Breaker Auxiliary
4 Contact Mechanism - General Electric Model CR105X. This
5 is not used in the PVNGS design.
6 78-06, Defective Cutler-Hammer Type M Relays With
7 DC Coils. Not used in the PVNGS design.
8 Exhibit 3F-2, continuation with Bulletins. 79-05,
9 05A, 05B, 05C, 06, 06A, 06B, and 06C are all addressed as
10 part of NUREG-0737.
11 79-09 on Failures of GE Type AK-2 Circuit Breaker
12 in Safety-Related Systems, we will follow manufacturer's
13 service advice in preventive maintenance.
14 79-11, Faulty Overcurrent Trip Device in Circuit
15 Breakers for Engineered Safety Systems. Westinghouse DB-50's
16 are not used in the PVNGS design.
17 Exhibit 3F-3, continuing with IE Bulletins. 79-25,
18 Failure of Westinghouse BFD Relays in Safety-Related Systems.
19 Not used in the PVNGS design.
20 79-27, Loss of Non-Class IE Instrumentation and
21 Control Power Bus During Operation. The PVNGS design does
22 provide for two ungrounded non-IE instrument distribution
23 panels and four ungrounded vital panels. All Non-IE
24 instrumentation has a IE counterpart to provide continuous
25 control room readout of shutdown parameters even with a

total loss of all non-IE instrumentation. This Bulletin is addressed further in Section 4 later today.

79-28, Malfunction of NAMCO Limit Switches. NAMCO has corrected the problem by the use of a suitable gasket material. Action has been taken to ensure that all NAMCO switches on PVNGS will be installed with suitable gasket material.

Exhibit 3F-4, continuing with IE Bulletins. 80-06, Engineered Safety Features Rest Controls. PVNGS ESF actuated devices remain in emergency mode on reset of an ESF actuation signal with the following clarifications: Actuated devices with different safety modes in response to different ESF actuation signals by design may actuate to a different safety mode on reset of an ESF actuation signal. We will discuss this in a little more detail with specifics in Item 4 later this morning. The auxiliary feedwater valves by design cycle closed on automatic AFAS reset. Again, that will be discussed in detail later in Item 4.

80-12, Decay Heat Removal System Operability. PVNGS design incorporates four independent power channels for ESFAS initiation and two full capacity, independent shutdown cooling trains. The series of events resulting in loss of decay heat removal are not possible in the PVNGS design.

Exhibit 3F-5, continuing with IE Bulletins. 80-16,

1 Misapplication of Rosemount Pressure Transmitters. PVNGS
2 use of the subject Rosemount pressure transmitters has been
3 reviewed and their use in safety-related applications are
4 within the calibrated range of the transmitter.
5 80-20, Failure of Westinghouse W-2 Type Spring
6 Switches. Westinghouse Type W-2 control switches are not
7 used in the PVNGS design.
8 80-23, Failures of Solenoid Valves Manufactured
9 by Valcor Engineering Corporation. No Valcor solenoid valves
10 are used in safety-related service in the PVNGS design.
11 We will now go on with IE Circulars on Ehxibit 3F-6.
12 78-08, Environmental Qualification of Safety-Related
13 Electrical Equipment at Nuclear Power Plants. Qualification,
14 as stated before, will be per IEEE 323 and NUREG-0588.
15 78-19, Manual Override or Bypass of Safety Systems
16 Actuation Signals. Override of an ESF actuation signal in
17 the component logic places the component under manual control
18 blocking any subsequent ESF actuation. Override is auto-
19 matically removed on reset of the ESF actuation signal. Once
20 in the override mode, the SESS alarms at the system level
21 every system impacted when the component is returned to its
22 normal non-ESF position. The only exception is the contain-
23 ment purge isolation valves do have separate override logic
24 for the CPIAS and the CIAS.
25 Exhibit 3F-7, continuing with IE Circulars.

80-01, Service Advise for GE Induction Disc Relays. Field inspection is in progress to identify affected relays in work.

80-12, Valve Shaft-to-Actuator Key May Fall Out of Place When Mounted Below Horizontal Axis. On PVNGS, Loctite adhesive is used in addition to the press fit key connection.

80-16, Operational Deficiencies in Rosemount Model 510DU Trip Units and Model 1152 Transmitters. Neither of these are used in the PVNGS design.

81-01, Design Problems Involving Indicating Pushbutton Switches Manufactured by Honewell Incorporated. Review of this circular is still under way.

Exhibit 3F-8 proceeds with Information Notices. Information Notice 79-22 on Qualification of Control Systems. Analysis of high energy line break effects on control systems resulting in complicating failures is in process. We will cover this more in Item 4 today.

79-29, Loss of Nonsafety-Related Reactor Coolant System Instrumentation During Operation. The design does provide for two ungrounded non-IE instrument panels and four ungrounded vital Class IE panels to provide continuous control room readout of shutdown parameters even with a total loss of all non-IE instrumentation.

79-30, Reporting of Defects and Noncompliance

1 With 10CFR21. We are in compliance.

2 80-08, The States Company Sliding Link Electrical

3 Terminal Blocks. These are not used in the PVNGS design.

4 80-10, Partial Loss of Non-Nuclear Instrument

5 System Power Supply During Operation. Instrumentation

6 provided is Class IE and would not cause the operator to be

7 instrument blind.

8 Continuing with IE Information Notices on Exhibit

9 3F-9. 80-13, GE Type SBM Control Switches with Defective

10 Cam Followers. All SBM switches used on PVNGS are post-

11 1976 manufacture and not subject to defective cam followers.

12 80-20, Loss of Decay Heat Removal at Davis Besse

13 Unit No. 1 While in Refueling Mode. This was discussed

14 earlier in the Bulletins. The series of events resulting in

15 the loss of decay heat removal are not possible in the PVNGS

16 design, which uses four independent sources of instrument

17 power and has two independent full-capacity trains for

18 shutdown cooling which do not isolate on spurious ESF

19 actuation signals.

20 80-31, Maloperation of Gould-Brown Boveri Type 480

21 Volt K600S and K-Don 600S Circuit Breakers. Not applicable

22 to PVNGS supplied breakers, which were supplied after 1977.

23 Exhibit 3F-10, continuing with the Information

24 Notices. 80-40, Excessive Nitrogen Supply Pressure Actuates

25 SRV Operation to Cause Reactor Depressurization. PVNGS

1 design uses spring-loaded relief valves. The atmospheric
2 dump valves have redundant solenoid valves in pneumatic
3 supply to isolate overpressure source. Leakage through
4 solenoid valves would be to atmosphere.
5 81-01, Possible Failure of General Electric Type
6 HFA Relays. Field inspection is in process to identify
7 affected relays.
8 81-05, Degraded DC System at Palisades. PVNGS
9 design incorporates breaker alarms on the DC system annunciated
10 on the SESS.
11 81-06, Failure of ITE Model K-600 Circuit Breaker.
12 This information notice is in process of review.
13 MR. ALLEN: Any questions from the Board?
14 MR. STERLING: Exhibit 3F-6. In your statement on
15 the right-hand side for 78-19, the first two sentences seem
16 to be in conflict with each other. You state in the first
17 one that when you override that you are blocking any
18 subsequent ESF actuation, and in the second one, you say the
19 override is automatically removed.
20 Let me withdraw the question. Let me ask another
21 question. If one signal comes in and another signal comes
22 in, normally would it cancel? In other words, can one
23 signal remain and another come in or is it normal that when
24 another comes in, it cancels the first one?
25 MRS. MORETON: For a device which has a single ESFAS

1 signal actuating that device, the override is very simple,
2 as we discussed earlier on the override circuitry. For
3 devices which are actuated by more than one ESF signal, once
4 the first signal has come in and the operator has armed the
5 override, that effectively blocks any future signals from
6 performing their function with the exception of the contain-
7 ment purge isolation valves, which were specifically addressed
8 by the IE Circular, and the design has been modified to
9 provide independent override circuitry.
10 MR. STERLING: Is there a case where the operator puts
11 an item into override and the ESF actuation signal disappears
12 at that point and fails to reset it, then another action in
13 the plant causes another signal to come in which would have
14 required this valve to go to whatever its safe position was
15 and it failed to do so because the other was not reset?
16 MRS. MORETON: If the operator failed to reset the
17 first ESF actuation signal when the initiating circuitry
18 returned to normal?
19 MR. STERLING: Yes.
20 MRS. MORETON: It is still annunciated on the SESS.
21 Can you clarify your question?
22 MRS. STERLING: Well, I was trying to think of an
23 example, but say, for example, you've got containment
24 isolation and then you put some valves in override to open
25 up some lines for whatever you are going to do and then

1 the signal goes away.

2 MRS. MORETON: The containment isolation signal goes

3 away or high containment pressure signal goes away?

4 MR. STERLING: The containment isolation signal goes

5 away.

6 MRS. MORETON: Then the override is reset automatically.

7 It is automatically removed.

8 MR. STERLING: Your second statement is that the

9 reset is not an operator action then. That is an automatic

10 reset?

11 MRS. MORETON: Reset of the override is automatic.

12 When you use the word "reset," that can also be construed

13 to mean the reset of the CIAS signal, which is manual after

14 the initiating conditions have cleared.

15 MR. PHELPS: On Exhibit 3F-8, with reference to 79-29

16 and 80-10, do you have some sort of alarm or indication in

17 the control room that specifically alerts the operator to

18 the loss of a non-IE instrument bus?

19 MRS. MORETON: 79-29 was addressed in the AC Review

20 Board in a great deal of detail to close out an action item

21 and it is provided in Section 4. To answer your question

22 specifically, alarms are provided, and we can get into that

23 in detail when we get to Section 4.

24 MR. MINNICKS: I've got one on 3F-2, 79-09, you say

25 you will follow manufacturer's service advice in preventive

maintenance. Could you elaborate on that a little bit more?

MRS. MORETON: The information provided by GE was that they would provide service advice to prevent the problems that were experienced with the Type AK-2 circuit breakers and that service advice will be available to you. We don't know what it is at this time.

MR. MINNICKS: GE is going to provide it to Bechtel or to APS?

MR. BINGHAM: Yes, both.

MR. MINNICKS: On Exhibit 3F-3, 79028, and this also is the same question I've got kind of generic to two others. One is a Bulletin and one is a Circular, 80-13 and 80-31. It has to do with spare parts. Bechtel is procurring some spare parts on purchase orders. The NAMCO limit switch, 79-28, for instance, says that actions have been taken to assure that PVNGS will only get gasket material that is suitable and these other two identify equipment that was manufactured after a certain date, that that is the only equipment that we are receiving. I am curious as to what assurance we have that spare parts that are also procurred by Bechtel will meet that same criterion.

MR. BINGHAM: The Bechtel Engineering Group would be assuring through review that the spare parts are purchased to the proper requirements through review of the purchase documentation.

1 MR. MINNICKS: I think the last one I have was on
2 3F-5 on 80-16. You are very specific there about the fact
3 that Rosemount transmitters that are used in safety-related
4 applications are within the calibrated range. Has there
5 been an investigation made to assure that Rosemount trans-
6 mitters in applications that could confuse or cause adverse
7 indications to the operator have also been checked to assure
8 that they are within the calibrated range of the transmitters?
9 In other words, these particular Rosemount transmitters have
10 been found to do funny things when they are overpressurized.
11 MR. BINGHAM: Well, let me see if I understand the
12 problem. You are talking about transmitters in harsh
13 environments or transmitters in harsh and non-harsh environ-
14 ments?
15 MR. MINNICKS: I guess it could be either.
16 MR. BINGHAM: Well, it makes a difference to answer
17 the question. In harsh environments, I am not sure that we
18 have any Rosemount transmitters on Palo Verde. I believe
19 that's correct.
20 MR. MINNICKS: We do have some inside the containment.
21 MR. ALLEN: In Combustion's scope, diversity, they
22 have diverse transmitters from Rosemount.
23 MR. BINGHAM: There are six diverse ones in
24 Combustion's scope for the plant inside and Combustion would
25 have to answer to that particular question, but I am sure

1 they are looking at the qualifications.

2 MR. MINNICKS: How about the non-harsh environment?

3 MR. BINGHAM: In the non-harsh environment, I suppose

4 that they might give a false reading due to high pressures.

5 In the non-harsh environment, of course, we don't expect

6 high pressures. All of the instruments are qualified for

7 the environments that they will see, radiation, humidity.

8 MR. ALLEN: I think I can clarify that. Jim is

9 talking about with high process pressure.

10 MR. MINNICKS: That's right. This Bulletin applies to

11 overranging those particular transmitters, not environmental.

12 MR. BINGHAM: I am sorry, I missed the question.

13 John, there seems to be some confusion on our part.

14 Is it the nonsafety-related transmitters you are referring

15 to or the safety related?

16 MR. MINNICKS: The nonsafety related. You made a

17 very definitive statement relative to the safety related.

18 What I am concerned about is those identified as nonsafety

19 related but still could have a very confusing effect upon

20 the operator.

21 MR. BINGHAM: We have not looked into the detail of

22 the nonsafety-related transmitters. To answer your question,

23 we have not looked into that same depth of detail.

24 MR. ALLEN: I guess to carry that on a little further,

25 do you intend to?

1 MR. BINGHAM: No.

2 MR. MINNICKS: I have a feeling it would be wise if
3 that were done, because pretty much of the balance of plant
4 instrumentation in the area of transmitters are Rosemount's.
5 Just about everything that the operator is seeing on his
6 Foxboro 270 is being supplied by a Rosemount transmitter.

7 MR. BINGHAM: John, perhaps we should have a conversa-
8 tion with APS outside the meeting since we are talking about
9 nonsafety-related transmitters and come to agreement on what
10 should be done for the project.

11 MR. ALLEN: I can see Jim's point. If you don't look
12 at them, there is a possibility that this type of transmitter
13 if overranged would cause false readings to make the operator
14 take inappropriate action, so I think it is an issue that
15 should be kept open and resolved.

16 MR. BINGHAM: I don't know how to resolve it for this
17 forum. If the agreement is to go ahead and look at it,
18 certainly we can look at them.

19 MR. ALLEN: Without going back and looking at the
20 answer you provided us when this Bulletin came out, I would
21 think it wouldn't be a real overwhelming task to apply the
22 same criteria on the other ones.

23 MR. BINGHAM: We will look at them.

24 MR. MINNICKS: I just had one other question on 3F-7.
25 80-12 says on PVNGS, Loctite adhesive is used in addition

1 to press fit. Is that Loctite adhesive supplied by the
2 vendor, or that is going to be done by whom?
3 MRS. MORETON: We have a letter from Pratt stating
4 that that will be done by Pratt. It was done before the
5 valves were shipped.
6 MR. MINNICKS: The same engineering review relative
7 to spare parts would account for that, also?
8 MR. BINGHAM: Yes.
9 MR. ROGERS: Exhibit 3F-9, Bulletin 80-20. Would you
10 clarify what you mean in the response there about full-
11 capacity trains for shutdown cooling? Are those indeed full-
12 capacity trains? What does that mean?
13 MR. KEITH: Each train is capable by itself without
14 the other one operating of bringing the reactor to a cold
15 shutdown condition.
16 MR. ROGERS: However, the temperatures may be somewhat
17 different depending on whether you are using one train or
18 two trains, is that not correct?
19 MR. KEITH: Yes, and, of course, the speed at which
20 you come down to that, also.
21 MR. ROGERS: Fine. Very good.
22 MR. ALLEN: Any further questions from the Board?
23 I've got one kind of a generic question on this
24 whole issue of I&E Bulletin review. We have exhibits that
25 indicate that such and such an item is not used in the

1 Palo Verde design. My question is how do we assure that when
2 the initial investigation was done, maybe Engineer A checked
3 it, and we order TMI-related equipment tomorrow and Engineer
4 B does that work; how does he ensure that he is not procurring
5 some of the stuff that we said we did not use in the Palo
6 Verde design?
7 MR. BINGHAM: There are several levels that we have
8 of assurance. First of all, when the Bulletin comes in, we
9 send letters to all of the potential manufacturers and ask
10 them to research their supply. This would include the NSSS
11 vendor. They will come back and say yes or no regarding
12 whether the equipment is applicable to the bulletin. We then
13 make that information known to APS through a letter and to
14 our procurement people, and there are separate quality
15 bulletins that are sent out to all of our people in the
16 procurement area and the inspection area. We have had
17 occasion where vendors with their subsuppliers have not been
18 thorough. Through the industry, we have found out about
19 those. We factor that information back into our system.
20 Now regarding your specific question on TMI items,
21 the designer still is under a supervisor that has that
22 information and we rely on the designer and the supervisor
23 to make sure that any of these requirements are incorporated
24 in the design. There are fall-back positions, because the
25 procurement group will also have the information and have

1 been trained to be aware of the fact that there is a
2 deficiency and that they should not order material from a
3 supplier even if it is specified by the engineer. If that
4 fails, there is another fall-back position, and that is
5 that all of our procurement documents and purchase orders
6 are reviewed and approved by Arizona Public Service, who are
7 also aware of the deficiencies. The final fall-back position
8 would come with the inspection on the part of our procurement
9 department where those people have been trained to look for
10 particular deficiencies, and I guess a final fall-back
11 position comes from the QA audits of suppliers both by
12 Bechtel and APS and other utilities on the supply of materials.
13 MR. ALLEN: Just one clarification. Do you publish
14 maybe a defective component list or "don't use" list like
15 don't use Type M relays?
16 MR. BINGHAM: There are two things. One, the chief
17 engineers put out a problem alert that goes to the designers
18 to make sure that they don't use that particular component.
19 There is also what we call the QA bulletin that goes to all
20 members of the project; in other words, procurement,
21 engineering, management, QA. So we have a wide distribution
22 of the particular problem in house.
23 MR. ALLEN: Any further questions from the Board?
24 NRC?
25 MR. ROSENTHAL: Yes. On this general issue, circulars

1 or notices coming from the NRC staff or manufacturers
2 recognize that an isolated problem which may have been
3 reported as an LER in fact had generic implications, but
4 that doesn't meant that these lists are complete. Because
5 this is a design review meeting rather than a compliance
6 with NRC criteria meeting in part, is your system more
7 extensive than the I&E Notices, Bulletins and Circulars, and
8 information you may have gained from INPO or reading LER's?
9 What other efforts do you do?
10 MR. BINGHAM: Well, are you asking the utility or
11 Bechtel? Let me, John, take just a moment. Generally, we
12 know about most of these issues before the bulletin comes out
13 through either information from the utilities through their
14 contacts or through our inspection findings and we will be
15 looking at our projects far in advance of these documents
16 coming in. We generally also look at if there are other
17 implications that would be peculiar to a particular project
18 that may have been overlooked in other reviews. So in our
19 corporation, at least in Bechtel, we have separate indepen-
20 dent projects and each project will be looking at this
21 particular issue as it applies to that project and generally
22 there is a cross-fertilization of the information. Then we
23 have with a major system the chiefs that are also looking
24 at the implications from a technical viewpoint and how it
25 might apply generically across all of our projects. That is

1 what is done in Bechtel. The utilties have their own
2 different ways of approaching the issue and maybe John or
3 someone from APS might want to describe that program.
4 MR. ALLEN: APS at least on the nuclear side, we
5 have procedures in effect where we look at all these
6 bulletins and procedures. We the same as you have cross-
7 fertilization between us and the fossil side. In several
8 instances, problems have come up on some of the fossil units
9 which are directly applicable to the nuclear side, so we
10 identify problems from that end.
11 Go ahead, Carter.
12 MR. ROGERS: I will expand a little bit. We not only
13 look at the NRC bulletins in a formal manner, but we also
14 look at the INPO SOER's in a formal manner in the engineering
15 office, and it is my understanding that our Operations is
16 doing a review of the SOER's from their side, also. We take
17 part in a number of industry-related groups that share
18 information. This includes an active participation in the
19 Edison Electric Institute and EPRI groups, so we follow
20 those. We get information bulletins from Combustion
21 Engineering related to plant operations. We periodically
22 discuss with Combustion Engineering problems which we ask
23 about as being related to our plant and how Combustion
24 Engineering will ensure us that we won't have a similar kind
25 of a problem with our plant. So we do quite a bit of industry

1 review outside of that that is specifically NRC and that is
2 applied to the design as we have it and are designing and
3 procurring.
4 MR. SIMKO: On the Operations side, we are gearing
5 up for an operational review program in which I believe the
6 shift technical advisors are going to review INPO studies,
7 LER's, operational reviews from other utilities, and that
8 program is being developed right now. It is not implemented,
9 because we are not operating it, but we are going to have
10 a total review program.
11 MR. BINGHAM: John, might I ask, does that deal with
12 the question?
13 MR. ROSENTHAL: Thank you.
14 MR. ROGERS: Just one other thought was that we are
15 also members of Notepad and are regularly involved with the
16 Notepad network, which communicates with INPO and INSAC.
17 MR. ALLEN: Any further questions from the Board before
18 we move on?
19 MR. MECH: Can I go back to that previous one?
20 MR. ALLEN: Sure, go ahead.
21 MR. MECH: I apologize for not having distinguished
22 in my notes between CESSAR notes and Palo Verde notes, but
23 the statement in CESSAR is not refuted in Palo Verde, so let
24 me read the statement in reference to interlocks. "... if
25 there should be a loss of all AC power. The interlocks are

automatically connected to the emergency buses. This is to assure that the interlocks and valves will be able to operate under all operating conditions." This is in Paragraph 7.6.1 of CESSAR. That implies to me now that you can lose all power through these interlocks.

MR. KEITH: I think it implies that you cannot lose all power, because in the event of a loss of all offsite AC power and the diesels, you still have these things connected to the batteries, four independent batteries for the four channels that feed these interlocks, so it is very unlikely that you will lose any of them let alone all four of the channels which provide input to the interlocks.

MR. MECH: You are saying then that the system is not as described here? It is not interruptible?

MR. KEITH: I don't know that that really implies that it is interruptible. I don't know if CE would like to comment on that. Ours is not interruptible.

MR. MECH: Very good.

MR. ALLEN: Further questions? Go ahead, Bill.

MR. BINGHAM: The next section we would like to cover is 3.G., Compliance With Regulatory Requirements, NUREG-0737.

MRS. MORETON: Referring back to Figure 3-1 on regulatory requirements, we will now address requirements applicable to instrumentation and controls as defined in NUREG-0737.

1 Exhibit 3G-1. Item 1.D.1, Control Room Design
2 Reviews. APS has formed a Control Room Design Review
3 Management Team and is performing a preliminary assessment
4 of the PVNGS control room. The early part of this effort
5 was divided into three phases. Phase I of the study developed
6 the guidelines to be used while conducting the control room
7 design review. Phase II consisted of the detailed data-
8 taking effort and the identification of human factors
9 deficiencies. The three task areas addressed were human
10 factors, systems factors, and operator preparedness factors.
11 The deficiencies identified were anlyzed for proper resolution
12 and assigned priorities to assist in determining a schedule
13 for implementation.
14 Continuing on on Exhibit 3G-2, Phase III, which is
15 currently in progress, includes preparation and publication
16 of a preliminary report. The review has resulted in APS
17 initiating implementation to date of color demarcation,
18 instrument relocation, alarm prioritization, and additional
19 instrumentation. When the control room design review is
20 completed, a final report will be submitted to the NRC.
21 The submittal date is targeted for December, 1981.
22 Exhibit 3G-3, Item 1.D.2 on Plant Safety
23 Parameter Display Console. We are in compliance with the
24 requirements as set forth in NUREG-0660. An SPDS is being
25 developed to display to operating personnel a minimum set of

1 parameters which define the safety status of the plant. The
2 SPDS will provide continuous indication of direct and derived
3 variables. The requirements of NUREG-0696 will be uitilized
4 in development and installation of the SPDS.
5 Exhibit 3G-4, Item II.B.3 on Post-Accident Sampling
6 Post-accident sampling is in compliance with the requirements
7 of Item II.B.3 and Reg. Guide 1.97, as we discussed when we
8 presented post-accident monitoring.
9 Exhibit 3G-5, Item II.D.3, Direct Indication of
10 Relief and Safety Valve Position. PVNGS will comply. The
11 design does not utilize power-operated relief valves. The
12 PVNGS primary code safety valves, located at the top of the
13 pressurizer, are headered into the reactor drain tank inside
14 containment. Upstream of the common header, each code safety
15 valve is monitored for seal leakage by an in-line RTD.
16 Indirect indication of code safety valve leakage is provided
17 by an increase of RTD pressure and a decrease of pressurizer
18 pressure and pressurizer level, which is monitored by safety
19 grade instrumentation. Positive indication of safety valve
20 position will be provided in the control room. The instru-
21 mentation will be environmentally qualified. A plant
22 annunciator alarm will be provided to alarm valve opening.
23 Exhibit 3G-6, Item II.E.1.2, Subpart 2, on the
24 Auxiliary Feedwater System Flow Rate Indication. Flow rate
25 indication is provided. It is Class IE. It is monitored

flow to both steam generators. The flow indicator channels are displayed on the main control boards. In addition, there are Class IE pressure indicators located upstream of the manual block valves and Class IE steam generator level indicators are also provided. All of these indicators are powered from Class IE buses.

Exhibit 3G-7, Item II.E.3.1 on Emergency Power for Pressurizer Heaters. Pressurizer heaters are covered by the NSSS design. CE interface requirements for the pressurizer heaters are incorporated in the PVNGS design.

Exhibit 3G-8 identifies the number of heaters and the power provided to the heaters.

Exhibit 3G-9, Item II.E.4.2 on Containment Isolation Dependability. Item 1, in compliance. A containment isolation signal is diversely generated by either a high containment pressure signal or a lower pressurizer pressure signal. The power access purge and refueling purge are additionally isolated by high containment purge radioactivity by the containment purge isolation signal.

Exhibit 3G-10, continuing with Item II.E.4.2. Item 4, we are in compliance. Override of a CIAS signal is available for each containment isolation valve via the control switch for that valve. Resetting of a CIAS does not result in the automatic opening of containment isolation valves. Reopening does require operator action for each

1 valve and does not compromise the containment isolation
2 signal.
3 Item 5. As identified before, the containment
4 isolation setpoint on high containment pressure is 5 psig.
5 Calculations are in progress confirming that the trip
6 setpoint represents the minimum value compatible with normal
7 operating conditions.
8 Exhibit 3G-11, continuing with Item II.E.4.2.
9 Both the power access purge and the refueling purge do
10 isolate on high containment purge radioactivity as provided
11 by the CPIAS logic.
12 Exhibit 3G-12, proceeding with Item II.F.1,
13 Additional Accident Monitoring Instrumentation. Monitoring
14 instrumentation is in compliance, as discussed earlier in
15 post-accident monitoring. Requirements continue on Exhibit
16 3G-13. There is a clarification on a subsequent letter
17 sent on October 30, 1979, on the containment radiation
18 levels. We are in compliance with that letter.
19 Exhibit 3G-14, continuing the post-accident
20 monitoring. Again, in compliance.
21 Exhibit 3G-15 continues with post-accident
22 monitoring related to containment water level. In compliance.
23 Exhibit 3G-16, continuing with post-accident
24 monitoring as related to the containment hydrogen concentra-
25 tion monitors. We are in compliance. Continuous indication

1 of containment atmosphere hydrogen concentration is available
2 in the control room within 30 minutes after the initiation
3 of safety injection.
4 Exhibit 3G-17, Item II.F.1, Instrumentation for
5 Detection of Inadequate Core Cooling. PVNGS will comply.
6 Control room indicators of the following parameters will be
7 provided as indication of ICC: core exit thermocouples,
8 subcooled margin monitor, and heated junction thermocouples.
9 Exhibit 3G-18, Item II.G.1, Power Supplies for
10 Pressurizer Relief Valves, Block Valves, and Level Indicators.
11 PVNGS is in compliance. This is continued on Exhibit 3G-19.
12 Exhibit 3G-20, Item III.A.1.2, Upgrade Emergency
13 Support Facilities. PVNGS will comply. Display of data
14 at the TSC and EOF will be in accordance with NUREG-0696.
15 Exhibit 3G-21 continues with the requirements
16 for the operational support center and the emergency
17 operating facility.
18 MR. ALLEN: Questions from the Board? Fred.
19 MR. MARSH: On Exhibit 3G-9 regarding the containment
20 isolation system, could you briefly describe the extent of
21 redundancy in the measurement figures there for containment
22 pressure and pressurizer pressure?
23 MRS. MORETON: Containment pressure is measured by
24 four independent sensors as required by the NSSS ESFAS.
25 Pressurizer pressure is also measured by four independent

1 sensors as required by the NSSS ESFAS.

2 MR. MARSH: Actuation is then the two-out-of-four

3 logic?

4 MRS. MORETON: Yes.

5 MR. ALLEN: Further questions?

6 MR. ROGERS: A clarification of Exhibit 3G-18. This

7 discusses power operated relief valves and block valves. I

8 think the record should show that we do not have either

9 PORV's or block valves.

10 MR. BINGHAM: We will make that correction.

11 MR. STERLING: On Exhibit 3G-8, I just wanted to

12 confirm that the 150 kw capacity from either group is

13 sufficient for natural circulation.

14 MR. BINGHAM: I'm sorry, would you repeat the question

15 again?

16 MR. STERLING: The 150 kw capacity from either of the

17 three element groups is sufficient, there is 100% redundancy?

18 MR. BARNOSKI: I can only offer a speculation. I

19 think that's correct. I'm not positive.

20 MR. ROSENTHAL: The pressurizer heaters are not

21 safety grade, we have merely asked that they put on a

22 safety grade bus, so I think that one must be able to show

23 that one can operate the reactor without the heaters,

24 including in a natural circulation mode. The reason for

25 adding the heaters was that it would be easier for the

1 operator to maintain pressure. Otherwise, the pressure
2 would be constantly decreasing. I think it should be
3 confirmed that you shouldn't need those heaters in order
4 to be in natural circulation. The reason for putting the
5 heaters on the emergency bus is to provide pressure control
6 to help the operator. That is an important distinction to
7 your design.
8 MR. STERLING: It is an alternative method from the
9 required method. My question is if we are going to do that
10 and you needed to pick the heaters necessary to fulfill that
11 requirement or that need for help, then it should be 100%
12 redundant between Train A and Train B.
13 MR. ROSENTHAL: You have to look at your post-
14 accident emergency procedures, decide whether those emergency
15 procedures -- you will have to tell me the answer to this --
16 instruct the operator to maintain the plant at pressure or
17 how to depressurize the plant and what is the emergency
18 procedure planned rate of depressurization. Having studied
19 the emergency procedures to decide what you are going to do,
20 you should then link it to the heater capacity. I think
21 that that is the order that things should be done. Now,
22 can you tell me, do you need those? Do your emergency
23 procedures require or instruct the operator to use those?
24 MR. STERLING: The emergency procedures are not
25 written yet. The guidelines on which they will be based are

1 being formulated by the CE Owners Group activity. CE I
2 would say would provide that interface as to whether to use
3 heaters in that procedure, what size they would be, or what
4 size you would need, so I assume that is where you got that
5 figure.
6 MR. KEITH: This is the CE interface, Ed, that we
7 provide power to these heater groups, so we are meeting the
8 CE interface requirements.
9 MR. STERLING: The final procedures, however I have
10 not see the guideline for that, so I don't know how the
11 Owners Group guideline intends to operate natural circulation.
12 MR. ROSENTHAL: It will be unclear to me two months
13 from now reading the transcript if the heaters were deemed
14 to be required for safety or were considered to be of
15 convenience to the operator such that he could keep the plant
16 in pressure in a mode that he was used to operating in, and
17 that distinction is now important to resolve in my mind.
18 MR. STERLING: My understanding of it is they are a
19 convenience. What I can't tell you is where that convenience
20 shows in those guidelines. I have not seen the guidelines.
21 Maybe Mike would be able to -- you haven't seen them yet?
22 MR. BARNOSKI: No.
23 MR. ALLEN: Further questions from the Board?
24 I would like to have an open item. Maybe, Mike,
25 you could call back during lunch and ask your people back

1 there whether they are required or not required.

2 MR. BARNOSKI: What I will do is try to find out

3 what conclusions the Owners Group has come up with. As far

4 as I know, there has been no work -- I am not sure that

5 there is no work -- to directly correlate that with this

6 particular CE plant, but I'll find out as much as I can.

7 MR. ALLEN: Further questions? Jack?

8 MR. ROSENTHAL: Yes, please. We had a bulletin,

9 circular, or notice on errors in steam generator level or

10 pressure indication due to a high-energy line break --

11 perhaps you can refresh me -- due to a high-energy line

12 break inside of containment. Combustion's design results

13 in an error in the indicated reading of the steam generator

14 level or pressure and provides also a correction table to be

15 used by the operator. From an operation's standpoint, does

16 that hardware meet the intent of the guidance that we have

17 attempted to put out post-TMI providing the operator with

18 reliable information and not encumbering the operator need-

19 lessly?

20 MRS. MORETON: Excuse me, Jack, for clarification,

21 we need some assistance in understanding what CE has

22 committed to, what the errors CE reports there will be, and

23 then would you please restate your question?

24 MR. BESSETTE: May I add some clarification to this?

25 Bulletin 79-21 addressed this concern. In the IDR we had on

1 Chapter 7 for CESSAR, we did address this and we did take
2 an open item on it, which was subsequently closed. It was
3 Item No. 48. We did discuss an analysis that was performed
4 that showed that the error was in the conservative direction.
5 I am not aware of any remaining concern on that.
6 MR. KONDIC: To brief and summarize, the whole thing
7 is because of the reference leg density depending on the
8 containment temperature, there is this error which is
9 tabulated, so what Jack is now pointing out is the operator
10 has to perform the following steps: to look into the history
11 of the recent containment temperature, to choose the highest,
12 to look into the corrections, and then to correct the
13 setpoint for that error which was tabulated. We know about
14 the error, maximum 24%. All these tests he has to undertake
15 in order to properly correct the setpoint. This is a
16 cumbersome operation.
17 MR. BESSETTE: The action the operator takes is not
18 a setpoint adjustment per se. He would take manual control
19 of his emergency feed. The analysis that was done showed
20 that if left in automatic that the system would still
21 function to maintain the generator at the same level. Should
22 the operator take manual control, the correlation that he
23 would be looking at for a corrective type table would be for
24 his knowledge of actual level versus indicated level, and
25 he then refers to containment temperature to obtain the

1 reference to the correction.

2 MR. KONDIC: I see no contradiction. There is a

3 correction necessary to be undertaken. That is what we

4 are both pointing out.

5 MR. BESSETTE: Yes.

6 MR. BINGHAM: What is the question for this group,

7 John?

8 MR. ALLEN: I guess what I understood is is there

9 additional information that needs to be given to APS from

10 Combustion with a correction table?

11 MR. ROSENTHAL: Given the hardware design that was

12 previously reviewed, given that hardware plus a correction

13 table which will be provided to the operator, recognizing

14 that the operator is burdened by an additional task in the

15 course of running his auxiliary feedwater system in a manual

16 mode, my question is not a hardware-related question, but

17 rather an operator-related question, and that is do you

18 consider this a sufficient, reliable, correct indication to

19 the operator within the context of the guidance that the

20 NRC has attempted to provide post-TMI about providing the

21 operator with reliable information and not encumbering him

22 with unnecessary tasks.

23 MR. KEITH: I just heard Combustion Engineering say

24 that the operator could leave the auxiliary feedwater system

25 in automatic and still maintain the plant in a safe condition.

1 MR. ROSENTHAL: That's true.

2 MR. KEITH: I think the operating procedures would
3 reflect that and you would not have the operator until he
4 had completed other priority items worry about going into
5 manual and looking at his correction table.

6 MR. ROSENTHAL: But it is planned that the operator
7 will in fact take manual control of that system --

8 MR. KEITH: At some time.

9 MR. ROSENTHAL: -- at some time and he will go into
10 a modulating mode rather than a bang-bang control scheme.

11 MR. KEITH: Yes.

12 MR. ROSENTHAL: So my question is not a hardware one,
13 but a human one. Is that scheme, including the manual use
14 of correction tables, consistent with today's thoughts about
15 what we expect of operators?

16 MR. ALLEN: I think no one is ready to make that
17 decision until we have seen the operating procedures and
18 somebody has made a judgment. Maybe that should go into the
19 later part of the human factors study or something like that.
20 I don't think we could sit here today and say yes or no. I
21 don't think anybody here has read the procedures and could
22 truly say.

23 MR. BINGHAM: If I understand, John, where Jack is
24 heading is should we be looking at the design in order to
25 preclude this from being a consideration. Is that the point

1 you are getting at?

2 MR. ROSENTHAL: Yes. From an instrumentation stand-
3 point, one could choose to take the CE scope of supply and
4 then the owner could modify that information, for instance,
5 by using a simple microprocessor to provide a direct
6 indication to the operator for which he wouldn't have to use
7 the correction tables, and in that context, it would then
8 become a classical instrumentation control issue.

9 MR. ALLEN: Through automatic compensation.

10 MR. ROSENTHAL: Yes. I am not suggesting that that is
11 necessary. I am asking if you have thought it out and what
12 are your views on whether that should be necessary or not.

13 MR. MARSH: Did I understand Combustion Engineering to
14 say that if this correction is not made that the errors are
15 in a conservative direction and would not interfere with
16 the function of the steam generators? Did I understand that
17 correctly?

18 MR. BESSETTE: That's correct.

19 MR. MARSH: So from a plant operations standpoint,
20 if the operator does not make this correction at all, is he
21 in any way endangering the function manually or automatically
22 and, in fact, couldn't this correction be made or not made
23 and not affect the proper function of the steam generators?

24 MR. ROSENTHAL: The operator will choose to take
25 manual control of the system, adjust his emergency feedwater

1 flow rate, and monitor the steam generator level such that
2 he has a controlled cooldown rate in that steam generator.
3 It is not a question of what goes on the first three minutes,
4 but what goes on over the next two hours, and I don't know
5 if an automatic system is necessary or if the procedures
6 are okay or if he could ignore it throughout the evolution.
7 MR. ALLEN: Having heard what CE said about being
8 conservative and it can be done without this automatic
9 compensation, it appears to me, maybe someone else would care
10 to comment on it, that this might just be a betterment type
11 of an item that somebody would want to look into. It
12 doesn't seem like a safety item.
13 MR. BINGHAM: The thought that crossed my mind is if
14 it is in the conservative direction, why is CE providing a
15 table for the operator?
16 MR. BESSETTE: My response to that would be in
17 response to Bulletin 79-21.
18 MR. KONDIC: We are entering into the philosophy of
19 the setpoint. There is a maximum error of 24%. We do know
20 that a Delta P measurement has seven or more real causes
21 of error, so we may be adding to that maximum 24% or reducing
22 it. Now the question is shall we stick to the established
23 setpoint or just let it float for plus or minus. That is
24 why they do have the correction.
25 MR. ALLEN: Let us take it as an open item and get

1 with Combustion Engineering and see if there is any guideline
2 or procedures written yet and take a look at it with the
3 Operating Department and then come to some conclusion. I
4 don't think we can resolve it here today.
5 MR. BINGHAM: I guess my concern, John, is that you
6 have set a time frame at the beginning of the session in
7 order to respond and some of these issues are going to fall
8 outside that time frame.
9 MR. ALLEN: That has been the case in the past.
10 MR. BINGHAM: Certainly this one I think falls in that
11 category. If it is acceptable to do that or to have a
12 preliminary response or interim response, that would be
13 satisfactory. The reason I was being hesitant is I am not
14 sure that we could gather the facts to close or resolve this
15 particular issue that was brought up. Further, it sounds
16 like the NRC representatives aren't totally enamored with
17 the results of the CE analysis. Is that correct?
18 MR. ROSENTHAL: I think we understand the Combustion
19 system that is being provided and the analysis is fine and
20 the hardware does what it is stated to perform. I would like
21 to link that aspect with what is going to be done at the
22 plant. We have considered suggesting or perhaps even
23 requiring automatic compensation rather than manual compensa-
24 tion, and I was asking for your thoughts on the matter.
25 MISS KERRIGAN: Let me make one statement. I don't

1 know if it has to be an open item for the Board or not and
2 the NRC would not be that concerned about the schedule that
3 you are trying to keep for the Board. We would like the
4 question addressed either within the Board or outside the
5 Board. The NRC will pursue it. You can handle it in what-
6 ever way you want or on whatever schedule you want, but we
7 will be looking into it.
8 MR. ALLEN: Take it as an open item, Bill.
9 Any further questions? Comments?
10 How long is the next section?
11 MR. BINGHAM: I think maybe it would be appropriate
12 to break at this time, John.
13 MR. ALLEN: Why don't we break for lunch now. Try
14 to be back here in one hour.
15 (Thereupon the meeting was at recess.)
16
17 June 18, 1981
1:05 p.m.
18
19 MR. ALLEN: Dennis Keith indicated he's got a few
20 answers to some open items. We can just as well address
21 those now and close them out.
22 Go ahead, Dennis.
23 MR. KEITH: A concern was raised on the fuel building
24 essential ventilation actuation signal, and we discussed
25 this somewhat already yesterday, that if we took one channel

1 out of service, should we take special precautions because
2 the other channel is out of service. The thing we have done
3 since then, we looked at the SAR and the analysis in there
4 does consider a fuel handling accident with no ventilation
5 and the dose theory is less than 10% of Part 100, just to
6 provide you what the analysis showed. We do feel that this
7 is sufficient such that it would not be necessary to Tech.
8 Spec. if you had a channel out of service to operate the
9 system.
10 MR. ALLEN: Any comment on that?
11 MISS KERRIGAN: Thank you for the position.
12 MR. KEITH: A concern was raised this morning on
13 spurious action of some of our BOP ESF system or ESFAS
14 system, and specifically the concern raised was the
15 sequencer and whether a failure of that was a concern. Then
16 the question was also raised on whether we did a fault tree
17 analysis. We have looked at the sequencer and possible
18 failure modes in great detail. We have not done any formal
19 fault tree analysis, but, as I said, we have looked at it
20 a great deal. I was reminded that at the AC IDR, a question
21 was raised as to what if we lost a bus and the sequencers
22 actuated during power operation, and we responded to that that
23 some equipment would come on, but that it would not adversely
24 affect reactor operation. We feel that that previous response
25 really addresses the concern on spurious action. There are

1 a number of different things you could postulate, but we
2 feel, particularly because none of the valves operate on the
3 sequencer, that we aren't going to do anything which is
4 going to cause an upset as far as the reactor operation.
5 The other item we have to address is the question
6 raised on what Failure Modes and Effects Analyses were
7 conducted for support systems. The support systems to the
8 CE ESF systems are covered in Chapter 9 and 10 of the FSAR.
9 The analyses performed there really just give one item saying
10 electrical failure, and, because of the redundancy that we
11 have in those systems, it shows that we are all right. We
12 do, of course, design all the instrumentation for those
13 support systems with redundancy and then everything is routed
14 to meet Reg. Guide 1.75 so that the cabling and all is
15 adequately separated. We feel this is adequate as far as
16 looking at the support systems.
17 MR. ALLEN: Any comments on that?
18 MR. KEITH: All right. Then we will get into
19 Section 4.
20 MR. ALLEN: There is, I believe, an open item that we
21 had asked Combustion Engineering to look into over lunch
22 and I think Mike has some information on that.
23 MR. BARNOSKI: With regard to the pressurizer heaters,
24 in the CESSAR PSAR, they were shown as being not required
25 for safety. That was when we were looking at our normal

1 cold shutdown scenario without natural circulation, so as
2 of that time, they were not required for safety. However,
3 CESSAR P did have an interface requirement for 150 kilowatts
4 per train to be established on each diesel generator. That
5 was based on a conservative estimate of the ambient heat
6 losses from the pressurizer. That was the basis for the
7 150. Since TMI came along and the concern about natural
8 circulation cooldown, we have done analyses to show that
9 pressurizer heaters are not required to do that. They
10 certainly though are desirable, and the emergency guidelines
11 that are being put out shortly by the CE Owners Group will
12 note that fact. They are very desirable to use for control
13 in natural circulation just as in the normal scenario of
14 safe shutdown to cold condition.
15 MR. KEITH: Just a point of clarification. The
16 response I gave on the fuel building essential ventilation
17 actuation signal and how we are not concerned about having
18 one channel out that any particular precaution need be taken,
19 that really addresses, I believe, an open item which was
20 concerned with what a short time interval meant as far as
21 how long you have a channel out of operation. We don't
22 really feel there is any additional analysis that needs to
23 be done as far as that for the systems we are talking about.
24 MR. ALLEN: You are saying then that that system
25 function or time interval out, the same logic could be used

1 for the rest of the systems?

2 MR. KEITH: Yes.

3 MR. ALLEN: I guess since they have different functions,

4 I have a little trouble correlating or buying that. Who

5 raised that question?

6 MR. HELMAN: I did. I would have that same problem,

7 especially like MSIS as compared to fuel building ventilation.

8 MR. KEITH: MSIS is not part of this.

9 MR. HELMAN: That's true, but still, if you want to

10 look at it on a function-by-function basis, I would think

11 rather than trying to draw the corollary that says hey, so

12 what? If the thing is out, we don't care, because we are

13 still less than Part 100 releases on the fuel building.

14 MR. KEITH: Well, if we look at the others, the

15 control room essential filtration actuation signal, all

16 that equipment is also actuated by an SIAS and that is really

17 when you have that concern as far as needing to have that

18 system. What the CREFAS does for you is there is a radiation

19 monitor on the control room air intake, but if we have an

20 SIAS, that is all going to start automatically anyhow without

21 that radiation monitor working, so that one is taken care of.

22 If you want to go through them point by point --

23 MR. ALLEN: Most of them are ventilation-related

24 systems?

25 MR. KEITH: Yes.

1 MR. ALLEN: Any comments from anyone else?

2 MR. MINNICKS: I guess we will probably see something
3 in the balance of plant ESFAS Tech. Specs. relative to
4 time out of service. We have a rather undefinitive statement
5 in your presentation here of short time. We don't know what
6 that is. We don't know what that assumption is, whether a
7 short time to you is two hours or whether a short time is
8 two days.

9 MR. KEITH: I short time would be two hours. We are
10 just talking about the time to perform routine maintenance
11 on that channel.

12 MR. HELMAN: But a total integrated time over a year
13 testing the ESFAS on a weekly basis tends to add a fair amount
14 of time on that particular channel out of service, and then
15 based on the MTTR of that particular system, you would tend
16 to wonder if you would be exceeding a possible Tech. Spec.
17 limit for a channel out of service. I think that is your
18 concern, isn't it, Jim?

19 MR. MINNICKS: That, and that becomes a maintainability
20 criterion then, because if in fact we go past this Tech.
21 Spec. that we are talking about which is presumed to be
22 two hours, if we go past that, then I would think the action
23 requirement would be to trip possibly the other remaining
24 channel, and now we have actuated a safety system when really
25 there is no need to do that, and the whole process goes back

1 to what the definition of short time interval is. The
2 system is designed around that one-out-of-two versus two-out-
3 of-four. I think that short time is a very critical item.
4 MR. KEITH: Right now there is a Tech. Spec. on if
5 you have a train out of service, for example, one of the
6 essential filtration trains out of service, then you do trip
7 the other one and operate it.
8 MR. MINNICKS: Then this time limit no doubt will be
9 imposed of two hours, let's say, so I would then assume
10 that after this two hours, the action statement would then
11 require that other channel to be tripped, so now we have
12 both channels of the safety system in operation, which is
13 certainly safe, but we are taxing that safety system, so
14 to speak.
15 MR. KEITH: Well, you would only operate one train.
16 If you had a Tech. Spec. on a channel being out of service,
17 the most the action requirements would have you do would be
18 to operate one train of the system.
19 MR. MINNICKS: I thought your exception to the single
20 failure criterion was based on that short time that the
21 other channel could be out of service for maintenance.
22 MR. KEITH: I am not understanding your concern, I
23 guess.
24 MR. MINNICKS: In the single failure criterion, you
25 drew an exception to that and the clarification issue was

1 that the only time that would become a problem was if you
2 had a channel out for maintenance, and if that were the
3 case, you assume that to be, from what I hear now, two hours.
4 MR. KEITH: That two hours is just a ballpark. There
5 has been no analysis to look at the integrated time over a
6 year or anything else to try and define probability of you
7 having a failure in the other channel and that giving you a
8 problem. Like I said, with the system that we have talked
9 about, the fuel building ventilation system, there is no
10 problem there based on the accident analyses. The control
11 room essential filtration, there is no problem there because
12 you have the SIAS which could actuate that, which is where
13 you have the most concern for that system operating. The
14 control room ventilation isolation actuation signal gets
15 signals from the chlorine monitors and we have talked about
16 how we really aren't expecting much there, since the only
17 possibility of a chlorine accident is an offsite occurrence.
18 Containment purge, we have the containment isolation actuation
19 signal as a backup there. So I feel we are adequately backed
20 up.
21 I don't know where you want to go from here, John.
22 MR. ALLEN: Jim, do you believe that you need some
23 further justification for it or do you want to let it ride
24 with the Tech. Specs. to set the limit on outage time?
25 MR. MINNICKS: What I would like to do now is I will

take a look at what is written in the Tech. Specs. at this time. I think Dennis made a valid point before saying that if one channel was out of service for maintenance, the statement in the Tech. Spec. now was to trip the other channel. Is that correct?

MR. KEITH: I want to clarify. That is if the other train is out of service. I mean we've got the two channels, and if one of the two channels actuates, it actuates both trains of equipment. The only Tech. Spec. we have right now is if one train of equipment is out of service, then you must actuate the other train. We don't have anything related to the channels in the Tech. Specs. right now.

MR. MINNICKS: Why don't you go ahead? I want to take a look.

MR. ALLEN: Let's proceed. We will get back to this in a minute.

MR. BINGHAM: Let's move on then to Item No. 4 on the agenda, Additional Items of Concern.

MRS. MORETON: NRC sent APS a letter on April 16, 1981 identifying four ICSB items of concern. In Section 4, we have repeated these concerns and provided where we have provided the design feature addressing these concerns.

Exhibit 4-1, ICSB Concern 222.01, Loss of Non-Class IE Instrumentation and Control Power System Bus During Power Operation as required by IE Bulletin 79-27.

1 The concern is that the IE Bulletin be addressed and covered
2 in the FSAR. IE Bulletin 79-27 was covered as an open item
3 on the AC Review Board. The information is provided in
4 Section 5. If the Board wishes, we can go through that
5 information. It is available. The response will be included
6 in an FSAR amendment. To answer the specific concern brought
7 up earlier about annunciation, alarms are provided and you
8 will see the list of alarms in Section 5.
9 Exhibit 4-2 continues with the ICSB Concern 222.01.
10 MR. ROSENTHAL: Will you consider discussing each
11 one of these one at a time?
12 MR. BINGHAM: Yes, we will.
13 MR. ALLEN: Would you like to discuss them after they
14 finish?
15 MR. BINGHAM: May I make a comment, John? I forgot
16 to mention that Dennis had an urgent call. What we had
17 planned to do was to have Mary go through the material and
18 Dennis and I were going to come back and review the issues
19 and open the discussion and handle it in that fashion. I'm
20 sorry I forgot to mention that at the beginning.
21 MRS. MORETON: Continuing on with Exhibit 4-3,
22 ICSB Concern 222.02, Engineered Safety Features Reset
23 Controls addressed in IE Bulletin 80-06. If safety equipment
24 does not remain in its emergency mode upon reset of an
25 Engineered Safeguards Actuation Signal, system modification,

1 design change or other protective action of the affected
2 equipment is not compromised once the associated actuation
3 signal is reset. This issue was addressed in IE Bulletin
4 80-06. For facilities with operating licenses as of March
5 13, 1980, IE Bulletin 80-06 required that systems reviews
6 be conducted by the licensees to determine which, if any,
7 safety functions might be unavailable after reset and what
8 changes could be implemented to correct the problem. For
9 facilities with a construction permit including OL applicants
10 Bulletin 80-06 was issued for information only.
11 Continuing on Exhibit 4-4, the NRC staff has
12 determined that all CP holders, as a part of the OL review
13 process, are to be requested to address this issue.
14 Accordingly, you are requested to take the actions called
15 for in Bulletin 80-06 Actions 1 through 4 under "Actions to
16 be Taken by Licensees." Within the response time called for
17 in the attached transmittal letter, complete the review
18 verifications and descriptions of corrective actions taken
19 or planned as stated in Action 1 through 3 and submit the
20 report called for in Actions Item 4. The report should be
21 submitted to the NRC Office of Nuclear Regulation as a
22 licensing submittal in the form of an FASR amendment.
23 Exhibit 4-5 through the next few exhibits provide
24 a detailed response to the Concern. The Engineered Safety
25 Features Actuation Signals incorporated in the PVNGS design

include, as we have discussed earlier, the NSSS ESFAS including the containment isolation actuation signal, the containment spray actuation signal, the main steam isolation signal, the safety injection isolation signal, the recirculation actuation signal, and the auxiliary feedwater actuation signals. The BOP ESFAS signals include the fuel building essential ventilation actuation signal, the containment purge isolation actuation signal, the control room ventilation isolation actuation signal, and the control room essential filtration actuation signal. On Exhibit 4-6, reset switches are located at the plant protection system cabinet, ESFAS auxiliary relay cabinet supplied by CE, and at the BOP ESFAS cabinet. PVNGS equipment which may change position from the safety or emergency state on reset of an ESF actuation signal is identified in Table 1. These devices can be categorized as follows (Exhibit 4-7): Certain actuated devices require a maintained ESF signal through completion of their safety function. If an ESF actuation signal is reset prior to completion of valve stroke or completion of ESF load sequencing, the valve, as an example, would stop in travel or the sequencer, as another example, would not complete sequencing. Since completion of these actions takes no more than 60 seconds, ESF actuation signal reset is not considered. ESF actuation followed by clearing of the initiating signals with the requirement of manual reset at the appropriate cabinet

all occurring within a short time period on the order of one minute is not credible under true accident conditions. No modification to these equipment control circuits is required.

Another category is shown on Exhibit 4-8. A safety injection actuation signal is employed in some instances to trip non-ESF equipment off the IE buses. On reset of SIAS, this equipment will return to an automatic mode unless the control switch has been put into the pull-to-lock position. On return to the automatic mode, the equipment may start due to process demand. Since SIAS reset may only be accomplished after clearing of both initiating process conditions, low pressurizer pressure or high containment pressure, return of this equipment to automatic control does not defeat required ESF system functions. No modification is required to these equipment control circuits. However, administrative procedures should address placing the control switches in the pull-to-lock position to avoid bus overload on SIAS reset.

Continuing on with another category on Exhibit 4-9, certain actuated devices have different safety modes in response to different ESF actuation signals. In the event that ESF actuation signals requiring both safety modes occur, one safety mode by design will have priority. We address some of these on the BOP ESFAS, and examples are the fuel

building essential ventilation system where we have SIAS and FBEVAS actuating the equipment. SIAS does have priority. On reset of that particular ESF actuation signal, the actuated device will change position to the safety mode required by the remaining ESF actuation signal. This means of control does not defeat required ESF system functions, and no modification is required to these equipment control circuits.

The fourth category includes the AFAS 1 and AFAS 2 signals to the auxiliary feedwater valve. These cycles are designed to cycle based on steam generator level. This automatic resetting of the AFAS 1 and AFAS 2 does not affect the AFAS 1 and AFAS 2 signals to other actuated equipment. The valve cycling represents the desired ESF system and no modification is required.

The tables provided on Exhibits 4-10, 4-11, and 4-12 provide the specifics. No modification is deemed to be required to meet the IE Bulletin. We feel we are in compliance with the intent of the bulletin.

Continuing on to ICSB Concern 222.03 on Exhibit 4-13 concerning Qualification of Control Systems, this is identified in IE Information Notice 79-22. Operating reactor licensees were informed by IE Information Notice 79-22 issued September 19, 1979, that certain nonsafety grade or control equipment, if subjected to the adverse

environment of a high-energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. A copy of IE Information Notice 79-22 was enclosed and reprinted copies of an August 20, 1979, Westinghouse letter and a September 10, 1979, Public Service Electric and Gas Company letter which address this matter were provided. Operating reactor licensees conducted reviews to determine whether such problems could exist at operating facilities.

Continuing on with the Concern on Exhibit 4-14, we are concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review to determine what, if any, design changes or operator actions would be necessary to assure that high-energy line breaks will not cause system failures to complicate the event beyond your FSAR analysis. Provide the results of your reviews including all identified problems and the manner in which they are resolved.

The specific scenarios discussed in the referenced Westinghouse letter are to be considered as examples of the kind of interactions which might occur. Your review should include those scenarios where applicable, but should not necessarily be limited to them. Applicants with other light water reactor designs should consider analogous interactions as relevant to their designs.

1 Concern 222.03, as identified on the slide, is
2 under review. A little bit more discussion will be provided
3 on that in a few minutes.
4 Exhibit 4-15, ICSB Concern 222.04 on Control System
5 Failures. The analyses reported in Chapter 15 of the FSAR
6 are intended to demonstrate the adequacy of safety systems
7 in mitigating anticipated operational occurrences and
8 accidents. Based on the conservative assumptions made in
9 defining these design bases events and the detailed review
10 of the analyses by the staff, it is likely that they
11 adequately bound the consequences of single control system
12 failures. To provide assurance that the design basis event
13 analyses adequately bound other more fundamental credible
14 failures, you are requested to provide the following
15 information: Identify those control systems whose failure
16 or malfunction could seriously impact plant safety.
17 Continuing on Exhibit 4-16, indicate which, if any,
18 of the control systems identified receive power from common
19 power sources. The power sources considered should include
20 all power sources whose failure or malfunction could lead to
21 failure or malfunction of more than one control system and
22 should extend to the effects of cascading power losses due to
23 the failure of higher level distribution panels and load
24 centers.
25 Indicate which, if any, of the control systems

1 identified receive input signals from common sensors. The
2 sensors considered should include, but should not necessarily
3 be limited to, common hydraulic headers or impulse lines
4 feeding pressure, temperature, level or other signals to two
5 or more control systems.
6 Continuing on Exhibit 4-17, provide justification
7 that any simultaneous malfunctions of the control systems
8 identified resulting from failures or malfunctions of the
9 applicable common power source or sensor are bounded by the
10 analyses in Chapter 15 and would not require action or
11 response beyond the capability of operators or safety systems.
12 This item is also in review.
13 MR. BINGHAM: Thank you, Mary.
14 I think what we will do now, John, is go through
15 them one by one. We will put them back up and entertain
16 questions and add some response on those items that are in
17 review. I will ask the Board if there are any questions on
18 this particular one.
19 MR. ALLEN: Any questions from the Board?
20 That was answered as part of the AC System Review
21 Board.
22 MR. BINGHAM: So it is satisfactory. All right.
23 Let's go to the next one.
24 MR. PHELPS: I have one general question on your
25 approach to this issue. Did you go through a systematic

1 evaluation of all the possible interactions of non-IE
2 equipment with the IE equipment, in particular for those
3 systems that have dual functions, for example, charging
4 pumps or pressurizer heater elementary controls, considering
5 all possible modes of operation, loss of offsite power,
6 manual or automatic?
7 MR. BINGHAM: When you say all possible modes, you
8 mean all modes applicable to this issue?
9 MR. PHELPS: All possible normal operating modes.
10 MRS. MORETON: When IE Bulletin 79-27 was addressed,
11 the review consisted of ensuring that adequate information
12 was available to the operator to allow him to perform a
13 safe shutdown and that information was available to the
14 operator to allow him to know he had had a loss of a non-IE
15 instrument bus. The level of detail you are talking about
16 on interactions was not included in that review.
17 MR. PHELPS: Was it included in one of your reviews
18 as part of the normal design?
19 MR. BINGHAM: I don't believe it was.
20 MR. PHELPS: Do you intend to?
21 MR. BINGHAM: I suspect with the new issues that are
22 coming up that we will in some manner look at those, yes.
23 MR. PHELPS: I recommend that you ensure that you do
24 do it, because in response to this issue when it first came
25 up on San Onofre, we did that type of review and we discovered

1 a few areas where we had to make some design changes.
2 MR. BINGHAM: Fine. Thank you.
3 MR. ALLEN: Additional comments?
4 MR. ROSENTHAL: Yes. The orientation of the review
5 of 79-27 has been procedural and has focused on safe shutdown
6 and you are addressing this issue. I see also Exhibit 5.2,
7 the response to Bulletin 79-27 seems hardware oriented. The
8 question is has the loop been closed vis-a-vis emergency
9 procedures?
10 MR. ALLEN: Over in the attachement, I believe it
11 addresses that, Enclosure B, which is a letter to me from
12 Operations indicating that emergency procedures would be
13 developed and used.
14 MR. ROSENTHAL: Thank you.
15 MR. BINGHAM: Shall we move to the next item?
16 MR. ALLEN: Jack, do you have any other comments on
17 this?
18 MR. ROSENTHAL: No.
19 MR. BINGHAM: Questions, John?
20 MR. PHELPS: Are you restricting the questions to the
21 page you have displayed there or do you just want questions
22 in general on that response?
23 MR. BINGHAM: No, to the item.
24 MR. PHELPS: On Exhibit 4-8, the approach that you
25 are using, namely, the safety injection actuation signal to

1 isolate non-IE equipment in the event that there is an
2 emergency, you do that I think because you don't want to
3 risk having unqualified equipment in some way degrade the
4 power supplies that are operating the IE equipment. To have
5 it automatically reclose when the signal clears I think is
6 a violation of your criteria it seems to me unless you have
7 a justification for it.
8 MRS. MORETON: Two things that are important to
9 consider are that the SIAS has to be manually reset, so
10 procedures should be developed to caution the operator before
11 resetting that. Procedures would have to be developed to
12 make sure that the bus is not overloaded when the SIAS is
13 reset. If those control switches are left throughout the
14 excursion of the SIAS in the automatic position, the examples
15 we are talking about are the CEDM fans, containment normal
16 fans, and the normal chiller, which are four shutdown loads
17 available on the ESF buses that are tripped on an SIAS.
18 MR. PHELPS: You have pressurizer meters, too.
19 Let me pursue this. You are talking about resetting the SIAS
20 at the system level before you can reconnect. Is that what
21 the permissive is?
22 MRS. MORETON: Excuse me?
23 MR. PHELPS: You have to reset the SIAS at the system
24 level in order to allow you to reconnect the non-IE loads.
25 MRS. MORETON: No, they can be overridden, like most

1 loads can. SIAS can be overridden and the loads can be
2 connected to the ESF bus.
3 MR. PHELPS: I guess what I am concerned about is
4 when I read this paragraph, it appears that when you clear
5 SIAS, whether it is a manual reset or what, the non-IE
6 loads automatically get reloaded back on the IE buses.
7 MRS. MORETON: If there is an automatic demand signal,
8 they may in fact get reloaded on the ESF bus.
9 MR. PHELPS: It seems to me like that is an undesirable
10 design. You should always want to manually load them back
11 on.
12 MR. BINGHAM: Are you looking for a response of why
13 this is under review?
14 MR. PHELPS: I haven't heard a justification yet why
15 it is okay to automatically load them back on.
16 MR. BINGHAM: Ralph, we are not exactly sure what part
17 of the criteria you believe is being violated.
18 MR. PHELPS: Let me give you a scenario that I can
19 picture. You enter into some type of event that initates a
20 safety injection actuation signal and you shed your non-IE
21 loads and you shed them for the purpose of maintaining the
22 qualified electrical system to support your safety actions.
23 Right? That's why you've got this feature. At some period
24 into the event when your control channels still may be
25 operable, in conditions of harsh environment, they still might

1 be operable, you decide that it is desirable to manually
2 reset SIAS to allow you to bring the nonessential systems back
3 into service, so when you do that, you automatically dump
4 these unqualified loads back on the IE buses. It seems
5 like you run the risk of degrading whatever actions you
6 might have to take after that point in time.
7 MR. BINGHAM: If I hear what you are saying, it is
8 they come back on automatically and they may overload the
9 bus.
10 MR. PHELPS: Yes, or something may have happened
11 inside containment to one of these unqualified systems so
12 that when you load it back on, it might propagate back into
13 the IE buses.
14 MRS. MORETON: There is a very high probability that
15 the operator may have already started the equipment we are
16 talking about anyway, because the reason for making them
17 available to be put on the ESF bus is because there are
18 operational concerns to provide IE power to these devices.
19 MR. PHELPS: Yes, but what I am concerned about is
20 he providing that capability, and he's got to have some
21 criteria before he elects to load them back on the IE system.
22 He's got to have made some assessment of whether that's okay
23 or not, and I associate that type of assessment with a manual
24 action, not an automatic action.
25 MR. KEITH: Presumably, before he reset SIAS, which he

1 has to do manually, the situation, whatever it was that
2 caused it, has been corrected.
3 MR. PHELPS: Well, are you saying there is never a
4 case where he might want to reset SIAS without loading these
5 loads back on the IE buses?
6 MR. ALLEN: I think, also, Dennis, if I understand
7 Ralph correctly, let's say you've got all these loads sitting
8 there which need to applied on the bus and the concern is
9 degrading the voltage on that bus down to a point where you
10 could have some of your other motors drop out. I don't know
11 what it was he said yesterday. At 75 or some percent
12 voltage, your motors will drop out on you again.
13 MR. PHELPS: That is part of my concern.
14 MR. BINGHAM: John, I don't recall us having us a
15 criterion that specifically says that is not allowed, but
16 let us take it as an item and give the justification why it
17 is the way it is.
18 MR. ALLEN: Maybe with the bus voltage and the extra
19 capacity you have on that bus, you can hit them all back on
20 at once and it will not degrade your voltage. Who knows.
21 MR. BINGHAM: That may be the case.
22 MR. ALLEN: If that is the case, it is not a big
23 problem.
24 MR. BINGHAM: We also have the case, as you know,
25 where we are putting the aux feedwater system on the other

1 diesel, so let us take a look and see if we can provide the
2 proper rationale.
3 MR. ALLEN: Further comments? Jack.
4 MR. ROSENTHAL: Yes. I would like to explore this
5 just a little bit more so that perhaps we can avoid rounds
6 of questions. A follow-on to the question that was asked
7 is we imagine that there were situations in which a valid
8 SIAS had been generated, ESF equipment had worked as designed
9 so that it was possible to reset SIAS, for instance, a
10 pressurizer pressure has come down, been restored, but you
11 really are in an emergency situation if you have an event that
12 the operator might want to reset SIAS on a system level.
13 Because he is concerned about other equipment, he wants to
14 realign the plant in a preplanned or non-preplanned manner,
15 and when he does that, he should be able to do that to a
16 component level without having to worry about other equipment
17 coming back on that he might not want.
18 MR. BINGHAM: Well, there is a corollary to that, and
19 that is, since this is equipment that possibly will need to
20 be on, he may forget to turn it on.
21 MR. ROSENTHAL: Well, I think one has to decide whether
22 you need the containment normal cooling system, and if you
23 really need it there, then it should be an ESF system, and
24 if you don't need it, then you don't have to turn it back
25 on.

1 MR. BINGHAM: The issue is whether you put it on the
2 emergency bus or the normal bus, and if you really don't
3 need it for emergency, then I would suspect you would put it
4 on the normal bus. That isn't the way things have worked out.
5 MR. ROSENTHAL: Let me give some further examples.
6 On the control room emergency ventilation system, where you
7 have a real accident going on with a real radiation hazard,
8 a safety injection actuation signal which eventually clears
9 and the operator wants to clear on the system level because
10 he wants to perform some planned or unplanned task, should he
11 have to worry that when he resets on the system level that
12 those dampers are going to change state and hope that the
13 control room CREFAS is working? Should he be burdened with
14 those things, or wouldn't it be better to have him reset
15 by component? We have seen other systems such as containment
16 hydrogen monitoring which was isolated and then automatically
17 reset and we have approved those figures because it was felt
18 that the information gained was more important than the
19 potential risk that was run. I for one would like to see
20 a point-by-point engineering justification of each of the
21 items.
22 MR. BINGHAM: I believe that is what we offered to do,
23 Jack, as the open item. We said we would go back and take
24 a look at the advisability of leaving the system the way it
25 is or whether there should be a modification, and we will do

1 that.

2 MR. ALLEN: Further comments?

3 I guess you can go to the next one, Bill.

4 MR. BINGHAM: Are there no other questions?

5 MR. ALLEN: No.

6 MR. KEITH: As we mentioned earlier in talking about
7 the separation criteria for the instrument lines, there are
8 some portions of our high-energy line break review which are
9 really just beginning, and this falls into that area. In
10 fact, we are just beginning to develop a plan with Combustion
11 Engineering. Obviously, this is a joint effort in this
12 particular case, since the concern is that failures of some
13 non-IE control systems can affect the accident analysis and
14 hence can affect safety, so we will be working with them.
15 The first step of the process will be to identify those
16 control systems which are of concern, which is largely
17 Combustion Engineering's scope, and then we, Bechtel, will
18 be looking at those control systems to determine if any of
19 the line breaks which have been postulated could take out
20 those control systems. Then Combustion Engineering, since
21 most of the control systems of concern will be in their scope,
22 will be looking at possible failure modes of those control
23 systems and what that could do to them. From that, we will
24 determine whether we have to protect those control systems
25 or not. So that is how we conceive of the program going right

1 now, and, as I said, we are just in the planning stage.
2 MR. ALLEN: Do you have any comments?
3 MR. BINGHAM: I think there is one item that has
4 come to our concern, John, and I just wanted to bring it up
5 for the Board's information, and that is that there is an
6 August 11th date on submittal of this information to NRC.
7 I suspect that, although I don't know, this letter has gone
8 out to all of the near-term operating license applicants with
9 the same date, and perhaps we can get some clarification on
10 that point, but I suspect that the timing will be such that
11 it is going to have to be a plan of what is intended rather
12 than all the details. Perhaps Janis or you can give us some
13 clarification on that point.
14 MISS KERRIGAN: Yes. It would be part of our
15 licensing review and any items for which you have made
16 commitments but have not completed the work would be left
17 as an open item in the FSAR in the response to any outstand-
18 ing items. It would then be NRC management's position as
19 to whether the total number of open items is too large to
20 proceed through, for example, a CRS or some other thing.
21 So it would be treated as an open item. You should give us
22 as much information as possible to support the SER issuance
23 date, keep the number of open items to a minimum.
24 MR. BINGHAM: There was one other clarification I
25 believe I asked was whether this letter has gone out to all

1 near-term applicants.

2 MISS KERRIGAN: I believe it has.

3 MR. BINGHAM: You believe it has?

4 MISS KERRIGAN: Yes.

5 MR. BINGHAM: With the same date?

6 MISS KERRIGAN: With a licensing date. You received

7 these concerns in a letter. You did not receive it as a

8 bulletin. That letter was supposed to have been sent to

9 all applicants containing these four concerns. I believe it

10 has been sent formally to all applicants.

11 MR. BINGHAM: And the question was the same response

12 date to all near-term applicants?

13 MISS KERRIGAN: It was my understanding that the

14 letter went out and the response date was geared to the SER

15 issuance date of the particular facility.

16 MR. BINGHAM: Thank you.

17 For the Board's information, that is about where

18 we stand on the issue. We are just in the very preliminary

19 stages with the Combustion plan.

20 MR. ALLEN: Was there an additional item? Is this

21 the last one?

22 MR. KEITH: One more.

23 MR. BINGHAM: There is one more item. Were there any

24 more questions on this item?

25 Let's go to the last item.

1 MR. KEITH: On the last item, we are in a similar
2 stage as we are with the previous one, the concern here
3 being common sensor lines plus common power supplies. Once
4 again it will be a joint Combustion Engineering/Bechtel
5 effort with Combustion Engineering once again identifying
6 those control systems which could affect their accident
7 analyses and then Becthel looking at the power supplies,
8 sensor locations, although some of those are provided by
9 CE. Then with those potential failures, CE will be evaluating
10 how those affect their accident analyses and whether they are
11 outside the bounds, and then, if we have to, make any
12 changes in order to take care of the problems. That is
13 once again the conceptual plan for this one.
14 MR. ALLEN: Any comments on that?
15 MR. BINGHAM: That concludes our presentation to the
16 Board, John.
17 MR. ALLEN: Are there any additional comments or
18 questions from the Board at this time?
19 We will go off the record for a minute.
20 (Thereupon a brief off-the-record discussion ensued,
21 after which proceedings were resumed as follows:)
22 MISS KERRIGAN: First, we would like to thank the
23 Board for letting us sit in as observers. It has added to
24 our understanding of the balance of plant side of the system.
25 I heard the same comments from the CE IDR, also, that it

1 aided in NRC's understanding of the instrumentation and
2 control systems.
3 I would like to talk a little about what NRC needs
4 to do to complete SER's for both CESSAR and Palo Verde.
5 After we get the transcript from this meeting and the CE
6 meeting, we will be sitting down and going through the
7 transcripts making sure that there are no additional questions
8 that NRC has. We would at that time be prepared to take
9 positions on the material presented, positions that would be
10 reflected in the SER. Some of those positions may be in
11 conflict with the positions that were taken by CE or APS,
12 and we would be willing to meet with you to discuss that and
13 give you an opportunity to change our minds on our positions.
14 The second thing that we expect to come out of a
15 review of the transcript is some additional questions on
16 particularly the interfacing between the CESSAR standard
17 system and the Palo Verde balance of plant system.
18 We would like to go back and talk to some of our
19 colleagues at NRC, but right now we feel that the most
20 fruitful way to complete our review and wrap this up is to
21 hold a meeting in Washington the week of July 27th with
22 both APS and Bechtel and see at the same time, understanding
23 that CE's participation in the meeting would be from a
24 CESSAR scope and not from a Palo Verde scope. We hope in
25 that meeting, which we expect would take two to three days,

1 to resolve all open issues, and any additional questions
2 that we had at the conclusion of the meeting the staff would
3 be prepared to write draft SER's for both CESSAR and Palo
4 Verde. What we would anticipate doing, also, is sometime
5 prior to this meeting, we would hope no later than the week
6 of July 13th, we would be sending you the positions that we
7 feel may be in conflict with your positions and the additional
8 questions that we would have in a draft form so that you
9 could prepare for the meeting and everybody is up to speed
10 and we could clean up the rest of the open issues. If there
11 is a change to what I have just outlined, we will be
12 contacting you.
13 MR. ALLEN: Janis, I have one question. Before July
14 27th, do you plan to have a draft SER?
15 MISS KERRIGAN: Well, it would be in the form of any
16 place where we feel that we would be taking a position in the
17 SER that would be in conflict with the position that either
18 APS or CE has taken, you would receive those positions.
19 MR. ALLEN: I would like to ask, also, if you have any
20 more comments, like has been done with some of the other
21 branches, just to give us a call and we will resolve them
22 over the phone.
23 MISS KERRIGAN: That would be no problem.
24 MR. ALLEN: Are there any other comments or questions
25 before we adjourn?

1 I would like to thank all the Board members and
2 the NRC and especially Bechtel for doing a good job of
3 presenting a lot of material.
4 If there is nothing else, I will declare the
5 meeting adjourned.
6
7
8 * * *
9
10
11 I HEREBY CERTIFY that I was present at the meeting
12 before the Balance of Plant Instrumentation and Control
13 Systems Review Board; that I made a shorthand record of all
14 proceedings had and adduced before said Review Board at
15 said meeting; that the foregoing 346 typewritten pages
16 constitute a full, true and accurate transcript of said
17 record, all to the best of my skill and ability.
18
19 Mark M. Grumley
20 MARK M. GRUMLEY
Court Reporter
21
22
23
24
25

ADDENDUM - OPEN ITEMS

1. Provide a drawing showing the routing and separation of reactor protection system and supplementary protection system circuits. (p. 20)

2. Address the BOP items in the list of 27 items of concern on Arkansas Nuclear One, Unit 2, relative to core protection calculators. (p. 21)

3. Provide a detailed list of differences between PVNGS project interface documents and the System 80 interface documents. (For discussion at the NRC follow-up meeting.) (p. 26)

4. Exhibit 2A1-6,-8. Describe the degree to which systems designed in accordance with IEEE 338-71 differ from IEEE-338-1975 or 338-1977 (to be included in follow-up meeting.) (p. 50)

5. Exhibit 2A1-19, Item B. What is the basis for the assertion that the bypass time will be short? (p. 78) Include time per event out-of-service and integrated time out-of-service. (p. 267)

6. Confirm that a) the plant can be taken to cold shutdown within the control room using emergency procedures (p. 123) and b) that PVNGS meets ICSB/PSB BTP 18. (p. 123)

7. Confirm that in the event of a single failure at the remote shutdown panel, the operator's procedures and training are such that he would take parallel actions to those required should the single failure occur in the control room. (p. 136)

8. Provide the basis for any exceptions to Reg. Guide 1.97, Revision 2. (p. 189)

9. Provide a strong commitment to the schedule specified in Reg. Guide 1.97, Revision 2, including what is in now and what will be installed in the future. (p. 189)

10. Exhibits 2C3-15 and 16. What are the design values of the auxiliary feedwater and essential cooling water system flows? (p. 193)

11. Describe the quality assurance and protection of the

COLSS software package. (p. 214)

12. Discuss the quality assurance of the reactor power cutback system computer software. (p. 214)

13. Describe how accuracies and setpoints assumed in accident analyses are carried through procurement, sensor, signal converter to indicator such that loop accuracy is within what was assumed in the accident analysis. (p. 241)

14. Exhibit 38-2. Add I/C to all sections of the exhibit. (p. 249)

15. Identify on the exhibits which Reg. Guide revisions and IEEE dates are being used by PVNGS. (p. 255)

16. Add a discussion of Reg. Guide 1.106 to Section 3C. (p. 259)

17. Identify and discuss any areas of conflict that may exist as a result of CE conforming to IEEE 338-1971 and BOP conforming to IEEE 338-1975. (p. 261)

18. Confirm that CE and BOP are using the same revisions of Reg. Guides, regulations and SRPs, and if they are not, confirm that no interface problems result. (p. 261)

19. Exhibit 3D-9. Provide a clarification of "less than normal time interval between generating station shutdowns", including the effect of 12 or 18 month refueling outages. (p. 269)

20. Exhibit 3D-8, Section 4.9 of IEEE-279. Does PVNGS employ temperature switches for the HVAC system? (p. 272)

21. Exhibit 3F-5, Bulletin 80-16. Provide assurance that Rosemount transmitters used on non-safety systems that could cause confusing or adverse indications to the operator have been checked to assure that they are within their calibrated range. (p. 290)

22. Exhibit 3G-18. Amend the exhibit to indicate that neither poweroperated relief valves nor block valves are used in the PVNGS design.

23. Discuss the acceptability of the operator using correction tables to adjust steam generator level/pressure indication post-HELB. (p. 308)

24. Exhibit 4-8. Non-ESF equipment is automatically loaded after a SIAS clears. Is this a violation of PVNGS criteria, i.e., should non-ESF equipment be manually loaded after cessation of a SIAS? (p. 334)