INDEPENDENT DESIGN REVIEW

of the

PALO VERDE NUCLEAR GENERATING STATION

INSTRUMENTATION AND CONTROL SYSTEMS

Before the

INSTRUMENTATION & CONTROL SYSTEMS REVIEW BOARD

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The Instrumentation and Control Systems Review Board of the Palo Verde Nuclear Generating Station convened at the Holiday Inn - Metrocenter, Phoenix, Arizona, on the 17th day of June, 1981, Mr. John Allen, Nuclear Engineering Manager, Arizona Public Service Company, presiding.

MR. ALLEN: Welcome to Phoenix and the Instrumentation and Control Systems IDR. My name is John Allen. I am one of two Nuclear Engineering Managers reporting to the Vice-President of Nuclear Projects management for Arizona Public Service Company who usually chairs these Independent Design Reviews. Due to a previous commitment, Mr. Van Brunt cannot attend to chair this session. I am responsible for the areas of Electrical Engineering, Instrumentation and Control, Licensing, Health Physics and Records Management for the design and engineering of the Palo Verde Nuclear Generating Station. Today I will act as chairman for this IDR.

The purpose of today's meeting is to perform an Independent Design Review of the Palo Verde Nuclear Generating Station's Balance of Plant Instrumentation and Control Systems. An IDR for the instrumentation and control for the NSSS scope of supply was held two weeks ago in Windsor, Connecticut, which is where Combustion Engineering, the PVNGS NSSS supplier, is located. The NRC reviewers here today also attended the IDR in Windsor. This IDR is intended to

complement what was reviewed earlier, thus giving the I&C for the total plant a thorough review.

For those of you who have not attended a previous IDR, basically what we do is take the design of a specific plant system, structure, or a specific program and review it for adequacy of design and compliance with regulations. This presentation is made by Bechtel personnel involved in that system, structure, or program. This formal presentation to a review board with NRC participants by the Bechtel project staff aids in the understanding of the design basis, construction, and operation of those systems, structures, or programs under review. This, in turn, minimizes, if not eliminates, the time required for the NRC to review that portion of the FSAR.

Upon completion of this IDR, Bechtel or other organizations will prepare formal responses to any open issues defined by the Review Board during this review. These responses will be reviewed by the Review Board for concurrence. When final satisfactory resolution of these items is accomplished, they will be provided to the NRC in writing.

For today's review, we have assembled a review board with a varied background. Since the actual responsibility for an adequate review lies with the applicant, that is, Arizona Public Service, the Board's basic formation starts with APS personnel, complemented with personnel

other groups who have expertise and experience on the system or program being reviewed not necessarily available within APS. Board members were provided with appropriate sections of several documents to familiarize them with the PVNGS Instrumentation and Control Systems. This included sections from PVNGS FSAR, the appropriate Standard Review Plans, and other materials.

At this time, I would like to introduce the members of the Board and then I will have Bill Bingham, Project Engineering Manager for Bechtel, introduce the Bechtel project representatives. Carter Rogers is the other APS Nuclear Engineering Manager who reports to the Vice-President of Nuclear Projects Management and has responsibilities for mechanical engineering, chemical engineering, civil engineering, nuclear fuels, and other nuclear-related items.

Ed Sterling is an APS Nuclear Engineering Department Supervising Instrumentation and Controls Engineer and reports to me. Ed is responsible for the review of the instrumentation and control portions of Palo Verde and the day-to-day interface with Bechtel and Combustion Engineering personnel in those areas. He is also a member of the NSSS I&C Review Board that was held in Windsor.

Norm Holman is an APS Nuclear Engineering Department Instrumentation and Controls Specialist. He reports to Ed Sterling. Norm is responsible for various technical

aspects of the electrical and I&C portions of Palo Verde and also the day-to-day interface with Bechtel and Combustion.

Bill Simko is a Palo Verde Senior Mechanical Engineer in the Operations Engineering Section. Bill reports to the Operations Engineering Supervisor. His responsibilities include review of plant systems for operability and balance of plant performance calculations.

Jim Minnicks is the PVNGS Instrumentation and Controls Supervisor and reports to the Maintenance Superintendent. Jim is responsible for calibration and maintenance of instrumentation and controls.

We have also asked Jim Mulligan, Control Systems Engineer with Arizona Public Service Company Generation Engineering, to participate in this review. Jim is responsible for instrumentation and controls for APS fossil power plants and currently is working on the Ocotillo and Four Corners Power Plants design.

Two Board members are from the Bechtel Power Corporation and have not been directly involved in the detailed design and engineering of Palo Verde. However, they have been used from time to time with the project team on various specific issues. These representatives are Fred Marsh, Chief Control System Engineer, from the Los Angeles Power Division, and Larry Johnson, Control Systems Engineering Specialist, San Francisco Power Division. Mr. Marsh is

responsible for review and approval of project control systems design and development of design standards. Larry is a cognizant engineer for Bechtel staff direction on control system design requirements and industry standards. He is also a member of the NSSS I&C Review Board and attended the meeting in Windsor.

Representing Combustion Engineering, who, as I said earlier, is the PVNGS Nuclear Steam Supply System supplier, are Mike Barnoski, Mike is the Palo Verde Assistant Project Manager, and Bernie Bessette, who is Technical Supervisor of I&C Project Engineering. Mike reports directly to the CE Project Manager and is responsible for PVNGS licensing support, including integration of CESSAR-FSAR, which is CE's standard plant safety analysis report. Bernie is Technical Supervisor on the CE System 80 design.

From Southern California Edison, which is one of our participants in the Palo Verde Project, we have Ralph Phelps. Ralph is Project Group Leader of Nuclear Engineering on Son Onofre Units 2 and 3 and supervises engineers in establishing design criteria and guidelines for safety-related work.

I would like to ask Janis Kerrigan, the Palo Verde Project Manager from the NRC, to introduce the NRC staff.

MISS KERRIGAN: This is Jack Rosenthal. He is from the Instrumentation and Control Systems Branch. He is

the primary reviewer in this area.

Joe Mech is from Argonne National Laboratory, a consultant on I&C.

Ned Kondic is with the ICSB Branch. He is a backup reviewer for the project.

We have Herman LaGow, who is an NRC consultant on the IDR process itself.

I would like to make a couple of comments about what we are hoping to see today. Because the I&C area interfaces with so many branches in NRC, we would like to get as complete a record a possible, so we will probably be asking a lot of questions that deal with what is your basis for making that statement. We understand that there is a lot of material to go through and probably a lot of our questions can be addressed in the second meeting, but we would like to get them on the record in this meeting.

The second area that we would like to concentrate on very heavily is the CE interfaces, and perhaps Ed Sterling and Mike Barnoski can help us out there. The transcript from the CE meeting is not yet available at this time, and we will bring up those areas during this meeting.

MR. ALLEN: We will provide a transcript of this meeting to the NRC as soon as we have received it and proofed it from our court reporter. I would like to ask Terry Quan and Gerry Kopchinski to review the transcript and develop a

joint list of the open items for the court reporter to append to the transcript of the meeting.

The Board is instructed to review the open items to ensure they reflect the issues that were raised upon receipt of the transcript. For the benefit of the court reporter, I would like to ask that the Review Board members or anyone else who makes a statement to please clearly identify himself. This holds true if someone from the audience happens to ask a question. At the completion of the review, Bechtel or other responsible organizations will be designated to prepare responses to the open items. These responses will be sent to members of the Board for their review, comment, and ultimate concurrence. Upon complete Board concurrence, these responses will be formally sent to the NRC for their review.

To assure that these independent design reviews are completed in a timely manner that will not impact the PVNGS licensing review, we have prepared, in conjunction with Bechtel, a schedule that calls for completion of this review in approximately eleven weeks. This (indicating) is the time schedule that we intend to meet. As you can see, this is a very ambitious schedule, and for us to adhere to the schedule, cooperation from everyone will be necessary and it will require very quick turn around on review of the open items. Please note that reconvening may be accomplished

with a conference call. It does not necessarily mean that we will physically reconvene the Board. Also, the NRC reviewers have requested a follow-up meeting during the week of July 27, 1981. The Review Board will not reconvene for this meeting, but will be informed of any substantial outcomes.

If there are no questions from any of the Board members, I would like to ask Bill Bingham to introduce his staff.

MR. BINGHAM: Thank you, John. My name is Bill Bingham. I am Project Engineering Manager for Bechtel Power Corporation assigned to the Palo Verde Project. As John Allen indicated, we are here today to present a review of the BOP Instrumentation and Control Systems at the Palo Verde Nuclear Generating Station facility. This is the eighth in a series of Independent Design Reviews for the Palo Verde Project. I have the following people with me today to assist in the presentation: Dennis Keith, Assistant Project Engineer; Gerry Kopchinski, Nuclear Group Supervisor; Mary Moreton, Controls Systems Group Leader; and Dan Jensen, Nuclear Engineer. Also arriving later this morning to assist in the presentation are Konstantinos Soteropoulous, Controls Systems Group Supervisor, and Stephen Shepherd, Nuclear Engineer.

The Instrumentation and Control Systems includes

the Reactor Trip System, discussed in Standard Review Plan 7.2; Engineered Safety Features, discussed in Standard Review Plan 7.3; Systems Required for Safe Shutdown, discussed in Standard Review Plan 7.4; Safety-Related Display Instrumentation, discussed in Standard Review Plan 7.5; All Other Instrumentation Required for Safety, discussed in Standard Review Plan 7.6; and Control Systems Not Required for Safety, discussed in Standard Review Plan 7.7. The Reactor Trip System was discussed in detail by CE at an earlier Independent Design Review presented during the first week of June. Our discussion today will address the remaining instrumentation and control systems.

In previous system Review Board meetings, we have discussed how the Design Criteria which are approved by APS and are the basis of the plant design are dealt with. In particular, we discussed how the final design was achieved using the Design Criteria as the starting point, and, as part of these discussions, we reviewed the various project procedures which guide the design process and the documentation of the design process. In addition, we have discussed our procedures for assuring interface data are properly included in the design and procurement for the various components. Since this material has been discussed at previous system Review Boards, we propose to refer the Board to Section V of the handout package for a more detailed

presentation of the design method, and I would ask, John, at this time if that is an acceptable way to cover these issues.

MR. ALLEN: Yes.

MR. BINGHAM: Fine. Our presentation today and tomorrow will follow the agenda that is shown. There will be a substantial amount of material that we will be covering. There will be an overview of each system followed by a summary of conformance with regulatory requirements and additional items of concern. As with past reviews, I plan to accept questions at the end of the General Introduction section; Section 2.A.1.A, BOP ESFAS Design Criteria; Section 2.A.1.B, BOP ESFAS System Description; Section 2.A.3, ESF Load Sequencer; Section 2.B, Systems Required for Safe Shutdown; Section 2.C.1, Process Instrumentation; Section 2.C.2, Safety Equipment Status System; Section 2.C.3, Post-Accident Monitoring; Section 2.D., All Other Instrumentation Systems Required for Safety; Section 2.E., Control Systems Not Required for Safety; Section 3.A., SRP Acceptance Criteria; Section 3.B., General Design Criteria; Section 3.C., Regulatory Guides; Section 3.D., IEEE Standards, Section 3.E., Branch Technical Positions; Section 3.G., NUREG-0737; and Section 4., Additional Items of Concern. I would ask, John, that if there are minor clarifications that are essential to the Board for continuity of that section that

that would be appropriate to ask. However, I would ask that the questions be held until the end of the presentation of that section.

Dennis, would you start?

MR. ALLEN: I would like to say a couple of things first, Dennis, before you start the presentation. I would like to reemphasize what Bill said. Because of the huge volume of material we've got, please hold your questions until the sections as Bill indicated.

Also, Bill, I would like to ask you if someone asks a question that you know you are going to cover later on down the line, if you would so note so we are not answering questions two and three times in a row.

MR. BINGHAM: We will do that, John.

MR. KEITH: Figure 1-1 shows the scope of what we are going to be covering in the next two days. The figure actually shows the total scope of the instrumentation and controls as covered in the Palo Verde FSAR: The Reactor Trip System, ESFAS, Safe Shutdown Systems, Safety-Related Display Instrumentation, All Other Safety-Related Instrumentation, and Nonsafety-Related Control Systems. With each one of these, there is a balance of plant section and an NSSS section. The dotted line shows the scope of what we are going to be covering in the next two days, and that is all the balance of plant portions of these subjects plus NSSS

interface requirements as applicable to all subjects.

Figure 1-2 shows the Palo Verde general plant arrangement. Palo Verde consists of three identical units. Each unit has Combustion Engineering as the NSSS, develops 3,800 megawatts thermal of power and about 1,300 megawatts electric. Each of the three units is identical, so that this Figure 1-2 shows all three units consisting of the containment building, fuel building, turbine building, auxiliary building, radwaste building, control building, and diesel generator building. Also shown but not labeled is the main steam support structure where we house our main steam and main feedwater isolation valves and the auxiliary feedwater pumps. The Seismic Category I structures where we house our safety-related equipment consist of the containment, main steam support structure, auxiliary building, control building, diesel generator building, and fuel building, and it is those buildings which house the instrumentation we will be discussing in the next couple of days.

Figure 1-3. We have one common control room for controlling the plant. That is located in the control building at 40 feet above grade. I guess we don't show elevations, but in case we do later in the presentation, at all three units, we use a common grade of 100 feet so that we have one set of drawings for all three units, so this is at 140 feet or 40 feet above grade. It shows the main horseshoe

area within which the operator is located and controls the plant. Outside the horseshoe area, we have a number of cabinets, the computer room, and then various offices.

Exhibit 1-1 shows the Palo Verde classifications. These will be mentioned in the presentation when we talk about the classification of some of the instruments. We wanted to provide a background for that here. All of our safety-related components are qualified as Quality Class Q. This includes all Class IE instruments. It also includes all ASME Section III, which won't really be covered in this presentation. Anything classified as Quality Class Q means that it will have a full quality assurance program, a quality assurance program which meets all the requirements of 10CFR50, Appendix B.

For equipment which is required for power generation or is required for personnel safety which is not classified as Q, we developed another quality classification, Quality Class R. The quality assurance program for these components is similar to Q, but not as detailed as far as the amount of documentation required, particularly in the traceability area. All of our other equipment, which would consist of industry standard equipment, we classify as Quality Class S.

Then for seismic categories, all of our safety-related equipment is qualified as Seismic Category I, which means that it will remain functional for a safe shutdown

earthquake and an operating basis earthquake. In the instrumentation area, we have split off the Seismic Category I qualification into two different ones, Qf_1 for all equipment which remains functional before, during, and after an SSE, and Qf_2 for that equipment which is functional before and after the SSE, but not necessarily during. That latter classification Qf_2 applies primarily to recorders where you have the needle bouncing around during an SSE so you don't really get adequate readings.

Then corresponding to the equipment which is classified as Quality Class R, this equipment will be designed to meet Seismic Category II requirements, and Seismic Catetory II implies that the equipment will not malfunction for an equivalent static load of .13G horizontal and .09G vertical.

Then all the other equipment, the Quality Class S equipment, will be designed to Seismic Category III, which means designed for an equivalent static load of .05G or for uniform building code Seismic Zone 2.

For equipment classified as Quality Class R or S which is located in the vicinity of the Seismic Category I equipment and could in the event of an earthquake fall and damage Seismic Category I equipment, we have designed that equipment to meet Seismic Category IX requirements, which means that it will remain intact or remain supported during

an SSE.

Exhibit 1A-1. We will now cover the CESSAR interface requirements. The CESSAR, as John Allen mentioned, stands for the Combustion Engineering Standard Safety Analysis Report. This is a standard safety analysis report which has been submitted to the NRC by Combustion Engineering and it is referenced in the Palo Verde Final Safety Analysis Report. CESSAR contains many interface requirements which we are required to meet and we will be discussing the interface requirements for the Instrumentation and Control Systems in the next few slides. These requirements from CESSAR are rather general. We will go through them rather hurridly now and, if there are any detailed questions, we will respond to them.

CESSAR gives the power requirements in Section 8.3.1, and we are in compliance with that. The Palo Verde equipment is protected from the effects of natural phenomena. The Palo Verde safety-related instrumentation and control components are protected from pipe failure.

Exhibit 1A-2, continuing the CESSAR interface requirements. The safety-related equipment at Palo Verde is protected from the effects of missiles. The safety-related equipment is separated to meet the requirements of Reg. Guide 1.75.

Exhibit 1A-3. The cabling associated with our

equipment is separated so that a single credible event will not cause multiple channel malfunctions or interactions between channels.

Exhibit 1A-4. Our equipment is located and qualified such that we meet thermal limitations as presented in CESSAR Section 3.11. Our equipment will give an indication if it is not available. It is monitored to meet the CESSAR interface requirement presented.

Exhibit 1A-5. All of our Reactor Protection System and Engineered Safety Features Actuation System devices are capable of being manually actuated in the control room and those required for safe shutdown are also manually operable at the remote shutdown panel, which will be discussed later. All of our instrumentation is capable of being inspected and tested, and our equipment is located so that we do not exceed any environmental requirements as related to chemistry.

Exhibit 1A-6. The CESSAR requirement on materials is not applicable for instrumentation and controls equipment. Components are arranged to provide access for maintenance, testing, and operation, and we meet the requirement for analog and digital signals as far as sharing the same multi-conductor cable. We locate our radwaste lines such that they are not next to components which are not qualified due to the concern about electronic components exceeding any radiation limits.

Exhibit 1A-7. Our components are located not to exceed the pressure limits specified in CESSAR Section 3.11, once again getting back to the environmental requirement. We are providing fire protection as required to meet the requirements of **General** Design Criterion No. 3.

Exhibit 1A-8, physical identification. We do provide physical identification for all our safety-related cabling. All of our associated cabling is treated as Class IE cable so that it has the same coloring as our Class IE cable.

Exhibit 1A-9. We provide environmental support systems such that our safety-related equipment will not be subjected to environments exceeding the requirements of CESSAR Section 3.11, and our instrumentation meets the seismic design requirements as specified in CESSAR Section 3.10.

Exhibit 1A-10. Our inputs to the Reactor Protection System and the Engineered Safety Features Actuation System can be sent to the Plant Monitoring System for trending, data logging, and anything else we need to do with it at the computer.

Figure 1A-1. As you saw from the earlier figure, we are not discussing the Reactor Protection System, since that is completely within CESSAR's scope. However, there are some interface requirements from the Reactor Protection

System, and we will go through those. Figure 1A-1 shows the electrical and mechanical devices and circuitry required to initiate a reactor shutdown starting with the process systems variables, which are input to the Reactor Protection System and the Supplementary Protection System, which gives signals to in this case the reactor trip breakers, which can be controlled manually, and these, of course, send signals to the control element drive mechanisms to drop the control rods if the variables indicate that is needed.

Figure 1A-2 shows the various locations at one of the levels inside the auxiliary building, which is, of course, this area around here (indicating), and then inside the containment. It gives you an idea of where the various components are located, various transmitters for those process variables which we use in the Reactor Protection System and Engineered Safety Features Actuation System.

Exhibit 1A-11 shows the CESSAR interface requirements for the Reactor Trip System. The first requirement is that the preamplifiers for the fission chambers be located outside the secondary shield but inside the containment building and that the cabling be provided with physical and electrical separation. We do meet that interface requirement. The second requirement is that administrative procedures or other means be used to control changes to any of the constants in the core protection

calculators. We are in compliance with that, using the suitable administrative procedures.

That concludes the introduction.

MR. BINGHAM: Questions from the Board, John?

MR. STERLING: I had a question on Exhibit 1A-2, Item 5), Separation. In the CE IDR, there was a question asked concerning the commonality of the sensors between the various protection systems, in one case the SPS and the RPS. Are you going to be discussing the routing of the lines to show separation?

MR. KEITH: We are not in this presentation showing routing of lines. Pressurizer pressure is the input to the Supplementary Protection System and, of course, it is also an input to the Reactor Protection System. There are four channels for both the SPS and the RPS and the lines for Channel A comes off a single tap and then it branches off and there are two isolation valves, a separate one for RPS and a separate one for SPS. Then they are separated from that point to the transmitters.

MR. STERLING: Are the lines then from the isolation valves, since they are supposed to be separate redundant systems even though they are both Channel A, are they routed together or separately or are they physically separated to meet the rest of the criteria?

MR. KEITH: Starting from a common point, obviously,

and since it is right by the pressurizer, there are probably some line breaks which would take out both lines. I think the important thing to remember about the Supplementary Protection System is that the only reason that is there is to mitigate ATWS, which is not an event which would include a pipe break. So for those particular lines, I don't think the requirements as far as separation to meet the effects of a pipe break would be applicable.

MR. STERLING: Would it be fair to state that you wouldn't necessarily have separated those lines, that they could be running in the same area other than where the cap is?

MR. KEITH: Yes, they could be running in the same area.

MR. ALLEN: Ed, do you want it as an open item to have a drawing showing those routings? Are you satisfied?

MR. STERLING: Maybe if you could provide a drawing that would show how those are routed, a simplified drawing showing the areas where they are together.

MR. ALLEN: Anyone else have a question?

MR. BARNOSKI: I have a couple. On the interface requirements, the CESSAR IDR identified documents other than the interface requirements listed in CESSAR.

MR. BINGHAM: I'm sorry, we can't hear you, Mike.

MR. BARNOSKI: This is a general question. The CESSAR IDR identified other documents, specifically what CE calls

interface requirement documents, that put forth more detailed interface requirements on the applicant. You have demonstrated, I think, that you meet the interface requirements that are in CESSAR. Do you also comply with the CE interface requirement documents for the Instrumentation and Control Systems?

MR. BINGHAM: John, I just wanted to make one point clear about the question. I will give you the answer first. The answer is yes, we do include them, but we have for purposes of the licensing effort referenced CESSAR and then we presume that those documents that CESSAR uses or references as backup that are given to us are the appropriate documents.

MR. BARNOSKI: Since you are not going to talk about the trip system, there was one other item I recall being identified, and that dealt with the 27 items of concern on Arkansas relative to the CPC's. Are you going to address those? Not all 27 were applicable to the BOP, but a few were. Are you going to address them not necessarily here, but in some manner?

MR. BINGHAM: John, why don't you let us confer at break time. We believe we are addressing the issues, but we would like to check and then we will respond back.

MR. BARNOSKI: That's all I have.

MR. ROSENTHAL: We audited a set of interface

documents labeled SYS80-ICE and then a four numerical designator and, although those documents are not in the SAR they form a part of the basis of our review. Do you take exception to any of the standard System 80 interface requirements in those documents? Let me further explain.

MR. BINGHAM: Just a moment, please.

We're with you. Go ahead and clarify it, please.

MR. ROSENTHAL: The NRC is performing a review of the System 80 standard plant offering and we will issue an SER on the System 80 standard plant offering and we wish to assure ourselves that Palo Verde may appropriately reference the standard System 80 NSSS design, and that is the motivation for this question. You need not comply with all aspects of the standard System 80 interface requirements, but should you not comply, then we would like to know what alternate paths you have chosen.

MR. BINGHAM: You are asking a general question. Let me give a general response and then perhaps we can look at some specifics later in the day or two to clarify it for the Board. We are required to meet all interfaces that are given to us by Combustion Engineering whether they are in the documents you mentioned or in other documents. Combustion is obligated to review our interpretation of the requirements to assure that we have incorporated their needs in the proper manner. Now, this would be for Palo Verde. If there

are some differences in the standard System 80 that are not applicable to Palo Verde, we would expect that Combustion Engineering would so notify us with the proper documentation and give us the interfaces that we need to meet for balance of plant. I am sure that we have done that and we do have documentation in the files that shows that CE has reviewed our interpretation of the information through drawings and documents.

I think, John, I would have to ask the Board to assure that Combustion Engineering has sent Bechtel all the proper documentation and that that which is being sent to NRC for review is compatible with what they have sent us for the interfaces. I believe the answer is correct that we have, but we have not taken those particular documents and gone line by line by line necessarily.

MR. KEITH: Combustion Engineering, when they send us documents such as the one you are referring to, they send us the standard System 80 document plus a document which is unique to Palo Verde, so that what we meet is really the combination of those two documents. Because there will be some things in System 80 which for one reason or other may not be applicable to Palo Verde, they issue this supplementary document which is unique to the project.

MR. BINGHAM: I don't know how well that helps with your question, but there is a base document System 80 and

there is a project document. As Dennis said, the two documents are put together and those are the documents that we use to meet the interface requirements.

MR. STERLING: As a clarification there, if there is a project-related document versus a System 80-related document, maybe it might be appropriate to say what kind of things cause you to have a project-related document, since we are referencing a System 80 plant.

MR. BINGHAM: I can give you an example, not in this particular area, but we do have a desert site and that requires a different capacity heat exchanger to cool the water, for example, and that would not be standard. That would be unique to Palo Verde.

MR. KEITH: In this area, we may have unique hardware and the power requirements for that hardware would be different than the general ones given for the standard System 80, so that due to the hardware which Combustion Engineering had purchased for Palo Verde, there would be different power requirements.

MR. STERLING: Such requirements that are more critical such as thermal requirements, those types of things, would not this project-related document be different than the System 80 document, or would it be a fair statement that the project-related document is stricter than the System 80 document?

MR. BINGHAM: Well, it is certainly site specific and I would guess that, in general, the overall requirements that you talked about would be the same as the standard System 80.

MR. ALLEN: Jack, getting back to your question, you don't look like you are satisfied or you didn't get what you wanted. Maybe you can clarify a little bit more what you are looking for.

MISS KERRIGAN: I think I will clarify a little bit. When you say you are in compliance with an interface requirement, you really may not be. It may just be that you are in compliance with some requirement of the project as defined specifically for the Palo Verde project.

MR. KEITH: When we talk about being in compliance with interface requirements here, we are in compliance.

MISS KERRIGAN: But in response to Mike's question, when you say you are in compliance, I understand that these interface documents are much more detailed and you may be taking exceptions for the Palo Verde project and those show up only in the project-related document, is that right?

MR. KEITH: We are in compliance with the Combustion Engineering requirements, but Combustion Engineering sends us two documents related to the requirements. One is the standard System 80. That is what we may not be in complete compliance with. The other is the Palo Verde. That is from

Combustion Engineering, so we are in compliance with the Combustion Engineering requirements.

MISS KERRIGAN: At the second meeting with NRC, could you provide us with some sort of detailed list of the differences between the project documents and the CESSAR 80 document? Is that possible? Someone in the audience is nodding their head.

MR. ALLEN: Does that satisfy you?

MR. BINGHAM: Sure.

MR. ROSENTHAL: You may need time to prepare a summary list and I may choose to read some of those plant specific interface documents. I did spend a day reading the standard System 80 ones. What I am interested in is not a question of does Combustion typically supply 23 relays and 6 contacts and now you need a twenty-fourth relay in the same actuation circuit in, let's say, the ESF auxiliary relay cabinet, but, rather, things like are the system qualifications for the System 80 or the environmental qualifications, heat load, different for Palo Verde.

MR. BINGHAM: We can respond to that.

MR. ROSENTHAL: Substantive rather than nit-picking.

MR. BINGHAM: They are not, and usually the qualifications are handled in separate topicals by Combustion Engineering, and I think their environmental qualification is CENPD 255 and I believe their seismic is 1.83, if I

remember correctly. Those documents will form the basis for the qualifications, and I would expect that for Palo Verde, we would be in compliance for the qualifications. In other words, what we are saying is that there are specific unique things at Palo Verde that require some clarification or modification of their basic criteria. They tell us what it is. We implement it. So for a particular project, if you add the documents that were specific to Palo Verde, that would give you the complete picture.

MR. ALLEN: Also, you could identify how we designate a difference between CESSAR and our FSAR, a colored page.

MR. BINGHAM: Yes. If there are major exceptions, they will be noted in the SAR. I don't know if there are any.

MR. KEITH: Not in this area.

MR. BINGHAM: There are none in this area that we know of, John.

MR. KEITH: That, of course, is referring once again to CESSAR, deviations to CESSAR interface requirements. Bill answered your question, Jack, that the big things are the same for Palo Verde and CESSAR. It is these things like your example of the number of relays where there are differences, and that is where this specific document comes in. We will provide that summary or we will provide the actual document for you.

MR. BARNOSKI: May I make a clarification? Maybe it is more procedural than anything else, but the process CE uses to go from a general System 80 to a project need I think is a CESSAR issue and probably needs to be pursued, if anyone wants to pursue it, on the CESSAR docket. I understand what you are saying is that, whatever process he goes through to give you those interface documents, that you feel you are in compliance with the ones that are in CESSAR and the more detailed ones that we send you.

MR. BINGHAM: That's right.

MR. ALLEN: Joe, did you have a question?

MR. MECH: Might I just introduce an example to show the kind of confusion that we get into or might get into? It is subject to a lot of qualification and possibly definition. CESSAR states very definitively that all the ESF are supported by two-out-of-four logic. Palo Verde states that a good many of their ESF features are supported by one-out-of-two logic. Without looking at the individual cases, you from the surface, at least, reach a contradiction.

MR. KEITH: We will be going into that difference. I think there is ample justification for our design.

MR. MECH: That is one of the things.

MR. KEITH: We will go into that in detail. For all of the CESSAR, the things we need to protect, CESSAR equipment, that is all Combustion Engineering logic and it is all

two-out-of-four, so it is other qualification of plant items where we get into the one-out-of-two.

MR. ROSENTHAL: I have some more questions. On the insulation of impulse lines from root to transmitter, what are the insulation and separation criteria?

MR. BINGHAM: John, we talk about separation at just about every IDR we have in some particular form, and rather than just give a general review here, say in the afternoon, we will come back and specifically tailor it to this particular IDR.

MR. ALLEN: Then you are going to cover it during the IDR?

MR. BINGHAM: We will cover it.

MR. ROSENTHAL: One of your interface requirements is on thermal limitations. Have you a monitor to assure compliance with the thermal limits?

MR. BINGHAM: Which figure are you looking at, please?

MR. ROSENTHAL: 1A-4, Item 7).

MR. KEITH: In meeting this, there is a question which has been around relating to environmental qualification and the failure of the ventilation system and we have responded to that in 3.11. I will try and remember as much of the details as I can of that. Basically, we get an alarm upon the failure of any safety-related ventilation equipment, and in the event of that failure, we would monitor

the temperature in that room by means of portable monitors so that we have a record if we exceeded the environmental qualification temperature in a given room.

MR. ALLEN: Do you have additional questions, Jack?

MR. ROSENTHAL: Yes. Then from a strictly electrical standpoint, I take it that you define HVAC as a supporting system for an instrumentation control device and that you monitor with temperature switches.

MR. KEITH: I believe it is a failure of power to that equipment.

MR. ROSENTHAL: And you alarm it via bells, whistles, plant computers?

MR. KEITH: The plant annunciator. Jack, for these supporting systems, they are also included in our safety equipment status system, which will be discussed later as far as the loss of power or anything like that.

MR. ROSENTHAL: A real quick question on Figure 1A-2. Are the transmitters in rack panels or in cabinets?

MR. KEITH: They are open racks or they could be wall mounted.

MR. ROSENTHAL: On Page 1A-8, you identify the color coding of protection associated circuits. How do you treat cables and ultimate equipment downstream of a qualified buffer which interfaces between safety and nonsafety systems and would it be formally classified as an associated circuit?

MR. KEITH: That is treated as non-IE cable downstream of an isolation device.

MR. ROSENTHAL: If I have a piece of safety equipment and I have a buffer that is qualified for 480 volts on the output, not affecting the input, then the cable downstream of that buffer is non-IE cabling, but I should not submit that cabling or circuitry to a credible fault which would result in imposing a voltage greater than the 480 volts, the buffer qualification.

MR. KEITH: We do take care of that concern in our cable routing program by assuring that cable downstream of the buffer is routed only in a tray which has cabling of a comparable voltage level, that qualified for the buffer, 125 DC or whatever.

MR. ROSENTHAL: You have labeled these cables A, B, C, D, J, K, L, M and A, B. I believe we saw some cables with X and Y designators on them, also, in the CE scope of supply. Do you have any special way of treating them other than as you stated earlier?

MR. STERLING: Just a clarification. I think those were instruments that were indicated as being an X and a Y and they weren't channelized per se. I believe it was the pressurizer level.

MR. KEITH: Those particular cables which you saw we treat as A and B.

MR. ROSENTHAL: That particular circuit then you properly address and we are all aware of that one. I am concerned that there may be others and I am hoping that maybe the answer is programmatic by virtue of the cable routing.

MR. KEITH: Well, let me try and see if this addresses your concern. If there is any cabling which we provide to Combustion Engineering equipment which has been identified as safety-related, it would be treated by us as A, B, C, or D, the Class IE cabling.

MR. ROSENTHAL: I'm sorry, I am being slow.

MRS. MORETON: Maybe I can clarify. Our instrument tag numbers contain additional information above and beyond what Combustion gives us. They contain a digit in there that identifies the safety channel. On the particular two you saw, which were pressurizer level instrument tags, those are A and B because the CE measurement channel block diagram identified the cable as A and B. Downstream of that where there is nonsafety-related instrumentation that also carries a suffix of X and Y, the balance of plant tag number would not contain a safety designator and that is treated as non-IE downstream of the isolation. The X and the Y as suffixes on the tag numbers are not really factored into the design other than they exist in our tag number as suffixes, but the key in our tag number is another designator which

comes off of the hexagons you saw in the block diagram.

MR. STERLING: Would it be a fair statement that all cabling that is IE is in one of the four channels? There are no separate channel cables outside those four?

MRS. MORETON: The four safety channels and non-IE channels.

MR. STERLING: There is no fifth or sixth channel? There are no separate routings throughout the plant that are separate from those four channels in the Class IE?

MRS. MORETON: Unless CE specifically required special separations, as I think they do in the Plant Protection System and the auxiliary relay cabinet, that is a true statement, and those are routed in special conduits separate from all other cable.

MR. STERLING: Is there a special color designation for those particular ones?

MRS. MORETON: Not that I am aware of.

MR. STERLING: Do they carry the four-channel red, green, yellow, blue? Are they all black?

MR. BINGHAM: We believe they carry the colors.

Excuse me, John, we are getting down into quite a bit of detail on the color coding. Would it be appropriate to spend a few minutes sometime during the two days to outline what is happening? I would have thought that at the CESSAR IDR, although I wasn't there, that the interfaces would match

what is being done in the balance of plant, and I sense some confusion or some uncertainty. Would it help if we sat down with Jack during a recess and just indicated to him how the two mesh?

MR. ALLEN: Well, I will leave that up to you, Jack. Are you getting what you need from this discussion or would you rather do it separate?

MR. ROSENTHAL: I am not a good note taker, so I would prefer that it became part of the transcript. It was an issue that was raised at a related IDR and I think it can be put to bed somewhere over the two days and I would like to finish it formally.

MISS KERRIGAN: Either during this meeting or during the NRC follow-up meeting during the week of July 27th.

MR. ALLEN: Why don't we go through the presentation? I know they are going to get into it a little more. Then if you have any additional concerns, we could do it at the follow-up meeting.

MR. KEITH: Can we clarify maybe right now, if you could, Jack, just what your concern is still?

MR. ROSENTHAL: Let me make a programmatic statement. When it appears and we have a transcript going that an issue is being raised, I think it would be best to finish it rather than leave it dangling. I think that is in everybody's interest. Now for the technical concern. I believe

that you answered my concern by virtue of your statement about your cable routing, and that is that wherever you have a non-IE cable that goes to a buffer which, in turn, attaches to a piece of safety-related equipment, you know what is in that cable, you know the qualification of the buffer, and that on a programmatic basis, you ensure that you don't violate the design criteria for the buffer. The other part, and we will use the example of a pressurizer level control, is that we have two circuits with information of some importance which are independent, are downstream of buffers, and it sounds as if you would then conceivably intermingle those as you went on in routing cable in the plant because they are non-IE and there really aren't good criteria.

MR. BINGHAM: Let me see if I can find a way to respond to this thing. As I understand it, there are some concerns about how we interpret the CE requirements, and it sounds to me like there is some confusion about the fact that has CE that the A/E, in this particular case Palo Verde, has interpreted their criteria properly and has routed the cables properly. Perhaps there was a response from CE to that question at the IDR, but if there was not, then I think, John, today we can perhaps chat with CE and see what they have done in order to assure themselves that we have interpreted their criteria properly. Once they have done that, we can spell out clearly the criteria which we can

give to you for your review. I think then that will tie together the CE criteria, how it was interpreted by the A/E in the routing, and you would have the whole picture. Am I getting into the right concern?

MR. ROSENTHAL: Fine. Mr. Sterling and Mr. Johnson are on the Board here and were on the Board at the Combustion meeting. We don't have a transcript, unfortunately, from that meeting. The two of them might be able to help me. I remember that they also had questions.

MR. JOHNSON: Perhaps I can clarify the concern. Once the cable has passed by the isolator, it is now non-Class IE. What quality assurance procedures are in effect to ensure that that non-IE cable stays in a voltage level tray that that cable is designated for? I understand that you would have a rigorous quality control procedure for the IE cables, but once you have a non-IE cable, what prevents that 480 volt cable from getting into a 4 kV volt cable tray?

MR. BINGHAM: That we can answer. Is that the only issue?

MR. ROSENTHAL: That and what are your criteria for separation of, let's say, these X and Y designated channels downstream of the buffers, which would normally be considered non-IE and could in principle be intermingled.

MR. BINGHAM: All right. Here I was focusing on assuring we understood the Combustion Engineering criteria

that pass on to us for those particular circuits, and we will search that out and then we will demonstrate that we do meet those criteria.

MR. KEITH: The routing of the non-IE cable downstream of the buffer, that is the question which I addressed earlier. That is covered in our cable routing program, and that cable routing program applies to non-IE cable as well as the IE cable. It is all one program, so it is basically all under the same quality assurance program. That program assures us that we do not route 125 volt cable in with 4,160 volt cable or whatever. So we take care of that. Now, using the pressurizer level as an example where we have these two transmitters which have been designated as X and Y by Combustion and which we route as A and B, we route that as Class IE cable and the indication which is required for post-accident monitoring comes off of that as Class IE, and then after that point, we come to an isolator and then we have some black cable, non-IE cable, which goes to the level control system, which is nonsafety. That black cable from both the A and the B may be intermingled. There are no requirements from Combustion Engineering and we do not impose any requirements to keep that cable separate from each other.

MR. STERLING: But you do have requirements that indicate what voltage level that cable can be routed in?

MR. KEITH: Yes. That is the other concern which we addressed. We do assure ourselves that that voltage cable stays within the qualification of the buffer.

MR. STERLING: The interface requirements for the X and the Y type instrument, Combustion tells you outside the hexagon, the little A's and the B's, what channel it should get power from, what channel it should be routed in and associated with upstream of the isolator?

MRS. MORETON: Correct.

MR. BINGHAM: Does that satisfy the Board, John?

MR. ALLEN: I don't see any more hands. Why don't we proceed?

MR. BINGHAM: There were some particular things we were going to respond to. I think Dennis tried to respond to those questions and I wanted to hear whether we have satisfied the Board in those areas or not.

MR. STERLING: It is a different topic than this.

MR. ALLEN: Well, let's wait. I want to find out if that is satisfactory with everybody or if somebody wants an open item on it and additional information.

Okay, Ed, did you have an additional question?

MR. STERLING: Yes. The mounting of the instruments you say is on open racks.

MR. BINGHAM: That's correct.

MR. STERLING: You also on Exhibit 1A-5, Item 11),

indicate that you are in compliance with not exceeding chemistry limits. Are there any instruments that are provided in the balance of plant that are in the spray environment?

MR. BINGHAM: What do you mean by spray?

MR. STERLING: Chemical spray inside the containment.

MR. KEITH: None that have to survive the environment. I mean, obviously, there are instruments inside containment which we provide in addition to those which Combustion provides, but none which are required post-accident.

MR. STERLING: Are there any of those that could be affected by the sprays that would adversely affect the operation of the plant if they fail?

MR. BINGHAM: Well, John, if you have the spray actuated, I would expect the operators would be quite alarmed, and perhaps you could discuss that with the operating department.

MR. ALLEN: I don't think that is what Ed is getting at.

MR. STERLING: No. I mean are the instruments that are in the containment that are not protected from the spray, are they designed such that the chemical impact of the spray is not going to adversely affect downstream of the instrument any of the safety systems or safe shutdown of the plant?

MR. KEITH: Ed, the equipment which we have which is not designed for these chemistry limits is all nonsafety

grade equipment and it could be adversely affected. Does that respond to your question?

MR. STERLING: Do those feed back into the safety systems?

MR. KEITH: No, none of that equipment feeds into the safety channels.

MR. STERLING: Then your answer is that it couldn't affect the safe shutdown or the safe operation of the safety channels?

MR. KEITH: That's correct.

MR. ALLEN: Any further questions?

MR. BESSETTE: Exhibit 1A-6, Item 12), on materials. Do you have any instruments within your scope on the reactor coolant pressure boundary that might have to meet the ASME code requirements for materials?

MR. KEITH: Not as part of the reactor coolant pressure boundary.

MR. BESSETTE: Expanding that a little bit, possibly in the engineering safeguards systems where the systems went operational and became part of the reactor coolant pressure boundary.

MR. KEITH: Staying within systems which are connected to the primary system, all that instrumentation is provided by Combustion Engineering.

MR. ALLEN: Are there additional questions? Anyone

else? I guess we are ready to go on to the next section. We plan to take a break about 10:00.

MR. BINGHAM: The next section is our system overview, Engineered Safety Features System. We will cover the BOP ESFAS design criteria, John, and would suggest after the questions, we will have a break, and then we will carry on with the system description.

MRS. MORETON: Referring to Figure 2A-1, which shows the Engineered Safety Feature System, which consists of those electrical and mechanical devices and circuitry, including the sensors that sense the process variables, through the actuation devices required to initiate protective action, we show here the NSSS Engineered Safety Features Systems, which was discussed at CESSAR, the Balance of Plant Engineered Safety Features System, including our ESF load sequencers. Both the systems do actuate the NSSS ESF system, the BOP systems, and the BOP support systems. Some examples of those systems include containment isolation, main steam isolation, auxiliary feedwater, fuel building essential ventilation, our BOP ESF systems, fuel building essential ventilation, containment purge isolation, control room essential ventilation, and containment combustible gas control system, which is a manual system. BOP support systems include the diesel generators, the DG fuel oil storage and transfer, Class IE DC power, Class IE AC power,

essential cooling water, essential spray ponds, and chilled water system. For today, we will be discussing our BOP ESFAS. We will cover typical actuated device logics, which will address logics for all the ESF and ESFAS support systems.

Exhibit 2A1-1, Balance of Plant Engineered Safety Features Actuation System Design Criteria. The Balance of Plant Engineered Safety Features Actuation System, the BOP ESFAS, shall provide initiating signals for Balance of Plant Engineering Safety Feature System components which require automatic initiation following a design basis event. The BOP ESFAS actuation signals are the fuel building essential ventilation actuation signal, containment purge isolation actuation signal, control room ventilation isolation actuation signal, and control room essential filtration actuation signal. These automatically actuated BOP ESF systems are the fuel building essential ventilation, containment purge isolation, control room essential ventilation, and their support systems. There is one manually actuated BOP ESF system, which is the containment combustible gas control system.

Exhibit 2A1-2. Specific design criteria for the BOP ESFAS as detailed in IEEE 279-1971 "Criteria for Protection Systems for Nuclear Power Generating Stations," Section 3, are as follows, and will be covered over here, which include the design basis events, monitored variables,

number and location of sensors, normal operation nominal variable values, normal operation variable limits, actuation setpoints, margin to actuation, qualification, redundancy, and failure modes, and minimum performance requirements.

Design basis events requiring BOP ESF action are shown on Exhibit 2A1-3. An example of a typical design basis event would be a fuel handling accident in the containment building, which is mitigated using the containment purge isolation system and protection by the control room operators through the essential ventilation system.

Basis (2), shown on Exhibit 2A1-4, covers monitored variables initiating protective signals and the initiating protective actions. An example here would be the fuel building airborne activity, which actuates our fuel building events ventilation actuation signal. This signal actuates the fuel building filtration portion of the fuel building essential ventilation system and causes pressurized filtered recirculation of the control room essential ventilation system.

Basis (3) on Exhibit 2A1-5 covers the number and location of sensors required to monitor the variables. Another example here is the fuel building exhaust duct radiation level. It is monitored by Beta-scintillation detector. There is one detector located at the fuel building exhaust. The redundant parameter is monitored by a

Geiger-Mueller counter overlooking the fuel pool.

Bases (4), (5), (6) and (7) are covered on Exhibit 2A1-6. They cover the normal operation limits for each variable, the actuation setpoints, and the margin between the operation limits and actuation setpoints. An example shown here for the fuel building exhaust duct high activity. At full power, the nominal is at less than sensitivity, which is less than 10^{-6} microcuries per cubic centimeter. The normal operation limit is the same. The actuation setpoint is 2 to the 10^{-6} microcuries per cubic centimeter, and the margin to actuation is therefore 1×10^{-6} microcuries per cubic centimeter. Basis (8), shown on Exhibit 2A1-7, covers the qualification, redundancy, and failure mode requirements of the BOP ESFAS. BOP ESFAS components shall be qualified to withstand and remain operable during the environmental conditions maintained at the equipment locations before, during, and after the design basis events. The BOP ESFAS components shall withstand and remain operable during and after an SSE. A single failure within the BOP ESFAS shall not prevent proper protective action at the system level. A loss of power to the BOP ESFAS channels or to the logic system causes system actuation.

Finally, Basis (9), covered on Exhibit 2A1-8, covers the minimum performance requirements of the BOP ESFAS. This includes response time, which is the sum of the

measurement channel response time and the BOP ESFAS logic response time, and includes the measurement channel accuracy. An example here for the fuel pool area radiation, measurement channel response time is one-half second, BOP ESFAS logic response time is 1.278 seconds, with the measurement channel accuracy of plus or minus 20%.

Continuing on with the design criteria, Exhibit 2A1-9, only those ESF systems that, when actuated, do not cause a plant condition requiring protective action or disturb reactor operations shall be controlled by the BOP ESFAS. The automatically actuated BOP ESF systems shall use one-out-of-two input signal logic. The BOP ESFAS logic shall be contained in separate enclosures isolated from the NSSS two-out-of-four ESFAS and reactor protective system logic. The actuation system consists of the sensors, bistables, initiation logic, and actuation logic that monitor selected plant parameters and provide an actuation signal to each individual actuated component in the ESF system if the plant parameters reach preselected points. The BOP ESFAS shall provide the logic to automatically start and sequentially load the diesel generators and to shed all 4.16 kV Class IE loads on a loss of power.

Exhibit 2A1-10 addresses the standards used in the design of the BOP ESFAS, which include the IEEE standards, essentially 10CFR50, Appendix A.

Exhibit 2A1-11. The initiating circuits shall continuously monitor key process variables indicating accident conditions and transmitting digital, or on/off, signals to the BOP ESFAS initiating logic. The BOP ESFAS initiating logic provides two ESFAS initiation signals for the actuation logic. The system shall monitor the under-voltage relays on the 4.16 kV Class IE bus and initiate a logic signal on a two-out-of-four coincidence of bus under-voltage. This logic signal will be used to shed all Class IE 4.16 kV loads except the load center transformers, shed certain 480 volt loads, start the diesel generator, start equipment required after a loss of offsite power, and trip the 4.16 kV Class IE bus preferred power supply breakers.

Exhibit 2A1-12. The system shall provide sequencing logic for sequential loading of ESF and forced shutdown loads onto the ESF bus upon closing of the diesel generator breaker, a safety injection actuation signal, or an auxiliary feedwater actuation signal. The BOP ESFAS shall be designed to the requirements for nuclear safety-related systems such that the devices must maintain their safety-related functional capability under all normal and abnormal plant operating conditions. The two redundant initiating logic systems and the two redundant actuation logic systems shall be separated and identified by appropriate colored nameplate and wiring separation identification. Power for

each independent and redundant logic subsystem shall be supplied from a separate Class IE 120 volt-AC vital instrument and Class IE 125 v. .t-DC distribution bus. The system shall accept power input line variations and transients without producing false protective actuations or preventing required response to accident conditions.

Exhibit 2A1-13. Provisions for testing shall be in accordance with Reg. Guide 1.22 and IEEE 338-1971. Interlocks shall prevent the operator from bypassing more than one sensor channel at a time for any one type of trip. This interlock shall not compromise the redundance and independence of the channels. Should another accident condition occur after the load sequencer has started, the sequencer shall reset to zero. Equipment in operation at this time shall remain in operation. If a loss of offsite power signal is initiated after the load sequencer has started, all loads will be shed and resequenced on the diesel generator breaker closure.

This concludes the BOP ESFAS presentation.

MR. BINGHAM: John, are there any questions from the Board on the design criteria?

MR. ALLEN: I am sure there are.

Ed, go ahead.

MR. STERLING: Do you have thermal design criteria for the design limits?

MR. BINGHAM: Which figure are you looking at, Ed?

MR. STERLING: Well, there isn't one listed.

MR. BINGHAM: What is the question, please?

MR. STERLING: A thermal requirement for where these logics and actuation circuits should be located.

MR. BINGHAM: You are talking about equipment qualifications?

MR. STERLING: Well, there is a thermal requirement in the CESSAR interfaces. Do we have a design criterion for our electronics as to what thermal --

MR. BINGHAM: Yes, and at the IDR, I don't recall whether you were on the Board or not, we did go through the zones and the location of all the equipment and the sequencing we go through to qualify it. I believe that information is covered in detail in that particular transcript.

MR. STERLING: That would be helpful. You were referring to that transcript, then?

MR. BINGHAM: Yes.

MR. STERLING: On the load sequencer, Exhibit 2A1-13, do you intend to go through the complete description of what you are doing at that time?

MRS. MORETON: Yes, it will be covered under the ESF load sequencer. The design criteria will be repeated at that time and the system description will be covered.

MR. STERLING: I think I will hold my questions,

because I want to get into more detail on that.

MR. ALLEN: Further questions?

MR. KONDIC: Exhibit 2A1-5, the control room air intake chlorine level, is it done continuously or periodically, or how often, because it is difficult to visualize that that is continuous.

MRS MORETON: Continuously.

MR. KONDIC: Really? I'm glad.

MR. MECH: In a couple of places, you refer to the chlorine. Reading the FSAR, apparently you do not use chlorine on site.

MR. BINGHAM: We do not use chlorine gas.

MR. MECH: You do use it?

MR. BINGHAM: Do not.

MR.MECH: Then what is the reason or what is the logic behind the chlorine detector? I have looked through it to see what the necessity was.

MR. BINGHAM: What we use is sodium hydrochloride at the site. We did in the early days have a chlorine gas as part of our use, particularly in the water reclamation facility. The detectors are still there in case there is an inadvertent railroad car or truck or something nearby that might spill chlorine content.

MR. MECH: But you don't really need them.

MR. BINGHAM: No.

MR. ALLEN: Any Board member? Jack.

MR. ROSENTHAL: Do you have a containment vacuum relief system?

MR. KEITH: No.

MR. ROSENTHAL: On Exhibit 2A1-5, is the containment hydrogen analyzer, which works on the basis of thermal conductivity, the same hydrogen analyzer which will be used to satisfy the NUREG-0737 requirements?

MRS. MORETON: Yes.

MR. ROSENTHAL: Later on in the presentation, I would like a little bit more information on the sensor itself, the thermal conductivity device rather than --

MRS. MORETON: We can either cover it here or we can cover it under post-accident monitoring.

MR. ROSENTHAL: Later. This is related to Exhibit 2A1-10. You call out IEEE 338-71. I believe the later versions of IEEE 338 require response time testing, and on Exhibits 2A1-6 and 8, talking about response times, can you describe the degree to which the systems in fact differ from 338-75 or 77? I recognize that the licensing basis for the plant is the 338-71 version.

MR. BINGHAM: Would it be adequate to just address how we handle response time testing? Is that your concern?

MR. ROSENTHAL: There are two areas. One is the specific response time testing, and there is another area,

which is the licensing basis of the plant, because the docket date is 338-1971. I am under instructions, one, that you need not conform with later versions of the IEEE standards, but, two, we are supposed to understand where differences between conformance to the later versions exist and be able to draw the conclusions that the plant is safe.

MR. BINGHAM: We understand. Give me just one second.

MISS KERRIGAN: We would defer that question until the second meeting. It is probably a more detailed question, but let's leave it on the record and address it in the second meeting.

MR. BINGHAM: Janis, I am not sure that we need to do that necessarily. We wanted to try to take care of the needs, and we do appreciate the problem that Jack has. I was exploring whether we were going to cover it when we talking about Reg. Guide 1.18 or whether we are going to cover it in reviewing the SRP's, and maybe at that time we can address that particular issue. Would that be satisfactory?

MR. ROSENTHAL: Sure. You will pick up the response time testing at that time, also?

MR. BINGHAM: We will pick that up at that same time.

MR. ROSENTHAL: Fine. I have one last one in this section, and I am asking it because this is a design review meeting rather than a licensing type meeting. That is, having gone to all the pains on the undervoltage trip and loss of

offsite power relationship to the sequencer, why don't you trip the reactor, also, on loss of offsite power directly rather than indirectly?

MR. BINGHAM: John, would you like APS to address that issue? It is our criterion from APS to have a plant that will stay on line with loss of offsite power. Perhaps a member of APS might want to discuss the rationale with the Board.

MR. ALLEN: It was a design criteria I remember for APS when we got the NSSS system to try to prevent tripping of the reactor and keep the reactor on line as long as you can. Since there is no firm requirement from the regulators, that has been our design basis from the start. That and other cases also. What was the basis for your question?

MR. ROSENTHAL: I concur with you that there is no regulatory requirement and I only bring it up because it is a design review meeting and I am trying to understand the system. Post TMI, there was a fair amount of discussion of what would be called anticipatory trips and there seemed to be varying design philosophies, and I just thought I would like to understand why you don't do it, because if you lose offsite power, you are going to lose the plant. You can't run your primary pumps, for instance.

MR. ALLEN: If you look back, if you can take the reactor system down in a normal mode rather than tripping it,

you are preventing some kind of a transient. Everv time you trip the reactor, you get some kind of a transient on the system, so if you can minimize the number of trips, then you minimize the number of transients.

MR. KEITH: I think we need to clarify one thing Jack said on the pumps. The reactor coolant pumps are transferred to the turbine generator so that what we are designed for is to take the loss of the grid and keep the plant -- you know, without tripping the reactor, we keep the plant on line. The turbine generator will continue to run.

MR. ROSENTHAL: I didn't realize that the pumps were on the diesels.

MR. KEITH: On the turbines.

MR. ROSENTHAL: On the turbines.

MR. BINGHAM: Any other questions, John, from the Board?

MR. ALLEN: Anybody over here?

MR. BINGHAM: This might be an appropriate time to break.

MR. ALLEN: Why don't we have about a 15-minute break. Try to be back here about ten after.

(Thereupon a brief recess was taken, after which proceedings were resumed as follows:)

MR. ALLEN: Bill, why don't you proceed with the next

section.

MR. BINGHAM: We will now proceed with the System Description, Section 2.A.1.B.

MRS. MORETON: Before we get into the system description, we have prepared Figure 2A1-1 to show our signals from manual input, alarm, lights, OR gate, AND gate, not, on delay, off delay, which is the timed memory, high bistable showing the setpoint, memory set/reset, some abbreviations that you will see on the logic diagrams, safety equipment actuated status, which is part of our safety equipment status system, safety equipment inoperable status, and HS, which simply means handswitch.

Exhibit 2A1-14, the BOP ESFAS System Description. The BOP ESFAS measurement channels, process measurement channels are used to perform the following functions: Continuously monitor each selected generating station variable, provide indication of operational availability of each sensor to the operator, and transmit these signals to bistables within the ESFAS initiating logic. Protective parameters are measured with two independent process measurement channels.

We will be referring to Figure 2A1-2 as we go through this.

Exhibit 2A1-15 on the measurement channels. A measurement channel consists of instrument sensing lines, sensor, transmitter, power supply, isolation device, if that

is required to go to the plant annunciator or plant computer, and indicator to the operator. Each redundant measurement channel -- this (indicating) is our measurement Channel A, this (indicating) is measurement Channel B -- is powered by a separate and independent 120 volt AC vital distribution bus. The BOP ESFAS bistable and initiating logic is shown here on Figure 2A1-2. Initiating logics compare signals received from the sensor with a predetermined initiation setpoint in this bistable here (indicating), provide channel and signal status information to the operator in the form of lights on the front of BOP ESFAS cabinet, and annunciation to the plant control room operator, and they provide two ESFAS initiation signals for the actuating logic, one in this line here. The cross-channel logic is redundant and they are electrically isolated and physically separated.

Exhibit 2A1-16. The initiating logic does consist of the bistables, bistable output relays, trip output signals, indicating lights, and interconnecting wiring. Signals from the protective measurement channels are sent to comparator circuits where the input signals are compared to predetermined setpoints. Whenever a channel parameter reaches the predetermined setpoint, the channel bistable de-energizes an output relay. Each redundant channel bistable relay is supplied from a separate 120 volt vital AC bus. This would be, for example, from Channel A (indicating), from Channel B

(indicating). The bistable setpoints are adjustable from the front of the cabinet. Access is limited by means of a key-operated switch. Bistable setpoints are capable of being read out on a display located on the cabinet. The ESFAS initiation signals are generated in two channels designated A and B. A signal from the bistable output relay in either or both protective measurement channels generates ESFAS initiating signals to both actuation channels.

Exhibit 2A1-17, actuating logic. Referring back to Figure 2A1-2, the actuating logic performs a one-out-of-two incidence of the two channels, generates an output to the operator, provides a means for manual initiation, as shown here, in the control room. It provides annunciation out to the operator. The actuating logic is located in two ESFAS cabinets. The top portion of the slide would be in ESFAS Cabinet A; the bottom portion of the slide would be ESFAS Cabinet B. Each cabinet contains the logic for the ESF load group equipment. One cabinet contains the logic for Load Group 1 equipment and the other for Load Group 2 equipment.

Exhibit 2A1-18. The two initiating signals are arranged in a one-out-of-two logic in each actuation channel. Actuation of either signal de-energizes the group relay associated with that channel and results in an actuation signal. Each channel is supplied from a separate 125 volt AC distribution bus and a separate 125 volt DC distribution

bus.

ESF System Actuation. Components in each BOP ESF system are actuated by group relays. The group relay contacts are in the power control circuit for the actuated components of each ESF system. The initiating and actuating logic causes de-energization of the actuation relay whenever the bistable output relay is de-energized. De-energization of the group relay actuates the ESF system components.

Exhibit 2A1-19, Channel Bypasses. Initiating logic bypasses are provided in the BOP ESFAS and are employed to remove the initiating logic from service for maintenance. The actuating logic is converted to a single active channel for the ESFAS-monitored variable bypass. The bypass time interval for maintenance is a very short interval such that the probability of failure of the remaining measurement channel and initiating logic is acceptably low during maintenance bypass periods. Other ESFAS-monitored variable initiating logics that have not been bypassed in either of their two channels remain in a one-out-of-two actuating logic. The bypass is manually initiated, as shown on Figure 2A1-2. It does cause a block at the channel level of the initiating logic. An electrical interlock, shown here (indicating), is also electrically isolated and physically separated. The electrical interlock does prevent bypass of more than one channel at any one time. Bypasses are

annunciated visually and audibly to the operator. This is on the front of the BOP ESFAS cabinet, annunciation to the control room operator via the plant annunciator.

Exhibit 2A1-20, Operating Bypasses. The BOP ESFAS does not have any operating bypass system. Electrical interlocks in the BOP ESFAS prevent the operator from bypassing more than one channel at any one time.

Exhibit 2A1-21, Redundancy. Redundant features of the BOP ESFAS include two independent channels from process sensor/transmitter through the actuation output relays. Two initiating logic paths are present for each actuation signal. Each actuation signal actuates two output trains so that redundant system components may be actuated from separate trains. Power for the system is provided from two separate buses. Channel A is powered from the Load Group 1 bus and Channel B is powered from the Load Group 2 bus. The result of these redundant features is that the system does meet the single failure criterion.

Exhibit 2A1-22, Diversity. The BOP ESFAS is designed to eliminate credible dual channel failures originating from a common cause. The failure modes of redundant channels and the conditions of operation that are common to them are analyzed to assure that the monitored variables provide adequate information during the accidents, the equipment can perform as required, and the interactions of protective

actions, control actions, and the environmental changes that cause, or are caused by, the design basis events do not prevent the mitigation of the consequences of the event.

Exhibit 2A1-23, continuing on diversity, the system cannot be made inoperable by the inadvertent actions of operating and maintenance personnel. In addition, the design is not encumbered with additional components or channels without reasonable assurance that such additions are beneficial.

We will now discuss a little bit about testing. Provisions are made to permit periodic testing of the BOP ESFAS. The tests will cover the trip actions from sensor input through the protection system and the actuation devices. The system test does not interfere with the protective function of the system, and such testing does meet the requirements of IEEE Standard 338-1971 and Reg. Guide 1.22.

Exhibit 2A1-24, continuing with testing. Testing is performed on the BOP ESFAS by complete actuation such that the BOP ESFAS does not disturb normal plant operating conditions. Sensor checks are performed during reactor operation by cross-checking outputs of similar channels and cross-checking with related measurements. During extended shutdown periods or refueling, these measurement channels are checked and calibrated against known standards. The bistable trip test is accomplished by manually varying the

input signal to the trip setpoint level on one bistable at a time and observing the trip action, and it is done at this point (indicating) entering the bistable.

Exhibit 2A1-25. When the bistable of a protective channel is in a tripped condition, the following conditions should exist: The bistable output relay is de-energized, the group relay in each actuation channel is de-energized, the ESF components are in the ESFAS actuation position, and actuation is annunciated in the control room, so there will be two separate places for trip annunciation and actuation annunciation.

Exhibit 2A1-26. Proper operation may be verified by the following: Checking the position of each ESF component, checking the actuation annunciation, and checking the ESF component status indication. What is done here is repeated for the other bistable.

Continuing on with Exhibit 2A1-26, response time testing. Response time testing will be performed at refueling intervals. These tests include the sensors for each ESFAS channel and are based on the previously defined system response time criteria.

Exhibit 2A1-27. We will now go into some of the BOP ESFAS acutated systems and explain their function in the ESFAS specific logic. Fuel Building Essential Ventilation System. In the event of fuel handling accident in the spent

fuel area, sensors in the fuel building will detect the fission products released from the fuel. The fuel building essential ventilation actuation signal, called FBEVAS, is initiated by one-out-of-two high airborne activity signals from radiation monitors. One of these is a gaseous monitor, it is in the fuel building normally, and the other is an area radiation monitor on a wall overlooking the fuel pool. These two signals combine in the fuel building essential ventilation system to provide the FBEVAS actuation. On Figure 2A1-3, the FBEVAS also sends a signal to the CREFAS logic that we will discuss in a few minutes. The fuel building essential ventilation system is automatically actuated by an FBEVAS from the BOP ESFAS to reduce the release of fission products into the environment.

If we refer to our simplified diagram of the fuel building essential ventilation system, Figure 2A1-4, we see radiation monitoring overlooking the spent fuel pool, another radiation monitor on the exhaust duct. On high radiation, these generate the FBEVAS signal which performs to terminate normal air handling units intake and exhaust by closing the dampers and stopping the fans and will actuate intake through the essential air filtration units out to the atmosphere. It causes a slight depressurization of the fuel building to prevent out leakage other than through the essential air filtration units.

Exhibit 2A1-28. The system is designed such that a loss of electric power to one-out-of-two like channels will cause a fuel building essential ventilation actuation signal and actuate the system. Manual initiation of the fuel building essential ventilation system is provided in the control room. The fuel building essential ventilation system is composed of components in redundant load groups. You can see here (indicating) there are two essential air filtration units, two sets of dampers. Independence is adequate to retain the redundancy required to maintain equipment functional capabilities following those design basis events that require fuel building ventilation isolation.

Exhibit 2A1-29. The fuel building essential ventilation actuation system is combined with the safety injection actuation system in the NSSS ESFAS in the device control circuits so that any one of the signals activate the required devices. During SIAS, the fuel building/auxiliary building essential ventilation system is aligned to exhaust from the auxiliary building. The SIAS takes precedence over FBEVAS should both signals be present at the same time.

Figure 2A1-5. As you can see, this is a typical actuated device logic for one of our fuel building essential ventilation fan. The SIAS is combined in this OR circuit with the FBEVAS to start the fan.

Back to Figure 2A1-4. On the SIAS mode, intake

is taken from the auxiliary building ESF pump rooms. The dampers are aligned. These dampers (indicating) would be closed taking air from the fuel building such that the auxiliary building pump rooms are exhausted through the essential air filtration units.

Continuing on with another ESF system, Exhibit 2A1-30, the containment purge isolation system. In the event of a fuel handling accident inside the containment, sensors will detect the fission products released from the fuel. Containment purge isolation actuation signal is initiated by one-out-of-two high airborne activity signals from redundant radiation monitors located in close proximity with the power access purge exhaust duct and the refueling purge exhaust duct. These two monitors are shown on Figure 2A1-6. The containment purge isolation system is automatically actuated by the CPIAS from the BOP ESFAS to prohibit release of radioactive material into the environment. The CPIAS also sends a signal to the CREFAS logic, which we will get into in a few minutes.

Exhibit 2A1-31. The system is designed so that loss of electric power causes actuation. Manual initiation is provided in the control room. The containment purge isolation system is composed of components in redundant load groups such that independence and redundancy is maintained to retain the functional capability following design basis

events. The CPIAS is combined with the containment isolation actuation signal in the control circuits of the isolation valves such that either signal as shown on Figure 2A1-7 can actuate the containment purge isolation valves.

Exhibit 2A1-32, our control room essential ventilation systems. The control room essential ventilation systems are the control room isolation system and the control room essential filtration system. The control room ventilation isolation actuation signal, CRVIAS, is initiated by one-out-of-two control room outside air intake high chlorine signals. That is shown on Figure 2A1-8. The control room ventilation isolation system is automatically actuated by a CRVIAS from the BOP ESFAS to activate the control room essential air handling units and isolate the control room from outside air. The control room essential filtration actuation signal, or CREFAS, is initiated by one-out-of-two control room outside air intake high airborne activity signals. It is also actuated, as we were pointing out earlier, by a fuel building essential ventilation actuation signal or a containment purge isolation actuation signal.

Exhibit 2A1-33. The control room essential filtration system is automatically actuated by a CREFAS from the BOP ESFAS to activate the control room essential air handling units and to route the air through the essential

filtration units to pressurize the control room and prevent infiltration of untreated air. We have a simplified diagram on Figure 2A1-10. You will notice the outside air intake. Radiation is monitored. On high radiation, a CREFAS is actuated. Chlorine detectors will actuate a BOP ESFAS signal, CRVIAS. There are two modes of operation. Both of them do start the essential air handling units and isolate the normal air intake to the control room. On the CREVAS mode, the circulation is performed as well as intake from outside air to slightly pressurize the control room and prevent in-leakage. On the CRVIAS mode, essential intake is eliminated and air is just recirculated through the essential air handling units. The system is designed so that loss of electric power to one of the two like channels does perform actuation. Manual initiation of both signals is provided in the control room.

Exhibit 2A1-34. Both of the systems are composed of components in redundant load groups and CREFAS is combined with the SIAS in the device control circuits so that any one of the signals does actuate the required components. Figure 2A1-11 shows a typical actuating device logic. This is for one of the dampers that closes on the CRVIAS and will open on an SIAS or a CREFAS, the logic being combined at the device level. The CRVIAS is combined with the signals that actuate the control room essential filtration system in the

device control circuits so that any of these signals combined in a logical OR can actuate the isolation valve common to both of the control room essential ventilation systems. The CRVIAS takes precedence over CREFAS to isolate the control room should both signals be present at the same time.

Exhibit 2A1-35. In addition to the automatic initiating signals, two independent smoke detectors are provided in the outside air intake plenum. Upon detection of smoke, an audible and visible alarm will alert the operator to manually initiate the control room ventilation isolation system.

Exhibit 2A1-36, containment combustible gas control system. The containment hydrogen gas concentration may increase to a combustible concentration following a LOCA. In the unlikely event that a LOCA does occur, the containment hydrogen gas concentration is maintained less than the lower combustible limit by operation of the containment combustible gas control system. The principal parameter monitored for determining when the containment combustible gas control system is to be placed in service is hydrogen concentration. The containment hydrogen analyzer is normally on standby. Following a design basis event, the hydrogen analyzer is placed in service with controls mounted on the main control board. The containment combustible gas control system components are controlled manually from control switches

located at local panels. The local panel will be accessible after a design basis event.

Exhibit 2A1-37. A control switch with an override feature is provided for each of the containment combustible gas control system isolation valves. Figure 2A1-12 shows the control switch performing the override. This control switch override feature is functional only after receipt of a containment isolation actuation signal shown here (indicating). If the containment isolation actuation signal is not present, the override will not be enabled. The open and closed positions of these valves, in addition to the override status, are indicated in the control room. We will be going into a lot more detail on overrides and how they are implemented in a few minutes. The containment combustible gas control system is composed of components in redundant load groups. The containment combustible gas control system test pressure is greater than the peak containment design pressure. This precludes system overpressurization by the inadvertent opening of the isolation valves.

That concludes the BOP ESFAS presentation.

MR. BINGHAM: Any questions.

MR. MARSH: On Exhibit 2A1-24 with regard to bistable trip testing, you state manually varying the input signal to the trip setpoint level on one bistable at a time is accomplished to check the trip action. Could you explain in

a little more detail how that is accomplished? Particularly I am concerned about what means is provided to assure that the system is returned to normal following the test.

MRS. MORETON: On the radiation monitor, the bistable is actually part of the radiation monitoring system. There is a local unit that is plugged into the radiation monitor where the signals can be varied and they are displayed through that unit back to the operator. It is accessible only by key lock control. Because he has that display, the technician would then have to verify that he resets his setpoint back to where it should have been.

MR. MARSH: That is done at the field device?

MRS. MORETON: It is done at the radiation monitoring cabinet in the control room. If testing is performed at the field device, it would automatically reset when you go back into normal operation.

MR. ROSENTHAL: I would like a little bit more explanation on the bistable test. A bistable is essentially a summer. Either you put in a test signal to that leg which would receive the monitoring device or alternately you can change the other leg of the summer reference or the setpoint signal. In which cases are you injecting a signal in lieu of the normal sensing device and looking at where the bistable changes stage and in which cases are you changing the referencing, which I would call the bistable setpoint

typically operated by a part with a screwdriver, and in the latter case, how do you accomplish the reset?

MR. BINGHAM: Let's have Steve Shepherd answer that question, since it is part of the radiation monitoring system we are dealing with right now.

MR. SHEPHERD: There are two ways to check. The first way is as we mentioned a minute ago, which is to physically move the setpoint down and bring it back up again. The other way is to adjust the setpoint such that when the unit goes into automatic check source, it physically perturbs the measured variable by exposing the radiation so it is coming back, so it automatically goes through the system. You can do it from the sensor level and you can do it from the setpoint level.

MR. ROSENTHAL: When do you do which to what?

MR. SHEPHERD: You would do this as part of the response time testing at refueling. There is automatic check source activation normally once a day, but that is not checking setpoint, that is checking response to monitor, but you can move the setpoint down to check it at any time you want to, since actuation of the device doesn't cause any problems. It normally would be at a refueling period.

MR. ROSENTHAL: That is the sensor half. On the screwdriver to a part half, the setpoint, how do you reset the setpoint?

MR. SHEPHERD: Physically, assuming that we are making the change at the field unit, you administratively turn the control panel to local. That issues the alarm to the system so it is aware you are in a test mode. You use a key path, physically key in, since it is a digital computer system, a new setpoint. You evaluate the results and then you can return it. However, if you do not return it, when you turn the key back to normal, the system will automatically reset. Now, in the control room master console, if you make that same change, whatever you now select becomes the permanent setpoint until you administratively change it back.

MR. ALLEN: One thing you want to remember here, Jack, he is talking just about the radiation monitoring and not necessarily bistables and some of the other stuff, because that's different.

MR. ROSENTHAL: What do you do at the bistables?

MR. BINGHAM: Excuse me, what is the next question, John? What about the bistable, is that the question, Jack?

MR. ROSENTHAL: Mr. Allen, can you clarify your clarification?

MR. ALLEN: What I indicated was what he is talking about in this digital key in is strictly for radiation monitoring systems. He is not indicating it is done the same way on all the rest of the ESFAS.

MR. KONDIC: Exhibit 2A1-36, the second paragraph, the containment hydrogen analyzer. How and when do you check its operability, and, second, what kind of alarm annunciation it gives when there is hydrogen?

MR. SOTEROPOULOUS: The hydrogen analyzer as it is presently mechanized to test, we could put the device into a calibrated mode where we could inject into the system a 4% concentration of hydrogen and the system would go into alarm.

MR. KONDIC: What kind of alarm? Annunciator or sound alarm?

MR. SOTEROPOULOUS: It would be an annunciator alarm.

MR. KONDIC: Thank you.

MR. ROGERS: I want to go back to Figure 2A-1 and also Exhibit 2A1-24 and ask for a clarification. On Figure 2A-1, on the right-hand side, there is a list of balance of plant systems which seems to indicate that it includes such things as the containment isolation, main steam isolation, and auxiliary feedwater. The page right after that doesn't list those as systems that you are going to discuss. Clearly, Exhibit 2A1-24 says that you test balance of plant systems on line, and I am wondering if you can do a test of a main steam isolation on line without disturbing the plant. Are you going to address these main steam isolation, auxiliary feedwater, and containment isolation as a part of

this presentation, Bill?

MRS. MORETON: They will be addressed only from a typical actuated device logic level. The reason they are on there is because they are BOP ESF systems, but they are not actuated by the BOP ESFAS, which is the system description we just went through. They are BOP ESF systems, but they are actuated by the NSSS ESFAS.

MR. ROGERS: So the testing and design criteria are really not covered in this particular system review; they would have been covered at the Combustion Engineering system review?

MRS. MORETON: The testing of the ESFAS would have been covered at the Combustion Engineering review. The testing of the components would be covered at those various system reviews.

MR. ROGERS: Well, let me ask that again. Whatever actuates main steam isolation and how that is tested and how the logic is set up and design criteria for main steam isolation would have been covered at the Combustion Engineering system review, is that correct?

MR. BESSETTE: That's correct.

MR. JOHNSON: May I clarify that? Just the testing of an MSIS itself. The MSIV test was not covered.

MR. ROGERS: I understand. We are talking about the instrumentation and controls, not the hardware of the valves.

MR. JOHNSON: Not the controls of the valve, either, just the MSIS signal itself. It did not get into the actuation device logic circuitry. That is downstream of the NSSS ESFAS. That was not discussed in the CESSAR review.

MR. ROGERS: Will that be discussed here?

MRS. MORETON: The typical actuated device logic will be discussed. The specific testing of the MSIV, no.

MR. STERLING: On that same list, do you intend to talk about the atmospheric dump valve? That is not on that list.

MRS. MORETON: The atmospheric dump valves are part of the safe shutdown system and they will be discussed when we discuss the safe shutdown system.

MISS KERRIGAN: I am still kind of unclear about Carter's question. Who is going to address it? It sounds like CE isn't and it sounds like balance of plant isn't. Who is going to address it?

MR. BINGHAM: Let me see if I can try. What Mary said was we are not going to specifically deal with the particular one he had in question. We are going to talk typical. If there is a need from the Board to explore a particular one, we will explore it.

MISS KERRIGAN: I think that was Carter's question.

MR. ROGERS: Well, my question is really one that comes from Exhibit 2A1-24. It talks about the testing on

line, and going from that and back to the list in Figure 2A-1, it shows this main steam isolation as being part of the balance of plant. I started asking for clarification. It doesn't seem that you could test the actuation logic of main steam isolation under what you state right here on Exhibit 2A1-24, and if that is not correct, where is the testing covered? Are you going to discuss it here or was it discussed at Combustion Engineering, or was the logic for that circuitry, and how are tests performed in operation?

MR. BINGHAM: I think that is probably some Chapter 10 things, but, Carter, we will take a look at the break and see if we can put it in perspective for the Board. If it would help for this discussion, we'll talk about it. This chart was trying to really give you the scope of where things fell, where the interfaces were, how we categorized them with the SRP's as general overall information of how to tie the interfaces together rather than to give you an outline of what will be covered in the presentation.

MR. ROGERS: Bill, I understand that, but I was confused.

MR. BINGHAM: John, are there any other questions?

MR. ALLEN: I've got a couple, Bill. Those detectors for smoke, are those IE sensors?

MRS. MORETON: No.

MR. ALLEN: Also, I noticed on one slide up there

where you had your various sensors in the intake plenum for the control room ventilation. What type of separation protection do you have in that plenum so you can't get a tornado missile in there? Is that steel louvers?

MR. BINGHAM: I think we will have to check the details. It is a concrete shield for some missiles, I can tell you that much. If you would like the details, John, we can provide those.

MR. ALLEN: What I was getting at is, bearing in on tornado missiles, I thought in the back of my head I had read somewhere where it was steel louvers so you can't get a missile in there to knock it out.

MR. BINGHAM: I am not sure. Let me just find out. We have the louvers. Whether they are steel are not, there is protection.

MR. ALLEN: Are there additional questions?

MR. BESSETTE: Could I expand on your question? Are your radiation monitoring units and your chlorine monitoring units Class I?

MRS. MORETON: Yes.

MR. MECH: In reference to Figure 2A1-11 and possibly 12, this is a logic diagram and it shows indicating lamps for valve position. The first part of the question, does Palo Verde use a standard system for valve lamp indication or valve wiring such as to provide the indication?

MR. BINGHAM: Could you please repeat that?

MR. MECH: All right, let's put it in a different way. Is there a uniform method for indicating valve position used throughout the plant?

MRS. MORETON: Yes.

MR. MECH: The second part of the question, you show lamps at the motor control center, so this makes me wonder if the lamps are a direct measure of the valve position.

MRS. MORETON: They are a direct measurement of valve position.

MR. MECH: Do you wire the valve at the motor control center or is the motor control center indication simply an indication that the contactor is opening and closing to move the valve?

MRS. MORETON: It is wired back to the motor control center. Limit switches on the valves are actually used to stop the motor during travel, so they are wired back from the valve to the motor control center to complete the valve logic, and they are also used for indication at the motor control center, and then they are wired into the control room to provide that indication from the valve limit switches.

MR. MECH: Thank you.

MR. STERLING: On Exhibit 2A1-37, the first bullet, if you have overridden and you receive another safety signal, the override is removed, but does the actuated device change

state?

MRS. MORETON: If the containment isolation signal is present, the valves will go closed. If the operator performs the override of the containment isolation signal, he then has to position the valve into the open position. The containment isolation signal is then removed, the override will be disenabled, the valve will not change state.

MR. STERLING: If you reset the CIAS, that would be the same as removing it, it still will not change state?

MRS. MORETON: Correct.

MR. STERLING: So it is an operator action then to do anything with that valve once that safety signal is --

MRS. MORETON: Yes.

MR. STERLING: If the safety signal reappears, that valve will drive to whatever the actuated condition is?

MRS. MORETON: Yes.

MR. ALLEN: Questions?

MR. ROSENTHAL: Yes, please. First, on 2A1-37, I take it that the containment combustible gas control system is installed for the purpose of showing it conforms with 10CFR50.44.

MR. BINGHAM: Yes.

MR. ROSENTHAL: And is designed for the limits specified in 50.44?

MR. BINGHAM: That's correct.

MR. ROSENTHAL: Fine. On the override, the reset of the CPIAS, can you state the sequence that the operator goes through in order to reopen the valve?

MRS. MORETON: Jack, we are going to cover that in a lot of detail under our ESF actuated logic typicals.

MR. ROSENTHAL: 2A1-19. You bypass one of two channels. That is permitted in IEEE 279 where you can show that the bypass time is small relative to its need. You have an assertion as Item B on that page that that bypass time is small. What is the basis for the assertion?

MRS. MORETON: The primary basis for the assertion is that we only implement the bypass for maintenance. It is not implemented for testing, for calibration, or anything else, only for maintenance.

MR. ROSENTHAL: If I have two systems both with an unreliability of the order of 10^{-2} to 10^{-3} and I take one of them out for maintenance and checking, that is a major contributor to reducing the total system reliability. Do you have other numerical goals for each channel of the two-channel systems that back your assertion or limits in Tech. Specs. on the time that one channel can be taken out of bypass or something? Can I take it out for three weeks?

MR. BINGHAM: Let us confer here a minute.

John, I think what we would like to do is to study the response and we will come back after lunch with the

criterion that was used.

MR. ROSENTHAL: 2A1-30. Can you show me the location of the rad mountings relative to the valves?

MR. SHEPHERD: There are two sets for each duct. There is a small mini-purge valve and there is a large refueling purge valve. They are about eight feet apart. Directly between them there is a support post and the radiation monitors are put on the posts between the two ducts.

MR. ROSENTHAL: If I have a fuel handling accident and I initiate the system, I close the purge valves, does my signal then cease to appear at my rad monitors?

MR. SHEPHERD: It would depend on whether you had activity still existing in the duct.

MR. ROSENTHAL: But they are downstream of the large butterflies?

MR. SHEPHERD: That's correct. The butterflies are right next to the containment.

MISS KERRIGAN: What is the mini-purge?

MR. SHEPHERD: The mini-purge is what we call a power access purge which is used during power operation.

MISS KERRIGAN: That is your 10-inch or something, little one?

MR. SHEPHERD: Eight inch, I believe.

MR. ALLEN: Do you have some additional questions,

Jack?

MR. ROSENTHAL: Figure 2A1-4. Again, because FBEVAS is a one-out-of-two, you can be operating some time with that system actuated. Are there any time limits that you have on the time that you are exhausting through the essential AFU?

MR. KEITH: What is your concern, Jack? We can operate it continuously.

MR. ROSENTHAL: I have a one-out-of-two system. Should that system fail, the operator would have the option of tripping that system and continuing to keep the plant in power until we got around to fixing it. In that mode, which could last for some period of time, you would be pumping air through the charcoal filters and the HEPA filters and continual use of those filters may diminish the effectiveness of the charcoal, so it would be prudent for one not to operate in that mode for extended periods of time. Is there some Tech. Spec. or procedure or something which limits that mode of operation?

MR. KEITH: There is not a Tech. Spec. as such. There will be a requirement, and I believe there is -- it is probably covered in Reg. Guide 1.52, although I can't recall right now -- that the charcoal in the HEPA filters be tested periodically to assure that they do have the required efficiency.

MR. ROSENTHAL: The filters are normally handled by other engineering groups within the NRC, and let me relate the concern back to what would be a more conventional instrumentation and control branch concern, and that is that if one is worried about the reliability of an FBEVAS in the bypass mode when you are down to one channel, one would be tempted to require that if you don't have both channels available to trip FBEVAS. Now, the problem with requiring such an operating mode because one is concerned over the reliability of FBEVAS is that one may be degrading the charcoal filters should you have a real event where you need them, so I believe that there is an interrelationship between the prudent amount of time that you should be running on essential AFU versus the thoughts about the availability of FBEVAS, and I am seeking your advice on what would be a prudent way of monitoring these relationships.

MR. KEITH: Jack, one thing to keep in mind about this system as far as the FBEVAS logic is the only time we would be concerned about that logic actuating the system is during the refueling mode of operation when you are actually handling fuel inside the fuel building. That is the only time you have a possibility of a problem inside the fuel building. As far as the other mode when we use the essential air handling units in the fuel building, that during normal power operation is actuated by an SIAS, which, of course, is

the two-out-of-four logic. So we are talking about a relatively limited period of time just during fuel handling operations inside the fuel building when you are worried about this one-out-of-two logic.

MR. ROSENTHAL: I do try to check what I am doing with other functional groups and I was tempted to require because it is a one-out-of-two system that if one channel is down, you trip the system, and my Accident Analysis Branch people said gee, that may not be prudent, because you are unduly taxing the charcoal filters. Can you make an argument that, because of the limited time that you need FBEVAS that no Technical Specifications are needed relating the availability of these two systems?

MR. KEITH: I think we can. Another thought comes to mind on the fuel handling accident. As I recall, you can make the assumptions for that accident and not use this system at all and still be inside the guidelines of 10CFR100.

MR. ROSENTHAL: The Accident Evaluation Branch has assumed those filters would work and the Palo Verde SAR showed small fractions of CFR100, so effectively you have taken credit for the system to show the small fraction.

MR. KEITH: We and they I believe have both done analyses assuming it is not there. You still, obviously, have higher doses than you do if it is running, but it is still acceptable for the 10CFR100 guide. So I think that

and the small amount of time when you are actually handling fuel would argue for not having a Tech. Spec. requirement that you activate this system in the event that one channel be down.

MR. ROSENTHAL: Would it not be prudent to either demonstrate that either one of the two channels of FBEVAS has a high reliability, a high numerical reliability, or alternately to restrict the time that any one channel can be in bypass.

MR. BINGHAM: Isn't there also, Jack, another demonstration where you put them all together and demonstrate the system is adequate? I think that is the approach that we have taken.

MR. ALLEN: Bill, are you going to take that as an open item?

MR. BINGHAM: Well, I am not exactly sure what to take as an open item, John, and perhaps you could get a clarification on what we might provide. I believe what we have said is that we only need it during refueling and that is a short time.

MR. ROSENTHAL: Excuse me, you can be shuffling fuel in the spent fuel pool lots of times, not only during refueling.

MR. KEITH: You can be, that's correct, but that doesn't happen a lot.

MR. BINGHAM: We are assuming there is not a lot of activity during operations, and I believe that was one thing that we said. We also, I think, indicated, didn't we, Dennis, or we have thought in the past that degradation of those filtering systems would be checked in accordance with what, 1.52, to make sure that we had sufficient capability.

MR. KEITH: I believe that covers it.

MR. BINGHAM: We do have redundancy in the systems, and then we said that even in our analysis when we assumed they didn't exist that the doses were still within the requirements or limits of 10CFR100. Would the Board like a followup, John, on that rationale? As I understand from Jack's question, it is demonstrated that you don't need to put a Tech. Spec. limit on the time that that system --

MR. ALLEN: Or trip the channel.

MR. BINGHAM: Or trip, yes.

MR. ALLEN: Is that what you meant?

MISS KERRIGAN: You have stated your position.

MR. ALLEN: I think we can take that as an open item.

MISS KERRIGAN: To us, it does not need to be an open item. I think the position has been stated and NRC will go home and either agree or disagree with that position. If we disagree with that position, you will be hearing from us again.

MR. ALLEN: Any further questions?

MR. BESSETTE: I have another question regarding the control room air intake activity in the radiation monitoring system. You indicated that was IE. You also indicated previously that the bistable action was a computer based action or microprocessor based action. Did I understand that correctly?

MR. SHEPHERD: Yes.

MR. BESSETTE: Could you explain the scope of that system as to what portions are IE?

MR. BINGHAM: How much detail would you like?

MR. BESSETTE: The actual setpoint determination and the monitoring of the parameters, whether or not you exceed the setpoint, all that is done in the computer. Therefore, is that computer a IE system or is the microprocessor a IE device?

MR. SHEPHERD: The field unit, that is, the sensor, its microprocessor, and the microprocessor and the safety-related monitoring system cabinet in the control room are all IE.

MR. ALLEN: To follow up on that, I think what he is asking is where is the setpoint calculated and the determination made whether to trip the channel. Is that done by software or is that hardware?

MR. SHEPHERD: It is done by software.

MR. ALLEN: Is that your question?

MR. BESSETTE: That is the question. Thank you.

MR. STERLING: Is that software changeable by a technician or is it an always in there type of program that is nonadjustable? Could somebody get into the software and inadvertently change that?

MR. SHEPHERD: First of all, the safety-related monitoring system cabinet is where they would have to go, which is in the control room, so I presume that any changes to that system are under normal administrative control for control room access. Secondly, to change setpoints and to change physical values such as calibration constants, you do have to use a key switch under administrative control. You could, however, physically pull out the boards, at which point the system would go into alarm. You could start pulling EPROMs and change that type of level of software, but I don't think that is what you are asking for.

MR. STERLING: Is the only activity the technician would be doing in that cabinet entering a new set of setpoints to that software? Is there any other activity in that software other than the setpoints that he could be performing?

MR. SHEPHERD: Yes. As an example, the system is not automatically put into test on the safety-related monitors, it has to be manually initiated to go into test, so he could go up and say go into a test mode of checking a test routine.

MR. STERLING: Well, that is alarmed, but to do that,

he doesn't have to turn his key to the programmable position.

MR. SHEPHERD: That's correct.

MR. STERLING: So at that point, the physical key position will not allow him to change software?

MR. SHEPHERD. He has not changed the response of the system under those conditions. You must turn the key to change any of the privileged data.

MR. STERLING: I guess basically what my question is can he be doing something else besides changing his setpoints in there and inadvertently have the setpoint changed and is unaware of it?

MR. SHEPHERD: No.

MR. ROSENTHAL: Can you describe the use of **read** only memory versus **EPROM** versus **EPRAM?**

MR. SHEPHERD: I would rather not get into a technical discussion. Let me take that as an open item to get into the details and simply state there is a battery backed up memory that contains various setpoints and the like. The function to determine whether the computer is operating correctly is in **EPROM** and would not require that backup, but the data, the counts, have been received on channels on erasable memory.

MR. ROSENTHAL: But the program is on **E-P-R-O-M?**

MR. SHEPHERD: That is correct.

MR. ALLEN: Did you have a question?

MR. BINGHAM: Excuse me just a minute, John. We talked about an open item. Do we need to carry an open item on this issue? Do we need more detail?

MR. ALLEN: I don't see any need.

MR. MARSH: Just one more thing.

MR. BINGHAM: No I heard?

MR. ALLEN: No.

MR. MARSH: A followup on that concern about the possibility of accidentally changing setpoints. Can you conclude whether that would be more or less likely with this digital monitor than it would be with the older style analog electronic system?

MR. SHEPHERD: Yes, it is less likely with the digital, because you can protect certain functions. Normally in an analog monitoring system, your only protection is a cover shield which you key lock and remove out of the way and then you have control of any action you want to.

MR. BINGHAM: Any other questions on this system?

MR. ALLEN: I guess you can proceed, Bill.

MR. BINGHAM: Let's move on to 2A2, ESF Actuated Device Logic - Typicals.

MRS. MORETON: I am referring to Exhibit 2A2-1 and Figure 2A2-1, which we will go through in detail. For a typical logic of an actuated device, this would be an NSSS device or a BOP device, this is the steps through our

device level components, level logic. Each ESF system actuated device receives an ESFAS signal or combination of ESFAS signals to automatically actuate the device to its safe position, as shown on Figure 2A2-1. The safe position for the purposes of this typical device logic discussion will be defined as tha position required to perform the ESF system function. The ESFAS signals block inadvertent operator action with this block here (indicating) to prevent the operator from inadvertently changing the device to its normal position or that opposite from the safe position. By normal, you don't necessarily mean the operating position, but the opposite of the safe position. The reset of the ESFAS signal does not cause the device to change status. The device remains in its safe mode of operation on reset of an ESFAS signal. Resets of an ESFAS signal, as we have discussed earlier and as was discussed in the CE IDR, can occur only after the initiating conditions have cleared and the operator has manually reset the ESFAS signal logic. Each ESFAS actuated device is provided with manual control and the control switch is located on the main control board to enable the operator to actuate the devices as necessary for system operation and for testing. Feedback to the operator is provided in the form of red and green lights in the control room. They are located either in the switch or above the switch. Electrical protection circuits are

provided as shown here to preclude physical damage under overloaded conditions. In the case of motor operated valves, the thermal overload protection is bypassed by the ESFAS signal. Annunciation of electrical protection is provided to the control room operator.

Exhibit 2A2-2. An ESF system actuated device is provided with the capability to override the ESFAS signal to allow manual control of the ESF system. In general, there are a few exceptions, but the override of the ESFAS is performed as follows: With the ESFAS signal present, the operator will turn his control switch to the safe position, which is the same as that actuated by the ESFAS signal. If a pump is to start, the operator will turn the switch to the start position. This will arm the override and provide feedback to the operator in the form of a white light on the main control board. The override mode is automatically reset. If the ESFAS signal does clear, it is automatically reset, so the operator cannot enable the override mode if an ESFAS signal is not present, and if the ESFAS signal clears or resets, the override is automatically removed. The override functions to block the ESFAS signal shown here and to enable manual control of the actuated device. The override itself does not change the state of the device. The actuated device can then be returned to normal when the operator positions the switch into the normal position. This

requires two operations by the operator, one to arm the override by turning the switch to the safe position; when he gets feedback by the white light, the second action required by the operator to turn the switch to the normal position to actuate change of the device state.

Exhibit 2A2-3. Each ESF system actuated device is monitored by the safety equipment status system. We provide two alarms. One is the safety equipment inoperable status alarm, which is an indication that the device is not available, has been bypassed or rendered inoperable, it is not available, loss of power or breakers racked out, if the ESFAS signal should occur. The other alarm we provide is the SEAS, the actuated status alarm to annunciate that the ESFAS signal has been received and the device has not traveled to its safe state. Interfacing signals are also provided as required to interface with supporting equipment or devices.

That concludes the presentation on the typical device logic. We've got some slides here. (Slide 1) This is a slide of the PVNGS simulator, which is a duplicate of the main control room on all three units. This (indicating) is the horseshoe area shown on the slide. This (indicating) is what we call B01 or the electrical mimic board, the ESF panel here with our safety equipment status system components in a system level annunciation, chemical and volt control

systems panel, reactor regulating panel, plant protection system panel where the plant protection system initiating parameters are displayed and where the manual actuation switches are available, the steam generator, turbine generator, feedwater control panel, and B07, which is our auxiliary panel.

Slide 2. The purpose of this slide is to try and show what the manual actuation switches look like in the control room. These are the manual actuation switches for all the ESFAS signals. This is listed here as it will be provided. These are the BOP ESFAS manual switches for Train A, and on the second slide, we show the actuation switches for Train B.

This is a mock-up of the core protection calculator display. Annunciation for the BOP ESFAS is provided. Also on that same panel, our BPS panel B05, signal actuations are alarmed, CPIAS, FBEVAS, CRVIAS, CREFAS. Then also in this same annunciator are the reactor protection system alarms.

If we go to the next slide, Slide 5, we will see an enlargement of this left-hand area showing the BOP ESFAS alarms, the channel trip alarms, trouble alarms, test alarms, channel bypass alarms.

In the next four slides, we will try to demonstrate what the operator does and what he sees when he performs an

override function. This particular valve (indicating) on the left-hand side of the screen has been driven closed by the containment purge isolation actuation signal. It is shown by the green light indicating closed to the operator. It is not very well lit here, but that light is light. You will see the contrast in a few minutes. This switch (indicating) has been positioned by the operator. The switch has been turned to the closed position, which has armed the override and provided feedback to the operator in the form of these two white lights illuminating.

The next slide shows that the operator has now positioned this switch to the open position and the valve is in mid-travel. Both these lights (indicating) are on. Nothing has changed on this switch (indicating).

The operator has now performed the same two actions on the second switch causing this valve (indicating) to travel. The first valve is now fully open. The green light has extinguished.

On this slide, both green lights are now extinguished. Both red lights are now on showing that the valves are open and that the operator has them in the override mode.

I think we can take questions now.

MR. STERLING: On Figure 2A2-1, at the top of that figure underneath the red light on the far right, you have the safety equipment annunciator. Is that driven by the

logic or is it driven by the actual device position?

MRS. MORETON: It is driven in the case of valves by limiter position switches and on breakers by the breaker auxiliary contacts.

MR. ALLEN: While we are on that slide, Mary, when you go into override, what is the effect of the interaction of the support systems or devices? Anything?

MRS. MORETON: It is specific to the specific logic.

MR. ALLEN: What I am trying to get at, when it goes into override, does it override another system?

MRS. MORETON: The example would be the air handling units for the containment supply pump room, which are started by an auxiliary contact, which is what we are trying to demonstrate here, off of the pump breaker. If the pump is in fact stopped, the air handling unit does stop, but if the pump is put in the override mode, since the pump would not change state, the air handling unit would not change state.

MR. STERLING: Just to follow up on that, when you put the primary device in override, is there an override indication on the secondary device?

MRS. MORETON: No.

MR. STERLING: So if the operator were to look at the secondary device and it hadn't changed state, then just by looking at the secondary device, he would not know whether

it had failed or that the primary device had moved other than if he had moved it himself.

MRS. MORETON: If the failure were one that would be alarmed because of an electrical protection or because of process failure, he would know from his annunciation that it had failed. If it had stopped because he stopped the primary device, no, he would not know. Typically, the kind of support devices we are talking about aren't directly controlled from a control board light in the air handling units.

MR. STERLING: One more question. The white light remains on as long as you are in override. If the ESFAS signal is removed, the white light will also be removed.

MRS. MORETON: Yes.

MR. STERLING: Or will it stay on until the operator moves the thing back to the normal position?

MRS. MORETON: The override is disenabled when the ESFAS signal is removed and the white light is extinguished. The device does not change state.

MR. ALLEN: Any further questions?

MR. BINGHAM: Shall we proceed? Might I ask, when are you scheduled for lunch?

MR. ALLEN: We are going to break about noon for lunch. How does that fit in with the next section?

MR. BINGHAM: I believe we can get through the next

section, so we will do 2A3, ESF Load Sequencer Design Criteria and System Description.

MRS. MORETON: Exhibit 2A3-1, ESF Load Sequencer System Design Criteria. We repeat here the design criteria specific to the load sequencer system. These design criteria were presented this morning as part of the BOP ESFAS. The BOP ESFAS shall provide the logic to automatically start and sequentially load the diesel generators and to shed all 4.16 kV Class IE loads on a loss of power. The system shall monitor the undervoltage relays on the 4.16 kV Class IE bus and initiate a logic signal on a two-out-of-four coincidence of bus undervoltage. This logic signal will be used to shed all Class IE 4.16 kV loads except the load center transformers, shed certain 480 volt loads, start the diesel generator, start equipment required after a loss of offsite power, and trip the 4.16 kV Class IE bus preferred power supply breakers. The system shall provide sequencing logic for sequential loading of ESF and forced shutdown loads onto the ESF bus upon closing of the diesel generator breaker, a safety injection actuation signal, or an auxiliary feedwater actuation signal.

Exhibit 2A3-2. Should another accident condition occur after the load sequencer has started, the sequencer shall reset to zero. Equipment in operation at this time shall remain in operation. If a loss of offsite power signal

is initiated after the load sequencer has started, all loads will be shed and resequenced on the diesel generator breaker closure.

That concludes the design criteria other than the General Design Criteria that apply to the entire BOP ESFAS. We will now go into the ESF load sequencer system description.

Exhibit 2A3-3. Each redundant ESF load sequencer system performs logic functions to generate a loss of offsite power signal or load shed signal, a diesel generator start signal, load sequencer start and permissive signals. Each ESF load sequencer is supplied from a separate 120 volt vital AC distribution bus and a separate Class IE 125 volt DC distribution bus. ESF load sequencer system signals are generated from two load groups designated Load Group 1 and Load Group 2. The logic is physically located in the two BOP ESFAS cabinets. One cabinet contains the logic for ESF Load Group 1, the other cabinet contains the logic for ESF Load Group 2.

Exhibit 2A3-4, Redundancy. Redundant features of the ESF load sequencer system include two independent logic paths from input signals through and including output relays, and power for the system is provided from two separate buses. Power for control and operation of redundant actuated components comes from separate buses. Load Group 1 components and systems are energized only by the Load Group 1 bus and

Load Group 2 components and systems are energized only by the Load Group 2 bus.

Testing. Provisions are made to permit periodic testing of the ESF load sequencer system. Tests cover the trip actions from input signals through the system and the actuation devices. System tests do not interfere with the protective function of the system.

Continuing on with the Testing on Exhibit 2A3-5, actuation of the components controlled by the ESF load sequencer system does not disturb normal plant operating conditions. Therefore, the ESF load sequencer system is tested by complete actuation. Proper operation may be verified by checking the position of each ESF component, checking the actuation annunciation, checking the ESF component status indication. Response time testing will be performed at refueling intervals.

Exhibit 2A3-6, ESF load sequencer system signal logic. The loss of offsite power signal/load shed signal logic is shown on Figure 2A3-1. Each LOP signal/load shed signal logic continuously monitors the Class IE 4.16 kV buses for undervoltage, provide indication and annunciation of an undervoltage relay trip to the operator, indication on the BOP ESFAS cabinet, provides a logic output on a two-out-of-four coincidence of undervoltage relay trip or manual actuation located at the BOP ESFAS cabinet. This logic

generates an LOP signal to the diesel generator to initiate a diesel generator start signal, it initiates an LOP signal through a 60-second off delay to the forced shutdown system loads, also initiates a load shed, which is a one-second pulse, to trip preferred power supply breakers and to trip the selected loads for load shed, and provides indication and annunciation to the operator. It also provides a signal to the load sequencer for load information.

Exhibit 2A3-7, the diesel generator start signal logic. It is shown on Figure 2A3-2. Each DGSS logic performs the following: It combines the LOP signal, AFAS-1, AFAS-2, and SIAS with manual actuation from the BOP ESFAS cabinet to generate a combined DGSS signal to actuate the diesel generator.

The load sequencer start and permissive signal logic is shown on Figure 2A3-3. Each load sequencer start and permissive signal logic performs the following functions: It monitors input, determines the appropriate mode of operation, and generate sequentially timed start and permissive signals to ESF and forced shutdown loads as required to prevent instability of the Class IE buses. Start signals actuate devices by de-energizing actuation relays. Permissive signals allow loading of devices by energizing actuation relays.

Exhibit 2A3-8. The load sequencer controls only

pumps, fans, and chillers and as such does not cause complete ESF system actuation. The ESF load sequencer does not control any valves or dampers. The load sequencer is designed to respond to a loss of coolant accident with offsite power available, to a LOCA without offsite power available, to an accident other than LOCA with offsite power available, to an accident other than LOCA without offsite power available, to a loss of offsite power with or without an accident other than a LOCA followed at a later time by a LOCA, and a loss of coolant accident followed at a later time by a loss of offsite power.

Exhibit 2A3-9. The load sequencer has a normal mode, which we call Mode 0, and four operating modes. Operating Mode 1 is initiated by an SIAS/CSAS with a loss of offsite power signal not present. Mode 1 actuates the loss of coolant accident loads with offsite power available. Mode 2 is actuated by a safety injection actuation signal, containment spray actuation signal and a loss of offsite power. Sequencing is initiated when the diesel generator breaker closes. This mode actuates the local loads without offsite power available. Mode 3 is loss of offsite power signal without the containment spray/safety injection actuation signal. Sequencing for the shutdown loads is initiated when the diesel generator breaker closes. Mode 4 is other signals without a safety injection or containment

spray signal and without loss of offsite power. These signals are the CRVIAS and CREFAS combined in a logical "OR," FBEVAS, AFAS-1 and AFAS-2 combined in a logical "OR," or a signal if the diesel generator is running.

Exhibit 2A3-10. Receipt of subsequent input signals requiring a change of operating mode causes the load sequencer to reset, transfer to the required mode, and initiate sequencing of the required loads. The devices sequentially actuated through the load sequencer receive a load shed signal on bus undervoltage to trip the device load and a load sequencer start signal to start the device at the appropriate time. Reset of the load sequencer and its actuation relays does not stop or shed actuated devices. Devices are shed only on the load shed signal.

If we go back to our typical logic for an ESF system device, Figure 2A3-4 modifies that logic we discussed previously to show the sequencer signals replacing the ESFAS signals in the device logic to actuate the device, and it is overridden and is treated as another ESFAS signal in addition to the load shed signal which is required to shed the load on a loss of offsite power.

MR. BINGHAM: Are there questions from the Board?

MR. STERLING: Exhibit 2A3-4. Your last statement on that page was system test does not interfere with the protective function of the system. Would you describe what

happens if you are in test and you do get a safety actuation, what does the sequencer do?

MRS. MORETON: Testing is performed by actuating the load sequencer. If a safety signal did come in, the load sequencer would change modes during testing.

MR. STERLING: So to the sequencer, it doesn't know the difference between a design input and a regular input, it just would respond?

MRS. MORETON: Correct.

MR. ALLEN: Isn't this an auto test sequencer?

MRS. MORETON: The sequencer does have an automatic tester that will periodically scan through the entire BOP ESFAS to check logic. If you are in automatic test and a safety signal comes in, the sequencer when it changes out of Mode 0 terminates auto test.

MR. STERLING: Continuing on that, if we might have Figure 2A3-3, to help me understand this, where is your test? It would test through Modes 1 through 4?

MRS. MORETON: Manual test?

For manual test, you would actuate these signals individually in their combinations until you achieved the desired mode output to verify their operation.

MR. STERLING: Then you are testing all the way through your actuated devices?

MR. MORETON: Yes.

MR. STERLING: So your diesel would start and you would go through your load sheds?

MRS. MORETON: Yes.

MR. ALLEN: Any other questions?

MR. MECH: The diesel supply breaker is interlocked to not close on a faulted bus or into an energized bus. At some point, one of these signals will open the breaker that energizes the bus so the diesel breaker can close. Can you describe that in more detail?

MRS. MORETON: Can we go back to Figure 2A3-1? On reset of an undervoltage, the load shed signal does trip the supply breaker.

MR. MECH: It will trip it even though there may be voltage on that bus?

MRS. MORETON: There is no voltage, because the undervoltage relays have dropped out.

MR. MECH: Well, whatever the condition of the undervoltage says.

MRS MORETON: What are the setpoints for undervoltage?

MR. MECH: Setpoints, yes.

MR. BINGHAM: The question was what are the undervoltage setpoints? That was probably covered in the AC review. We can go back, John, if you would like and pull those out for information.

MR. ALLEN: Maybe over lunch we could look in the FSAR

or something just to get those numbers.

MR. BINGHAM: We just don't have them.

MR. ALLEN: Or we can call over to our office and get them.

MR. MECH: That's okay. It is not zero at that point, though. I mean it is something like 70%.

MR. ALLEN: It is 70, 80%, somewhere in that order.

MR. BINGHAM: Is that satisfactory?

MR. MECH: That's all I need to know.

MR. PHELPS: On Exhibit 2A3-8, there is a statement made at the top that the load sequencer controls only pumps, fans, and chillers and does not control any valves. What controls the valves?

MRS. MORETON: The valves are not sequenced. They are controlled directly by the ESFAS signals. If there is no power on the bus, the signals will still be present when the bus is re-energized and the valves will go to their proper position.

MR. PHELPS: What if you receive a safety injection actuation signal and there is no loss of offsite power? Does the sequencer then load all the SIAS components on simultaneously?

MRS. MORETON: No.

MR. PHELPS: But all the valves actuate?

MRS. MORETON: Yes.

MR. PHELPS: And you have insured that there are no interaction problems?

MRS. MORETON: Yes.

MR. ALLEN: A followup, Mary, on that. Doesn't the sequencer give permissives to some of the valves?

MRS. MORETON: The permissive signals generated by the sequencer are to allow the operator to manually load on those loads that may be required later on like the charging pumps. They are not signals to the valves.

MR. ALLEN: Further questions? Mike.

MR. BARNOSKI: I have a question on Figure 2A3-1 in regard to the 60-second delay. My concern is on loss of offsite power establishing feed flow to the generator. I assume that with that 60-second delay, that effectively eliminates the starting of the motor driven aux feed pump if it is just loss of offsite power for 60 seconds and you would rely on the aux feed actuation signals to initiate the load sequencer. I guess that meets the minimum.

MRS. MORETON: Yes.

MR. BARNOSKI: My question was for a loss of offsite power event, what logic led you to include that 60-second delay specifically for actuation of aux feed to the generator?

MRS. MORETON: The loss of offsite power signal does not actuate the auxiliary feedwater pumps. The loss of

offsite power signal actuates selective groups of forced shutdown loads to minimize equipment damage like the CEDM coolers or the continual normal coolers and their associated dampers as an example. The auxiliary feedwater pumps are actuated by the sequencer, not by the LOP load check logic on an AFAS signal.

MR. BARNOSKI: I am not sure I got the answer I was looking for. What you are telling me is that for a real loss of offsite power, I am going to get that aux feed actuation signal coming on pretty quickly and that even if the operator had power available, the time is so short that he would get the aux feed actuation signal before he would have a chance to manually go put those aux feed pumps on.

MR. BINGHAM: Just a minute. What answer were you expecting?

MR. BARNOSKI: I'm just trying to rationalize why for loss of offsite power when you clearly have to get aux feed going as soon as you can, why the 60-second delay?

MRS. MORETON: There is no 60-second delay in the initiation of aux feed. The 60-second delay is in the LOP logic.

MR. BARNOSKI: Yes, I understand that.

MRS. MORETON: The signal that goes to the load sequencer, this is an aux delay, which is a timed memory. It is not a delay. It is not an "on" delay, it is an "off"

delay, which means that when this signal goes away, this remains for 60 seconds. It does not delay the signal. It maintains the signal for 60 seconds after the interval has cleared to keep the sequencer in its undervoltage mode.

MR. BARNOSKI: Fine.

MR. ALLEN: Any further questions?

MR. PHELPS: I would just like to make one general observation, and that is when you defined the interfaces with Combustion Engineering for performing the accident analyses that you make sure that you have the most adverse time delays for the actuating components associated with all the modes in the sequencer's operation and the valve operations.

MR. ALLEN: Jack, did you have a question?

MR. ROSENTHAL: Yes, please. Exhibit 2A3-9, Item 4. What was the rationale for not including MSIS on that list?

MRS. MORETON: The MSIS does not actuate any pumps, fans, or chillers required to meet sequence onto the Class IE bus.

MR. ROSENTHAL: Apparently I don't understand the system, which is my failing. MSIS would surely be a precursor of emergency feedwater demand signals, and I don't see why it wouldn't be a good idea to get a head start on getting those diesels running.

MR. KEITH: Well, the logic, as we say, for the MSIS

and AFAS comes from Combustion Engineering and it was needed by them to support their accident analyses. On an MSIS, we are only shutting some valves, the main steam isolation valves, main feedwater isolation valves. I am sure that the Combustion Engineering analysis supports that, that in the event of an accident requiring an MSIS that the AFAS logic will support the feedwater needs of the generator. So that is why we have the logic the way it is.

MR. ROSENTHAL: Surely the Chapter 15 analysis involving the aux feedwater indicates that there is plenty of time for aux feedwater to the steam generator, but the time delay until you get down to low steam generator water level, at which point you will generate an AFAS, can be some period of time, especially if you had an MSIS which bottled up the system. With a loss of offsite power, wouldn't it be prudent to get those diesels running?

Let me rephrase the question. I understand your statement that the Chapter 15 analysis in CESSAR supports the design as indicated on this exhibit. My question is would it not be prudent to start the diesel generators on an MSIS?

MR. BINGHAM: Were you asking that for CE to consider or would you like just our view?

MR. ROSENTHAL: Your view. I assume that their position is that they don't need it to support their

Chapter 15 analysis.

MR. BINGHAM: Yes. They are one of many designers of this plant, but as I indicated earlier, Jack, it is our obligation to design a matching system.

MR. ROSENTHAL: You can do more.

MR. BINGHAM: We generally have APS that encourages us not to do that.

MR. ROSENTHAL: Okay. Well, the answer to my prudent question.

MR. BINGHAM: Let us talk for a minute and see if we can answer that question.

John, we haven't had, obviously, an opportunity to talk to the APS counterparts, but I think Dennis can give our overview response now, and if the Board would like that followed up in some detail, we can do that.

MR. KEITH: Jack, we don't think it would adversely affect the system at all. It would provide some benefits. We don't feel offhand that the benefits which could be provided would offset the increased complexity of the circuits which you get involved with to do it. We don't see that much benefit at this point in time.

MR. BINGHAM: Any other questions?

MR. JOHNSON: As your sequencing valves on the bus after the --

MR. KEITH: We don't sequence valves.

MR. JOHNSON: They do not sequence, but the signals that substitute them come in at varying times in accident scenarios. Correct?

MR. KEITH: Depending on the accident.

MR. JOHNSON: Yes, depending on the accident. It takes various stroke times depending on the size and the type of valve. Have you taken into account the degraded bus voltage caused by large equipment loadings into the sizing of the valve actuators? Your bus will swing high and low as each heavy load comes on.

MR. KEITH: Yes, that was covered in some detail in the AC systems review, the degraded bus voltage question, and all the equipment is sized to meet those requirements.

MR. JOHNSON: Thank you.

MR. STERLING: Is the answer to his question that we are adequately designed?

MR. KEITH: Yes. I thought I said that.

MR. ALLEN: Further questions?

MR. BESSETTE: We were discussing previously the interface basically that we've got in our Chapter 15 analysis, which brings another question to my mind, which is the criteria or administrative controls that the operator would use in overriding ESF components where the systems are assumed operational. In the Safety Analysis, we went through the circuitry and procedure that he would use to

override a component, but what control do you apply to him that he does not do that indiscriminately?

MR. BINGHAM: Excuse me, when you are talking about "we," you are talking about Combustion Engineering?

MR. BESSETTE: I am talking about the operator manually overriding a safeguard component.

MR. BINGHAM: I understand that part, but before you said some criteria was discussed.

MR. BESSETTE: Yes. That relates to assumptions that we may have made in our Chapter 15 analysis regarding availability of these safeguard systems or your ESF systems.

MR. BINGHAM: And there was information passed on to the utility for particular requirements by Combustion, is that correct?

MR. BESSETTE: I guess it would have come down as an interface. I cannot identify a specific one. I am saying we make assumptions as to the cooling systems being available and that the support systems to our safeguard systems are available. The operator, once the system is initiated, has the capability to override and to reverse the direction of some of these components. What controls or administrative procedures do you apply that he does not do that?

MR. BINGHAM: John, I think I would have to refer to the operating group on this particular question.

MR. ALLEN: Do one of you guys want to address it

from Operations or do you want to carry it as an open item and then respond as an open item?

MR. SIMKO: I can't speak for Operations in particular, but we do have the CE guidelines that we are using and they have all the accident analysis and transients, and we are putting those into the operating procedures so our operators do not inadvertently override these.

MR. BARNOSKI: Can I get a clarification on that? Then you are saying you are going to be using the emergency guidelines that are currently being prepared and going to the CE Owners Group. You are going to adopt those and use those.

MR. SIMKO: I don't know if it is the CE Owners Group.

MR. STERLING: I think we will clarify this a little. There are two sets of procedures, one out of the Owners Group, which is the emergency guidelines that are a part of the 1.C.1 Task item. There are administrative operating procedures which are being generated by the project office of Combustion. In either case, those form the basis of the procedures that will be used to operate the plant. I assume that Combustion Engineering has used those or has based those guidelines on their Chapter 15 analysis. I will say, too, that we do receive for our input the assumptions that were used by Combustion to perform their Chapter 15 analysis, so we are aware of what needs to be available.

MR. BESSETTE: I guess the answer that I hear is the operator is restricted by the procedures as to when he can use these for that function.

MR. STERLING: Yes, that's correct.

MR. BESSETTE: I have two other questions, much more general. One is has any consideration been given to the functional grouping of indicators and controls to layout and design of the control board?

MR. STERLING: I will respond to that. As was pointed out on the slide that we saw of the control board with the missing indicator, our thorough human factors review of the control board is identifying those areas so that the control board will be able to support whatever procedures are required to adequately control the plant. So that function is under the 1.D Task of 0737. Also, I might point out that Combustion Engineering is reviewing those procedures that are being prepared to the guidelines.

MR. BESSETTE: Then my last question is does the operator rely on the CRT indication for any safety action?

MR. BINGHAM: No.

MR. ALLEN: It is well past noon. I think we had better shut it down right now and go have lunch. If anyone has any additional questions on this section of the presentation, just hold them until after lunch and we will address them to Bechtel.

(Thereupon the meeting was at recess.)

June 17, 1981
1:20 p.m.

MR. ALLEN: Were there any questions left over before lunch before we proceed to the next section?

Seeing none, go ahead, Bill.

MR. BINGHAM: We will continue the presentation with 2.B, Systems Required for Safe Shutdown.

MRS. MORETON: Figure 2B-1 identifies those systems required for safe shutdown. It includes the electrical and mechanical devices and circuitry required to achieve and maintain a safe shutdown condition of the plant. There are sensors, device logic, control room displays, remote shutdown displays for the NSSS and the BOP safe shutdown systems. The NSSS systems include the boron addition portion of the chemical and volume control system and the shutdown cooling system. The BOP systems that we will be discussing on a general basis as it relates to the remote shutdown panel and typical information for sensors and manually activated device logic include the diesel generators including the ESF load sequencer, diesel generator fuel oil storage and transfer system, Class IE DC and AC power systems, auxiliary feedwater, atmospheric steam dump, essential cooling water, essential spray ponds, and the

essential chilled water systems. Most of the discussion will concentrate on the remote shutdown panel and the ability to go to cold shutdown outside the control room.

Starting on Exhibit 2B1-1, the design criteria, design for maintaining the plant in a safe shutdown condition when the main control room is inaccessible shall be in accordance with 10CFR50, Appendix A, GDC 19, "Control Room." Safe shutdown requirements comprise the capability for prompt hot shutdown when the reactor is subcritical at normal operating pressure and temperature, including the necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and the potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures and controls and instrumentation outside the control room. Access back into the main control room will generally be achieved prior to the initiation of cold shutdown. However, the capability for bringing the reactor to cold shutdown conditions exists outside the control room through the use of suitable procedures and secondary controls. Control room evacuation is initiated from an "undefined" cause; for example, control room environment not habitable.

Exhibit 2B1-2, continuing with design criteria. Design basis accidents are assumed not to occur simultaneously with control room evacuation. LOP and seismic events shall

not jeopardize the safe shutdown function. Systems, controls, and indications essential to the residual heat removal function during hot shutdown shall be designed with suitable redundancy in accordance with 10CFR50, Appendix A, GDC 34, "Residual Heat Removal." Loss of safe shutdown system redundancy does not occur as a result of the event, excluding a control room fire, requiring control room evacuation. All seismically qualified automatic functions perform as required. Design of the remote shutdown panel, system controls, and surveillance instrumentation shall not degrade the primary shutdown controls located in the main control room and shall be designed in accordance with the applicable sections of IEEE 279-1971.

Exhibit 2B1-3. We are now going to the Remote Shutdown Panel and Cold Shutdown Capability System Description. The following systems are required for safe shutdown: auxiliary feedwater, atmospheric steam pump, diesel generators including ESF load sequencer, the diesel generator fuel oil storage and transfer system, essential cooling water, essential spray ponds, essential chilled water, class IE AC power, Class IE DC power, the boron addition portion of the chemical and volume control system, and the shutdown cooling system.

Exhibit 2B1-4, continuing on with our system description, should the control room become inaccessible, the

reactor may be manually tripped from the control room as it is being evacuated or from the reactor trip switchgear system, which is located in the auxiliary building, elevation 120. Hot shutdown conditions can be maintained from outside the control room by control of pressurizer pressure and level, auxiliary feedwater flow, and atmospheric steam dump. Instrumentation and controls are available at the remote shutdown panel and ESF switchgear, both located in the control building, elevation 100, for these systems and components. The remote shutdown panel, which is shown on Figure 2B1-1 down at the lower section, is located in the control room building. This is all at elevation 100, which is at grade. The remote shutdown panel consists of three physically separate cabinets. Instrumentation and controls for Channel A and Train A systems and components are provided in one cabinet, shown up here (indicating). Instrumentation and controls for Channel B and Train B systems and components are provided in a second cabinet. A nonsafety-related cabinet is provided for instrumentation. That is this third cabinet (indicating). Controls for Channel C are provided in a separate subsection of the Train A cabinet and controls for Channel D are provided in a separate subsection of the Train B cabinet. Controls for large horsepower components, 480 volt and 4.16 kV, are provided at the ESF switchgear, switchgear located here (indicating) for Train A

and here (indicating) for Train B. The Train A remote shutdown panel is physically separated from the Train B remote shutdown panel by a fire wall separating the two panels. There is an access door providing access to the panels.

Exhibit 2B1-5. In the event of a loss of offsite power, the diesel generators will automatically be started and sequentially loaded by the ESF load sequencer system and the diesel generator control systems. Control outside of the control room is provided at local panels in the diesel generator building. Cold shutdown can be achieved from outside the control room through the use of suitable procedures and local controls. Parallel control between the control room and the remote shutdown panel, ESF switchgear or local control is utilized. Transfer of control is used only for analog control, an example being the auxiliary feedwater turbine speed control. Redundant features include two independent instrumentation and control channels for safe shutdown systems and components and power provided from two separate buses.

Exhibit 2B1-6 identifies instrumentation provided on the remote shutdown panel. As shown on that exhibit, you can see there is redundant instrumentation provided for Train A or Channel A and Channel B.

Exhibit 2B1-7 identifies the controls at the

remote shutdown panel. Again, redundancy is provided in Channel A and Channel B. There is a point of clarification. The auxiliary feedwater Channel A system is a DC system and, therefore, has controls associated with the pump, because it is turbine driven, but you do not see it duplicated in Channel B. The Train B pump is started at the ESF switchgear, which will show up on Exhibit 2B1-8, which shows the components controlled from the switchgear.

Exhibit 2B1-9 identifies local controls provided to enable the operator to bring the plant to cold shutdown from outside the control room.

We have a typical device logic for a safe shutdown system on Figure 2B1-2. This device happens to be started by the load sequencer. Some of the devices are also started up by high safety features actuation systems. The only difference between this logic and the logic we have discussed previously is the parallel control at the remote shutdown panel and the main control room with parallel indication.

A typical control scheme for the atmospheric dump valve is shown on Figure 2B1-3, which shows the atmospheric dump valves. Typical for each atmospheric dump valve, there is one dump valve per steam line, two steam lines per steam generator. This identifies the parallel controls provided at the remote shutdown panel and at the control room and feedback to the operator for valve

position information. There are two solenoid valves blocking air to the atmospheric dump valve system which prevent inadvertent opening of the atmospheric dump valves. One is powered from one instrument channel, the other is powered from the other instrument channel. Backup instrument air is provided from a nitrogen actuator which is automatically transferred over on lack of normal instrument air. These atmospheric dump valves also provide control throughout the hot shutdown sequence.

That concludes the discussion on safe shutdown.

MR. ALLEN: Any questions? Jack.

MR. ROSENTHAL: Do you believe that you meet RSB Branch Technical Position 5.1 with respect to achievement of cold shutdown from the control room?

MR. BINGHAM: Yes.

MR. KEITH: Yes, we do have the capability to achieve cold shutdown from the control room.

MISS KERRIGAN: With no local operation required?

MR. KEITH: Correct.

MR. ROSENTHAL: What about the SIT isolation valves?

MR. BINGHAM: What about it? Excuse me.

MR. ROSENTHAL: I will be clearer. I am concerned about the ability to go to cold shutdown conditions from inside the control room, which is one of the goals of RSP BTP 5.1. One of the specific systems of concern is the

safety injection tanks. For normal operation, the block valves are open, and in some of this documentation, I think it is in the SAR, it says that power is removed from the motor operator to the block valves. Can you reinstate power from the control room, and, if so, then do you -- I'm sorry, I will wait for the answer.

MR. KEITH: Jack, we can depressurize the safety injection tanks from the control room. I was concerned about a possible conflict between this answer and my last answer, but we achieve cold shutdown leaving those isolation valves open.

MR. ROSENTHAL: Do I take it that you have the ability to reduce nitrogen overpressure in the SIT tanks?

MR. KEITH: From the control room.

MR. ROSENTHAL: Is there an analysis to confirm that that is a suitable means of operation such that you don't dump nitrogen into the primary, or an excess amount, and is there also suitable analysis to show that that mode of operation is consistent with concerns related to low temperature of the pressurization of the primary?

MR. KEITH: I think it is handled procedurally. As you are coming from hot shutdown to cold shutdown, you are meeting various pressure/temprature relationships in the RCS. You must vent the safety injection tanks at certain times, so as long as you are meeting the procedures and

staying within those limits, you won't have a problem.

MISS KERRIGAN: You are talking about a procedure. This is in your normal operating procedures that that is how you normally do it? You normally would not do what is in the FSAR I mean this would be your normal way of going to cold shutdown and it would be in the normal operating procedures, is that right?

MR. KEITH: I am just trying to get a clarification of do you consider that method of going to cold shutdown the normal method as opposed to shutting the safety injection tank isolation valves?

MISS KERRIGAN: Yes.

MR. KEITH: I am going to have to check. I don't know what -- Mike, can you help us? Or you are not sure.

MR. BARNOSKI: No. Clearly, the normal way would be to close the valves.

MISS KERRIGAN: Right.

MR. KEITH: So this would be some kind of abnormal operating procedure in order to do it completely from the control room.

MISS KERRIGAN: Right. That is the Branch Technical Position, and I guess we would like to kind of leave that as a thought for you to assure yourselves that you can go to cold shutdown from the control room in the normal --

MR. ROSENTHAL: No, in emergency.

MISS KERRIGAN: Yes.

MR. ROSENTHAL: Using emergency procedures.

MISS KERRIGAN: Right.

MR. KEITH: That we have an emergency procedure to --

MISS KERRIGAN: That covers that mode of going to cold shutdown totally within the control room.

MR. ALLEN: We will take that as an open item and confirm it with operations.

MR. KONDIC: May I rephrase a portion of Jack's question? Are we sure that during the normal operation of the plant there will not occur a depressurization via the system we are discussing now that we shall not lose the gas?

MR. ROSENTHAL: Yes, that is equivalent, or, alternately, do you meet ICSB/Power Systems Branch Branch Technical Position 18?

MR. KEITH: We meet CE requirements on the system. We have two valves in series as far as the vent on the safety injection tanks which are powered from different power sources.

MR. KONDIC: Thank you.

MR. ALLEN: Any other questions?

MISS KERRIGAN: That was kind of a funny way to phrase the answer, that you meet CE requirements. Do CE requirements meet the ICSP position?

MR. BINGHAM: Well, we have the interface problem.

In the presentation, I am sure that they have presented what they mean.

MISS KERRIGAN: So you would leave that as a CE open item?

MR. BINGHAM: We would leave that as CE.

MR. BESSETTE: That was addressed at our last presentation two weeks ago as far as our position on this Branch Technical Position.

MR. ROSENTHAL: Our position with respect to 5.1 is the valve, and I would request that if we are leaving this as a general open item, the achievement of cold shutdown from the control room, that in the course of preparing to respond, you look at several related Branch Technical Positions as an involvement and do your homework. I just point out that if you don't want the nitrogen to get out, you put two valves in series, if you do want it to get out, you put two in parallel, and now you have conflicting goals. I am sure you will do your homework thoroughly and you should consider not only that specific system, but all the systems involved in achieving cold shutdown.

MISS KERRIGAN: That would be an item that we would want to go into in our second meeting probably in quite more detail.

MR. BINGHAM: So the issue is how do we go to cold shutdown from the control room --

MISS KERRIGAN: And still meet all the requirements.

MR. BINGHAM: -- and still meet all requirements of the Branch Technical Positions.

MISS KERRIGAN: Yes.

MR. ALLEN: Bill, are you going to answer that?

MR. BINGHAM: Well, I think, John, since it involves both CE and Bechtel and APS on the interfaces and the Operating Department as well that we probably ought to coordinate the response so that we have gone through the spectrum of concern.

MR. SIMKO: Did we ever get a valid question out of this? I am not sure what they are asking.

MISS KERRIGAN: I guess the question is how do you meet RSB BTP 5.1.

MR. BINGHAM: Just for my own understanding, is this basically a Chapter 5 question or position? Is that where it would come up normally?

MR. ROSENTHAL: Five/six.

MR. BINGHAM: The reason that we are concerned is because we try very hard in these presentations to address all the Branch Technical Positions and the SRP's, and for 7, of course, it will be absent from this presentation. If it is in 5, we would expect that that would be a CESSAR directed question, and that is why I want to get that clarification so that you understand you won't see it today.

MR. ROSENTHAL: Fine. We have done some coordination at the NRC side, and when you do make your presentation, I will ensure that we have systems people and ICSB type people present so we can properly respond to you.

MR. ALLEN: Additional questions? Go ahead, Jack.

MR. ROSENTHAL: You have a list of equipment on the remote shutdown panel. Ideally, that would come in part based on reviewing procedures. I take it the plant doesn't have procedures yet. How do you know that this list is complete? The corollary --

MR. BINGHAM: Is there more to the question?

MR. ROSENTHAL: The corollary of that is alternately, given that this is all the equipment that will be provided, how are we assured that the plant emergency procedures or plant procedures when they are written don't use more equipment than is physically present?

MR. KEITH: Jack, the basis of the equipment that we have included comes from Combustion Engineering, which, as you know, has designed many NSSS's and have operating procedures. Although the detailed operating procedures are not developed for Palo Verde, we are relying on what has been done on other plants, and then to that basic equipment which Combustion requires which is directly necessary to ke the reactor cool, we added our supporting systems which were necessary to keep that equpment running such as HVAC

and things like that and the cooling water systems that are part of the balance of plant. So, obviously, as we get into the detailed operating procedures, it is highly unlikely that we are going to find anything that we need that is not already on here. If we do, then we will have to make a design change.

MISS KERRIGAN: So that is a commitment on your part. I take it that is a commitment.

MR. KEITH: We intend to meet the requirements.

MISS KERRIGAN: You will make a design change. If you find that the operating procedures require more equipment, you commit to make that design change to get that equipment on the remote shutdown panel.

MR. KEITH: If it is equipment required for hot shutdown. Hot shutdown we are doing at the remote shutdown panel. For all other equipment, we can control it outside the control room, but not at the remote shutdown panel.

MISS KERRIGAN: Through manual procedures?

MR. KEITH: Yes.

MR. STERLING: Dennis, would it be a fair statement then that in the design of the plant utilizing Combustion's interface requirements for remote shutdown that you have designed the plant to be shut down using the functions laid out on this panel?

MR. KEITH: That's correct.

MR. STERLING: And by design, you don't need any more functions for hot shutdown than what are on the panel?

MR. KEITH: That's correct.

MR. STERLING: And for cold shutdown, what is on the panel plus your additional local instruments.

MR. KEITH: Yes.

MR. STERLING: It would be up to APS then to implement those pieces of equipment to shut down.

MR. KEITH: I didn't understand the last statement you made there.

MR. STERLING: In procedures, then it would be up to APS to implement that equipment according to the design to shut down the plant.

MR. KEITH: Yes, APS will develop the operating procedures to shut down the plant.

MR. STERLING: Utilizing that equipment.

MR. KEITH: Utilizing that equipment, yes.

MR. ALLEN: Carter, did you have a question?

MR. ROGERS: Yes. Dennis, I believe that there are procedures for shutting down the plant which are being used or have been used on our simulator which is in operation at the present time. Has anybody taken this list of equipment on the remote shutdown panel and compared it against those procedures which have been developed for the simulator?

MR. BINGHAM: The procedures that we have been using

to develop the simulator have not been plant specific procedures. I think they fall in the same category, Carter, as the procedures or the input that Dennis was talking about. The development of the simulator was based also on inputs from the Combustion Engineering equipment we required for the Palo Verde System 80 plant. I think what I heard asked or I thought I heard Janis say was that if for some unlikely reason when you finally get all the specific operating procedures written and you are not able to take the plant to hot shutdown, then would there be a modification to correct the deficiency, and I think we said of course.

MR. ALLEN: Go ahead.

MR. MECH: How do you plan to limit the access to the remote shutdown area? It has doors I noticed on Figure 2B1-4 where it shows the doors.

MR. BINGHAM: Why don't we put that figure up so we can see? On this Figure 2B1-1, these are the fire doors we are talking about here (indicating).

MISS KERRIGAN: We are talking about an interface, really, between your security procedures and not being in conflict with the need for quick access to the remote shutdown panel.

MR. BINGHAM: I am not sure that we have exactly how they are controlled or will be controlled. I know they would be tied in with the security system and part of the

fire protection requirements.

MISS KERRIGAN: It might be more appropriate to direct the question to APS.

MR. ALLEN: Norm, do you want to answer it? Before you do, though, use your own judgment on divulging any security information.

MR. HELMAN: Those doors labeled (C) and (D) here and the interim door are controlled and require a high level of access. Does that answer your question?

MR. MECH: For an instant, it looked like you might have to go through there to get to the one switchgear room, for example. It might be easier to do that perhaps than going around some other way. It looks like it might be a passageway.

MR. HELMAN: That's true. There is another door over on the right-hand side of the picture that you see up there to access the Train B ESF switchgear room and that is the normal access. This other is by higher level controlled access, shall we say.

MR. ALLEN: People that have to get in there will have the necessary clearance to get in there and nobody else will.

MR. MECH. Another question. On Exhibit 2B1-5, you state on Item 7 that there is parallel control between the control room and the remote shutdown panel. Can you provide some idea of the thinking behind that parallel control?

This seems to depart from the usual method, which is to lock out the control from the control room when the remote shutdown area is being used.

MR. BINGHAM: We will have Dino give you a response.

MR. SOTEROPOULOUS: The rationale behind parallel control for all of our circuits and not using any lockouts is to keep the reliability of our control circuits up. Any time you add components to a control system, you degrade the reliability of those circuits in question, so our circuits are basically designed with continuous parallel control active at all times. With the controlled access to the switchgear rooms and the remote shutdown panels, we preclude the potential of people going in and operating components.

MR. MECH: Is there communication between the remote shutdown panel and the control room?

MR. SOTEROPOULOUS: Yes, sir.

MR. MECH: So if you had an operator there, you could talk to him?

MR. SOTEROPOULOUS: Yes.

MR. MECH: That would be under not emergency conditions, but under normal conditions?

MR. SOTEROPOULOUS: There is communication with the control room from that area, yes.

MR. ROSENTHAL: From an equipment rather than a human standpoint, I am concerned that equipment failures at the

remote shutdown panel may put the reactor in an upset mode and deny appropriate mitigation capability from the control room. Have you systematically postulated single failures of equipment in the remote shutdown panel for all the systems involved and found that you have adequate control from the control room?

MR. BINGHAM: Jack, just for clarification, we designed the plant to take a single failure. Had you some other complication in mind that would go beyond the single failure criterion?

MR. ROSENTHAL: No.

MR. MECH: One last question. On Figure 2B1-1, I observe that the remote shutdown panel is in the same building as the control room. This is at elevation 100. The control room is up 40 feet, but otherwise the remote shutdown panel is substantially fairly close to the main control room. Have you analyzed to see that some incident which might cause the evacuation of the control room will not necessitate evacuation of the remote shutdown panel? I postulate a fire in the lower cable room.

MR. ROSENTHAL: Exclusive of fire.

MR. MECH: Exclusive of fire.

MR. BINGHAM: Would you like to repeat the question?

MR. MECH: Have you made an analysis to see that the same condition which might cause the evacuation of the

control room will not necessitate evacuation of the remote shutdown area?

MR. BINGHAM: Dennis will answer the question. I guess the answer to the question is we don't have a formal analysis, but there is a reason. He will give you the reason.

MR. KEITH: The requirements for evacuation of the control room, there has never been any mechanism postulated for that other than a fire, which is under discussion, so we haven't really done an analysis. Because there is no mechanism postulated, there is, therefore, nothing to analyze.

MR. MECH: All right. Thank you.

MR. ALLEN: Any other questions? Jack.

MR. ROSENTHAL: I'm sorry, I'm not sure I had my question answered. Let me give an example. As you systematically look down the list, if the pressurizer backup heater Group 1 failed in an "on" demand signal, which is surely an anticipated operational occurrence, a minor upset to the plant, do the procedures reflect should this event happen the operator's attempt to defeat that inadvertent "on" signal whether it comes from the control room or the auxiliary shutdown panel?

MR. BINGHAM: I think what we said is that regardless of where you hypothesize it coming from, we have to be able

to deal with the issue, the single failure. In this particular case, I am not sure exactly how we have handled that. Maybe I am getting off --

MR. ROSENTHAL: Yes. I was looking for a programmatic answer more than a specific answer for any one system. It would seem to me that if the operator realized that he had an inadvertent demand signal in the control room, he would obviously in the control room attempt to trip the actuated device on the component level to save the day. We also can start postulating failures on the remote shutdown panel, which is now an active and parallel system rather than isolated by a transfer switch, and again is the operator's training and procedures such that he would in a similar and like fashion to faults in the control room mitigate a failure due to faults from the remote shutdown panel?

MR. BINGHAM: Jack, let's see if we can answer this. I will have Dino answer it again. I would indicate one thing, that in the control room, I am not sure that the operator would know where the signal is coming from regardless, so I am not sure that is an issue, but let's go through the rationale.

MR. SOTEROPOULOS: The question of parallel control from the control room with the remote shutdown panel, the only controls that are there that are in fact parallel and active are digital on/off controls for pumps specifically.

The one control that is down there for analog is for the feed pump turbine, and that is in fact transferred, because we can't have an analog signal from more than one place at a given time. The on/off switches that are on that panel, we don't feel as though it is credible to have fault signal from a manual "off" switch. There isn't a credible failure that could give you a signal from the remote shutdown panel if nobody is there other than some event which is that subject we are not talking about which is addressed someplace else.

MR. ROSENTHAL: I think we have traditionally postulated a simple short of a toggle switch as an initiating event. I am not saying that that event can't happen or that you should design such that it won't happen, but, rather, are the controls then in the control room through the emergency procedures and the operator's training sufficient such that he suitably copes with those events?

MR. KEITH: It seems to me the question you are asking really doesn't have anything to do with the parallel controls, but it is just a general one of, say, if we had a switch in the control room that failed and turned the pressurizer heaters on and you couldn't turn them off from the control room, then the operator would have to go and pull fuses or whatever was necessary to de-energize them. There is flexibility at the local switchgear and local motor

control centers or whatever to do those kinds of things.

MR. ROSENTHAL: And his procedures and training are such that if the single random failure occurred at the remote shutdown panel, he would take perhaps the same actions or parallel actions as he would take if the single random failure occurred in the control room?

MR. KEITH: The procedures would be the same for the remote shutdown panel as they would be for the control room.

MR. ROSENTHAL: When they are written.

MR. BINGHAM: When they are written.

MR. ALLEN: I guess, Jack, I really don't know what you are looking for right now. Are you looking for a commitment from APS that we will write procedures? I think that is a foregone conclusion.

MISS KERRIGAN: No, I guess what we are saying is when you do write your procedures, you assure yourselves that in event of failure at the remote shutdown panel, you utilize those same procedures and the operator's training is such that he would use those same procedures and would recognize that it is da-da-da-da-da.

MR. ALLEN: Let's take that as an open item and assign it to APS.

MR. BINGHAM: All right.

MR. ALLEN: Any other questions?

MR. ROSENTHAL: I have one more question. Do the

A and C channels of instruments come to the same panel? Within the panels, do you follow Reg. Guide 1.75?

MR. KEITH: Yes.

MR. ALLEN: Any further questions?

MR. STERLING: I have one. On Figure 2B1-2, your remote shutdown controls have no override feature nor are they tied to the sequencer. Is that because of the criterion that you are assuming no DBA at the time that you go to the remote shutdown panel?

MRS. MORETON: Yes.

MR. ALLEN: Any further questions from the Board?

MISS KERRIGAN: I would like to give a little bit more clarification on the question that was discussed before. Since you do have a parallel system, then your procedures should reflect the fact that somebody down at the remote shutdown panel isn't in conflict with somebody in the control room doing things at cross purposes.

MR. BINGHAM: Let me add a point here, because we seem to be getting a little confused. At least, I am. People can be at the switchgear and do things that would be equally as concerning to the operator, so whether it is the remote shutdown panel, the switchgear, or whatever, it is still a problem that has to be dealt with and written into the emergency procedures I would believe. Is that correct?

MR. ALLEN: Plus the security system will go in that

room. You know darned well if something is in that room, the operator is going to be aware of it. So, actually, I think the remote shutdown area would be safer than maybe the switchgear or something else as far as knowing someone is there.

MR. BINGHAM: I think one of your panel members had a question down there.

MR. MARSH: I would like to just ask a clarification type question along those lines. It would occur to me that without having a transfer switch on that remote shutdown panel, the potential types of failure modes would be fewer, in fact, and that the analysis that was done would be simpler with this particular design for parallel control. In other words, if the transfer switches were provided, wouldn't all of the same kinds of failures and perhaps some others as well be possible from the transfer switch itself? Is that a true statement?

MR. BINGHAM: That is a true statement.

MR. BESSETTE: I would also like to add what I think is clarification to this issue. In the event that you do have a hot short in the remote shutdown panel that energizes your heaters, if you want to take this example, you will still have indication in the control room that your heaters are on, you will have indication that the pressure is increasing, you probably will receive a high pressure alarm,

you would get indication that your sprays are running more frequently, or backup. I think you have an auxiliary spray. In any case all these indications are available to the operator. I am not sure that it is a factor in emergency procedures so much as it is the operator's normal training to recognize that my heaters are on, I can't shut them off, my pressure conditions are increasing. Similarly, where a pump is energized, should it be a pump or something as opposed to heaters that you turn on again, he would have indication that this device is running. Again he would have positive indication he can't de-energize. It seems a rather logical sequence that the operator would follow in diagnosing that this fault has occurred and it is again a logical process that he would go through in correcting the problem as opposed to making that a factor in the emergency procedures.

MISS KERRIGAN: He would just be using normal emergency procedures.

MR. BESSETTE: I am comparing emergency procedures to simple diagnostics of a fault that the operator becomes aware that conditions are digressing and he follows some logical path because of this training to narrow the problem out to its source and either himself or the fuel people take other actions to de-energize and correct it if he does not have control of it. What I am saying is it is just a part

of the operator's logical process of training.

MR. ALLEN: Anything else?

Go ahead, Bill.

MR. BINGHAM: The next section we would like to cover is 2.C., Safety-Related Display Instrumentation.

MRS. MORETON: Figure 2C-1 represents the safety-related display instrumentation which is available to the operator to allow him to monitor conditions so that he may perform manual actions important to plant safety. This consists of sensors, monitoring process system variables, the NSSS ESF, ESF support, BOP ESF, and the reactor trip system to provide displays in the control room to the operator. The NSSS system includes the safety-related plant process display instrumentation, reactor trip system monitoring, ESF systems monitoring, CEA position indication, and post-accident monitoring. What we will be covering today are the BOP systems, which include process monitoring including the ESF systems monitoring, post-accident monitoring, and our automatic bypass indication system called the safety equipment status system.

I would like to go first to the process instrumentation design criteria, Exhibit 2C1-1. Design Criteria for process instruments come from the piping and instrument diagrams, detailed design criteria for the process system, and general codes and standards are provided to meet the

IEEE and GDC. Additional design criteria are as follows: instruments shall be provided to operate at a nominal 115 volt-AC supplied to instrument cabinets. Controls and annunciators shall operate at 120 volt-AC or 125 volt-DC nominal. The maximum and minimum voltage limits for the 120 volt-AC and 125 volt-DC systems are given in the electrical systems design criteria.

Exhibit 2C1-2. Resistance temperature detectors, RTD's, shall utilize a three-wire circuit. The RTD sensors shall have a resistance of 100 ohms (preferred). Exceptions will be considered on a case-by-case basis. Thermocouple materials shall be chromel-alumel, Type K. Electronic transmitter loops shall utilize a current range of 4 to 20 milliamperes. Pneumatic loops shall utilize 3 to 15 psig instrument air. Critical data acquisition, alarming, and protective controls are energized from a DC power source. All control systems designs shall include shielding, grounding, and physical separation provisions which will minimize the effects of high voltage switching surges, inductive coupling, and onsite radio transmission signals. Aluminum shall not be used in or around equipment containing or producing ammonia. Aluminum and zinc shall be excluded wherever possible from instrument and control device casing which are in the containment and could be exposed to the containment spray fluid. Exposed aluminum shall not be used for

instruments installed in the circulating water system where contact with the circulating water is possible.

Exhibit 2C1-3. Provisions shall be made such that the response time testing can be performed on safety-related channels. Nuclear instrumentation and radiation monitoring indicators and records shall have log scales and charges. All other indicating and recording devices with the exception of motor current indicators shall be linear direct reading with a minimum scale length of four inches. Wherever possible, alarms shall not be initiated from indicators or recorder contacts. In-line paddle type flow switches shall not be used. Magnetic type flow meters are perferred for sludge or slurry service. Flow elements shall be sized, wherever practicable, for 100 inch water and design flow shall be 85% of range. Equipment control circuit status shall be indicated on the control room control panels along with the equipment status. All overrides of Engineered Safety Features Equipment shall be indicated. In general, time delay relays shall not be used to bypass short time nuisance alarms upon equipment startup. Nuisance alarms shall be bypassed upon manual shutdown of standby or redundant components.

Exhibit 2C1-4. Mercury shall not be used for any application within the containment building, spent fuel pool area, boron recovery area, chemical and volume control areas,

or in the radwaste building. Switches using mercury, whether encapsulated or not, and mercury-wetted relays shall not be used in safety-related equipment. Mercury shall not be used in instruments in direct or indirect contact with the primary coolant system, the feedwater and condensate systems, or systems which provide makeup to the primary, feedwater, and condensate systems. Instruments containing mercury for level, pressure differential pressure, temperature, or flow switches may be used outside of the specific mercury exclusion areas and systems. Only hermetically-sealed mercury switch assemblies contained within NEMA-4 housings shall be used. Care shall be taken in selecting instruments for use such that a broken mercury switch capsule shall not result in mercury entering sumps. Switches which will contain the mercury within the instrument case may be used. An example is the Magnetrol type switch.

Exhibit 2C1-5. Mercury manometers shall be restricted from use in the plant operating process instrumentation, but may be used in instrument shops. All systems shall include the required straight runs for flow measurement nozzles. Flow metering runs shall be in accordance with ASME Publication, "Fluid Meters, Their Theory and Application," Supplement to ASME Power Test Code 19.

We will proceed now with the Process Instrumentation System Description, Exhibit 2C1-6. A typical process

instrumentation loop consists of sensor, processing electronics, and display. Various sensors include thermocouples and RTD's, pressure transmitters including differential pressure transmitters for level and flow monitoring, radiation monitors, example Beta scintillation, Geiger-Mueller, analyzers such as hydrogen, which is thermal conductivity, or chlorine, which is chemically impregnated paper tape, and float and displacer type level instruments. Processing electronics include signal converters such as I-to-E, E-to-E isolators, square root extractors, and bistables. Processing electronics are housed within control room cabinets. Two separate Class IE cabinets are provided, A and B, and separate non-IE cabinets are provided.

Exhibit 2C1-7. Types of displays include indicators, recorders, indicating lights, and annunciator.

Figure 2C1-1 is a typical instrument loop diagram. This one happens to be for the fuel building HVAC system. It shows a transmitter with a 40 milliamp signal going to the signal converter, which is in the control room processing rack. It goes to a bistable which causes annunciation via the isolation cabinet and display on the main control board.

Some of our process instrumentation for the Engineered Safety Features System is provided in Exhibit 2C1-8. A typical example would be the fuel pool area radiation monitor located in the control room with a range

of 10^{-1} and 10^{4} mR per hour, displayed accuracy of plus or minus 20%. Additional examples follow on Exhibit 2C1-9 through 2C1-10, 11, and 12. This covers our BOP ESF system. We also cover in this table the auxiliary feedwater system, including the pump discharge pressure indicator in the control room.

Exhibit 2C1-13 also indicates the rest of the auxiliary feedwater instrumentation, and the ESF status panel indicates system availability. This we will discuss as part of the SESS in the following presentation.

MR. BINGHAM: I believe that we will go ahead and present 2.C.2, Safety Equipment Status System, John, and then we can have questions at that time.

MRS. MORETON: Going on to 2C2-1, Design Criteria for the Safety Equipment Status System, the safety equipment status system shall function to alert the operator by visual and audible means insofar as practicable at a system level when any piece of automatically actuated ESF equipment has been bypassed or rendered inoperable and not available for use. The SESS shall also, in the event of an ESFAS, monitor all of the ESF components and alert the operator by visual and audible means when any piece of equipment has not completed the transition to the safe operating position. The safety equipment status system will be designed in compliance indicated on Exhibit 2C2-1 and continued on

Exhibit 2C2-2. The system shall consist of two portions, one reporting the status of safety Train A equipment, the other reporting the status of Safety Train B equipment. The system shall accept channelized Class IE associated inputs. The system inputs are Class IE associated; therefore the system shall be powered from Class IE 125 volt-DC power supplies. Status contacts shall continuously monitor the availability of control power and the position of circuit breakers of all automatically actuated ESF devices. A loss of control power or deliberate racking out of a breaker shall automatically indicate at the component level the device which has been rendered inoperable. Simultaneously, a system level indication with audible alarm shall be initiated. Proceeding with the design criteria, Exhibit 2C2-3. The capability for initiating a manual bypass indication and alarm is provided to indicate the bypass condition to the operator for those manual valves and other components which are not automatically monitored. The initiation and removal of manual bypass indication will be under administrative control. A system of status contacts shall monitor the safe operating position of all automatically actuated ESF devices during an ESFAS. These status contacts shall automatically indicate at the component level the device which has failed to automatically complete the transition to the safe operating position within a normal

time period. Simultaneously, a system level indication with audible alarm shall be initiated. All systems affected by the bypassing or inoperability of a given component which is shared by multiple systems automatically generates a bypass/inoperable audible and visual alarm in each system affected. Indication and annunciation test capability is provided by simulating a trouble contact condition when the test button is depressed. The test feature is independent for each channel. A minimum of two lamps, connected in parallel, shall be furnished for each annunciator window, indicator window, and indicator switch.

Exhibit 2C2-4. All components, including Solid-State devices, transformers, resistors, and relays, shall be of a quality and shall be used in the system in a way that will ensure high reliability, minimum maintenance requirements, and low failure rates. Ease of maintenance shall be a primary consideration in the equipment design of all components operated below their electrical and thermal rated values, taking into account all possible combinations of operating environments, power source ranges, and transient conditions. The safety equipment status system shall be located in the control room and seismically qualified to the following acceptance criteria: Structural failure which would cause the system logic cabinets and/or window displays to dislodge from their mounting or cause any part of these

subassemblies to detach and fall during an OBE and SSE shall ... be permitted. The equipment shall not cause short circuits or spurious signals that would adversely aff... the Class IE equipment providing inputs to this system.

We will now go into the Safety Equipment Status System Description starting with Exhibit 2C2-5 and referring to Figure 2C-1A on the system arrangement of the safety equipment status system. The safety equipment status system consists of two physically separate systems shown here (indicating). One of these systems provides monitoring and annunciation for safety Train A equipment. The other system provides monitoring and annunciation for safety Train B equipment. Each of the train-related systems consists of system level window cabinet, component level indicator light panel, system control panel, logic cabinet, audible alarm devices shown here (indicating), and interconnecting cables.

Exhibit 2C2-6. Each of the train-related systems performs indication of safety equipment actuated status and safety equipment inoperable status. Each of the train-related systems is powered from a separate Class IE 125 volt-DC distribution bus. The annunciation sequence of operation and testing for SESS alarms is the same as that for the plant annunciator. The safety equipment actuated status

logic is shown in Figure 2C2.

Exhibit 2C2-7. The SEAS logic continuously monitors the operating status of ESF and ESF support system actuated devices, continuously monitors the status of ESFAS signals down here on the bottom of the figure (indicating), provides "failure to automatically actuate" annunciation if all actuated devices -- this would be all devices for a particular system -- do not transition to the "safe" position required to perform the ESF system function after receipt of an ESFAS signal and an allowable transition time. This time is adjustable to meet the transition requirements. This annunciation is audible and indicated on the system level window cabinet, which is in the main control room. It provides indication of components or group of components which failed to transition to the "safe" position. This indication is on the component level indicator light panel, and that is indicated by these blue lamps (indicating). It provides "failure to automatically actuate" annunciation if all the actuated devices in a support system do not transition to the "safe" position required to perform the ESF support system function. The support system interface in the logic diagram is shown here (indicating). If the support system is required to actuate and does not transition, it will cause an alarm for that system, or if this particular system is a support system to another ESF

system, it will provide input logic to that system's logic.

Exhibit 2C2-8 and Figure 2C-3 will describe the logic of the safety equipment status system inoperable status. The SEIS logic continuously monitors the "availability" of ESF and ESF support system components, shown here as the component "available" to respond to and perform the ESF system functions when required. Availability consists of the following as appropriate: Availability of control power to actuate the device, circuit breaker is not racked out, or manually operated valve intended for use more than once a year is properly aligned. The SEIS logic provides "inoperable status" annunciation if any monitored component in a system is not available to perform its required function. This is at the system level, the annunciation. It provides a means to manually initiate system "inoperable status" if a manual valve intended for use less than once a year or other component is removed from service. This initiation is under administrative control. It is provided here (indicating) with feedback to the operator in the form of a white light. It provides "inoperable status" annunciation if any support system monitored component is inoperable or has a manual "inoperable status" initiation. The support system interfaces are shown.

Figure 2C-4 is a figure that shows the SESS

system level annunciator panel in the main control room. This would be identical for Train A and a dublicate one for Train B.

Figure 2C-5 is the control panel where the operator may manually initiate "inoperable status" of a manual valve that is used less than once a year is rendered inoperable. It is under administrative control. This (indicating) is also the test pushbuttons to perform system tests.

Figure 2C-6 is a layout of the component status panel.

We have some slides of these. This slide is a photograph of the safety equipment status system BO2 or the ESF panel on the simulator, which is identical to the one in the main control room. These two windows up at the top of the slide, one for Train A, one for Train B, are the system level alarms. The panels right below them, one for Train A and one for Train B, are the component level windows. Directly below that on the lower portion of the control panel are the two control panel inserts for the SESS.

Looking at a closeup of the system level annunciator, this slide shows you the windows and a closeup of the indicator panels.

On the logic diagram, you noticed there were two lights, a blue light and a white light, for each system.

On the annunciator panel and on the indicating light panel, the white light is in the upper half of the annunicator or in the component level, and this indicates inoperable status. There is a blue lamp, two sets actually, in the lower half of each component window in each annunciator panel which indicates a failure to automatically actuate. This gives the operator component level feedback of either failure to auto actuate or inoperable status.

This is a photograph of the system control panel, and on the next slide, this shows the illumination of the upper white light, which indicates that the operator has pressed his pushbutton indicating back to him that the system has been manually put into a bypass state because some manual valve was racked out.

This slide is just an example of our control room indicator. This happens to be the HVAC intake chlorine indicated on the main control panel.

This is our mock-up model of what the indicators look like on the control board. This little lower segment here (indicating) is the indication that will light up to indicate the process variables.

The last slide we have shows an example of our recorders. These are for post-accident monitoring recorders. The red nameplate indicates these are all in Channel A, strip chart and indication on the recorder with the lights

indicating power availability.

MR. BINGHAM: Any questions?

MR. STERLING: At the Combustion IDR, there was some concern over what indication the operator would receive from this instrumentation in the control room or the indicators upon loss of power. Could you briefly discuss what happens to the indicators when the power goes out?

MRS. MORETON: The PVNGS displays are Foxboro Model 270 indicators. On a loss of power to the rack, the indicators will completely go out. They do require 120 volts to illuminate them, and it will just extinguish. On loss of power to the recorders, the small light you saw at the bottom of the recorder will go out.

MR. STERLING: Are there not cases when the indicator will either go full-scale high or low or will sit there and fluctuate center? Are there failure modes in these indicators either because of power failure or sensor failure or whatever it is that would cause a false reading on these types of neon discharge indicators?

MR. BINGHAM: I am not exactly sure where the question is heading.

MR. STERLING: Well, for example, on the simulator, we did have the problem of chips inside that caused these things to go haywire either full-scale high or low.

MR. BINGHAM: That's right, but that wasn't a production model simulator.

MR. STERLING: No, I understand that. That problem has been fixed. What I am trying to get at is the operator going to be misled by some failure in these Foxboros either in the power supplies to the indicators or to the loops that they sit in that is going to mislead the operator?

MR. BINGHAM: Well, we would hope that that isn't the case, and to finish off, I suspect that you could postulate any individual case where a particular instrument might give a false indication of some kind, but there are other backup instruments and procedures that the operator would use to quickly assess what it was he was seeing.

MR. STERLING: Is there a case where that thing could fail at a reading, reading something and it could just fail right there?

MR. BINGHAM: I don't know if that has been the case with the failures that have been seen, and we will go back to the Foxboro experience. Usually they were flashing or they weren't exhibiting any reading at all, but I don't recall offhand whether there was a case or not where it stayed on at a misreading.

MR. STERLING: I had another question on your process instrumentation, I guess Exhibit 2C1-4. That may not be the right exhibit. I don't find the right exhibit, so I will

just ask my question. The lines from the sensors to the transmitters, do you have a criterion there for proper sloping, and so forth, for air entrapment, fluid entrapment? That criterion doesn't appear in this list.

MR. BINGHAM: It is part of the design standards. The documents do exist. We didn't list them in this particular presentation. We do have them.

MR. ALLEN: Any questions?

MR. MECH: On Exhibit 2C1-3, this is your criteria, and it talks about testing in Item 10. Is it necessary when you do this testing to remove wires or use jumpers or remove components?

MRS. MORETON: It may be necessary.

MR. MECH: I believe it is a requirement of one of the standards that your testing should be built into the system, your test capability.

MR. ALLEN: Could you identify the standard you are talking about?

MR. MECH: I don't recall the number offhand.

MISS KERRIGAN: We have it here. We will look it up during the break and get back to you on that.

MR. MECH: I have one more little question.

MR. ROSENTHAL: Let me hit it right now. Reg. Guide 1.118, which was issued after the date of your CP, speaks about periodic testing of electrical power and protection

systems and Section C-6 discourages the use of jumpers and pulling fuses, et cetera. Within the context that this Reg. Guide is for protection systems and within the context that the Reg. Guide was published Rev. 02, June, '78, after the date of your CP date, will you identify where your system is designed such that you have jumpers, fuses pulled, et cetera, and why you feel that's okay.

MR. BINGHAM: Jack, what Mary was thinking about when we were talking about some testing was the fact that an RTD or a thermal weld may have to be disconnected or lab bench tested, and she wasn't focusing on the protection system. Maybe with that clarification, or maybe we can add some more information, but that was the reason for her response.

MR. ROSENTHAL: I called that out and emphasized that to tell you at least our regulatory basis and how far I thought in a regulatory sense we could push this issue. On RTD's, the response time testing is deferred from CESSAR to the applicant's SAR in total with respect to Chapter 7. For RTD's, are you using loop current testing procedures?

MR. BINGHAM: Let us take that as an item to respond to, John, because we do have to talk to APS, unless you have the answer.

MR. MINNICKS: We do plan on using the loop current test response methodology.

MR. ROSENTHAL: And that will be documented where?

MR. MINNICKS: There will be procedures developed to that testing by that procedure that uses that methodology.

MR. ALLEN: Any further questions?

MR. MECH: One more quick one. On 2C-3, 4 and 5, if we could flash back quickly and compare them --

MR. KEITH: The figures or exhibits?

MR. MECH: I think those are figures. They were pictures of annunciator panels.

MR. ALLEN: Do you want the slides? Is that what you are talking about?

MR. MECH: Five shows a small panel at the bottom and 4 does not. Is Figure 4 supposed to have one, also, a similar panel?

MRS. MORETON: No. Figure 2C-4 is the system level annunciator windows. Figure 2C-5 is the control panel where the operator will manually initiate a bypass alarm for a system. This insert here (indicating) is for system testing.

MR. MECH: In the FSAR, there is a similar figure for SESS Train A, which I think is the identical one for -- I think you had two pictures that showed for Train A and Train B with the small panel on the bottom.

MRS. MORETON: Those are on the slides, yes.

MR. MECH: So Train A will have its own panel and

Train B will have its little panel?

MRS. MORETON: Correct.

MR. MECH: Okay, that's what I wanted to know.

MR. ALLEN: Mary, I've got a question. On Figure 2C-3 you indicated the SESS input logic from support systems. Could you touch on it, just give me an example?

MR. MORETON: An example of where you will see this kind of feeding from system to system, you could take the safety injection system, which depends on the essential HVAC, which depends on the essential cooling water system, which depends on the essential spray pond system. You will see an input, as an example, on the essential cooling water system, an input from the essential spray pond system to the essential cooling water system, and one from the essential cooling water system to, as an example, the essential chilled water system.

MR. STERLING: Exhibit 2C2-2, Item 4. You say you will accept channelized Class IE associated inputs. Are those buffered inputs from the Class IE systems or are they connected directly to the Class IE circuits?

MRS. MORETON: Those inputs come from separate limit switches or breaker auxiliary contacts from the actuated devices. They are not separated from the IE signals or cables and they are not isolated.

MR. STERLING: Since they are coming from limits which

contact some switch contacts, and so forth, I guess there is no way they could get back to the Class IE function.

On the testing portion of the SESS, if we go to Exhibit 2C2-3, could you explain Item 9? What do you mean by simulating a trouble contact condition?

MRS. MORETON: There are two test pushbuttons provided to allow testing on the logic. These are an inoperable test pushbutton which will test the SEIS logic and a status test pushbutton which will test the SEAS logic. Those test pushbuttons induce a signal into all cards in the SESS cabinet which will cause all lamps on the system level and on the component level to alarm, to light and flash, and then the operator would go through the reset actions to reset those lamps.

MR. STERLING: So that is at the input point to the SESS. It would be the same input point as the limit switch from the source device.

MRS. MORETON: Yes.

MR. STERLING: The status test does the same?

MRS. MORETON: For the status inputs, inoperable is coming from loss of power contacts, breaker racked out contacts. These are coming from limit switches and breaker auxiliary contacts.

MR. STERLING: In the action of the SESS, you get a safety actuation. On your logic, I guess it is -- do you

have the one with the blue lights on it? When you get an actuation, that panel will show all blue lights and they will go out as the items are activated?

MRS. MORETON: That's correct.

MR. STERLING: Then after a suitable time delay, you will not get an audible until after that suitable time delay.

MRS. MORETON: That's correct.

MR. STERLING: If you take one of your actuated devices and put it into bypass or override it but don't change anything, it is not going to affect his panel?

MRS. MORETON: That's correct.

MR. STERLING: If you take that device and then turn it to the unsafe or to the normal or change it, then you will get an actuation.

MRS. MORETON: We will get the blue light and the system level light and the audible.

MR. STERLING: Would you also get a white unavailable light if it goes into override?

MRS. MORETON: No.

MR. ALLEN: Any other questions?

MR. JOHNSON: Yes, on Exhibit 2C2-2, Item 5. Can you explain your rationale for not including a spring charge contact in availability of the breaker?

MR. SOTEROPOULOUS: There is a limit switch in the spring charge for the breakers which has not been wired into

this system. All of our switchgear breakers monitor the spring charge with a white monitor light that is down at the switchgear and that is the place where that would be periodically monitored to verify that the motor has wound up the spring for the closing of the switchgear. It has not been wired into this system.

MR. STERLING: Is it not the case that when those breakers are reset that that motor at that time rewinds the spring and it is latched?

MR. SOTEROPOULOUS: Every time you trip the breaker, the motor will wind up the spring for the next closure, at which time the limit switch will close and there will be a white light that monitors that contact at the switchgear panel.

MR. JOHNSON: Your rationale is then that the electrical technician is responsible, not the operator for knowing the status.

MR. SOTEROPOULOUS: Yes.

MR. ALLEN: Any other questions?

MR. MULLIGAN: There are two panels sitting side by side on the SESS and it seems to me like if you have a failure in one train, say Train B, that then your indications are going to be contradictory. Is that right? Which is he supposed to believe, the operator? What kind of action should he take?

MRS. MORETON: The purpose of having two panels is to monitor the two separate systems. The Train A panel monitors the Train A components and the Train B panel monitors the Train B components, so the operator would know if he had annunciation in one train that that train was not available. The other train would be assumed to be available.

MR. MULLIGAN: There are also pushbuttons there like for containment isolation signals. You push the button and a whole bunch of valves are supposed to close?

MRS. MORETON: No, this is only an indication system. When you push the pushbuttons, it is done because of an administrative procedure. A manual valve, as an example, is opened for some maintenance reason and would not be monitored automatically, because it is not anticipated that it would ever be open more than -- it would be open less often than once a year. The operator would then under administrative procedures push the containment isolation button to indicate to himself that the containment isolation system or containment isolation valves are not available. Pushing that pushbutton causes no system action, only indication.

MR. MULLIGAN: On containment isolation signals, I think there are some valves on both sides of the wall, so there is a lot of lines. How does the logic work, that both valves have to be closed or just one to say that you

have isolation on that line?

MRS. MORETON: The safety equipment actuated status logic would monitor the Train A valve and Train B would monitor the Train B valve. The operator would have to form the conclusion.

MR. MULLIGAN: So in a situation like that where they are both inside containment and outside containment, one is on Train A and one is on Train B?

MRS. MORETON: Right.

MISS KERRIGAN: I have a logistical question. A lot of the information that we are discussing like that on the control room panel display, will that be reproduced in the control room design presentation that is coming up in a few weeks?

MR. STERLING: What exact information are you looking for?

MISS KERRIGAN: Annunciator status and blue lights, white lights, what lights on the panels, and things.

MR. STERLING: We will report on the adequacy of the presentation as far as the information being given to the operator for him to do his job. We won't be providing a design document on the SESS per se. The SESS part of the control board is being looked at to assure that its presentation to the operator is --

MISS KERRIGAN: That's what I am asking. That will

be almost readdressed then in the control room Design Review Board.

MR. ALLEN: Anything further? Jack.

MR. ROSENTHAL: Yes, please. Item 4 on Exhibit 2C2-2. I would like to explore the question of associated circuits a little bit more. I recognize that in evolving interpretations of IEEE 384, people may or may not have considered a simple contact as an isolating device and now intend to provided there is physical separation. It's fine that it is treated as an associated circuit. That's proven. How much of the stuff really is associated as distinct from being buffered circuits by virtue of having a switch contact which is physically isolated from the actuated device?

MR. BINGHAM: We believe it is all associated and we would leave it that way.

MR. SOTEROPOULOUS: The system is associated in fact, not only the cable to it, the circuits to it, but the whole system is addressed as an associated system, if there were such an animal. By virtue of the fact that it is physically and electrically separated Train A, Train B, with 1.75 separation, we consider them associated systems.

MR. ROSENTHAL: Bearing in mind that our Reg. Guide 1.47 has no requirements on the quality of the hardware, can you tell us if this is a computer based system or is it a hard wired?

MR. SOTEROPOULOUS: It is a hard wired logic system, hard wired logic.

MR. ROSENTHAL: Has it been designed? Is the design complete?

MR. SOTEROPOULOUS: Yes, the design is complete and it has been fabricated and delivered.

MR. ROSENTHAL: I am concerned about completeness of indicating on the systems level the failure of support systems. Can you make some programmatic statement that you monitor all support systems -- lube oil, component cooling, electrical, HVAC?

MR. SOTEROPOULOUS: Yes, all support systems. We have the capability to alter that as necessary as our designs change by hard wire programming, jumper programming as you would an analog type of patch panel affair. We can alter the number of inputs, tie one support system to another support system as necessary as our designs evolve.

MR. ROSENTHAL: The last thing is the operator's procedures and training, especially his training, does that include a description of this panel and the interrelationships that are being displayed by the panel?

MR. ALLEN: Yes.

MR. STERLING: Yes.

MR. BINGHAM: Yes, it does.

MR. SOTEROPOULOUS: The system sort of evolved

addressing the regulatory requirements of 1.47, which really only impose as a requirement for monitoring the availability of safety systems. It became evident with all of the wiring that was brought into this panel that it would be a very simple addition to monitor the position status after an event as well, and that is why it sort of grew into the two halves. It was very convenient to do it that way even though there was no requirement to do this at the time.

MR. BINGHAM: Any other questions?

MR. MECH: Are any of these annunciators that you showed the first-in type?

MR. SOTEROPOULOUS: Not this system. The normal station annunciator does have first-out capability.

MR. ALLEN: Our schedule called for taking a break at 3:00. It is now ten after. Why don't we take about a 15-minute break.

(Thereupon a brief recess was taken, after which proceedings were resumed as follows:)

MR. BINGHAM: There was a question about the undervoltage setpoints. The drop out is at 68% and the pick up is at 75%. Let's proceed then with 2C3, Post-Accident Monitoring. John, I think in the interests of time, we won't go through the criteria in as much detail as we have, because you can read it from the exhibit. If there are some particular clarifications, we will come back and pick those up.

MR. ALLEN: Bill, could you indicate what you would like to try to go through tonight?

MR. BINGHAM: Yes. We would like to get through 3.F.

MRS. MORETON: Exhibit 2C3-1, Post-Accident Monitoring Design Criteria. These are the design criteria and the entire post-accident monitoring sections not currently in the PVNGS FSAR. These are the design criteria the Project is adopting and this information will be provided in the FSAR when it is finalized.

Design criteria for post-accident monitoring come from Regulatory Guide 1.97, Revision 2. The design and qualification criteria categories are unique definitions to PVNGS to sort of put it in the design framework that we use for the different categories. These are our interpretations of the requirements out of Reg. Guide 1.97, Revision 2, for the various categories.

Category 1. Instrumentation is qualified in accordance with Reg. Guide 1.89 and Reg. Guide 1.100. Instrumentation is designed to accommodate single failure. Instrumentation is powered from Class IE. Instrumentation is available prior to the accident as required by the Tech. Specs. or IEEE 279, Paragraph 4.11. Instrumentation is Quality Class Q.

Exhibit 2C3-2. Continuous indication is provided. Recording shall be provided on one channel. Transmission of

signals for use other than post-accident monitoring shall be through isolation devices. Types A, B, and C instruments shall be specifically identified on the control panels.

Category 2. Sensors shall be qualified in accordance with Reg. Guide 1.89. Seismic qualifications will be provided when instrumentation is part of the safety-related system. Instrumentation is powered from a non-Class IE instrument bus which has Class IE power as a backup, or they may be powered from Class IE power. The out-of-service interval is based on the Tech. Specs. The sensors shall be Quality Class Q. There are some cases where Quality Class R sensors are used. Displays shall be Quality Class R.

Exhibit 2C3-3, continuing on Category 2. Display shall be on an individual instrument or on demand on a CRT. Data recording is provided for effluent radioactivity monitors, area radiation monitors and meteorology monitors. Transmission of signals for use other than the post-accident monitoring shall be through isolation devices. Again Types A, B, and C instruments are specifically identified.

Category 3. Instrumentation shall be of high quality commercial grade and shall be selected to withstand the service environment. In Category 3, the display shall be on individual instrument or on demand on a CRT.

Exhibit 2C3-4. These are more General Design

Criteria. Servicing, testing, and calibration programs shall be provided. Whenever means for removing channels from service are included in the design, the design shall facilitate administrative control. The design shall facilitate administrative control of access to all setpoint adjustments, module calibration adjustments and test points. The monitoring instrumentation design shall minimize development of conditions which would cause meters, annunciators, recorders, or alarms to give anomalous indications potentially confusing to the operator. The instrumentation shall be designed to facilitate recognition, location, replacement, repair, or adjustment of malfunctioning components or modules. To the extent practicable, monitoring instrumentation inputs shall be from sensors that directly measure the desired variables.

Exhibit 2C3-5. The same instruments shall be used practicable for accident monitoring as are used for normal operations of the plant. Periodic testing shall be in accordance with the applicable portions of Reg. Guide 1.118.

Proceeding on with the Post-Accident Monitoring System Description, Exhibit 2C3-6, Type A variables are those variables to be monitored that provide the primary information required to permit the control room operator to take specific manually controlled actions for which no automatic control is provided and which are required for safety

systems to accomplish their safety function for design basis accident events. For the Type A variables, Combustion Engineering is providing a review of emergency guidelines to identify if each event required manual action, instrument consulted, required range and accuracy, and the qualification status. Completion of this activity is expected in November, 1981. In addition, a review of the emergency procedures after they are developed will be performed to ensure the required variables have been identified.

Exhibit 2C3-7 lists the Type B variables, which are variables required to provide information to indicate whether the plant safety functions are being accomplished. These functions include reactivity control, core cooling, maintaining reactor coolant system integrity, and maintaining containment integrity. Category 1 variables in the balance of plant design include coolant level in the reactor. The only part that is in the balance of plant design is the display, which will be two channels Class IE. Containment sump water level, wide range. Requirement, to monitor to bottom of containment to 600,000 gallon equivalent. We have provided sensors in the 11-foot range. Display is two channels, Class IE, with recording on one channel.

Exhibit 2C3-8, continuing on with Type B Category 1 variables. For containment pressure, two requirements exist, one to measure from zero to design pressure, the other to

measure from 10 psia to design pressure. Sensors provided will be from minus 5 psig to 180 psig. Display is in two channels, Class IE, with recording on one channel. Containment isolation valve position, excluding check valves. Display is provided for valve status for all automatic or remote manual containment isolation valves.

Category 2. Degrees of subcooling. Balance of plant on this is the display only, which will be two channels, Class IE. Containment sump water level, narrow range. The requirement is to monitor the sump. Sensors are provided one per sump. That measures the sump from 6 inches above the bottom of the sump to 6 inches above the top of the sump to provide overlap with the wide-range detector. There is one display per sump, since the sensor is qualified to the post-LOCA environment.

Exhibit 2C3-9, continuing on with the Type B Category 3 variables. Requirement, to measure RCS soluble boron concentration from zero to 6,000 ppm. This is accomplished in the post-accident sampling system. The range is from zero to 6,000 ppm, remote sample, in-line automatic with a grab sample backup.

Core exit temperature. The balance of plant provisions here are for display only, which will be two channels, Class IE.

Exhibit 2C3-10 covers Type C variables, which are

variables which provide information to indicate the potential for being breached or the actual breach of the barriers to fission product releases. The barriers are fuel cladding, primary coolant pressure boundary, and containment.

Category 1 variables include the core exit temperature, which we have discussed previously. Radioactivity concentration or radiation level in circulating primary coolant, the requirement is to monitor from one-half Tech. Spec. limit to 100 times Tech. Spec. limit in R per hour. Sensor range is provided to cover a range from 1R per hour to 10^5R per hour. Display is via a CRT, non-Class IE, and two safety-related channel displays at the radiation monitoring cabinet, which are Class IE and recording on one channel.

Containment pressure. The design requirements here for Type C variables include an additional requirement to measure from 10 psia to three times design pressure. Sensor provided covers that range, as discussed before.

Exhibit 2C3-11, continuing on with Type C Category 1. Containment sump water level, wide range, is provided as discussed before.

Containment hydrogen concentration. The requirement is to measure from zero to 10%, capable of operating from 10 psia to maximum design pressure. Sensor provided does measure from zero to 10%. It is available 30 minutes after initiation of safety injection, which is in conformance with

NUREG-0737. It is capable of operating from minus 5 psig to 60 psig. Display is on tw channels, Class IE, with recording on one channel.

Exhibit 2C3-12, continuing on with Type C variables Category 2. Containment sump water level, narrow range. Display is provided, as discussed before.

Containment effluent radioactivity - noble gases from identified release points. The requirement is to monitor from 10^{-6} microcuries per cc to 10^{-2} microcuries per cc. Sensor provided at the plant vent responds to 10^{-6} to 10^{-2} microcuries per cc. Display in the control room is via CRT. The sensor is qualified to post-accident environment.

Radiation exposure rate (inside buildings or areas which are in direct contact with primary containment where penetrations and hatches are located.) The requirement is to monitor from 10^{-1} R per hour to 10^{4} R per hour. PVNGS design will incorporate 13 monitors with sensor range of 10^{-1} R per hour to 10^{4} R per hour. Display is in the control room via CRT. Sensors will be qualified to post-accident environment.

Exhibit 2C3-13, continuing with Type C Category 2 variables. Effluent radioactivity - noble gases from buildings, as indicated above. The requirement is to monitor from 10^{-6} microcuries per cubic centimeter to 10^{3} microcuries per cubic centimeter. It has a sensor off the fuel building

vent with a range of 10^{-6} microcuries per cubic centimeter to 10^{5} microcuries per cubic centimeter. It has a sensor off the fuel building vent with a range of 10^{-6} microcuries per cc to 10^{5}. Display is via CRT. Sensor qualified to post-accident environment.

Type C Category 3 variables. Analysis of primary coolant (Gamma Spectrum). The requirement is to monitor 10 microcuries per gram to 10 curies per gram or TID-14844 source term in coolant volume. The PVNGS design incorporates a post-accident sampling system, which is a remote sample. An in-line automatic isotopic sampling is done over a range of 10^{-3} microcuries per cc to 10 curies per cc.

Containment area radiation. The requirement is to monitor from 1 R per hour to 10^{4} R per hour. Sensor provided monitors over that range and display via CRT.

Exhibit 2C3-14, continuing with Type C Category 3 variables. Effluent radioactivity - noble gas effluent from condenser air removal system exhaust. The requirement is to monitor from 10^{-6} microcuries per cc to 10^{-2} microcuries per cc. Sensor provided monitors from 10^{-6} microcuries per cc to 10^{3} microcuries per cc. Display via CRT, with sensor qualified to post-accident environment.

We will now go to the Type D variables that provide information to indicate the operation of individual safety systems and other systems important to safety. These

variables are to help the operator make appropriate decisions in using the individual systems important to safety in mitigating the consequences of an accident. The Category 1 variable included here is the condensate storage tank level. PVNGS design has a sensor from zero to 50 feet with display on two channels, Class IE, recording on one channel.

Exhibit 2C3-15, Type D Category 2 variables. The primary system safety relief valve positions, closed - not closed. PVNGS will comply with this requirement. This is on the table in this form because the design is not far enough along to give any specific information.

Pressurizer heater status. The requirement is to monitor electric current. PVNGS will comply.

The safety/relief valve positions or main steam flow, closed - not closed. PVNGS will comply.

Auxiliary feedwater flow. The requirement is from zero to 110% design flow. Sensor provided from zero to 2,000 gpm. Display, two channels, Class IE.

Containment atmosphere temperature. The requirement is to monitor from 40 to 400 degrees F. PVNGS will comply.

Containment sump water temperature. The requirement is to monitor from 50 to 250 degrees F. This design implementation is still under review.

Exhibit 2C3-16, continuing with Type D variables Category 2. Essential cooling water system temperature.

The requirement is to monitor from 32 to 200 degrees F. Sensor provided is from zero to 200 degrees F, with display provided for each train.

Essential cooling water system flow. The requirement is to monitor from zero to 110% design flow. Sensor provided monitors from zero to 20,000 gpm, with the display on each train.

Emergency ventilation damper position. The requirment is to monitor open-closed status. Control room display includes damper status for all automatic or remote manual emergency ventilation dampers.

Status of standby power and other energy sources. The requirement is to monitor voltages, currents, and pressures. Display is provided in the control room of all ESF voltages and currents. The displays are Class IE. Low pressure alarms are provided on the accumulators for the MSIV, MFIV, and atmospheric dump valves.

Exhibit 2C3-17, Type D Category 3. Reactor coolant pump status. The requirement is to display motor current. This is provided.

High-level radioactive liquid tank level. The requirement is to monitor from top to bottom. Main control room alarm is provided of the radwaste system trouble. The radwaste systems are normally controlled from the radwaste control room in the main control room.

Radioactive gas holdup tank pressure. The requirement is to monitor from zero to 150% design pressure. Display is provided via control room alarm of radwaste system trouble. Again, the radwaste systems are normally controlled from the radwaste control room.

Exhibit 2C3-18, Type E variables. Those variables are to be monitored as required for use in determining the magnitude of the release of radioactive materials and continually assessing such releases.

Category 1 variable includes the containment area radiation-high range. The requirement is to monitor from 1 R per hour to 10^7 R per hour. The sensor is provided over that range with a nonsafety-related CRT display and two safety-related display channels at the radiation monitoring cabinet, which are Class IE. Recording is provided on one channel.

Exhibit 2C3-19, Type E Category 2 variables. Radiation exposure rate (inside buildings or areas where access is required to service equipment important to safety). The requirement is to monitor from 10^{-1} R per hour to 10^4 R per hour. PVNGS design incorporates 10 monitors with a sensor range over the required range. Display is via CRT. Sensors are qualified to the post-accident environment, and local display and annunciation at the monitors is provided.

Containment or purge effluent - noble gases and

vent flow rate. The requirement is to monitor from 10^{-6} microcuries per cc to 10^{5} microcuries per cc and from zero to 110% vent design flow. These releases are through the plant vents. We will be discussing that on the next slide.

Common plant vent - noble gases and vent flow rate. The requirement is 10^{-6} microcuries per cc to 10^{3} microcuries per cc and zero to 110% design flow. This again will be discussed on the next slide.

Exhibit 2C3-20. Auxiliary building - noble gases and vent flow rate. This is the plant vent. The requirement is from 10^{-6} microcuries per cc to 10^{3} microcuries per cc and zero to 110% vent design flow. The PVNGS design has a sensor monitoring from 10^{-9} microcuries per cc to 10^{5} microcuries per cc at the plant vent. Display is via CRT. Sensor is qualified to post-accident environment, and flow measurement will be provided.

Condenser air removal system exhaust - noble gases and vent flow rate. The requirement is 10^{-6} microcuries per cc to 10^{5} microcuries per cc and zero to 110% vent design flow. Sensor is provided over that range with a CRT display. Flow measurement will be provided.

Vent from steam generators' safety relief valves or atmospheric dump valves - noble gases and vent flow rate. The requirement is 10^{-1} microcuries per cc to 10^{3} microcuries per cc. Duration of releases in seconds and mass of steam

per unit time. Flow monitor is provided per steam line over the range required. Display is CRT. Sensors qualified to post-accident environment.

Exhibit 2C3-21, continuing with Type E Category 2 variables. Fuel building vent - noble gases and vent flow. The requirement is 10^{-6} microcuries per cc to 10^{2} microcuries per cc, zero to 110% vent design flow. Sensor is provided over that range, with the display via CRT.

Exhibit 2C3-22, Type 3 variables Category 3. Particulates and halogens at all identified release points (except steam generator safety relief valves or atmopsheric steam dump valves and condenser air removal system exhaust) sampling, with onsite analysis capability. The requirement is over the range of 10^{-3} microcuries per cc to 10^{2} microcuries per cc, zero to 110% vent design flow. Monitors are provided over that range at the fuel building vent and at the main condenser air removal exhaust. Flow measurement will be provided.

Exhibit 2C3-23, continuing with Type E Category 3 variables. Radiation exposure meters, continuous indication at fixed locations per NUREG-0654. PVNGS will comply.

Airborne radio-halogens and particulates (portable sampling with onsite analysis capability) over the range of 10^{-9} microcuries per cc to 10^{-3} microcuries per cc. PVNGS will comply.

Exhibit 2C3-24, continuing with Type E Category 3 variables. Plant and environs radiation via portable instrumentation. The requirement is to monitor 10^{-3} R per hour to 10^4 R per hour, photons 10^{-3} rads per hour to 10^4 rads per hour, Beta radiations and low energy photons. PVNGS will comply.

Plant and environs radioactivity (portable instrumentation). The requirement is multichannel Gamma-Ray spectrometer. PVNGS will comply.

Exhibit 2C3-25, Type E Category 3 variables continues. Wind direction. The requirement is over a range of zero to 360 degrees, starting speed of one mile per hour, damping ratio between .4 and .6, distance constant of 2 meters. PVNGS has sensors monitoring from zero to 540 degrees plus or minus 5 degrees accuracy, a starting threshold of .75 miles per hour, damping ratio .4, distance constant 3.3 feet.

Wind speed. The requirement is zero to 30 meters per second or minus .22 meters per second. Accuracy for wind speeds less than 11 meters per second, with a starting threshold of less than .45 meters per second. PVNGS design has a wind speed from zero to 50 miles per hour plus or minus 1% or .15 miles per hour, whichever is greater, with a starting threshold of .6 miles per hour.

Exhibit 2C3-26, continuing with Type E Category 3 variables. Estimation of atmospheric stability. The

requirement is based on vertical temperature difference from primary system over a minus 5 degree C to 10 degree C or minus .15 degrees, the accuracy per 50 meter interval or analogous range for alternative stability estimates. PVNGS design provides based on a vertical difference of 160 feet plus or minus 6 degrees F analog and digital, plus 18 to minus 6 degrees F analog and .18 degrees F accuracy.

Exhibit 2C3-27, continuing with Type E Category 3 variables. On the accident sampling capability, primary coolant and sump via a grab sample, the requirement is for gross activity 10 microcuries per milliliter to 10 curies per milliliter. PVNGS monitors from 10^{-3} microcuries per cc to 10 curies per cc.

Gamma Spectrum via isotopic analysis is in compliance.

Boron content from zero to 6,000 ppm, in compliance.

Chloride content zero to 20 ppm, in compliance.

Dissolved hydrogen from zero to 2,000 cc STP per kilogram, in compliance.

Dissolved oxygen from zero to 20 ppm, in compliance.

pH from 1 to 13, in compliance.

Exhibit 2C3-28, continuing with the Type E Category 3 variables for accident sampling capability of containment air. Hyrodgen content from zero to 10%, in compliance.

Oxygen content from zero to 30%, in compliance.

Gamma Spectrum via isotopic analysis. PVNGS design provides isotopic analysis from 10^{-7} microcuries per cc to 10^{5} microcuries per cc.

MR. BINGHAM: Any questions?

MR. BARNOSKI: I have a couple questions. After going through all that, I would like to try to summarize what you said, because my eyes weren't quick enough to compare all the numbers and make sure of everything. I gather your intent is to comply with Reg. Guide 1.97, Rev. 2.

MR. BINGHAM: That's correct.

MR. BARNOSKI: On the Type A variables, you say the expected completion date is November, '81. I believe there is a considerable amount of work that needs to be done on a plant specific basis for the BOP to support a Type A analysis. I know the CESSAR schedule was November for the NSSS portion. Is the BOP going to be done on that same schedule, also?

MR. BINGHAM: I believe we were led to believe that. We can recheck that date if you would like.

MR. STERLING: I believe we led Bechtel to believe it was November, '81.

MR. BARNOSKI: I just have one other question, and I realize this is relatively new, but on the Type B, C, D, and E, some of the variables which were addressed during the

CESSAR review appear here. Others do not. Was that just because of time? Specifically, I'll take the first one. Coolant level in the reactor was addressed. However, T_{Hot}, T_{Cold}, and RCS pressure were not. Could you clarify what your intent is, if you have gotten that far, as to what you would be referencing CESSAR for?

MR. BINGHAM: I think you're right. It was a matter of timing. Once those are included in CESSAR, we will pick them up.

MR. BARNOSKI: Fine. That's all.

MISS KERRIGAN: I have just some very general questions. I can't really tell from this table what is in now and what you are planning to put in and when you plan to put it in. Is it only the places where you have called out PVNGS will comply? Are those the only instrumentation that is not in now?

MR. ALLEN: Janis, what do you mean by not in?

MISS KERRIGAN: Installed or bought, purchased.

MR. BINGHAM: When we have the ranges specified, that means we have enough information to procure it. It may not yet be installed, but it will be installed. Where we say we will comply, it generally means that we have not yet developed enough information to give all the particulars and that when we have it, we will meet the requirements.

MISS KERRIGAN: So you still really can't tell whether

you would be running into procurement problems later down the road. There is still a potential for running into procurement problems with some of these instruments where you have specified the ranges and things. Is it your intent to have everything installed prior to licensing or by June, '83?

MR. BINGHAM: Was June, '83 the correct date? I believe June, '83, but remember, Janis, we are getting behind the line of all the other utilities that are buying the same instruments in front of us.

MISS KERRIGAN: That's right.

MR. BINGHAM: I would hope that the industry can supply the equipment in a timely manner, but we still have one constraint.

MISS KERRIGAN: But you will keep the NRC apprised of any procurement problems and a separation of which of the instrumentation will be installed by licensing and which will be deferred until the June, '83, required date.

MR. BINGHAM: We will apprise APS. APS I am sure will keep you informed.

MISS KERRIGAN: The second question that I have is it looks like you are taking at least some exceptions to Reg. Guide 1.97, Rev. 2, and will those exceptions be discussed in the LLIR update and a basis provided for any deviation from the criteria?

MR. STERLING: I believe that those are already addressed in the LLIR.

MISS KERRIGAN: Okay, and a basis provided for the exceptions in the LLIR instead of hashing that out in this meeting?

MR. STERLING. I don't remember the exact words, but I believe that's correct.

MISS KERRIGAN: Maybe Bill can help us out.

MR. QUINN: I don't really believe that we have discussed thoroughly any such exceptions. We have provided the information.

MISS KERRIGAN: We would need that, and rather than address it in a meeting of this type, because we would be here for the rest of our lives, it would be acceptable to put it in the next LLIR, which is due when, Bill?

MR. QUINN: Well, we would like to shoot for August 1st.

MR. ROSENTHAL: Mr. Allen, the needs of the NRC with respect to this may be different than the needs of the Review Board, so you should determine whether this is an appropriate forum for discussion.

MISS KERRIGAN: I think probably what we will do is defer NRC's questions on this whole area until the LLIR submittal.

MR. KOPCHINSKI: Can I ask a procedural question?

The LLIR just covers NUREG-0737. Are you asking that we include a response to 1.97 in there?

MISS KERRIGAN: No.

MR. ROSENTHAL: We are asking all of the industry to comply with Reg. Guide 1.97, Rev. 2, by June, '83, and we would ask you to do the same thing. I would like to see as strong a commitment as you can make that you intend to conform by the implementation date. Next, you want to get a license before the implementation date of this plant, and if the Reg. Guide has never been published, we would still have to review in some depth the post-accident monitoring instrumentation. I think what I would like to do is go into the SER or the SSER stage with a clear understanding of what equipment is in as of that time, and I would consider your interim post-accident monitoring system and look for compliance by June, '83.

MR. KOPCHINSKI: Which document would you like us to provide?

MR. STERLING: Could I offer a suggestion? Maybe we could mark on these exhibits the ones that are in procurement, the ones that are being installed now, and maybe as an open item to explain for those areas where we have an exception the basis for it, because I know there are not that many exceptions.

MISS KERRIGAN: Yes, that would be acceptable.

MR. BINGHAM: All right. The intention of this whole section was to put everything out so that we could see where we are, and if that would help for us to do that, we will.

MISS KERRIGAN: Maybe a little bit more detail as an open item.

MR. ROSENTHAL: If you chose to discuss it for another ten minutes, it is up to you. My branch is the one who will review this conformance and I am one of the co-authors.

MR. BINGHAM: Well, why don't we discuss it for another ten minutes, and if there are some issues that we need to get out, let's get them out.

MR. ROSENTHAL: I saw under Category 2 variables seismic qualification --

MR. BINGHAM: What exhibit are you on?

MR. ROSENTHAL: It is way up in the front.

MR. STERLING: 2C3-2.

MR. ROSENTHAL: Seismic qualification in accordance with Regulatory Guide 1.100 shall be provided when the instrumentation is part of a safety-related system. It was clearly our intent that all Category 2 instruments be seismically qualified whether they were hung on seismic stuff or not.

MR. BINGHAM: Could you explain the rationale for doing that?

MR. ROSENTHAL: One, we wanted to keep the operator

informed of whether that system was functioning or not. Two, there is a good probability that a nonseismically qualified system will continue to function post a seismic event, and it seemed prudent that he had reliable indication of its status.

MR. BINGHAM: The reason I asked is that, of course, we like to keep the power plant intact as well for seismic events, and there are certain things that we do. Dennis discussed a qualification program that we implement that gives us some good assurance, but yet we don't go with the Appendix B type program and the very long lead time in order to get some of this equipment to implement. So if we were looking at early implementation, we would be much better off to specify only those parameters that give us the assurance that we will have some indication later on rather than specify quite a pedigree and wait a very long time to get it in the plant.

MR. ROSENTHAL: I would find it convenient if you could just indicate which of the Category 2 variables will have full seismic pedigree and which won't. This is a very prescriptive Reg. Guide, and we will treat it as a Reg. Guide and not as a regulation and we will permit exceptions, but I would like you to identify them.

Then if I go all the way up to 2C3-27, and just using this as an example, I look at gross activity, the

high range of your ability to analyze grab sample cross-sections is off by a factor of thousands. Is that a typo, 10 microcuries per milliliter versus 10 curies -- I'm sorry, same thing.

MR. KEITH: You are getting more than you asked for. Right?

MR. ROSENTHAL: Yes, you're right.

MISS KERRIGAN: I guess as an open item, though, I think the point that Jack was trying to make is any places where you did take exceptions to requirements, please provide a basis. That would be the open item. The other open item would be, as he had suggested, what is in now, what you plan to put in, and what in the future is to be put in, a strong commitment to Reg. Guide 1.97 on the schedule specified in 1.97.

MR. BINGHAM: Fine. We will do that, Janis.

MR. ALLEN: Ned, did you have a question?

MR. KONDIC: I have two questions. One pertains to the table again. We understand this is like a checklist, and for most of the properties or items, the requirements do mesh with design features, but in some places, we have more verbal or qualitative explanation. Can we assume that you imply that everything checks?

MISS KERRIGAN: They will document any places where they do not meet the requirements.

MR. KONDIC: The second question, to come back to this morning where we decided to postpone that chemical spray effect and water effect of the containment spray on the instrumentation, we decided to discuss this later this afternoon. Are there some instruments in the containment which may be adversely affected by water per se, in addition by chemicals in that water?

MR. BINGHAM: I thought we had discussed that in the morning, but, as I recall --

MR. KEITH: First, we said there were no safety-related --

MR. BINGHAM: Yes, no safety-related components.

MR. KONDIC: But then we discussed that maybe spray on some of those instruments may be involved in the judgment of the operator.

MR. ROSENTHAL: Let's take a specific example, a pressurizer pressure. Those transistors are not required to function to perform a safety function after some very short period of time, but those sensors also provide a long-term indication to the operator of what the primary pressure is, so with respect to the post-accident monitoring function, which will continue for months and months and months, you would like to know that it hadn't deteriorated.

MR. BINGHAM: I understand, and in the qualification program that Combustion Engineering has, they do look at,

what I guess they call non-IE devices to make sure that they are properly qualified. There is a category for that particular type instrument.

MR. KEITH: This particular one is IE, but the whole equipment qualification thing is being addressed.

MISS KERRIGAN: Is that in the 255?

MR. KEITH: Yes, that particular one would be.

MR. KONDIC: Another example, we had the preamps in the containment. Are the preamps waterproof?

MR. BINGHAM: That example falls in the same category as the previous one.

MR. ALLEN: Any other questions? Ralph.

MR. PHELPS: You've got a lot of your variables reading out on indication in the control room, and I think in NUREG-0696 for emergency support facilities, they have suggested that they want all the Reg. Guide 1.97 variables displayed in the technical support center and the EOF as well. Are you making any provisions for that type of thing?

MR. BINGHAM: Yes.

MISS KERRIGAN: Are you going to do it or not?

MR. BINGHAM: Yes, we are.

MISS KERRIGAN: So all the Reg. Guide 1.97 variables would be displayed both in the TSC and the EOF?

MR. BINGHAM: That is our intent.

MR. ALLEN: Further questions?

MR. MARSH: It is perhaps a small point. I wanted to clarify on Exhibit 2C3-17 regarding the radwaste liquid level. That annunciation is provided in the control room and indicators are provided in the radwaste control room. Do the indicators that are provided there meet the requirements of 1.97? You didn't explicitly state that.

MR. BINGHAM: We may not have heard the question correctly. Would you repeat it, please?

MR. MARSH: As I understand the table, Reg. Guide 1.97 requires an indication, for example, on the liquid tank level in the high level radioactive waste, top to bottom level indication. The design feature described there does not explicitly state whether the indicators or the radwaste control room panel meet that, provide an indicator from top to bottom or not. All it states is that there is an alarm in the main control room, an indicator in the radwaste control panel.

MRS. MORETON: There are indicators in the radwaste control room for high level radioactive liquid tank level and for radioactive gas holdup tank pressure. At this time, the pressure indicator does not meet the 150% design pressure requirement and it is under review.

MR. MARSH: How about the level?

MRS. MORETON: That meets the level requirement.

MR. ALLEN: Carter, have you got a question?

MR. ROGERS: I have a similiar type of a question on Exhibit 2C3-16. On essential cooling water system flow, the requirement is zero to 110% of design flow. You do not tell us what the design flow is, but you say that the high range is 20,000 gallons per minute. Does that meet the requirement?

MR. KEITH: We will have to check.

MR. STERLING: In addition, you might check on 2C3-15 the auxiliary feedwater flow, also.

MR. BINGHAM: I think we are going to be going through this and adding the columns. We will pick up those generic questions.

MR. ROGERS: That is satisfactory for me.

MR. ALLEN: Any additional questions before we move on?

MR. BINGHAM: Let's go on with 2.D., All Other Instrumentation Systems Required for Safety.

MRS. MORETON: Figure 2D-1 identifies all other instrumentation systems that are required for safety, which are those instrumentation systems designed to protect other vital systems from potentially damaging transients. For the purposes of this review, this does not include fire protection.

The NSSS features are the shutdown cooling system high injection valve interlocks and the safety injection tank isolation valve interlocks. In the balance of plant,

we will be discussing the Class IE alarm system and the safety parameter display system.

Exhibit 2D1-1 are the Class IE Alarm System Design Criteria. The Class IE alarm system is provided for a limited number of operational occurrences for which no specific automatic acutation of a safety system is required. The system alerts the operator to keep the plant operating within Technical Specification limits and aids in precluding equipment damage. The Class IE alarm system shall be designed in compliance with the standards listed on Exhibit 2D1-1 and continued at the top of Exhibit 2D1-2. Power for each redundant Class IE annunciator shall be supplied from a separate Class IE 125 volt-DC distribution bus. Each Class IE annunciator is an independent unit from the plant annunciator. The annunciation sequence for operation and testing for the Class IE annunciators shall be the same as the plant annunciator with the exceptions that the Class IE annunciator shall have a key locked alarm acknowledge function and the Class IE annunciator does not have a return-to-normal audible. The Class IE alarm system shall be designed to the requirements for nuclear safety-related systems such that the devices must maintain their safety-related functional capability under all normal and abnormal plant operating conditions.

Exhibit 2D1-3. This is our system description of

the Class IE alarm system. Class IE alarms are provided to alert the operator in the event of a loss of nuclear cooling water to the reactor coolant pumps seal coolers, inadequate safety injection tank pressure, and high water level in an ECCS pump room. Silencing of the alarm audible is provided by a key locked alarm acknowledge switch. Four Class IE annunciators are provided, two in instrument Channel A and two in instrument Channel B. The Channel A annunciators are physically separate and independent of the Channel B annunciators. The annunciators are supplied from separate 125 volt-DC Class IE distribution buses.

Exhibit 2D1-4 identifies the four Class IE annunciators. An annunciator is provided for inadequate safety injection tank pressure of Tanks 3 and 4, high water level in ECCS Train A pump rooms, one annunciator window per pump room. The same is provided on Channel B for safety injection Tanks 1 and 2 and for the ECCS Train B pump rooms. An additional annunciator is provided on loss of nuclear cooling water to the reactor coolant pumps seal coolers, one window per pump, and a redundant annunciator is provided on Channel B.

Exhibit 2D1-5. Each Class IE annunciator is a unit with integral windows, horn, power supply, and annunciator logic cards mounted in the annunciator section of the main control boards. Separate switches exist for alarm acknowledge,

flasher reset, lamp reset, and test.

Class IE alarm functions include the loss of nuclear cooling water to the reactor coolant pumps seal coolers. Redundant safety grade instrument channels are provided to continuously monitor nuclear cooling water flow to the seal coolers for each reactor coolant pump. Annunciation is provided if the nuclear cooling water flow rate is reduced below the minimum required for pump operation.

Inadequate safety injection tank pressure alarm. Safety grade instrument channels monitor the pressure in each safety injection tank and the pressurizer. Annunciation is provided if the pressure in a safety injection tank falls below 600 psig while pressurizer pressure is above 700 psig, indicating the unavailability of the safety injection tank.

Exhibit 2D1-6. A Class IE alarm is provided on high water level in an ECCS pump room. Safety grade instrument channels monitor level in the drain basin in the rooms for the low pressure safety injection pumps, high pressure safety injection pumps, and the containment spray pumps. Annunciation is provided on a high level signal indicating leakage in a pump room.

We will proceed now to the Safety Parameter Display System Design Criteria. This system is still in the design implementation and procurement phases. These are the design criteria that have been adopted by the project.

The safety parameter display system shall be provided to assist control room personnel in evaluating the safety status of the plant. The primary function of the SPDS is to aid the operator in rapid detection of abnormal operating conditions. The SPDS shall be designed to 10CFR50, Appendix A, General Design Criteria, IEEE 344 for seismic qualification, and NUREG-0696.

Exhibit 2D2-2, continuing with the safety parameter display system. The important plant functions related to the primary SPDS display while the plant is generating power shall include but not be limited to the reactivity control, reactor core cooling, heat removal from the primary system, reactor coolant system integrity, radioactivity control, and containment integrity. The SPDS function in the control room shall be provided during and following all events expected to occur during the life of the plant, including SSE. The SPDS display shall take account of human factors and the man-machine interface. The SPDS display shall be incorporated into the main control room with a location that will allow the displays to be easily observed by the operations staff. The SPDS display shall reflect and be capable of supporting all operating modes.

Exhibit 2D2-3. The SPDS display shall also be availabe in the TSC, the satellite TSC, and EOF. The SPDS shall be designed to an operational unavailability goal

as defined in NUREG-0696 of 0.01 for the data display function at each facility when the reactor is above cold shutdown status. In addition, the SPDS display function in the control room shall be designed to an operational unavailability goal of 0.2 for cold shutdown status including the refueling mode.

The SPDS System Description is provided on Exhibit 2D2-4. It is very brief. because the system has not yet been procurred. The SPDS consists of two display systems located in the control room: a full-color CRT display driven from the technical support center computer system, and a seismically qualified display system driven from a separate control room processor system. Plant functions included in the SPDS displays are those that were defined in the design critiera.

MR. BINGHAM: Any questions?

MR. ROSENTHAL: By when do you intend to install the SPDS?

MR. BINGHAM: Our present schedule is to have it installed prior to November of '82.

MR. HELMAN: I have a question on 2D2-3, Item 7). My question concerns the EOF and post-EOF. Could you explain a little further about the location of the current EOF and its compliance with 0696?

MR. BINGHAM: I'm sorry, when you say the location and its compliance, what did you have in mind, Norm?

MR. HELMAN: The current requirement, correct me if I am wrong, is if we have a close-in EOF, which we do currently, we are also required to have an alternate EOF at some further location with specific SPDS and TSC type displays in that location. I notice in here that you indicate that the SPDS display will be available in the TSC, satellite TSC, and EOF. I am concerned about addressing the alternate EOF.

MR. BINGHAM: I think, John, I would prefer that APS respond to that particular issue. That is the alternate EOF.

MR. ALLEN: Run that by one more time, Norm. You are saying explain why we've got a satellite TSC?

MR. HELMAN: No, I am asking about the possibility of an alternate EOF, because 0696 requires that if you have a close-in EOF, you must also have in addition an alternate EOF that is greater than ten miles.

MR. BINGHAM: There is a letter that APS has sent to NRC stating the position regarding the alternate EOF. I don't recall there being a response.

MR. ALLEN: We had met with the NRC a few weeks back, and at that time, they had indicated to us that they felt that our EOF location was satisfactory. However, they would verify that and let us know by letter.

MISS KERRIGAN: That's right.

MR. ALLEN: That is still in process, Janis?

MISS KERRIGAN: That's right. There has been a Commission paper prepared to propose to the Commission your design along with a few other plants and we have not yet gotten feedback on that from the Commission.

MR. HELMAN: Is there a specific commitment date for receipt of that letter?

MISS KERRIGAN: No.

MR. HELMAN: I wanted to hear that.

MISS KERRIGAN: We hope to get it out shortly.

MR. ALLEN: Any other questions?

MR. PHELPS: I've got a question regarding the monitoring of the cooling water flow to the pump seals. Are those transmitters placed in a portion of the line where they also monitor the cooling water to the pump motors?

MRS. MORETON: The flow transmitters are located in the nuclear cooling water lines that service all the coolers for the reactor coolant pump.

MR. PHELPS: Is that seismically designed for DBE?

MRS. MORETON: The nuclear cooling water lines?

MR. PHELPS: Yes.

MRS. MORETON: No.

MR. PHELPS: Then how do you meet your criteria for that event?

MR. KEITH: The nuclear cooling water lines to the

pumps are not Seismic Category I. The flow transmitters are Seismic Category I and seismically mounted. These transmitters were installed because of the concern that we had non-Seismic Category I cooling water going to the reactor coolant pumps. CE has done testing on these pumps showing that the pumps are fine for at least 30 minutes without any cooling water. The 30 minutes plus the alarm that we would get if we lost cooling water flow to the reactor coolant pumps, we would then have 30 minutes to shut down the reactor in an orderly fashion and stop the reactor coolant pumps.

MR. PHELPS: What type of flow meters are they?

MRS. MORETON: They are differential pressure transmitters.

MR. PHELPS: And you've got the orifice plate portion of that mounted seismically, so that even if a line breaks, they will still receive a no-flow signal?

MRS. MORETON: The orifice plate is not seismically mounted. Only the transmitters are seismically mounted. If the line ruptured, the impulse lines or sensing lines would also break, indicating no flow. The transmitter would fail to its no-flow position and cause the alarm.

MR. KONDIC: Are those flow meters checked and recalibrated because of numerous possibilities with time to give a different reading? You buy them and that's it, or is there any way to find out whether that orifice has, for

example, accumulated dirt? A Delta P is not a measure of the flow rate any more. This is something new.

MR. ALLEN: Jim, would you like to say what you intend to do on those orifices, if anything? Nothing. Is that satisfactory?

MR. KONDIC: The silence?

MR. ALLEN: No, there is no check of the orifices or anything after they are installed.

MR. KONDIC: Thank you.

MR. MECH: I have a question which might throw some light on that, perhaps. I am a little confused. On Exhibits 2D1, 5 and 6, you list the sensors used for the Class IE alarm functions. Now, let me get this straight. There are four annunciator panels.

MRS. MORETON: Yes.

MR. MECH: A, B, C, D.

MRS. MORETON: A, B, A, B, two A's and two B's.

MR. MECH: All right. Then the sensors that are involved with the safety injection tank, are they the same sensors that are involved with the safety injection tank interlocks?

MR. BINGHAM: We will have to look at the drawings to answer that question.

MR. MECH: Well, let me ask another question then that might help. From reading the FSAR, I find words like

on Exhibit 6, high water level in an ECCS pump room, I find words like one independent level sensor is used to monitor the level. What does that mean? What is that one independent level sensor?

MRS. MORETON: The Train A pump room, as an example, the containment spray pump room, has a Channel A sensor that supplies monitoring or annunciation only to this annunciator, to nowhere else. The Train B pump room would have a Channel B sensor.

MR. MECH: And this is a second sensor that is put in in addition to the one that is there for other reasons?

MRS. MORETON: Not in the same room. In a separate room.

MR. ALLEN: Any further questioning on that section?

MR. MECH: I asked what an independent level sensor was.

MR. ROSENTHAL: You lose CCW to the RCP's on a containment isolation actuation signal by design. The containment isolation actuation signal comes from lower pressurizer pressure as well as high containment pressure, so one expects that simple anticipated operational occurrences will generate a containment isolation and, in turn, isolate CCW to the RCT's, so with some frequency, you will isolate CCW to the CRP's, more than once a year. What is the rationale for not modifying the system such that you don't

CCW on a CIAS.

MR. BINGHAM: Let me see if I understand. You are saying during normal operating transients that you would expect containment isolation to occur at least once or more a year.

MR. ROSENTHAL: Yes. The containment isolation actuation signal some years past was on only high containment pressure and would happen hopefully very infrequently, while SIAS is induced by any overcooling event that drops the pressurizer pressure below 1,600. Now that you have added diversity to CIAS such that you pick up lower pressurizer pressure, any overcooling event, and we see even undercooling events which ten minutes later become overcooling events, will cause SIAS and CIAS, they are logically one and the same, and then by design, you isolate those lines in order to fulfill the classical containment function of buttoning everything up at this time, so now we have a situation in which the pumps have been tested and can withstand, based on limited testing, loss of CCW, and yet we expect a relatively high frequency due to simple plant transients to be challenging those pump seals, and loss of those pump seals gives you a small break LOCA. Given that, why did you decide to isolate CCW on containment isolation rather than choosing to take an exception to the normal containment isolation?

MR. BINGHAM: Regardless of whether it is seismic or not, the issue is there. Let us confer for just a second.

MR. KEITH: First, I am not convinced that we are going to have low pressure transients that often. I don't know how good the data is on that, but, anyhow, it doesn't seem to me like we should have them more often than once a year. But, at any rate, because we felt we could live with isolating these valves on a containment isolation actuation signal, we went ahead and did it that way. I am not sure that not doing it would be acceptable to your Containment Systems Branch. If it were, I think there is some rationale on not to shut them off on a CIAS. I would agree with your observations.

MR. ROSENTHAL: I have had discussions with the Containment Systems Branch, Auxiliary Systems Branch, Reactor Safety Branch myself on this issue. The design as you approach it seems to meet the requirements of the regulations in the area of equipment unavailability, which is a commercial concern which we wouldn't involve ourselves in, although this Board might. We weren't fully happy that we were sure we were doing the prudent thing, so I would appreciate an explanation of the rationale, and this is an area in which we would surely be anxious to hear your rationale one way or the other.

MISS KERRIGAN: I guess what Jack is saying is we

don't like to hear a rationale being used "because NRC told us to." The responsibility of safety of the plant is yours, not NRC's.

MR. BINGHAM: I don't believe that was the impression Dennis was trying to give you, Janis. This system has been the way it is since 1976 and it continues and remains to be that way until there is other evidence that there should be some change. What I guess I understand that Jack is saying is that there is some rethinking going on about the desirability of isolating that particular system.

MISS KERRIGAN: All right. I think that was back into one of the TMI concerns, the old lessons-learned concern about essential versus nonessential systems, and that was part of the responsibility of the vendors and utilities to rethink that, so we assume you have done that. And now have a very strong basis for defining that CCW is nonessential, and that is what we would like to hear.

MR. KEITH: I kind of alluded to that. Our evaluation based on the work that CE has done and assuming for most accidents, although it was beneficial at times at Three Mile Island to run the reactor coolant pumps, generally the reactor coolant pumps are not considered essential and needed, so, based on that, we have classified this as a nonessential system. Admittedly, it is borderline and I think we could go back and take another look at it.

MR. ROGERS: Let me ask a question before you get off into that. Is not the seal injection system which is connected with the charging system, which is not isolated in the case of a containment isolation signal, doesn't that provide secondary cooling to the seals on the reactor coolant pumps?

MR. KEITH: That's correct. There is that for the seals.

MR. PHELPS: I just wanted to make one additional point. If your original concern was correcting the low pressure safety injection actuation signal terminating recoolant water flow because of some of the TMI work while waiting for the loss to come back, CE's operating guidelines require the reactor coolant pumps to be tripped on the low pressure safety injection setpoint, so that concern goes away for the time being.

MR. ROSENTHAL: Excuse me, tripping of the pumps doesn't totally protect the seals, which are quite Delta T dependent. Yes, it would help, but I don't know if I am bordering on an equipment concern or a safety concern. That helps.

MR. ROGERS: The same system is a backup for the seals and will keep the seals intact if you lose cooling water. It is redundant in that sense to the component cooling water system as I understand it.

MR. BINGHAM: And that valve we don't shut. We leave that one open, so there is that, Jack. You might want to look at that particular feature.

MR. ROSENTHAL: Yes, we have.

MISS KERRIGAN: Were you going to go back and look at it or not? It's up to you.

MR. BINGHAM: It is up to the Board, of course. If you like, I believe we will have to go to Combustion to get their review.

MR. ALLEN: I think from our standpoint we are fairly well satisfied. If you would like us to look into it --

MISS KERRIGAN: No, it is the Board's decision. I think we have the position on record and that served our purposes.

MR. ALLEN: That position was discussed at the last IDR, also, on the containment system. Unless someone else on the Board has a desire to look at it, I would just as soon close it.

MR. BINGHAM: Any more questions?

MR. ALLEN: Any questions left?

MR. BINGHAM: Due to the lateness of the hour, we will present 2.E., Control Systems Not Required for Safety, and then end the day's work with that section. Then tomorrow morning, as I recall, we are convening at 8:00. I would like a few minutes to bring the open items that we

can from today and then we will move into Section 3, which is Compliance With Regulatory Requirements, if that is satisfactory to the Board.

MRS. MORETON: Figure 2E-1. Control systems not required for safety are those electrical and mechanical devices and circuitry required for plant operation but whose functions are not essential for the safety of the plant. Most of these systems are NSSS systems which were discussed in CESSAR. There are two NSSS systems that are outside the CESSAR scope, including the steam bypass control system option with two valves to atmosphere and the extended range feedwater control system that provides control from zero to 15% power. The balance of plant system is the loose parts monitoring system.

The design criteria for the control systems not required for safety are, on Exhibit 2E-1, the feedwater control system - extended range. For operation between zero and 15% power, the feedwater control system shall automatically control the steam generator downcomer water level. Steam generator level will be controlled during the following condition, assuming that all other control systems are operating in automatic: steady state operations, 1% per minute turbine load ramps between 0 and 15% NSSS power, loss of one of two operating feedwater pumps, and load rejection of any magnitude.

Design criteria for the steam bypass control system option, Exhibit 2E-2. The CESSAR system is modified for PVNGS to dump steam to atmosphere through two of the turbine bypass valves. These valves shall be the last to open and first to close during steam bypass operation.

Design criteria for the loose parts monitoring system on Exhibit 2E-3. A loose parts monitoring system shall be provided to detect and record signals resulting from impacts occurring within the reactor coolant system.

I will now proceed with the system description. Exhibit 2E-4, feedwater control system - extended range. Below 15% NSSS power, referring to Figure 2E-2, the feedwater control system performs dynamic compensation on the level signal to generate an Alpha signal indicative of the required feedwater flow. The Alpha signal is used to generate the downcomer valve position demand signal. When in this control mode, the economizer valve will be closed and the pump speed setpoint will be at its minimum value. You see the signal coming to the downcomer program. When we are below 15% power, the economizer valve is closed and the feedwater pump is set to minimum.

Exhibit 2E-5, steam bypass control system description. The CESSAR system is modified from four valve groups to five valve groups. Valve Group 5 contains the seventh and eighth steam bypass valves which discharge to atmosphere.

Valve Group 5 is the last group to sequence open and is not interlocked with a loss of condenser vacuum signal.

Figure 2E-3 is a simply block diagram of the steam bypass control system which is identical to the control system provided in CESSAR, still eight valves. The only change is that six go to the condenser and two to the atmosphere. Those two that go to the atmosphere do not receive condenser interlock signals.

Exhibit 2E-6, system description of the loose parts monitoring system. Eight high temperature piezoelectric accelerometers (transducers) will be located in the areas where loose parts are most likely to become entrapped. Two redundant transducers are clamp mounted on the in-core instrument guide tubes on the reactor vessel lower head. These are diametrically opposed. Two redundant transducers will be stud mounted on the reactor vessel upper head service structure flange, also diametrically opposed, and two redundant transducers on the lower head region of each steam generator. One transducer will be clamped to the primary inlet pipe and the other will be clamped to the primary outlet pipe.

Exhibit 2E-7, continuing on with the loose parts system description. A data acquisition panel is located in the control room area which contains alarm modules that continually monitor the incoming signals from the preamplifier

for the presence of impacting. The occurrence of a loose part impacting on the inside of the structure causes bursts of signals that exceed the alarm setpoint and trigger the alarm. The data acquisition panel includes tape recorders with playback and an audio monitor.

MR. BINGHAM: Questions?

MR. MECH: One little question. You don't list in the systems here the gross failed fuel monitor, which is generally considered desirable. In Chapter 9 of the FSAR, you have what you call a process radiation monitor, which appears to do the same function. Is this true?

MR. BINGHAM: That's true.

MR. MECH: Thank you.

MR. ALLEN: Jack, I think you had one.

MR. ROSENTHAL: Yes. Do you have a control grade reactor power cutback system? I assume that is part of the standard System 80 scope of supply.

MR. BINGHAM: We have it. Is it part of the standard System 80?

MR. BARNOSKI: Yes.

MR. ROSENTHAL: That system in some sense is in lieu of the anticipatory trip of the reactor on a turbine trip, which is a safety grade system and which we have required on other than CE NSSS plants. Would it be appropriate to have some requirements with respect to availability of that

system? It is no great scheme and one does have turbine trip. I believe that the Chapter 15 analysis shows it lifts the safeties, which is an undesirable characteristic.

MR. BINGHAM: I'm not sure that Bechtel is the one that that question should be directed to. Maybe, John, you could help us. If I understand, the question is, since that is a control grade system, should there be some other requirements on its availability to perform when required. Is that correct?

MR. ROSENTHAL: Yes.

MR. ALLEN: That sounds like a question that would have to be coordinated with Combustion. We can take it as an open item.

MR. BARNOSKI: If I might make a suggestion, I guess from our point of view, that is a CESSAR question as opposed to a question for these folks. We have noted it and we will be prepared to discuss that at the upcoming meeting in July.

MR. ROSENTHAL: Okay, fine.

MR. BINGHAM: Does that take care of it?

MR. ALLEN: A clarification on that. Some System 80 plants don't have that like Yellow Creek.

MR. BESSETTE: Let me clarify. All System 80 plants do have reactor power cutback. Some of the functions of the reactor power cutback on Yellow Creek, for example, aren't included because they have a third feed pump. Therefore,

there is no reactor power cutback initiated on a loss of a feed pump, because they still have 100% feed pump capability, but the reactor power cutback itself doesn't exist.

MR. ROSENTHAL: Another control grade system that you have is called COLSS. That system was discussed at Combustion and the level of QA of that system to the point that the software leaves Combustion's doors was discussed. That software now arrives at Palo Verde. Can you describe the quality assurance of it and protection of that COLSS software package?

MR. ALLEN: We will have to take that one as an open item. We don't have the people here to do that.

MR. BINGHAM: Maybe I could add enough, John, to get this before these folks.

MR. ALLEN: That is an Operations QA problem and I would like to see it addressed by Operations.

MR. BINGHAM: Fine.

MR. ROSENTHAL: Similarly, the reactor power cutback system, control grade system, does get some input from information which is stored on the plant computer. There should be some commensurate level of QA of the software for this control grade system performed by Palo Verde. We would like to discuss that.

MR. ALLEN: We will take that as an open item, also.

MR. SIMKO: There were some questions from the NRC

addressing these already. I can't remember where. A couple of months ago, they talked about this and I know our Licensing Group is addressing this type of question.

MISS KERRIGAN: In other words, they could have spent time with that first set of Ql's under the QA set of questions.

MR. SIMKO: You can leave it an open item, but I know we have addressed that.

MISS KERRIGAN: It could be that your response would be referring us to your Ql response.

MR. ALLEN: Any further questions?

MR. BINGHAM: No more questions?

MR. ALLEN: I guess then we will adjourn for the day and meet back at this room at 8:00 sharp tomorrow morning.

(Thereupon the meeting was at recess.)