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ACCESSION NBR: 8107230124 DOC. DATE: 81/07/15 NOTARIZED: YES DOCKET #
 FACIL: STN-50-528 Palo Verde Nuclear Station, Unit 1, Arizona Public 05000528
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 STN-50-530 Palo Verde Nuclear Station, Unit 3, Arizona Public 05000530

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SUBJECT: Forwards Vols 1 & 2 of transcript of 810617-18 independent design review of facility instrumentation & control systems before Instrumentation & Control Sys Review Board in Phoenix, AZ. *See notes*

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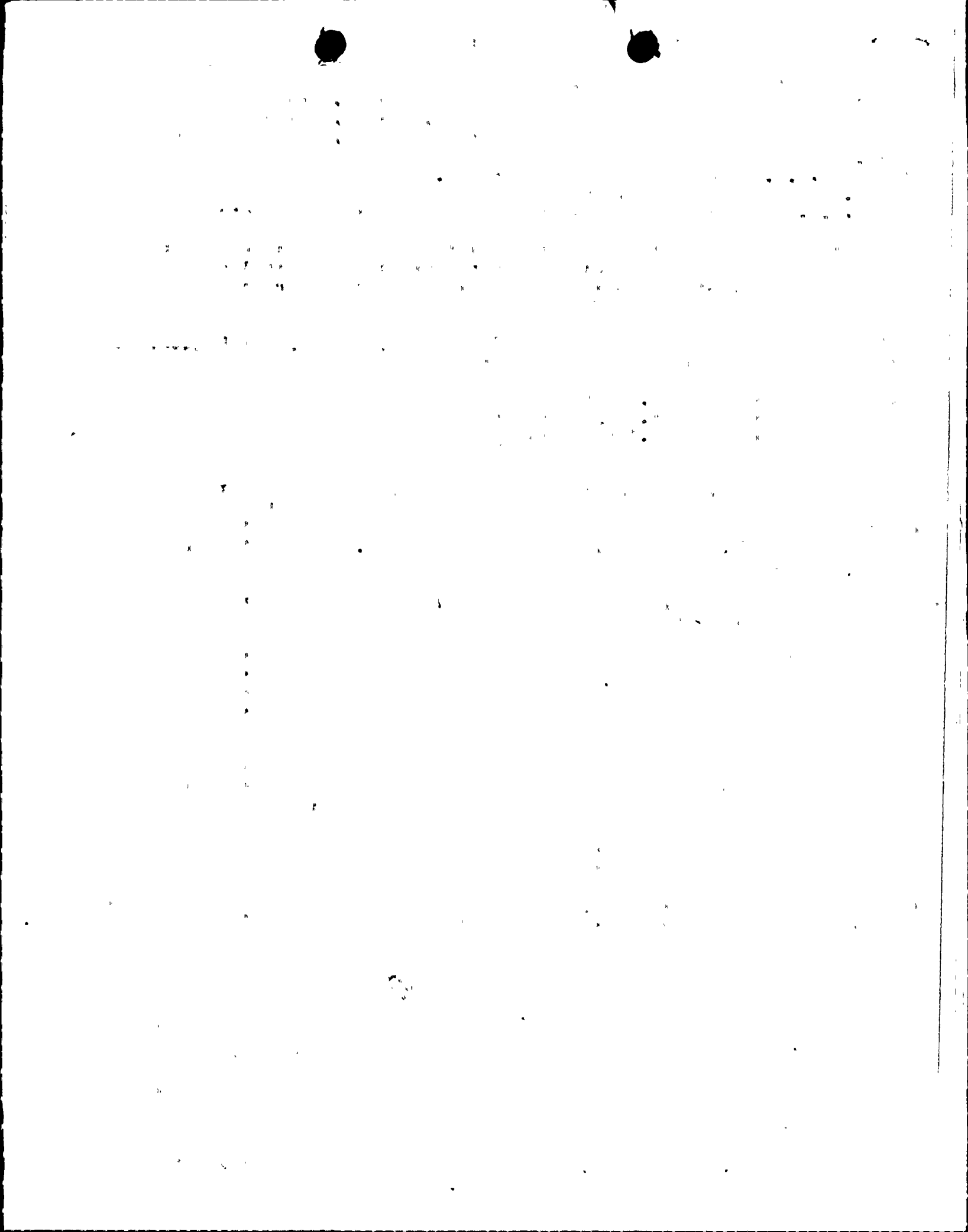
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ARIZONA



PUBLIC SERVICE COMPANY

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July 15, 1981

ANPP-18412 - JMA/TFQ

Mr. H. R. Denton
Director of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Palo Verde Nuclear Generating Station
(PVNGS) Units 1, 2 and 3
Docket Nos. STN-50-528/529/530



Dear Mr. Denton:

Attached are two copies of Volumes I and II of the transcript of the Independent Design Review conducted on June 17 and 18, 1981 for the PVNGS Balance-of-Plant Instrumentation and Controls. This transcript is submitted for your use and as a record of the Review.

Volume III of the transcript, compilation of the exhibits presented at the Review, is not presently available. Modifications to the exhibits have been requested by the board members. Volume III will be submitted to you when we submit the resolutions to the open items.

A list of open items is provided on Pages 347 through 349. These items consist of unanswered questions and requests for information made by our review board members and the NRC representatives. Resolution of the open items will be provided to the NRC in order to close the record of this Independent Design Review.

Very truly yours,

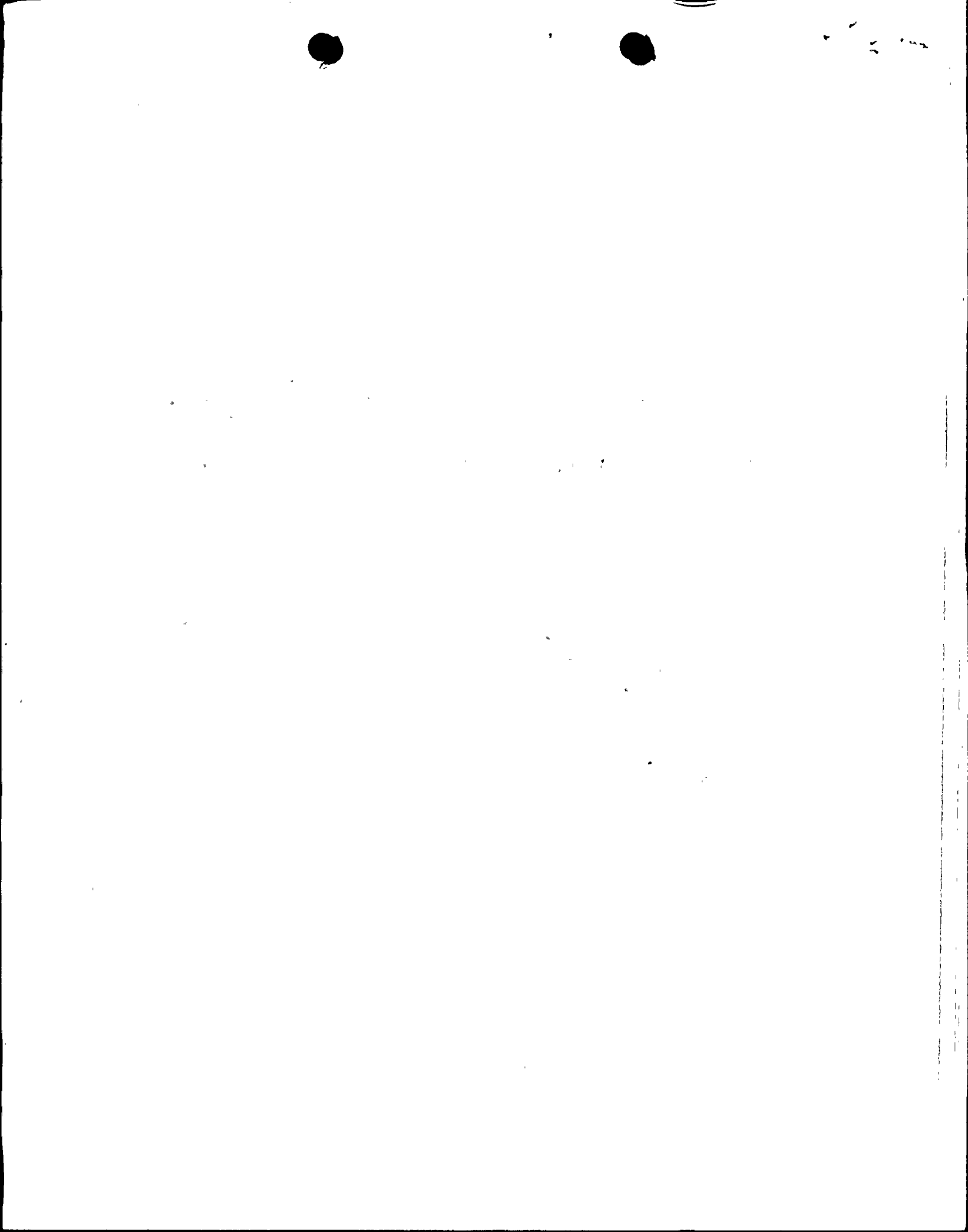
E. E. Van Brunt, Jr.
APS Vice President,
Nuclear Projects
ANPP Project Director

EEVBjr/TFQ/av
Attachment

cc: J. Kerrigan (w/attach.)
J. Rosenthal (w/attach.)
B. Myerson (w/attach.)
P. Hourihan
A. C. Gehr

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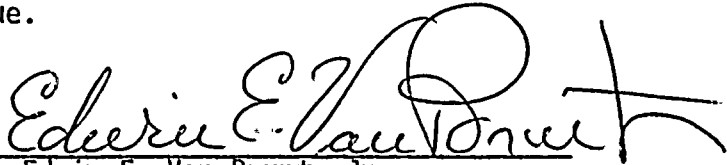
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Mr. H. R. Denton
July 15, 1981
ANPP-18412 - JMA/TFQ
Page 2

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, Edwin E. Van Brunt, Jr., represent that I am Vice President Nuclear Projects of Arizona Public Service Company, that the foregoing document has been signed by me on behalf of Arizona Public Service Company with full authority so to do, that I have read such document and know its contents, and that to the best of my knowledge and belief, the statements made therein are true.


Edwin E. Van Brunt, Jr.

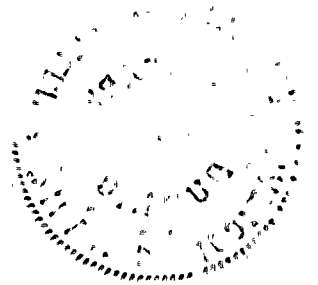
Sworn to before me this 15 day of July, 1981.


Notary Public

My Commission expires:

My Commission Expires Jan. 23, 1983

2



INDEPENDENT DESIGN REVIEW
of the
PALO VERDE NUCLEAR GENERATING STATION
INSTRUMENTATION AND CONTROL SYSTEMS

Before the
INSTRUMENTATION & CONTROL SYSTEMS REVIEW BOARD

VOLUME I of III

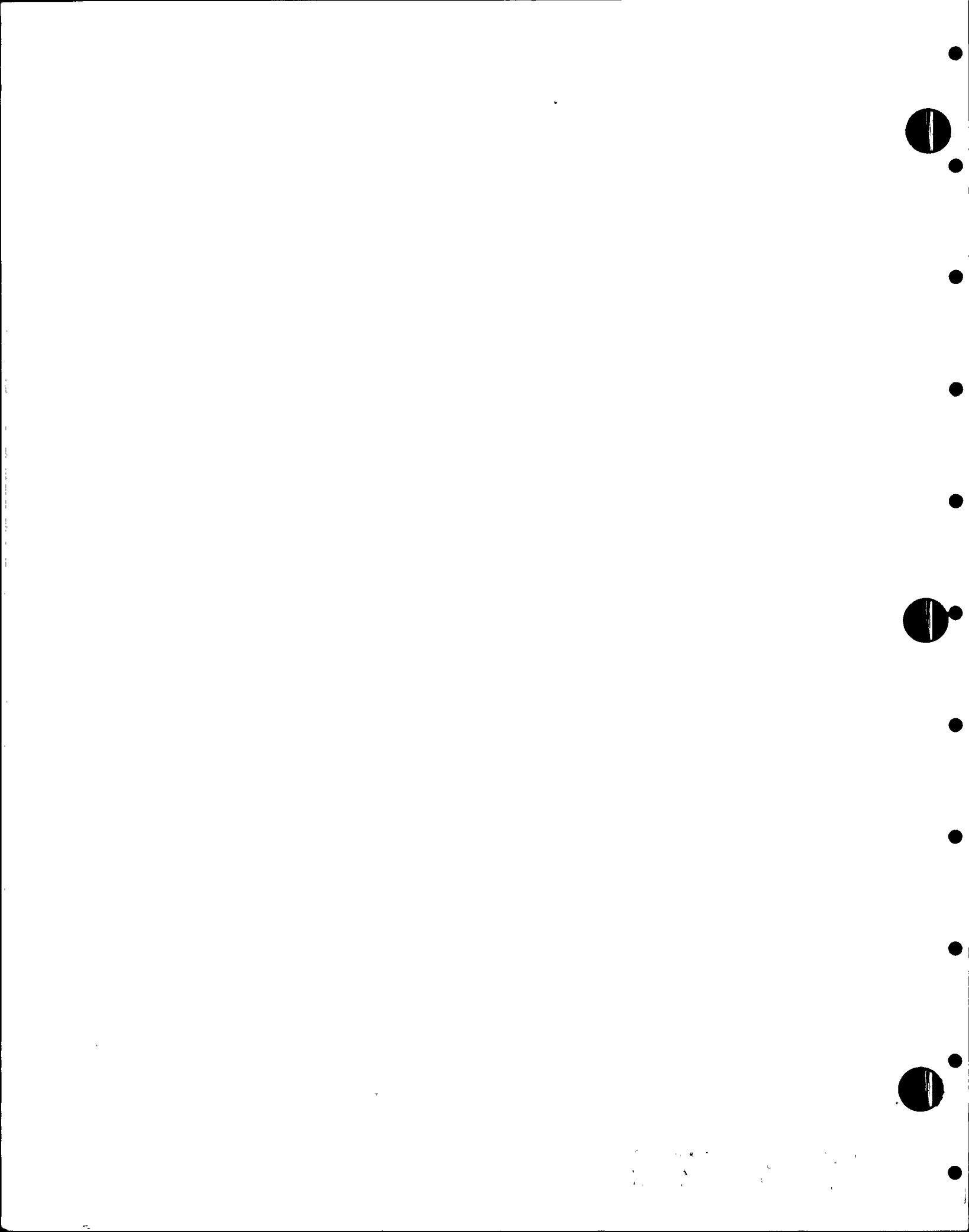
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Phoenix, Arizona

June 17-18, 1981

GRUMLEY REPORTERS
PHOENIX, ARIZONA

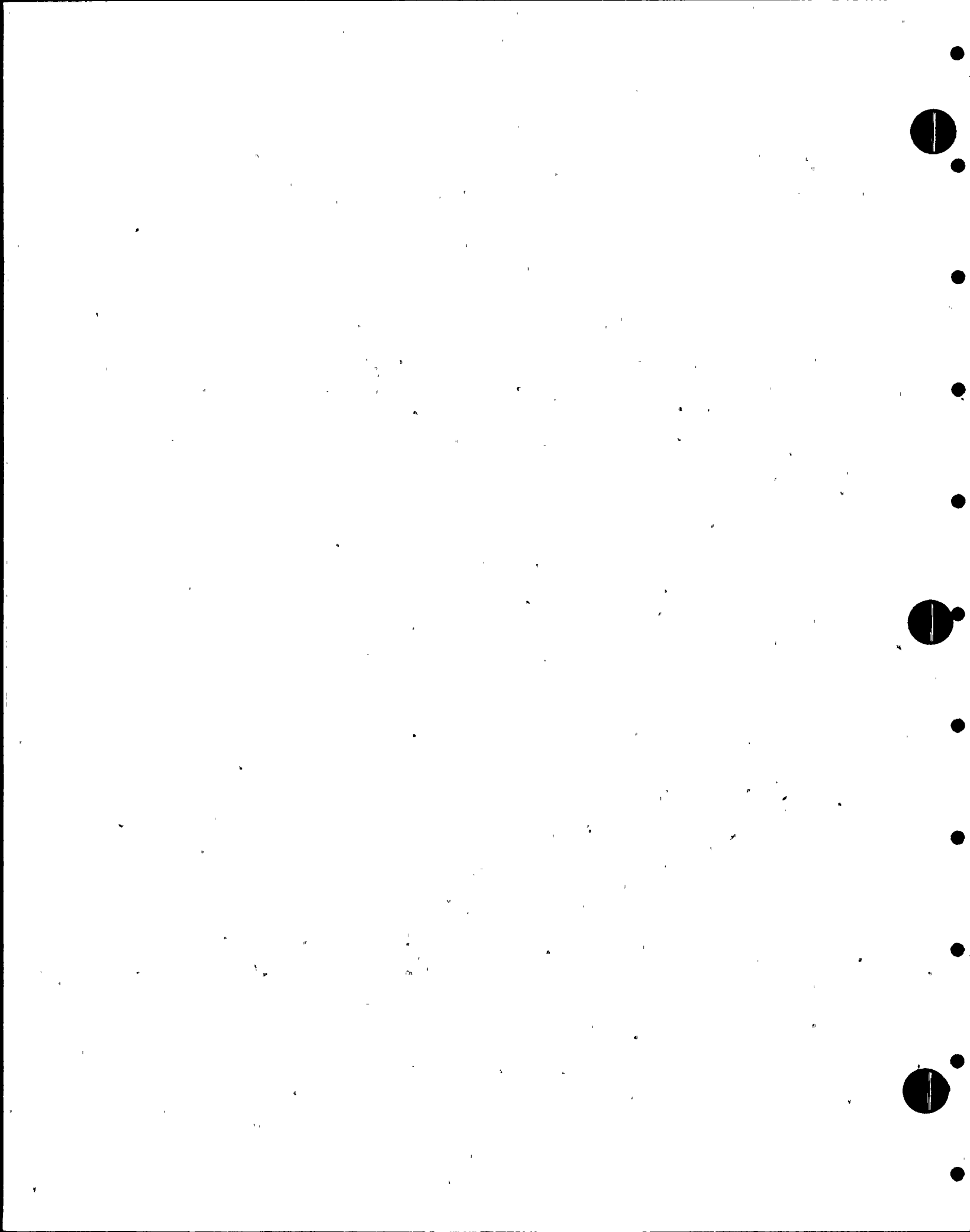
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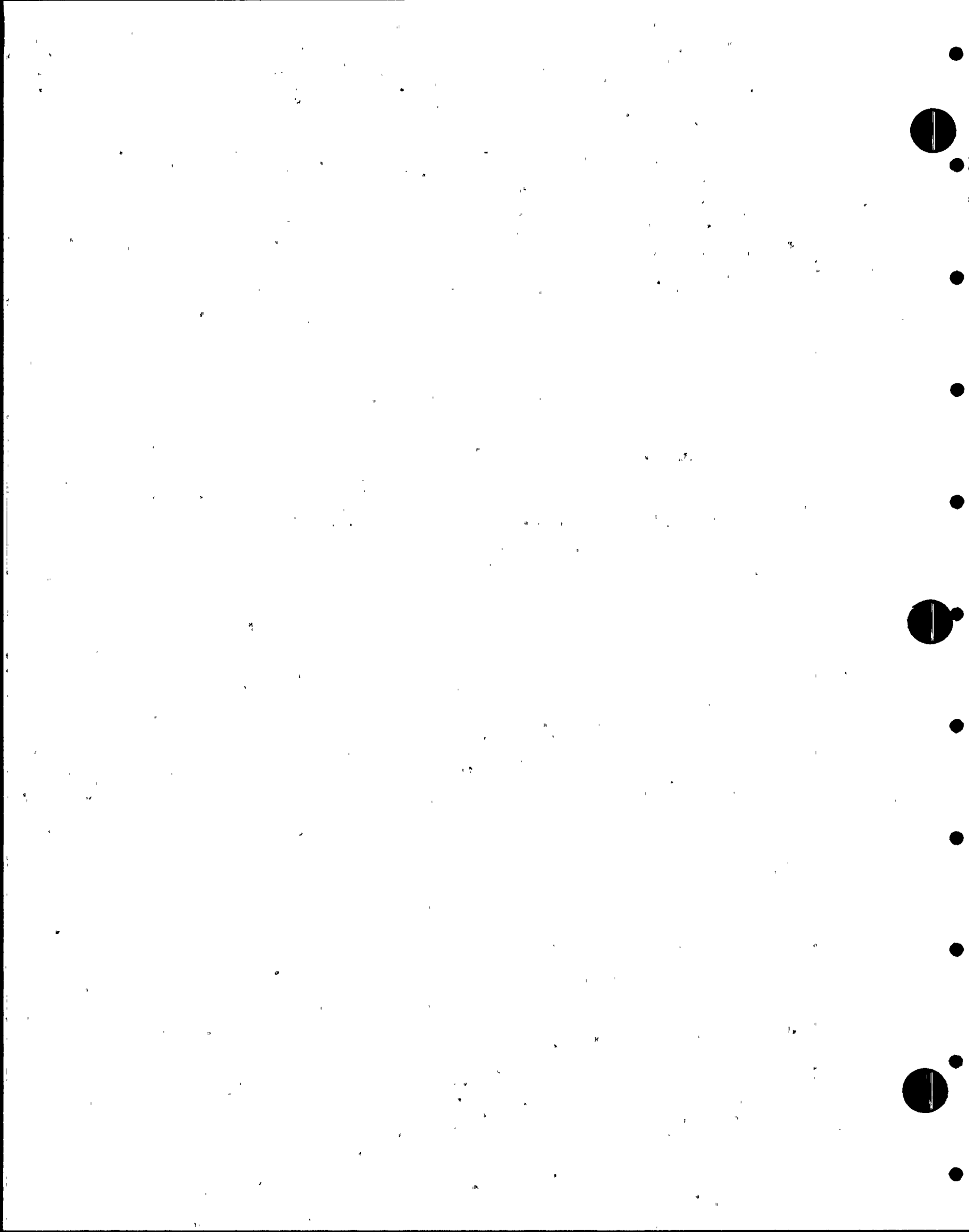
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VOLUME I

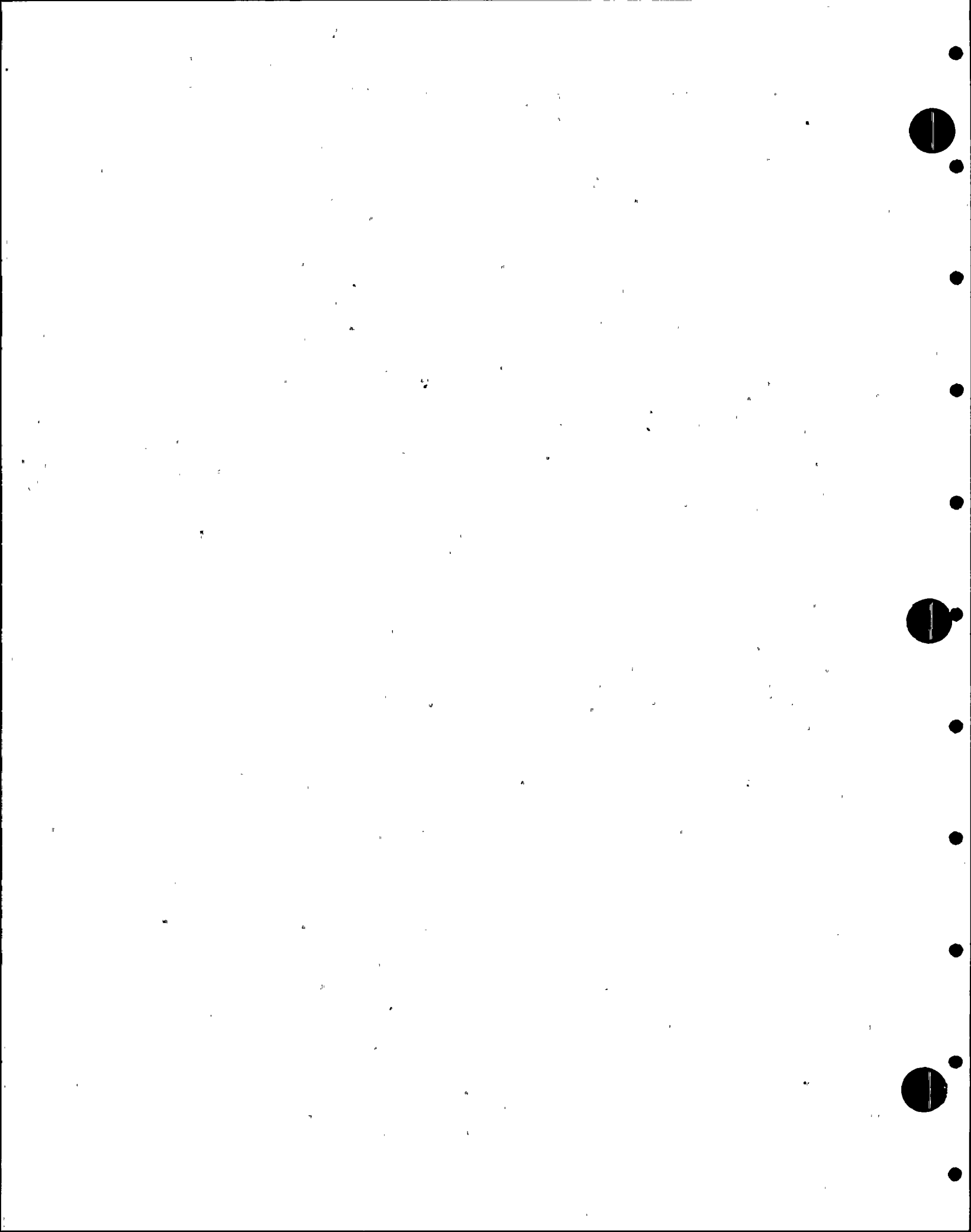
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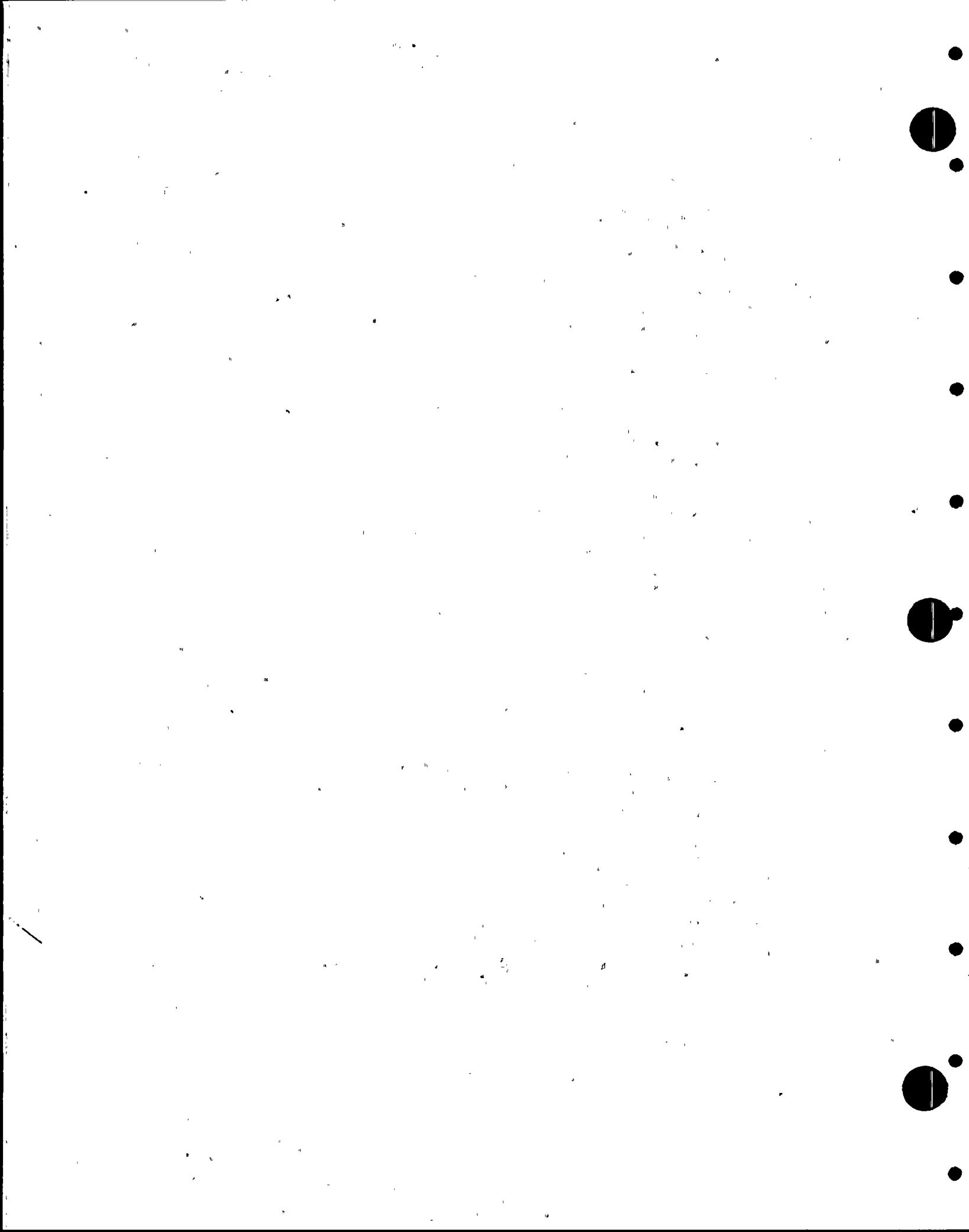
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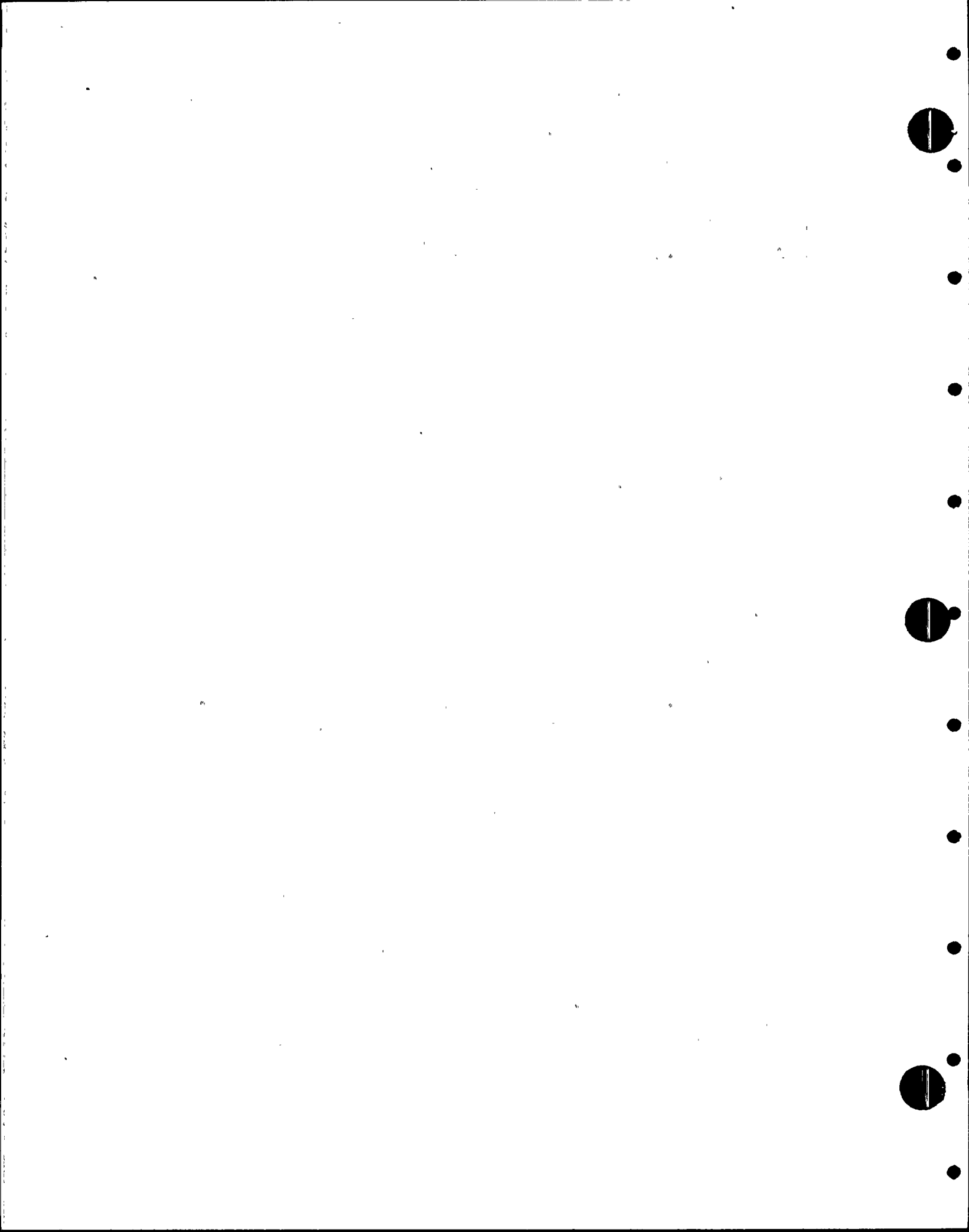
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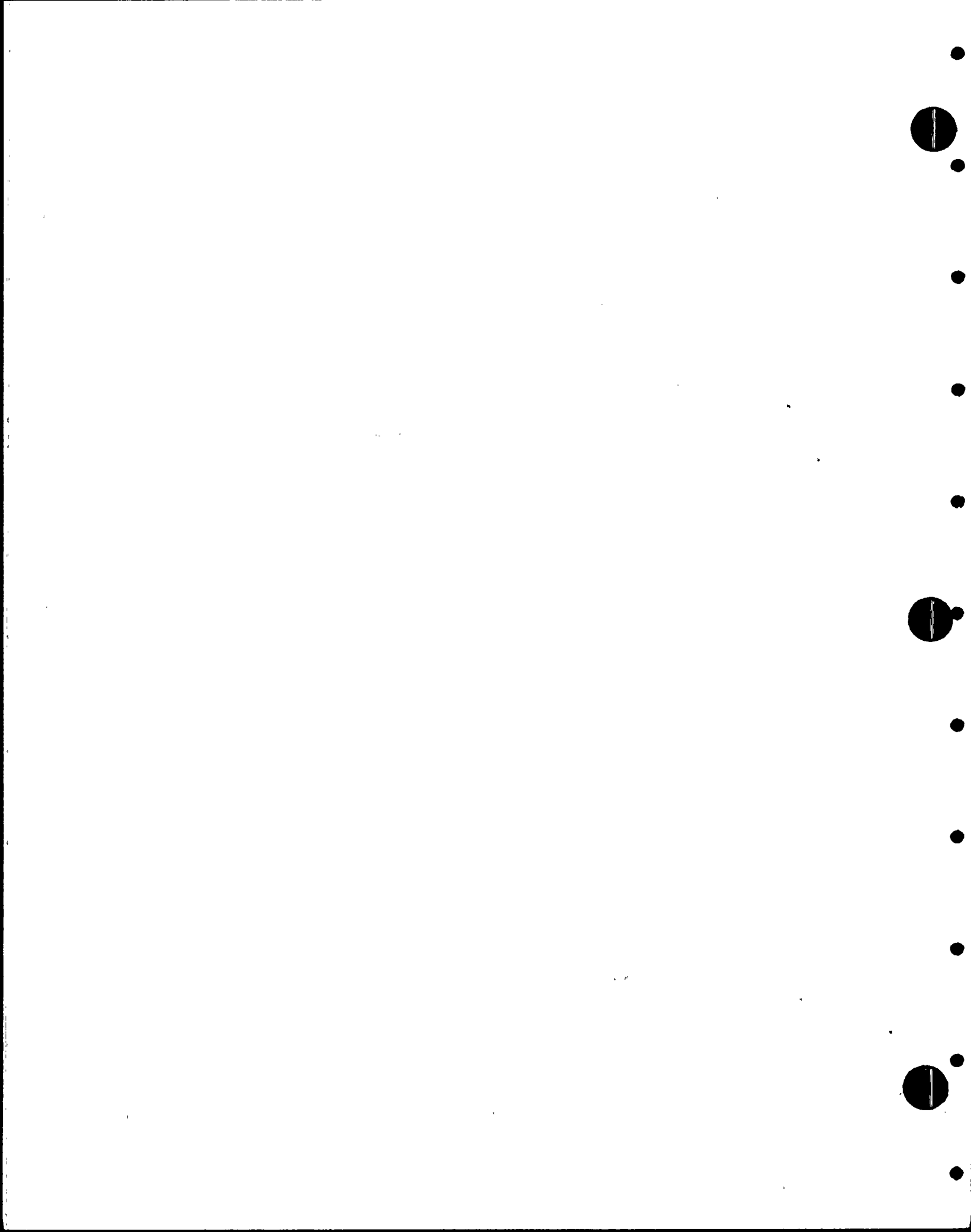
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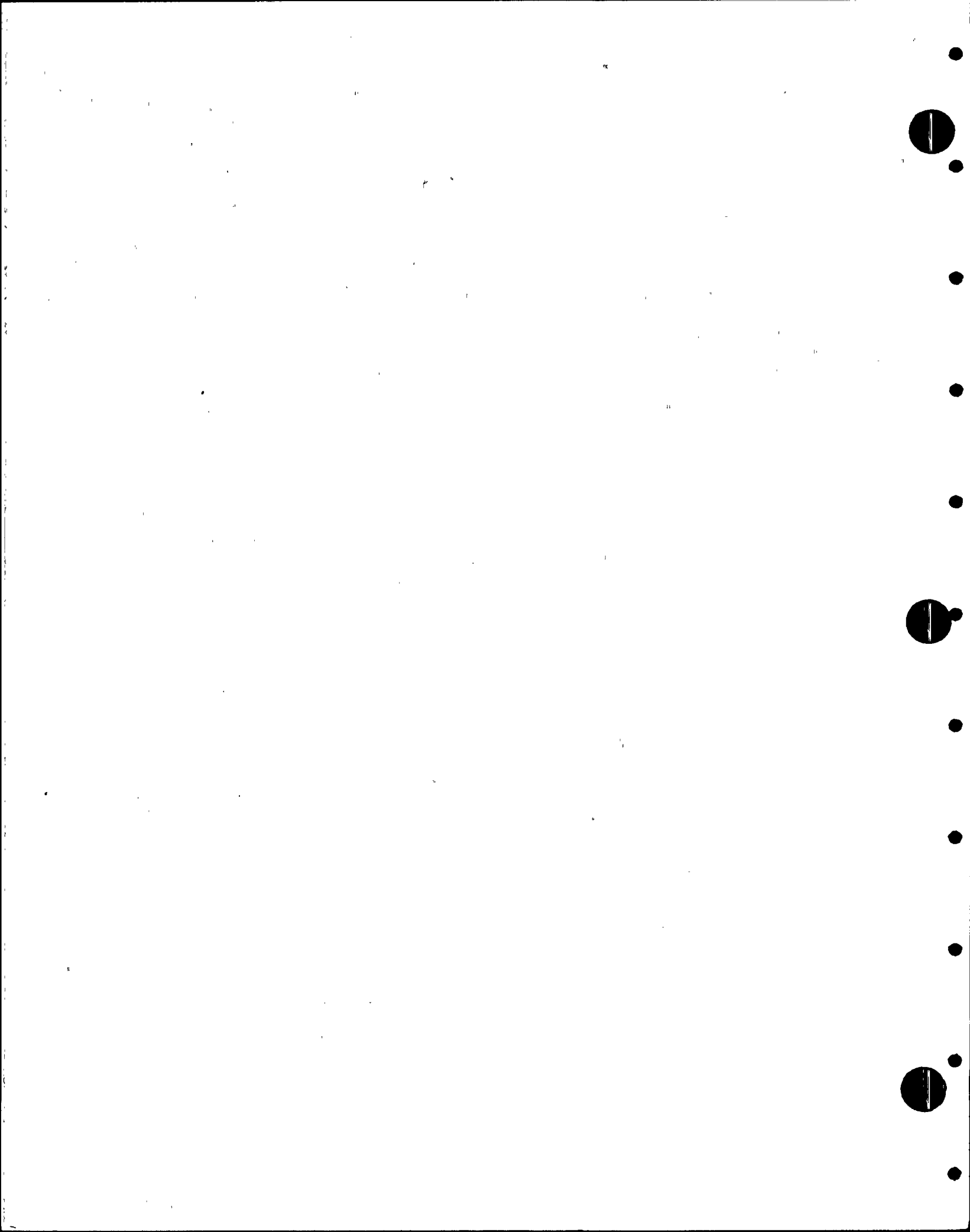


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The Instrumentation and Control Systems Review Board of the Palo Verde Nuclear Generating Station convened at the Holiday Inn - Metrocenter, Phoenix, Arizona, on the 17th day of June, 1981, Mr. John Allen, Nuclear Engineering Manager, Arizona Public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

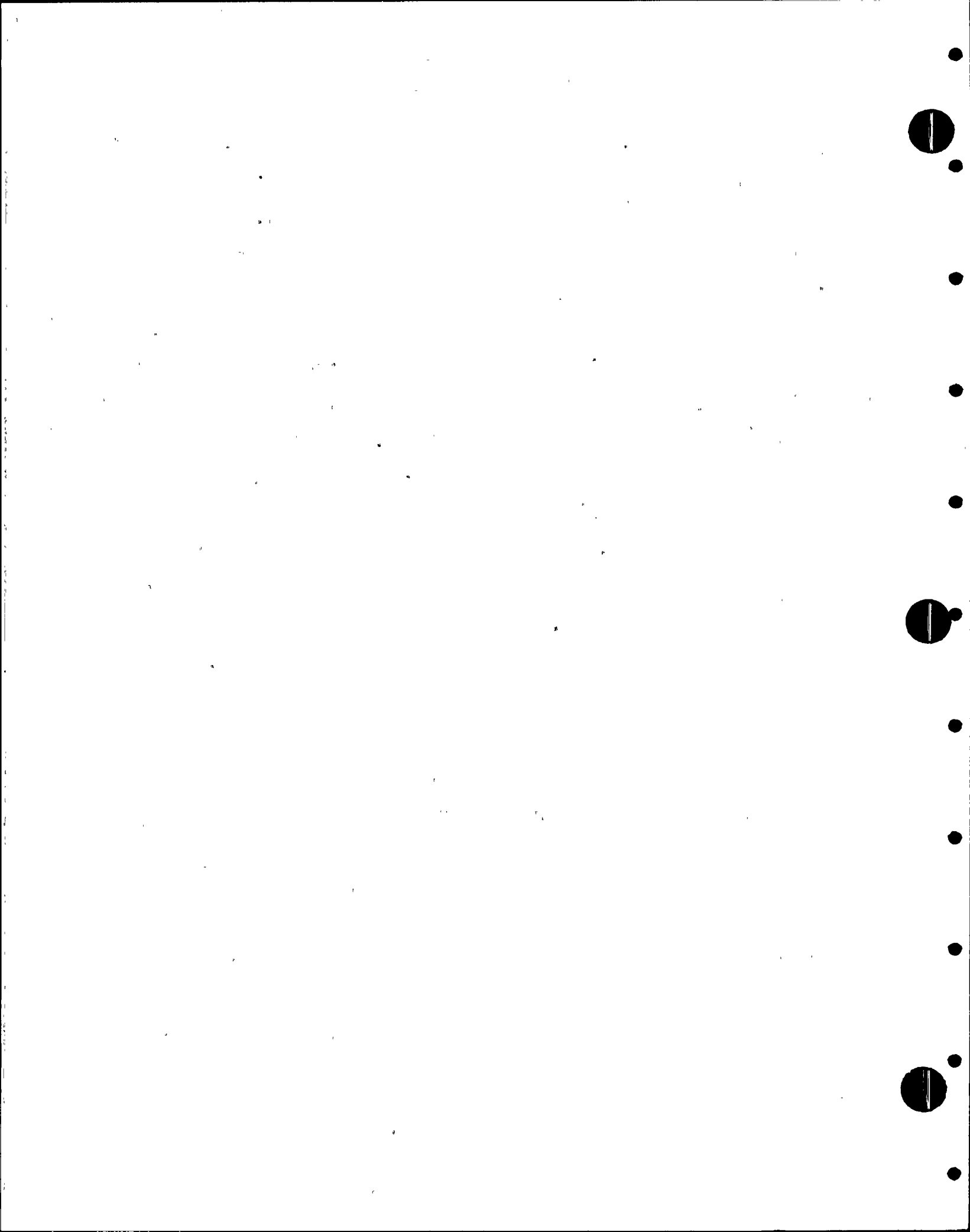


1 complement what was reviewed earlier, thus giving the I&C
2 for the total plant a thorough review.

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

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

21 For today's review, we have assembled a review
22 board with a varied background. Since the actual responsi-
23 bility for an adequate review lies with the applicant, that
24 is, Arizona Public Service, the Board's basic formation
25 starts with APS personnel, complemented with personnel from

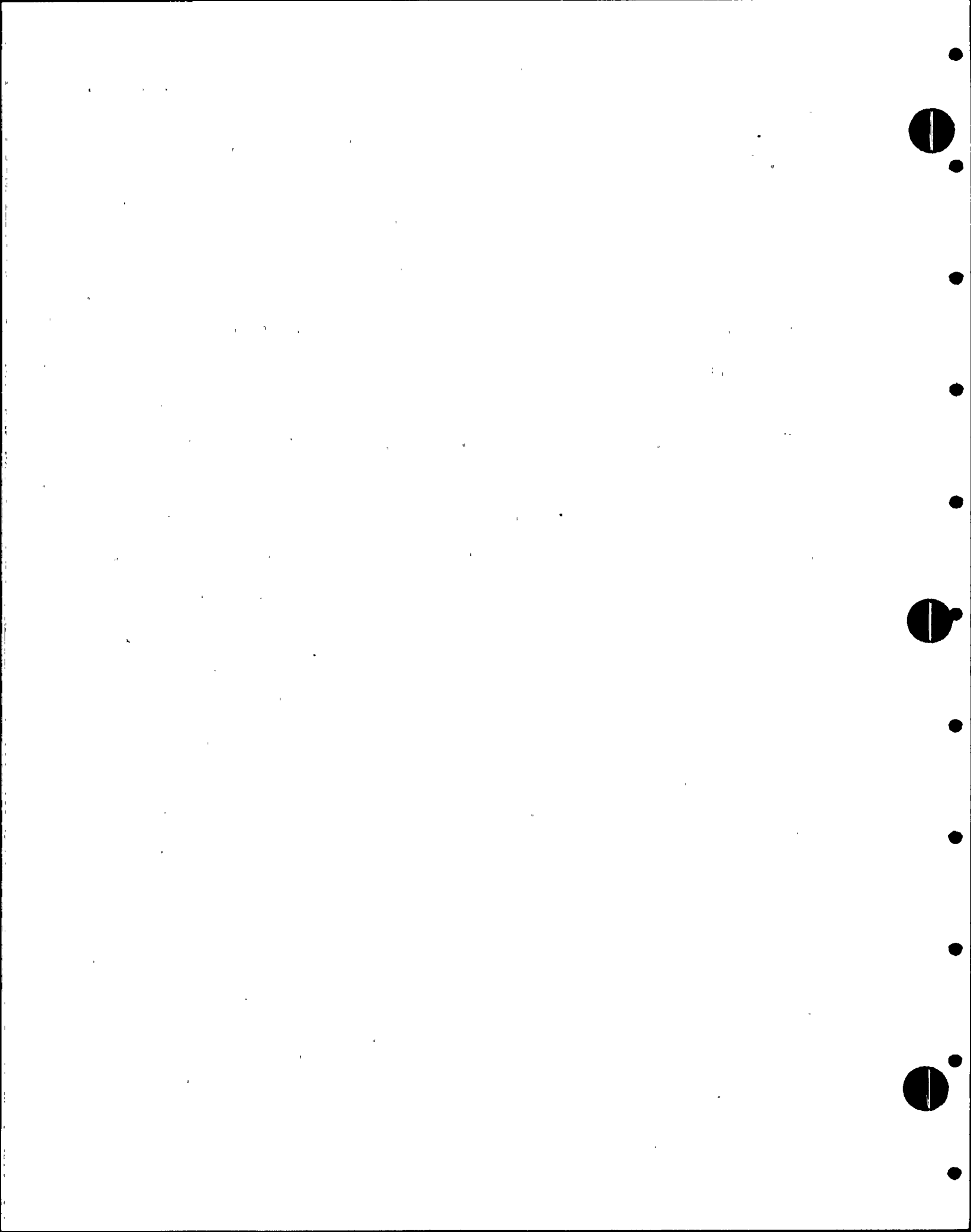


1 other groups who have expertise and experience on the system
2 or program being reviewed not necessarily available within
3 APS. Board members were provided with appropriate sections
4 of several documents to familiarize them with the PVNGS
5 Instrumentation and Control Systems. This included sections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

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

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

23 Norm Helman is an APS Nuclear Engineering Depart-
24 ment Instrumentation and Controls Specialist. He reports to
25 Ed Sterling. Norm is responsible for various technical



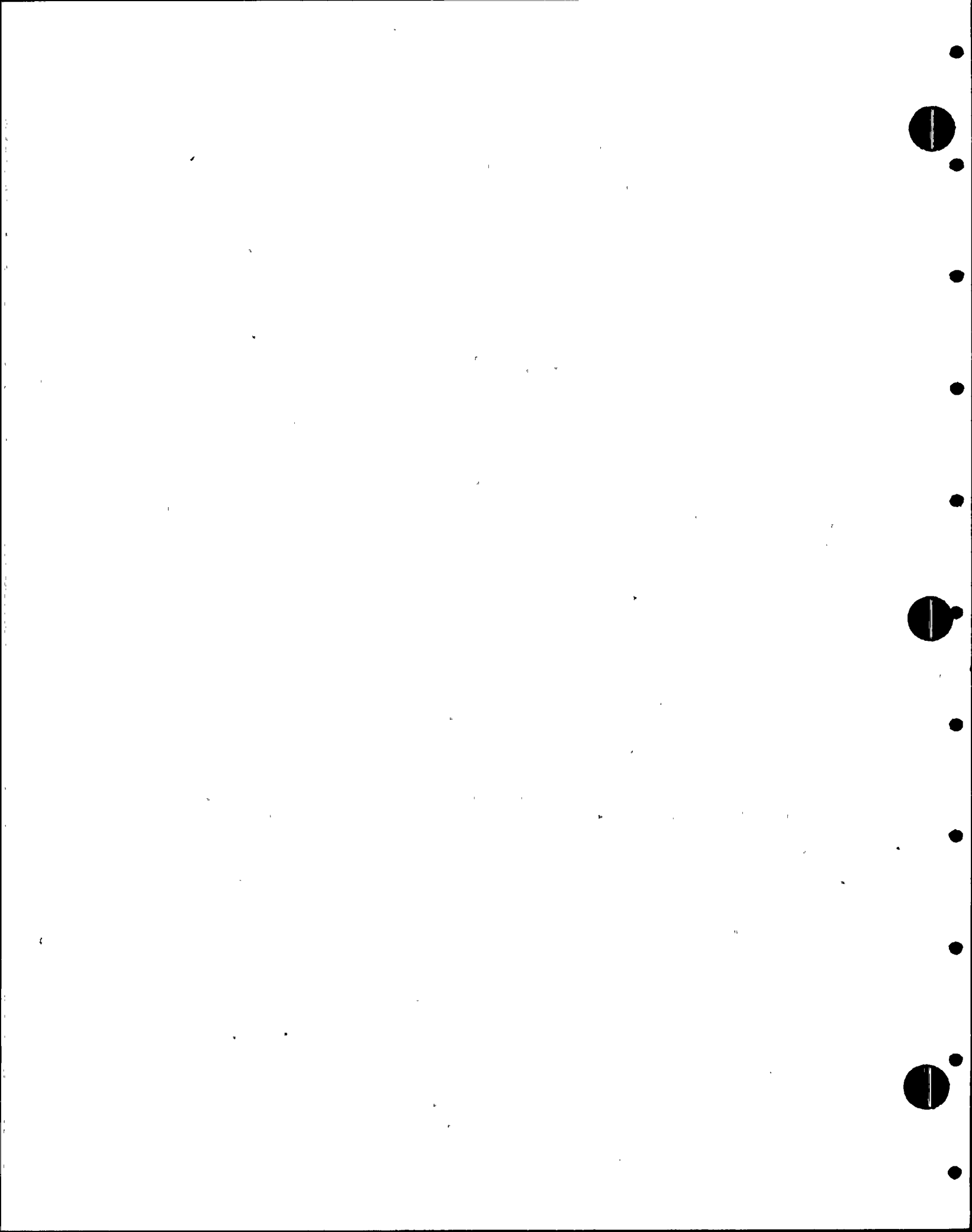
1 aspects of the electrical and I&C portions of Palo Verde
2 and also the day-to-day interface with Bechtel and Combustion.

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

8 Jim Minnicks is the PVNGS Instrumentation and
9 Controls Supervisor and reports to the Maintenance Superin-
10 tendent. Jim is responsible for calibration and maintenance
11 of instrumentation and controls.

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

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



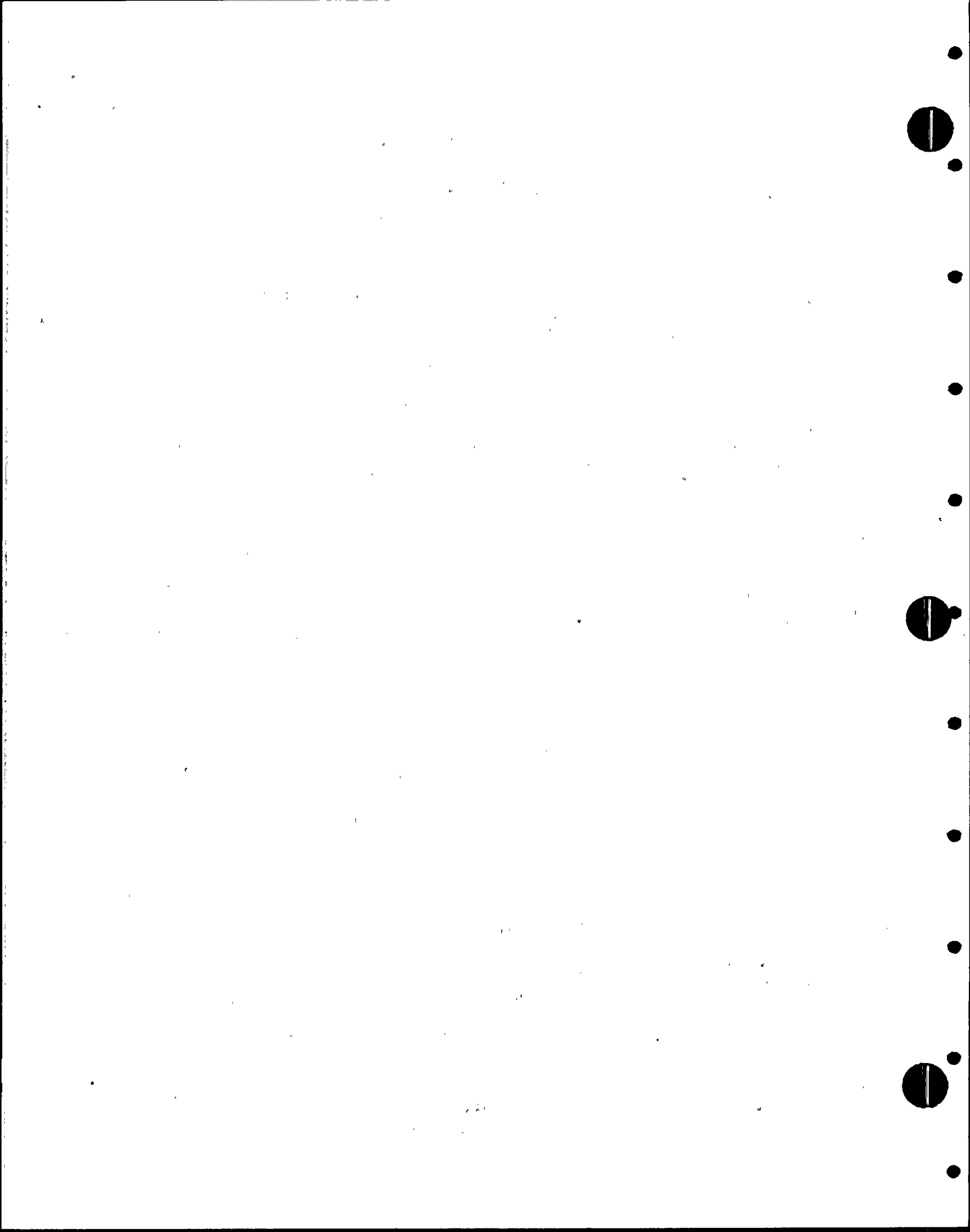
1 responsible for review and approval of project control
2 systems design and development of design standards. Larry
3 is a cognizant engineer for Bechtel staff direction on
4 control system design requirements and industry standards.
5 He is also a member of the NSSS I&C Review Board and attended
6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

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

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

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

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



1 the primary reviewer in this area.

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

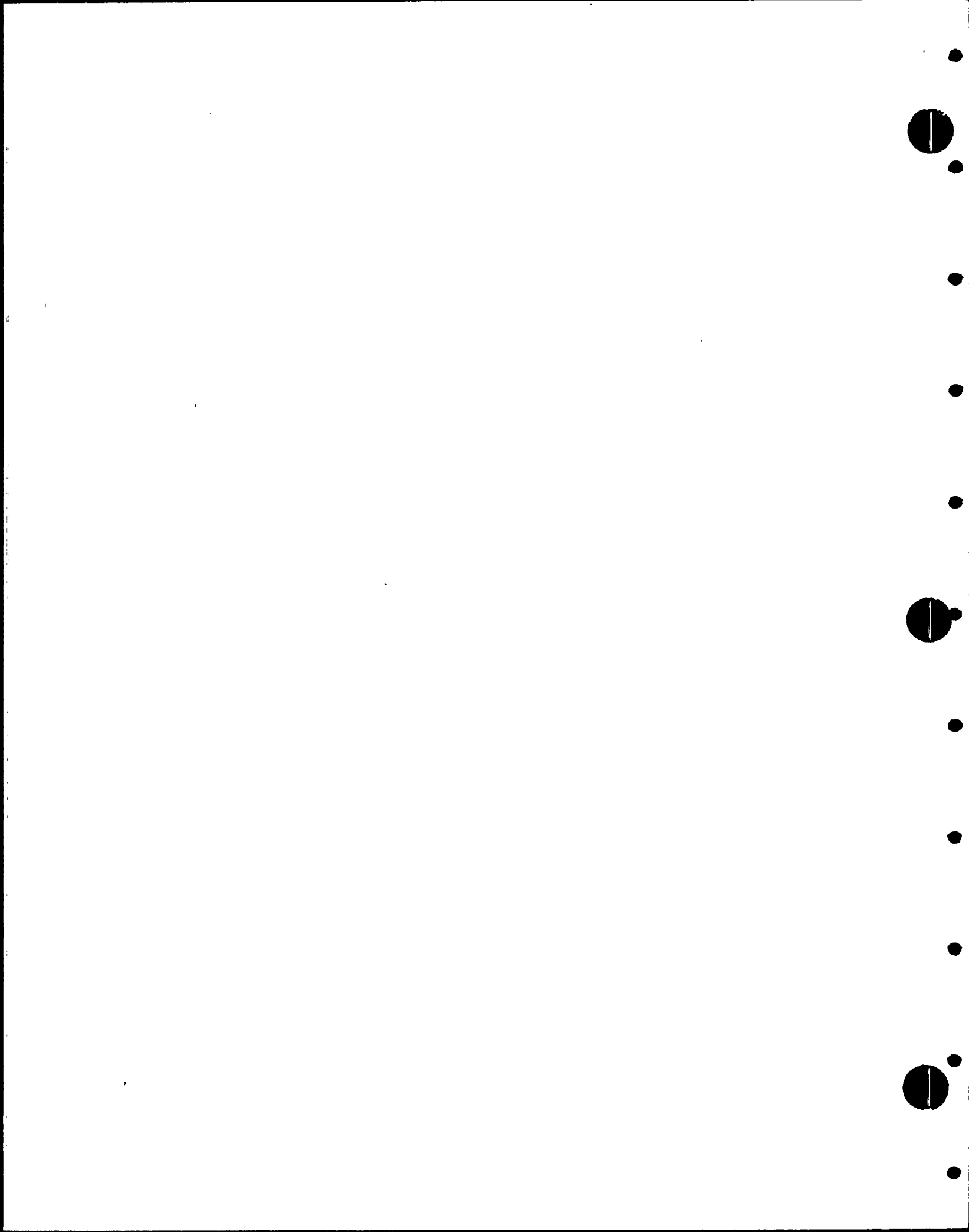
4 Ned Kondic is with the ICSB Branch. He is a
5 backup reviewer for the project.

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

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

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

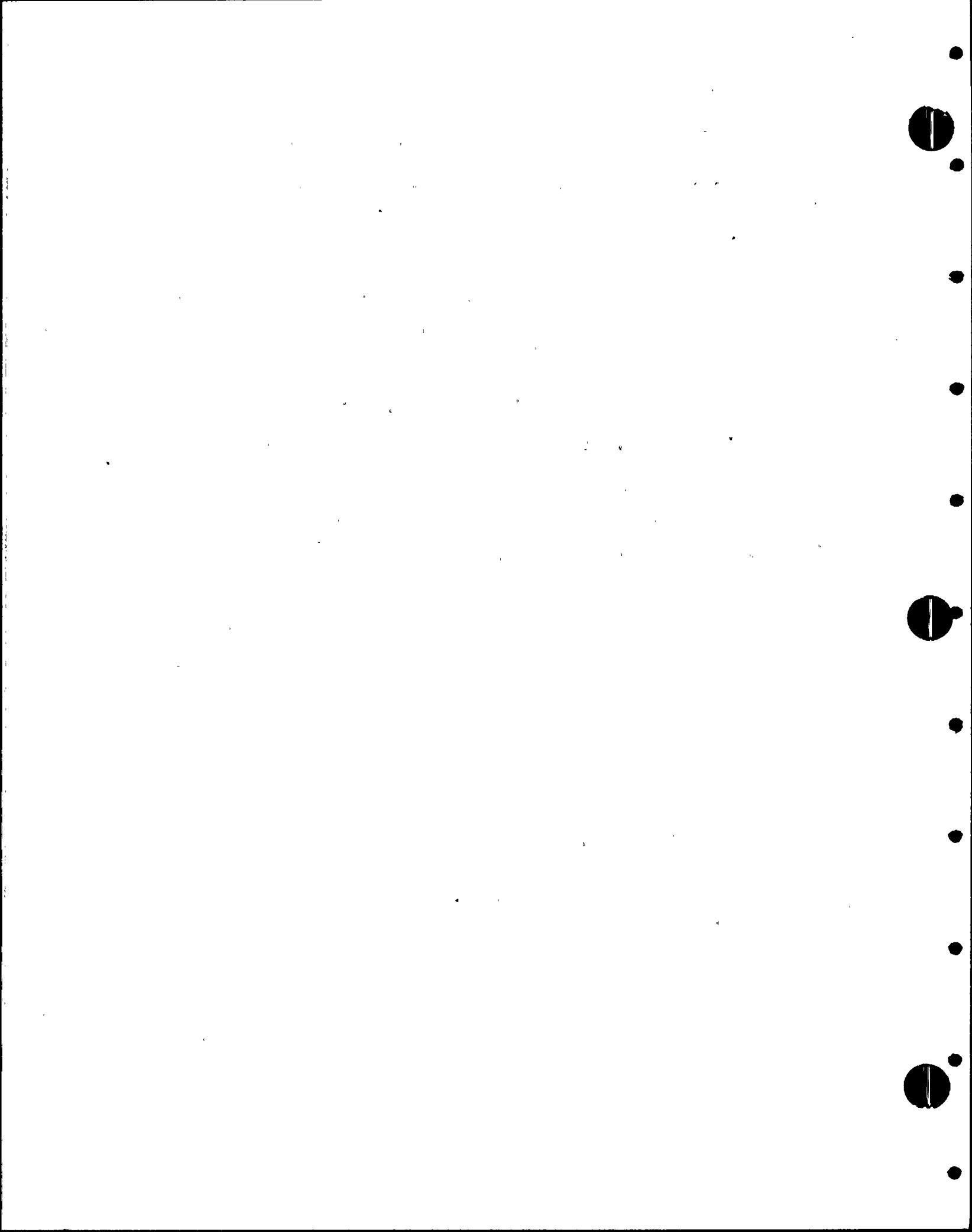
22 MR. ALLEN: We will provide a transcript of this meet-
23 ing to the NRC as soon as we have received it and proofed it
24 from our court reporter. I would like to ask Terry Quan and
25 Gerry Kopchinski to review the transcript and develop a



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

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

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

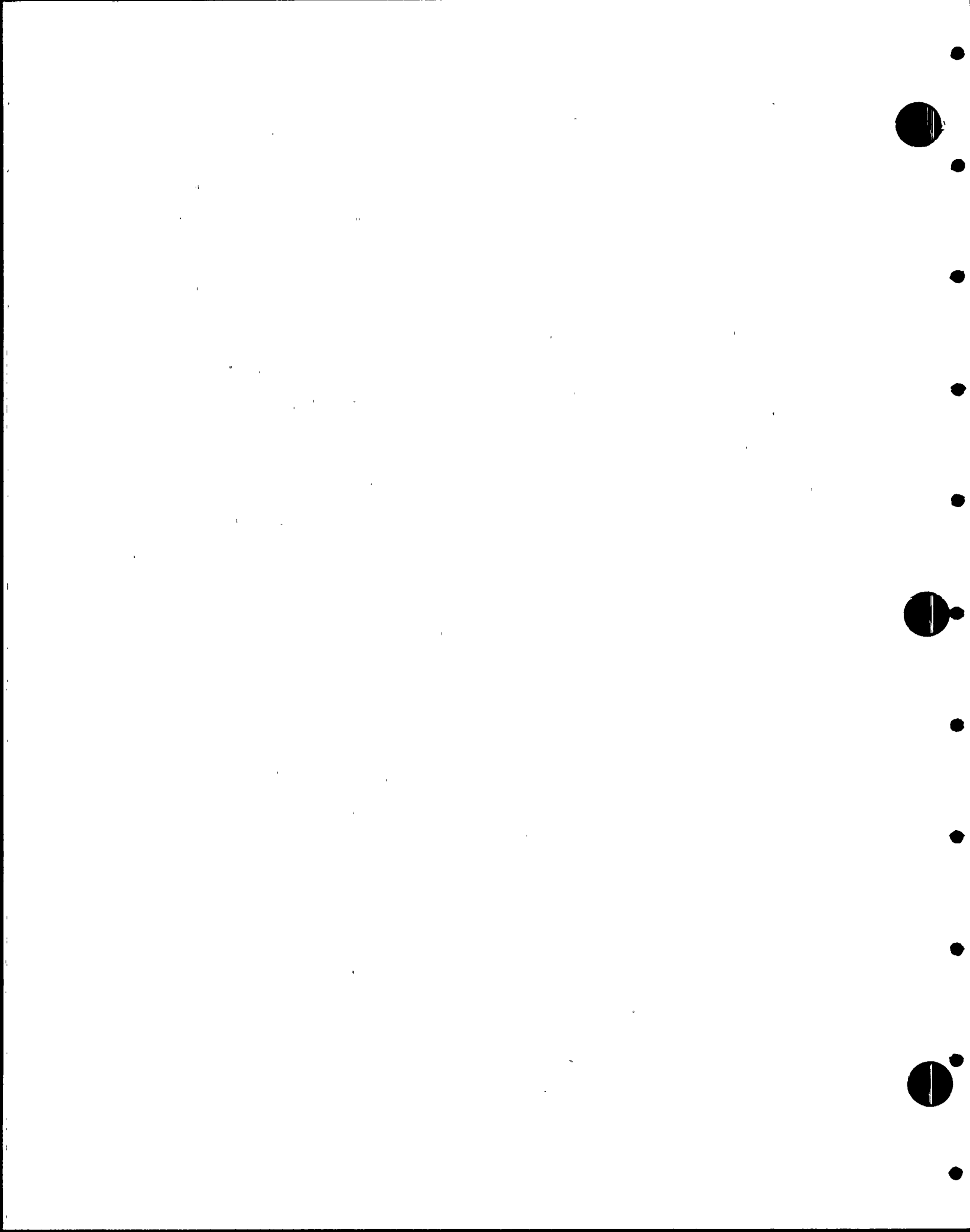


1 with a conference call. It does not necessarily mean that
2 we will physically reconvene the Board. Also, the NRC
3 reviewers have requested a follow-up meeting during the
4 week of July 27, 1981. The Review Board will not reconvene
5 for this meeting, but will be informed of any substantial
6 outcomes.

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

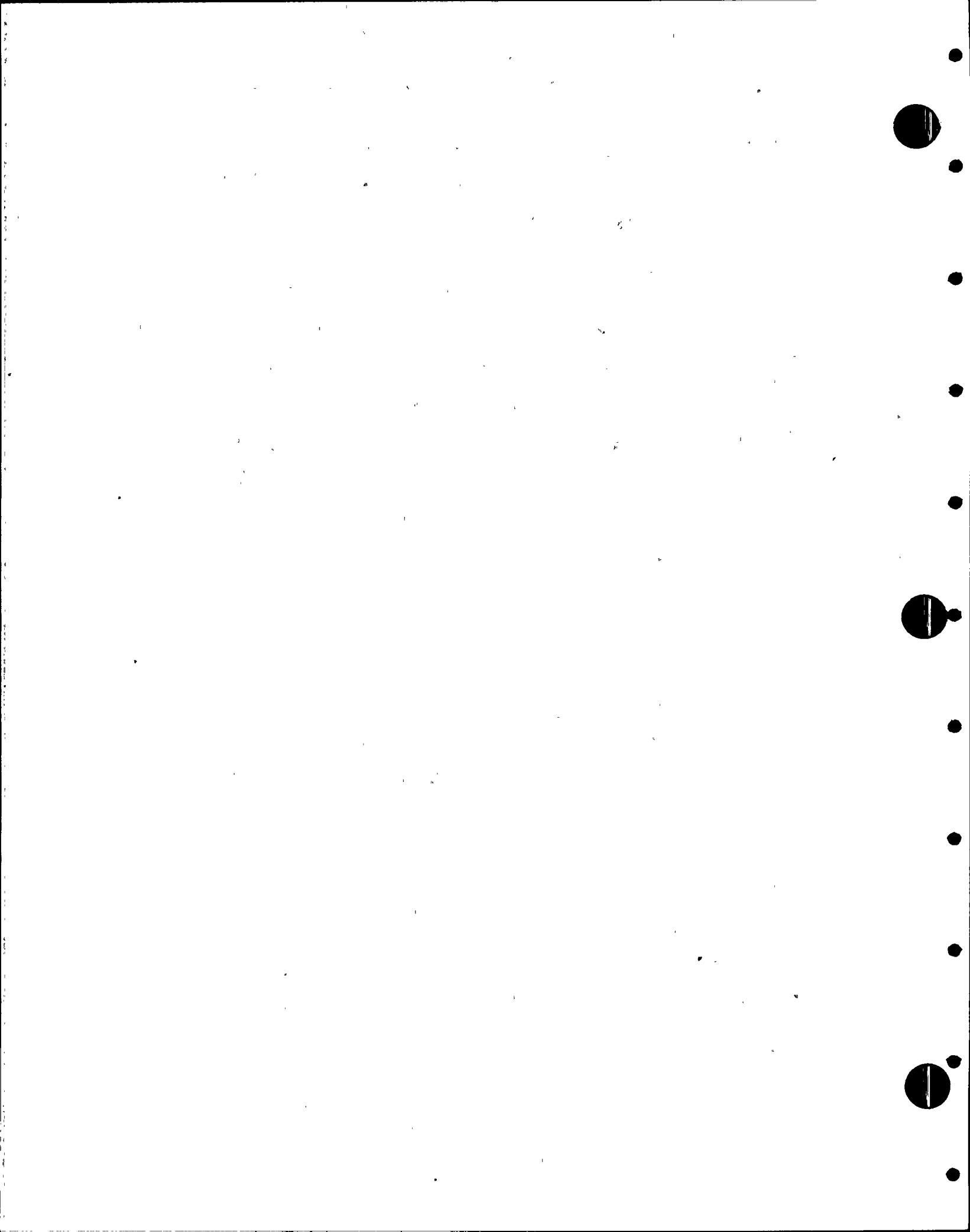
10 MR. BINGHAM: Thank you, John. My name is Bill
11 Bingham. I am Project Engineering Manager for Bechtel Power
12 Corporation assigned to the Palo Verde Project. As John
13 Allen indicated, we are here today to present a review of
14 the BOP Instrumentation and Control Systems at the Palo Verde
15 Nuclear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

25 The Instrumentation and Control Systems includes



1 the Reactor Trip System, discussed in Standard Review Plan
2 7.2; Engineered Safety Features, discussed in Standard Review
3 Plan 7.3; Systems Required for Safe Shutdown, discussed in
4 Standard Review Plan 7.4; Safety-Related Display Instrumenta-
5 tion, discussed in Standard Review Plan 7.5; All Other
6 Instrumentation Required for Safety, discussed in Standard
7 Review Plan 7.6; and Control Systems Not Required for Safety,
8 discussed in Standard Review Plan 7.7. The Reactor Trip
9 System was discussed in detail by CE at an earlier Independent
10 Design Review presented during the first week of June. Our
11 discussion today will address the remaining instrumentation
12 and control systems.

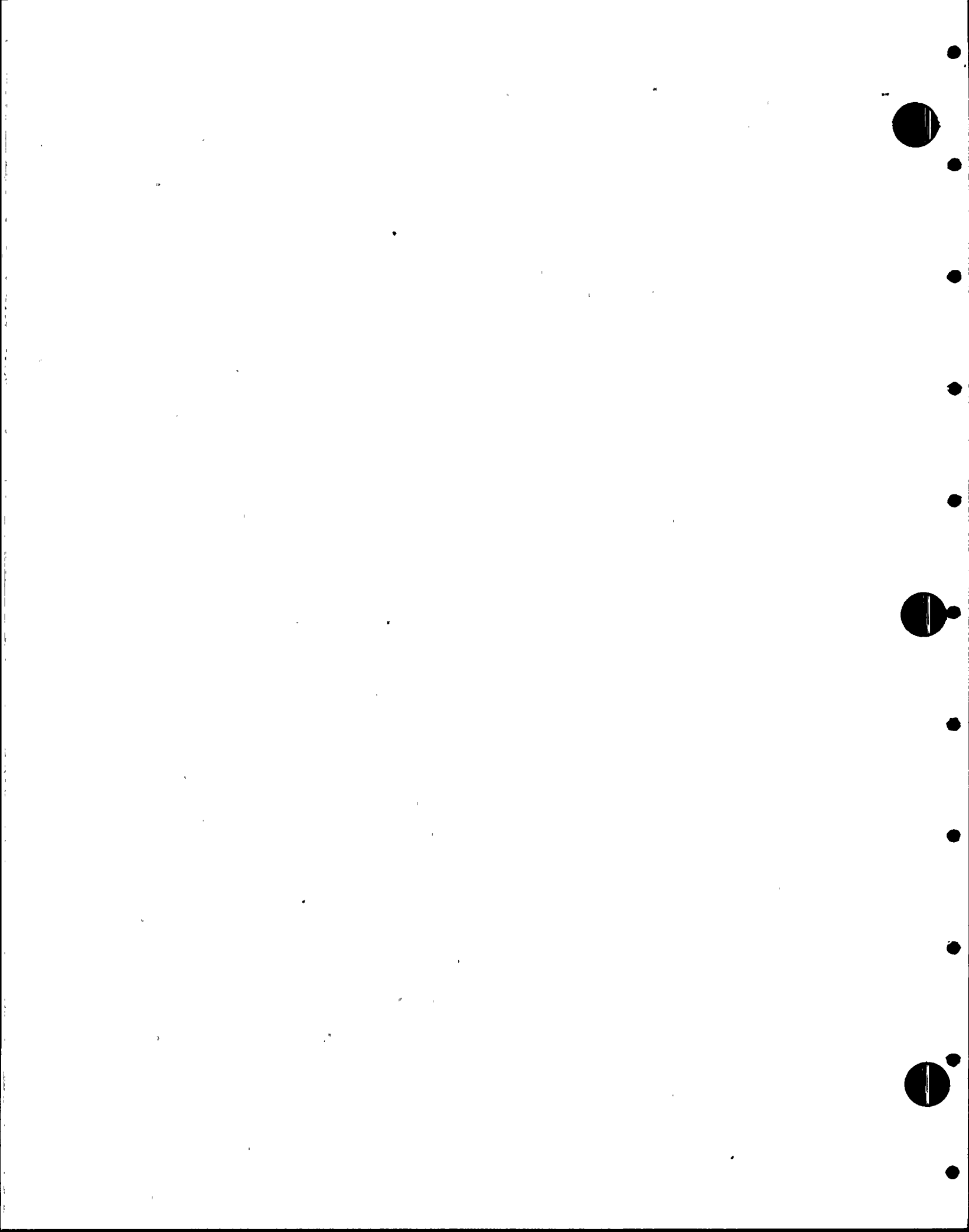
13 In previous system Review Board meetings, we have
14 discussed how the Design Criteria which are approved by
15 APS and are the basis of the plant design are dealt with.
16 In particular, we discussed how the final design was achieved
17 using the Design Criteria as the starting point, and, as
18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



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

4 MR. ALLEN: Yes.

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



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

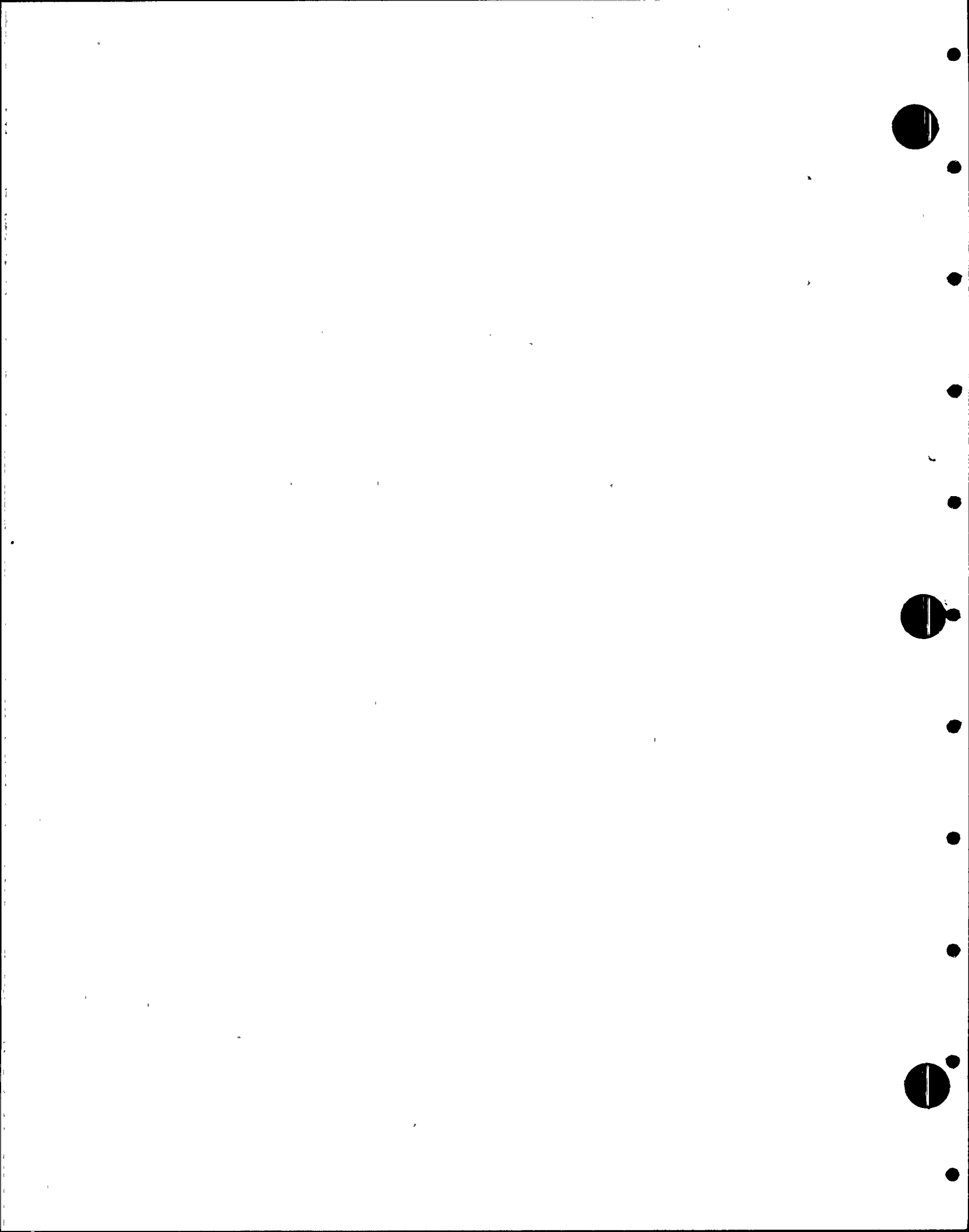
4 Dennis, would you start?

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

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

14 MR. BINGHAM: We will do that, John.

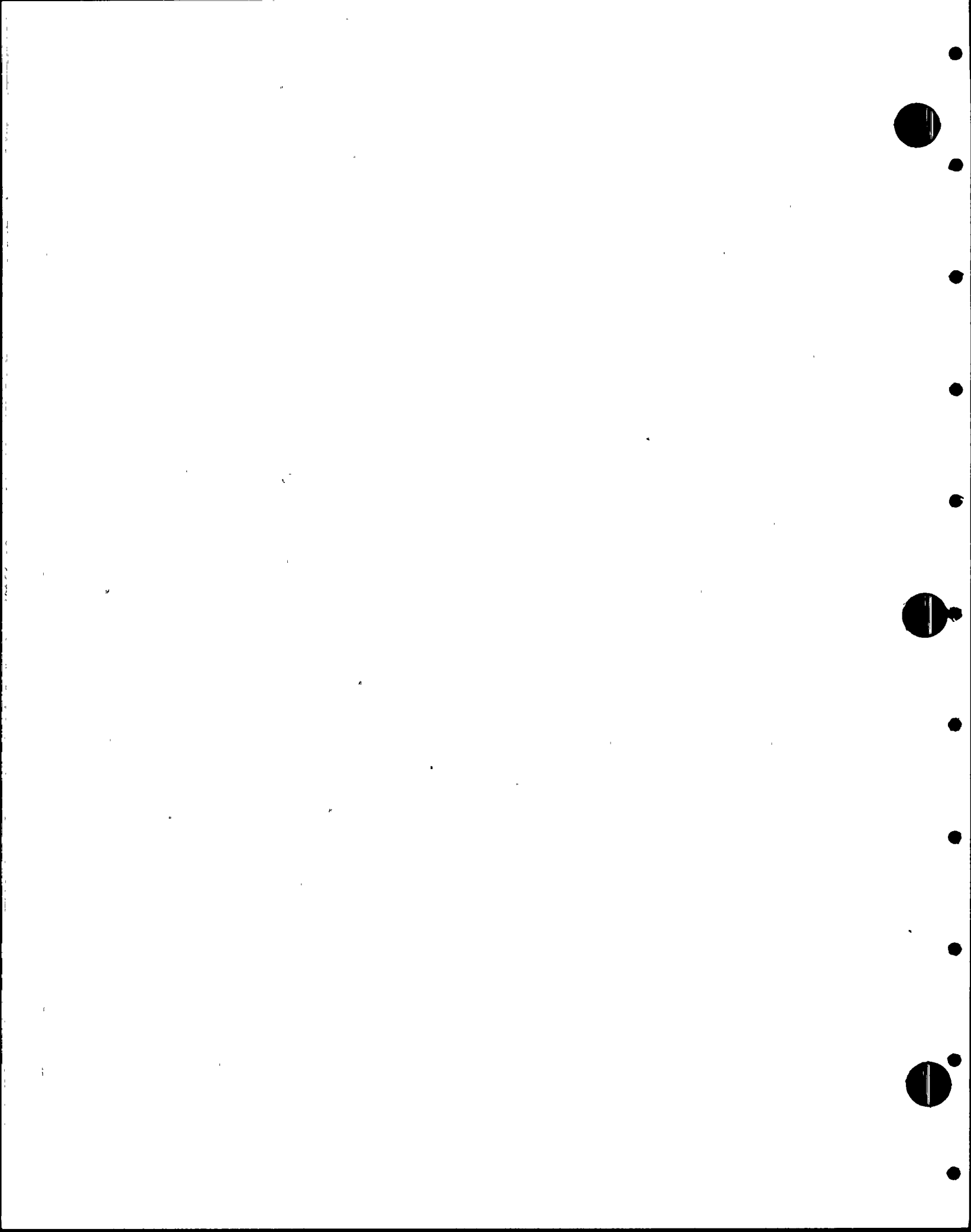
15 MR. KEITH: Figure 1-1 shows the scope of what we
16 are going to be covering in the next two days. The figure
17 actually shows the total scope of the instrumentation and
18 controls as covered in the Palo Verde FSAR: The Reactor
19 Trip System, ESFAS, Safe Shutdown Systems, Safety-Related
20 Display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



1 interface requirements as applicable to all subjects.

2 Figure 1-2 shows the Palo Verde general plant
3 arrangement. Palo Verde consists of three identical units.
4 Each unit has Combustion Engineering as the NSSS, develops
5 3,800 megawatts thermal of power and about 1,300 megawatts
6 electric. Each of the three units is identical, so that
7 this Figure 1-2 shows all three units consisting of the
8 containment building, fuel building, turbine building,
9 auxiliary building, radwaste building, control building, and
10 diesel generator building. Also shown but not labeled is
11 the main steam support structure where we house our main
12 steam and main feedwater isolation valves and the auxiliary
13 feedwater pumps. The Seismic Category I structures where
14 we house our safety-related equipment consist of the
15 containment, main steam support structure, auxiliary building,
16 control building, diesel generator building, and fuel building,
17 and it is those buildings which house the instrumentation
18 we will be discussing in the next couple of days.

19 Figure 1-3. We have one common control room for
20 controlling the plant. That is located in the ~~control~~
21 building at 40 feet above grade. I guess we don't show
22 elevations, but in case we do later in the presentation, at
23 all three units, we use a common grade of 100 feet so that we
24 have one set of drawings for all three units, so this is at
25 140 feet or 40 feet above grade. It shows the main horseshoe

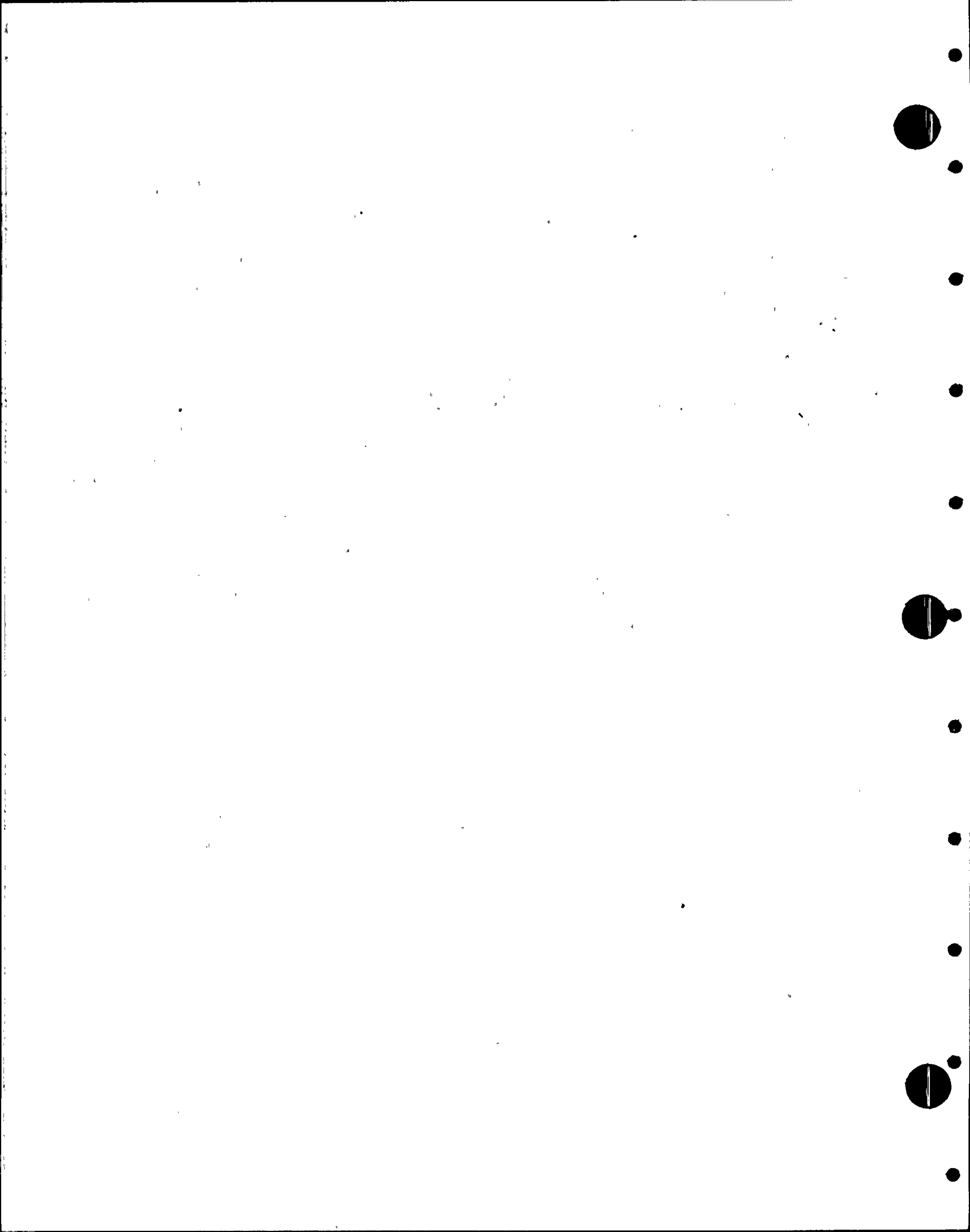


1 area within which the operator is located and controls the
2 plant. Outside the horseshoe area, we have a number of
3 cabinets, the computer room, and then various offices.

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

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

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

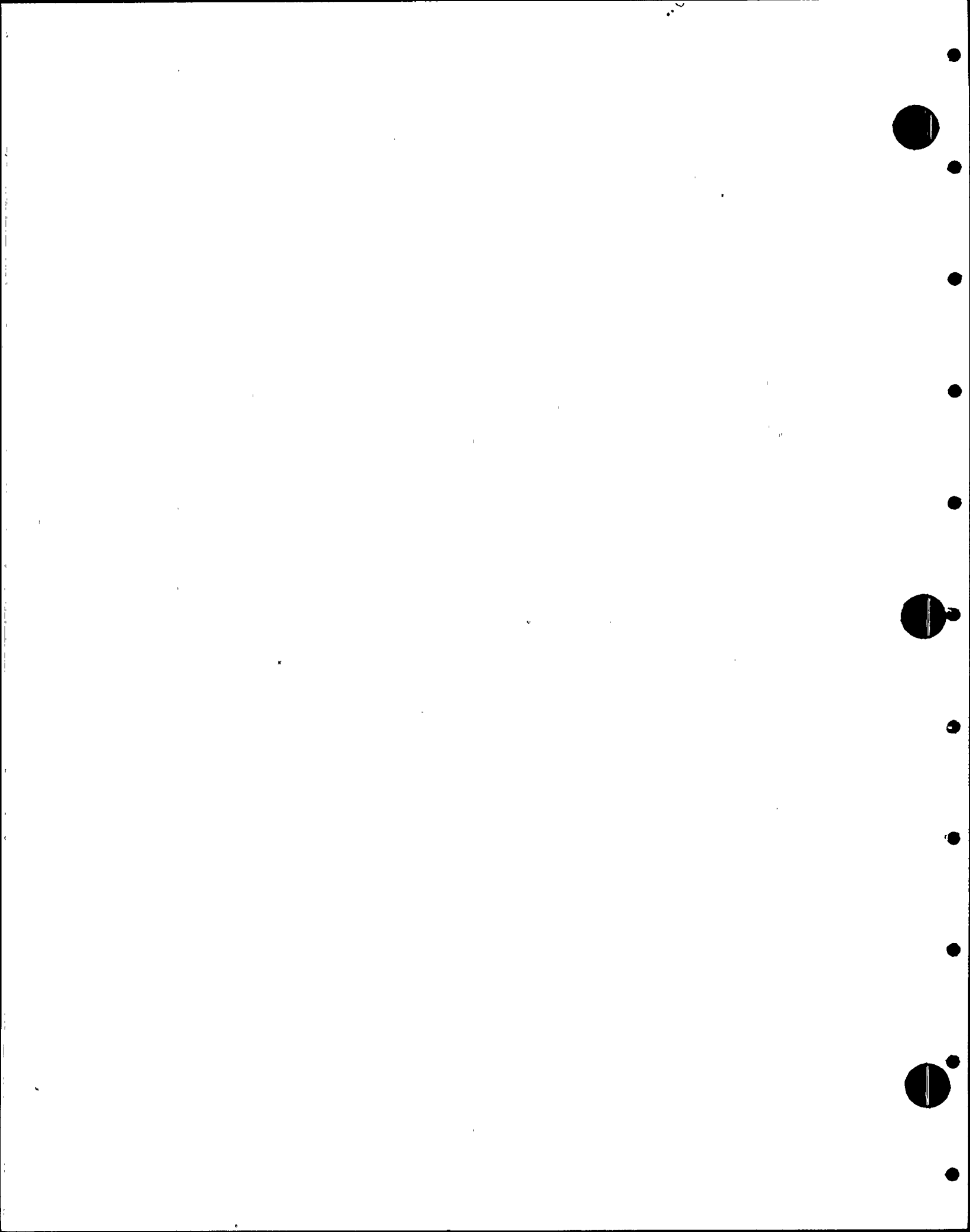


1 earthquake and an operating basis earthquake. In the
2 instrumentation area, we have split off the Seismic Category
3 I qualification into two different ones, Qf_1 for all equipment
4 which remains functional before, during, and after an SSE,
5 and Qf_2 for that equipment which is functional before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

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

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

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



1 an SSE.

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

15 CESSAR gives the power requirements in Section
16 8.3.1, and we are in compliance with that. The Palo Verde
17 equipment is protected from the effects of natural phenomena.
18 The Palo Verde safety-related instrumentation and control
19 components are protected from pipe failure.

20 Exhibit 1A-2, continuing the CESSAR interface
21 requirements. The safety-related equipment at Palo Verde is
22 protected from the effects of missiles. The safety-related
23 equipment is separated to meet the requirements of Reg. Guide
24 1.75.

25 Exhibit 1A-3. The cabling associated with our

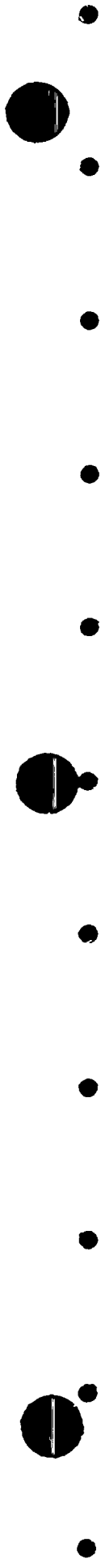


1 equipment is separated so that a single credible event will
2 not cause multiple channel malfunctions or interactions
3 between channels.

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

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

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



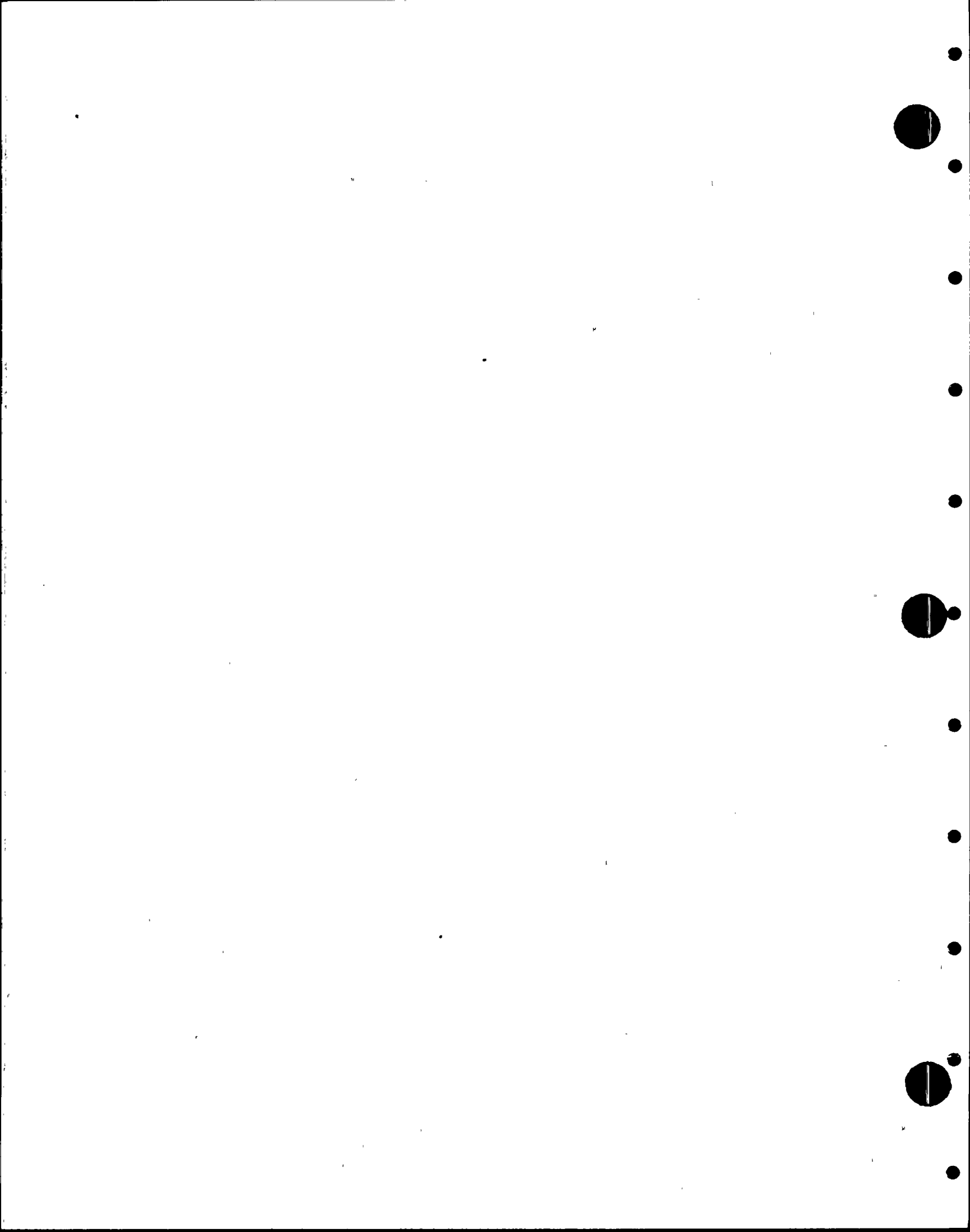
1 Exhibit 1A-7. Our components are located not to
2 exceed the pressure limits specified in CESSAR Section 3.11,
3 once again getting back to the environmental requirement.
4 We are providing fire protection as required to meet the
5 requirements of General Design Criterion No. 3.

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

11 Exhibit 1A-9. We provide environmental support
12 systems such that our safety-related equipment will not be
13 subjected to environments exceeding the requirements of
14 CESSAR Section 3.11, and our instrumentation meets the
15 seismic design requirements as specified in CESSAR Section
16 3.10.

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

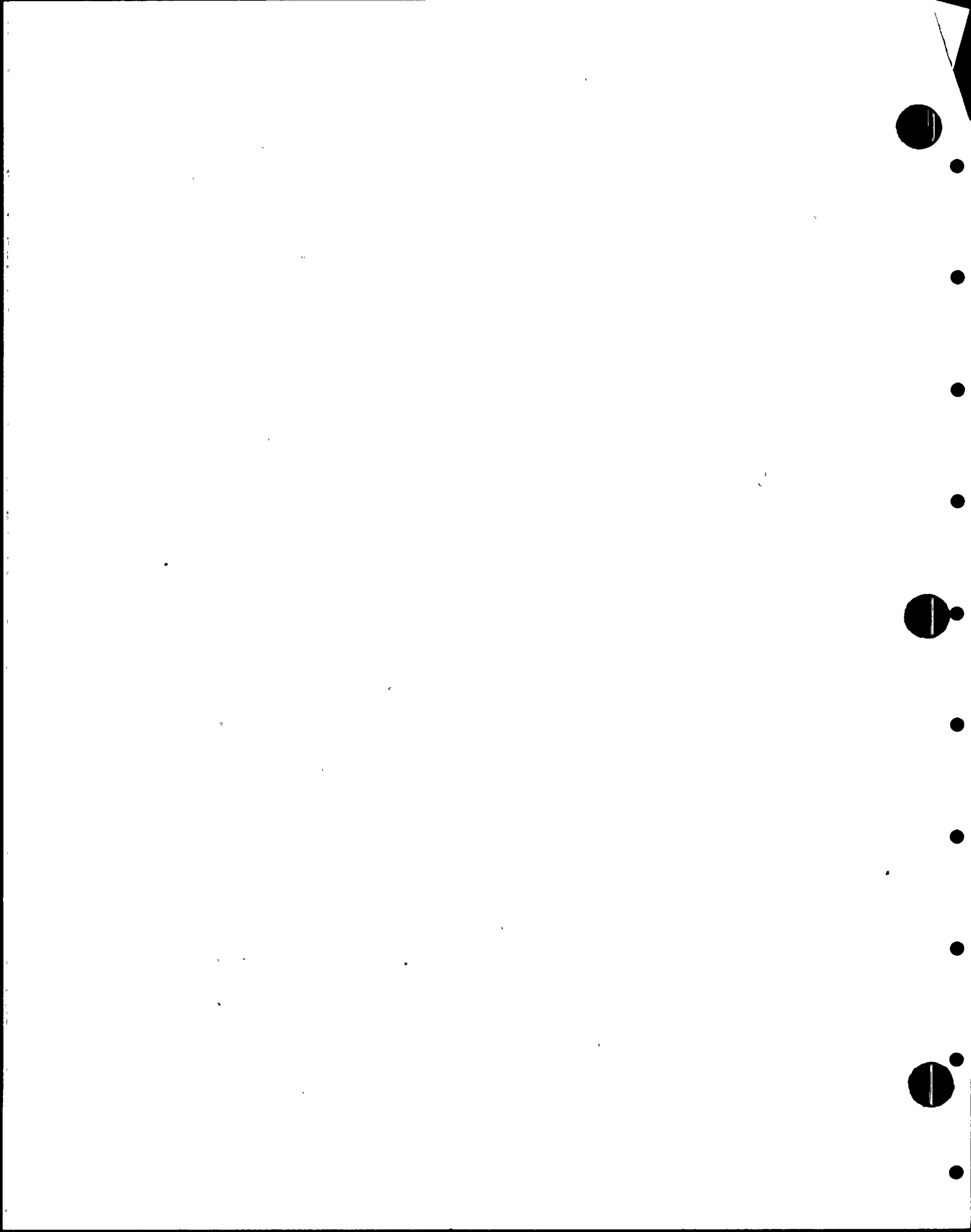
22 Figure 1A-1. As you saw from the earlier figure,
23 we are not discussing the Reactor Protection System, since
24 that is completely within CESSAR's scope. However, there
25 are some interface requirements from the Reactor Protection



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

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

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



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

3 That concludes the introduction.

4 MR. BINGHAM: Questions from the Board, John?

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

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

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

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



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

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

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

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

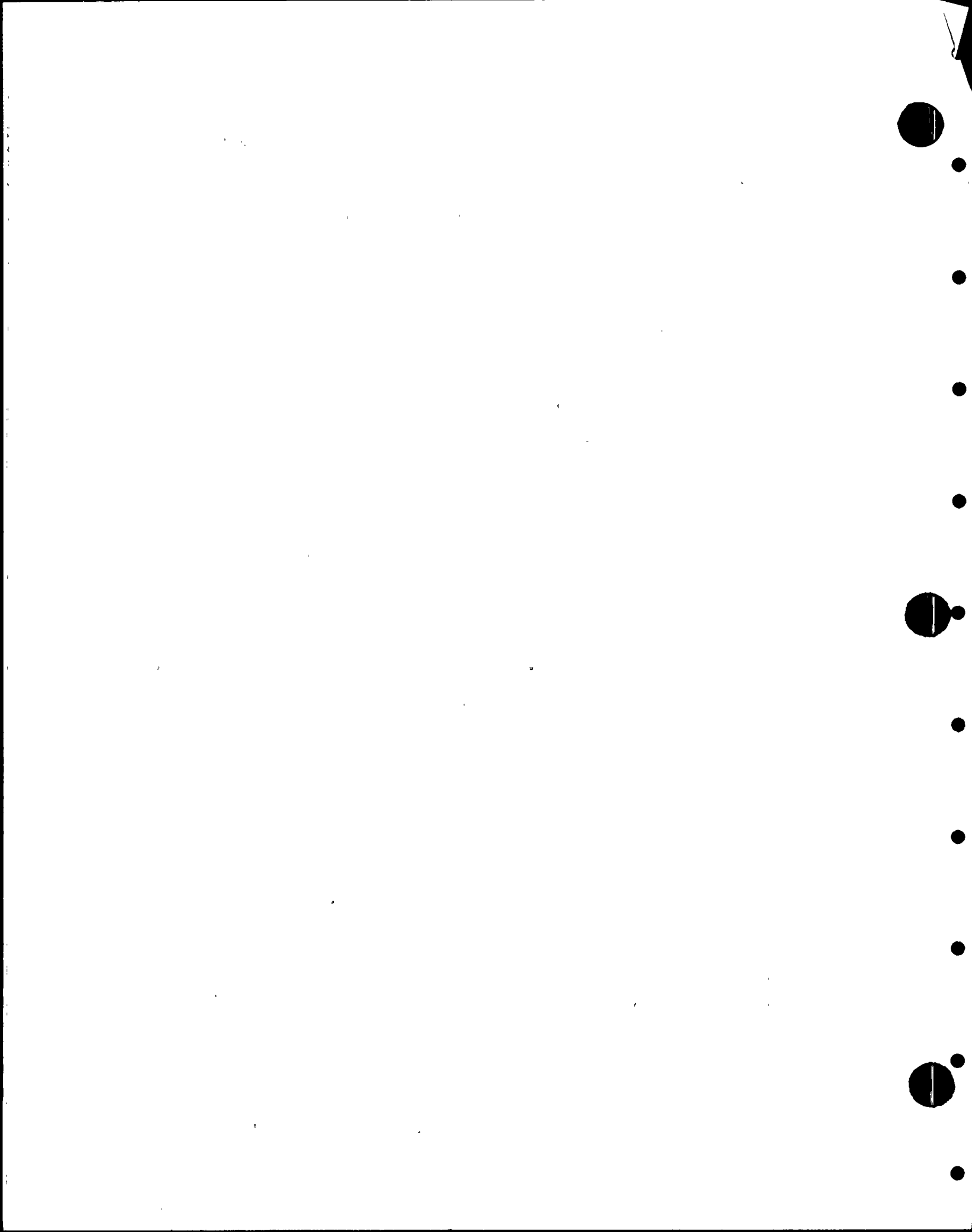
16 MR. STERLING: Maybe if you could provide a drawing
17 that would show how those are routed, a simplified drawing
18 showing the areas where they are together.

19 MR. ALLEN: Anyone else have a question?

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

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

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



1 interface requirement documents, that put forth more detailed
2 interface requirements on the applicant. You have demon-
3 strated, I think, that you meet the interface requirements
4 that are in CESSAR. Do you also comply with the CE interface
5 requirement documents for the Instrumentation and Control
6 Systems?

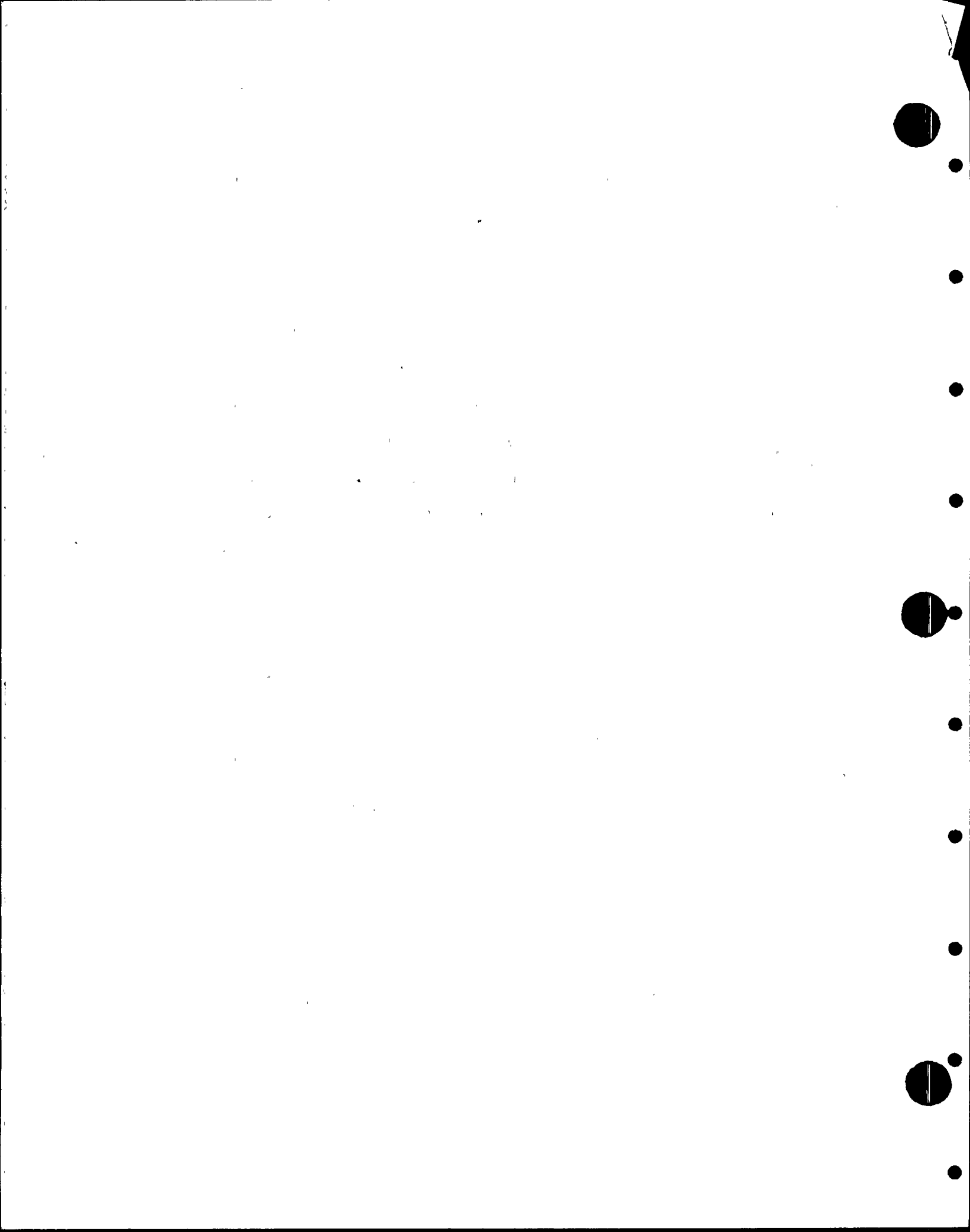
7 MR. BINGHAM: John, I just wanted to make one point
8 clear about the question. I will give you the answer first.
9 The answer is yes, we do include them, but we have for
10 purposes of the licensing effort referenced CESSAR and then
11 we presume that those documents that CESSAR uses or
12 references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

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

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

24 MR. BARNOSKI: That's all I have.

25 MR. ROSENTHAL: We audited a set of interface



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

6 MR. BINGHAM: Just a moment, please.

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

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

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

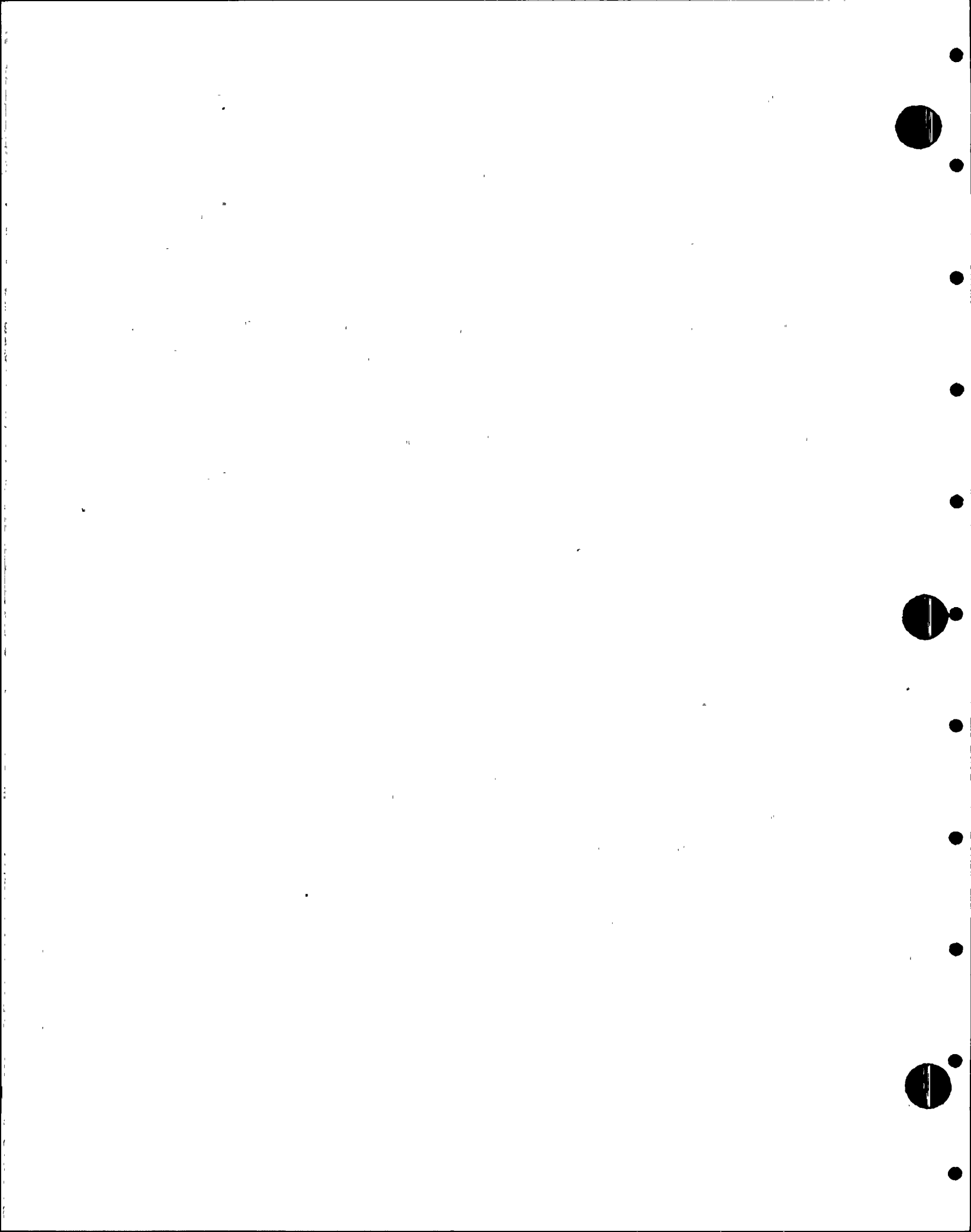


1 are some differences in the standard System 80 that are not
2 applicable to Palo Verde, we would expect that Combustion
3 Engineering would so notify us with the proper documentation
4 and give us the interfaces that we need to meet for balance
5 of plant. I am sure that we have done that and we do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

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

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

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



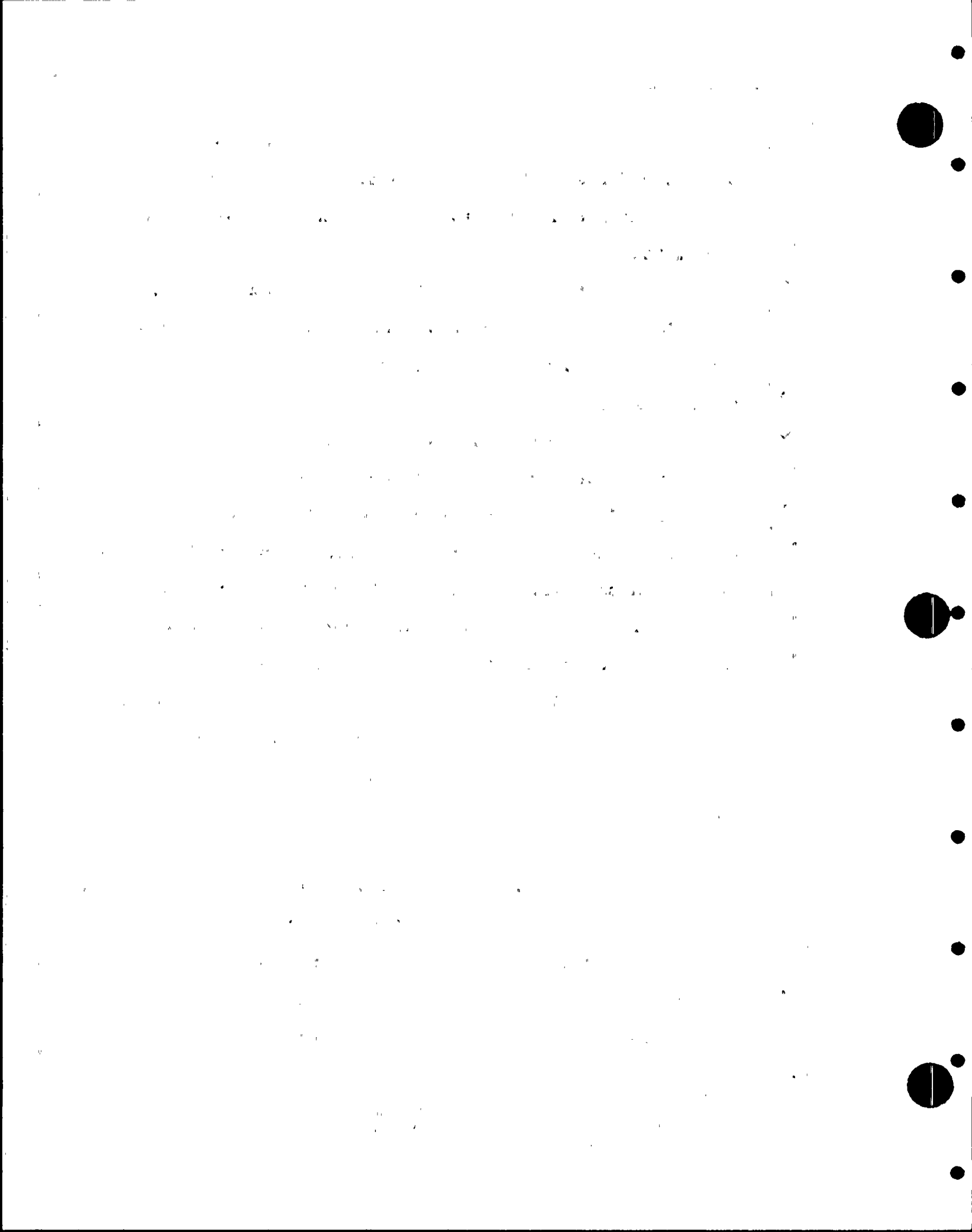
1 there is a project document. As Dennis said, the two
2 documents are put together and those are the documents that
3 we use to meet the interface requirements.

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

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

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

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



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

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

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

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

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

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

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INDEX

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

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

8 MR. ALLEN: Does that satisfy you?

9 MR. BINGHAM: Sure.

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

20 MR. BINGHAM: We can respond to that.

21 MR. ROSENTHAL: Substantive rather than nit-picking.

22 MR. BINGHAM: They are not, and usually the qualifica-
23 tions are handled in separate topical by Combustion
24 Engineering, and I think their environmental qualification
25 is CENPD 255 and I believe their seismic is 1.83, if I

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

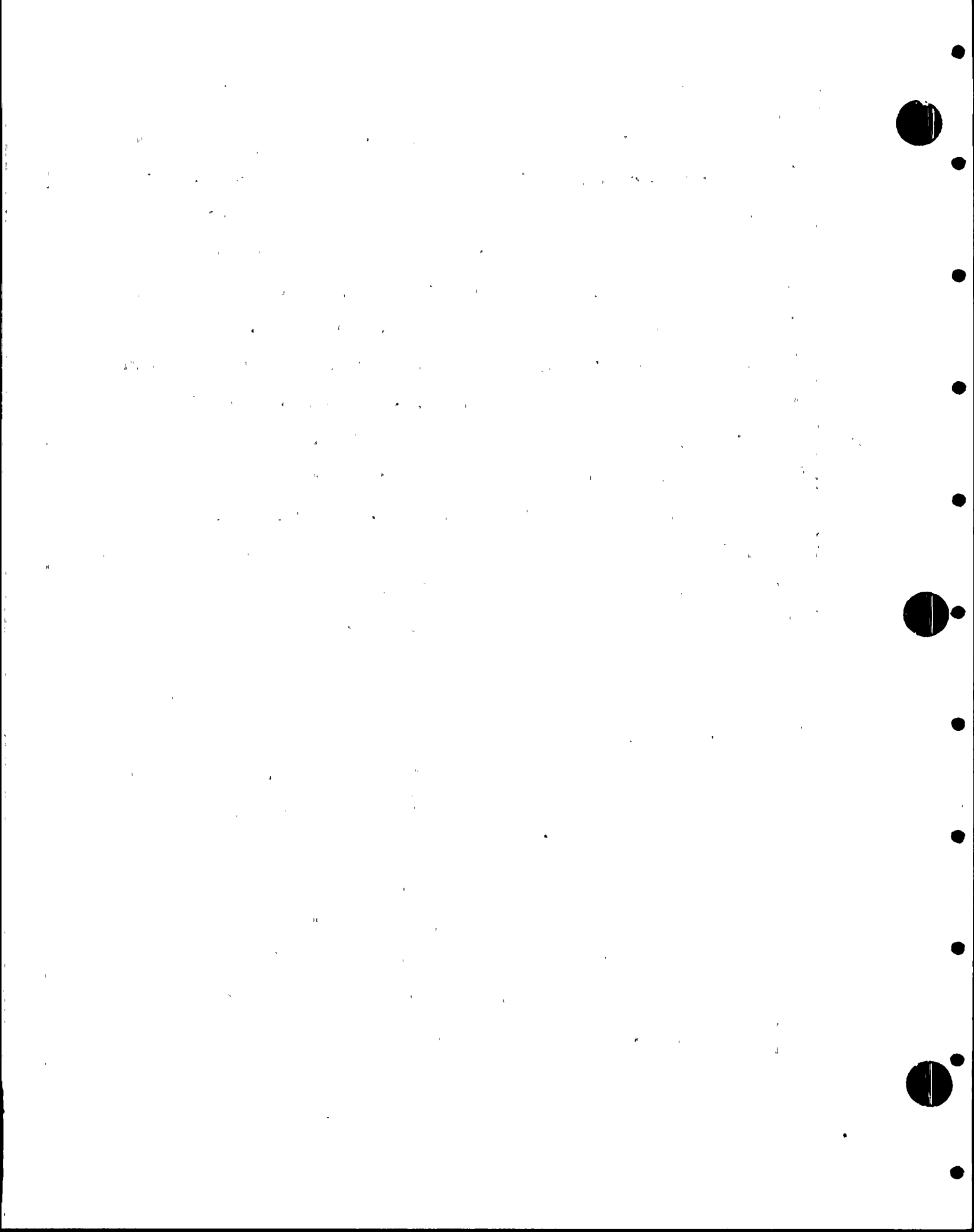
10 MR. ALLEN: Also, you could identify how we designate
11 a difference between CESSAR and our FSAR, a colored page.

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

15 MR. KEITH: Not in this area.

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

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



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

10 MR. BINGHAM: That's right.

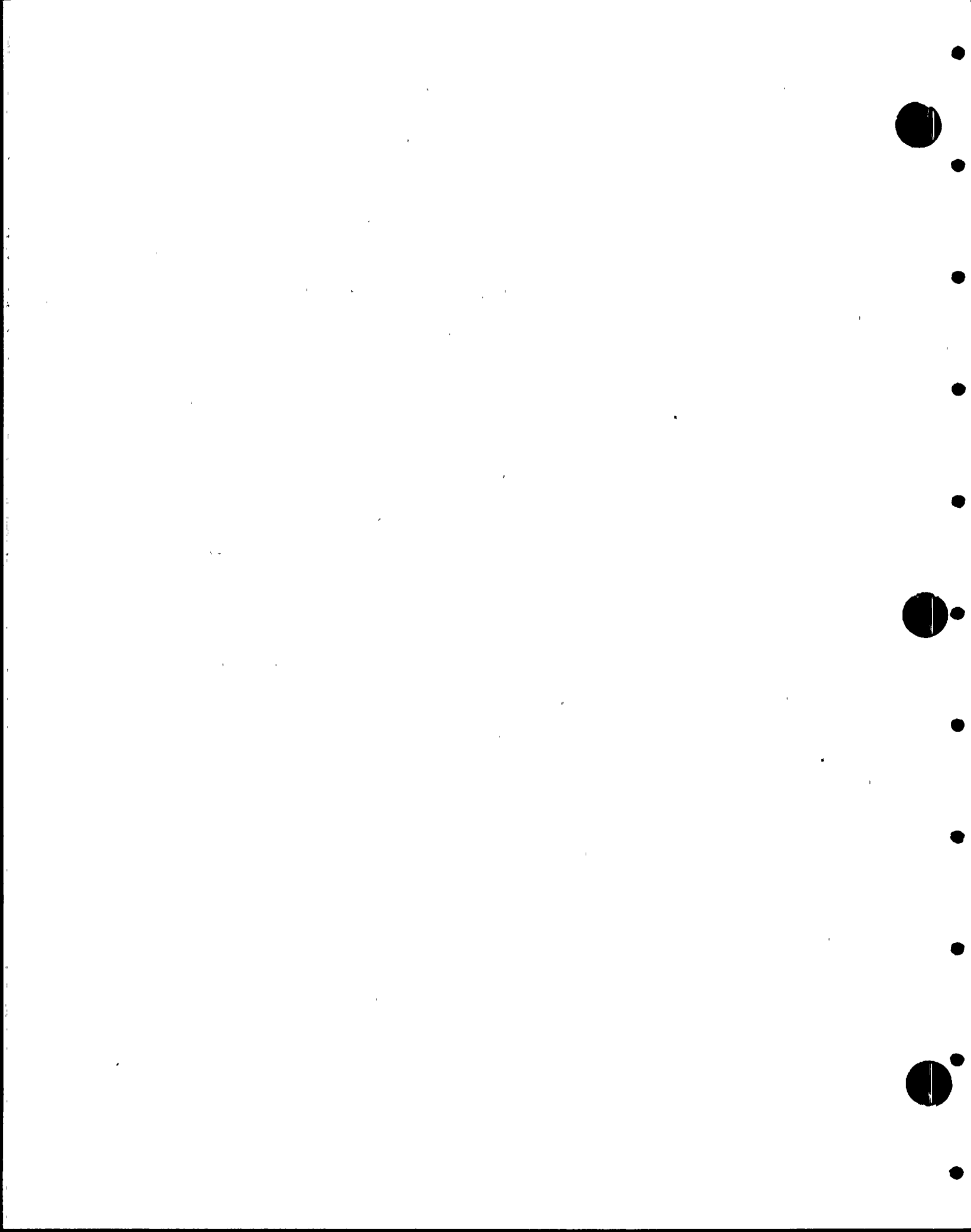
11 MR. ALLEN: Joe, did you have a question?

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

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

22 MR. MECH: That is one of the things.

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



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

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

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

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

13 MR. BINGHAM: We will cover it.

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

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

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

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



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

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

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

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

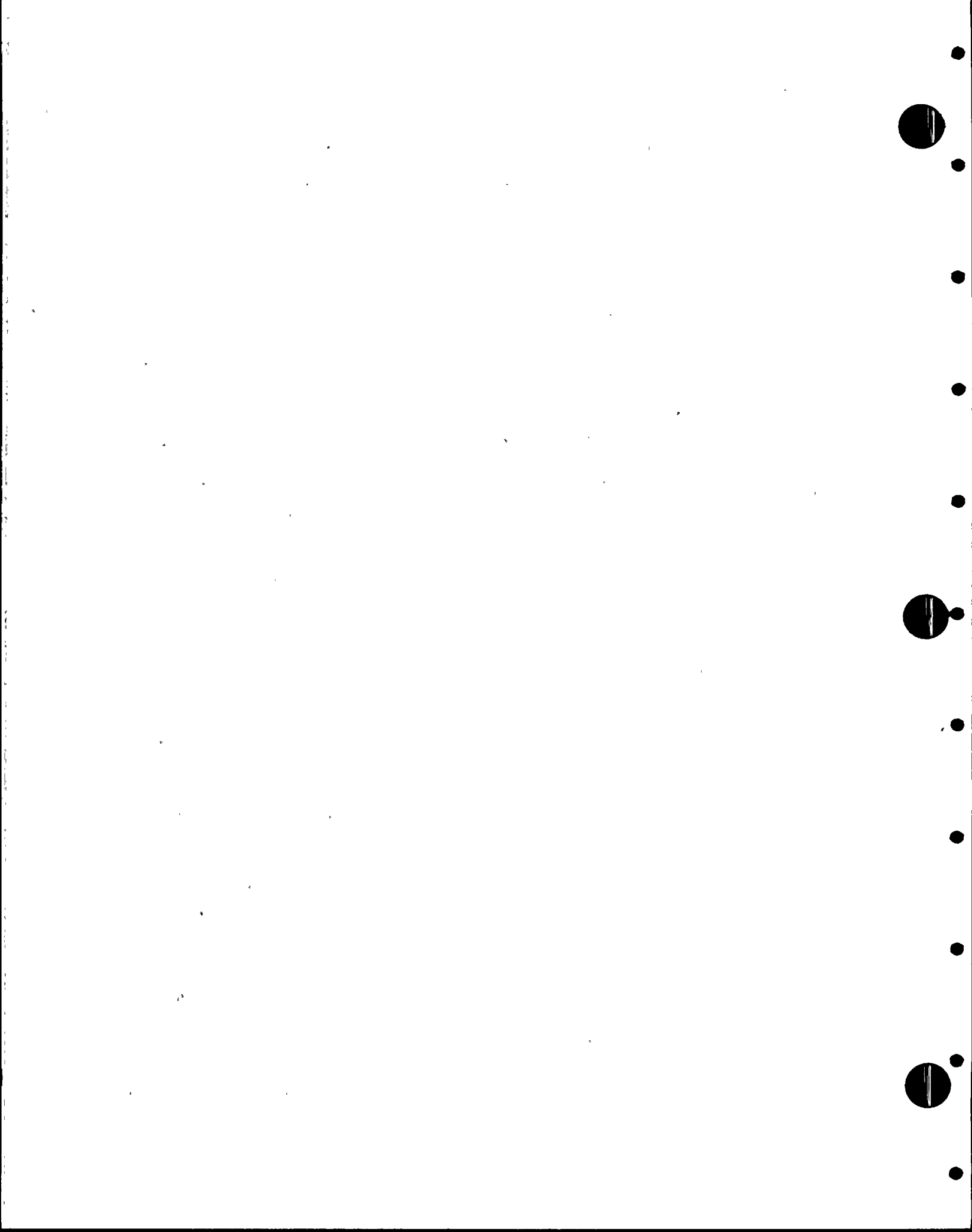
11 MR. ROSENTHAL: And you alarm it via bells, whistles,
12 plant computers?

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

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

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

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



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

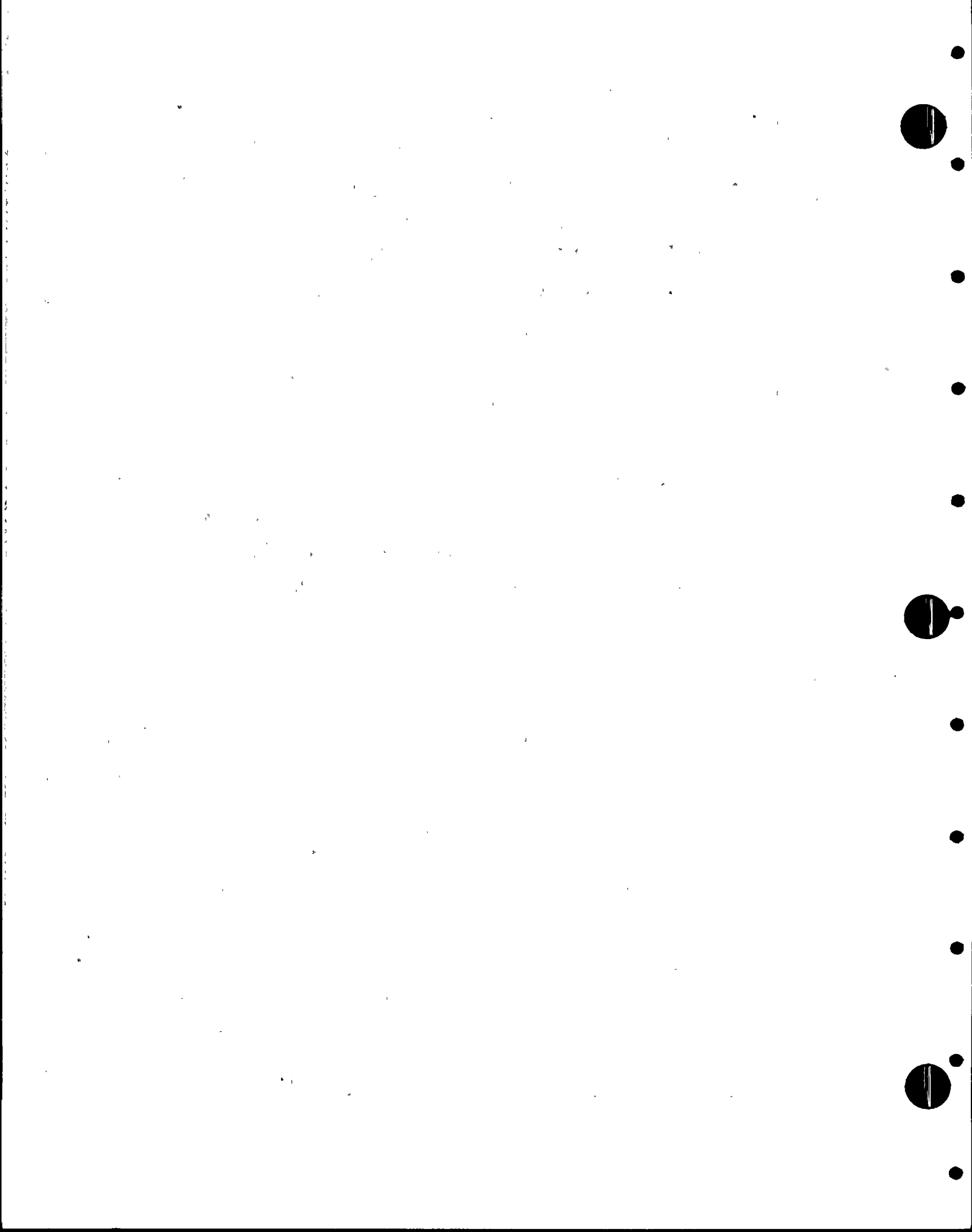
3 MR. ROSENTHAL: If I have a piece of safety equipment
4 and I have a buffer that is qualified for 480 volts on the
5 output, not affecting the input, then the cable downstream
6 of that buffer is non-IE cabling, but I should not submit
7 that cabling or circuitry to a credible fault which would
8 result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

10 MR. KEITH: We do take care of that concern in our
11 cable routing program by assuring that cable downstream of
12 the buffer is routed only in a tray which has cabling of a
13 comparable voltage level, that qualified for the buffer,
14 125 DC or whatever.

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

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

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

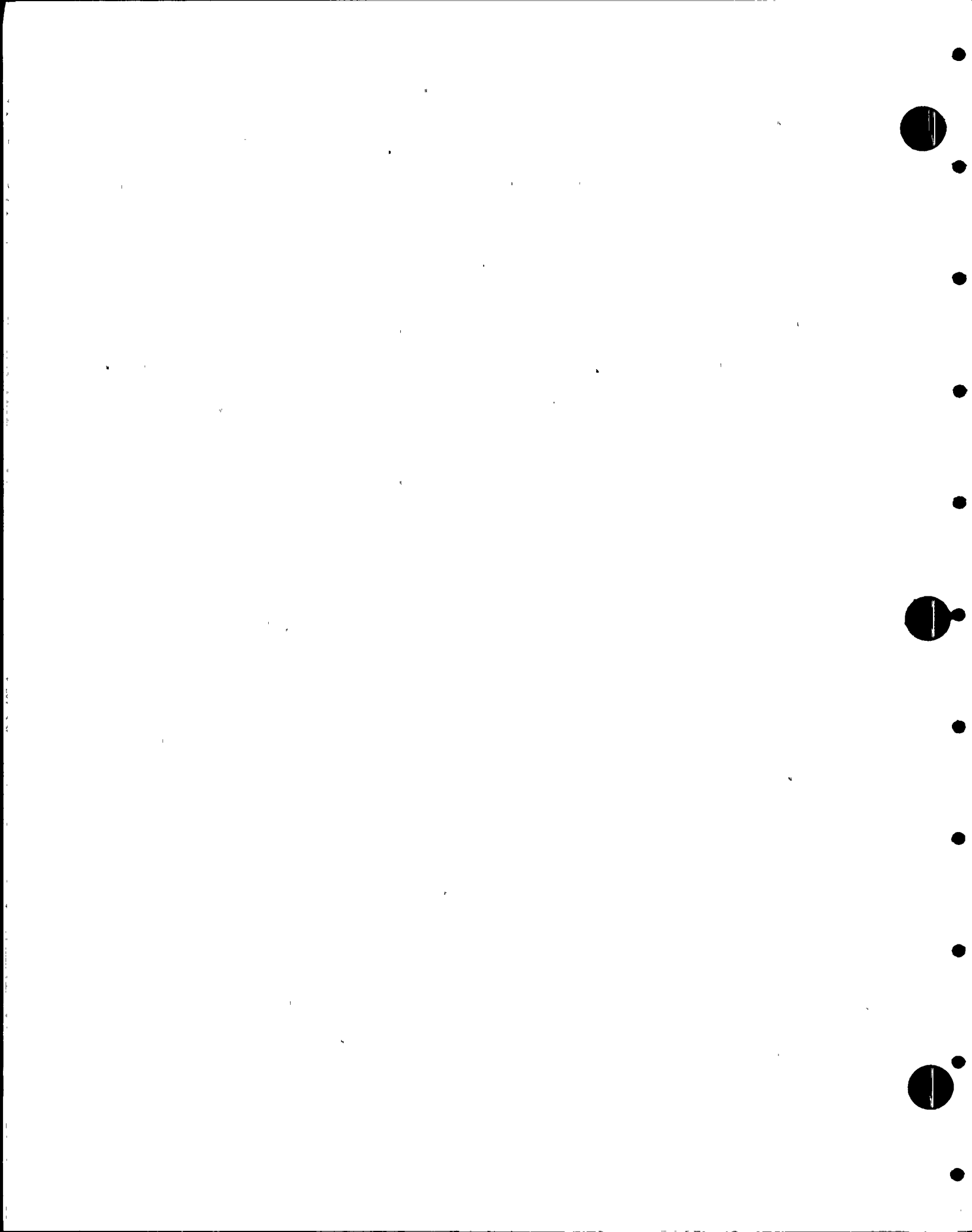


1 MR. ROSENTHAL: That particular circuit then you
2 properly address and we are all aware of that one. I am
3 concerned that there may be others and I am hoping that
4 maybe the answer is programmatic by virtue of the cable
5 routing.

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

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

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



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

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

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

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

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

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

17 MRS. MORETON: Not that I am aware of.

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

20 MR. BINGHAM: We believe they carry the colors.

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

1. The first part of the document discusses the importance of maintaining accurate records of all transactions and activities. It emphasizes that this is essential for ensuring transparency and accountability in the organization's operations.

2. The second part of the document outlines the various methods and tools used to collect and analyze data. It highlights the need for consistent data collection procedures and the use of advanced analytical techniques to derive meaningful insights from the data.

3. The third part of the document focuses on the role of technology in data management and analysis. It discusses how modern software solutions can streamline data collection, storage, and analysis processes, thereby improving efficiency and accuracy.

4. The fourth part of the document addresses the challenges associated with data management, such as data quality, security, and privacy. It provides strategies to mitigate these risks and ensure that the data remains reliable and secure throughout its lifecycle.

5. The fifth part of the document discusses the importance of data governance and the role of a data governance committee. It outlines the key principles and best practices for implementing a robust data governance framework.

6. The sixth part of the document focuses on the role of data in decision-making and performance improvement. It explains how data-driven insights can be used to identify trends, anticipate risks, and optimize organizational performance.

7. The seventh part of the document discusses the importance of data literacy and the need for ongoing training and development. It emphasizes that all employees should have a basic understanding of data and its applications in their work.

8. The eighth part of the document discusses the importance of data ethics and the need to ensure that data is used responsibly and in compliance with applicable laws and regulations. It outlines the key principles of data ethics and provides guidance on how to implement them in practice.

9. The ninth part of the document discusses the importance of data security and the need to implement robust security measures to protect the organization's data from unauthorized access, loss, or theft. It outlines the key components of a data security strategy and provides guidance on how to implement it.

10. The tenth part of the document discusses the importance of data integration and the need to ensure that data from different systems and sources is seamlessly integrated and accessible to all users. It outlines the key challenges of data integration and provides guidance on how to overcome them.

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

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

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

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

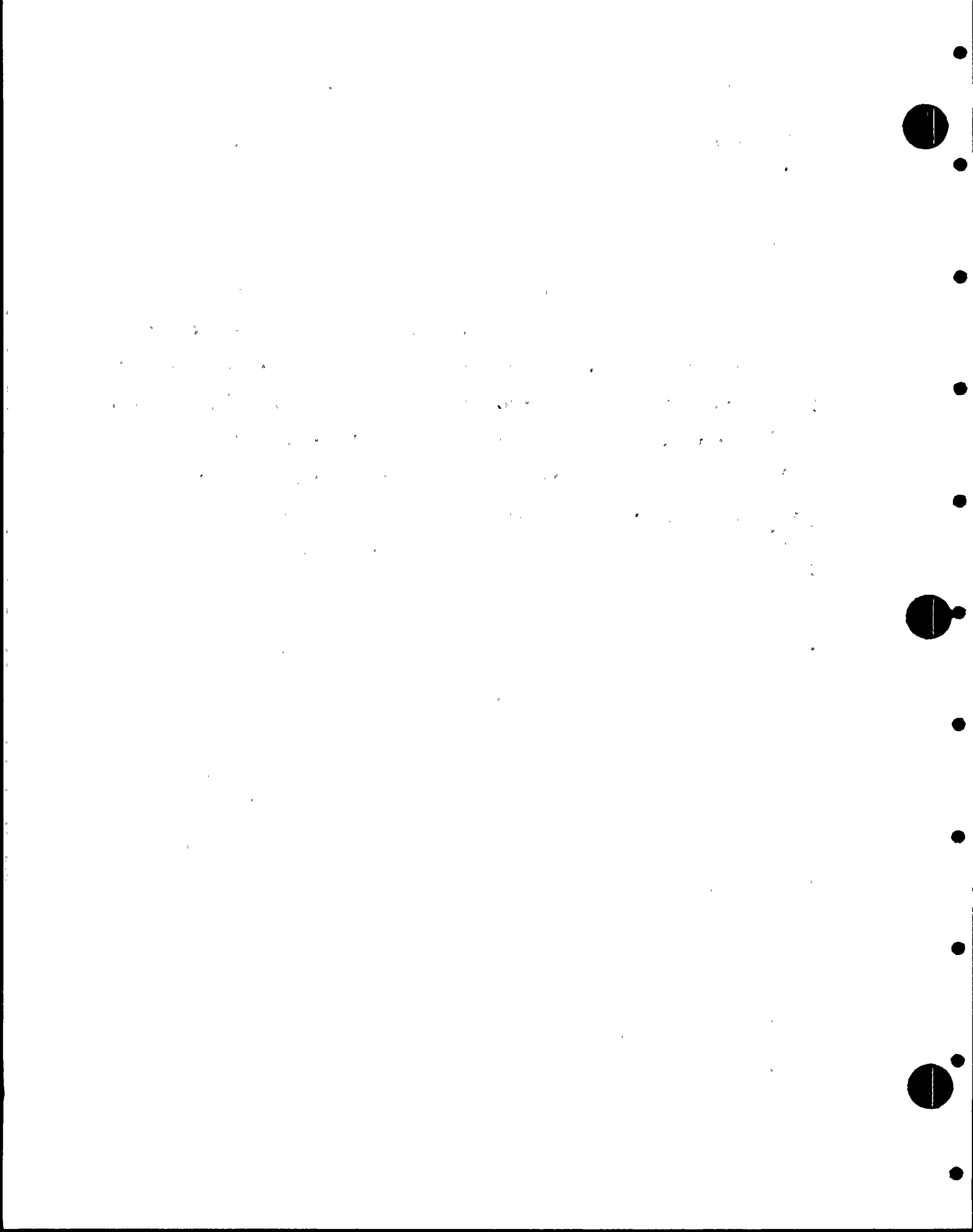
15 MR. ALLEN: Why don't we go through the presentation?
16 I know they are going to get into it a little more. Then
17 if you have any additional concerns, we could do it at the
18 follow-up meeting.

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

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

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

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



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

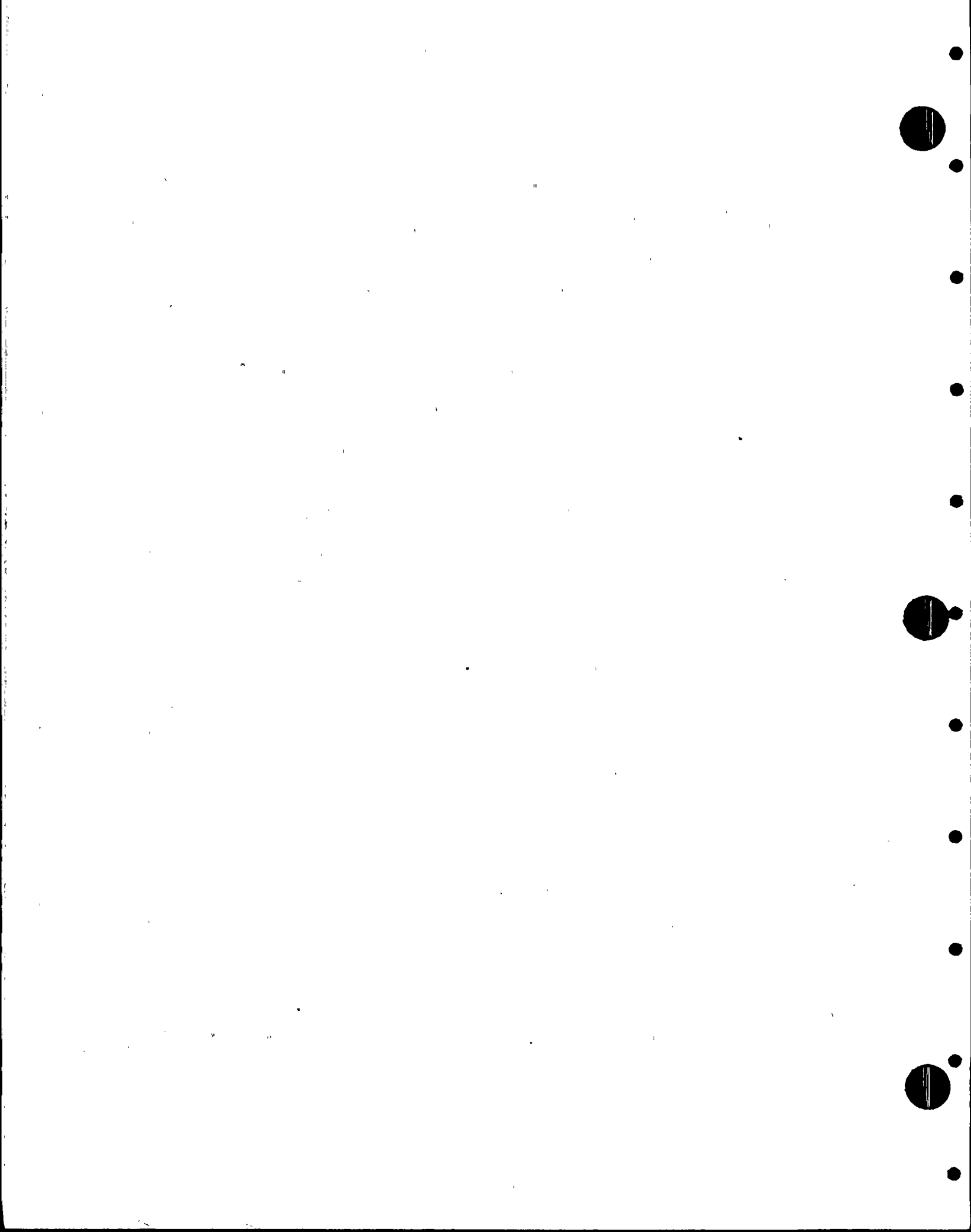
5 MR. ROSENTHAL: Fine. Mr. Sterling and Mr. Johnson
6 are on the Board here and were on the Board at the Combustion
7 meeting. We don't have a transcript, unfortunately, from
8 that meeting. The two of them might be able to help me.
9 I remember that they also had questions.

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

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

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

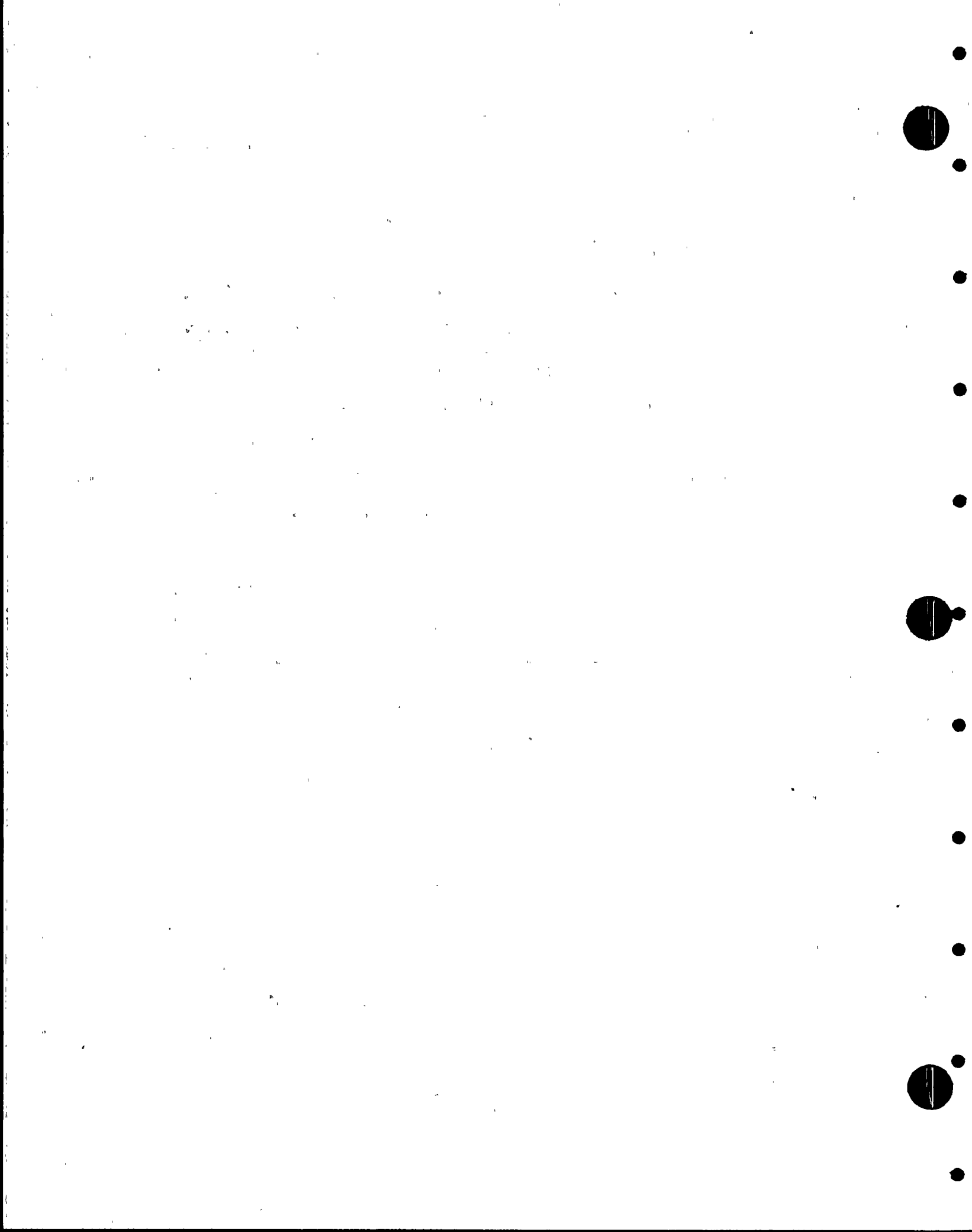
24 MR. BINGHAM: All right. Here I was focusing on
25 assuring we understood the Combustion Engineering criteria



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

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

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



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

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

9 MRS. MORETON: Correct.

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

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

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

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

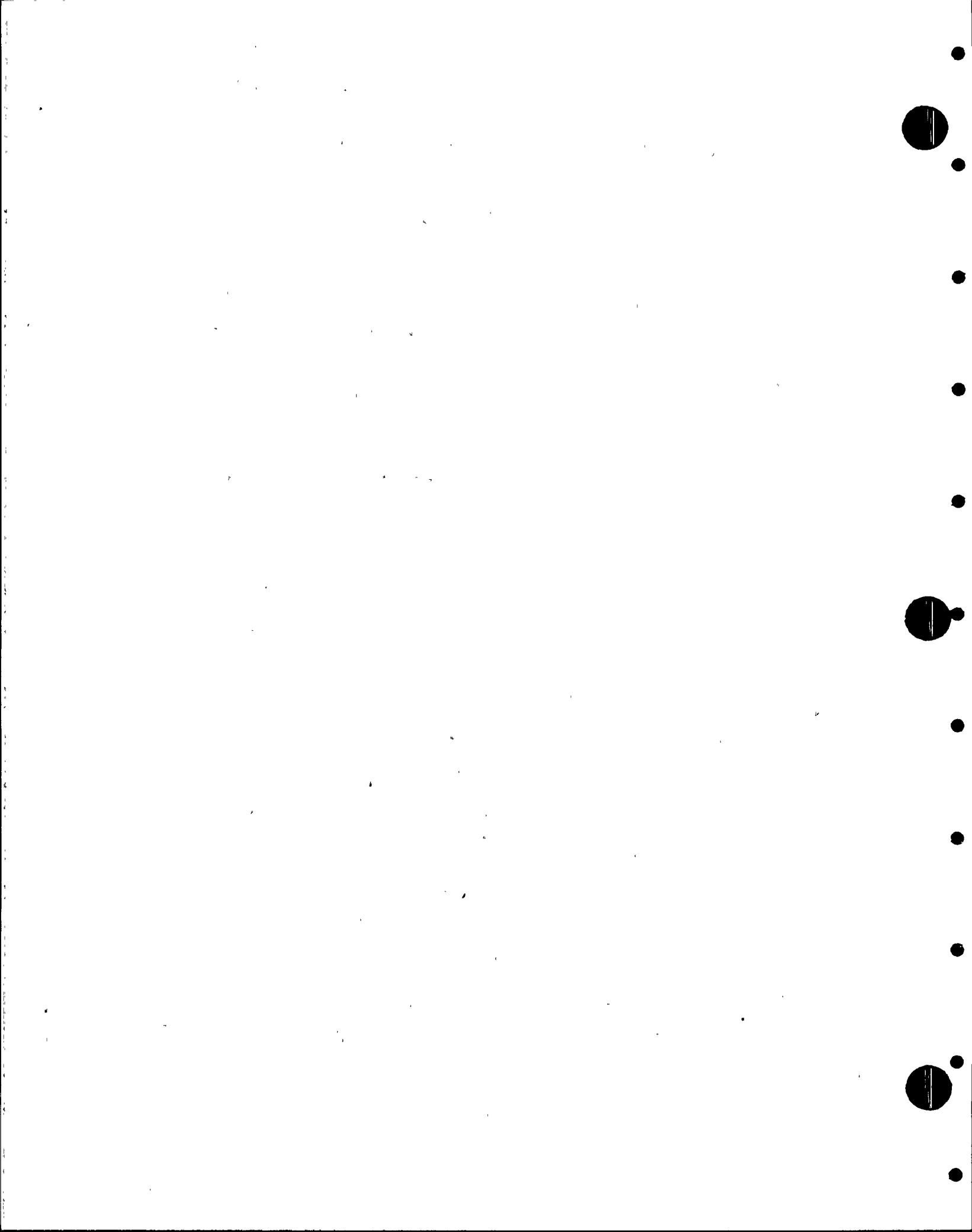
18 MR. ALLEN: Well, let's wait. I want to find out if
19 that is satisfactory with everybody or if somebody wants an
20 open item on it and additional information.

21 Okay, Ed, did you have an additional question?

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

24 MR. BINGHAM: That's correct.

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



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

4 MR. BINGHAM: What do you mean by spray?

5 MR. STERLING: Chemical spray inside the containment.

6 MR. KEITH: None that have to survive the environment.

7 I mean, obviously, there are instruments inside containment
8 which we provide in addition to those which Combustion
9 provides, but none which are required post-accident.

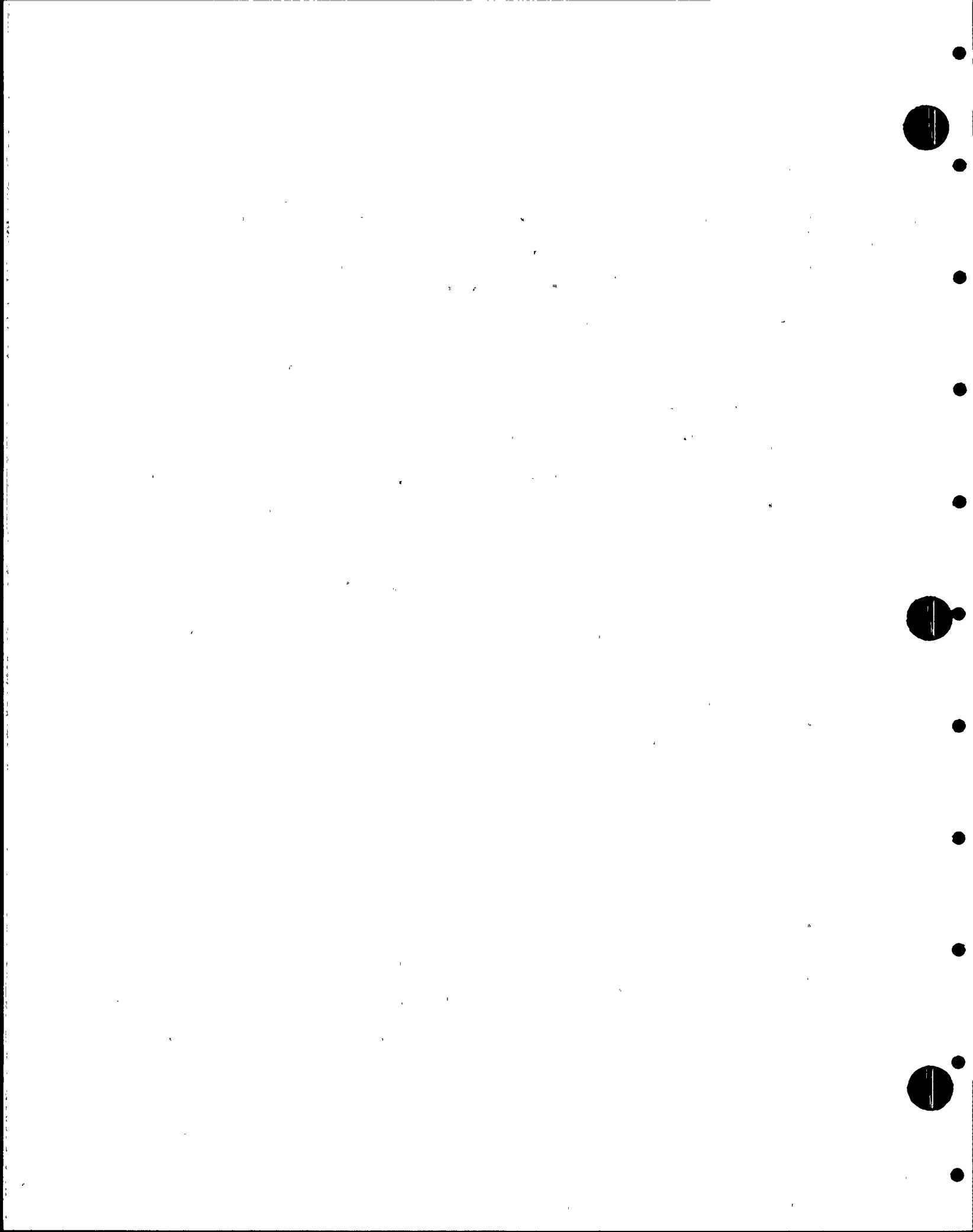
10 MR. STERLING: Are there any of those that could be
11 affected by the sprays that would adversely affect the
12 operation of the plant if they fail?

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

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

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

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



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

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

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

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

10 MR. KEITH: That's correct.

11 MR. ALLEN: Any further questions?

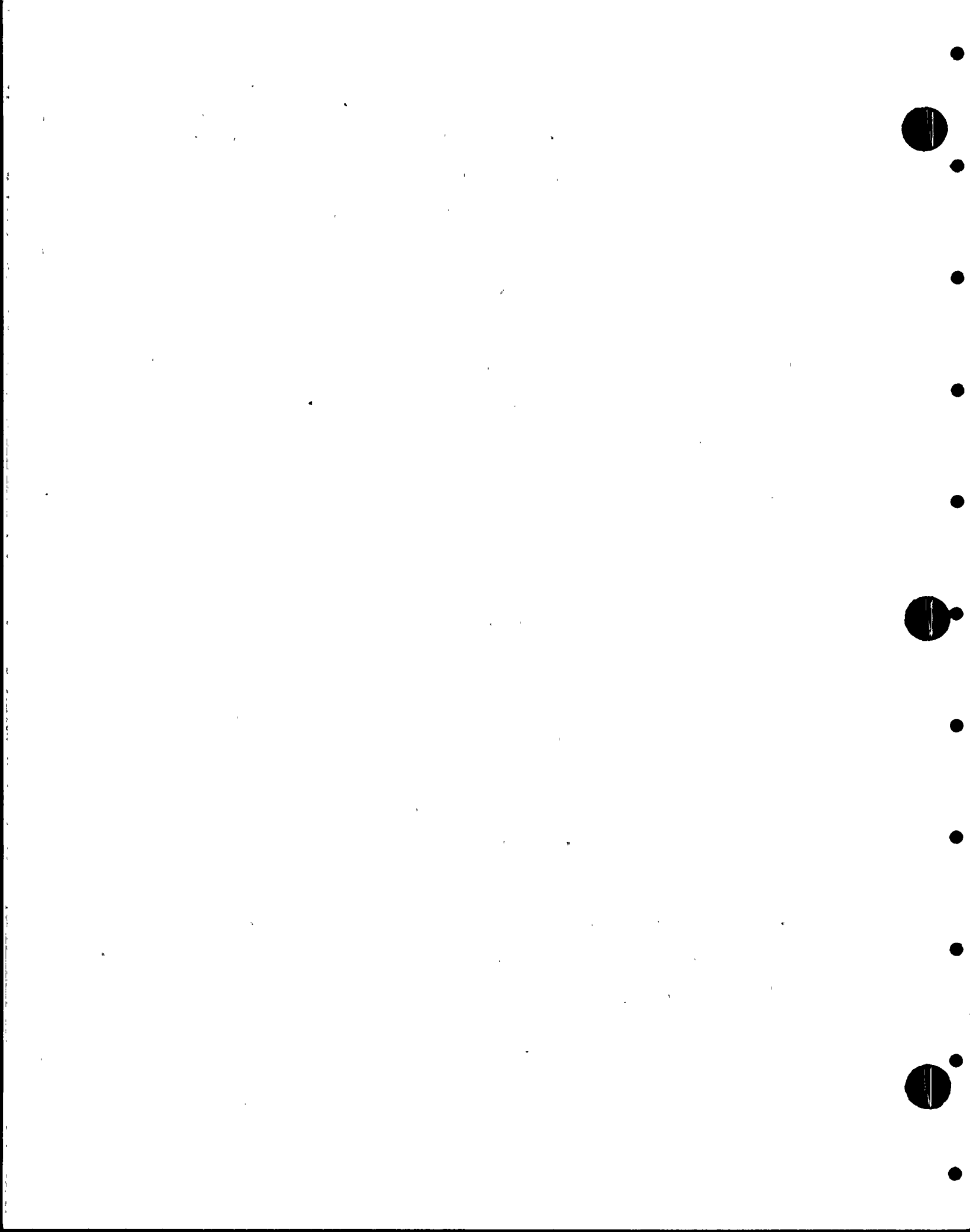
12 MR. BESSETTE: Exhibit 1A-6, Item 12), on materials.
13 Do you have any instruments within your scope on the
14 reactor coolant pressure boundary that might have to meet
15 the ASME code requirements for materials?

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

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

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

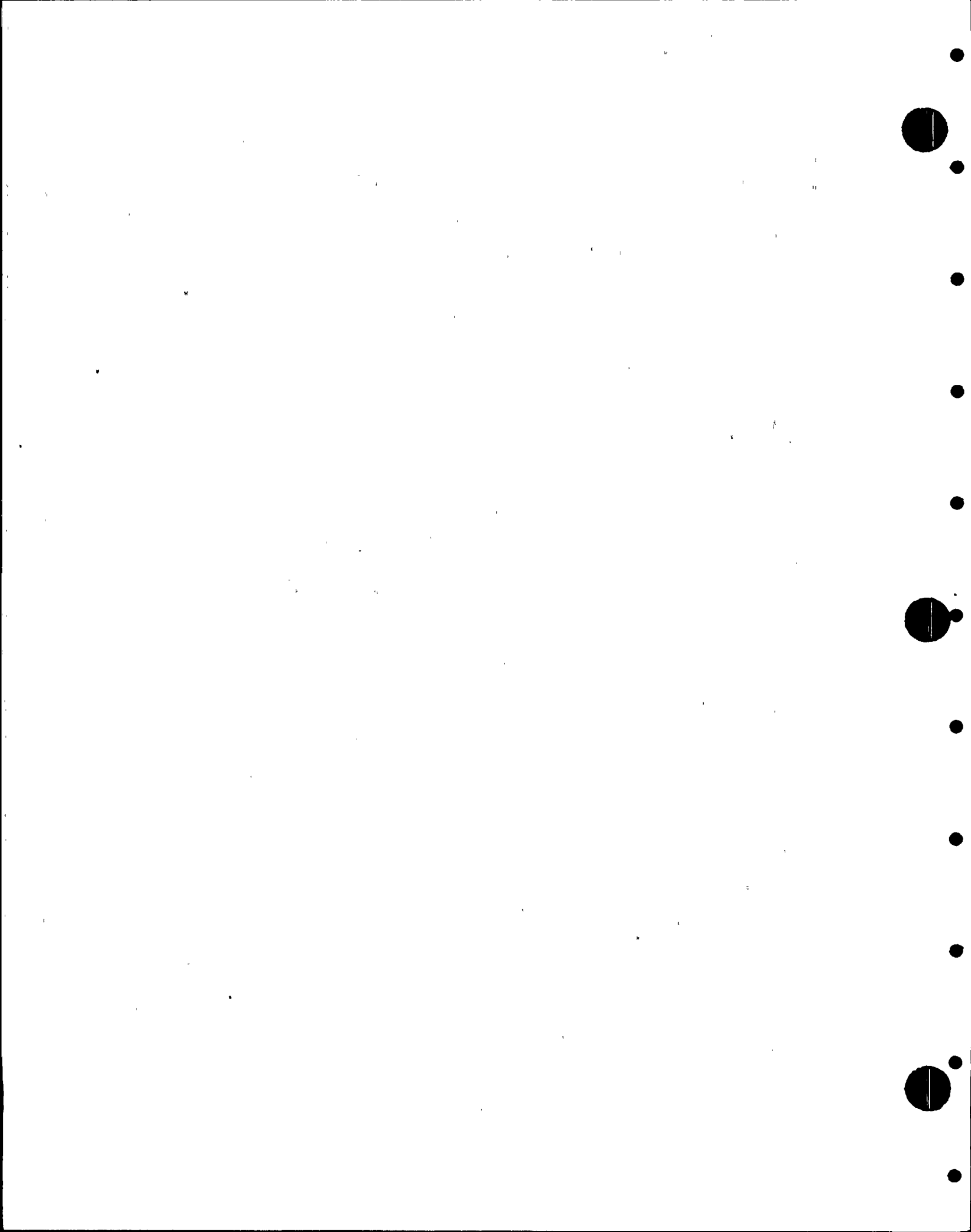
25 MR. ALLEN: Are there additional questions? Anyone



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

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

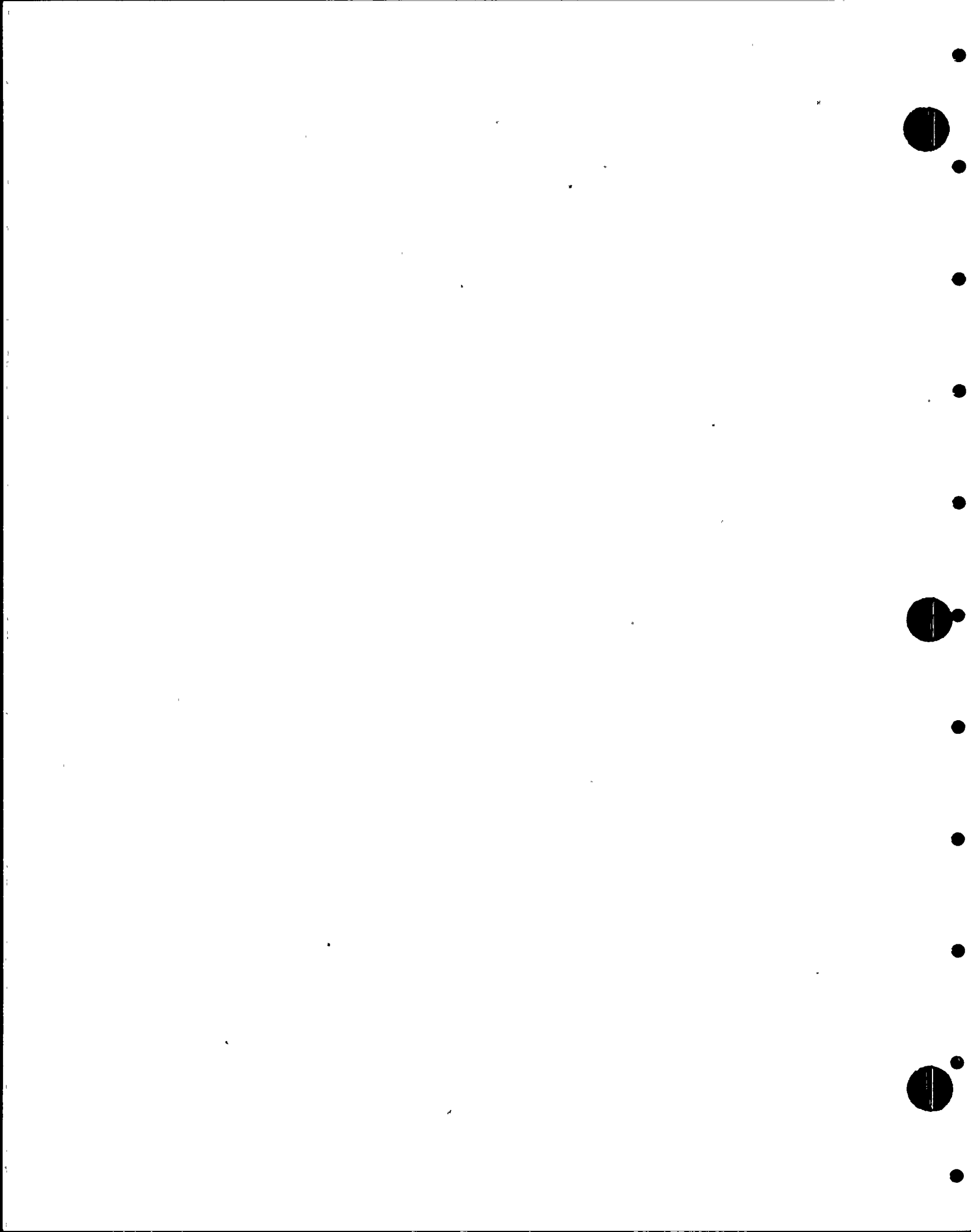
8 MRS. MORETON: Referring to Figure 2A-1, which
9 shows the Engineered Safety Feature System, which consists
10 of those electrical and mechanical devices and circuitry,
11 including the sensors that sense the process variables,
12 through the actuation devices required to initiate protective
13 action,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



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

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

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

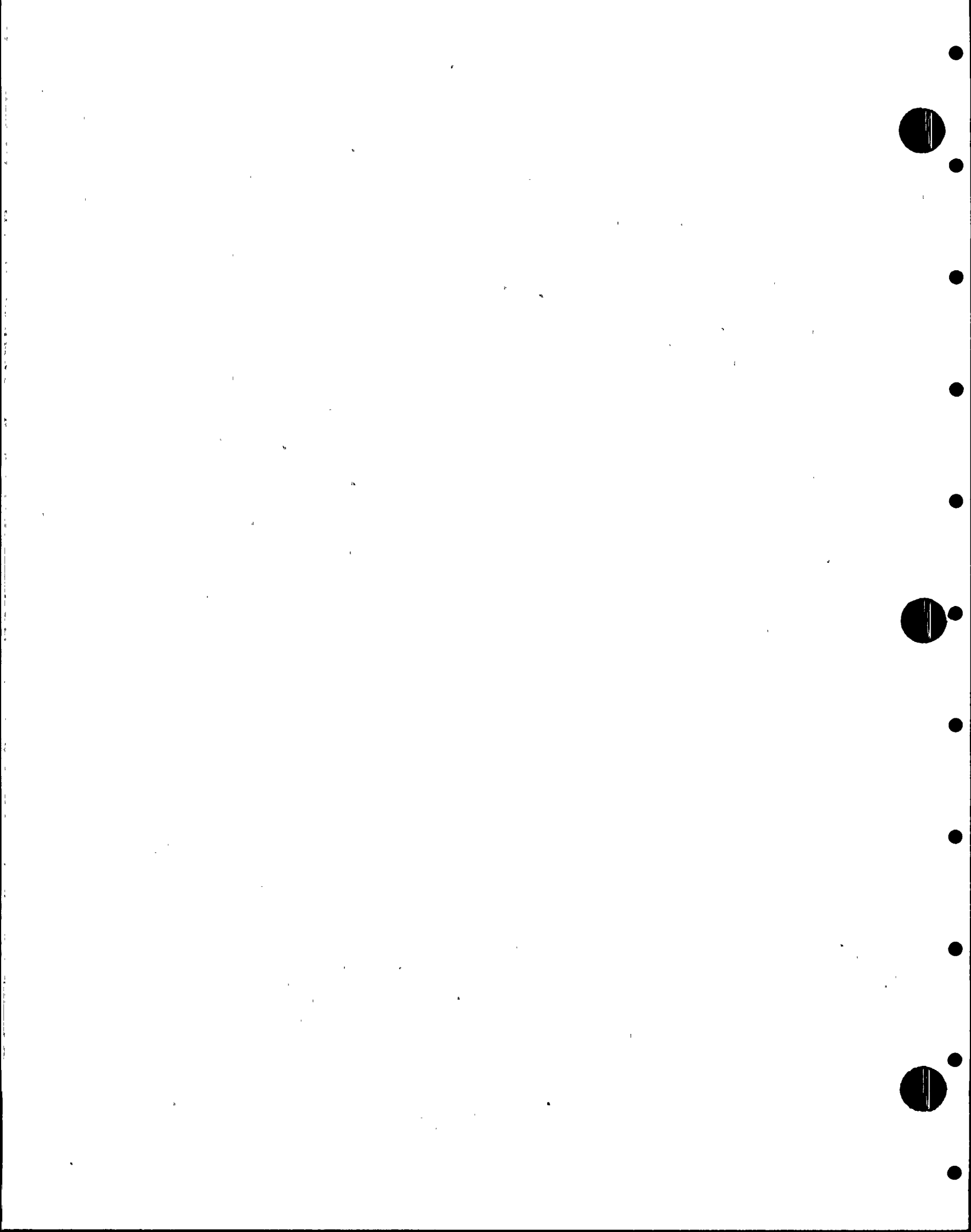


1 number and location of sensors, normal operation nominal
2 variable values, normal operation variable limits, actuation
3 setpoints, margin to actuation, qualification, redundancy,
4 and failure modes, and minimum performance requirements.

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

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

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



1 Geiger-Mueller counter overlooking the fuel pool.

2 Bases (4), (5), (6) and (7) are covered on

3 Exhibit 2A1-6. They cover the normal operation limits for

4 each variable, the actuation setpoints, and the margin

5 between the operation limits and actuation setpoints. An

6 example shown here for the fuel building exhaust duct high

7 activity. At full power, the nominal is at less than

8 sensitivity, which is less than 10^{-6} microcuries per cubic

9 centimeter. The normal operation limit is the same. The

10 actuation setpoint is 2 to the 10^{-6} microcuries per cubic

11 centimeter, and the margin to actuation is therefore 1×10^{-6}

12 microcuries per cubic centimeter. Basis (8), shown on

13 Exhibit 2A1-7, covers the qualification, redundancy, and

14 failure mode requirements of the BOP ESFAS. BOP ESFAS

15 components shall be qualified to withstand and remain

16 operable during the environmental conditions maintained at

17 the equipment locations before, during, and after the design

18 basis events. The BOP ESFAS components shall withstand and

19 remain operable during and after an SSE. A single failure

20 within the BOP ESFAS shall not prevent proper protective

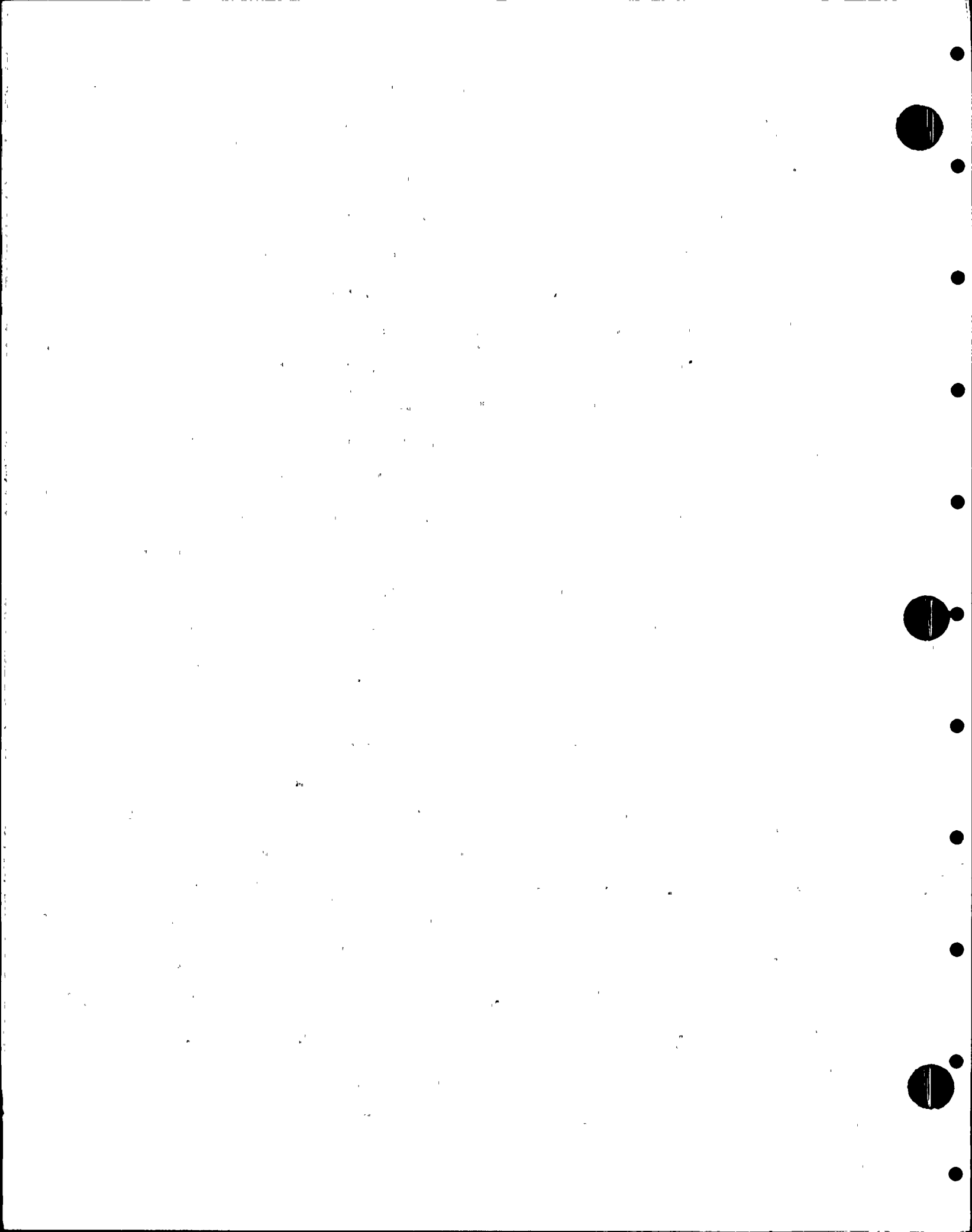
21 action at the system level. A loss of power to the BOP ESFAS

22 channels or to the logic system causes system actuation.

23 Finally, Basis (9), covered on Exhibit 2A1-8,

24 covers the minimum performance requirements of the BOP ESFAS.

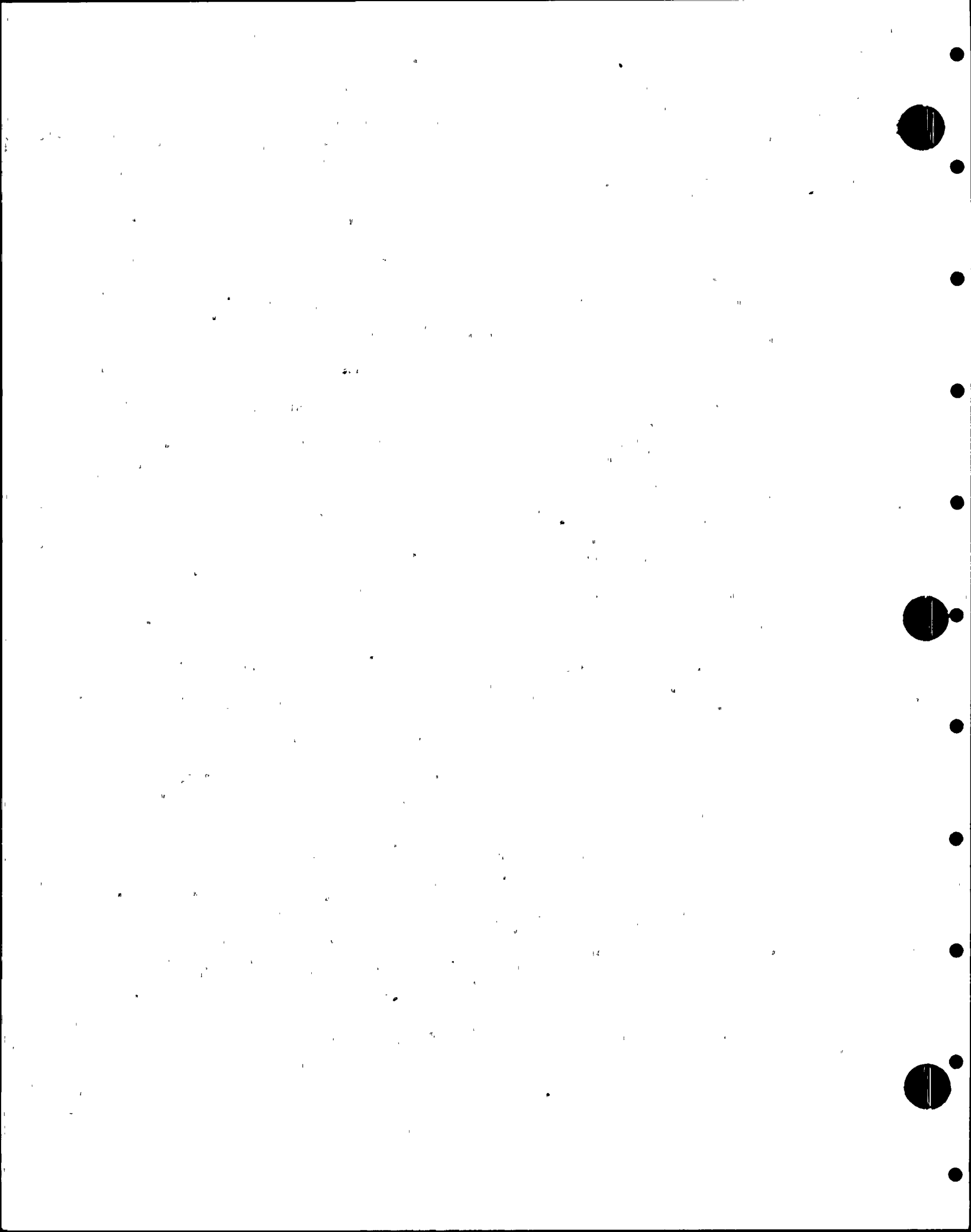
25 This includes response time, which is the sum of the



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

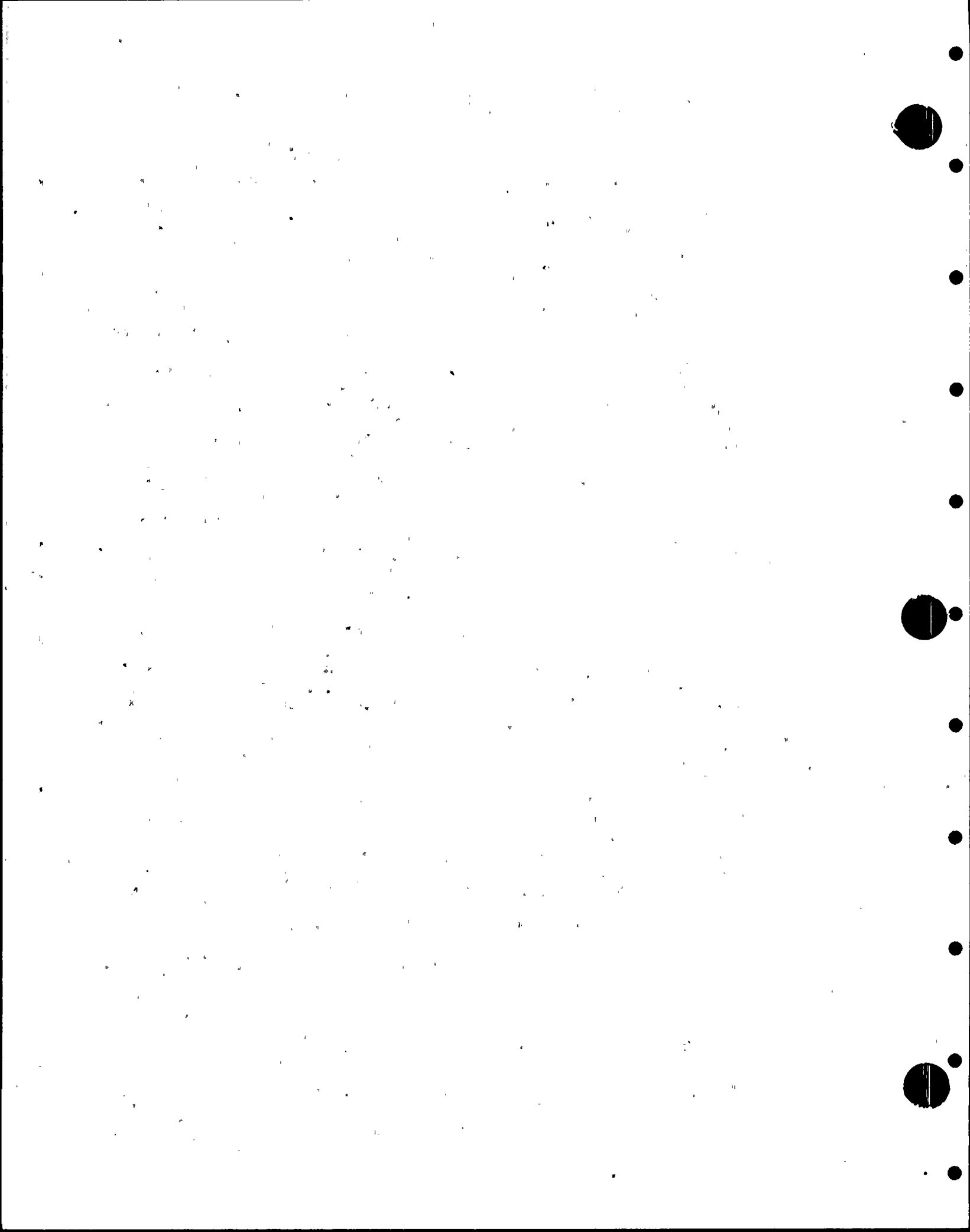
7 Continuing on with the design criteria, Exhibit
8 2A1-9, only those ESF systems that, when actuated, do not
9 cause a plant condition requiring protective action or
10 disturb reactor operations shall be controlled by the BOP
11 ESFAS. The automatically actuated BOP ESF systems shall use
12 one-out-of-two input signal logic. The BOP ESFAS logic
13 shall be contained in separate enclosures isolated from the
14 NSSS two-out-of-four ESFAS and reactor protective system
15 logic. The actuation system consists of the sensors,
16 bistables, initiation logic, and actuation logic that monitor
17 selected plant parameters and provide an actuation signal to
18 each individual actuated component in the ESF system if the
19 plant parameters reach preselected points. The BOP ESFAS
20 shall provide the logic to automatically start and
21 sequentially load the diesel generators and to shed all
22 4.16 kV Class IE loads on a loss of power.

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



1 Exhibit 2A1-11. The initiating circuits shall
2 continuously monitor key process variables indicating
3 accident conditions and transmitting digital, or on/off,
4 signals to the BOP ESFAS initiating logic. The BOP ESFAS
5 initiating logic provides two ESFAS initiation signals for
6 the actuation logic. The system shall monitor the under-
7 voltage relays on the 4.16 kV Class IE bus and initiate a
8 logic signal on a two-out-of-four coincidence of bus under-
9 voltage. This logic signal will be used to shed all Class IE
10 4.16 kV loads except the load center transformers, shed
11 certain 480 volt loads, start the diesel generator, start
12 equipment required after a loss of offsite power, and trip
13 the 4.16 kV Class IE bus preferred power supply breakers.

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



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

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

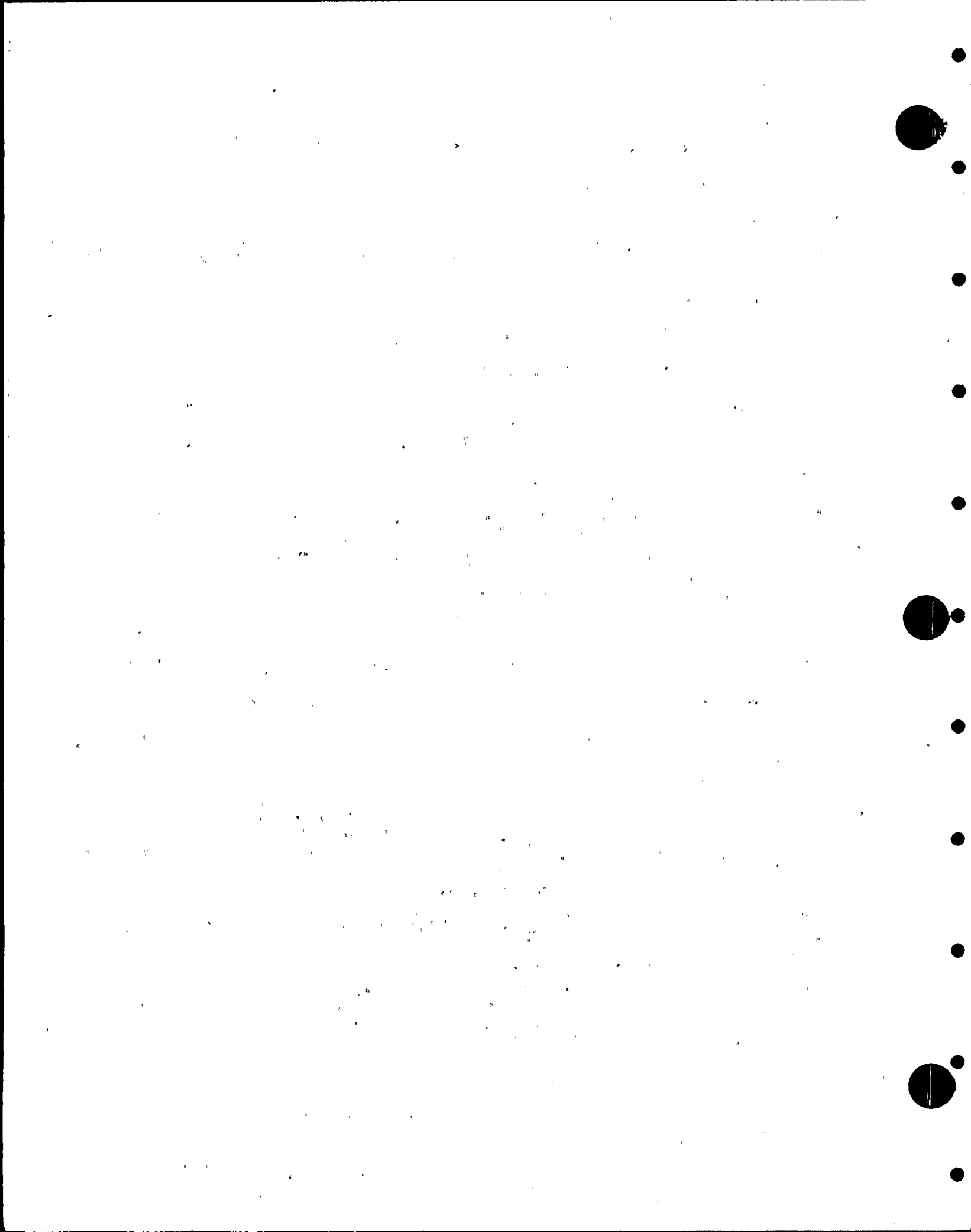
19 This concludes the BOP ESFAS presentation.

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

22 MR. ALLEN: I am sure there are.

23 Ed, go ahead.

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



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

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

3 MR. BINGHAM: What is the question, please?

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

6 MR. BINGHAM: You are talking about equipment
7 qualifications?

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

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

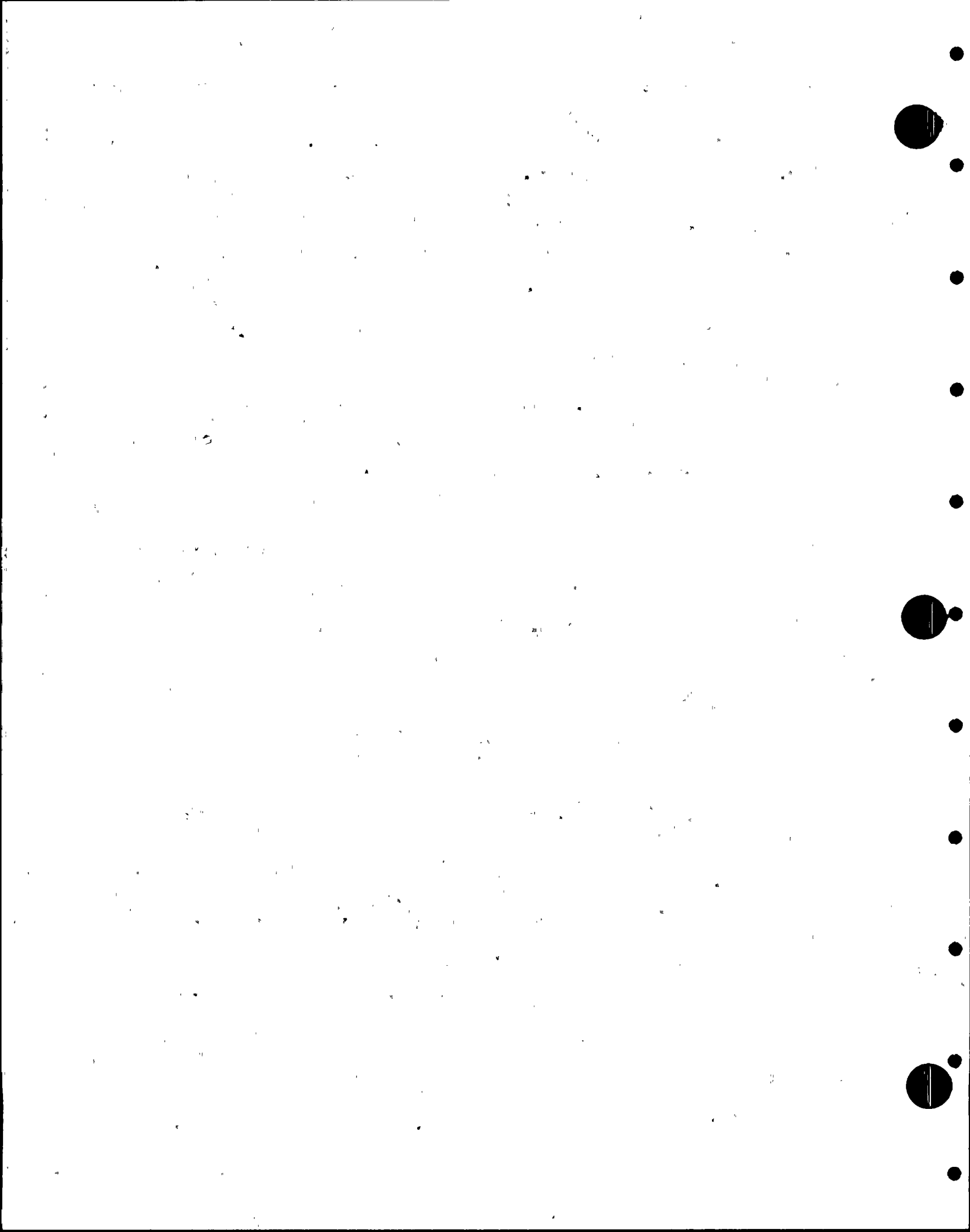
16 MR. STERLING: That would be helpful. You were
17 referring to that transcript, then?

18 MR. BINGHAM: Yes.

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

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

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



1 because I want to get into more detail on that.

2 MR. ALLEN: Further questions?

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

7 MRS. MORETON: Continuously.

8 MR. KONDIC: Really? I'm glad.

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

12 MR. BINGHAM: We do not use chlorine gas.

13 MR. MECH: You do use it?

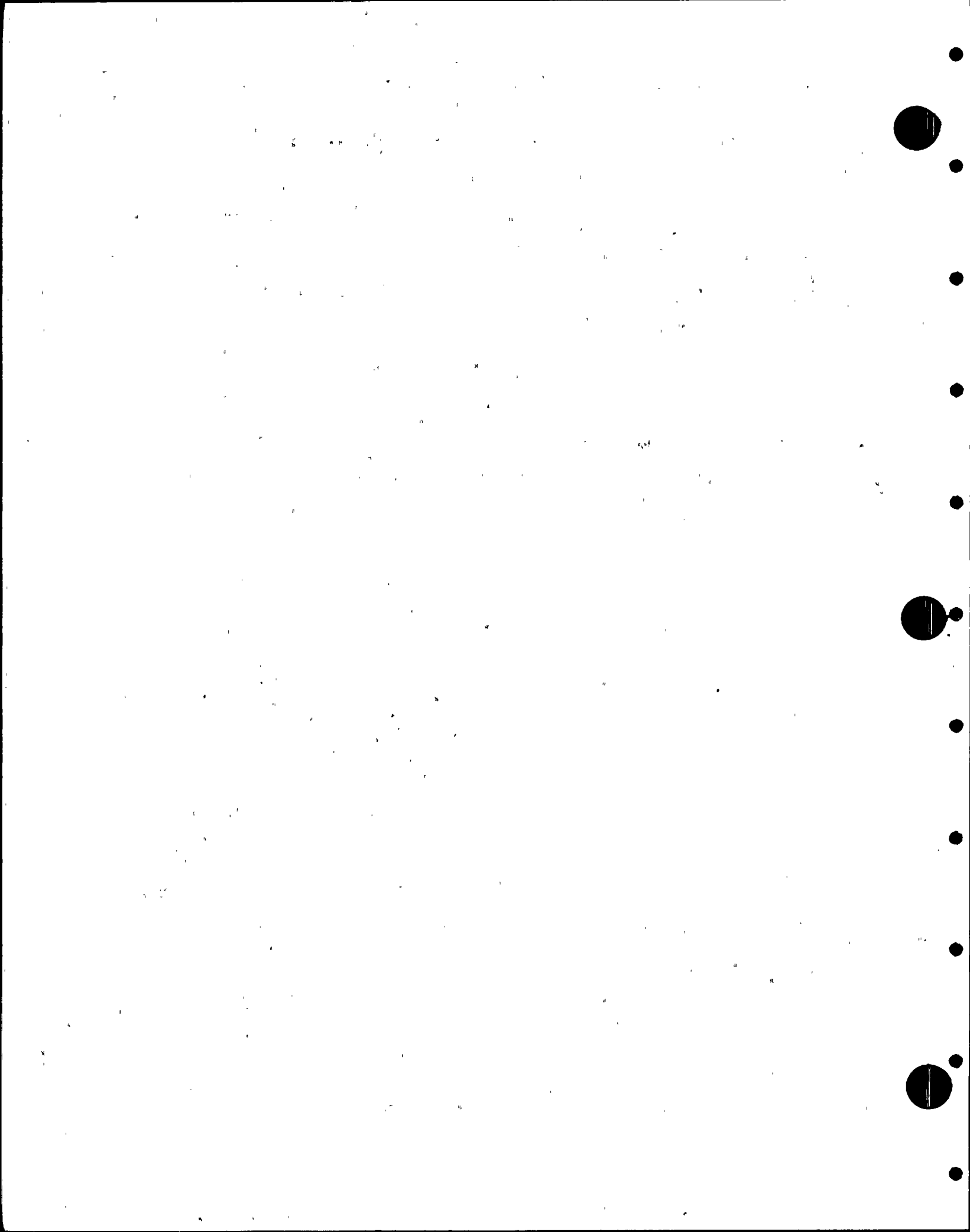
14 MR. BINGHAM: Do not.

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

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

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

25 MR. BINGHAM: No.



1 MR. ALLEN: Any Board member? Jack'.

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

4 MR. KEITH: No.

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

9 MRS. MORETON: Yes.

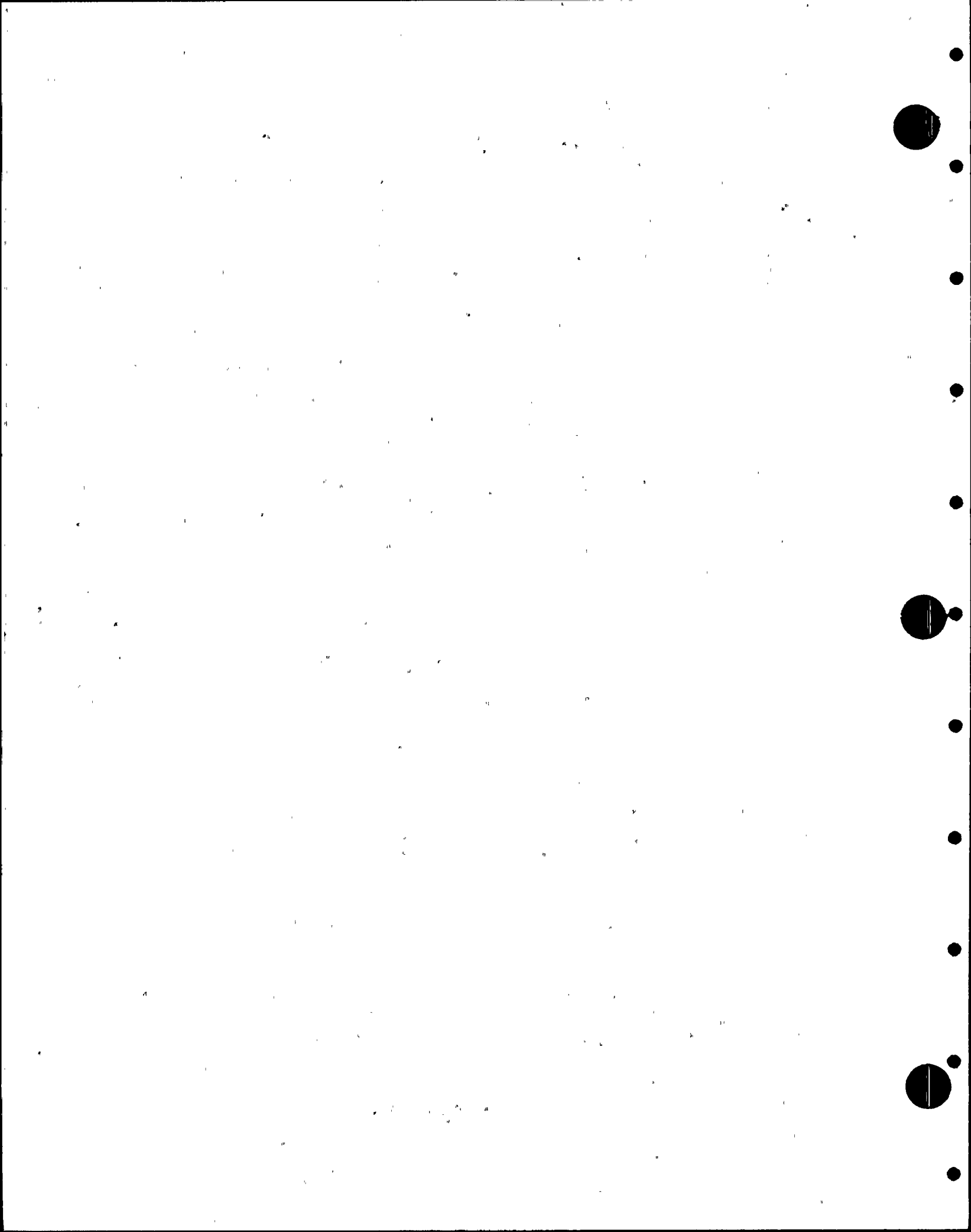
10 MR. ROSENTHAL: Later on in the presentation, I would
11 like a little bit more information on the sensor itself, the
12 thermal conductivity device rather than --

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

15 MR. ROSENTHAL: Later. This is related to Exhibit
16 2A1-10. You call out IEEE 338-71. I believe the later
17 versions of IEEE 338 require response time testing, and on
18 Exhibits 2A1-6 and 8, talking about response times, can you
19 describe the degree to which the systems in fact differ from
20 338-75 or 77? I recognize that the licensing basis for
21 the plant is the 338-71 version.

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

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



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

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

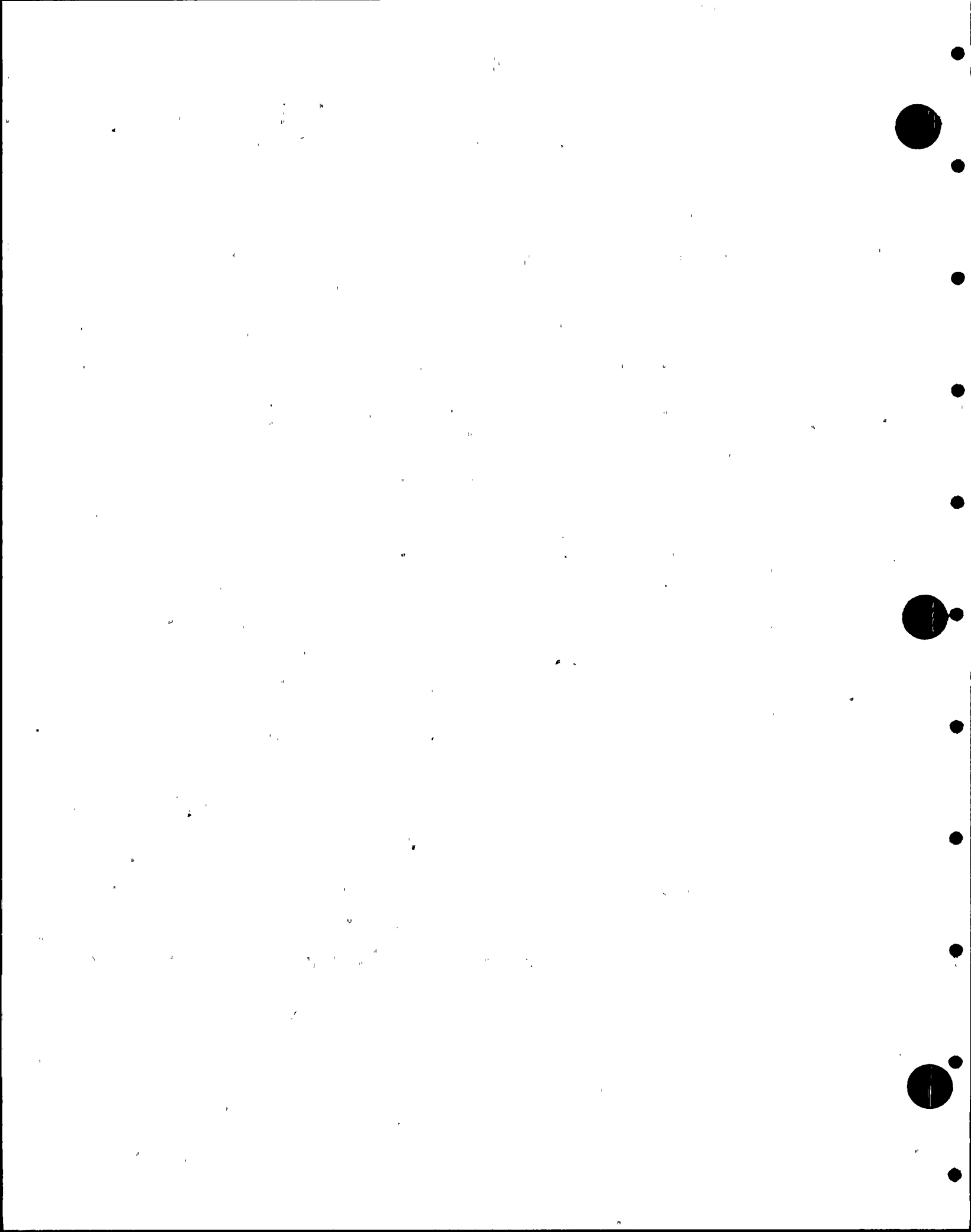
8 MISS KERRIGAN: We would defer that question until
9 the second meeting. It is probably a more detailed question,
10 but let's leave it on the record and address it in the second
11 meeting.

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

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

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

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



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

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

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

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

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

offer to... to the... directly

rather than indirectly

Mr. ... would not like to

that... It is an... from...

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a member of... to discuss the...

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Mr. ... It was a... remember for

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

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

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

14 MR. KEITH: On the turbines.

15 MR. ROSENTHAL: On the turbines.

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

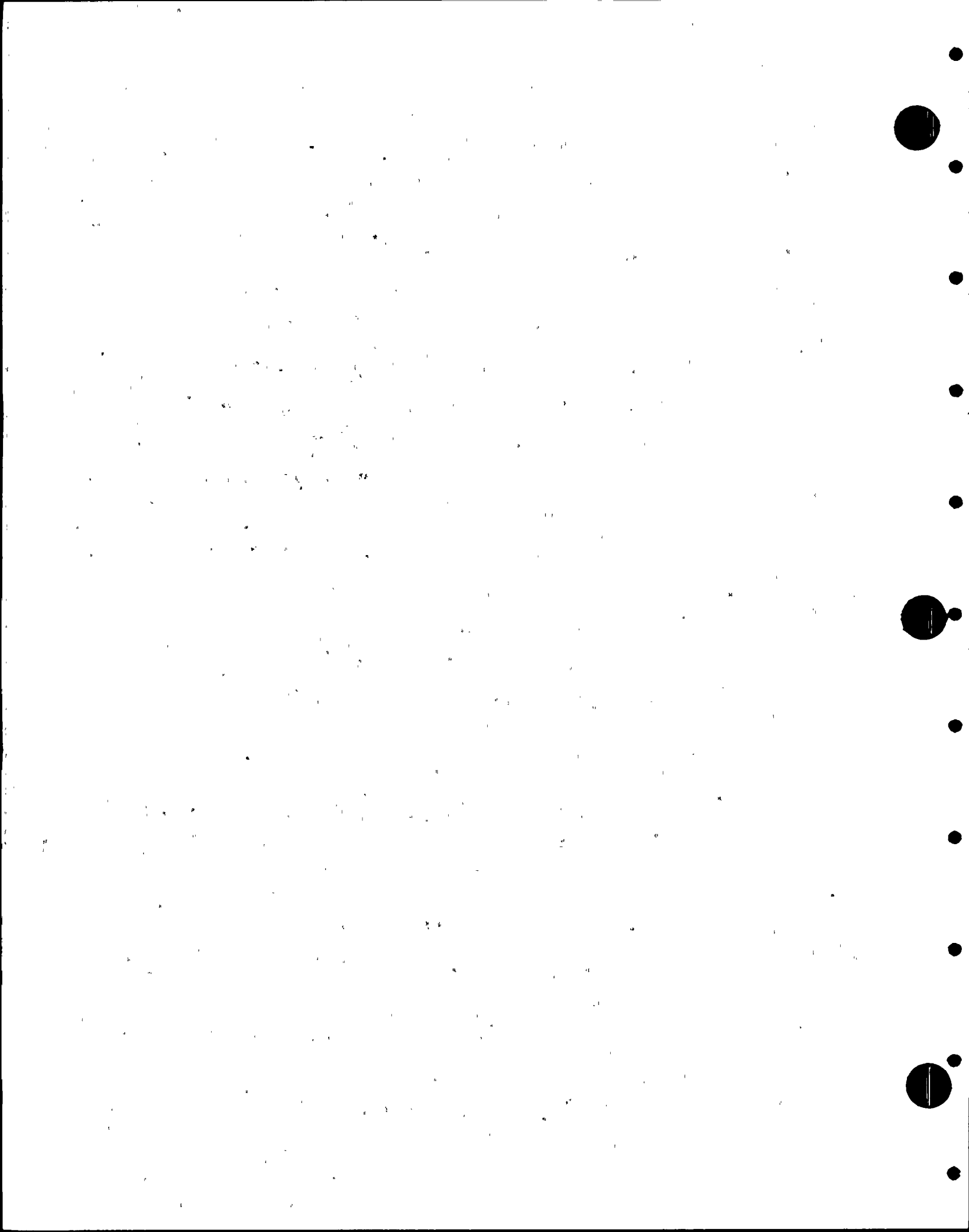
18 MR. ALLEN: Anybody over here?

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

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

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

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



1 section.

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

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

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

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

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

SECTION

1. The first part of the report is a description of the system.

2. The second part is a description of the hardware.

3. The third part is a description of the software.

4. The fourth part is a description of the test results.

5. The fifth part is a description of the conclusions.

6. The sixth part is a description of the recommendations.

7. The seventh part is a description of the references.

8. The eighth part is a description of the appendix.

9. The ninth part is a description of the bibliography.

10. The tenth part is a description of the index.

11. The eleventh part is a description of the glossary.

12. The twelfth part is a description of the list of figures.

13. The thirteenth part is a description of the list of tables.

14. The fourteenth part is a description of the list of symbols.

15. The fifteenth part is a description of the list of abbreviations.

16. The sixteenth part is a description of the list of acronyms.

17. The seventeenth part is a description of the list of definitions.

18. The eighteenth part is a description of the list of terms.

19. The nineteenth part is a description of the list of concepts.

20. The twentieth part is a description of the list of principles.

21. The twenty-first part is a description of the list of laws.

22. The twenty-second part is a description of the list of theories.

23. The twenty-third part is a description of the list of models.

24. The twenty-fourth part is a description of the list of methods.

25. The twenty-fifth part is a description of the list of techniques.

26. The twenty-sixth part is a description of the list of procedures.

27. The twenty-seventh part is a description of the list of processes.

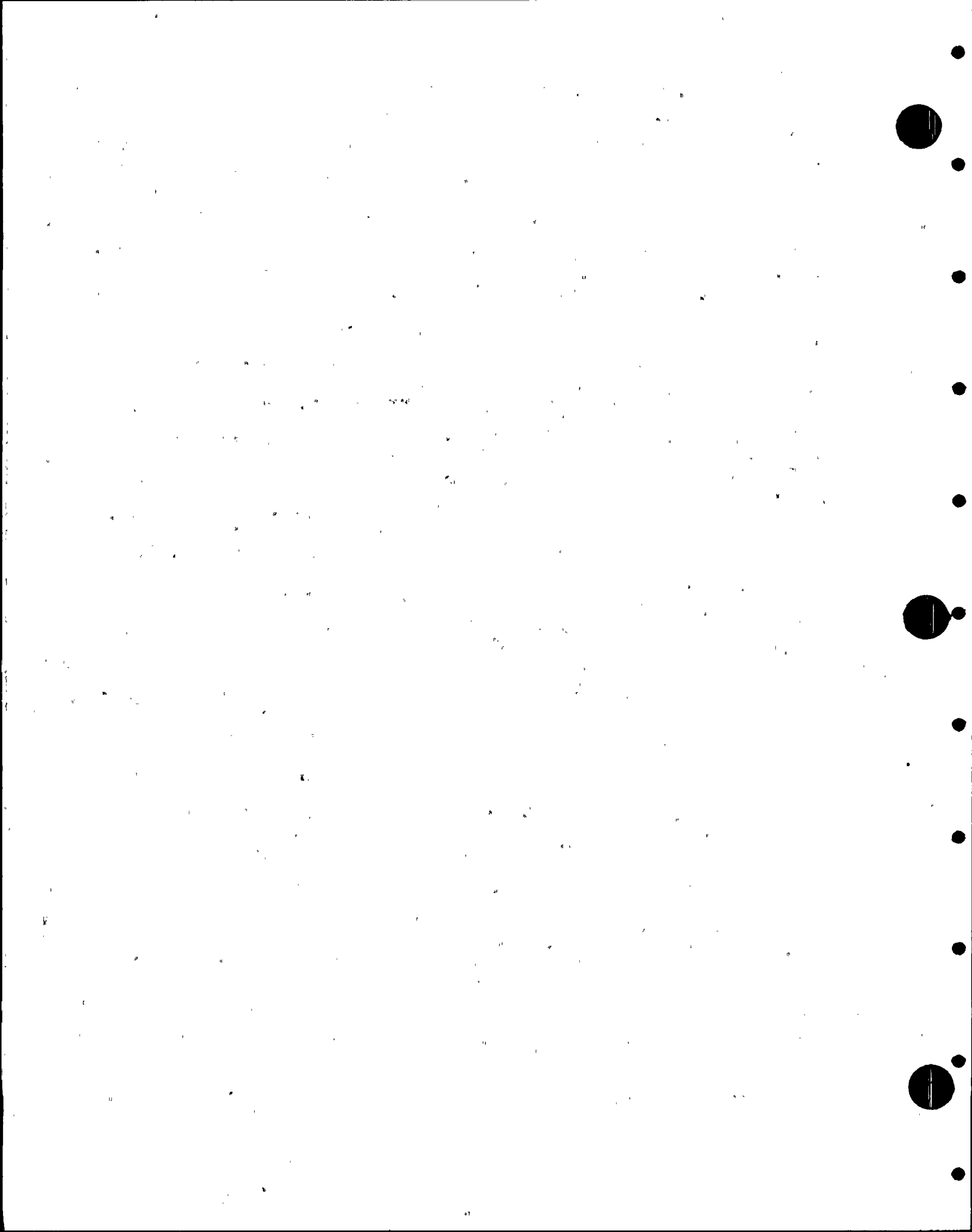
28. The twenty-eighth part is a description of the list of systems.

29. The twenty-ninth part is a description of the list of environments.

30. The thirtieth part is a description of the list of conditions.

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

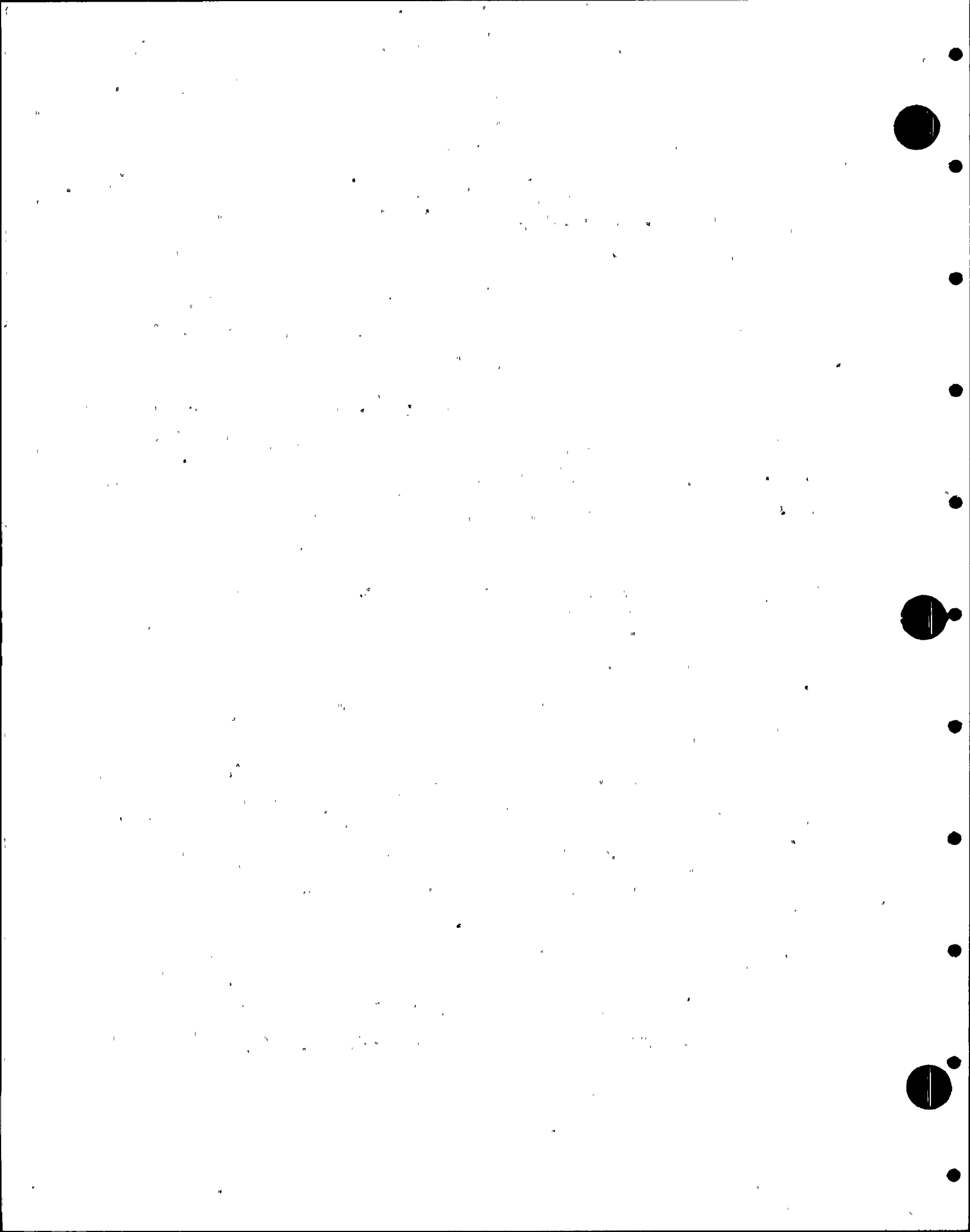
16 Exhibit 2A1-16. The initiating logic does consist
17 of the bistables, bistable output relays, trip output
18 signals, indicating lights, and interconnecting wiring.
19 Signals from the protective measurement channels are sent to
20 comparator circuits where the input signals are compared to
21 predetermined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



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

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

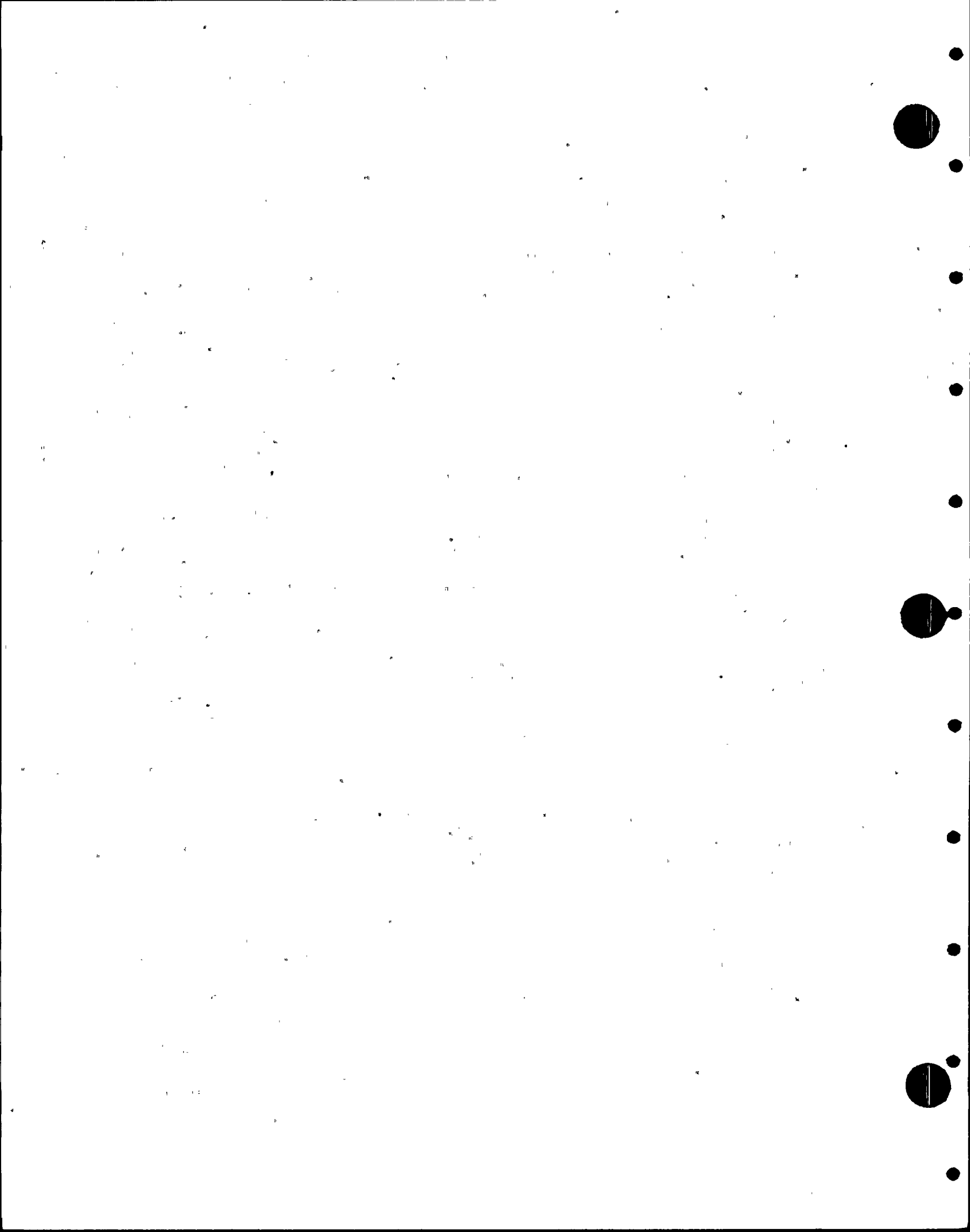
20 Exhibit 2A1-18. The two initiating signals are
21 arranged in a one-out-of-two logic in each actuation channel.
22 Actuation of either signal de-energizes the group relay
23 associated with that channel and results in an actuation
24 signal. Each channel is supplied from a separate 125 volt
25 AC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



1 bus.

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

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

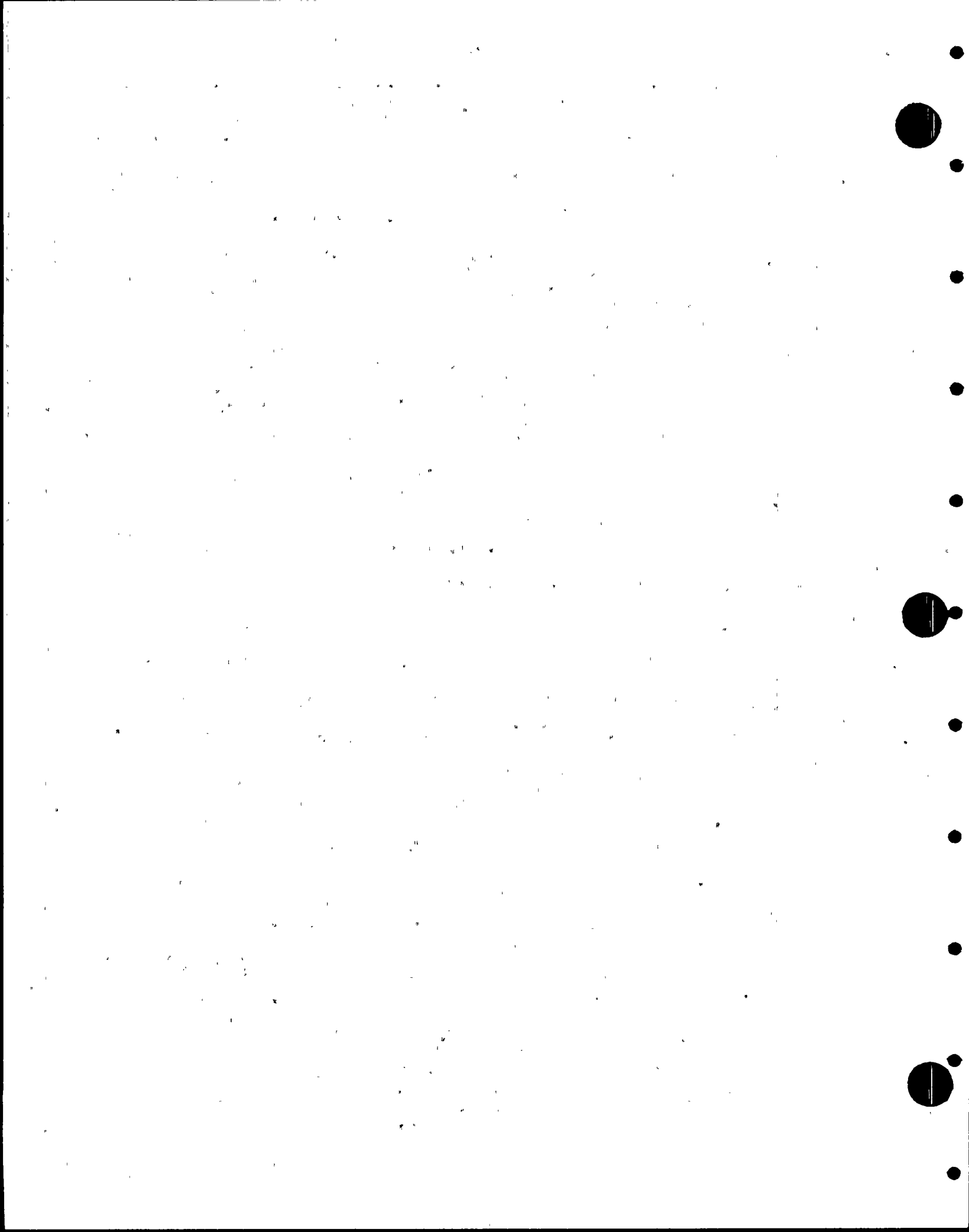


1 annunciated visually and audibly to the operator. This is
2 on the front of the BOP ESFAS cabinet, annunciation to the
3 control room operator via the plant annunciator.

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

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

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

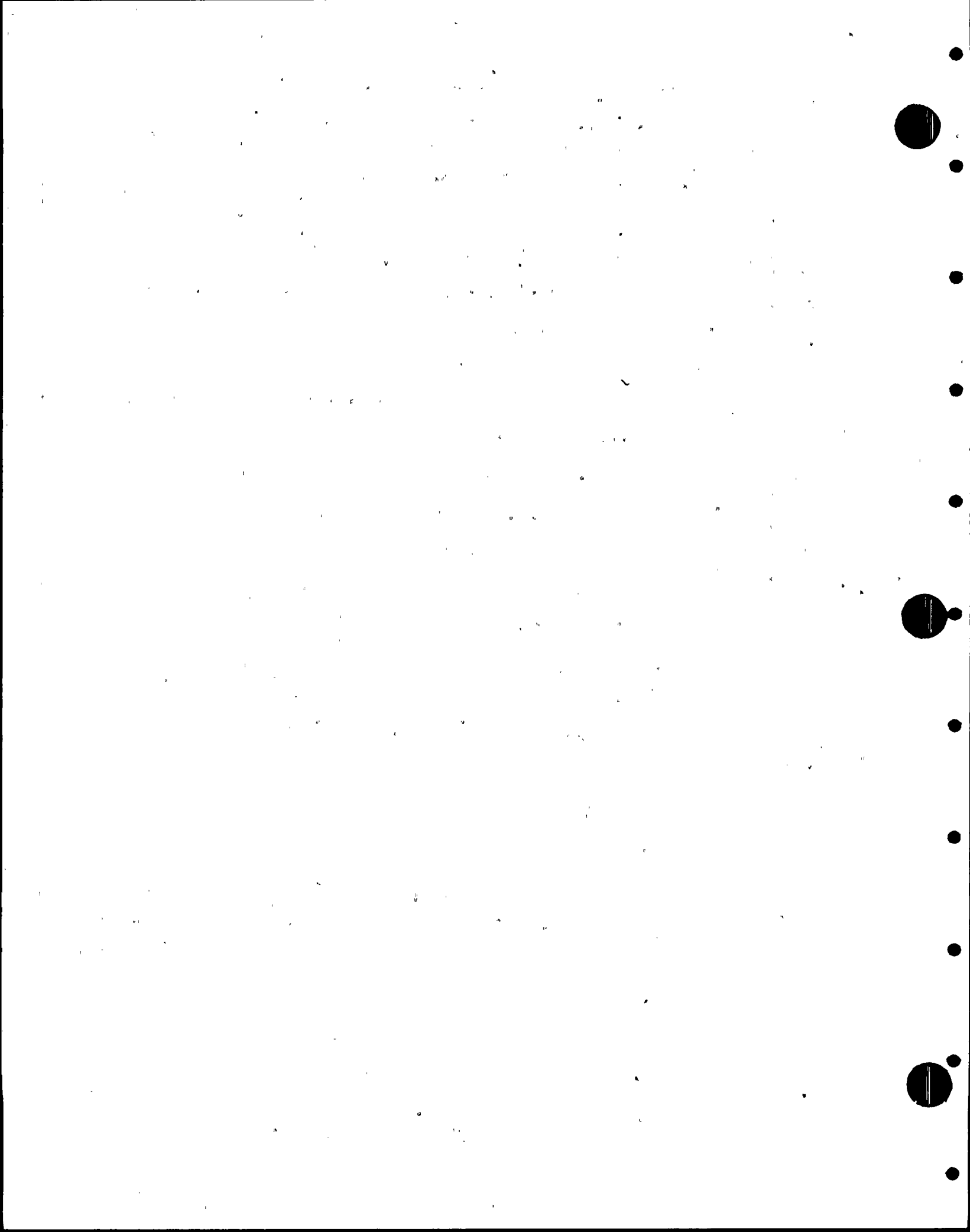


1 actions, control actions, and the environmental changes that
2 cause, or are caused by, the design basis events do not
3 prevent the mitigation of the consequences of the event.

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

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

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



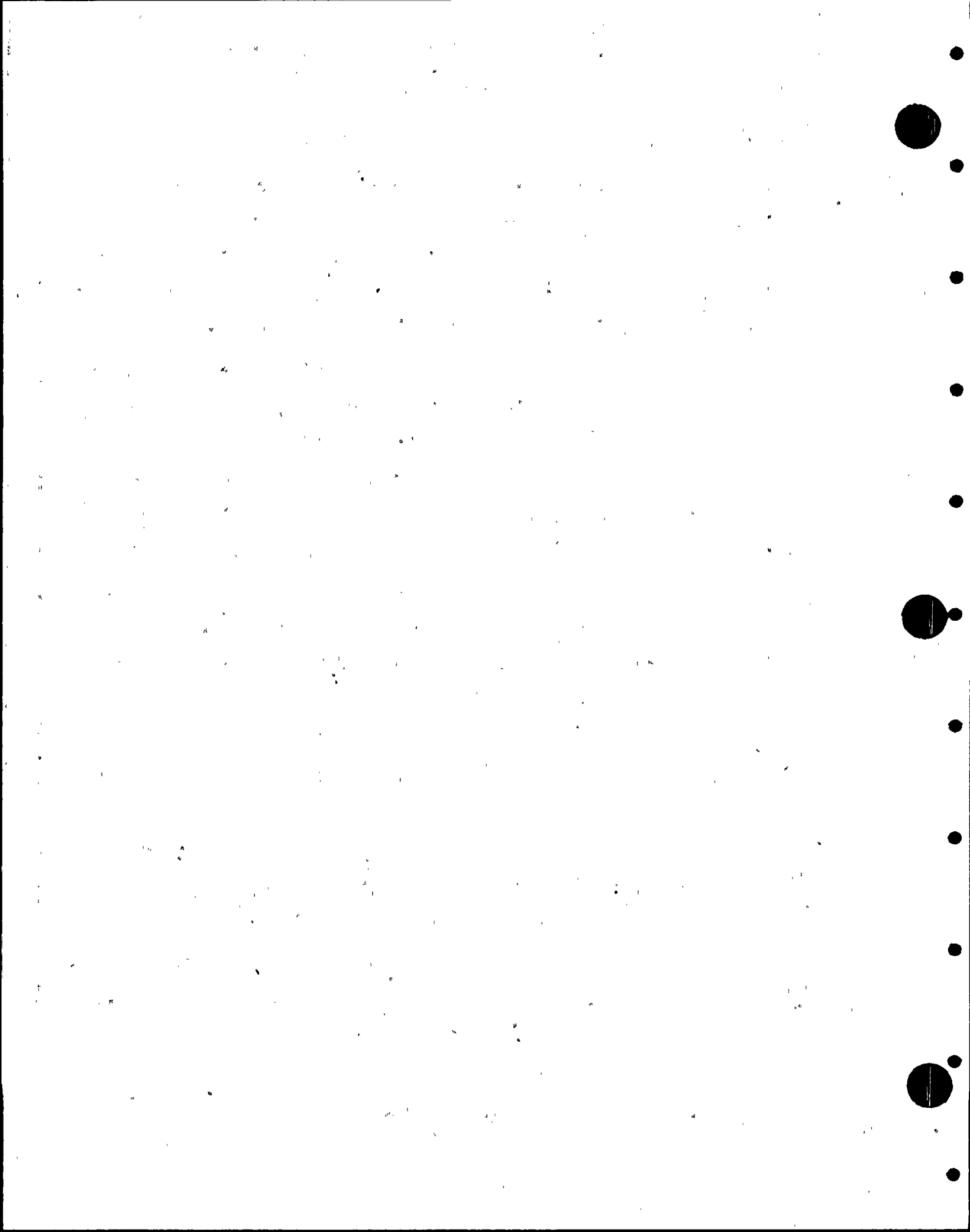
1 input signal to the trip setpoint level on one bistable at
2 a time and observing the trip action, and it is done at this
3 point (indicating) entering the bistable.

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

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

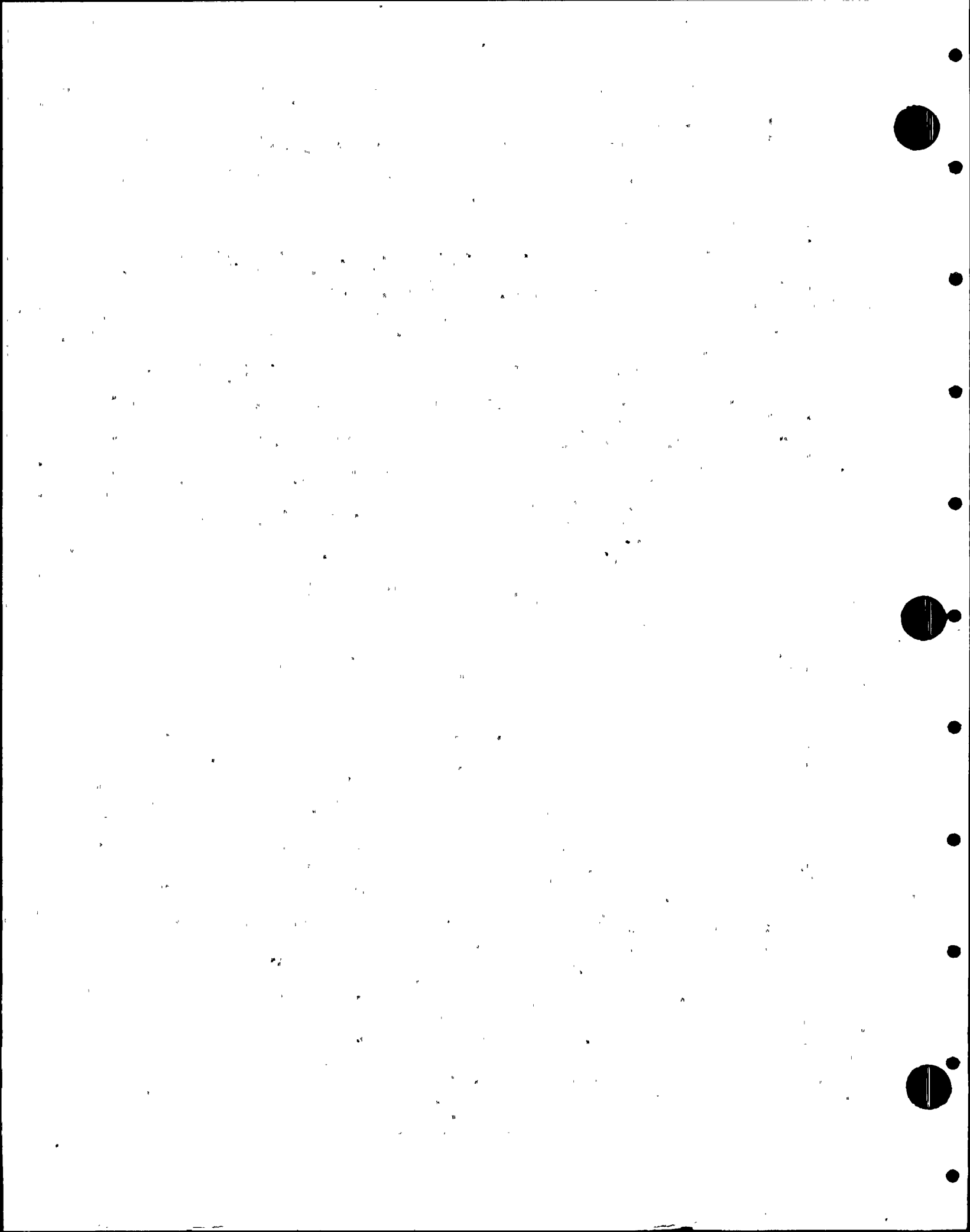
17 Continuing on with Exhibit 2A1-26, response time
18 testing. Response time testing will be performed at refueling
19 intervals. These tests include the sensors for each ESFAS
20 channel and are based on the previously defined system
21 response time criteria.

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



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

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

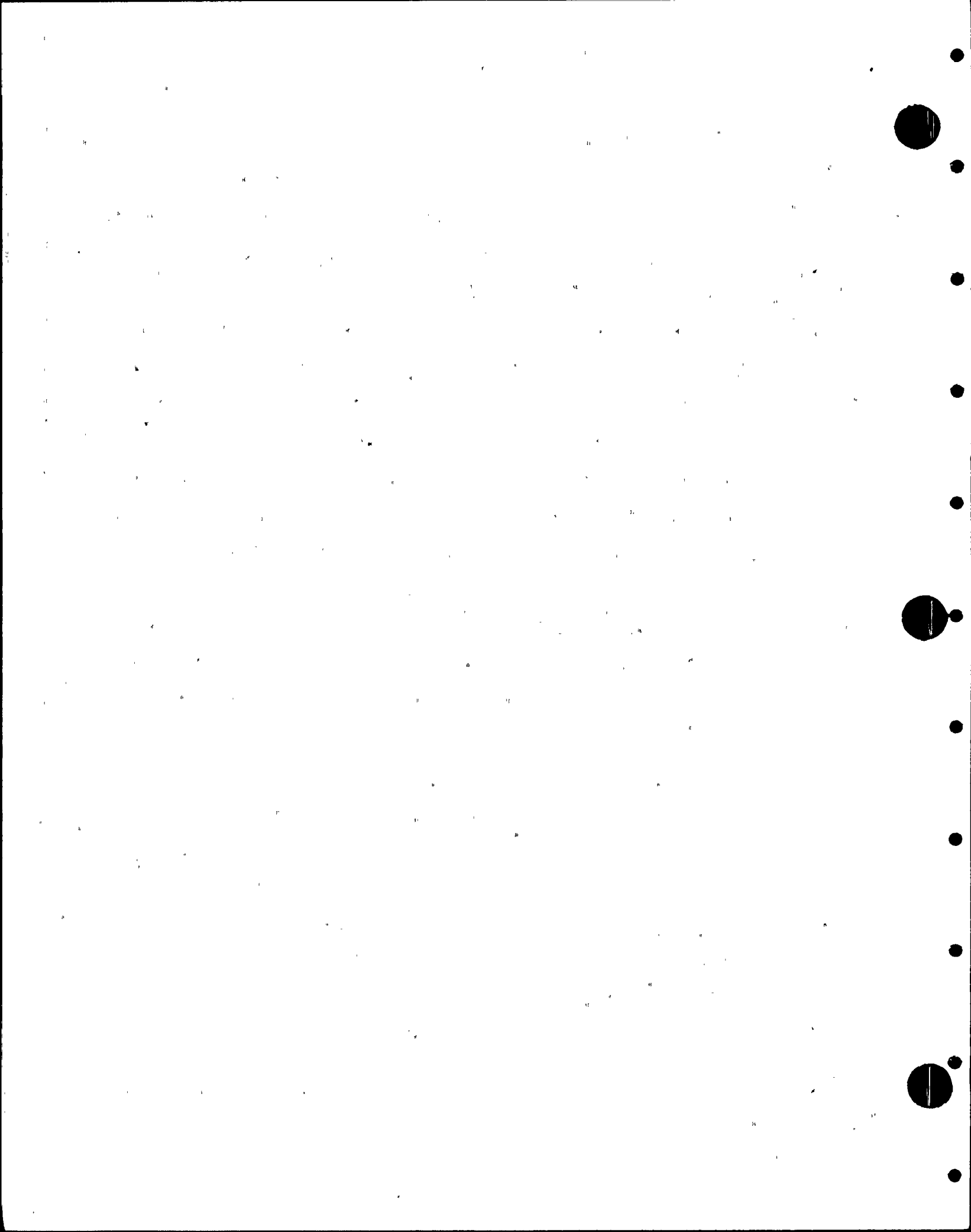


1 Exhibit 2A1-28. The system is designed such that
2 a loss of electric power to one-out-of-two like channels
3 will cause a fuel building essential ventilation actuation
4 signal and actuate the system. Manual initiation of the fuel
5 building essential ventilation system is provided in the
6 control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

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

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

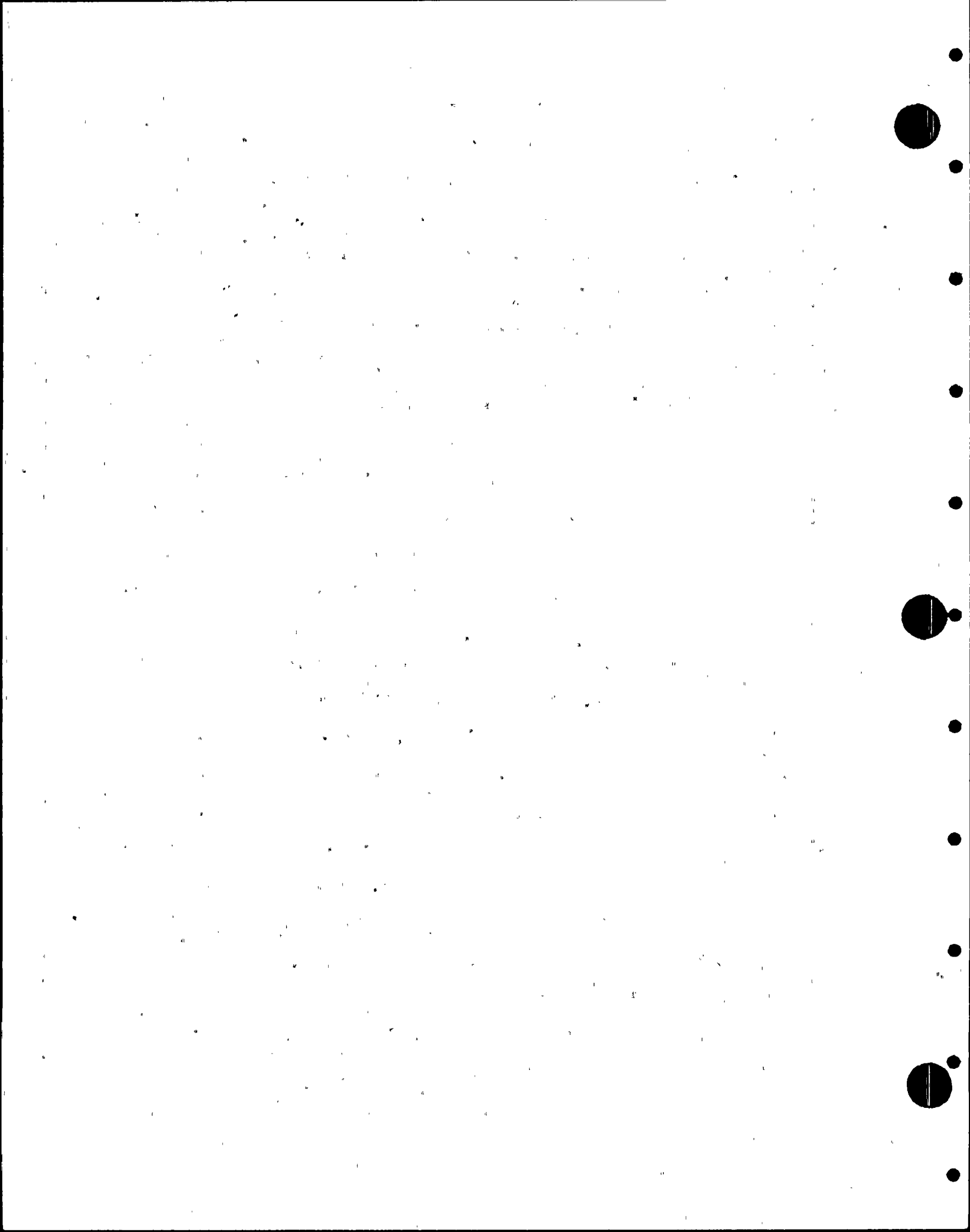
25 Back to Figure 2A1-4. On the SIAS mode, intake



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

6 Continuing on with another ESF system, Exhibit
7 2A1-30, the containment purge isolation system. In the event
8 of a fuel handling accident inside the containment, sensors
9 will detect the fission products released from the fuel.
10 Containment purge isolation actuation signal is initiated
11 by one-out-of-two high airborne activity signals from
12 redundant radiation monitors located in close proximity with
13 the power access purge exhaust duct and the refueling purge
14 exhaust duct. These two monitors are shown on Figure 2A1-6.
15 The containment purge isolation system is automatically
16 actuated by the CPIAS from the BOP ESFAS to prohibit release
17 of radioactive material into the environment. The CPIAS
18 also sends a signal to the CREFAS logic, which we will get
19 into in a few minutes.

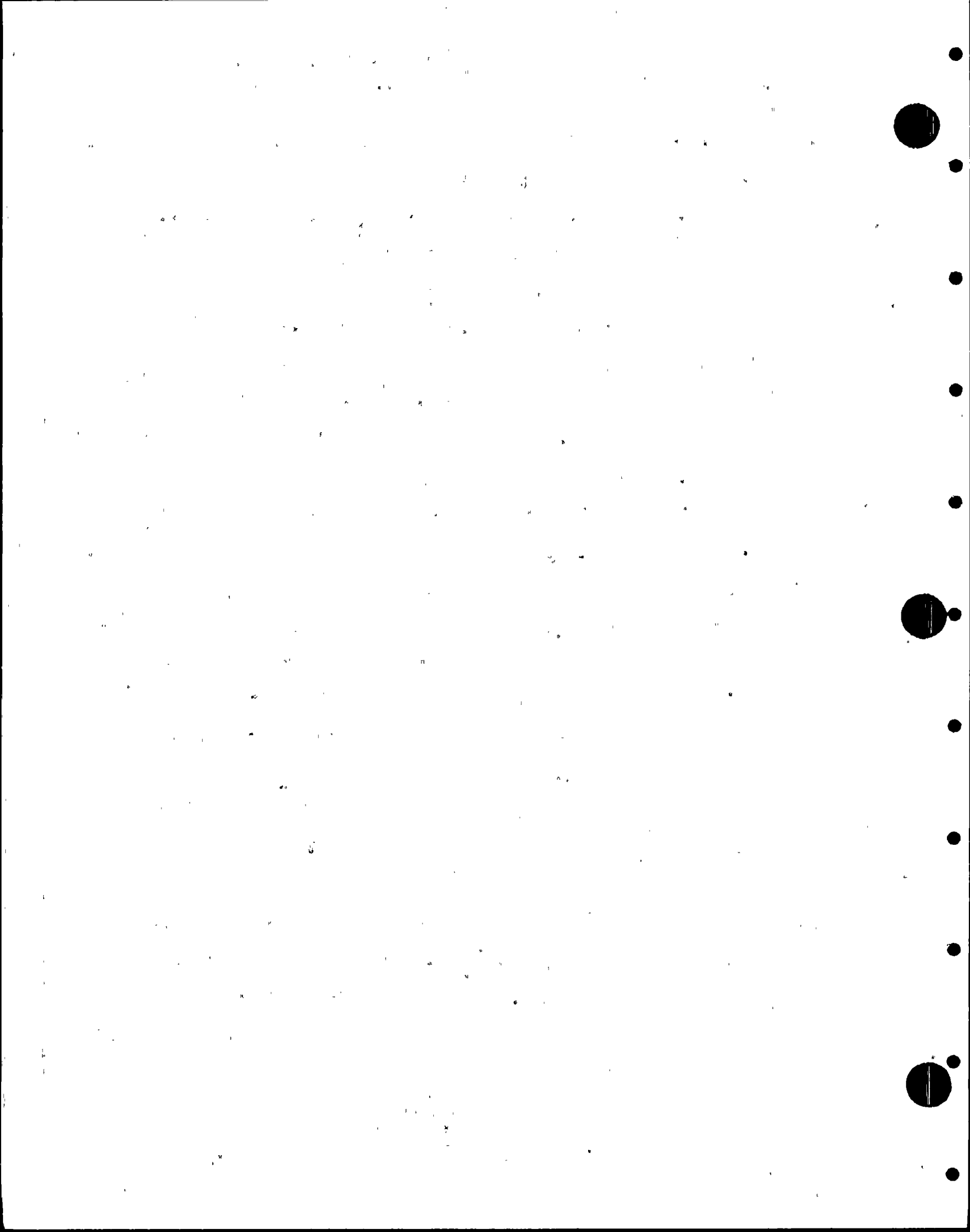
20 Exhibit 2A1-31. The system is designed so that
21 loss of electric power causes actuation. Manual initiation
22 is provided in the control room. The containment purge
23 isolation system is composed of components in redundant load
24 groups such that independence and redundancy is maintained
25 to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



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

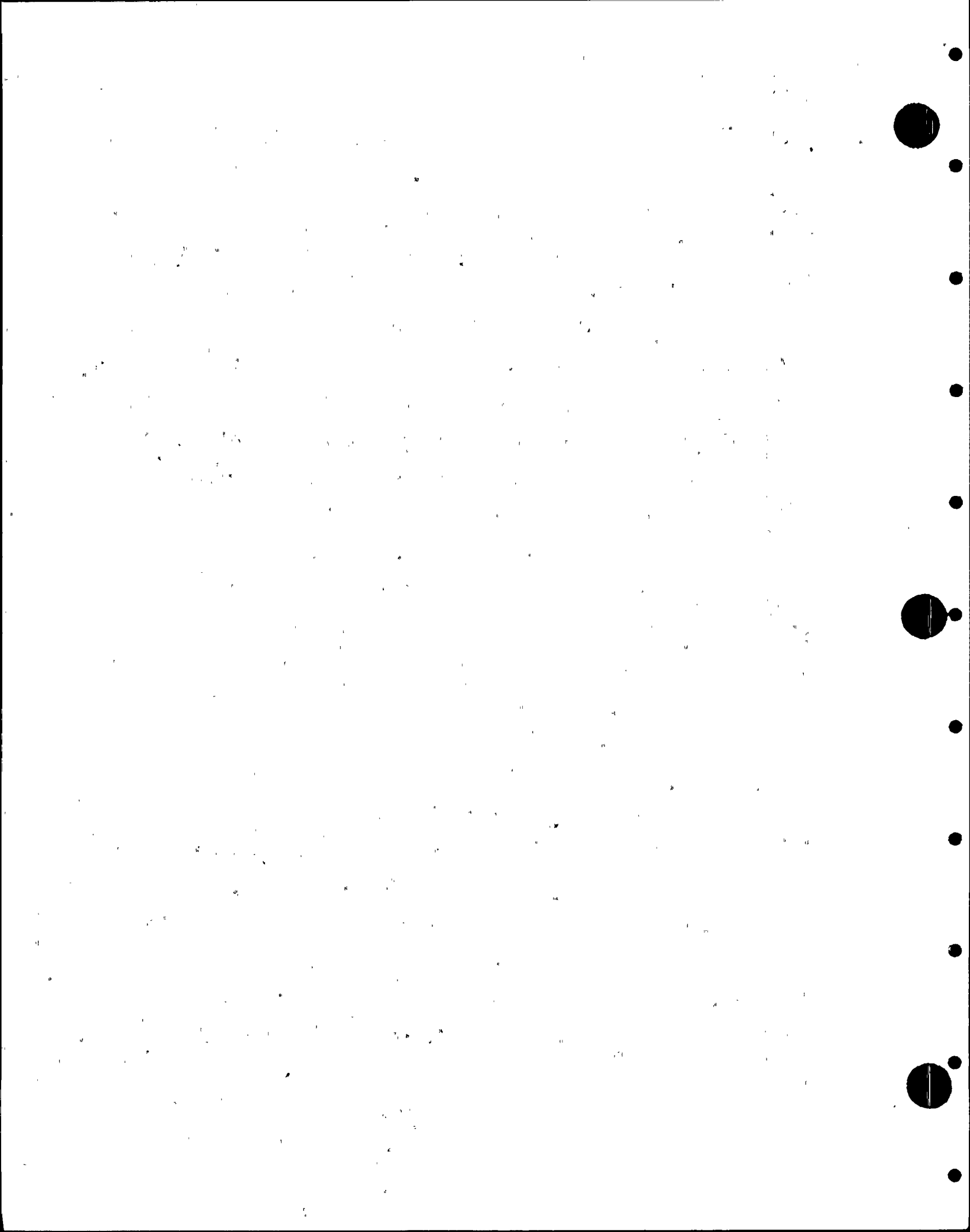
5 Exhibit 2A1-32, our control room essential
6 ventilation systems. The control room essential ventilation
7 systems are the control room isolation system and the
8 control room essential filtration system. The control room
9 ventilation isolation actuation signal, CRVIAS, is initiated
10 by one-out-of-two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

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



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

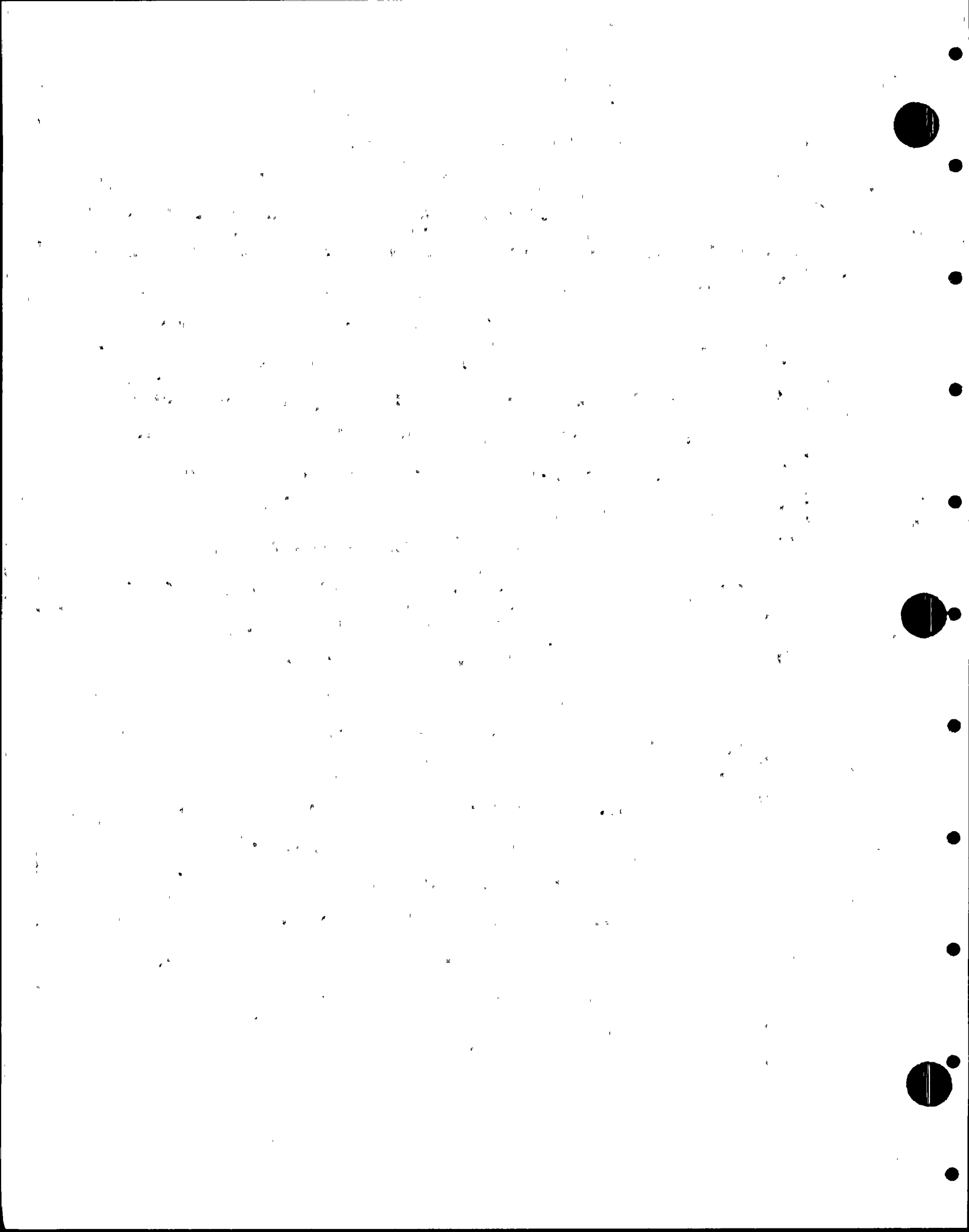
17 Exhibit 2A1-34. Both of the systems are composed
18 of components in redundant load groups and CREFAS is combined
19 with the SIAS in the device control circuits so that any one
20 of the signals does actuate the required components. Figure
21 2A1-11 shows a typical actuating device logic. This is for
22 one of the dampers that closes on the CRVIAS and will open
23 on an SIAS or a CREFAS, the logic being combined at the
24 device level. The CRVIAS is combined with the signals that
25 actuate the control room essential filtration system in the



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

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

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



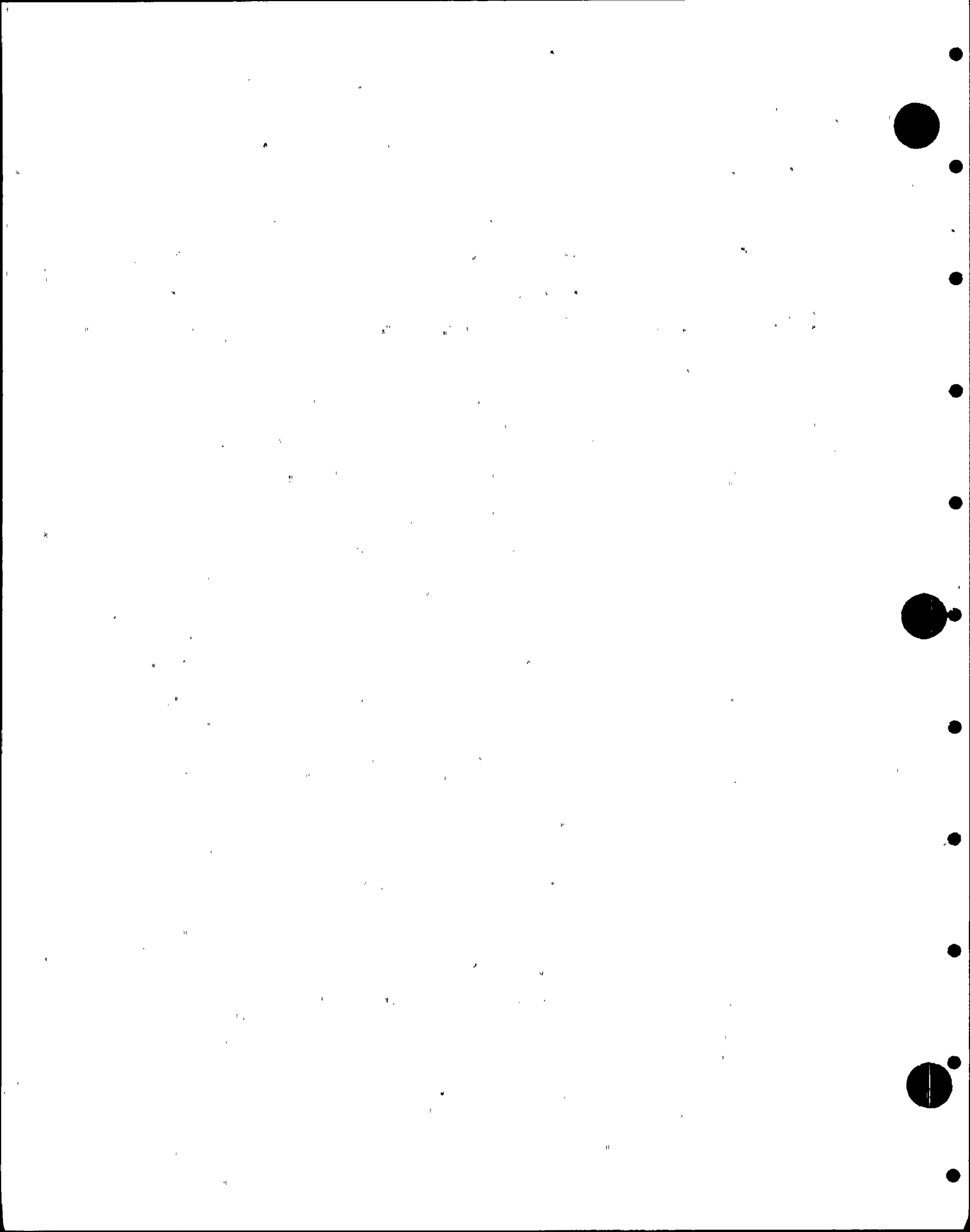
1 located at local panels. The local panel will be accessible
2 after a design basis event.

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

20 That concludes the BOP ESFAS presentation.

21 MR. BINGHAM: Any questions.

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



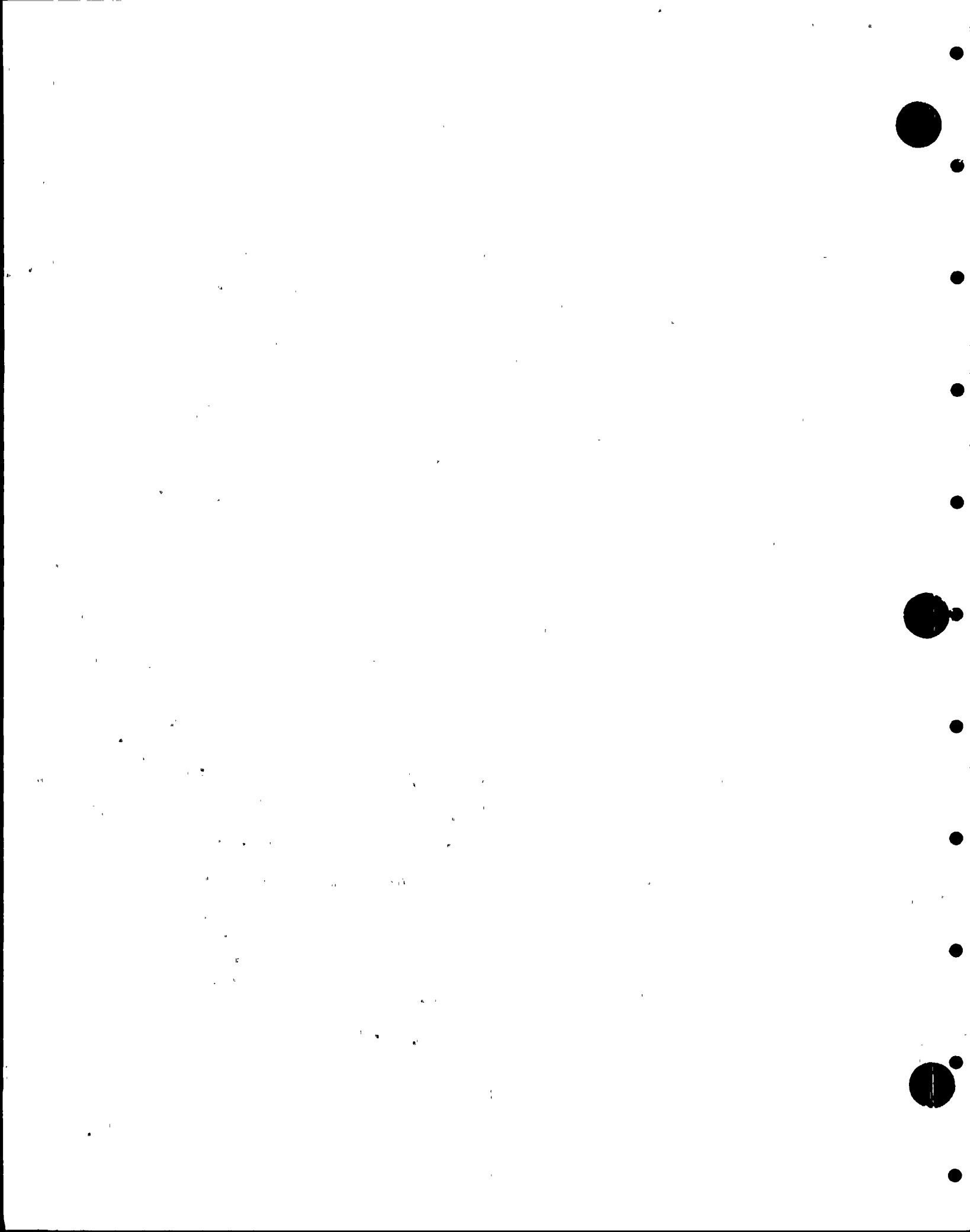
1 a little more detail how that is accomplished? Particularly
2 I am concerned about what means is provided to assure that
3 the system is returned to normal following the test.

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

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

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

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



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

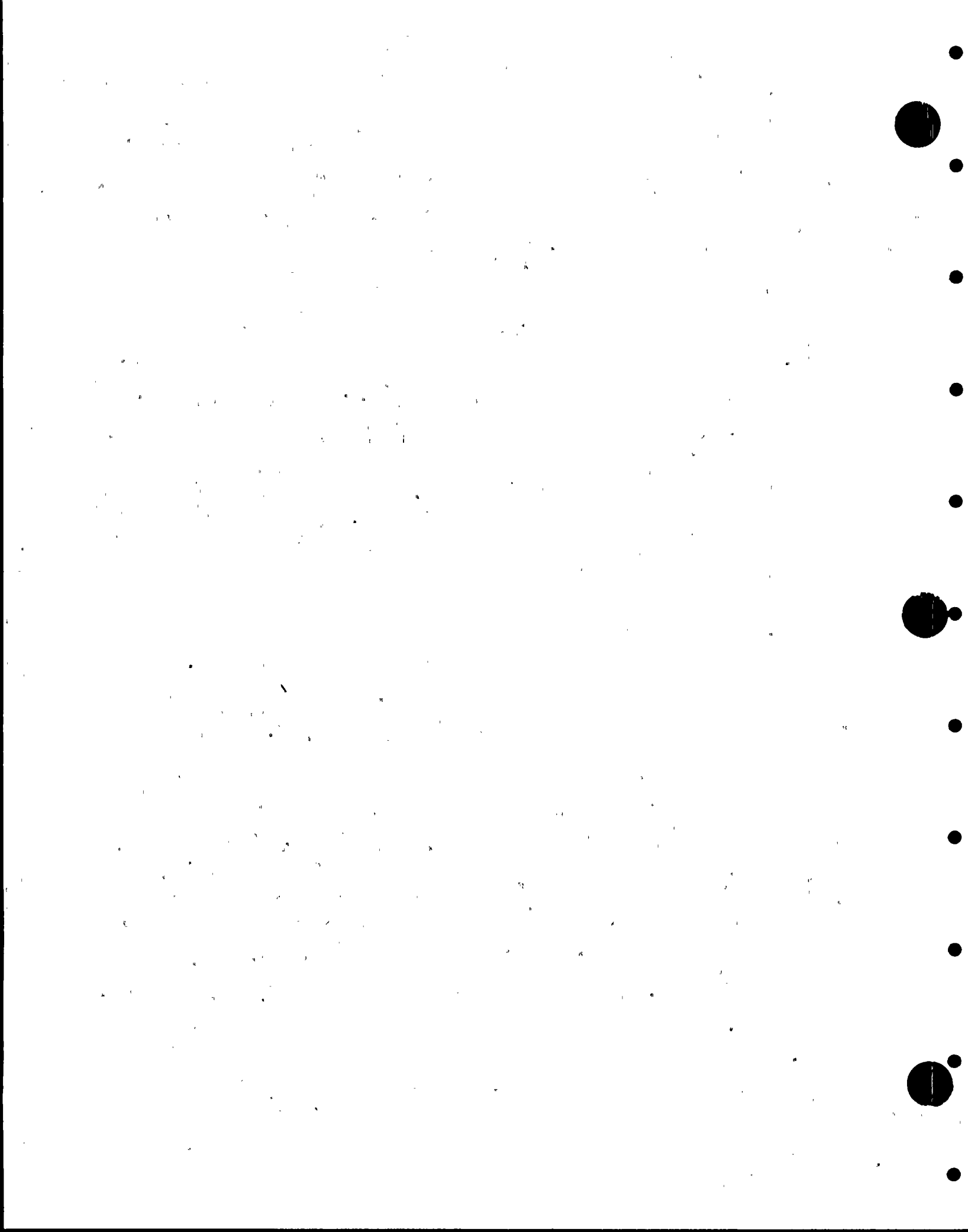
3 MR. BINGHAM: Let's have Steve Shepherd answer that
4 question, since it is part of the radiation monitoring
5 system we are dealing with right now.

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

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

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

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



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

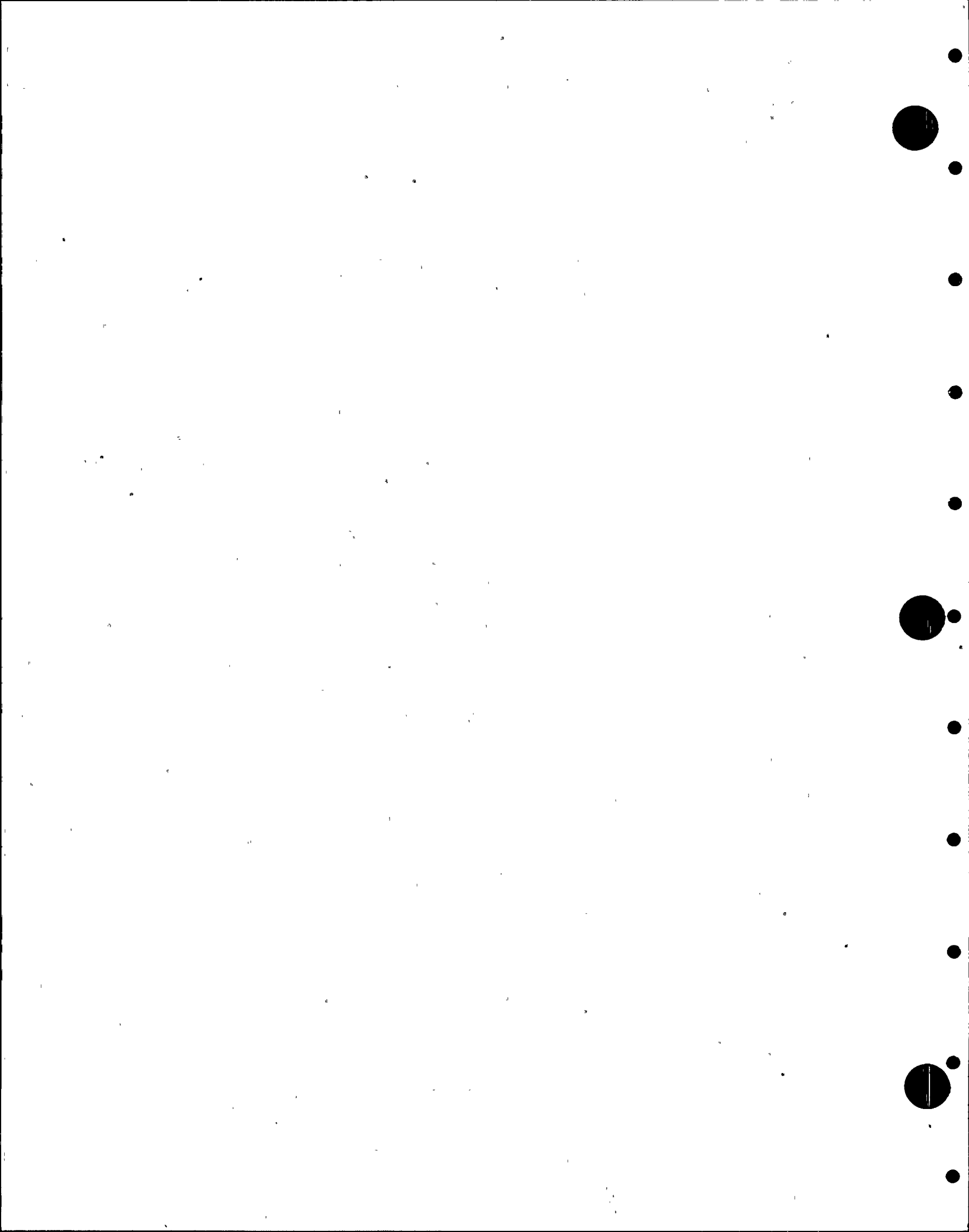
13 MR. ALLEN: One thing you want to remember here, Jack,
14 he is talking just about the radiation monitoring and not
15 necessarily bistables and some of the other stuff, because
16 that's different.

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

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

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

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



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

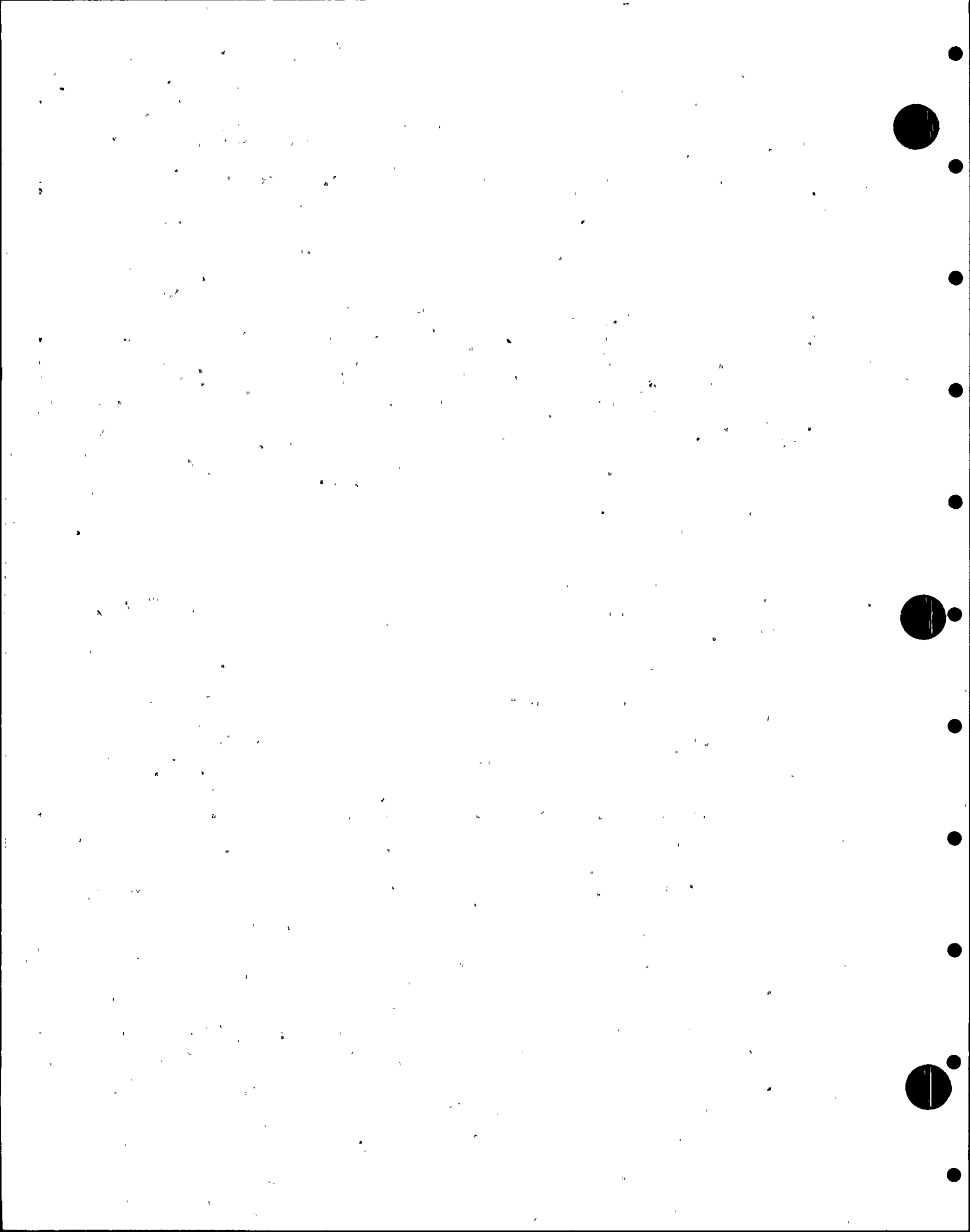
5 MR. SOTEROPOULOUS: The hydrogen analyzer as it is
6 presently mechanized to test, we could put the device into
7 a calibrated mode where we could inject into the system a
8 4% concentration of hydrogen and the system would go into
9 alarm.

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

12 MR. SOTEROPOULOUS: It would be an annunciator alarm.

13 MR. KONDIC: Thank you.

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



1 this presentation, Bill?

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

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

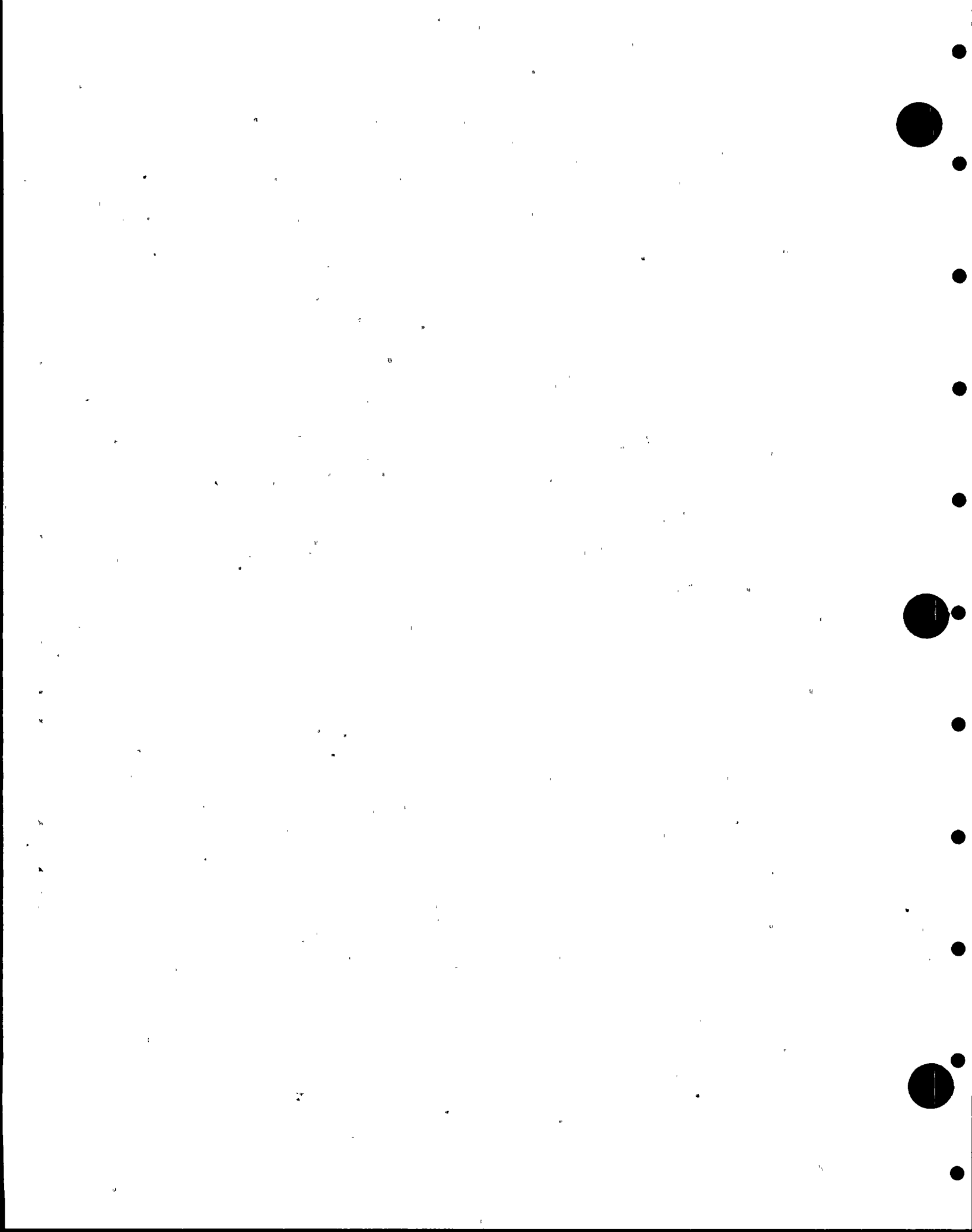
12 MRS. MORETON: The testing of the ESFAS would have
13 been covered at the Combustion Engineering review. The
14 testing of the components would be covered at those various
15 system reviews.

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

21 MR. BESSETTE: That's correct.

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

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



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

5 MR. ROGERS: Will that be discussed here?

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

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

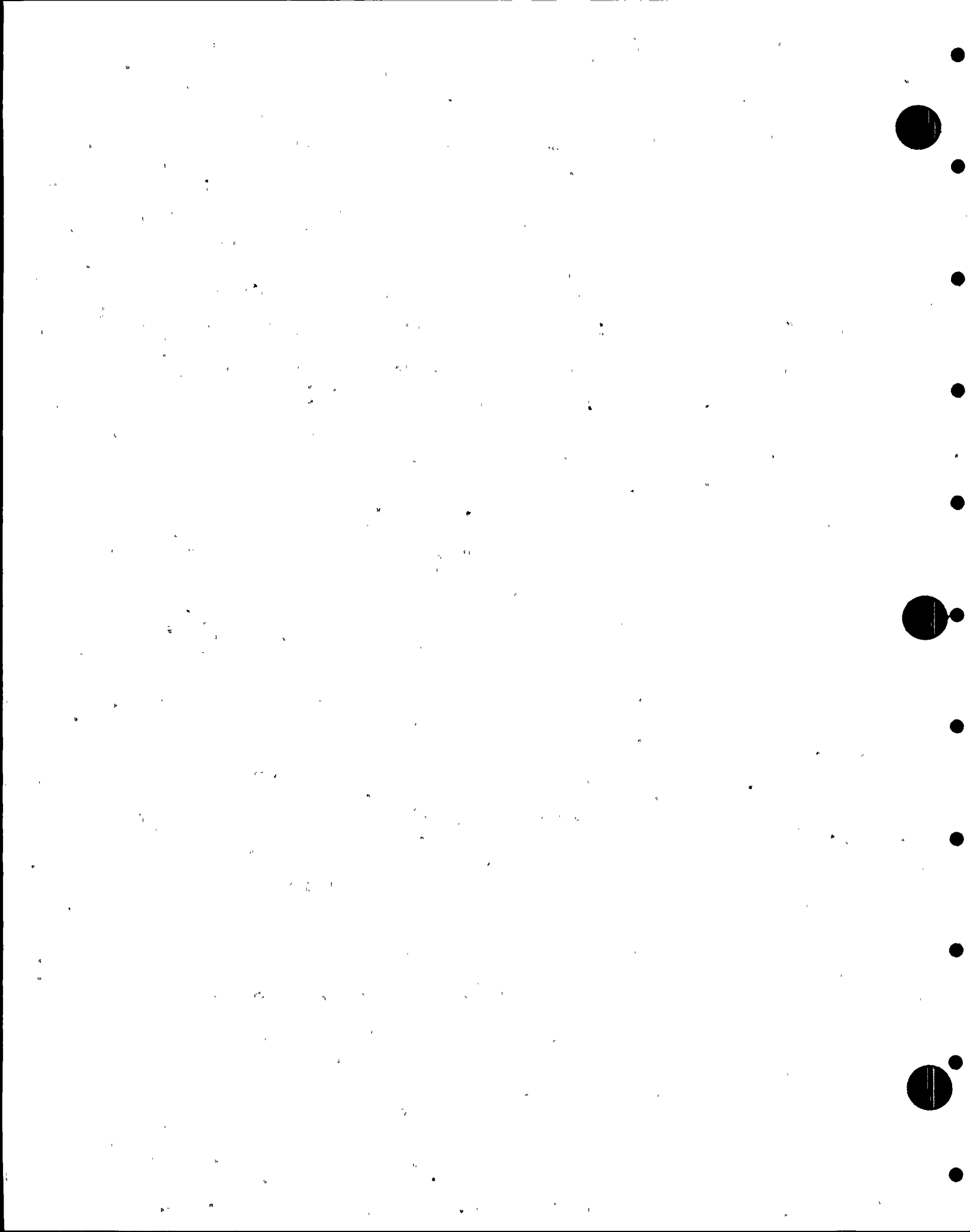
11 MRS. MORETON: The atmospheric dump valves are part
12 of the safe shutdown system and they will be discussed when
13 we discuss the safe shutdown system.

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

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

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

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



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

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

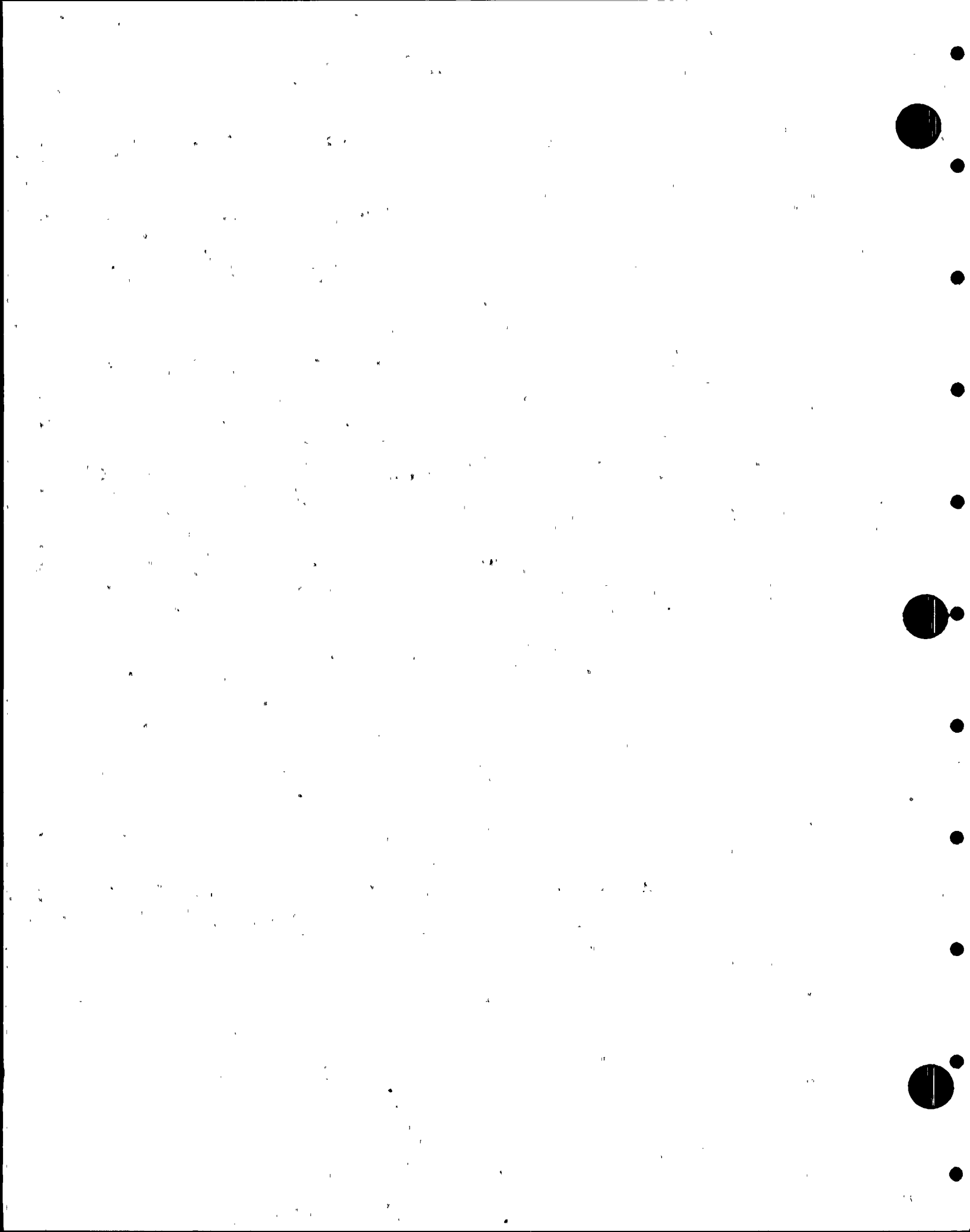
19 MR. ROGERS: Bill, I understand that, but I was
20 confused.

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

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

24 MRS. MORETON: No.

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



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

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

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

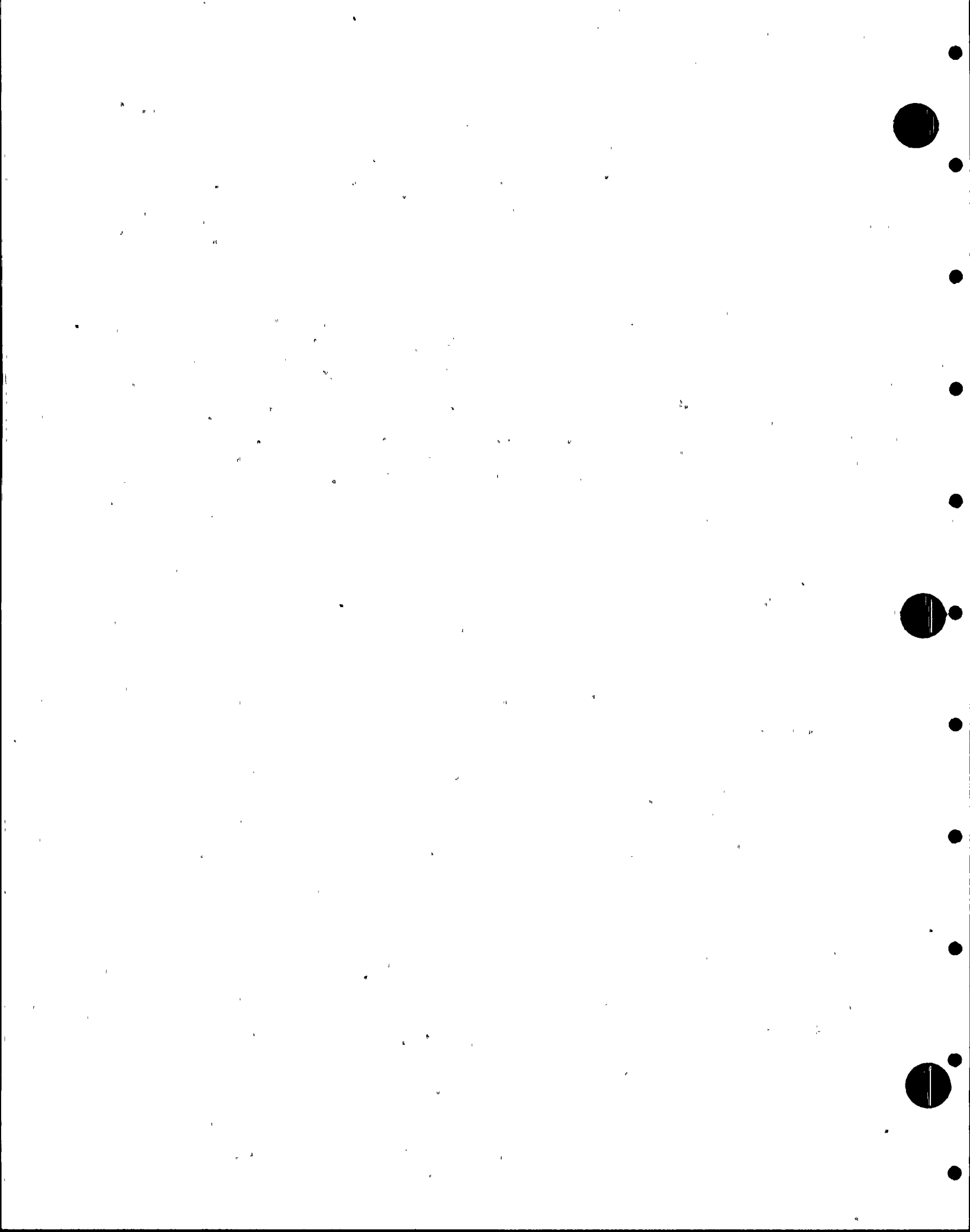
13 MR. BINGHAM: I am not sure. Let me just find out.
14 We have the louvers. Whether they are steel are not, there
15 is protection.

16 MR. ALLEN: Are there additional questions?

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

20 MRS. MORETON: Yes.

21 MR. MECH: In reference to Figure 2A1-11 and possibly
22 12, this is a logic diagram and it shows indicating lamps
23 for valve position. The first part of the question, does
24 Palo Verde use a standard system for valve lamp indication
25 or valve wiring such as to provide the indication?



1 MR. BINGHAM: Could you please repeat that?

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

5 MRS. MORETON: Yes.

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

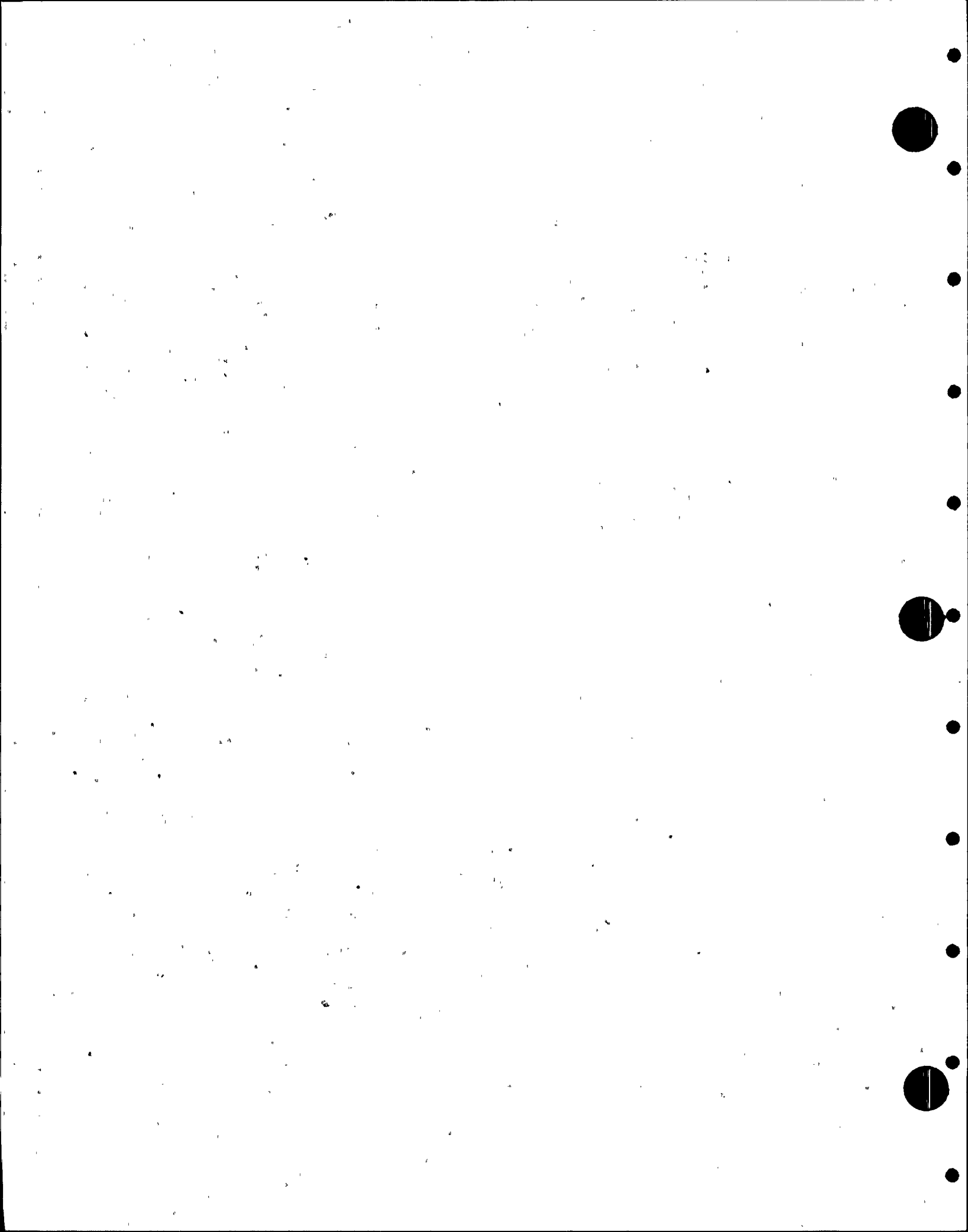
9 MRS. MORETON: They are a direct measurement of
10 valve position.

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

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

22 MR. MECH: Thank you.

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



1 state?

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

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

10 MRS. MORETON: Correct.

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

13 MRS. MORETON: Yes.

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

16 MRS. MORETON: Yes.

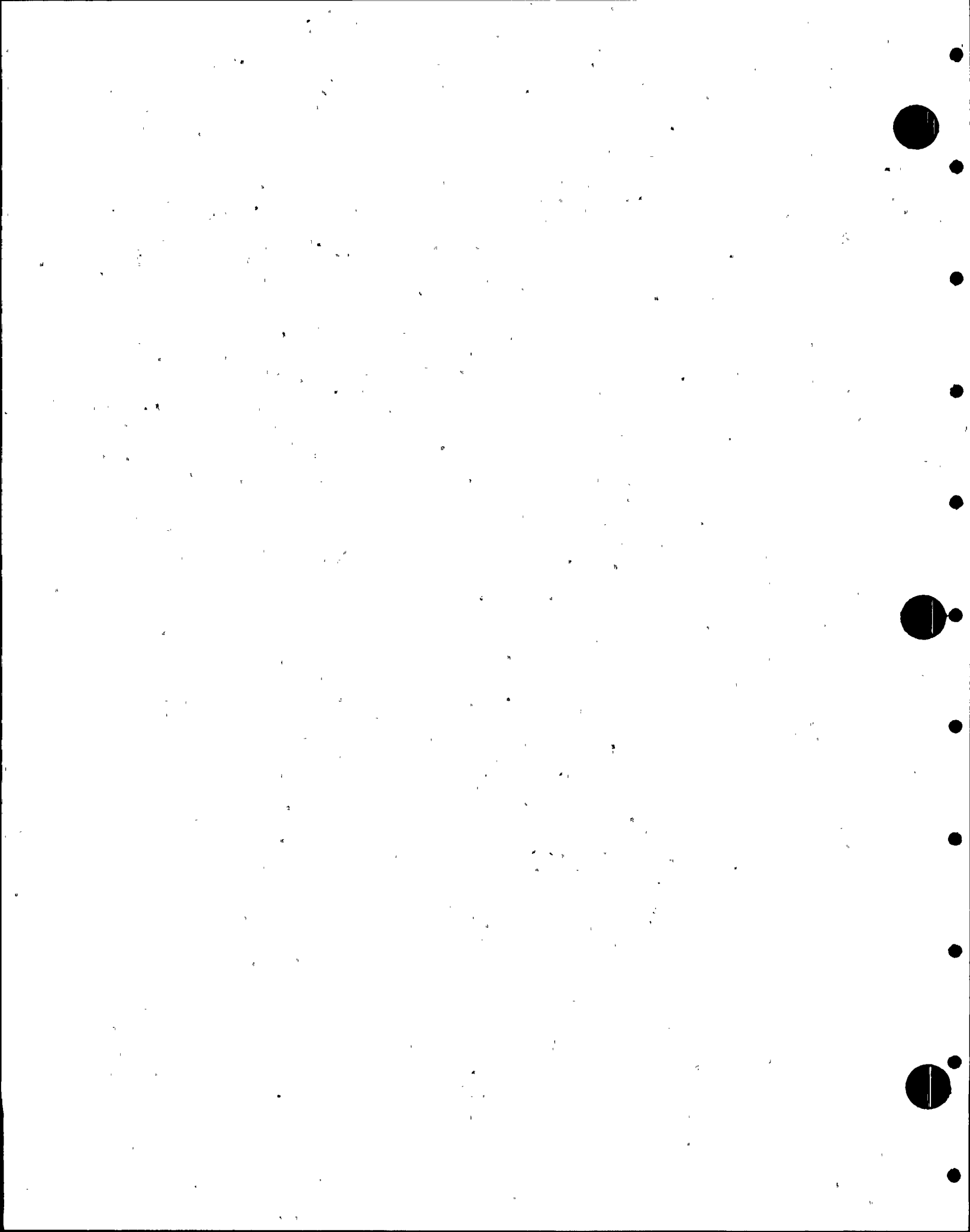
17 MR. ALLEN: Questions?

18 MR. ROSENTHAL: Yes, please. First, on 2A1-37, I take
19 it that the containment combustible gas control system is
20 installed for the purpose of showing it conforms with
21 10CFR50.44.

22 MR. BINGHAM: Yes.

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

25 MR. BINGHAM: That's correct.



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

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

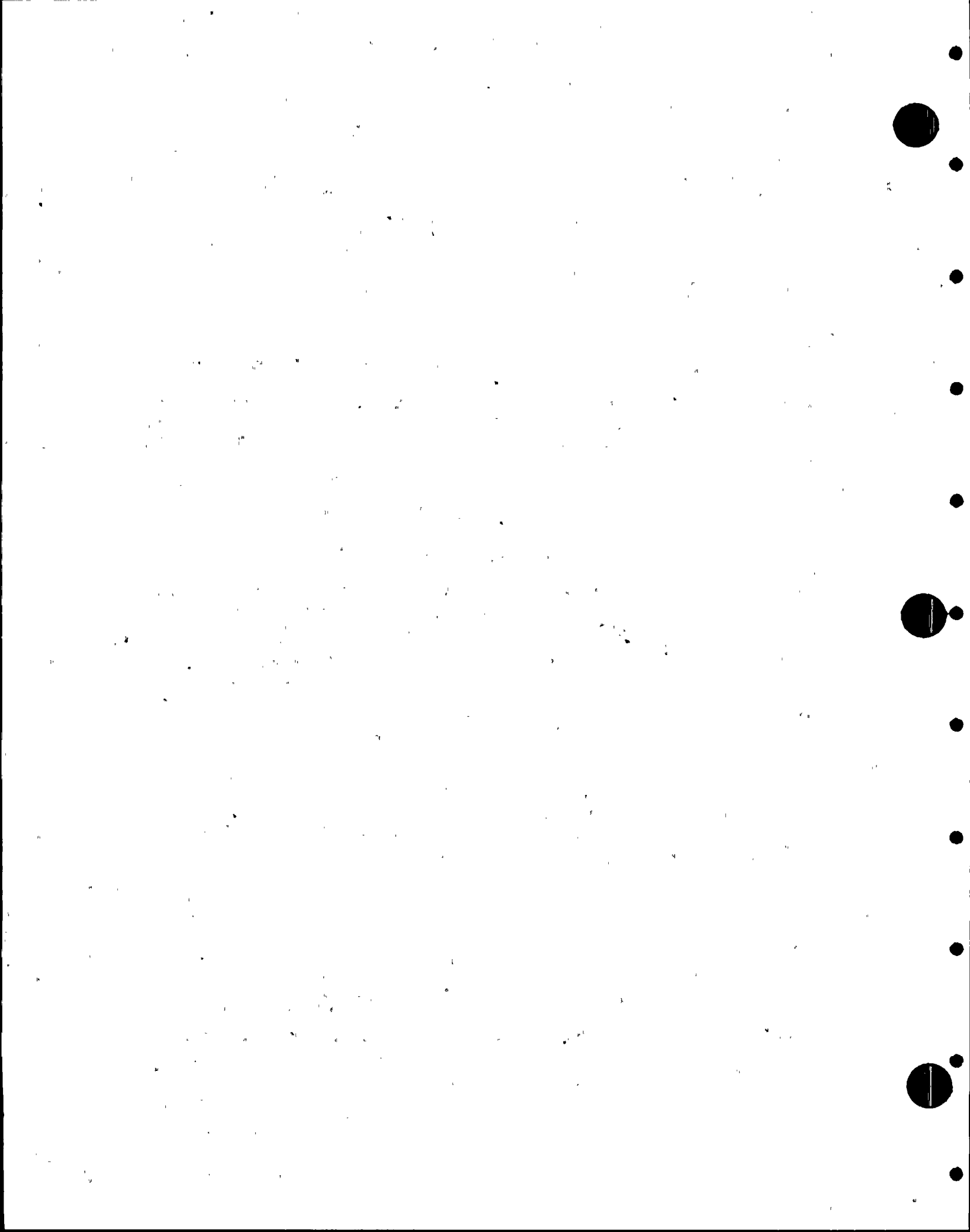
6 MR. ROSENTHAL: 2A1-19. You bypass one of two
7 channels. That is permitted in IEEE 279 where you can show
8 that the bypass time is small relative to its need. You
9 have an assertion as Item B on that page that that bypass
10 time is small. What is the basis for the assertion?

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

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

23 MR. BINGHAM: Let us confer here a minute.

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



1 criterion that was used.

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

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

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

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

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

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

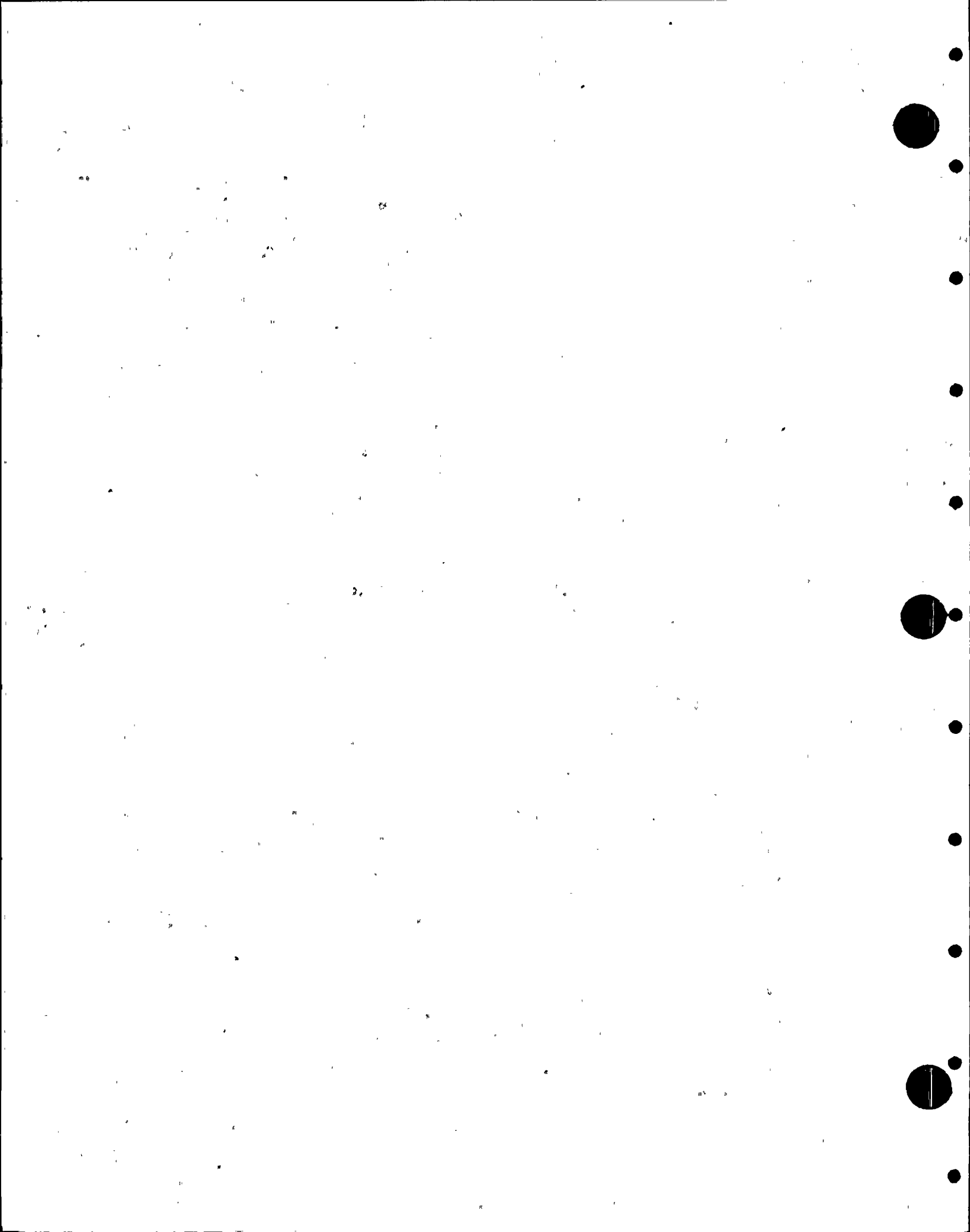
19 MISS KERRIGAN: What is the mini-purge?

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

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

24 MR. SHEPHERD: Eight inch, I believe.

25 MR. ALLEN: Do you have some additional questions,



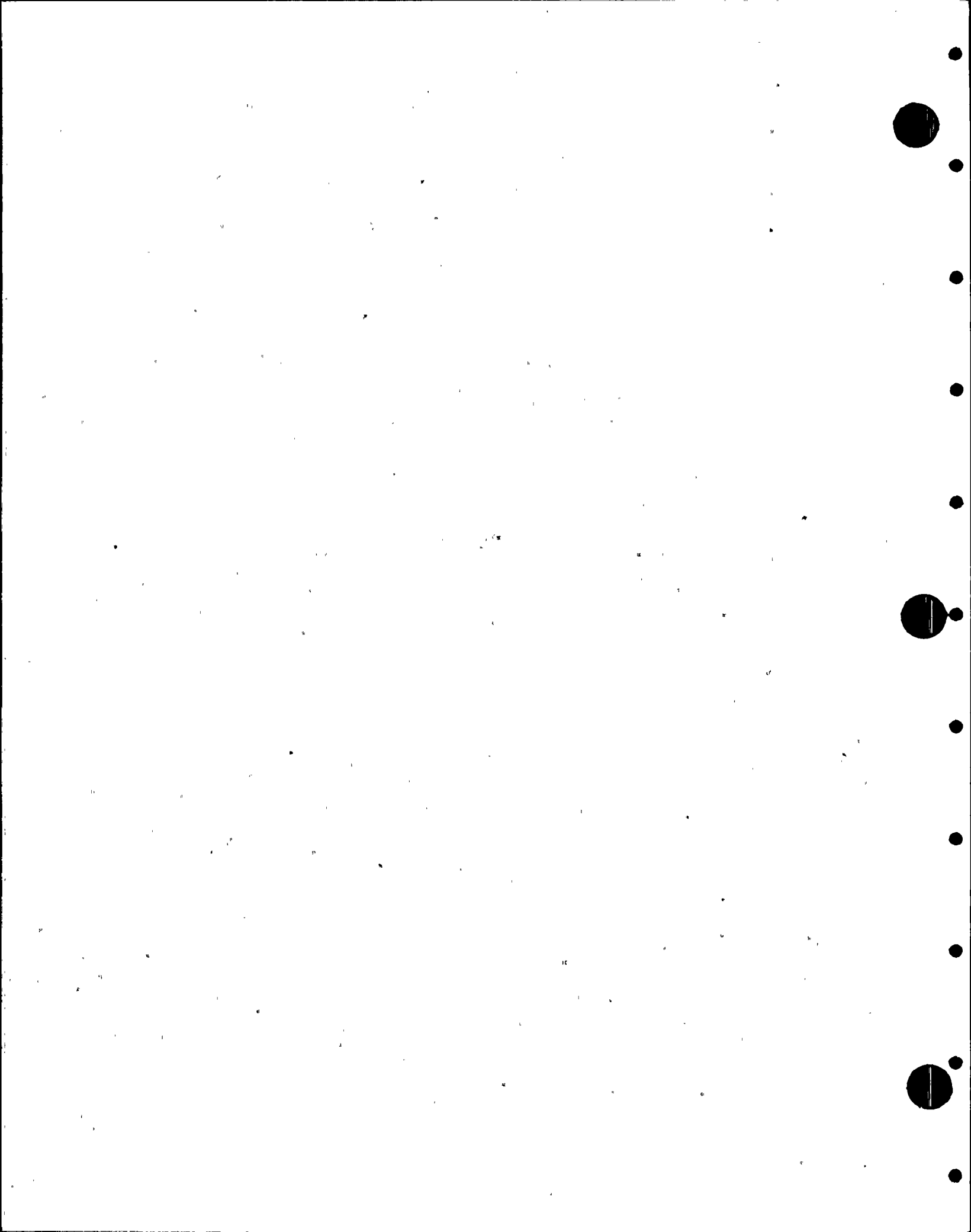
1 Jack?

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

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

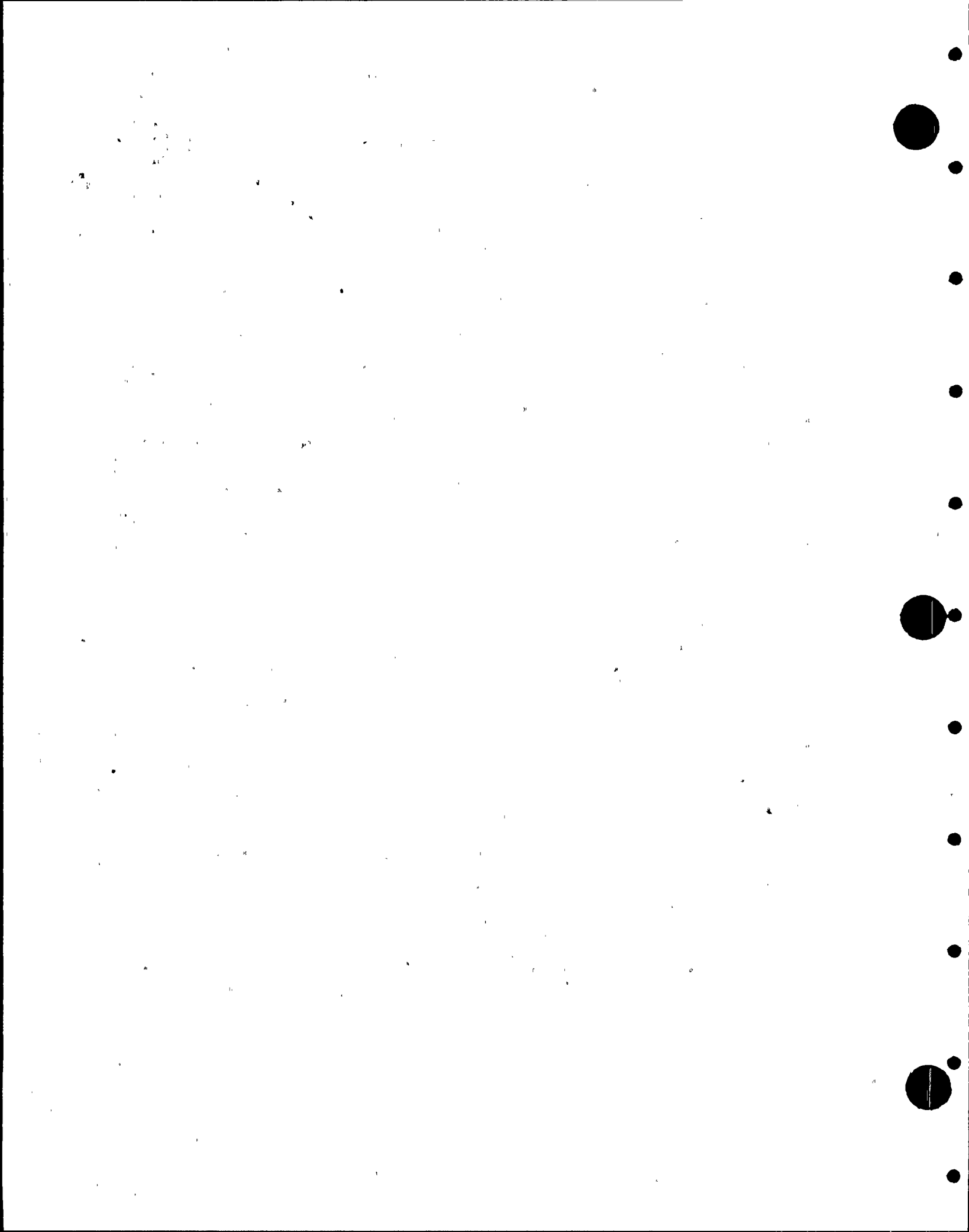
9 MR. ROSENTHAL: I have a one-out-of-two system.
10 Should that system fail, the operator would have the option
11 of tripping that system and continuing to keep the plant in
12 power until we got around to fixing it. In that mode, which
13 could last for some period of time, you would be pumping air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

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



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

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



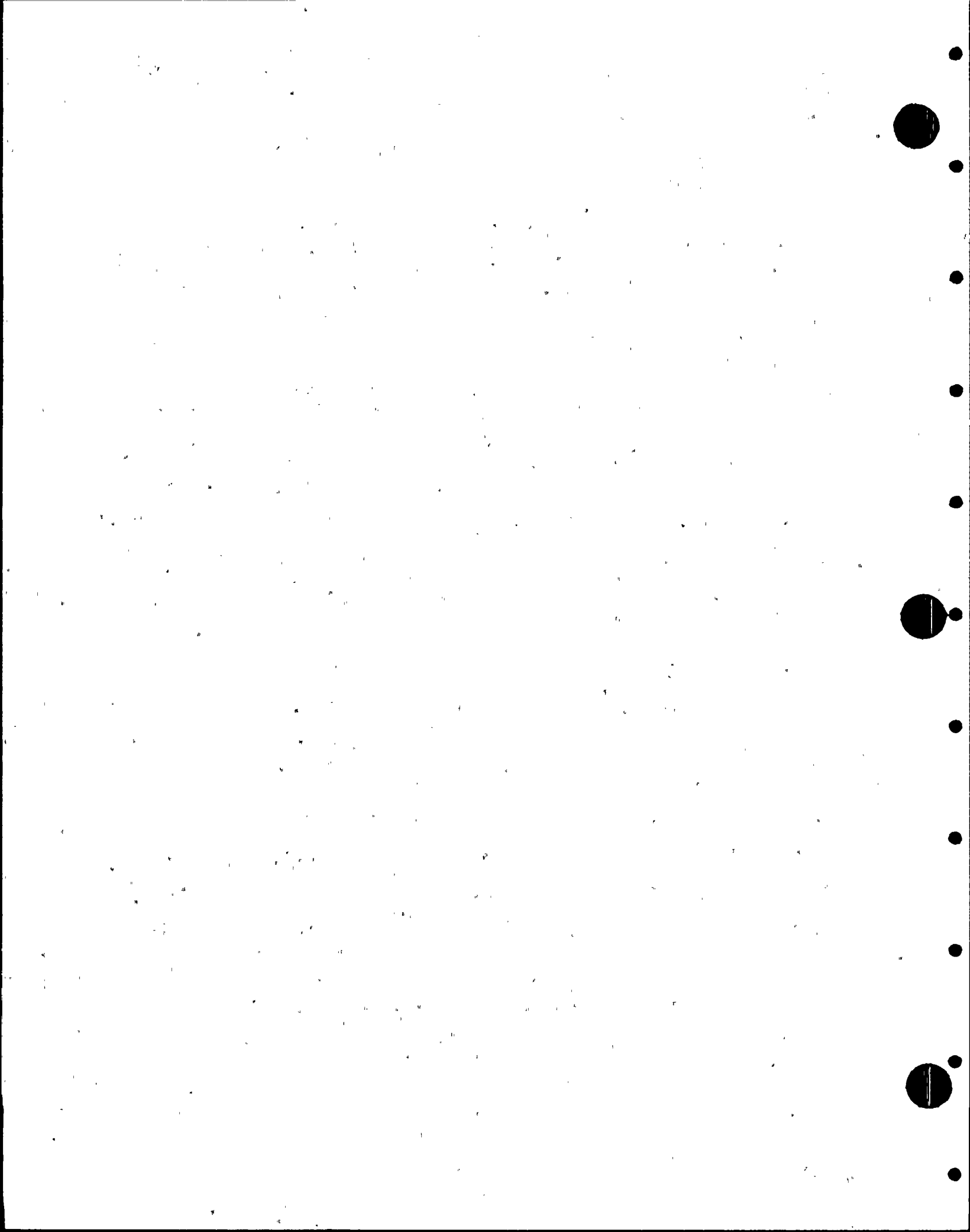
1 the two-out-of-four logic. So we are talking about a
2 relatively limited period of time just during fuel handling
3 operations inside the fuel building when you are worried
4 about this one-out-of-two logic.

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

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

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

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



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

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

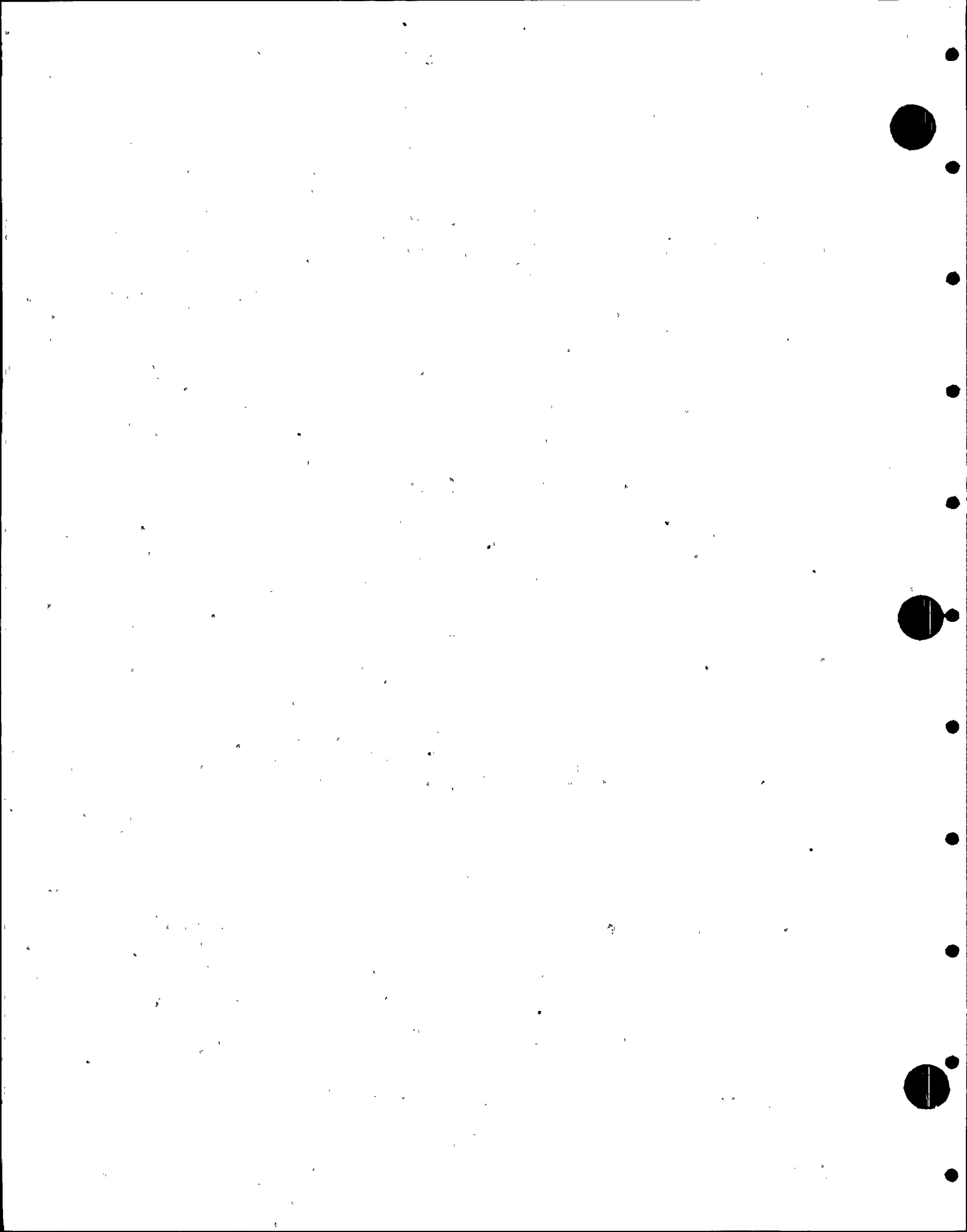
10 MR. BINGHAM: Isn't there also, Jack, another
11 demonstration where you put them all together and demonstrate
12 the system is adequate? I think that is the approach that
13 we have taken.

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

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

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

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



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

7 MR. KEITH: I believe that covers it.

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

15 MR. ALLEN: Or trip the channel.

16 MR. BINGHAM: Or trip, yes.

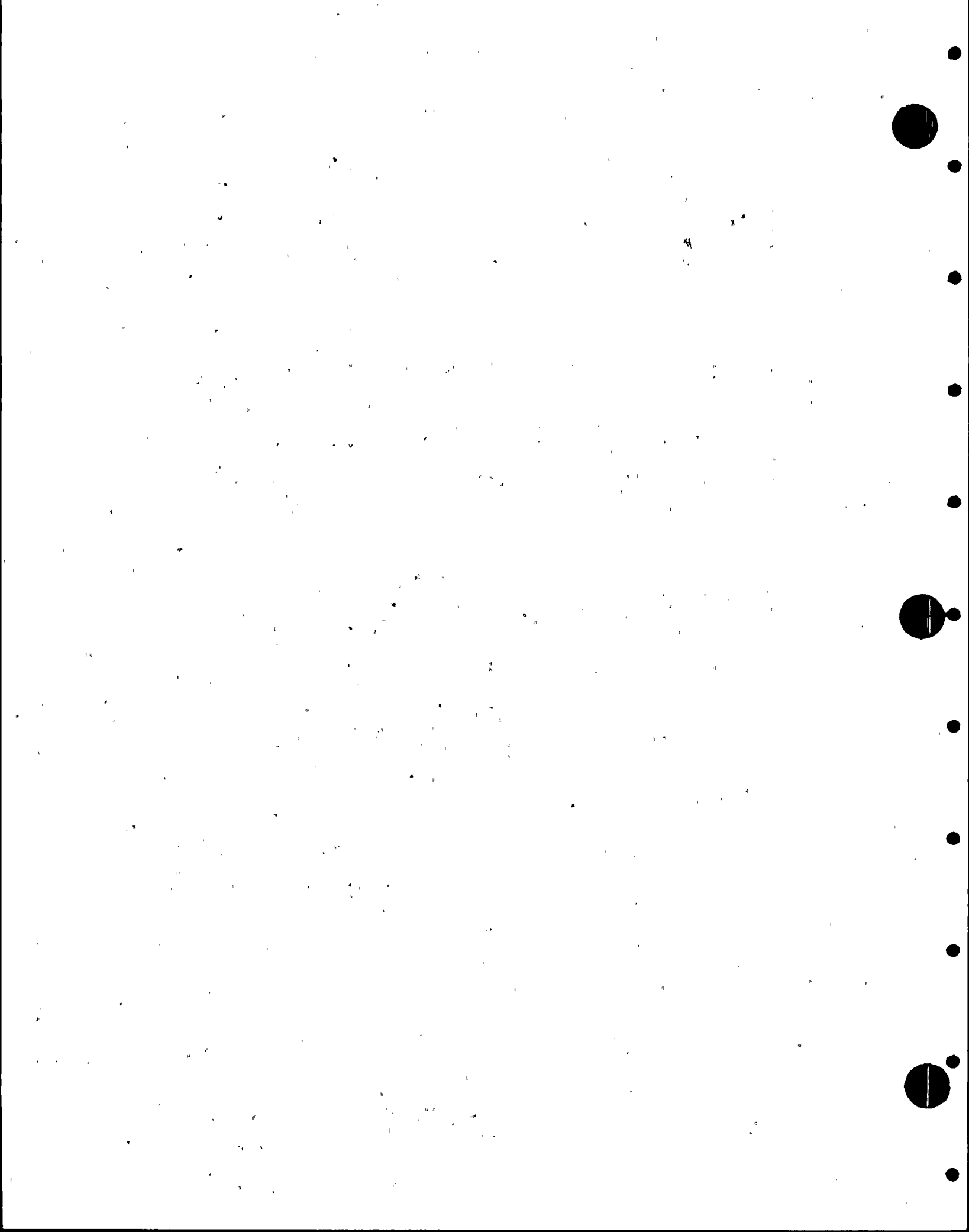
17 MR. ALLEN: Is that what you meant?

18 MISS KERRIGAN: You have stated your position.

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

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

25 MR. ALLEN: Any further questions?



1 MR. BESSETTE: I have another question regarding
2 the control room air intake activity in the radiation monitor-
3 ing system. You indicated that was IE. You also indicated
4 previously that the bistable action was a computer based
5 action or microprocessor based action. Did I understand that
6 correctly?

7 MR. SHEPHERD: Yes.

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

10 MR. BINGHAM: How much detail would you like?

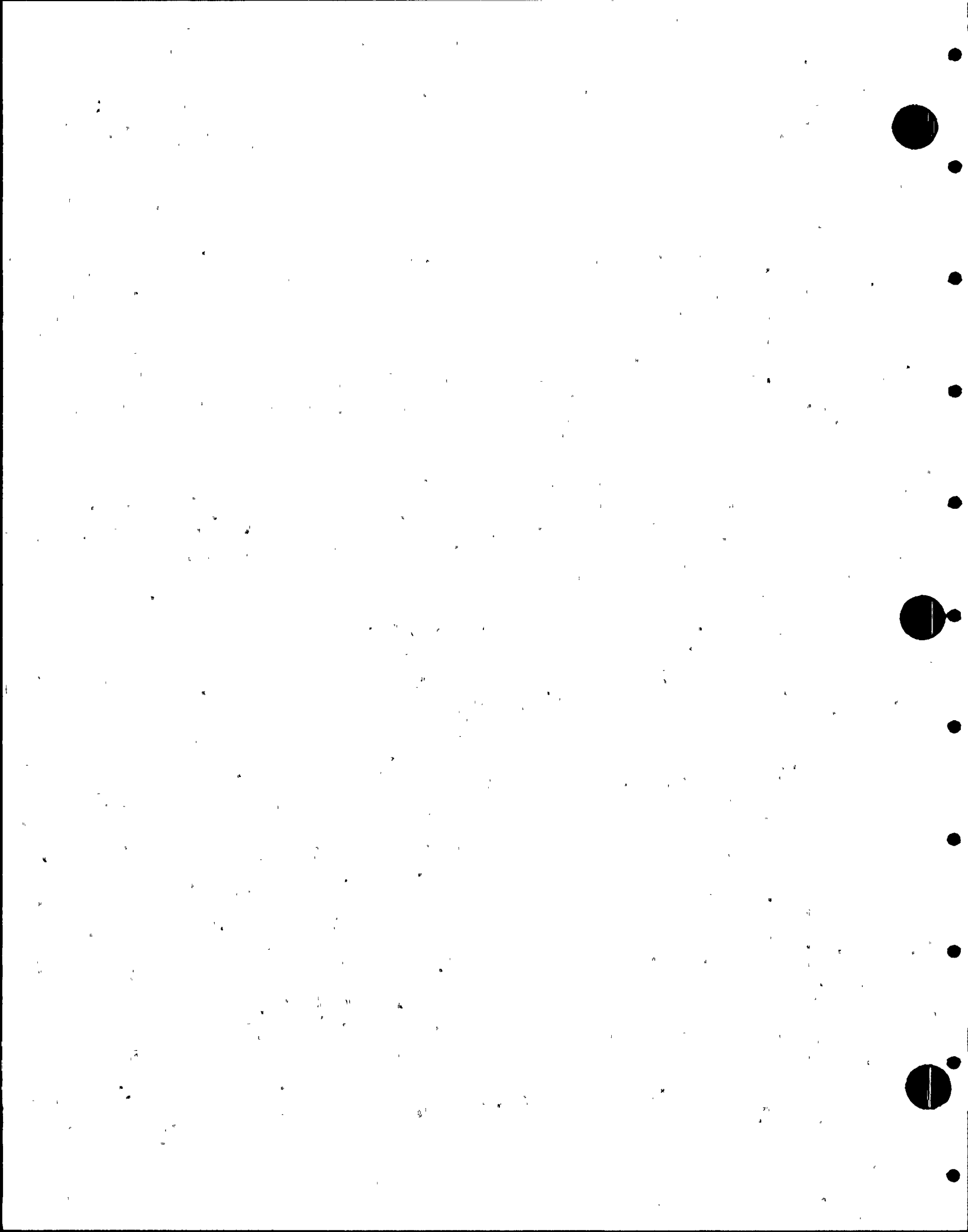
11 MR. BESSETTE: The actual setpoint determination and
12 the monitoring of the parameters, whether or not you exceed
13 the setpoint, all that is done in the computer. Therefore,
14 is that computer a IE system or is the microprocessor a IE
15 device?

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

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

24 MR. SHEPHERD: It is done by software.

25 MR. ALLEN: Is that your question?



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

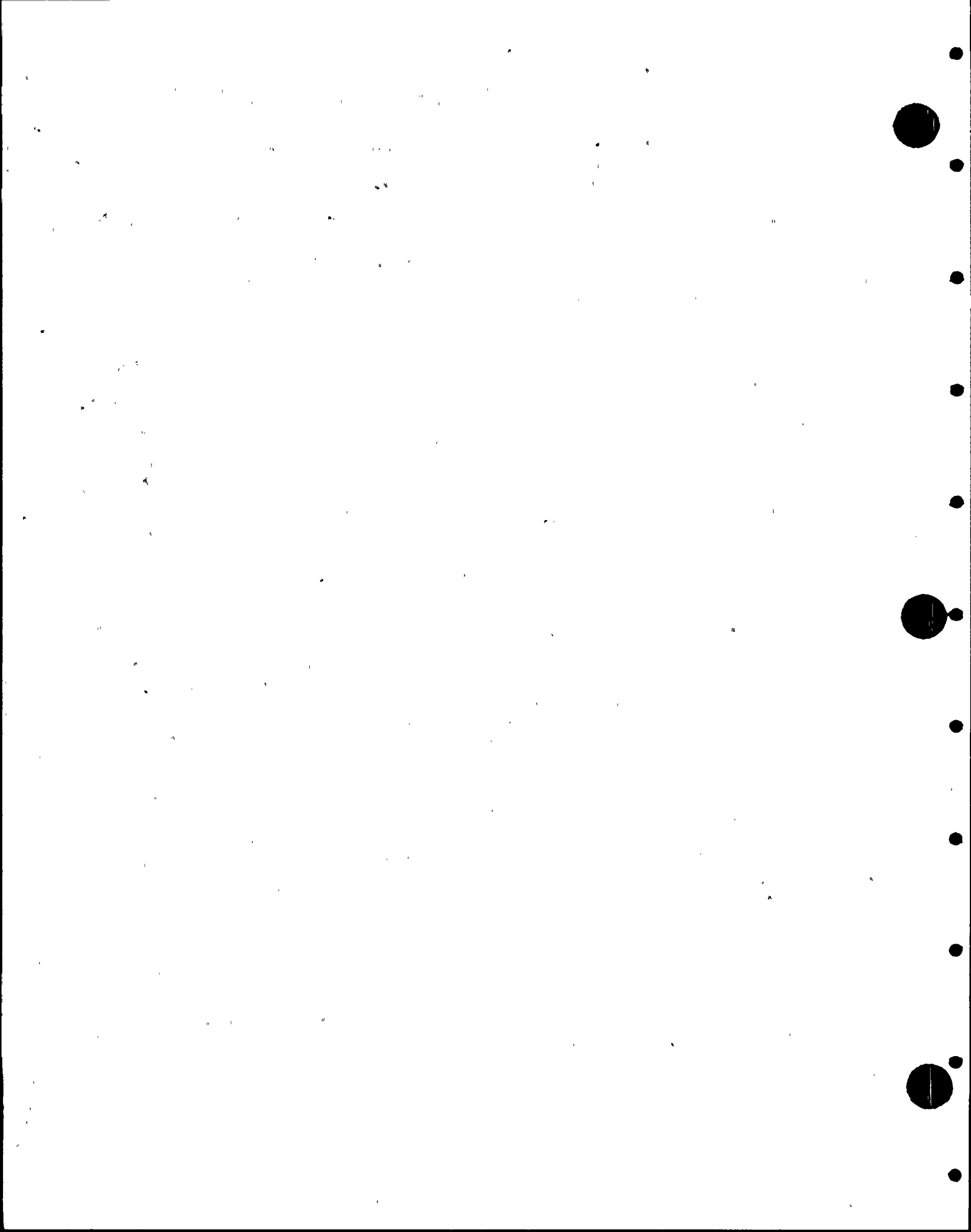
2 MR. STERLING: Is that software changeable by a
3 technician or is it always in there type of program that
4 is nonadjustable? Could somebody get into the software and
5 inadvertently change that?

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

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

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

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



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

2 MR. SHEPHERD: That's correct.

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

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

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

12 MR. SHEPHERD: No.

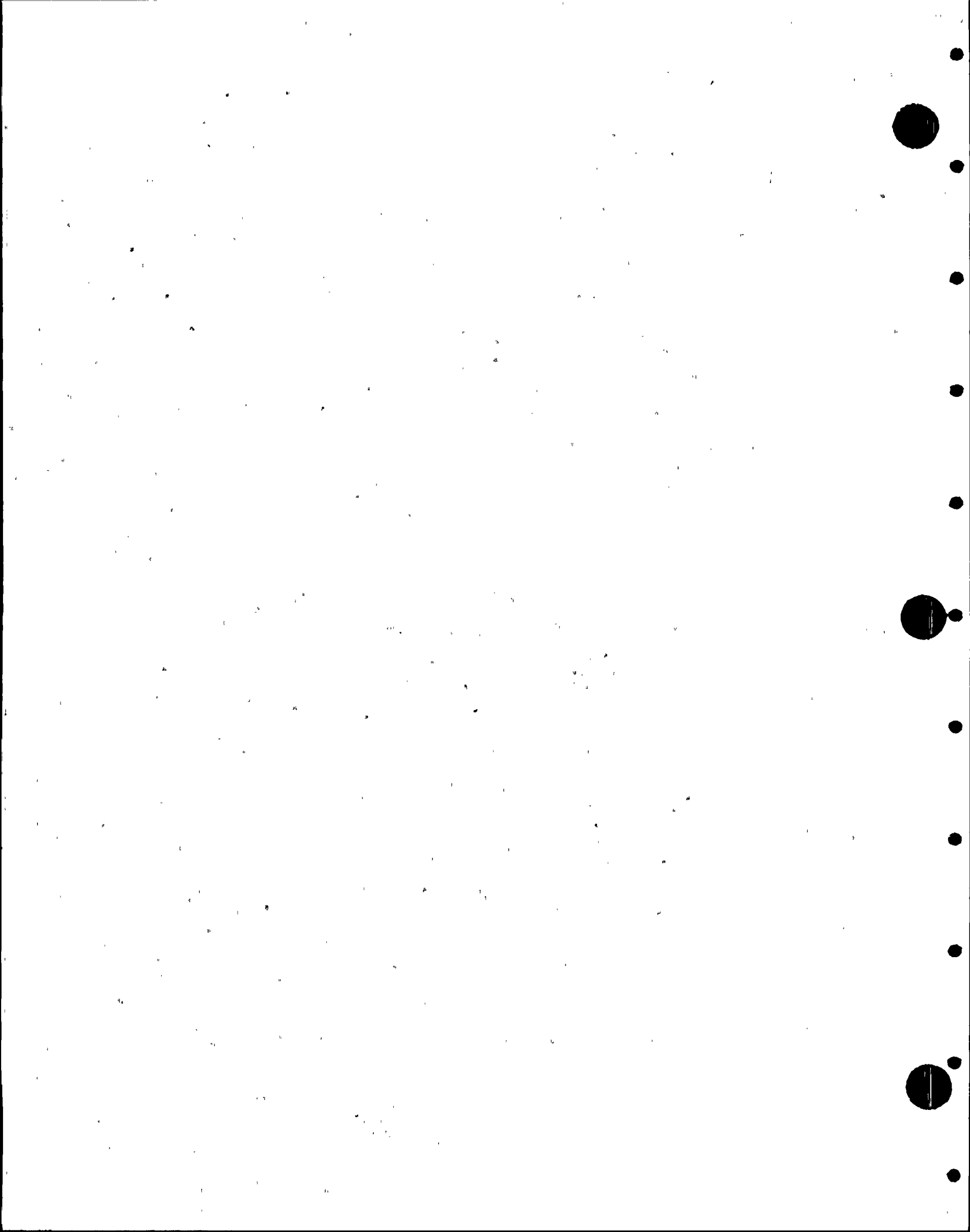
13 MR. ROSENTHAL: Can you describe the use of read only
14 memory versus EPROM versus EPRAM?

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

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

24 MR. SHEPHERD: That is correct.

25 MR. ALLEN: Did you have a question?



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

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

5 MR. MARSH: Just one more thing.

6 MR. BINGHAM: No I heard?

7 MR. ALLEN: No.

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

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

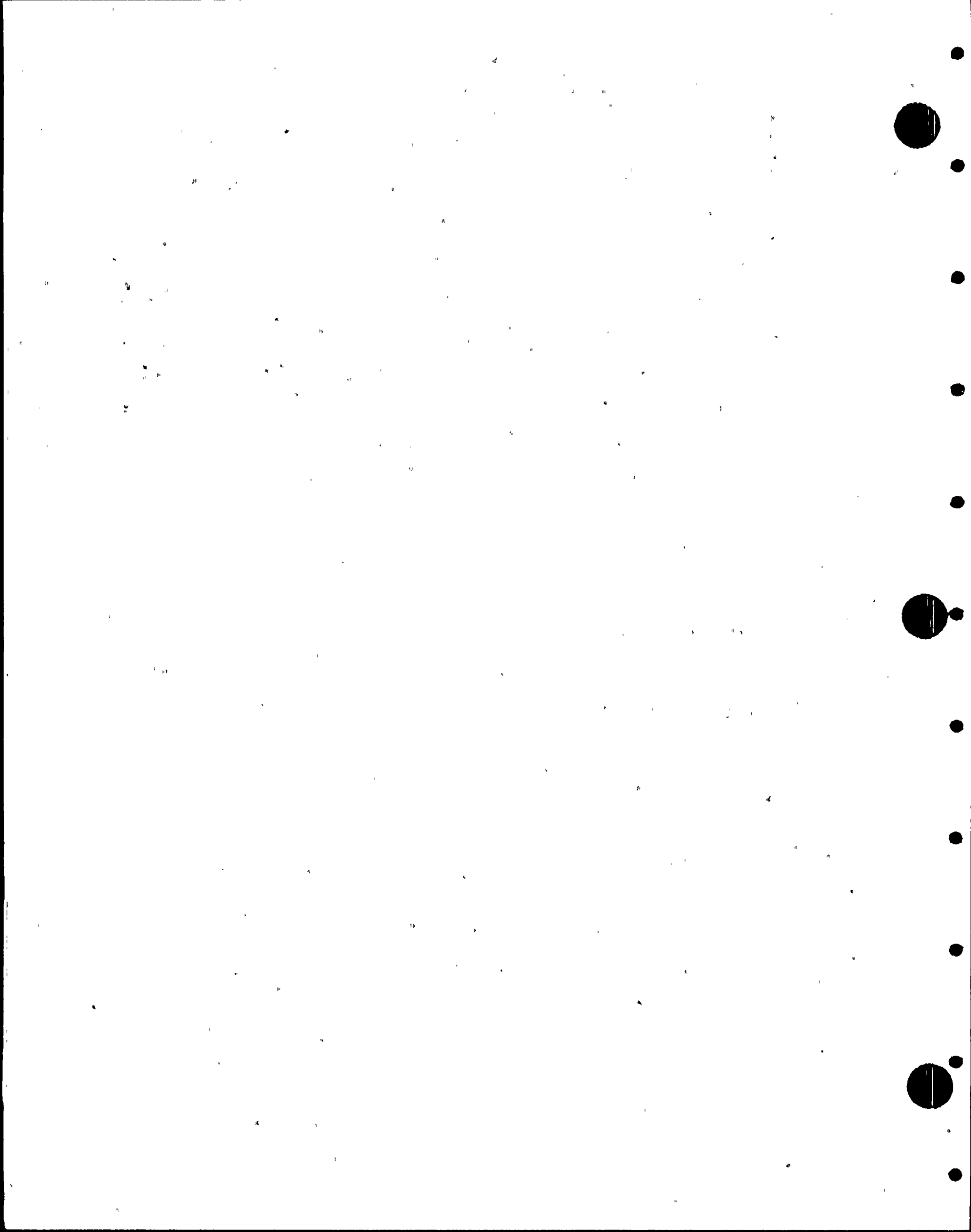
18 MR. BINGHAM: Any other questions on this system?

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

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

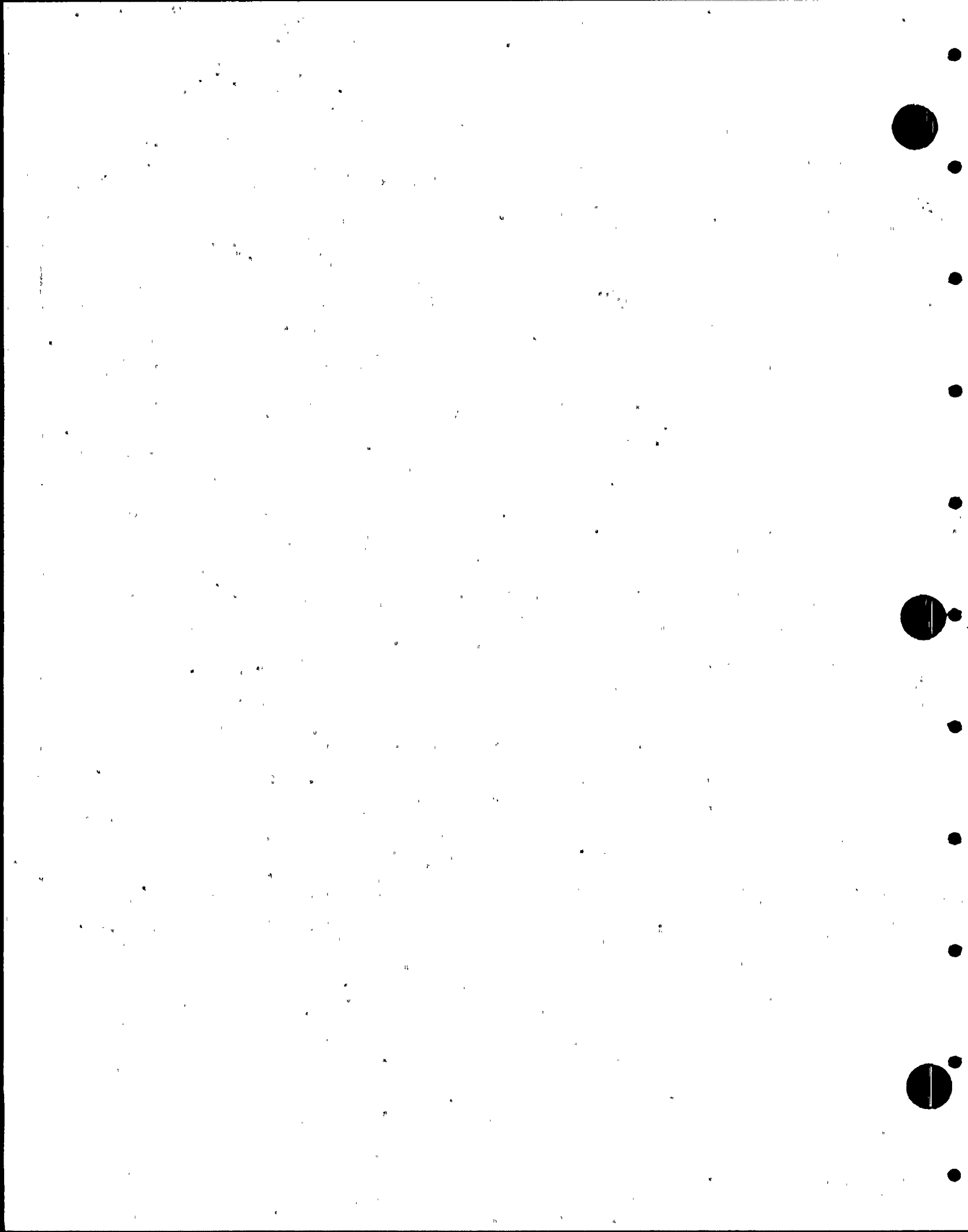
22 MRS. MORETON: I am referring to Exhibit 2A2-1 and
23 Figure 2A2-1, which we will go through in detail. For a
24 typical logic of an actuated device, this would be an
25 NSSS device or a BOP device, this is the steps through our

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



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

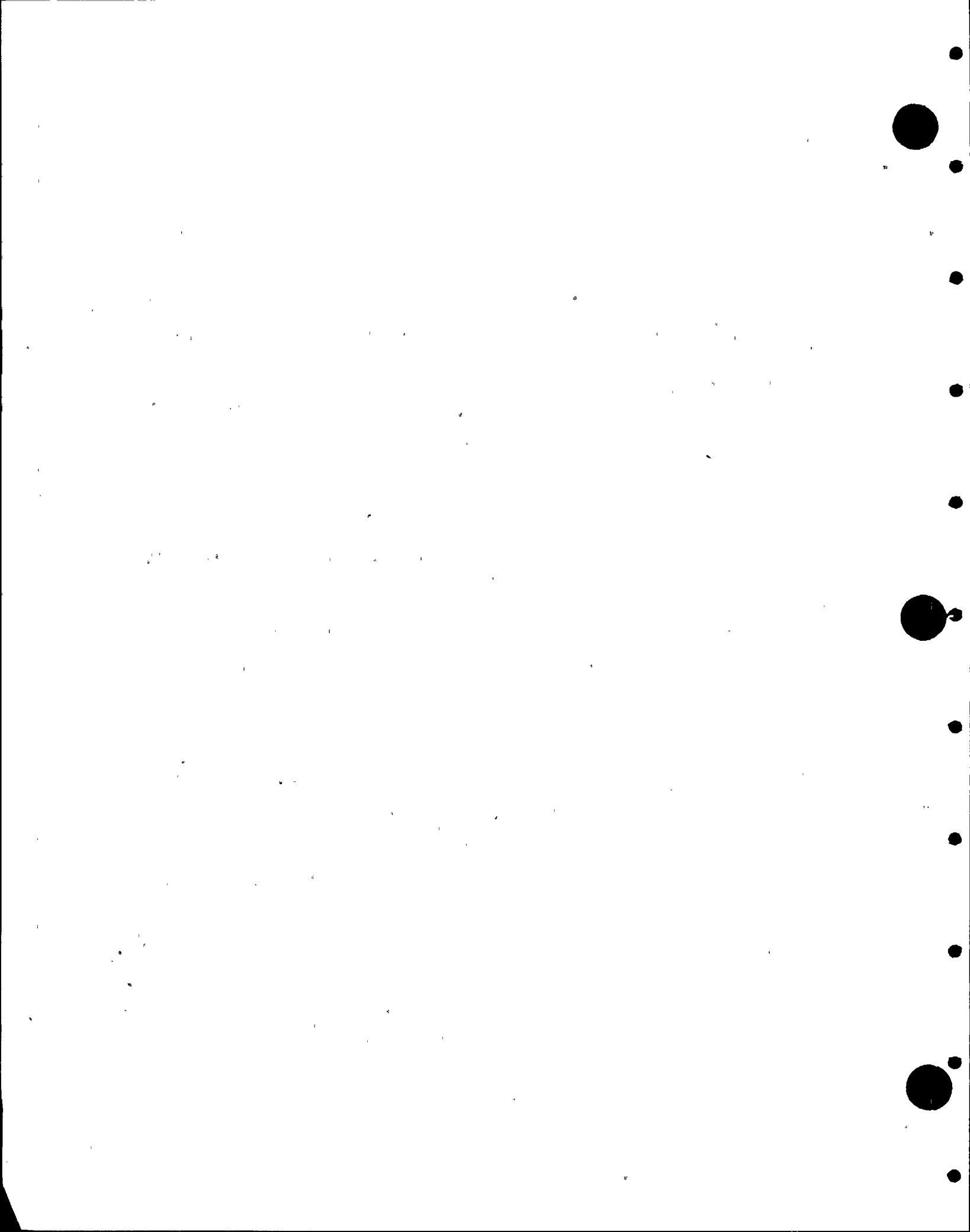
6 Exhibit 2A2-2. An ESF system actuated device is
7 provided with the capability to override the ESFAS signal
8 to allow manual control of the ESF system. In general, there
9 are a few exceptions, but the override of the ESFAS is
10 performed as follows: With the ESFAS signal present, the
11 operator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



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

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

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



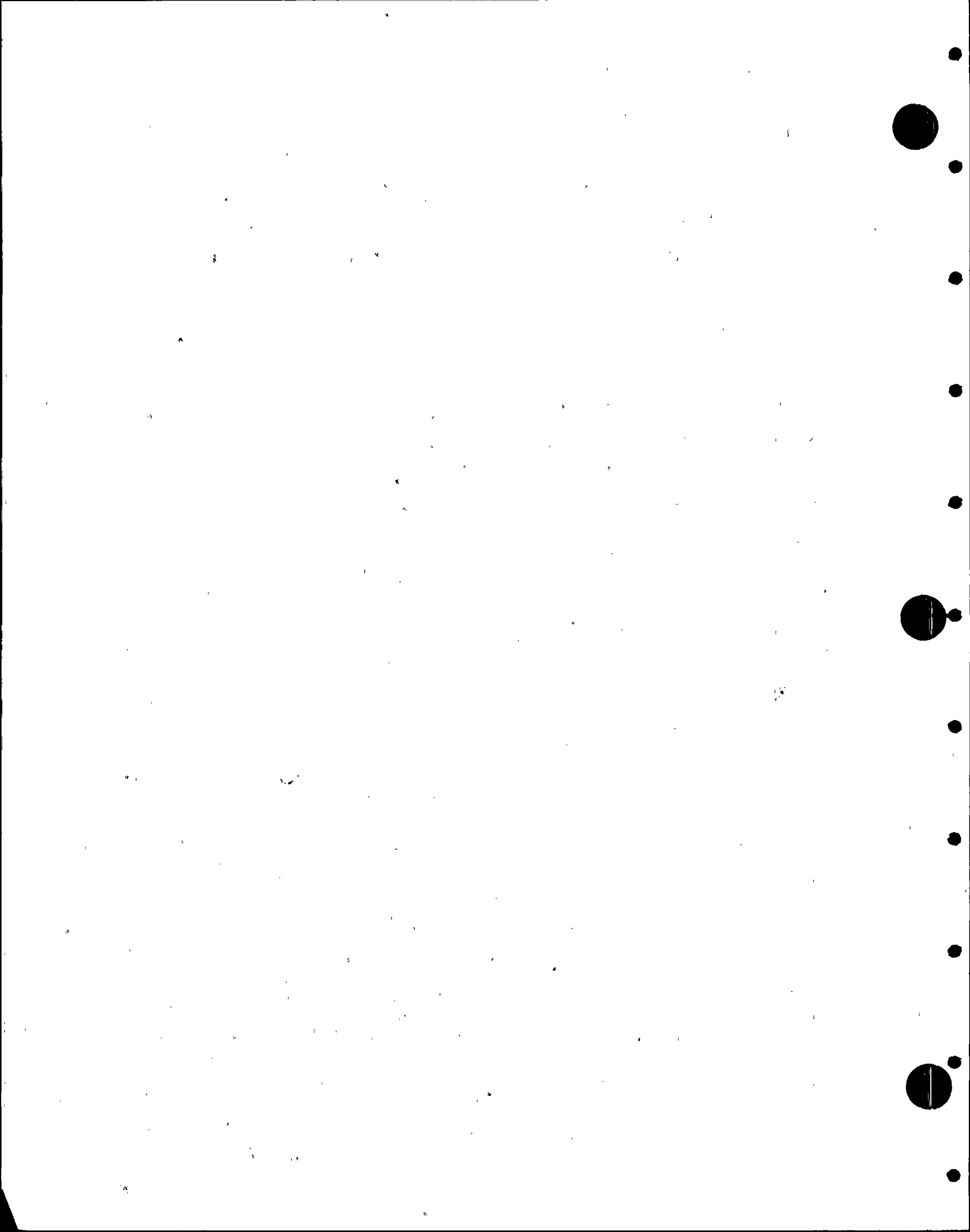
1 systems panel, reactor regulating panel, plant protection
2 system panel where the plant protection system initiating
3 parameters are displayed and where the manual actuation
4 switches are available, the steam generator, turbine generator,
5 feedwater control panel, and BO7, which is our auxiliary
6 panel.

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

14 This is a mock-up of the core protection calculator
15 display. Annunciation for the BOP ESFAS is provided. Also
16 on that same panel, our BPS panel BO5, signal actuations
17 are alarmed, CPIAS, FBEVAS, CRVIAS, CREFAS. Then also in
18 this same annunciator are the reactor protection system
19 alarms.

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

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



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

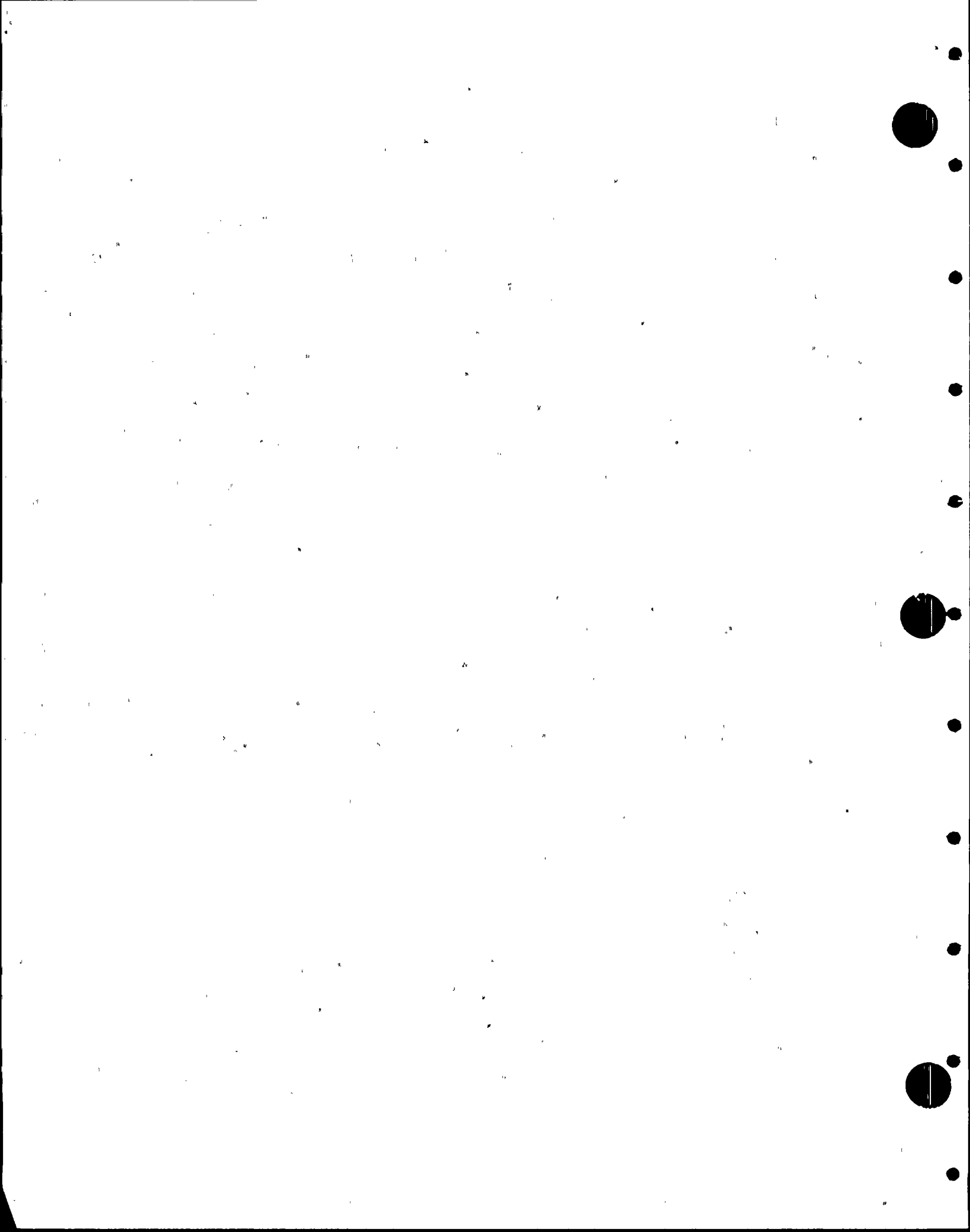
11 The next slide shows that the operator has now
12 positioned this switch to the open position and the valve
13 is in mid-travel. Both these lights (indicating) are on.
14 Nothing has changed on this switch (indicating).

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

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

22 I think we can take questions now.

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



1 logic or is it driven by the actual device position?

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

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

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

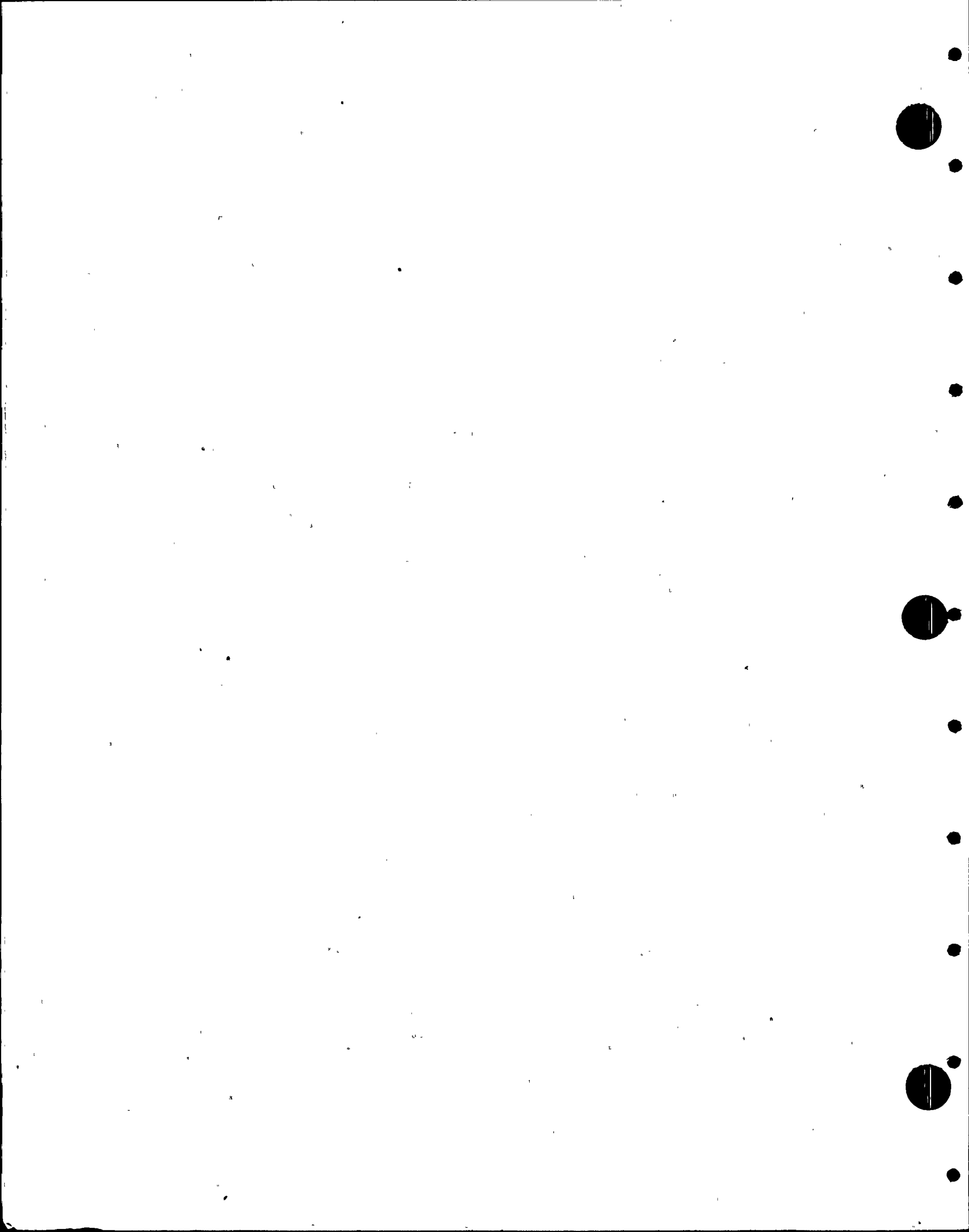
9 MR. ALLEN: What I am trying to get at, when it goes
10 into override, does it override another system?

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

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

22 MRS. MORETON: No.

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



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

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

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

14 MRS. MORETON: Yes.

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

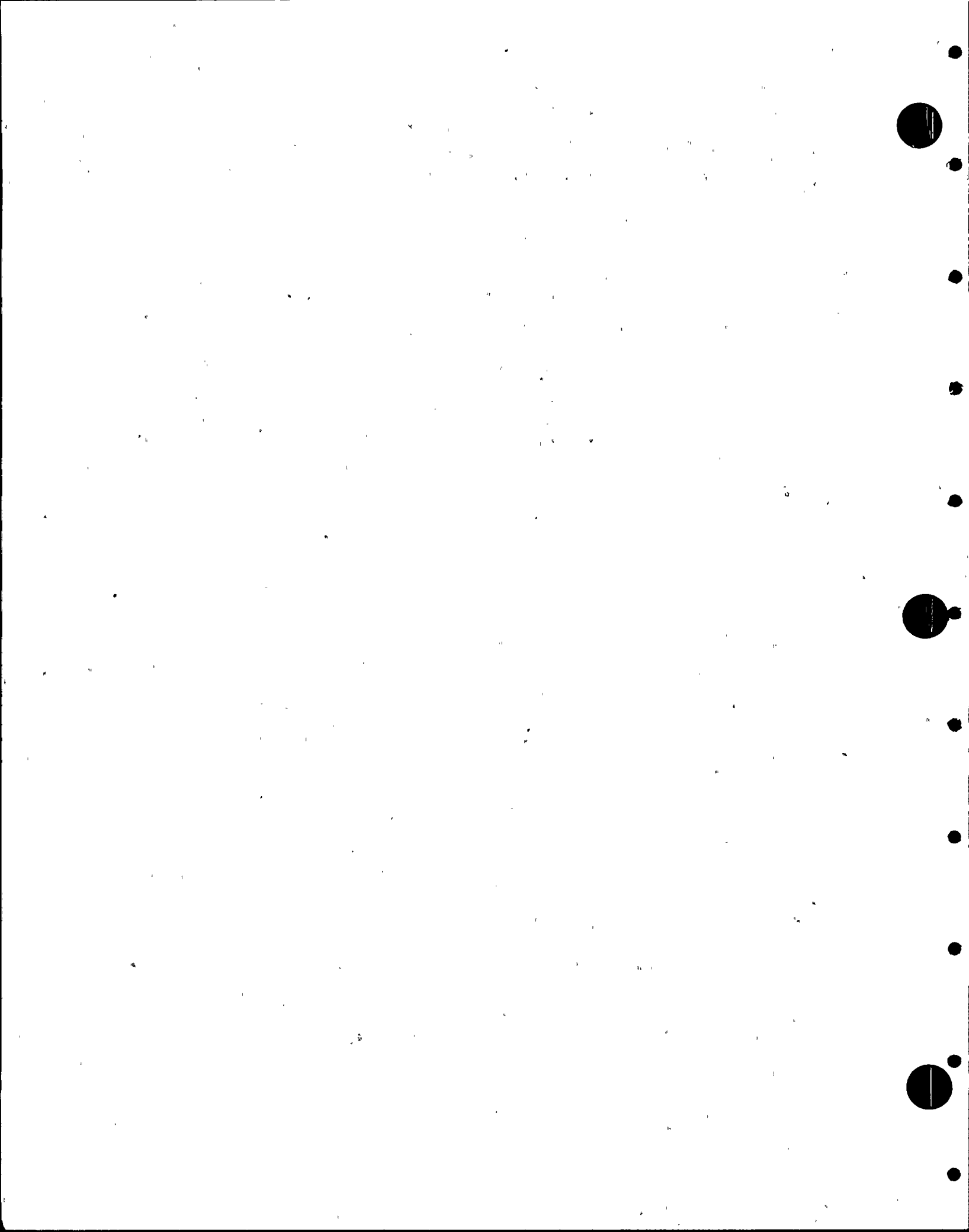
17 MRS. MORETON: The override is disabled when the
18 ESFAS signal is removed and the white light is extinguished.
19 The device does not change state.

20 MR. ALLEN: Any further questions?

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

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

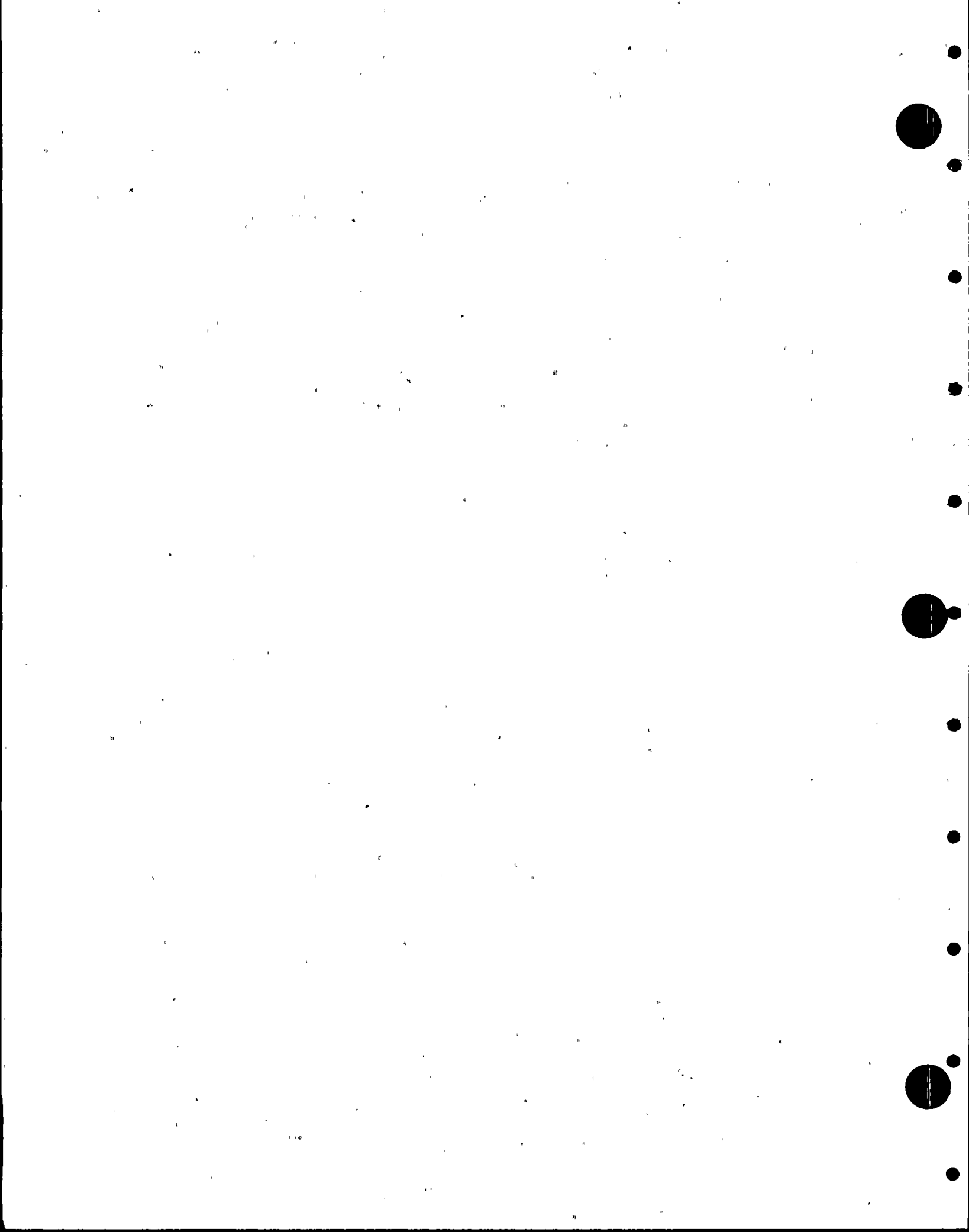
25 MR. BINGHAM: I believe we can get through the next



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

3 MRS. MORETON: Exhibit 2A3-1, ESF Load Sequencer
4 System Design Criteria. We repeat here the design criteria
5 specific to the load sequencer system. These design criteria
6 were presented this morning as part of the BOP ESFAS. The
7 BOP ESFAS shall provide the logic to automatically start
8 and sequentially load the diesel generators and to shed all
9 4.16 kV Class IE loads on a loss of power. The system shall
10 monitor the undervoltage relays on the 4.16 kV Class IE
11 bus and initiate a logic signal on a two-out-of-four
12 coincidence of bus undervoltage. This logic signal will be
13 used to shed all Class IE 4.16 kV loads except the load
14 center transformers, shed certain 480 volt loads, start the
15 diesel generator, start equipment required after a loss of
16 offsite power, and trip the 4.16 kV Class IE bus preferred
17 power supply breakers. The system shall provide sequencing
18 logic for sequential loading of ESF and forced shutdown loads
19 onto the ESF bus upon closing of the diesel generator
20 breaker, a safety injection actuation signal, or an auxiliary
21 feedwater actuation signal.

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

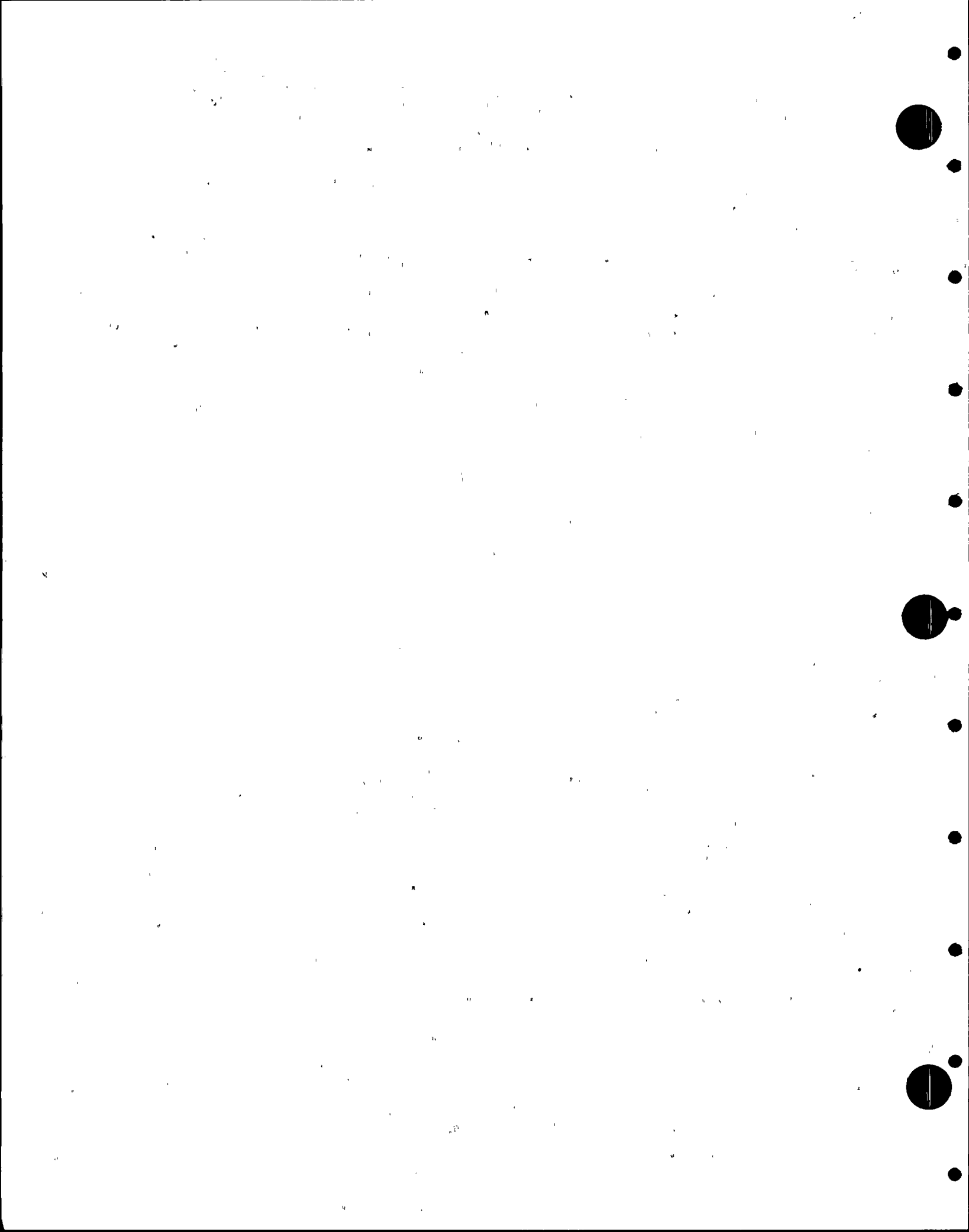


1 is initiated after the load sequencer has started, all
2 loads will be shed and resequenced on the diesel generator
3 breaker closure.

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

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

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

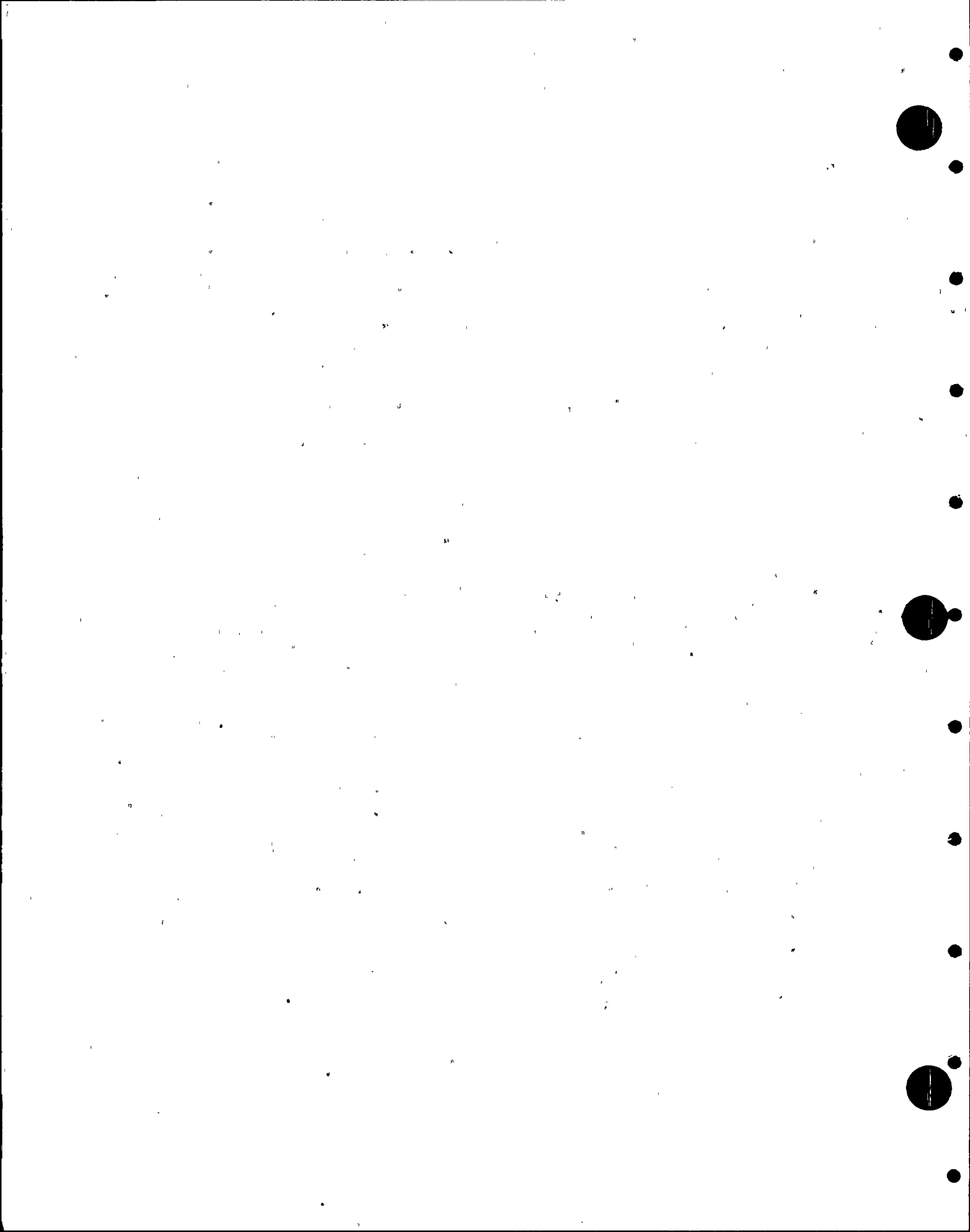


1 Load Group 2 components and systems are energized only by
2 the Load Group 2 bus.

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

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

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

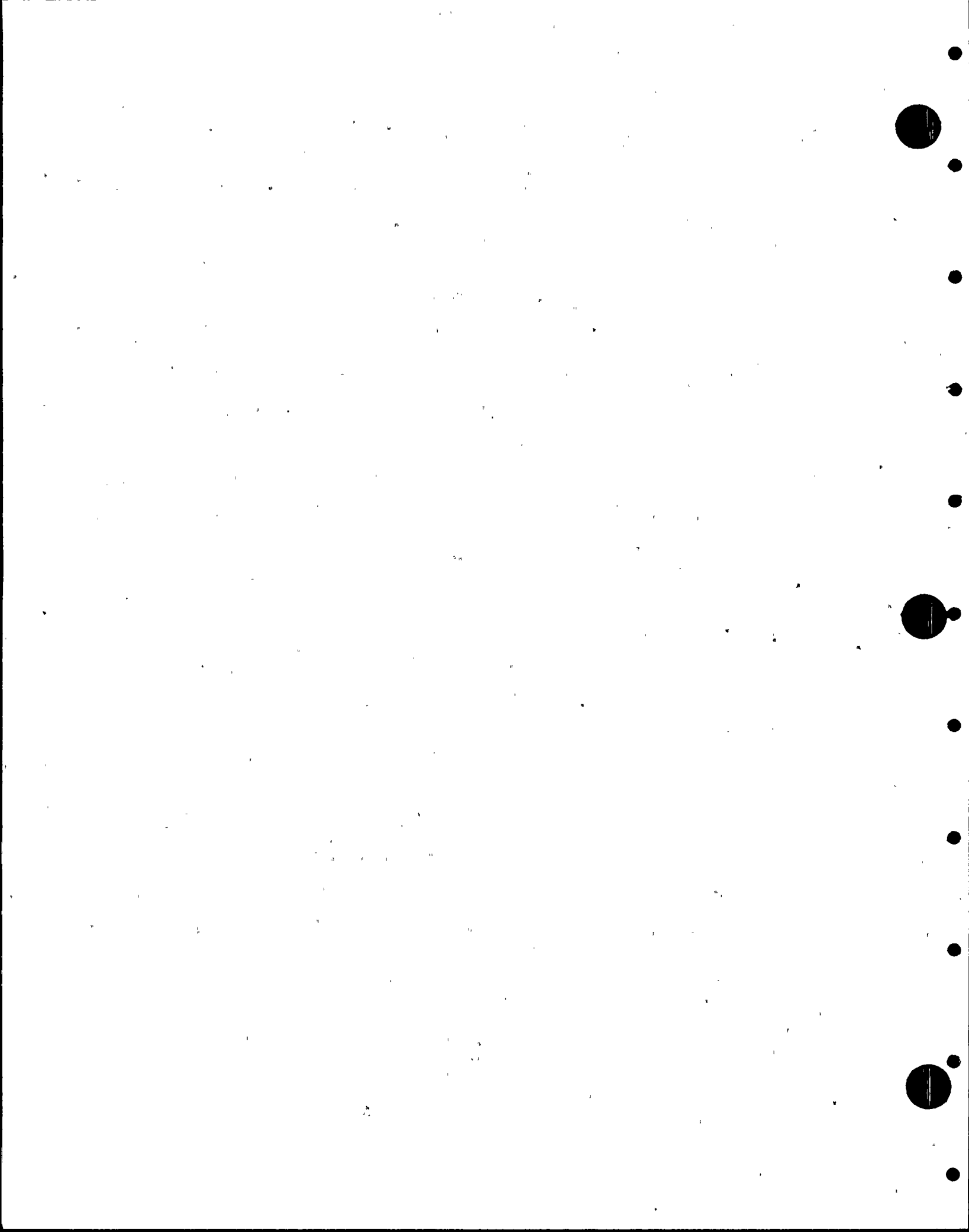


1 generates an LOP signal to the diesel generator to initiate
2 a diesel generator start signal, it initiates an LOP signal
3 through a 60-second off delay to the forced shutdown system
4 loads, also initiates a load shed, which is a one-second
5 pulse, to trip preferred power supply breakers and to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

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

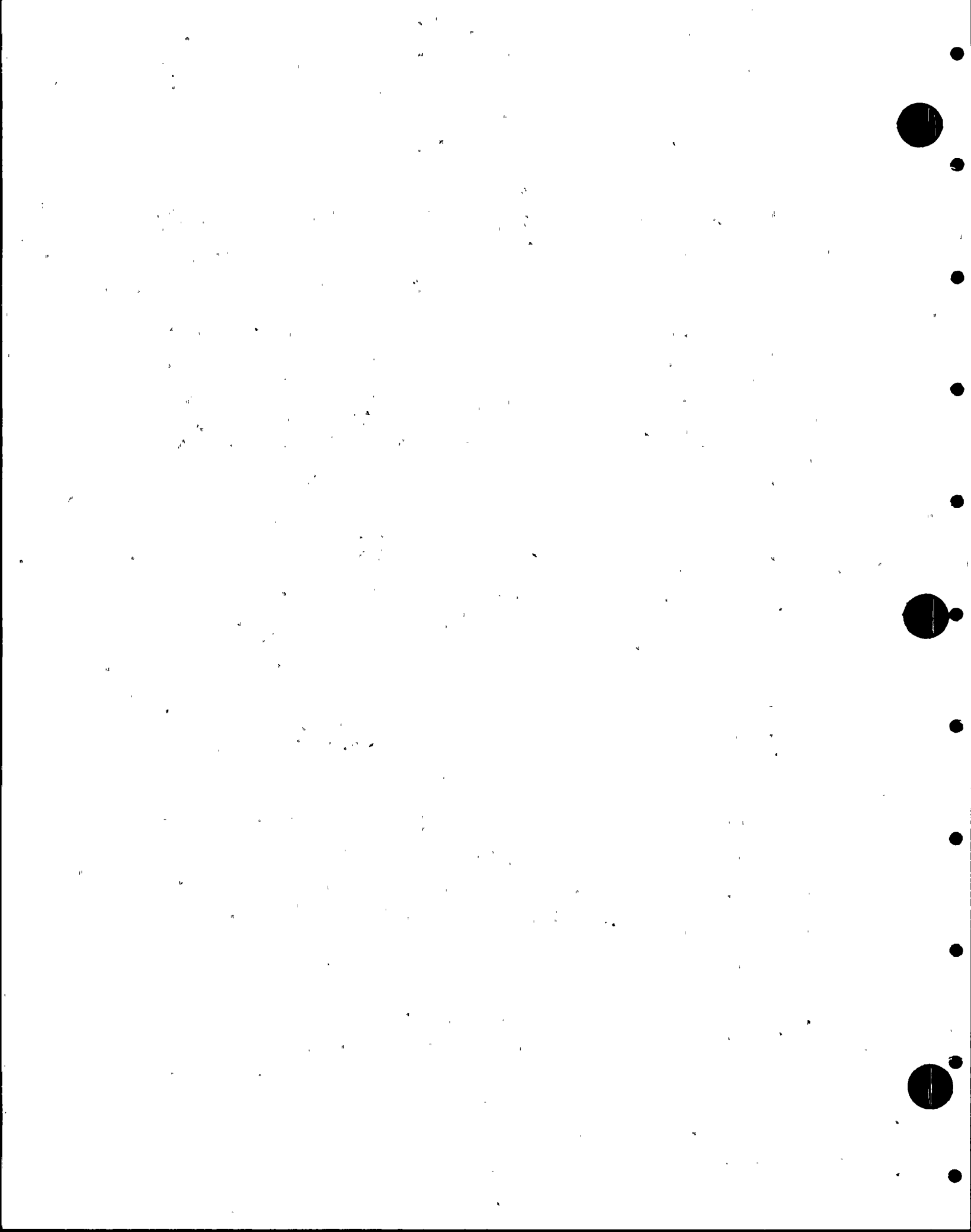
15 The load sequencer start and permissive signal
16 logic is shown on Figure 2A3-3. Each load sequencer start
17 and permissive signal logic performs the following functions:
18 It monitors input, determines the appropriate mode of opera-
19 tion, and generate sequentially timed start and permissive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

25 Exhibit 2A3-8. The load sequencer controls only



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

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



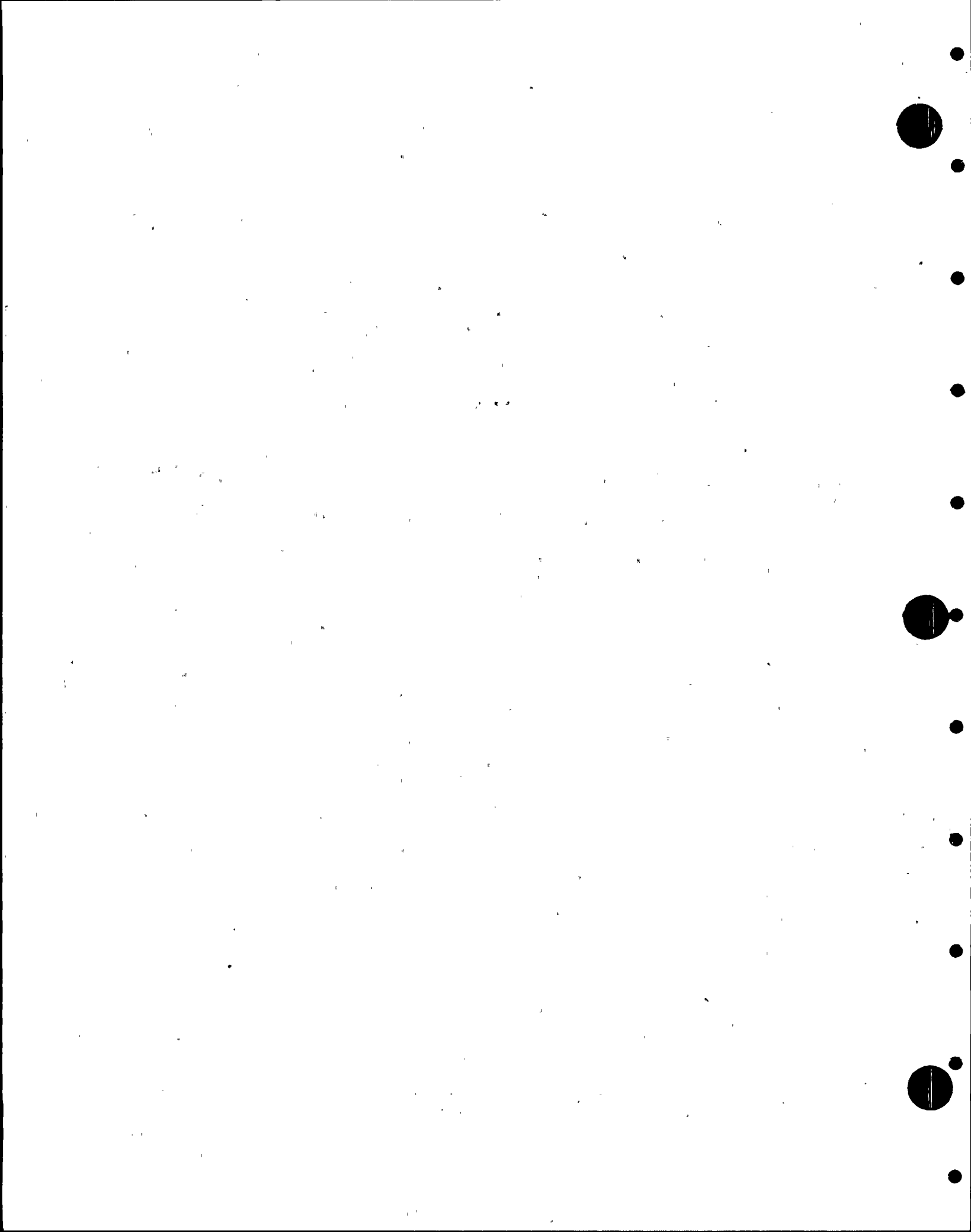
1 spray signal and without loss of offsite power. These
2 signals are the CRVIAS and CREFAS combined in a logical
3 "OR," FBEVAS, AFAS-1 and AFAS-2 combined in a logical "OR,"
4 or a signal if the diesel generator is running.

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

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

22 MR. BINGHAM: Are there questions from the Board?

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



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

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

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

9 MRS. MORETON: Correct.

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

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

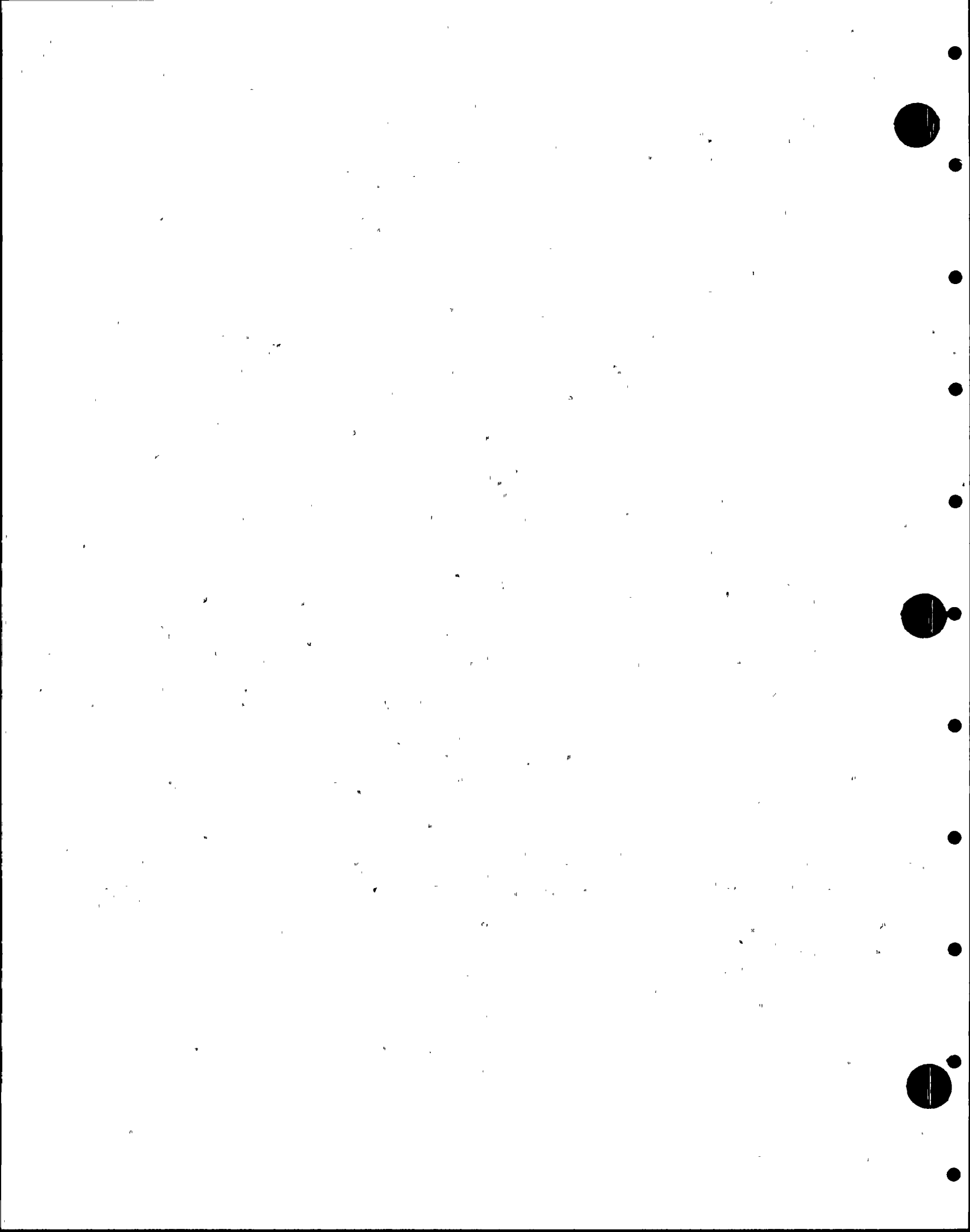
16 MR. STERLING: Continuing on that, if we might have
17 Figure 2A3-3, to help me understand this, where is your test?
18 It would test through Modes 1 through 4?

19 MRS. MORETON: Manual test?

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

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

25 MR. MORETON: Yes.



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

3 MRS. MORETON: Yes.

4 MR. ALLEN: Any other questions?

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

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

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

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

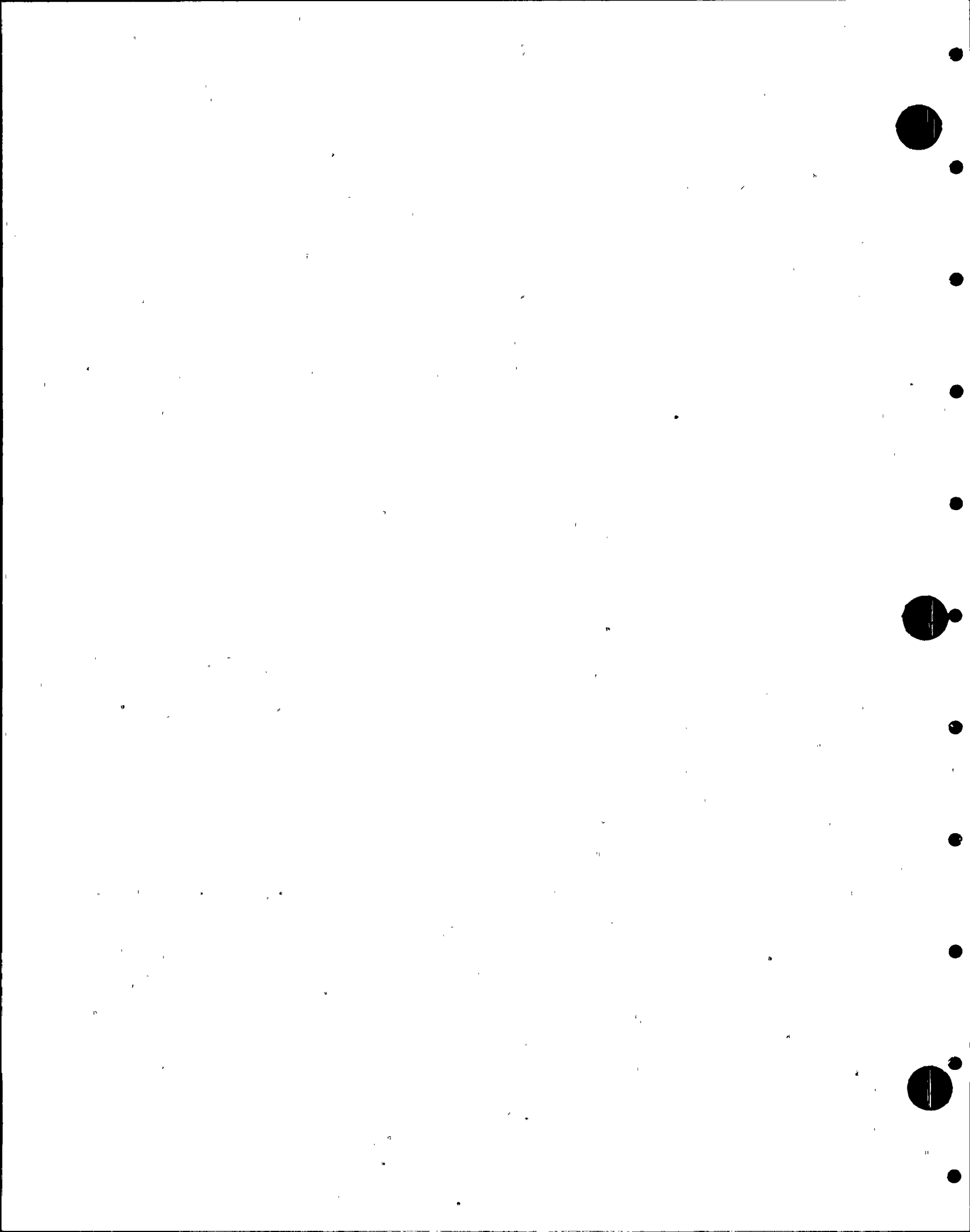
17 MR. MECH: Well, whatever the condition of the under-
18 voltage says.

19 MRS. MORETON: What are the setpoints for undervoltage?

20 MR. MECH: Setpoints, yes.

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

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



1 or something just to get those numbers.

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

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

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

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

8 MR. BINGHAM: Is that satisfactory?

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

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

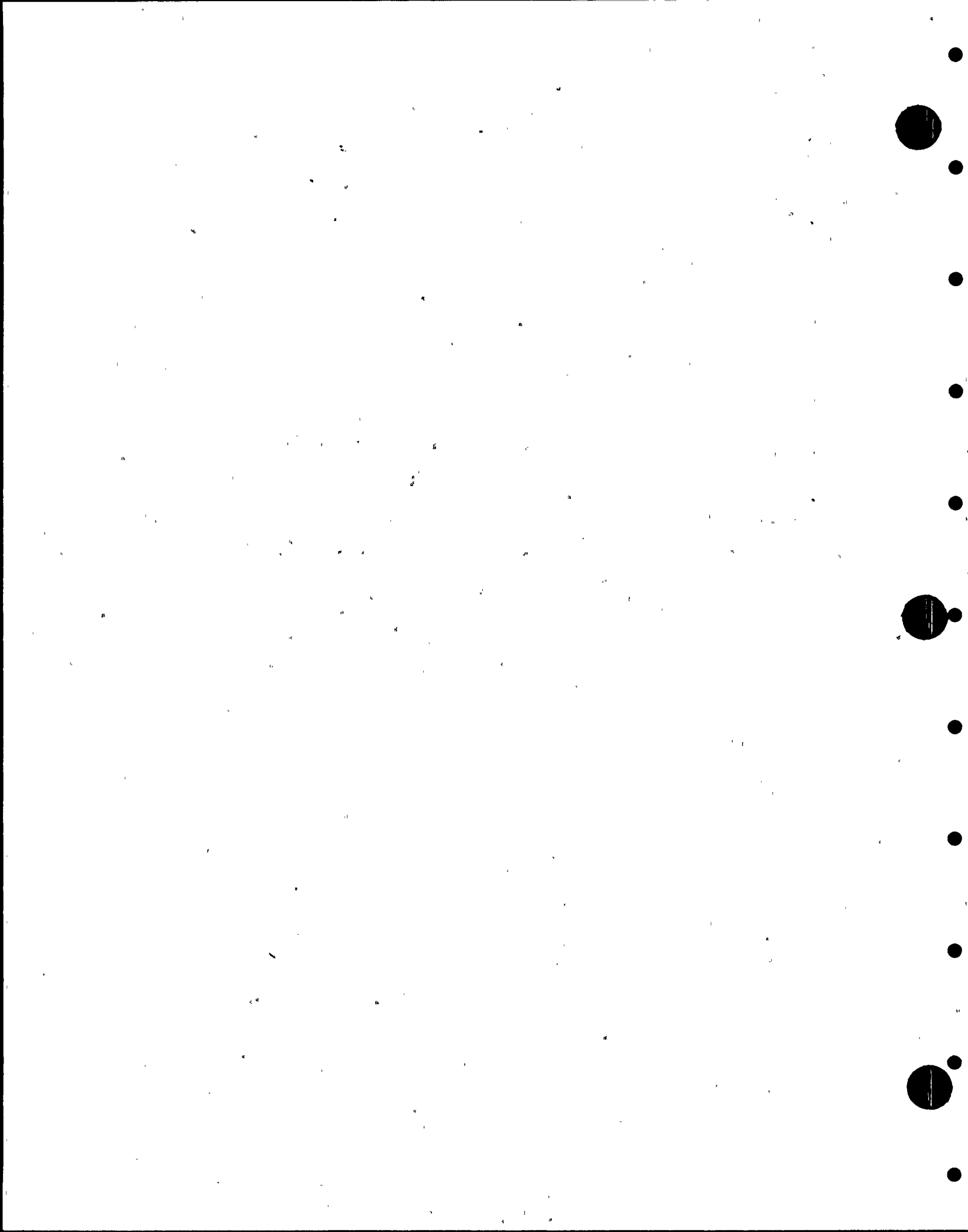
14 MRS. MORETON: The valves are not sequenced. They
15 are controlled directly by the ESFAS signals. If there is
16 no power on the bus, the signals will still be present when
17 the bus is re-energized and the valves will go to their
18 proper position.

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

23 MRS. MORETON: No.

24 MR. PHELPS: But all the valves actuate?

25 MRS. MORETON: Yes.



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

3 MRS. MORETON: Yes.

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

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

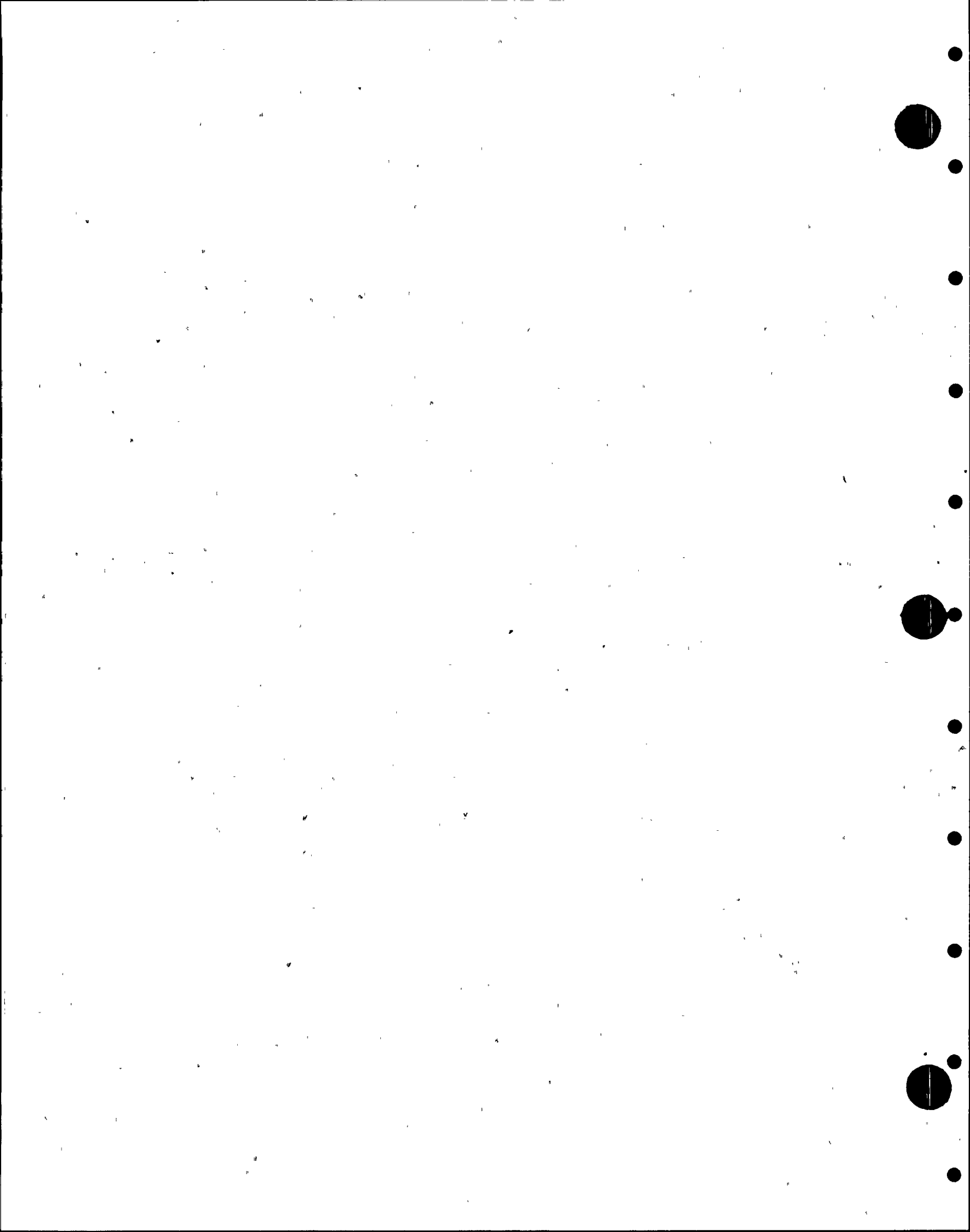
10 MR. ALLEN: Further questions? Mike.

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

19 MRS. MORETON: Yes.

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

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



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

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

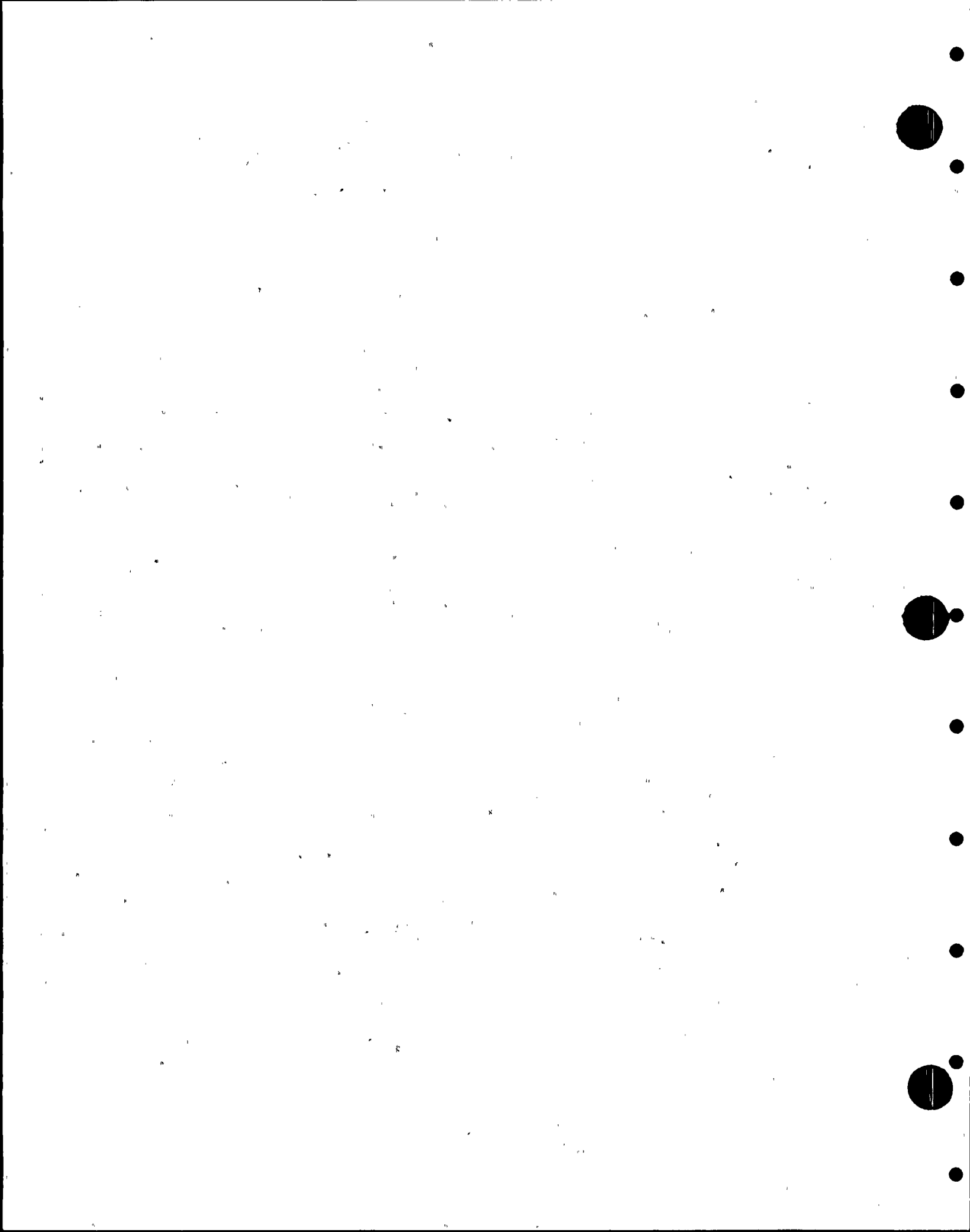
14 MR. BINGHAM: Just a minute. What answer were you
15 expecting?

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

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

22 MR. BARNOSKI: Yes, I understand that.

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



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

5 MR. BARNOSKI: Fine.

6 MR. ALLEN: Any further questions?

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

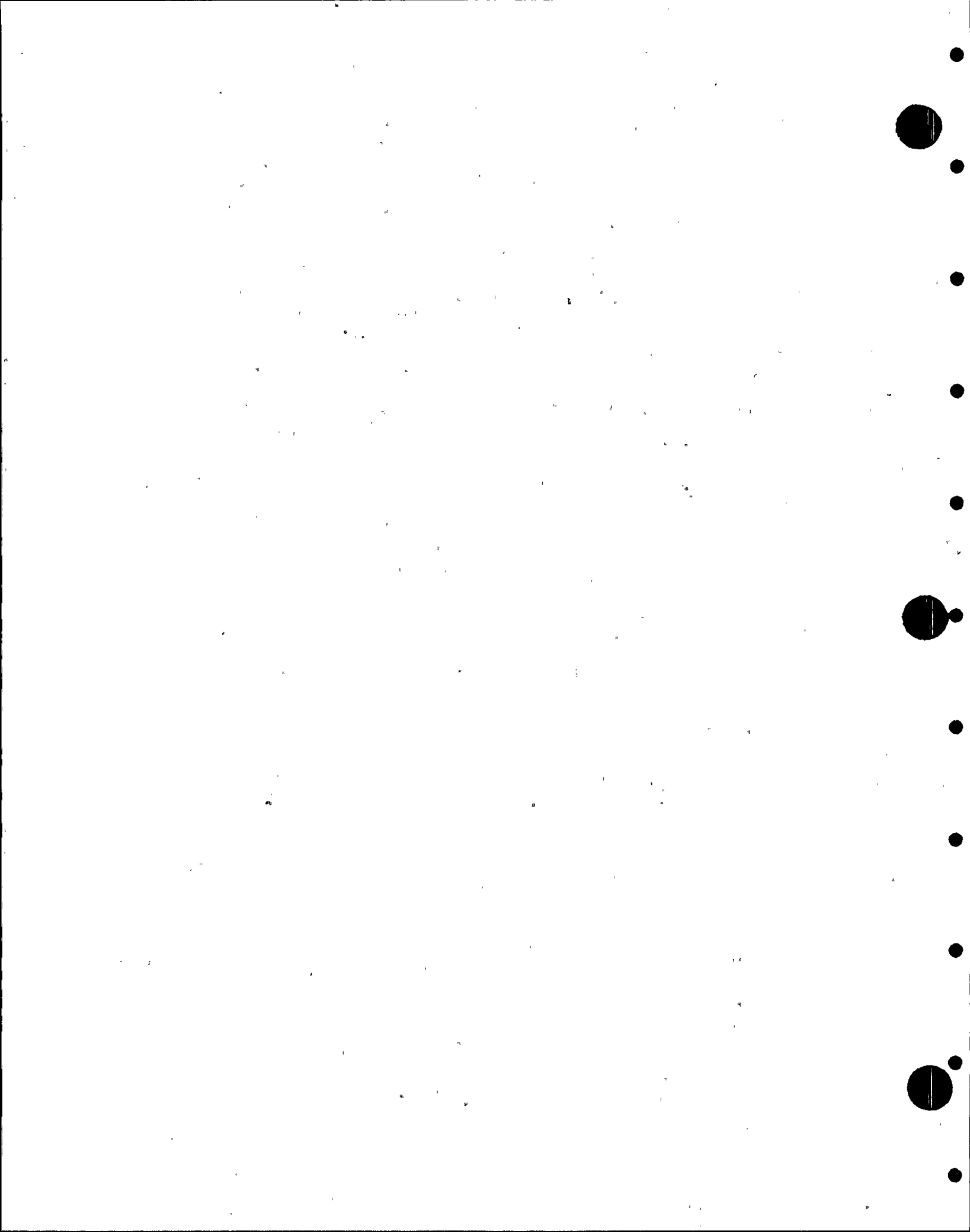
14 MR. ALLEN: Jack, did you have a question?

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

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

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

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



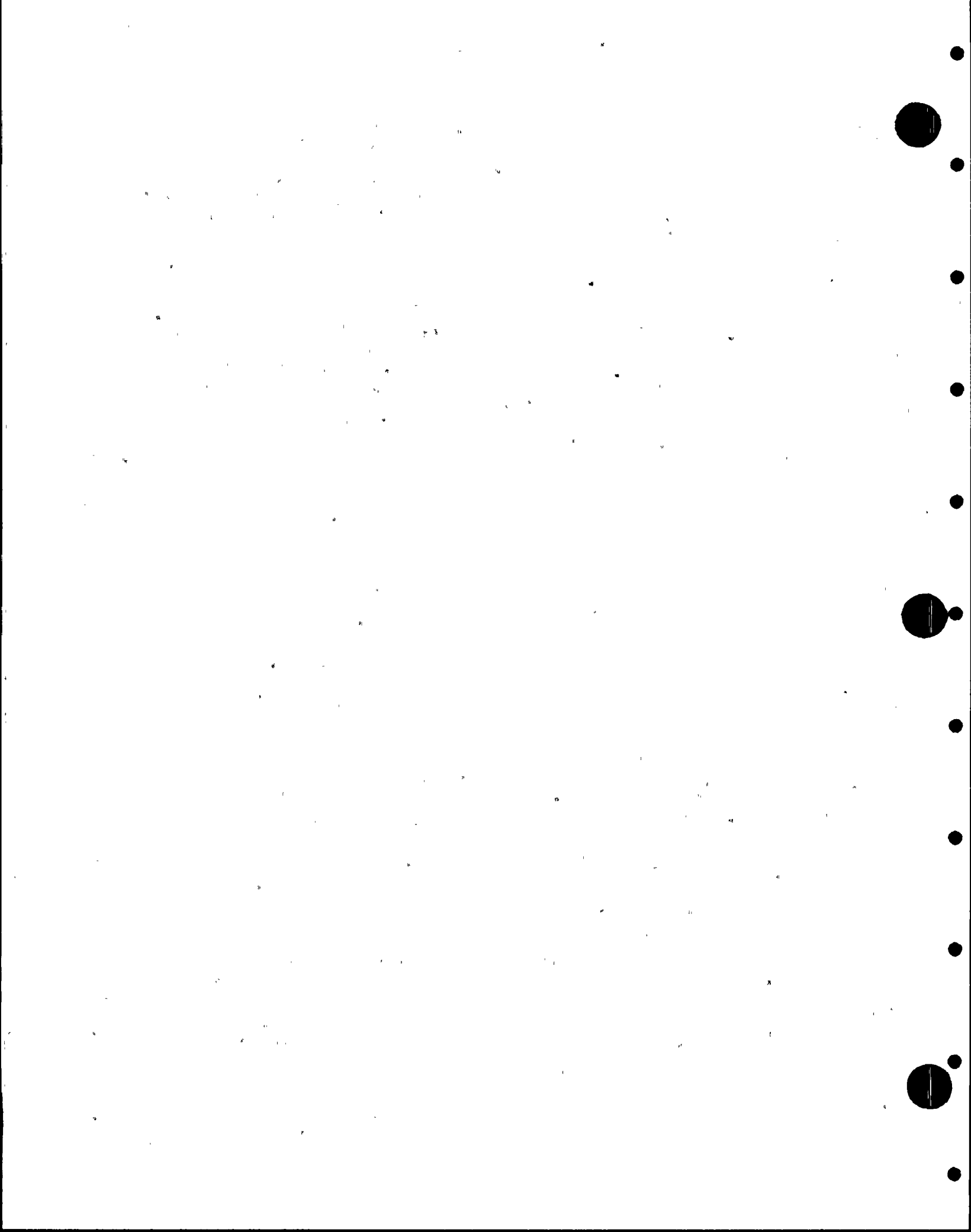
1 and AFAS comes from Combustion Engineering and it was needed
2 by them to support their accident analyses. On an MSIS,
3 we are only shutting some valves, the main steam isolation
4 valves, main feedwater isolation valves. I am sure that the
5 Combustion Engineering analysis supports that, that in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

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

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

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

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



1 Chapter 15 analysis.

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

5 MR. ROSENTHAL: You can do more.

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

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

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

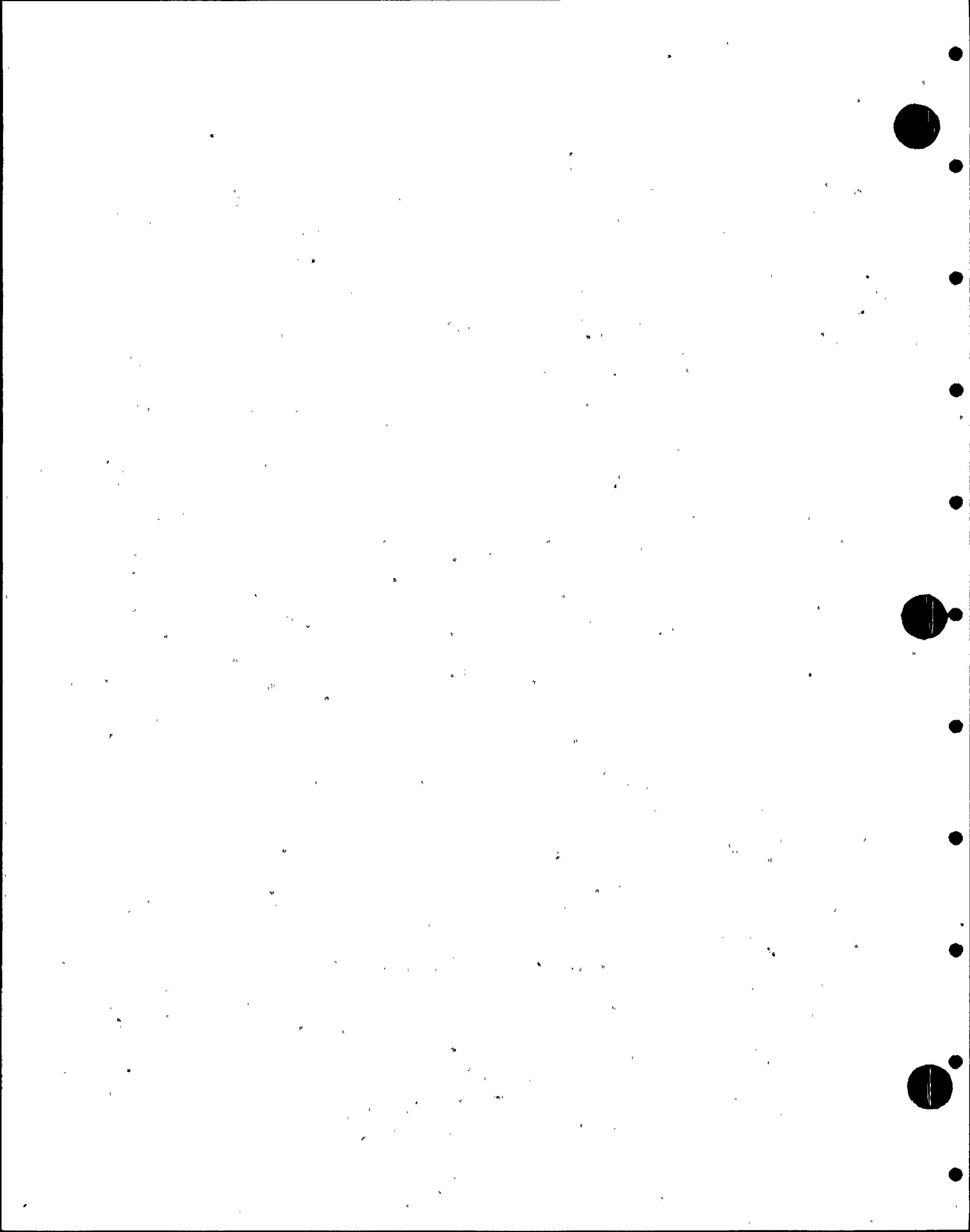
12 John, we haven't had, obviously, an opportunity
13 to talk to the APS counterparts, but I think Dennis can give
14 our overview response now, and if the Board would like that
15 followed up in some detail, we can do that.

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

22 MR. BINGHAM: Any other questions?

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

25 MR. KEITH: We don't sequence valves.



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

4 MR. KEITH: Depending on the accident.

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

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

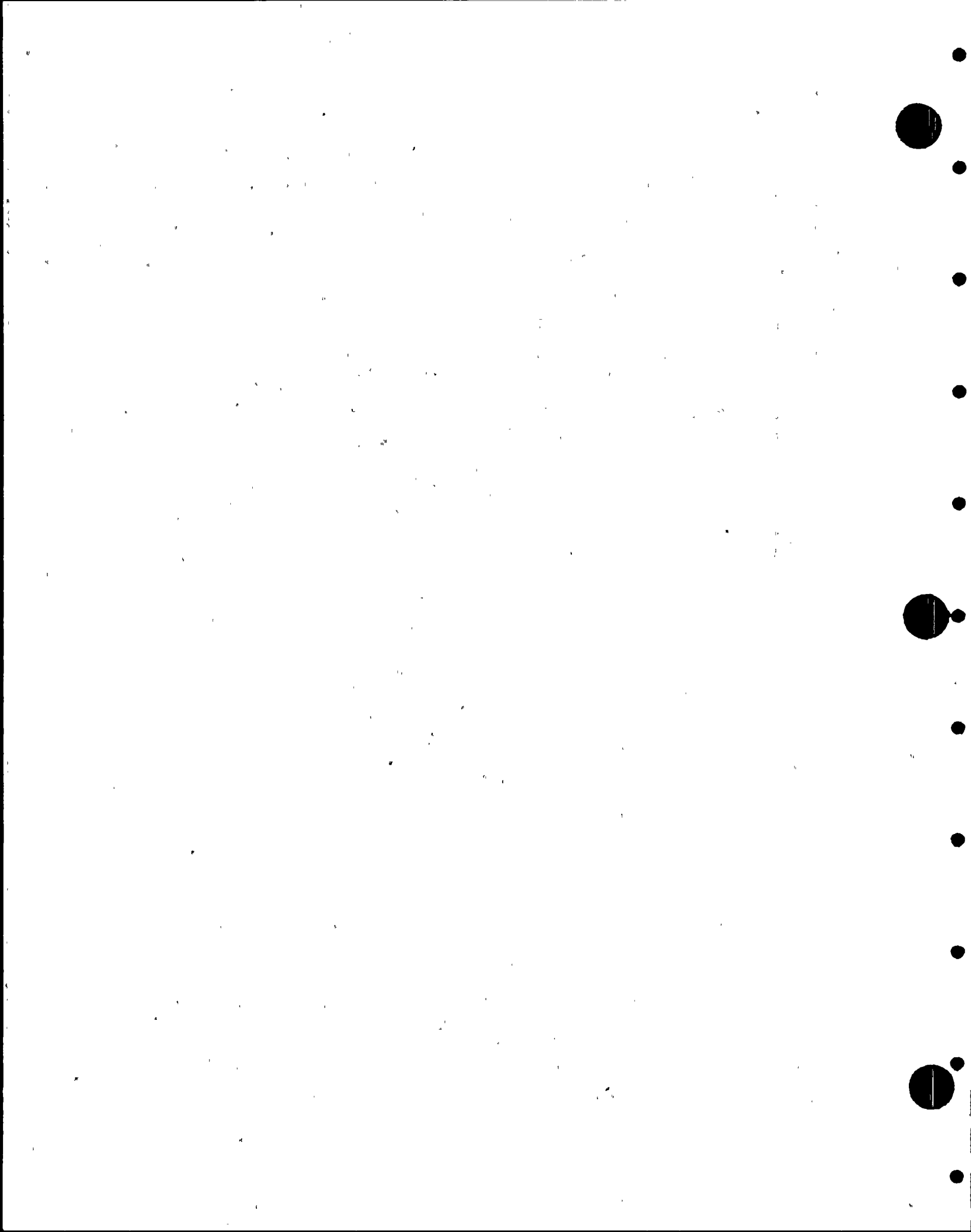
14 MR. JOHNSON: Thank you.

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

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

18 MR. ALLEN: Further questions?

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



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

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

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

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

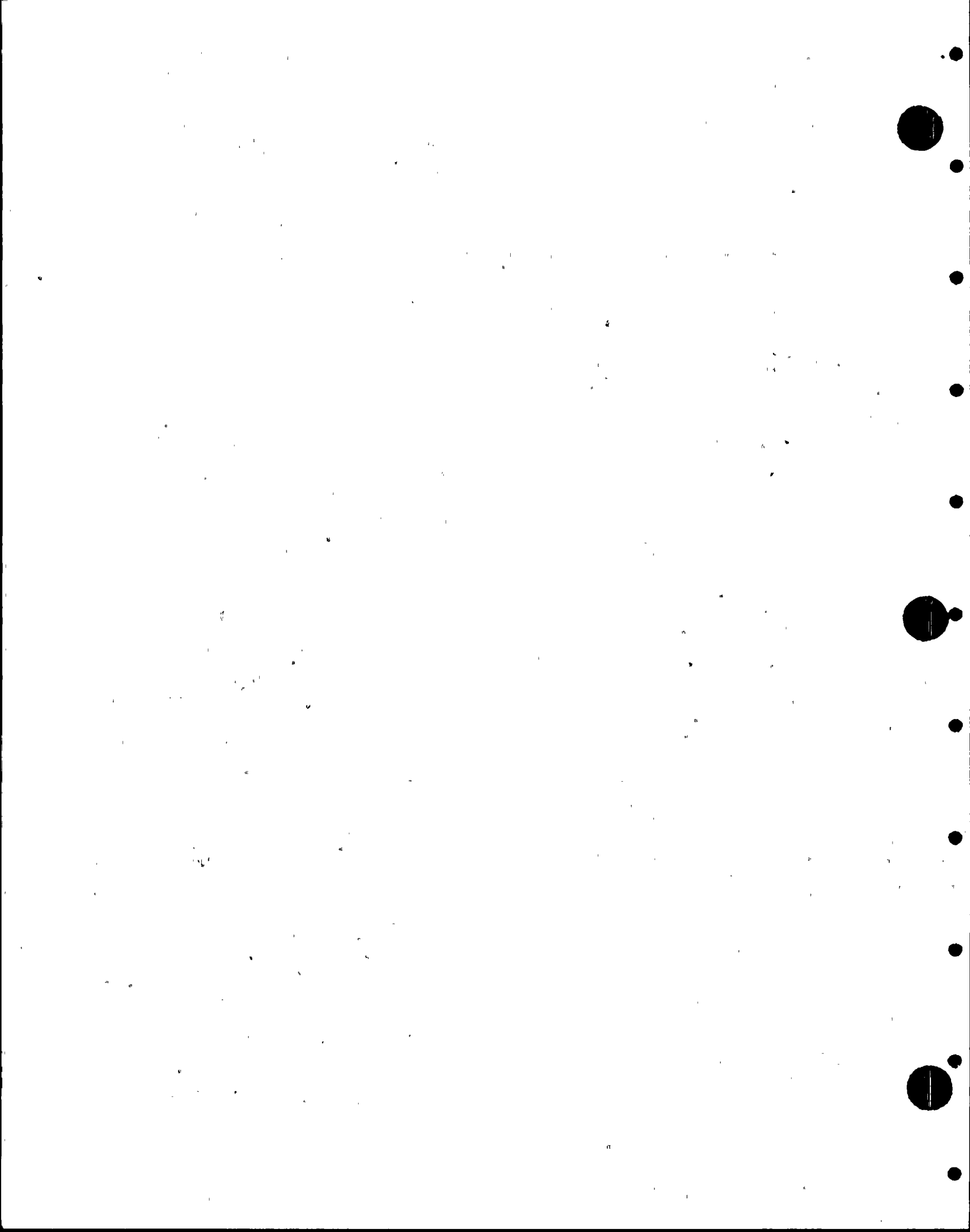
9 MR. BESSETTE: Yes. That relates to assumptions that
10 we may have made in our Chapter 15 analysis regarding
11 availability of these safeguard systems or your ESF systems.

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

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

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

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



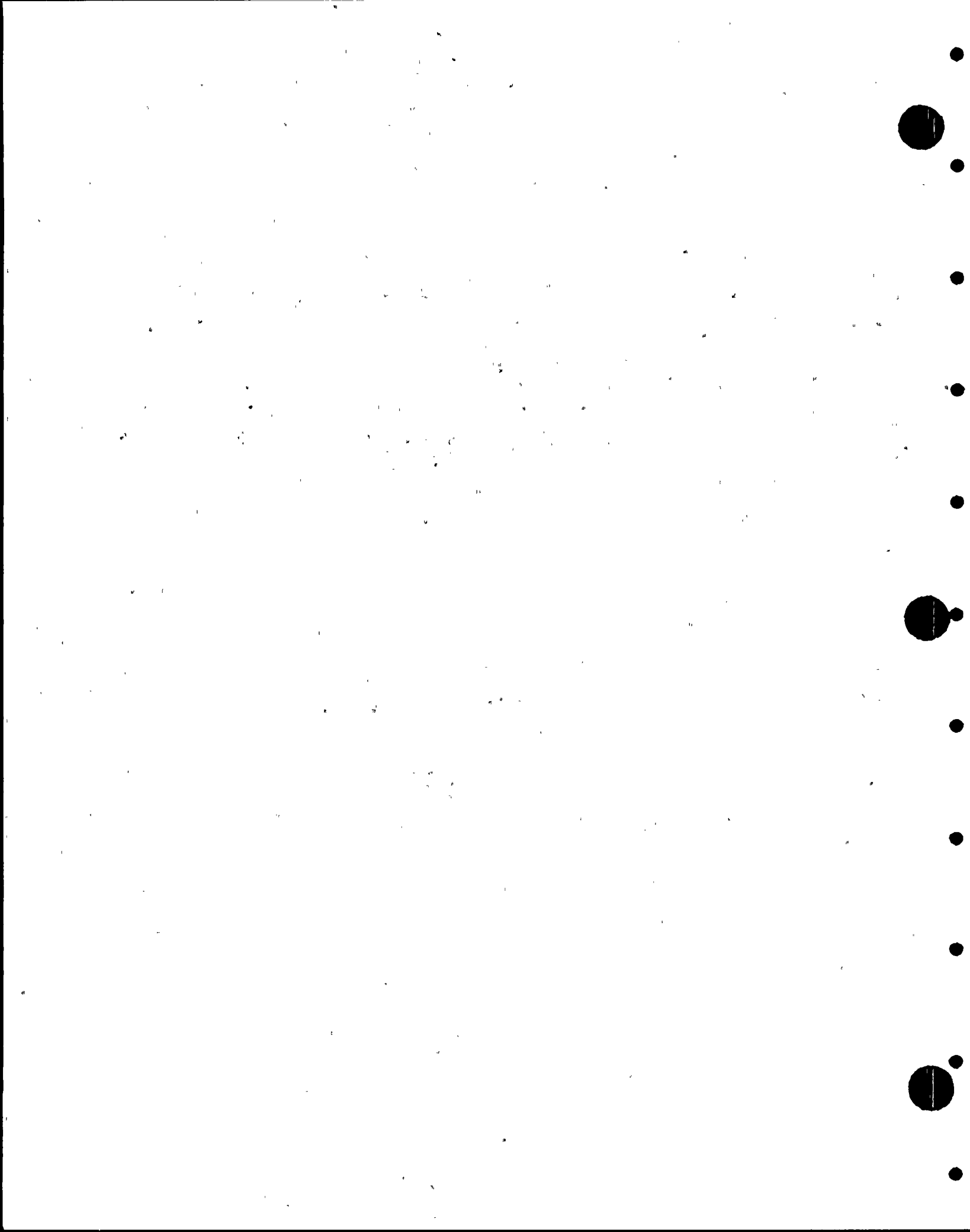
1 from Operations or do you want to carry it as an open item
2 and then respond as an open item?

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

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

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

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



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

4 MR. STERLING: Yes, that's correct.

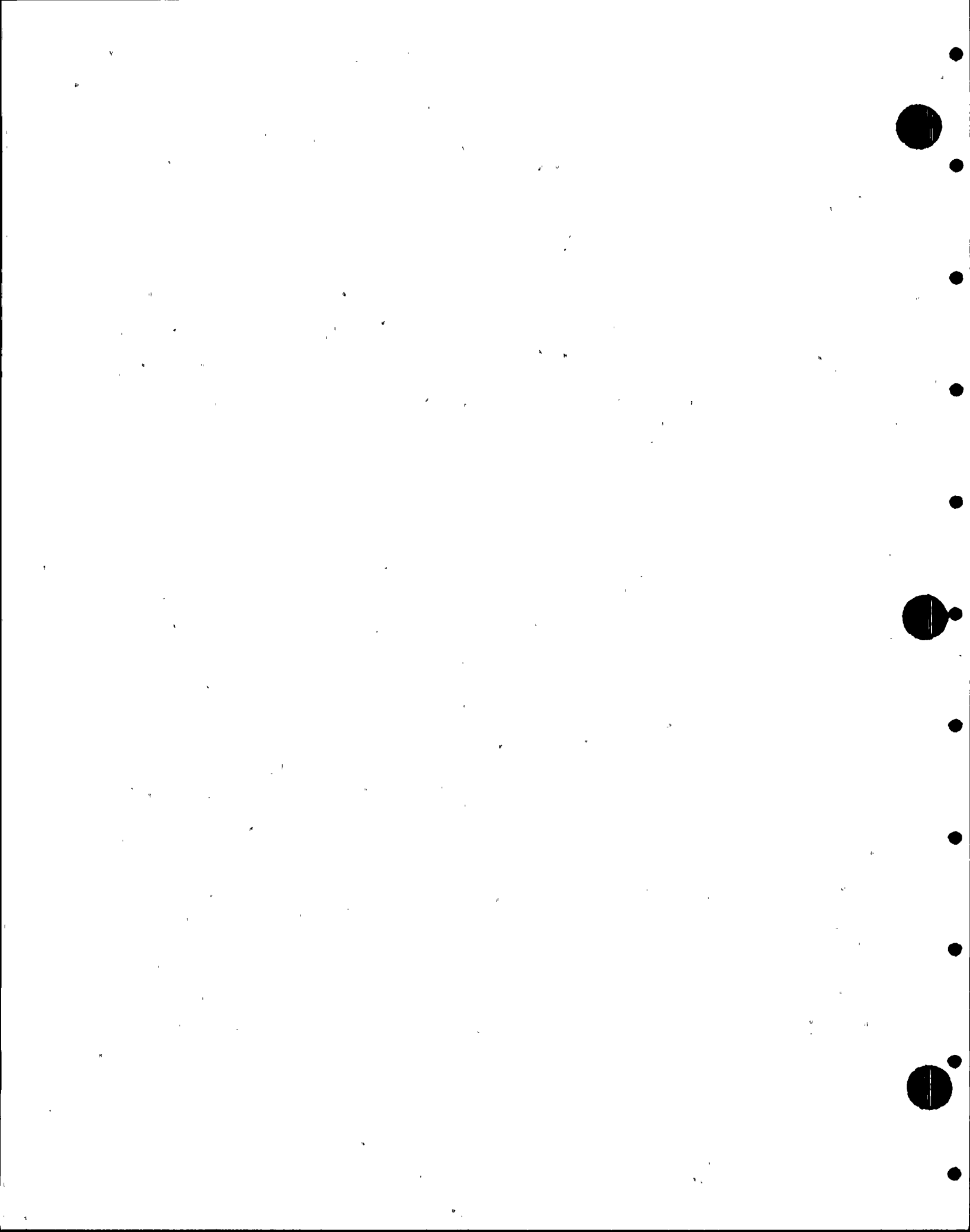
5 MR. BESSETTE: I have two other questions, much more
6 general. One is has any consideration been given to the
7 functional grouping of indicators and controls to layout and
8 design of the control board?

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

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

20 MR. BINGHAM: No.

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



1 (Thereupon the meeting was at recess.)

2

3

June 17, 1981
1:20 p.m.

4

5

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

7

Seeing none, go ahead, Bill.

8

9

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

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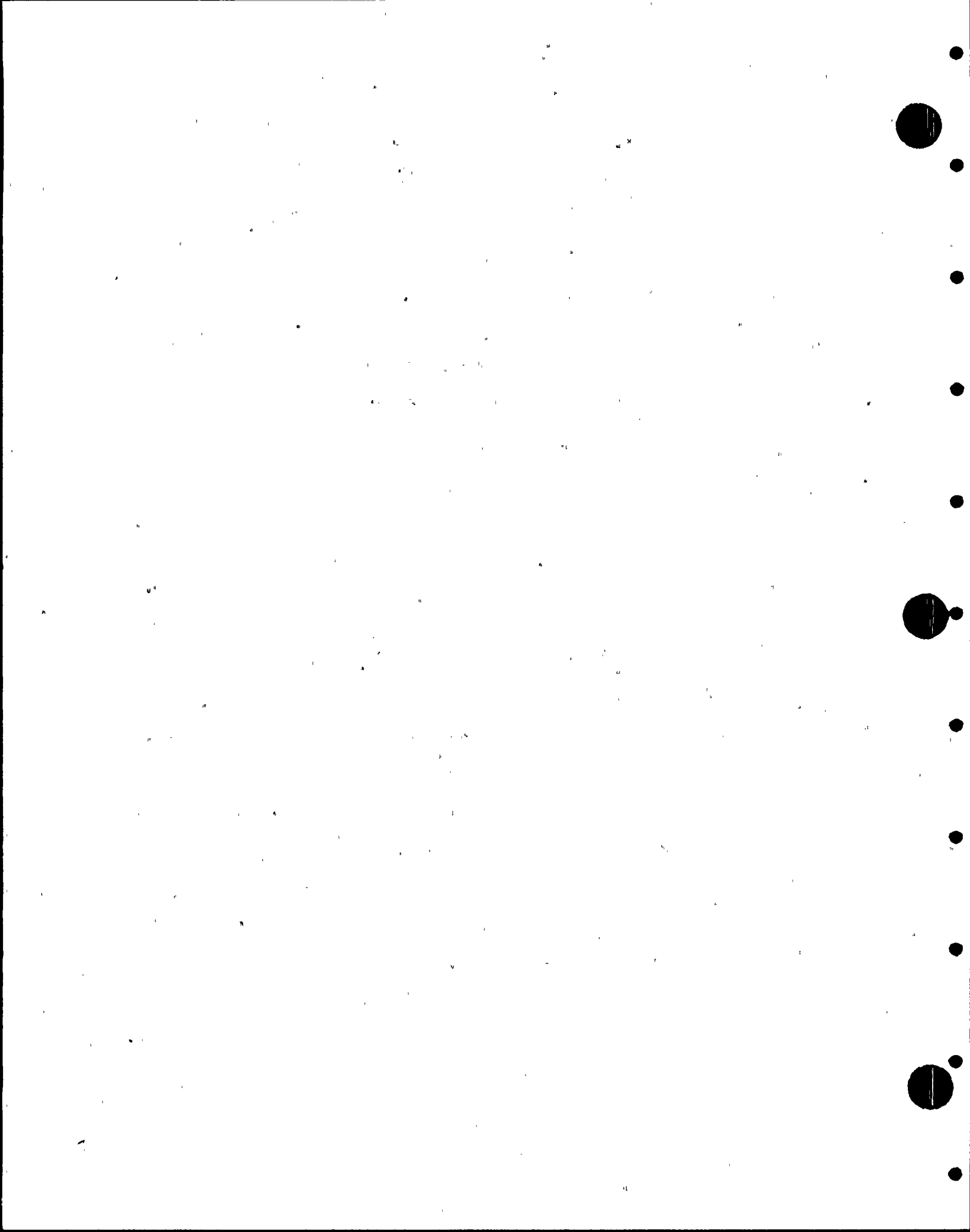
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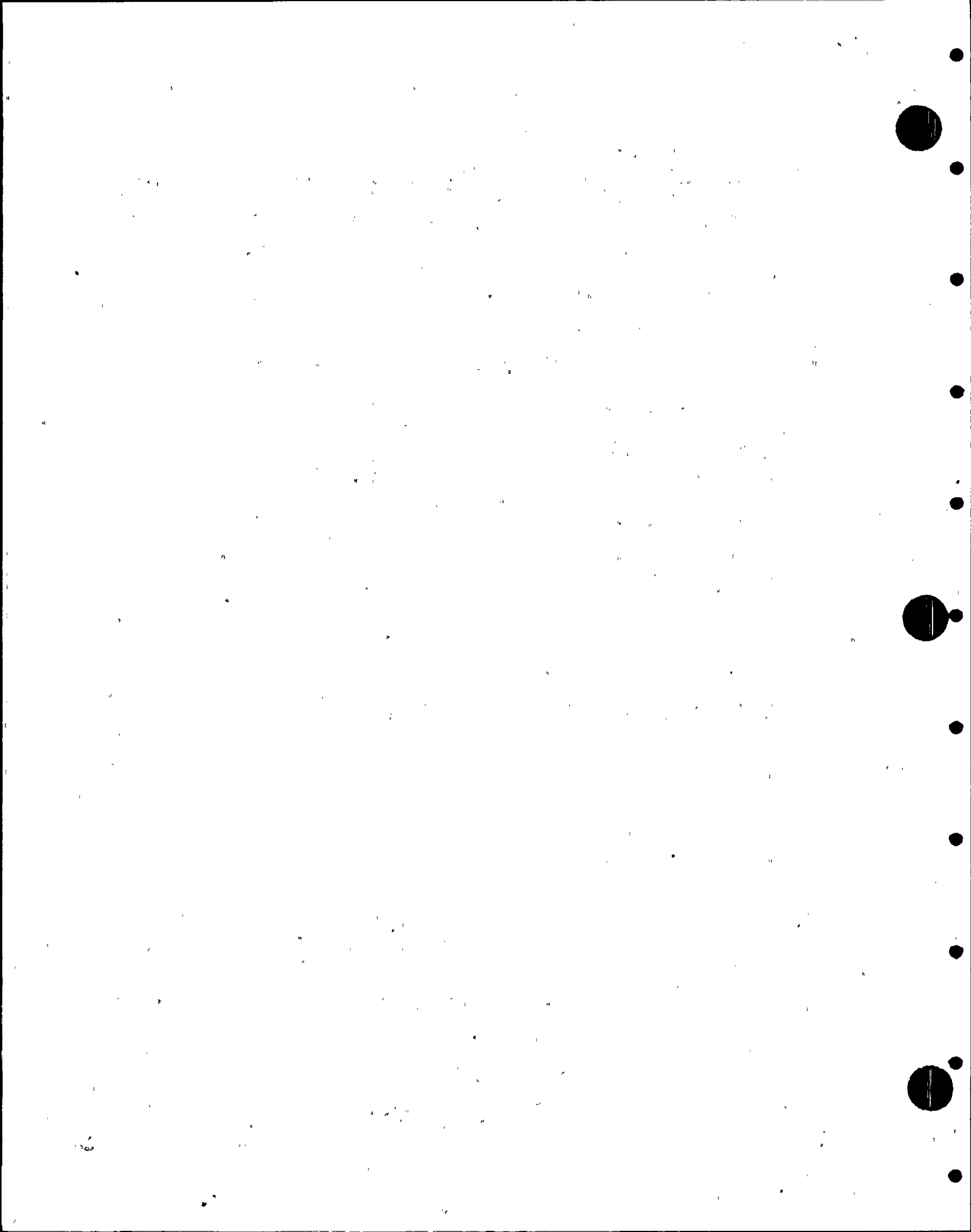
MRS. MORETON: Figure 2B-1 identifies those systems
required for safe shutdown. It includes the electrical and
mechanical devices and circuitry required to achieve and
maintain a safe shutdown condition of the plant. There are
sensors, device logic, control room displays, remote
shutdown displays for 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



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

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

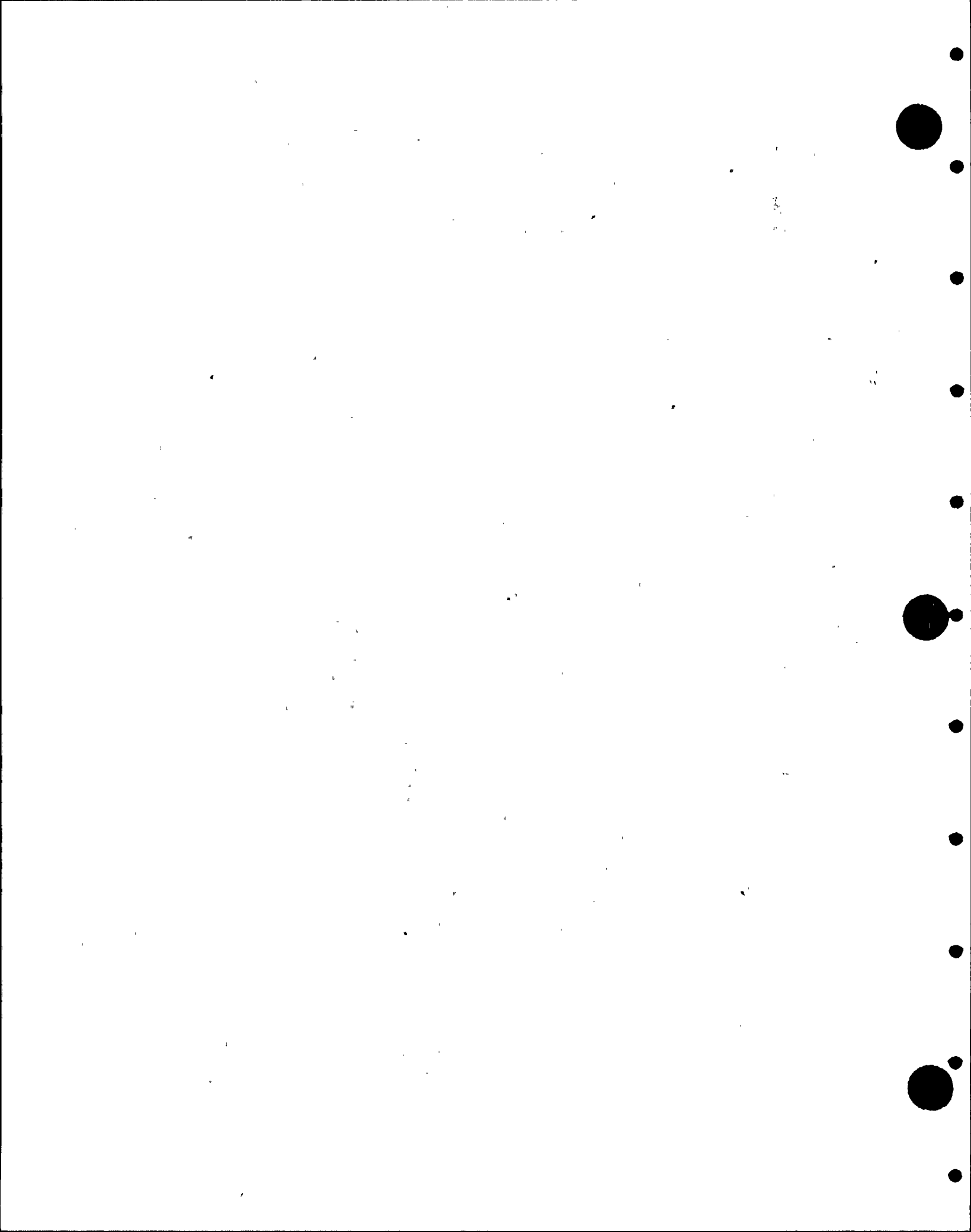
23 Exhibit 2B1-2, continuing with design criteria.
24 Design basis accidents are assumed not to occur simultaneously
25 with control room evacuation. LOP and seismic events shall



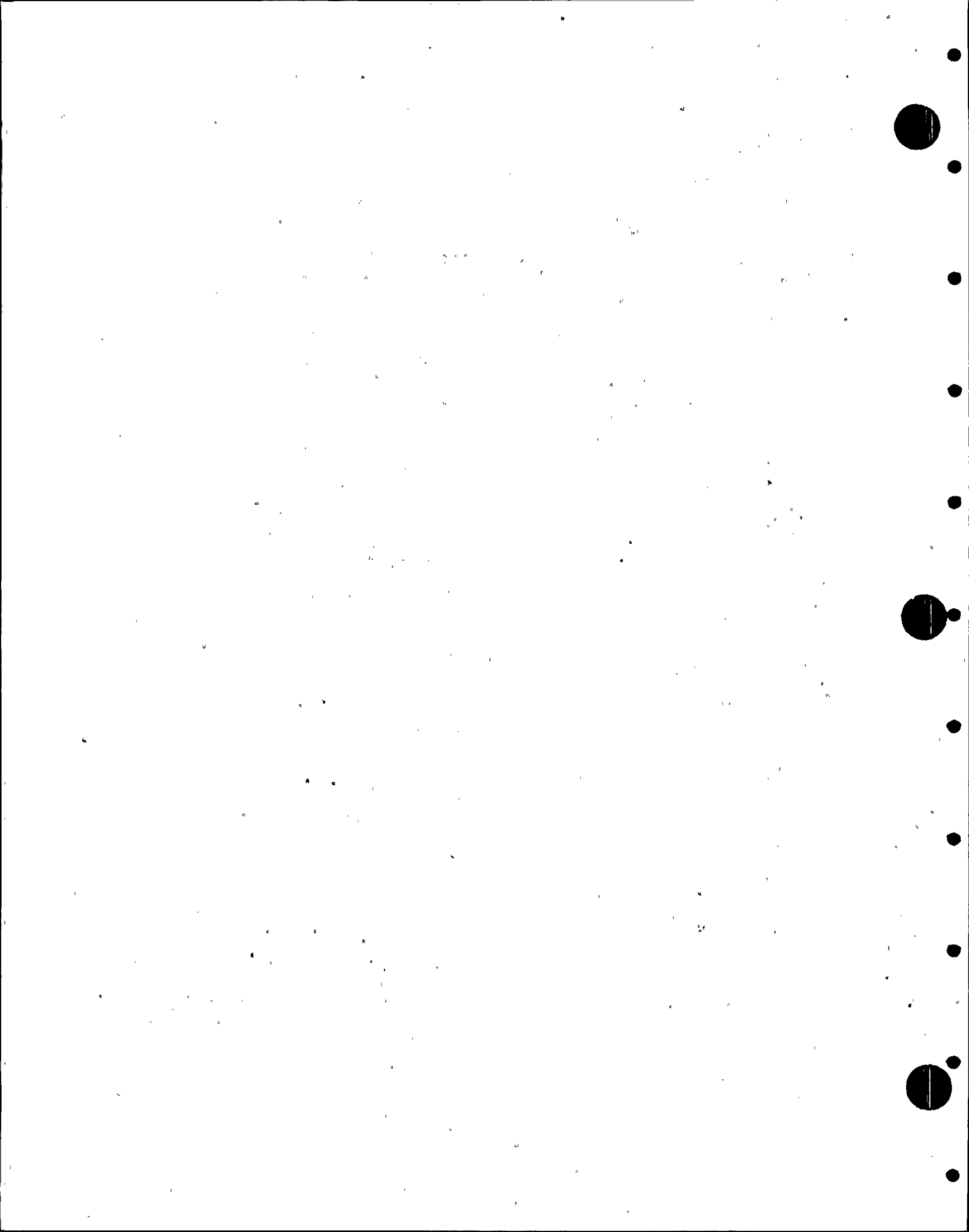
1 not jeopardize the safe shutdown function. Systems, controls,
2 and indications essential to the residual heat removal
3 function during hot shutdown shall be designed with suitable
4 redundancy in accordance with 10CFR50, Appendix A, GDC 34,
5 "Residual Heat Removal." Loss of safe shutdown system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

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

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



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

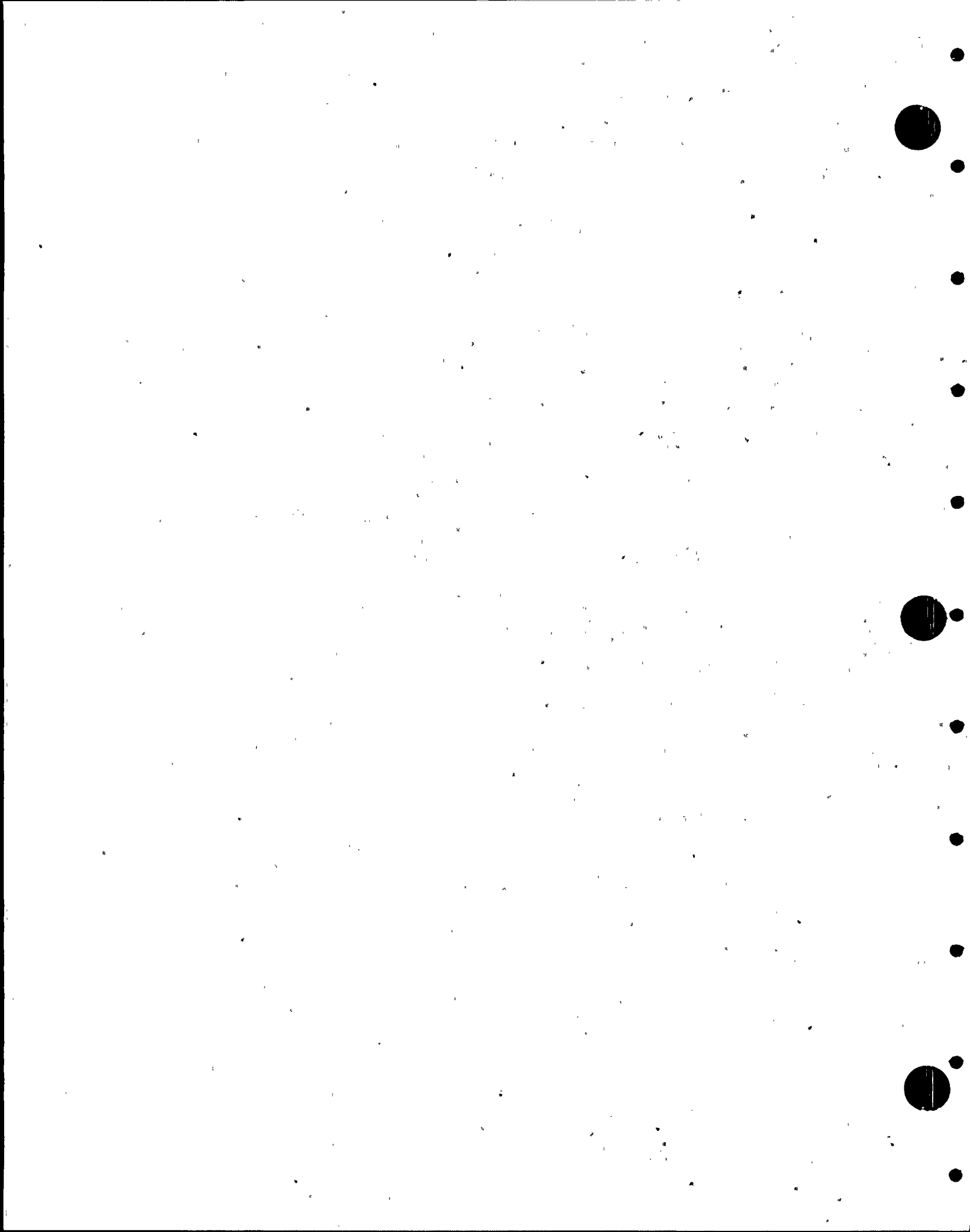


1 and here (indicating) for Train B. The Train A remote
2 shutdown panel is physically separated from the Train B
3 remote shutdown panel by a fire wall separating the two
4 panels. There is an access door providing access to the
5 panels.

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

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

25 Exhibit 2B1-7 identifies the controls at the

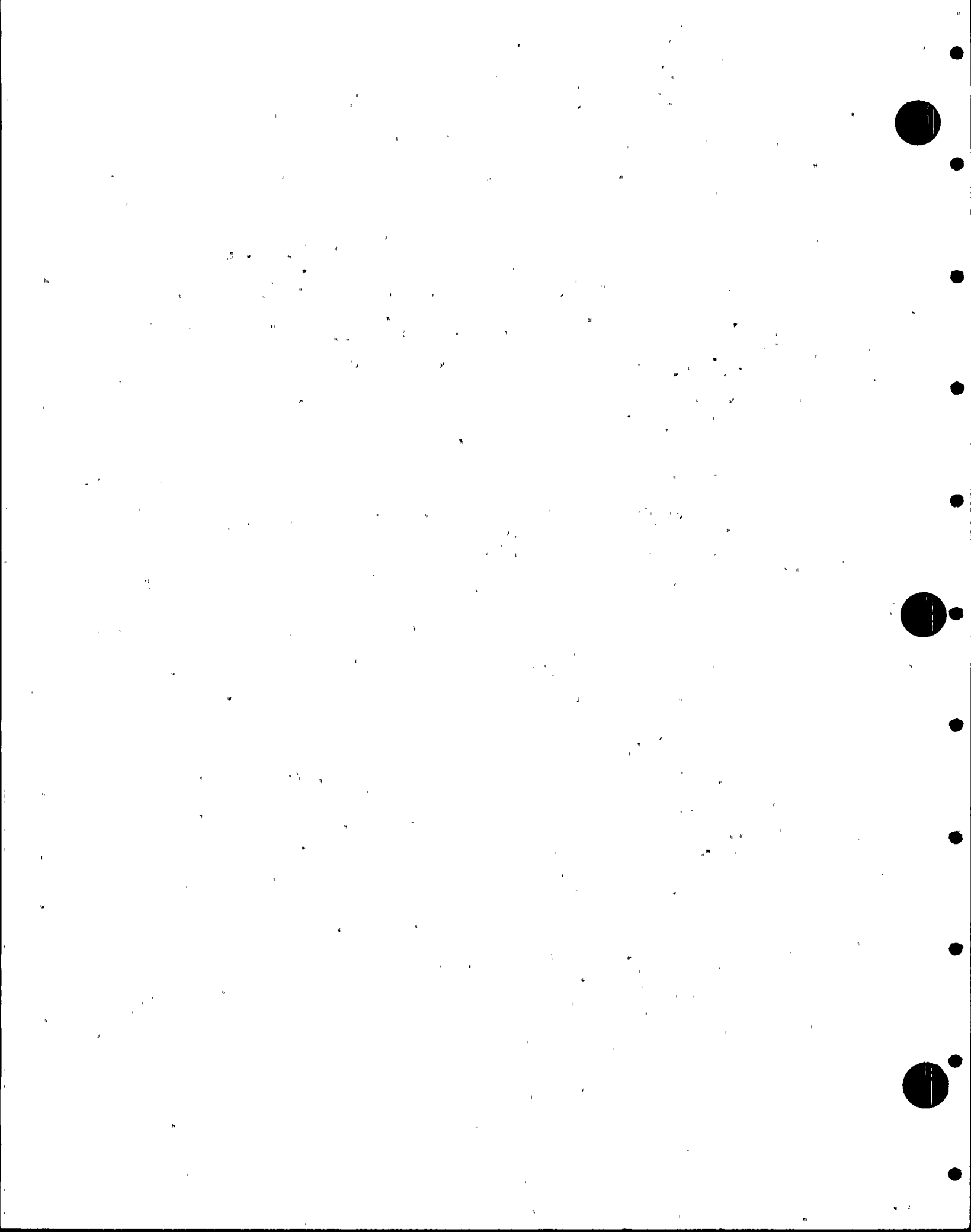


1 remote shutdown panel. Again, redundancy is provided in
2 Channel A and Channel B. There is a point of clarification.
3 The auxiliary feedwater Channel A system is a DC system
4 and, therefore, has controls associated with the pump,
5 because it is turbine driven, but you do not see it duplicated
6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

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

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

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



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

10 That concludes the discussion on safe shutdown.

11 MR. ALLEN: Any questions? Jack.

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

15 MR. BINGHAM: Yes.

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

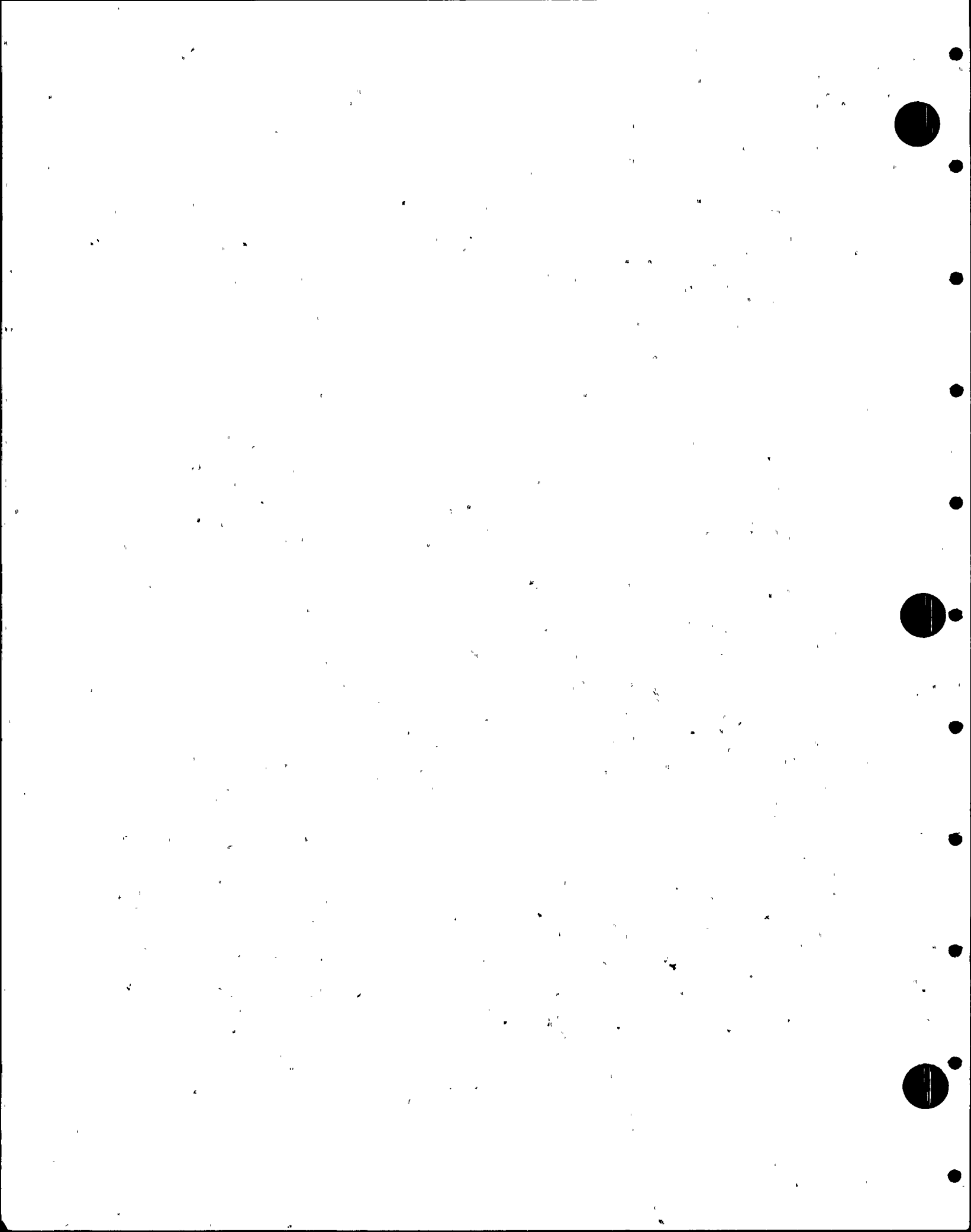
18 MISS KERRIGAN: With no local operation required?

19 MR. KEITH: Correct.

20 MR. ROSENTHAL: What about the SIT isolation valves?

21 MR. BINGHAM: What about it? Excuse me.

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



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

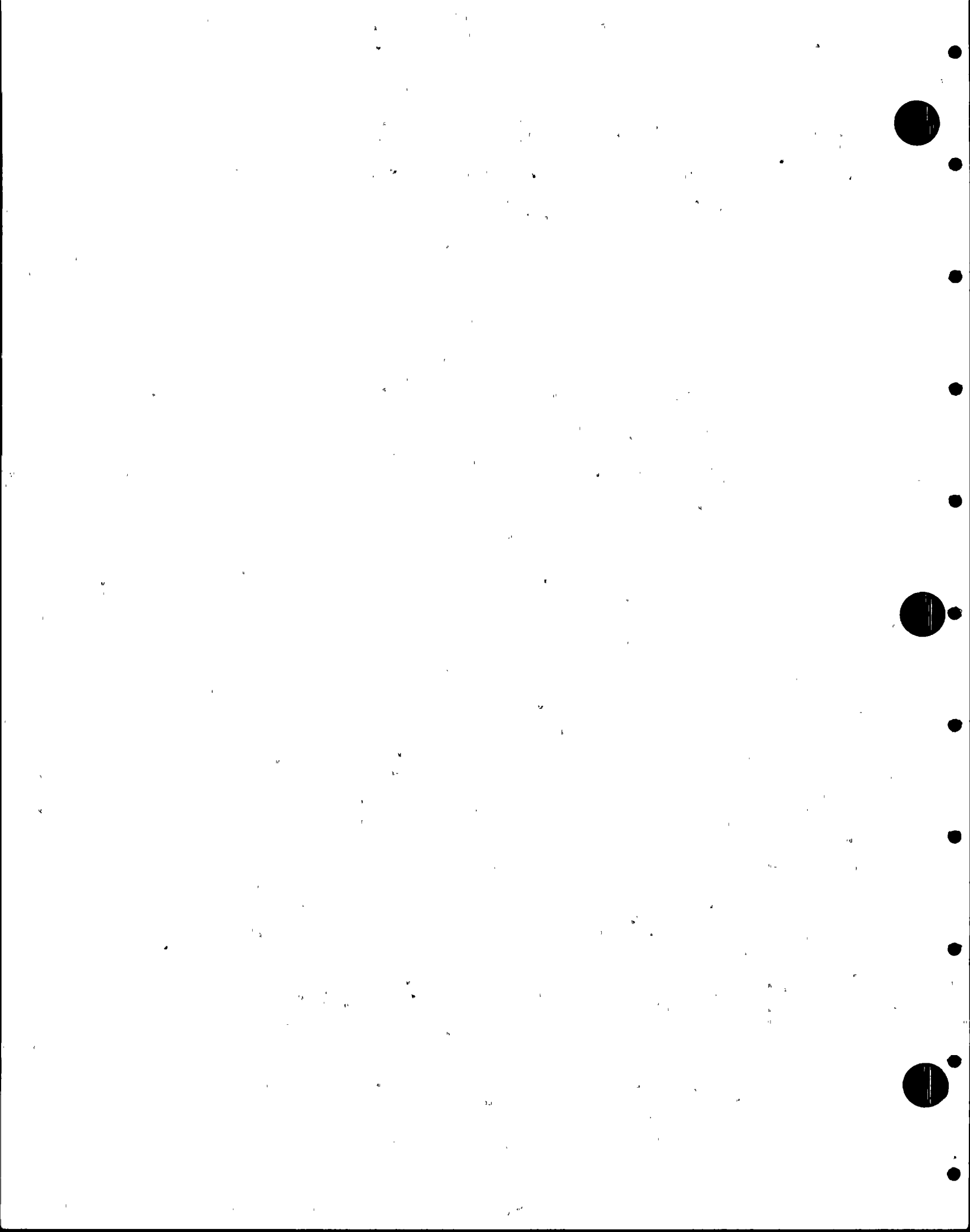
7 MR. KEITH: Jack, we can depressurize the safety
8 injection tanks from the control room. I was concerned
9 about a possible conflict between this answer and my last
10 answer, but we achieve cold shutdown leaving those isolation
11 valves open.

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

14 MR. KEITH: From the control room.

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

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



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

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

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

12 MISS KERRIGAN: Yes.

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

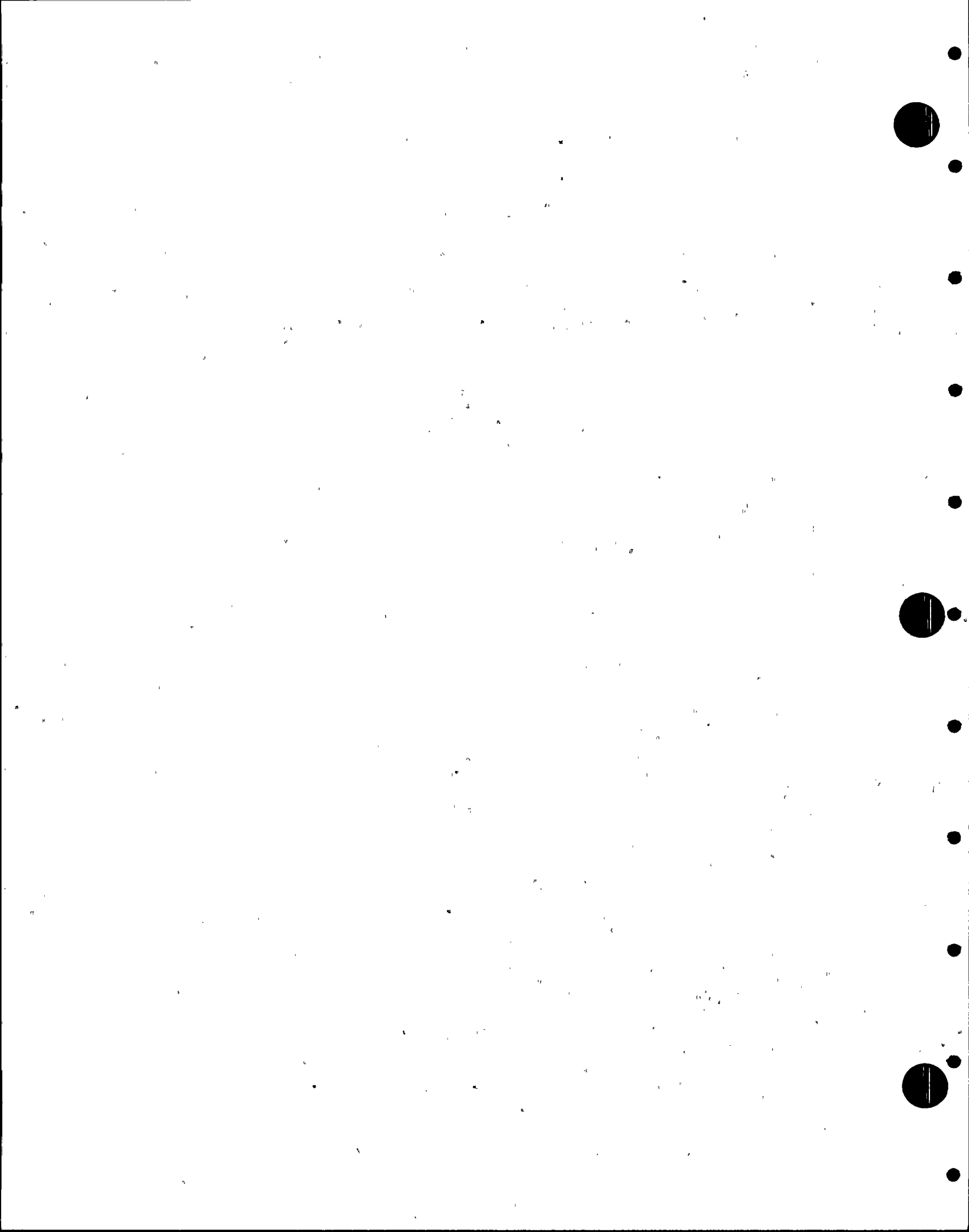
15 MR. BARNOSKI: No. Clearly, the normal way would be
16 to close the valves.

17 MISS KERRIGAN: Right.

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

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

25 MR. ROSENTHAL: No, in emergency.



1 MISS KERRIGAN: Yes.

2 MR. ROSENTHAL: Using emergency procedures.

3 MISS KERRIGAN: Right.

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

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

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

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

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

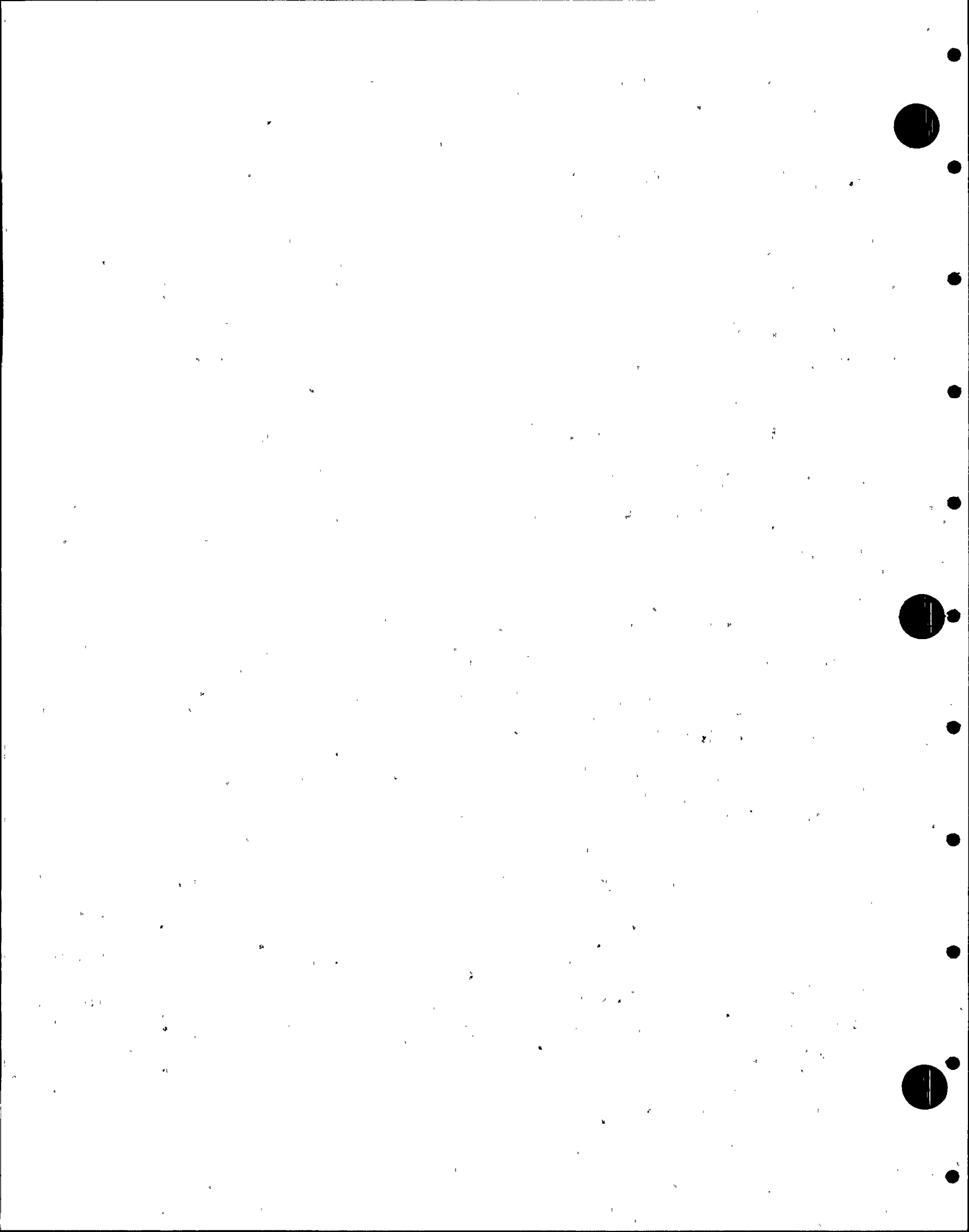
16 MR. KEITH: We meet CE requirements on the system.
17 We have two valves in series as far as the vent on the
18 safety injection tanks which are powered from different
19 power sources.

20 MR. KONDIC: Thank you.

21 MR. ALLEN: Any other questions?

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

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



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

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

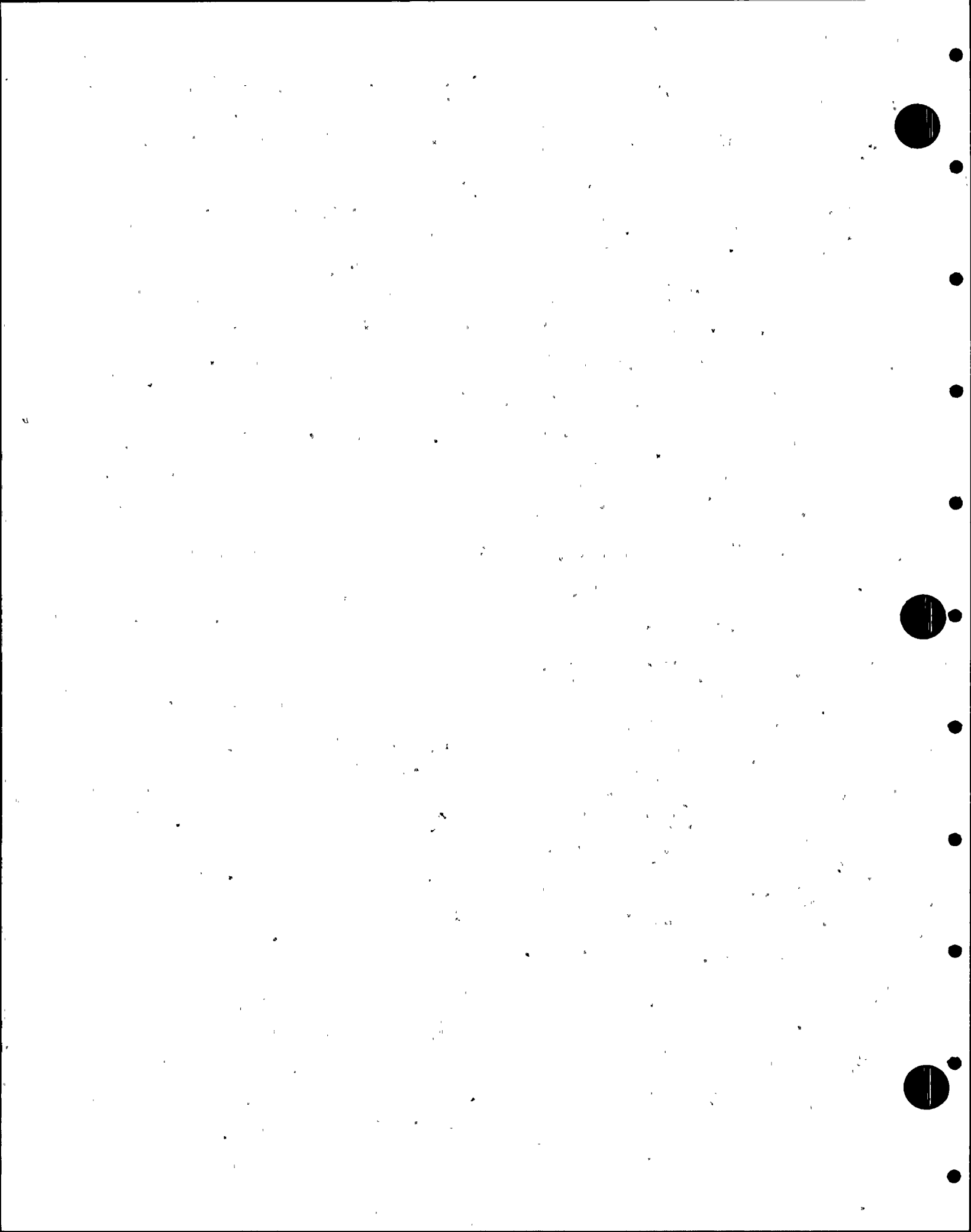
5 MR. BINGHAM: We would leave that as CE.

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

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

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

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



1 MISS KERRIGAN: And still meet all the requirements.

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

4 MISS KERRIGAN: Yes.

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

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

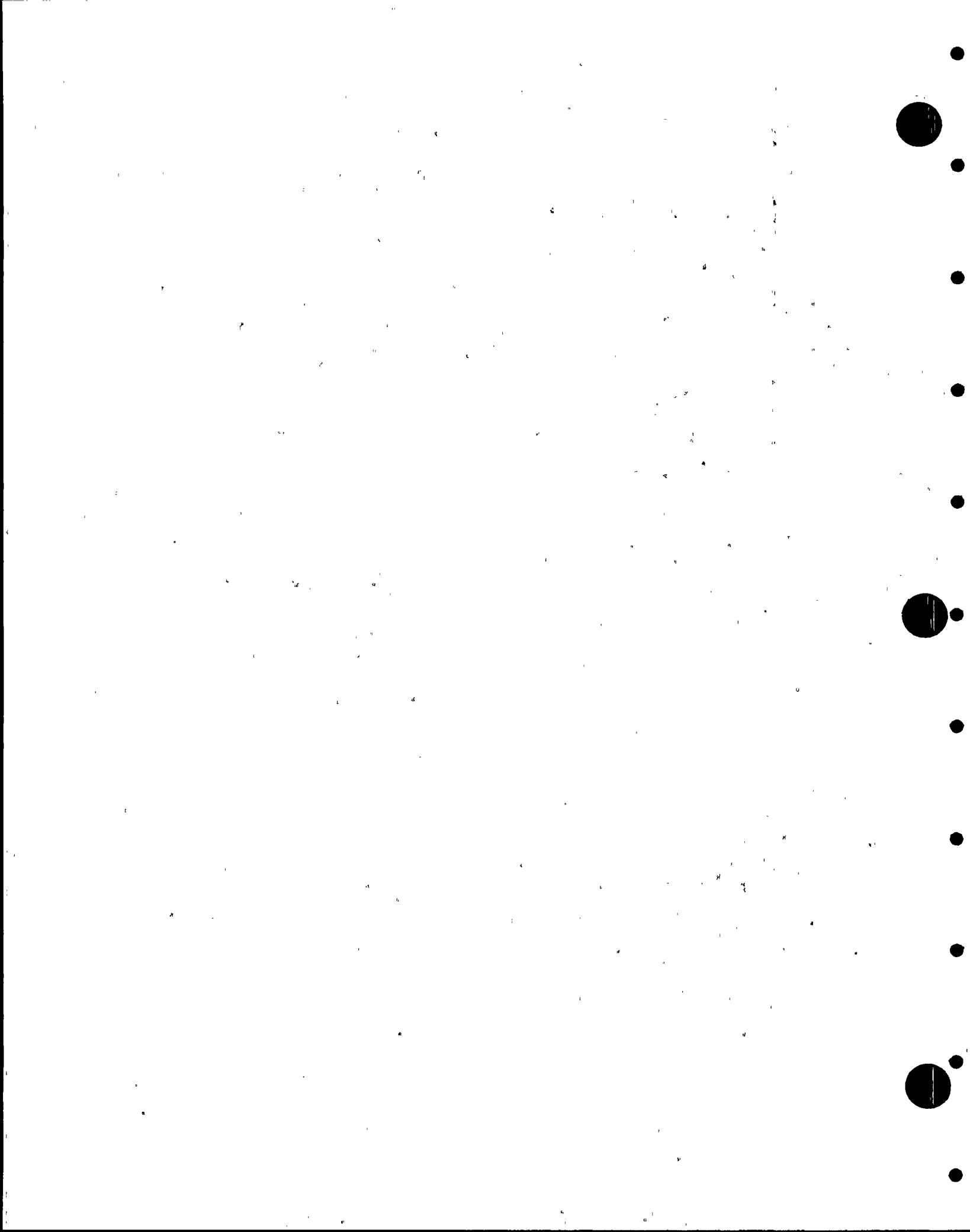
11 MR. SIMKO: Did we ever get a valid question out of
12 this? I am not sure what they are asking.

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

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

18 MR. ROSENTHAL: Five/six.

19 MR. BINGHAM: The reason that we are concerned is
20 because we try very hard in these presentations to address
21 all the Branch Technical Positions and the SRP's, and for
22 7, of course, it will be absent from this presentation. If
23 it is in 5, we would expect that that would be a CESSAR
24 directed question, and that is why I want to get that
25 clarification so that you understand you won't see it today.



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

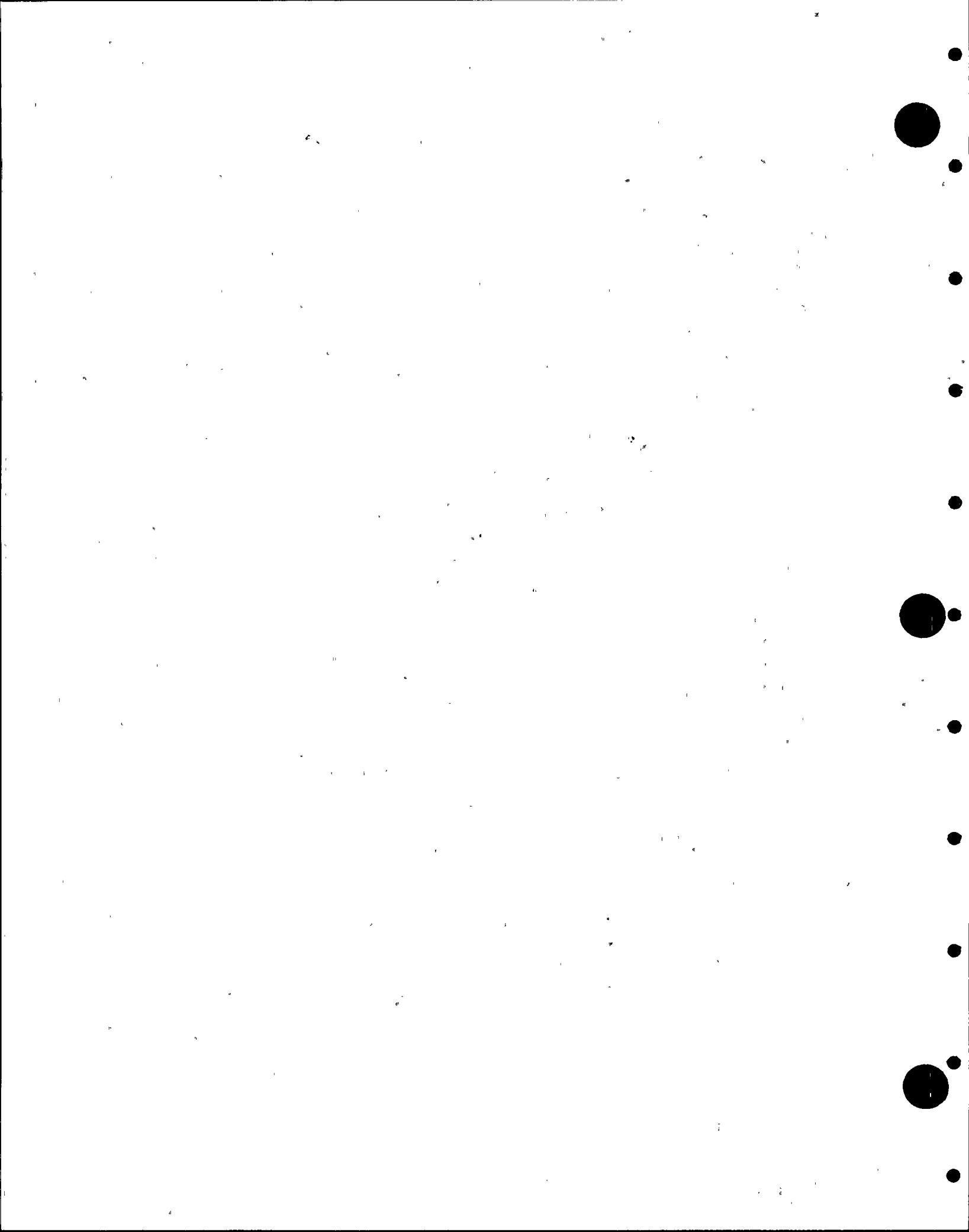
5 MR. ALLEN: Additional questions? Go ahead, Jack.

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

11 MR. BINGHAM: Is there more to the question?

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

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



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

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

9 MR. KEITH: We intend to meet the requirements.

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

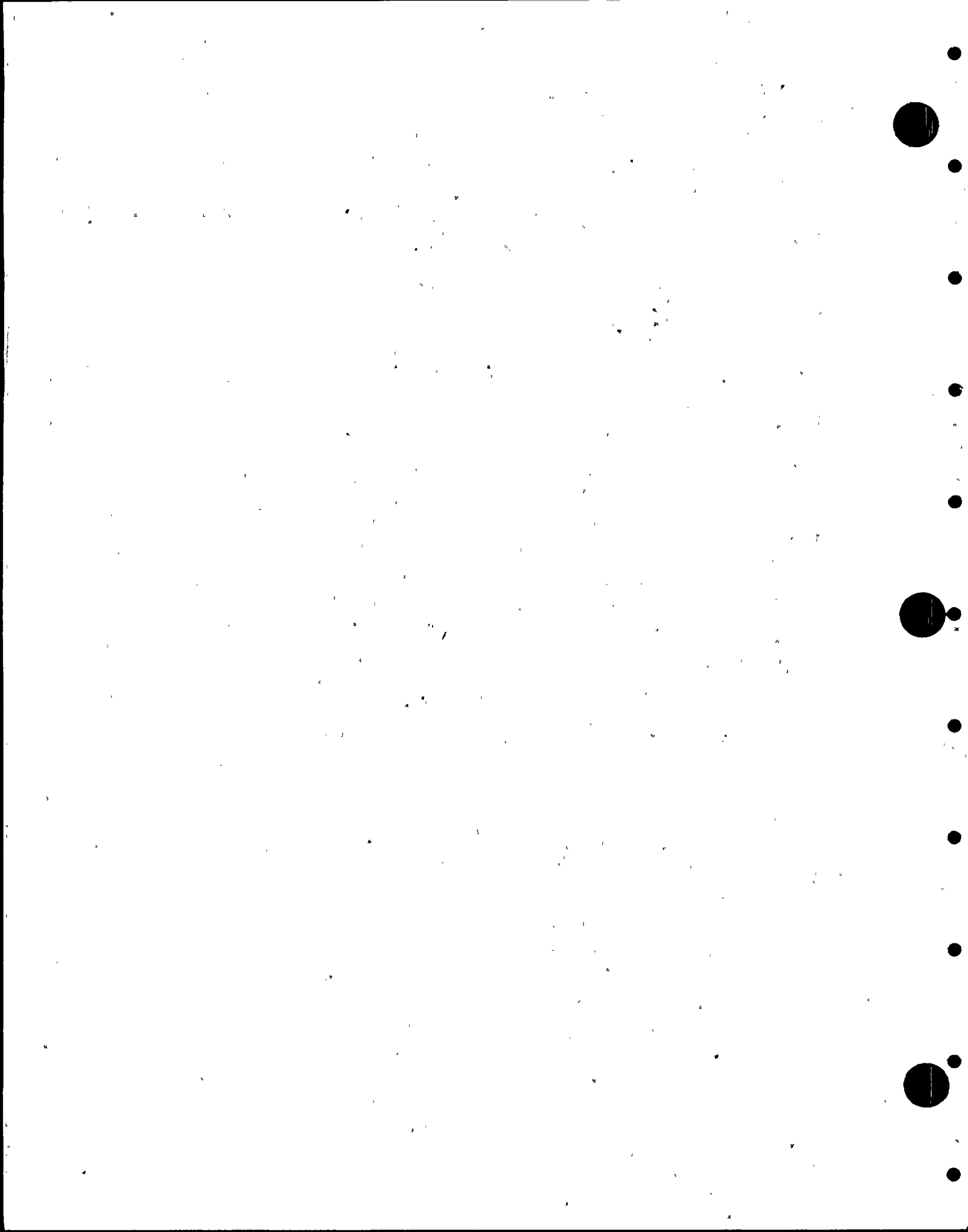
14 MR. KEITH: If it is equipment required for hot
15 shutdown. Hot shutdown we are doing at the remote shutdown
16 panel. For all other equipment, we can control it outside
17 the control room, but not at the remote shutdown panel.

18 MISS KERRIGAN: Through manual procedures?

19 MR. KEITH: Yes.

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

25 MR. KEITH: That's correct.



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

3 MR. KEITH: That's correct.

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

6 MR. KEITH: Yes.

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

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

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

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

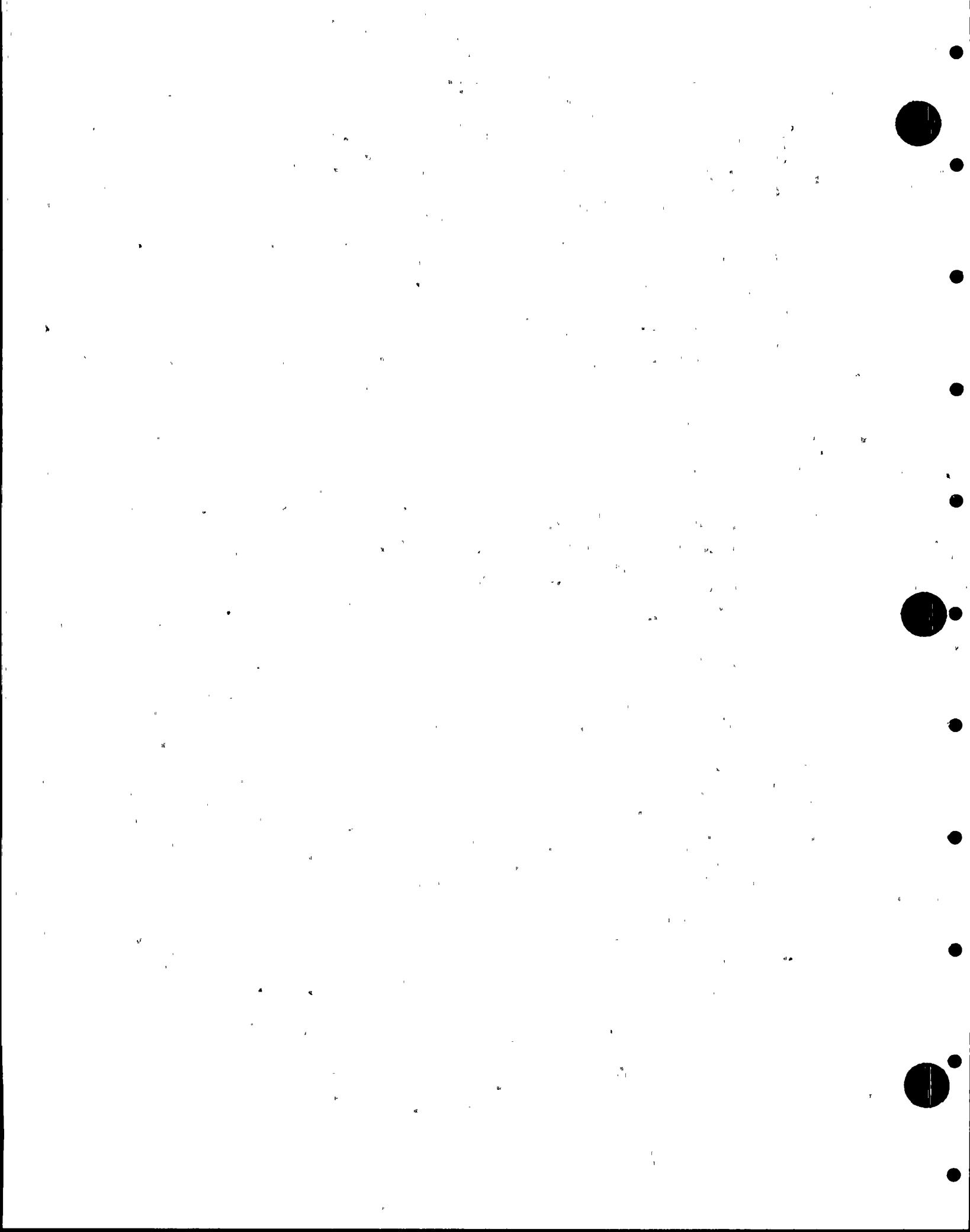
16 MR. STERLING: Utilizing that equipment.

17 MR. KEITH: Utilizing that equipment, yes.

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

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

25 MR. BINGHAM: The procedures that we have been using



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

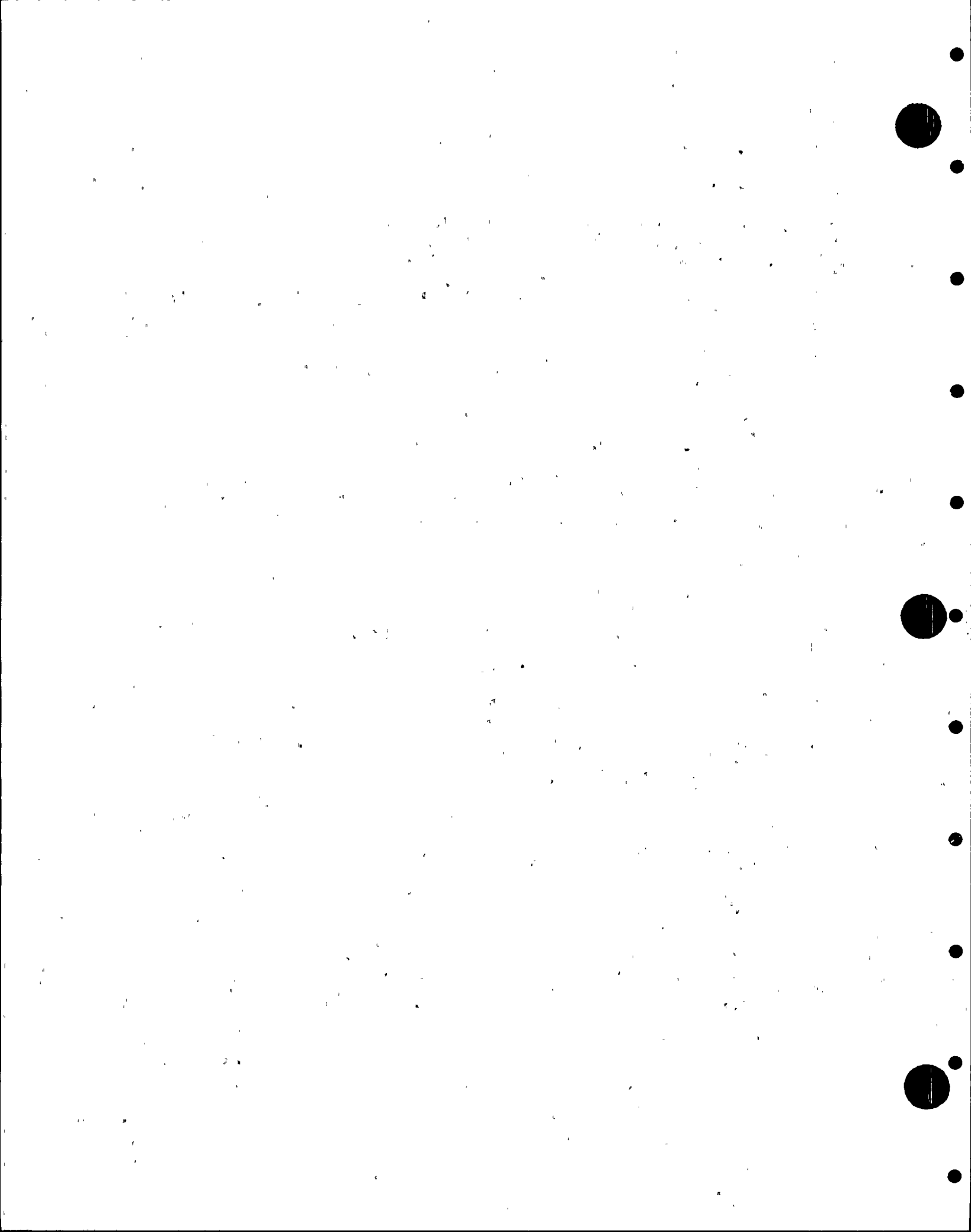
12 MR. ALLEN: Go ahead.

13 MR. MECH: How do you plan to limit the access to
14 the remote shutdown area? It has doors I noticed on Figure
15 2B1-4 where it shows the doors.

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

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

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



1 fire protection requirements.

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

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

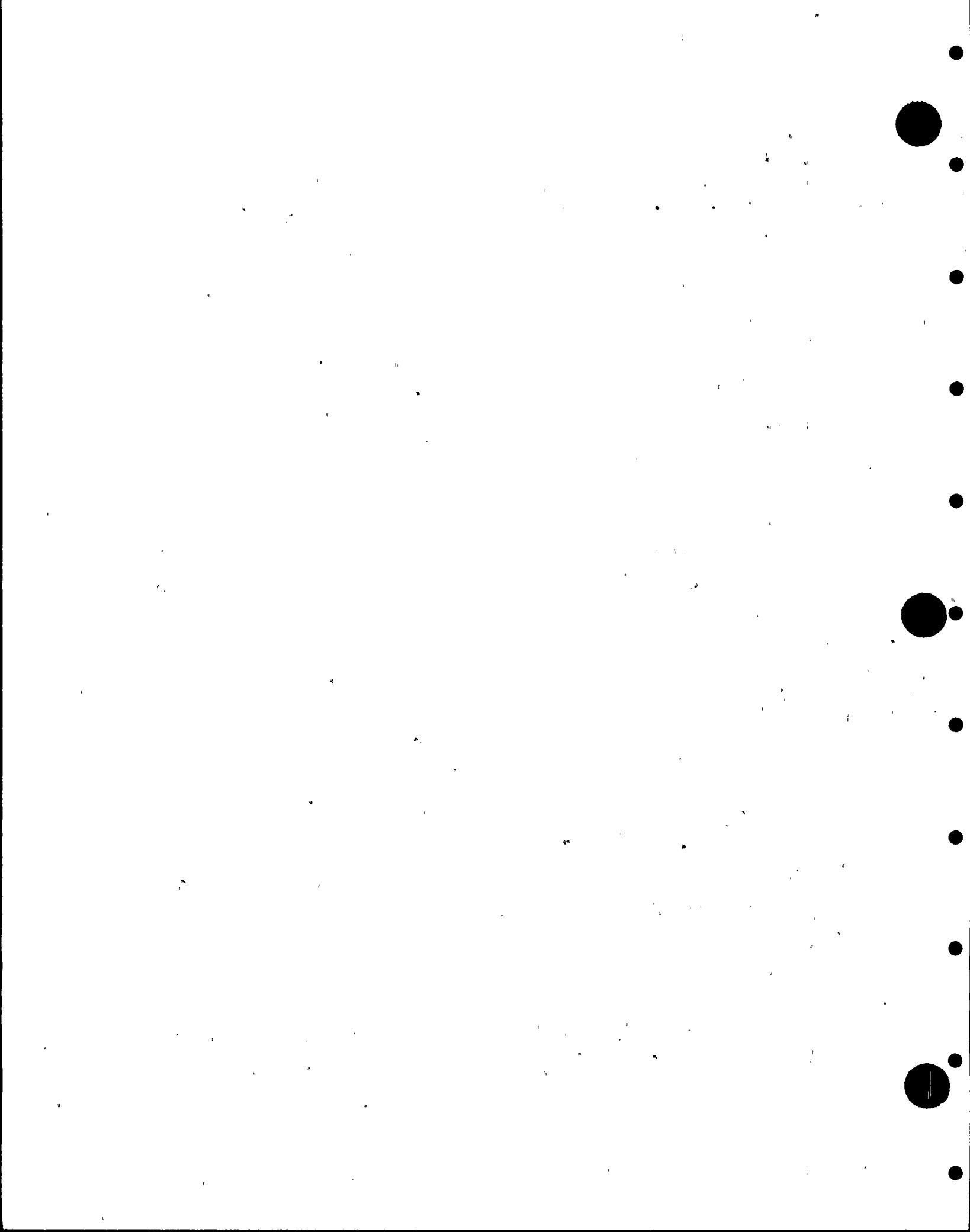
7 MR. HELMAN: Those doors labeled (C) and (D) here
8 and the interim door are controlled and require a high level
9 of access. Does that answer your question?

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

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

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

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



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

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

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

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

16 MR. SOTEROPOULOUS: Yes, sir.

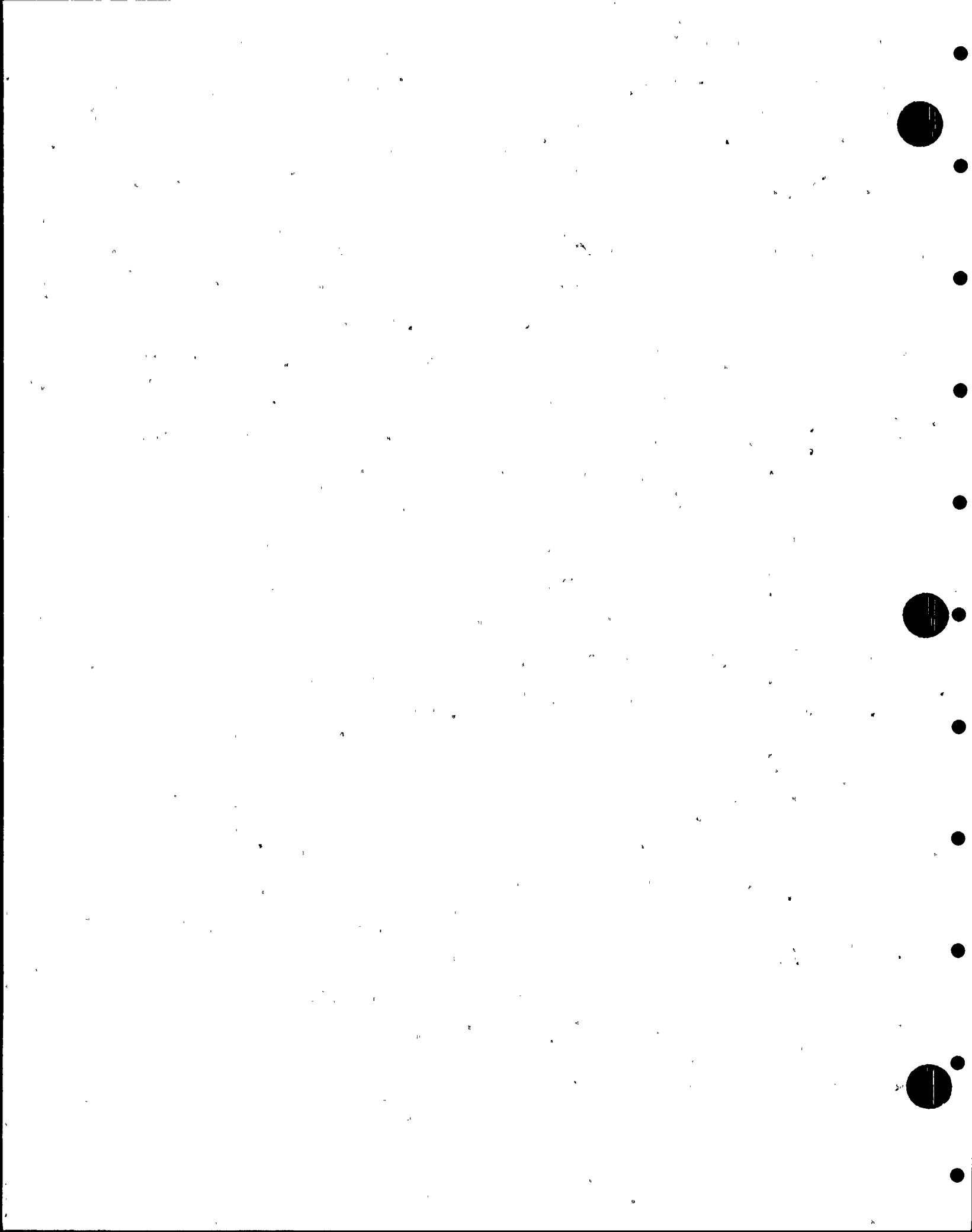
17 MR. MECH: So if you had an operator there, you could
18 talk to him?

19 MR. SOTEROPOULOUS: Yes.

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

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

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



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

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

11 MR. ROSENTHAL: No.

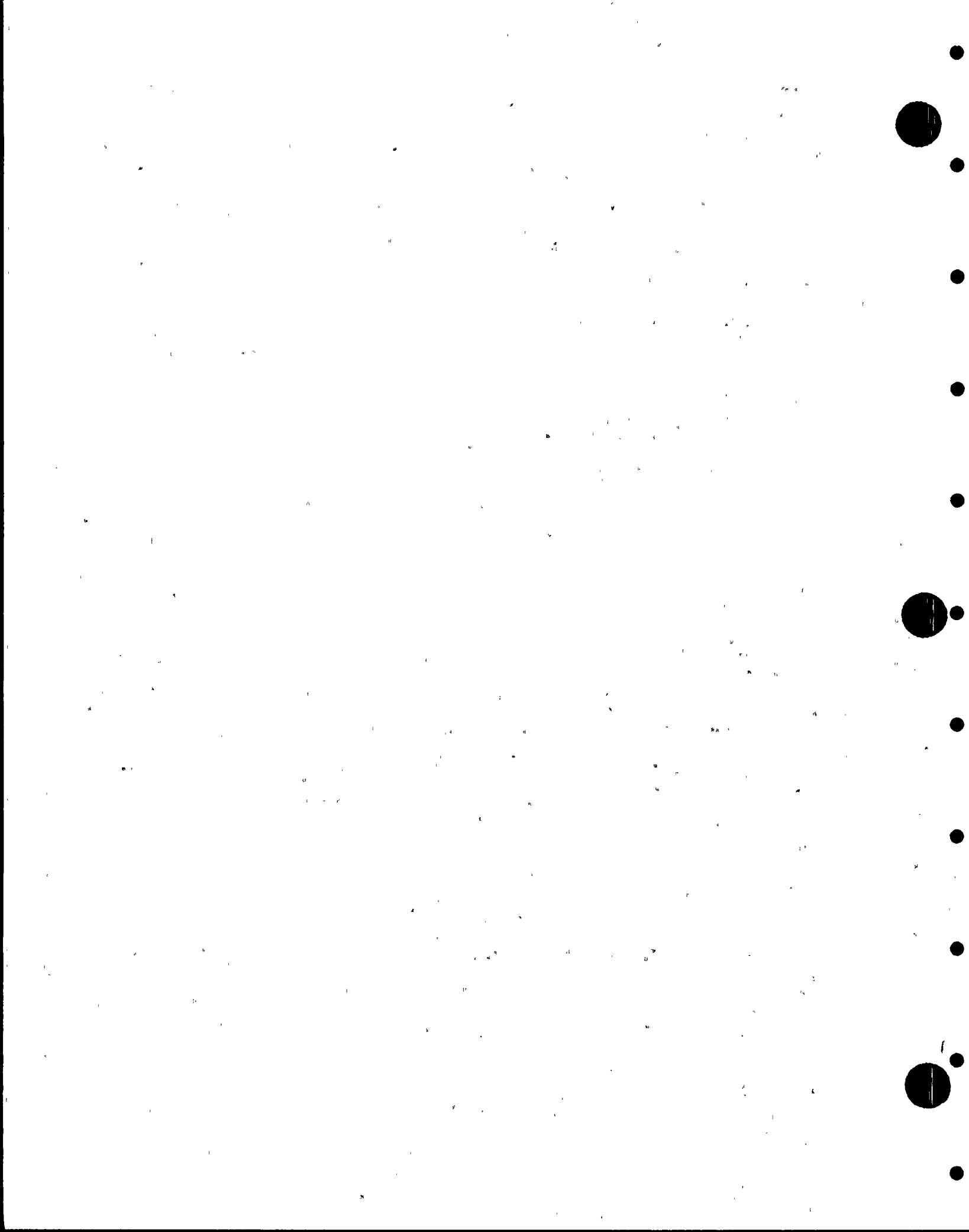
12 MR. MECH: One last question. On Figure 2B1-1, I
13 observe that the remote shutdown panel is in the same building
14 as the control room. This is at elevation 100. The control
15 room is up 40 feet, but otherwise the remote shutdown panel
16 is substantially fairly close to the main control room.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

21 MR. ROSENTHAL: Exclusive of fire.

22 MR. MECH: Exclusive of fire.

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

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



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

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

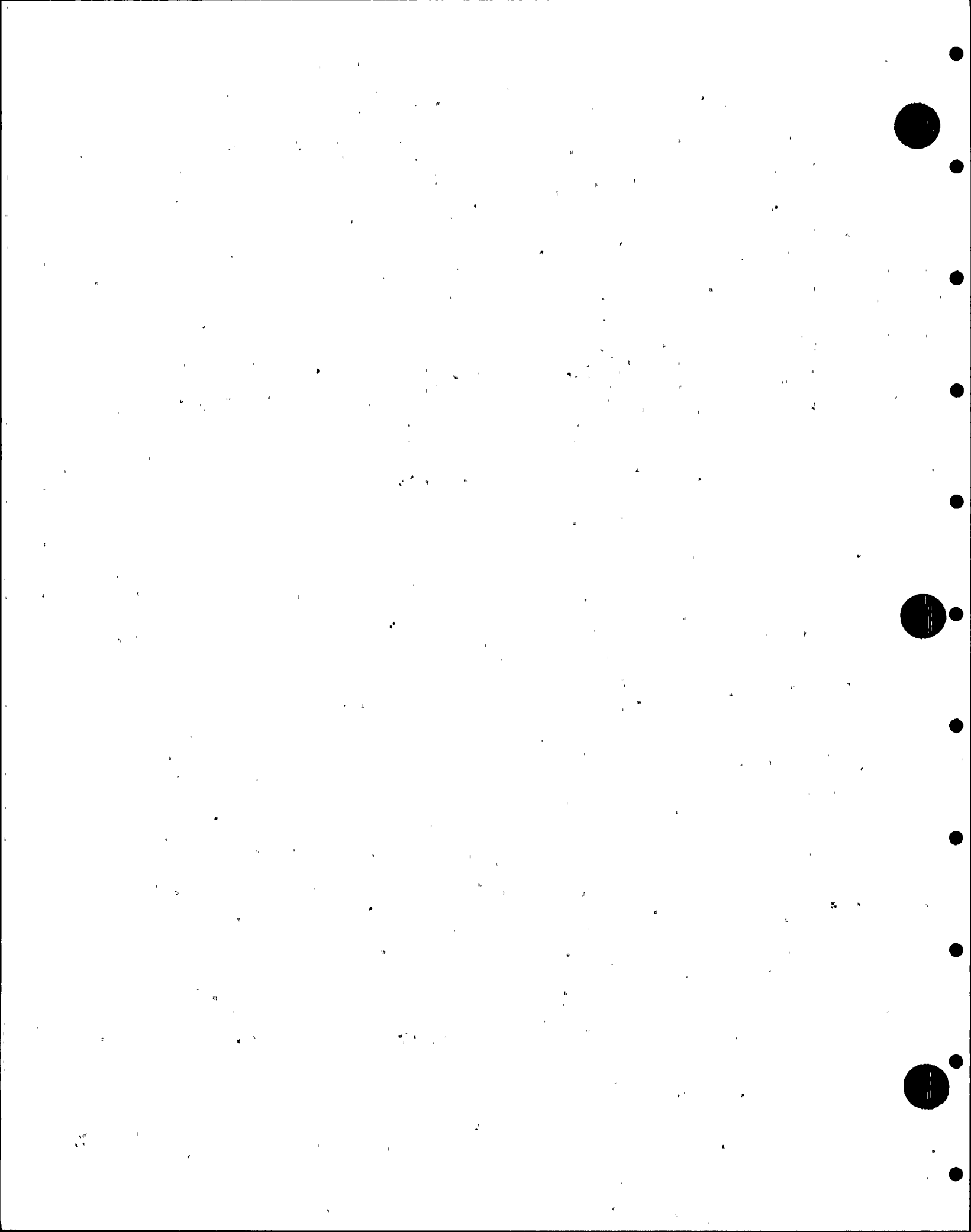
7 MR. KEITH: The requirements for evacuation of the
8 control room, there has never been any mechanism postulated
9 for that other than a fire, which is under discussion, so
10 we haven't really done an analysis. Because there is no
11 mechanism postulated, there is, therefore, nothing to
12 analyze.

13 MR. MECH: All right. Thank you.

14 MR. ALLEN: Any other questions? Jack.

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

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

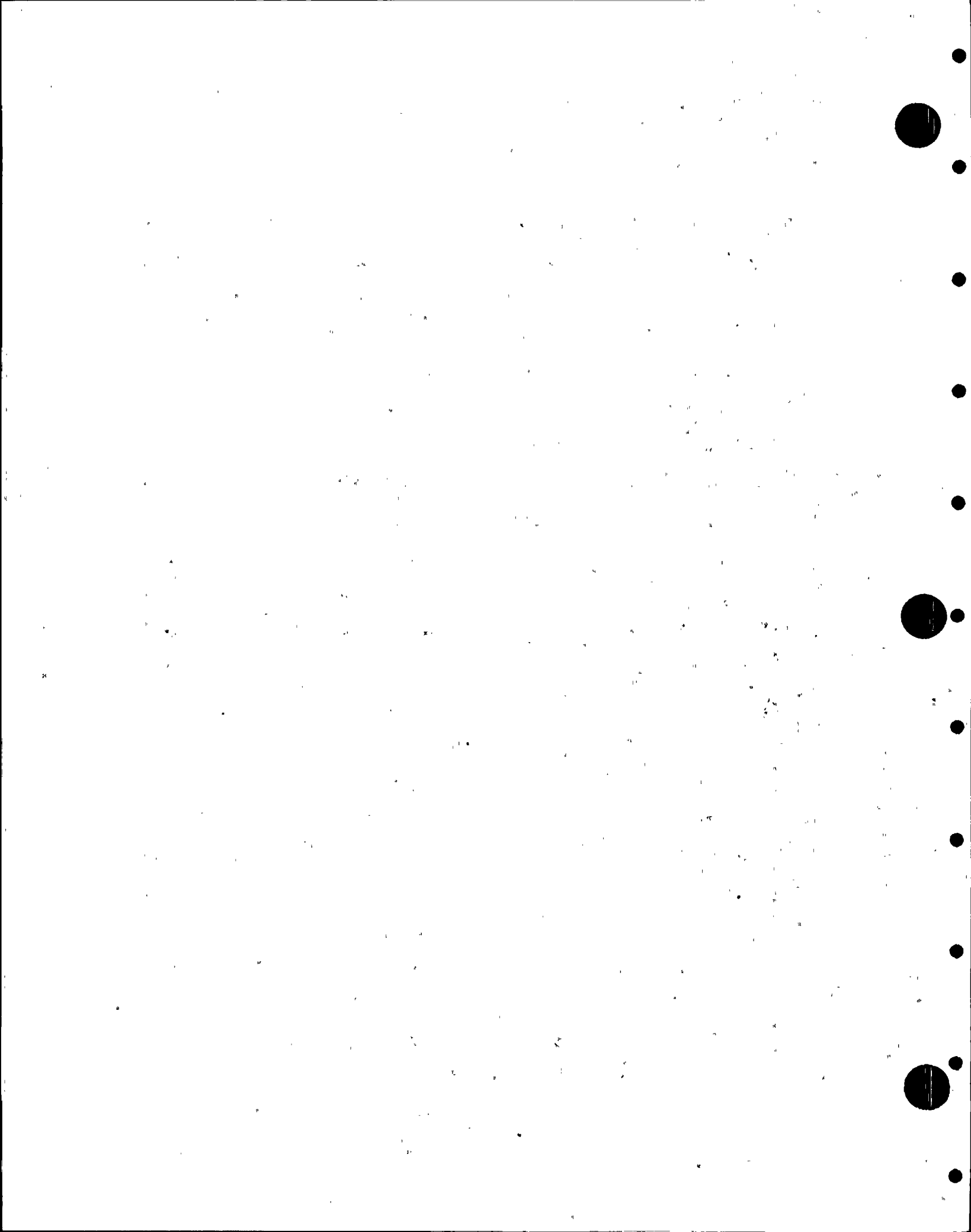


1 to deal with the issue, the single failure. In this
2 particular case, I am not sure exactly how we have handled
3 that. Maybe I am getting off --

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

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

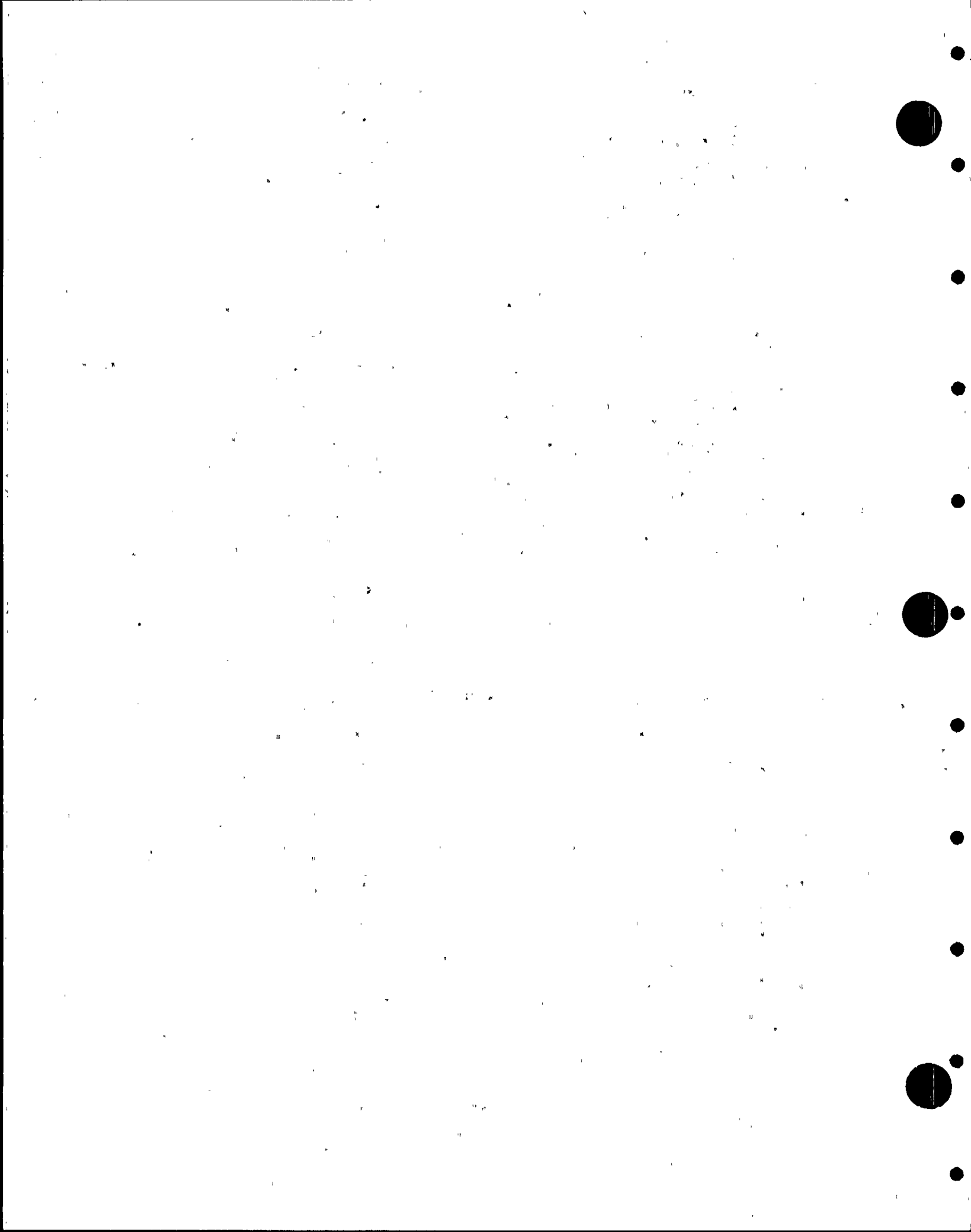
22 MR. SOTEROPOULOUS: The question of parallel control
23 from the control room with the remote shutdown panel, the
24 only controls that are there that are in fact parallel and
25 active are digital on/off controls for pumps specifically.



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

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

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



1 control centers or whatever to do those kinds of things.

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

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

9 MR. ROSENTHAL: When they are written.

10 MR. BINGHAM: When they are written.

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

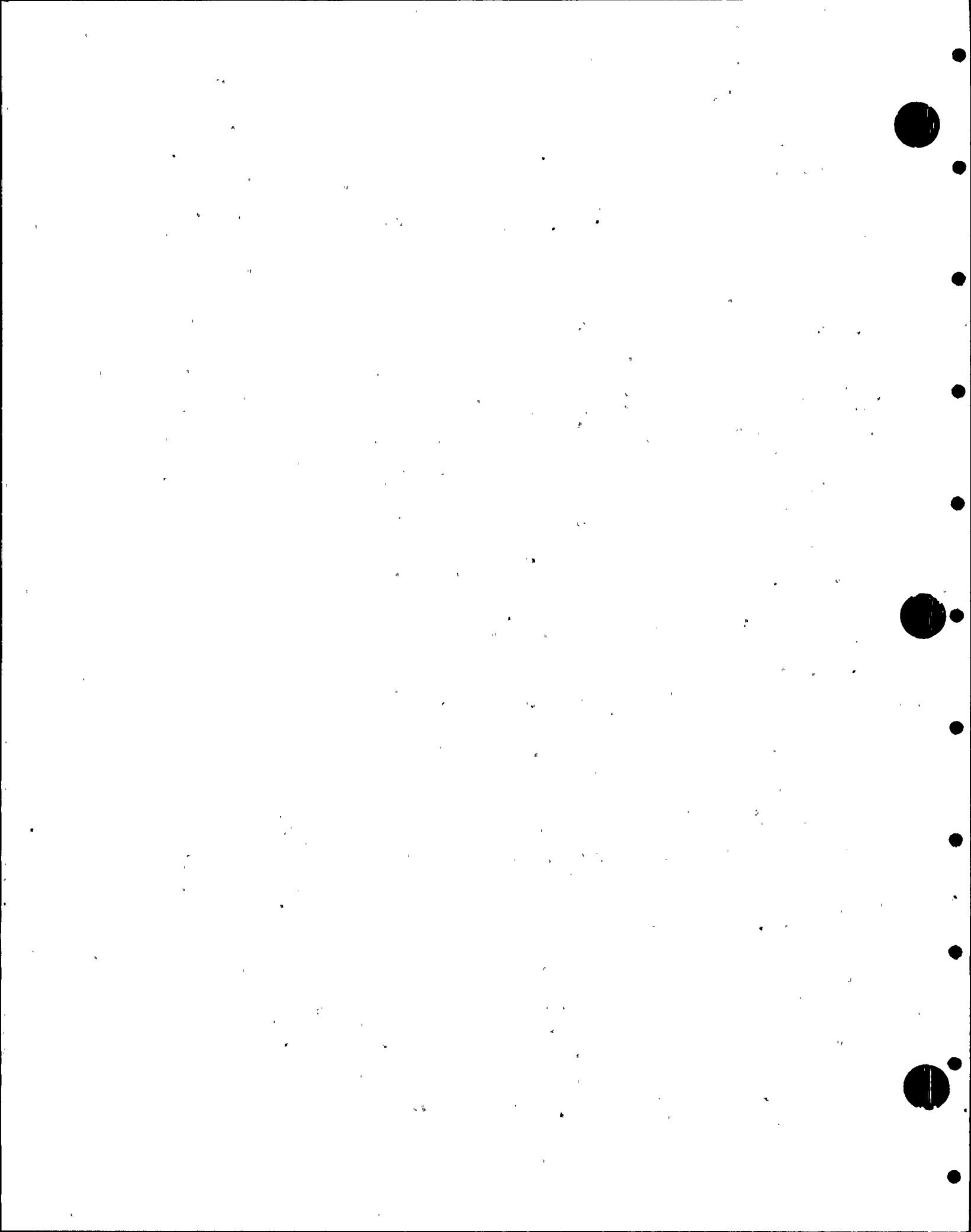
15 MISS KERRIGAN: No, I guess what we are saying is
16 when you do write your procedures, you assure yourselves
17 that in event of failure at the remote shutdown panel, you
18 utilize those same procedures and the operator's training is
19 such that he would use those same procedures and would
20 recognize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

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

23 MR. BINGHAM: All right.

24 MR. ALLEN: Any other questions?

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



1 A and C channels of instruments come to the same panel?

2 Within the panels, do you follow Reg. Guide 1.75?

3 MR. KEITH: Yes.

4 MR. ALLEN: Any further questions?

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

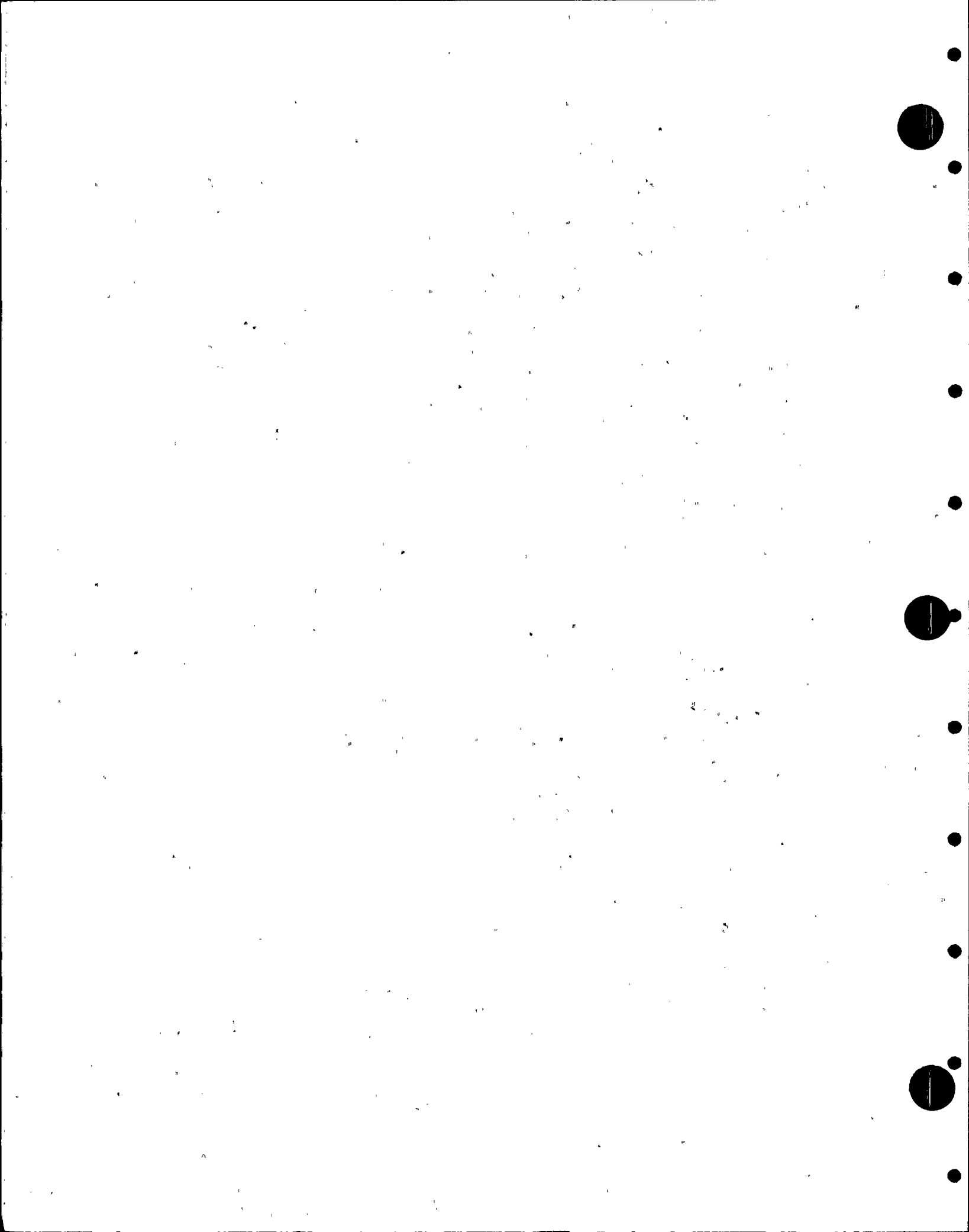
10 MRS. MORETON: Yes.

11 MR. ALLEN: Any further questions from the Board?

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

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

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



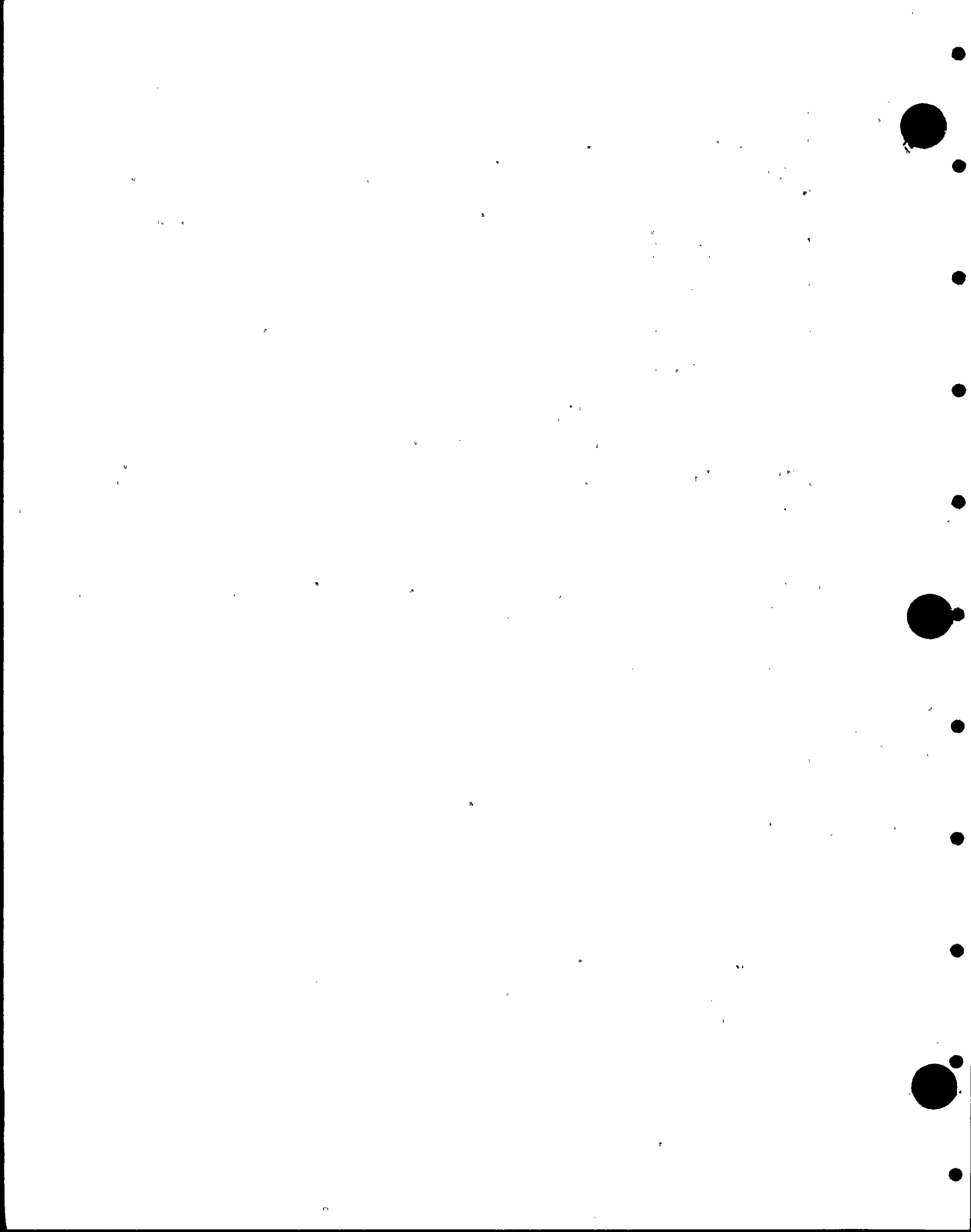
1 room. You know darned well if something is in that room,
2 the operator is going to be aware of it. So, actually,
3 I think the remote shutdown area would be safer than maybe
4 the switchgear or something else as far as knowing someone
5 is there.

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

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

18 MR. BINGHAM: That is a true statement.

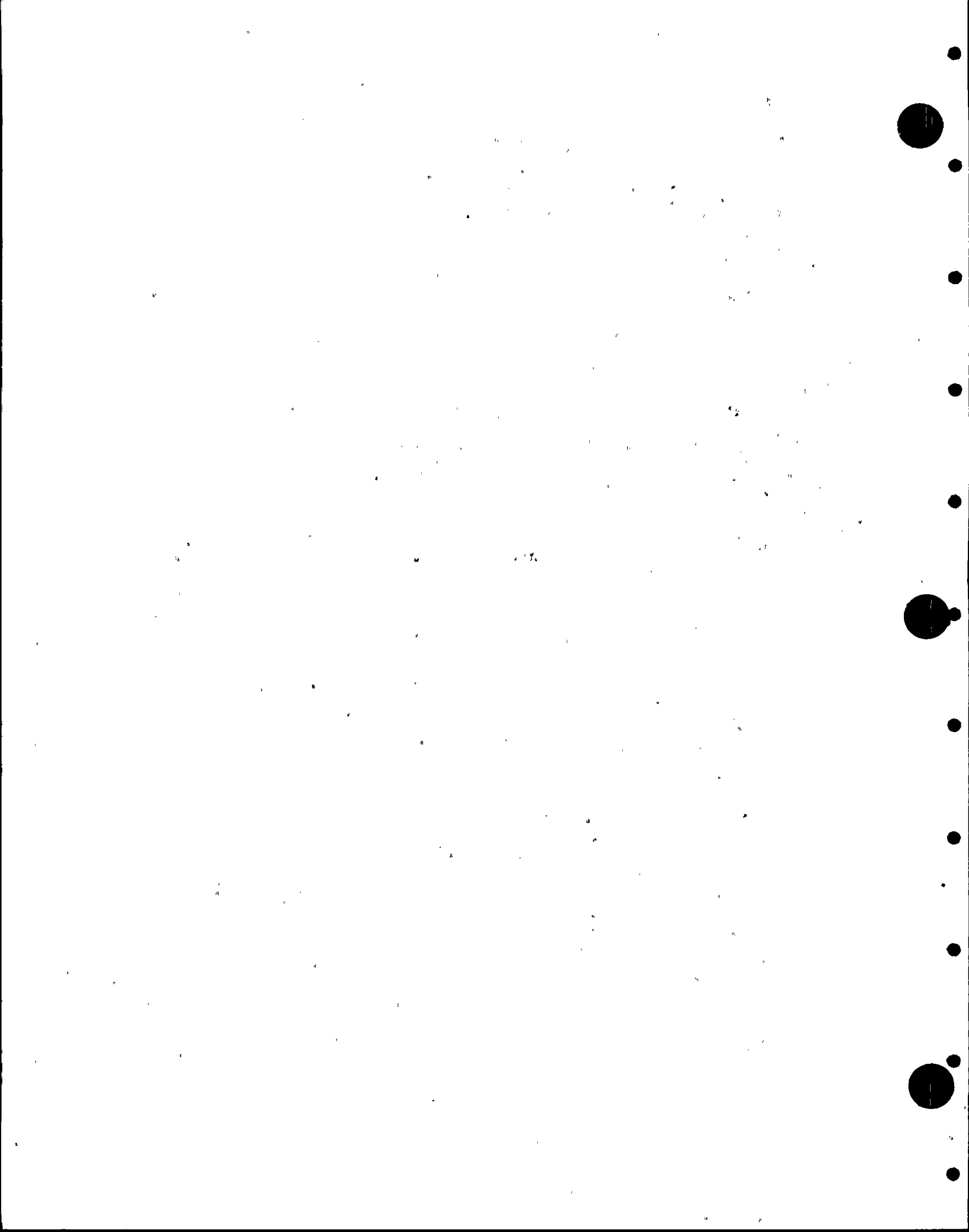
19 MR. BESSETTE: I would also like to add what I think
20 is clarification to this issue. In the event that you do
21 have a hot short in the remote shutdown panel that energizes
22 your heaters, if you want to take this example, you will
23 still have indication in the control room that your heaters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



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

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

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



1 of the operator's logical process of training.

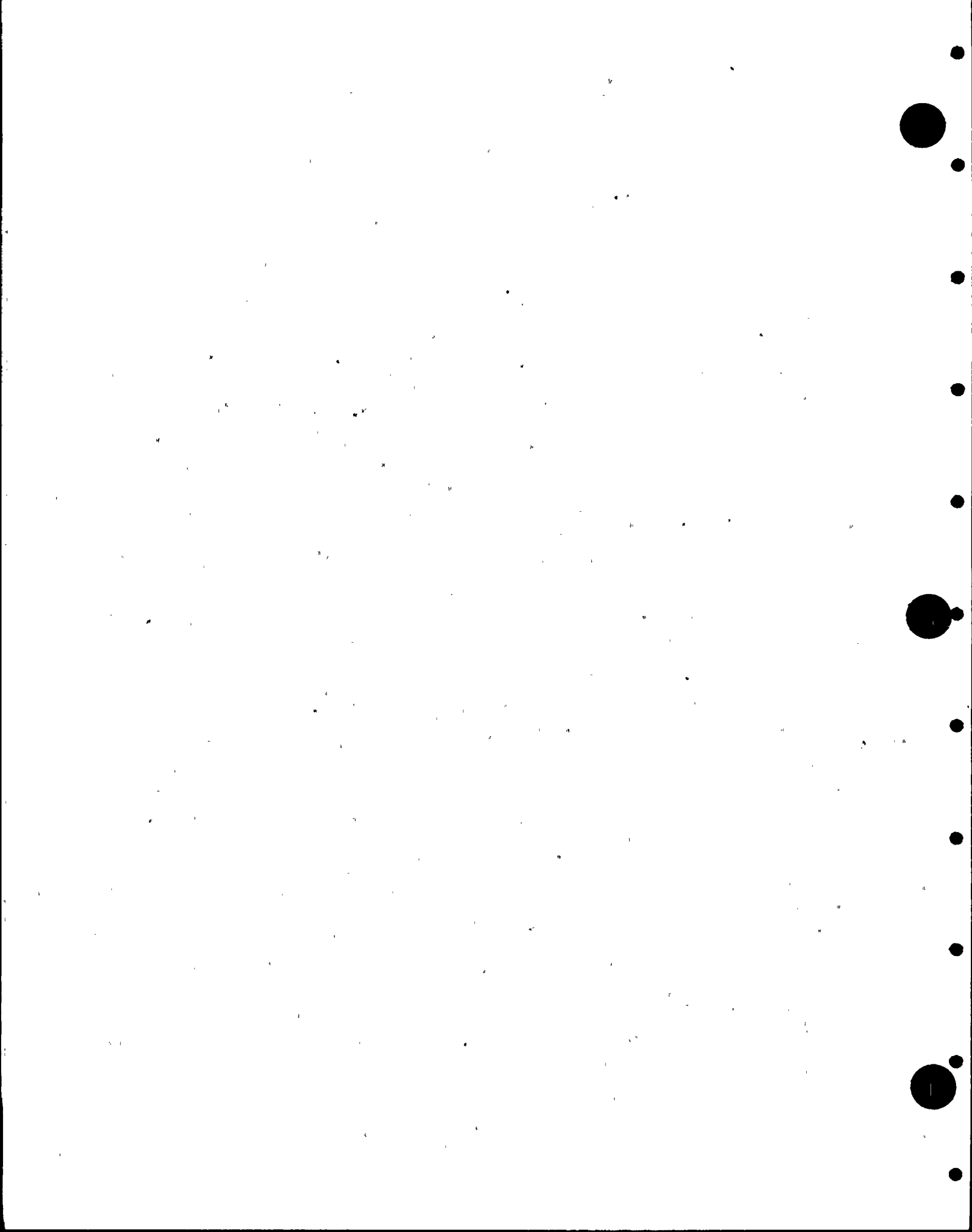
2 MR. ALLEN: Anything else?

3 Go ahead, Bill.

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

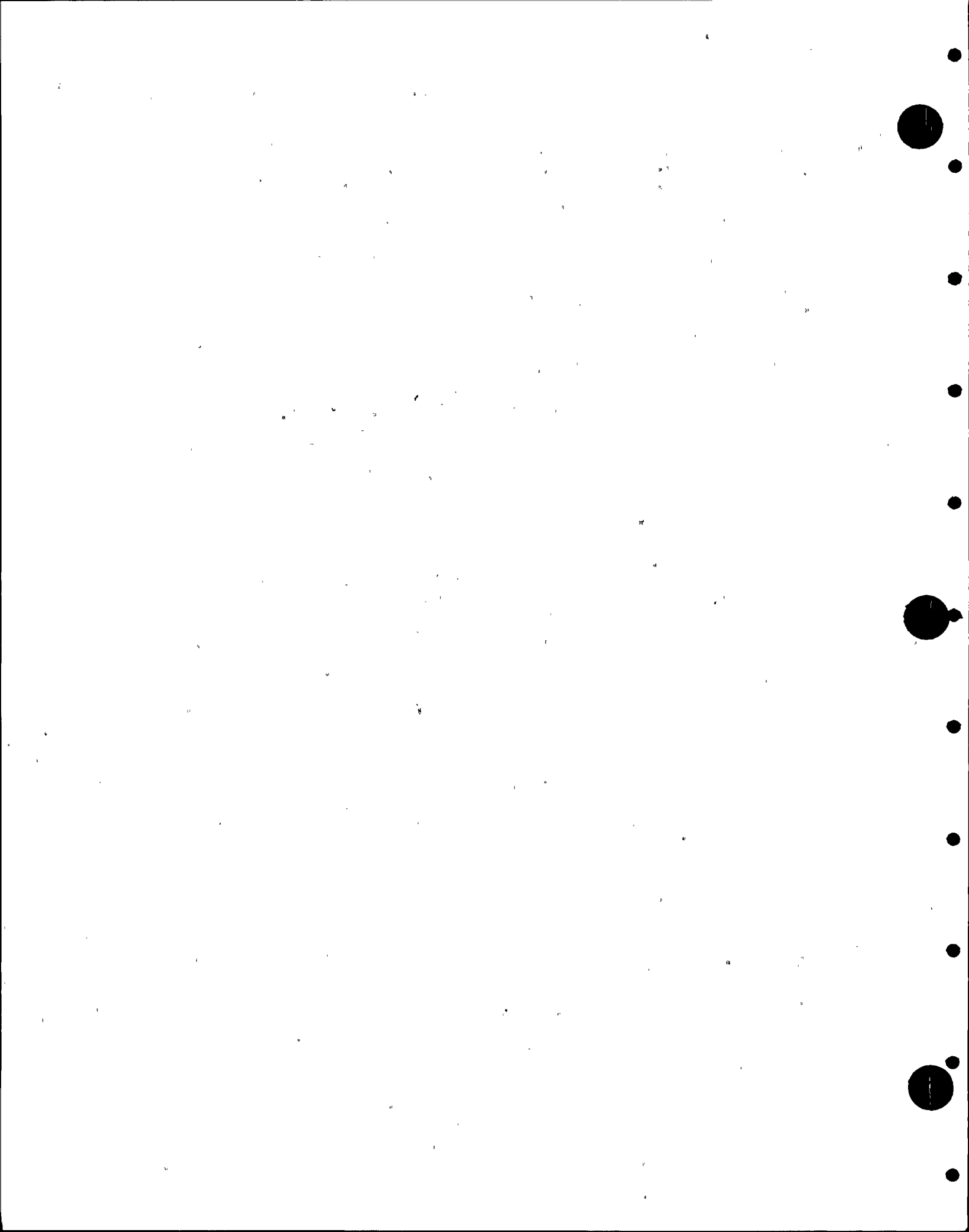
6 MRS. MORETON: Figure 2C-1 represents the safety-
7 related display instrumentation which is available to the
8 operator to allow him to monitor conditions so that he may
9 perform manual actions important to plant safety. This
10 consists of sensors, monitoring process system variables,
11 the NSSS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

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



1 IEEE and GDC. Additional design criteria are as follows:
2 instruments shall be provided to operate at a nominal
3 115 volt-AC supplied to instrument cabinets. Controls and
4 annunciators shall operate at 120 volt-AC or 125 volt-DC
5 nominal. The maximum and minimum voltage limits for the
6 120 volt-AC and 125 volt-DC systems are given in the
7 electrical systems design criteria.

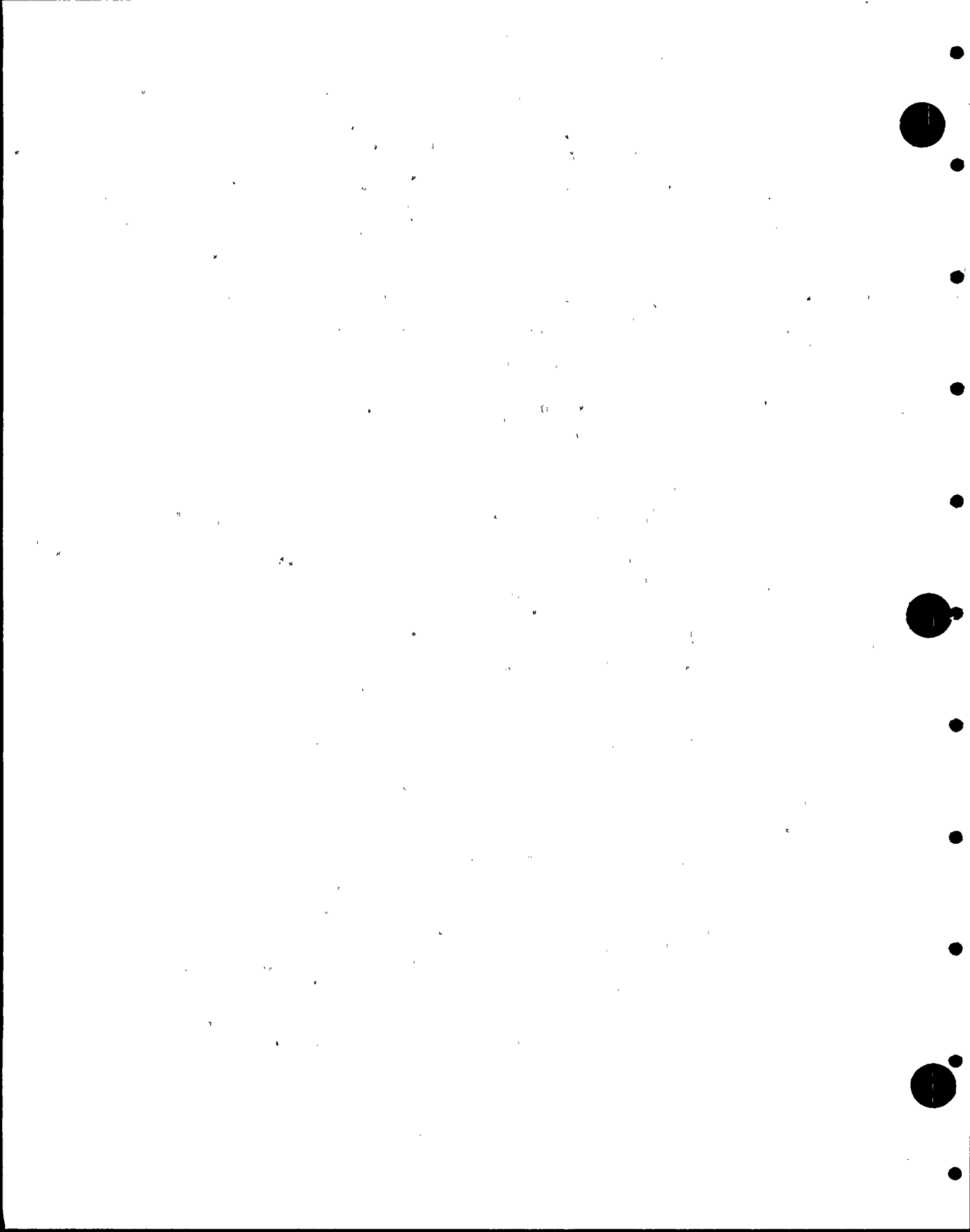
8 Exhibit 2C1-2. Resistance temperature detectors,
9 RTD's, shall utilize a three-wire circuit. The RTD sensors
10 shall have a resistance of 100 ohms (preferred). Exceptions
11 will be considered on a case-by-case basis. Thermocouple
12 materials shall be chromel-alumel, Type K. Electronic
13 transmitter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



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

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

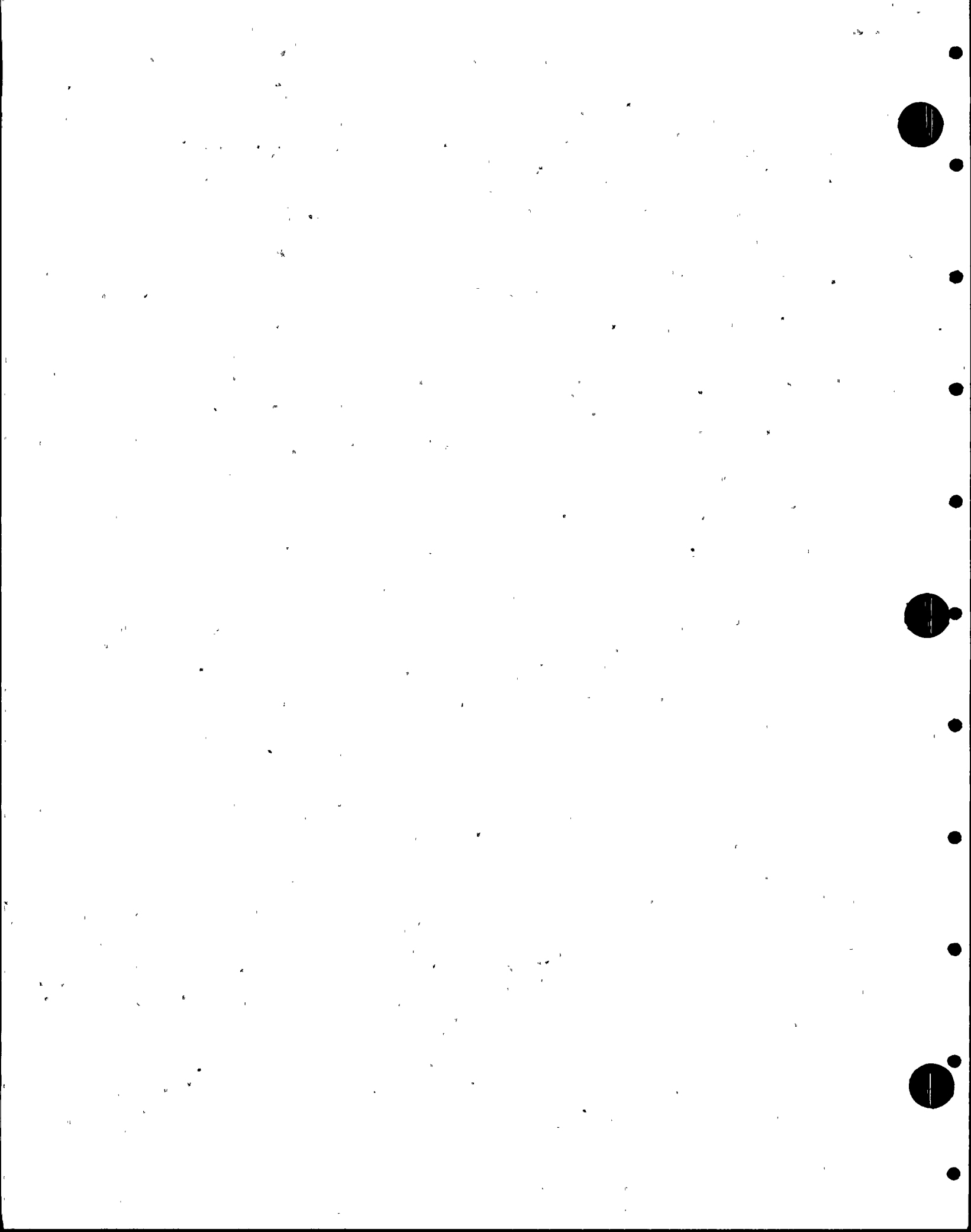
23 Exhibit 2C1-4. Mercury shall not be used for any
24 application within the containment building, spent fuel pool
25 area, boron recovery area, chemical and volume control areas,



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

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

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

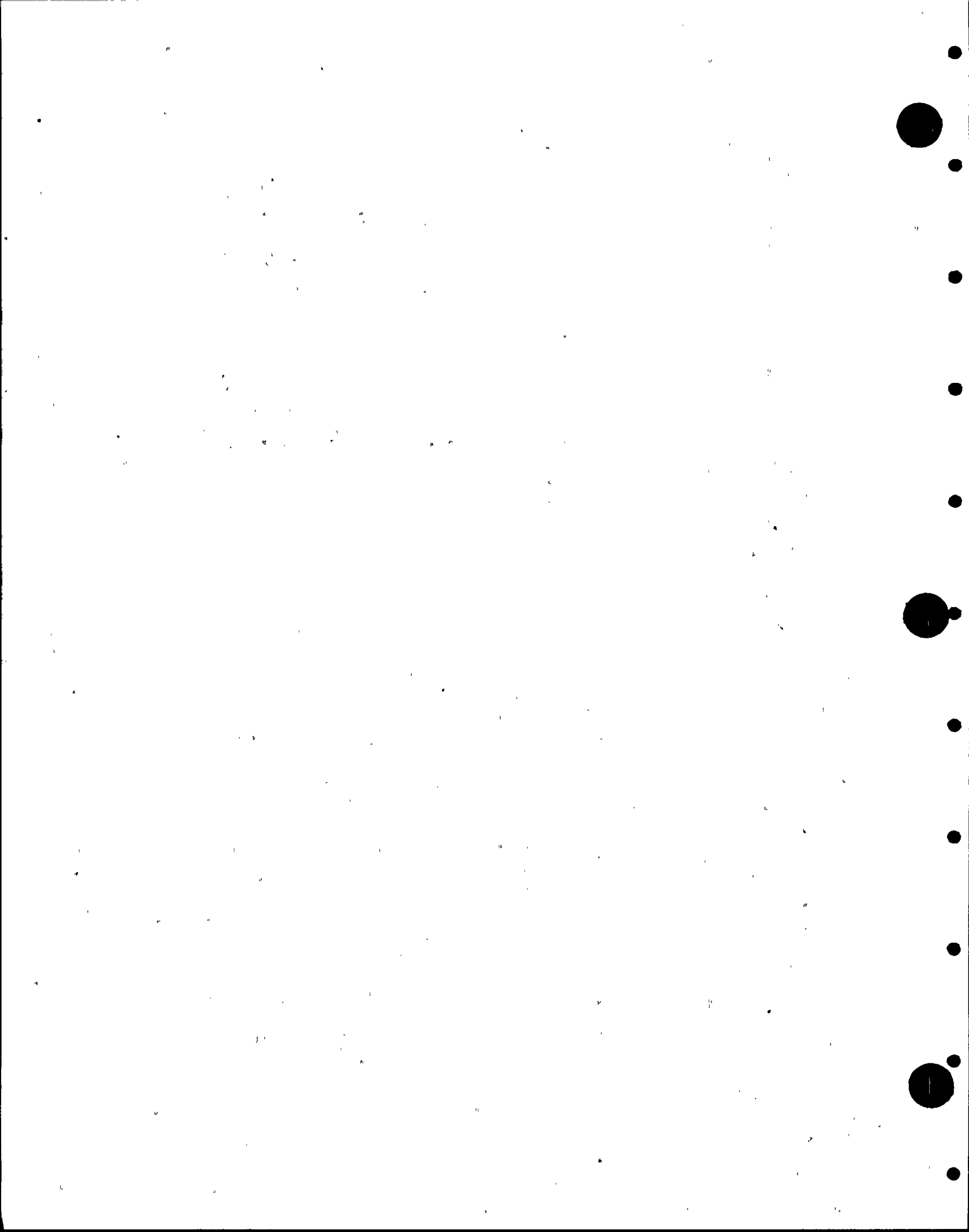


1 instrumentation loop consists of sensor, processing electronics,
2 and display. Various sensors include thermocouples and
3 RTD's, pressure transmitters including differential pressure
4 transmitters for level and flow monitoring, radiation
5 monitors, example Beta scintillation, Geiger-Mueller,
6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

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

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

22 Some of our process instrumentation for the
23 Engineered Safety Features System is provided in Exhibit
24 2C1-8. A typical example would be the fuel pool area
25 radiation monitor located in the control room with a range

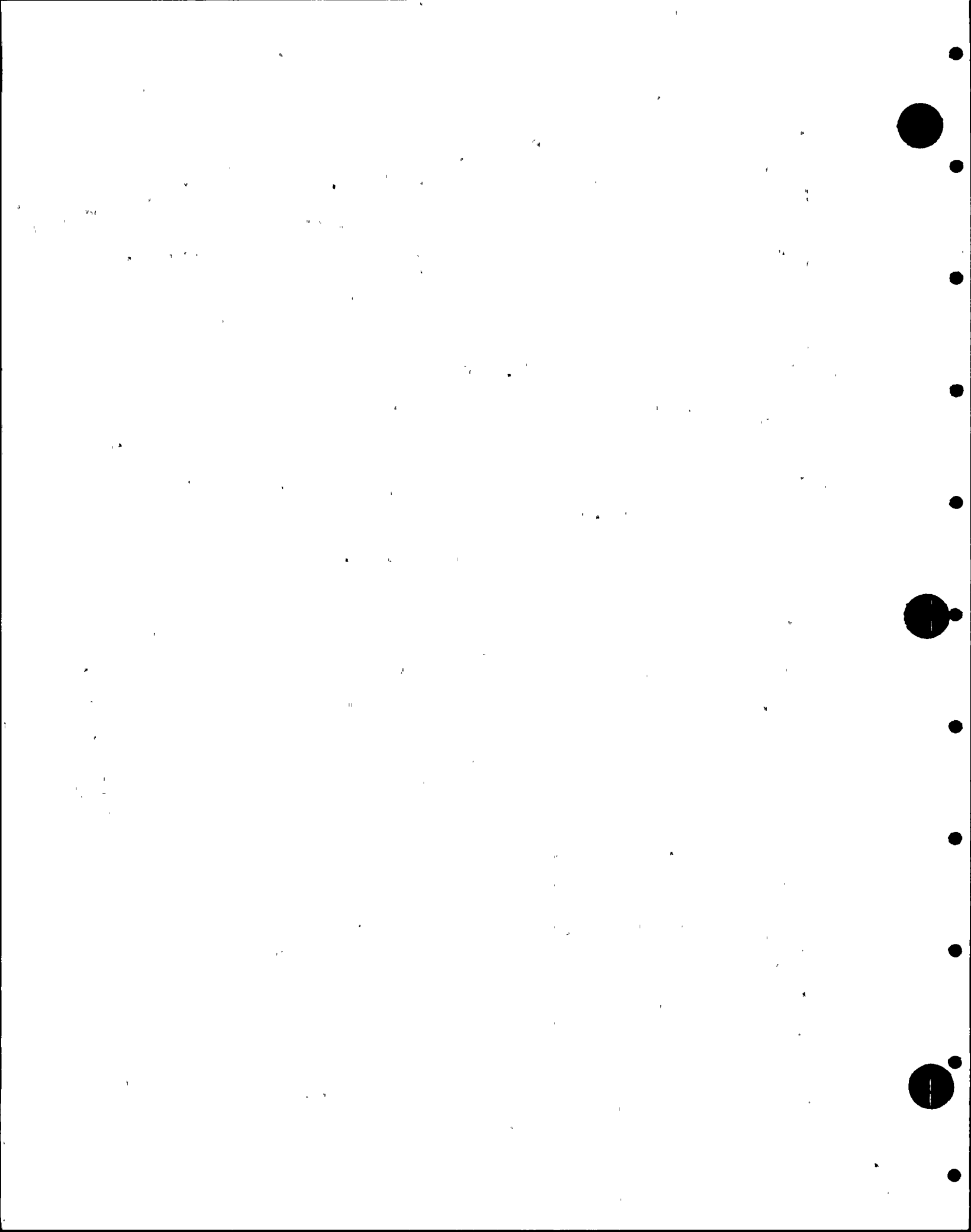


1 of 10^{-1} and 10^4 mR per hour, displayed accuracy of plus or
2 minus 20%. Additional examples follow on Exhibit 2C1-9
3 through 2C1-10, 11, and 12. This covers our BOP ESF system.
4 We also cover in this table the auxiliary feedwater system,
5 including the pump discharge pressure indicator in the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

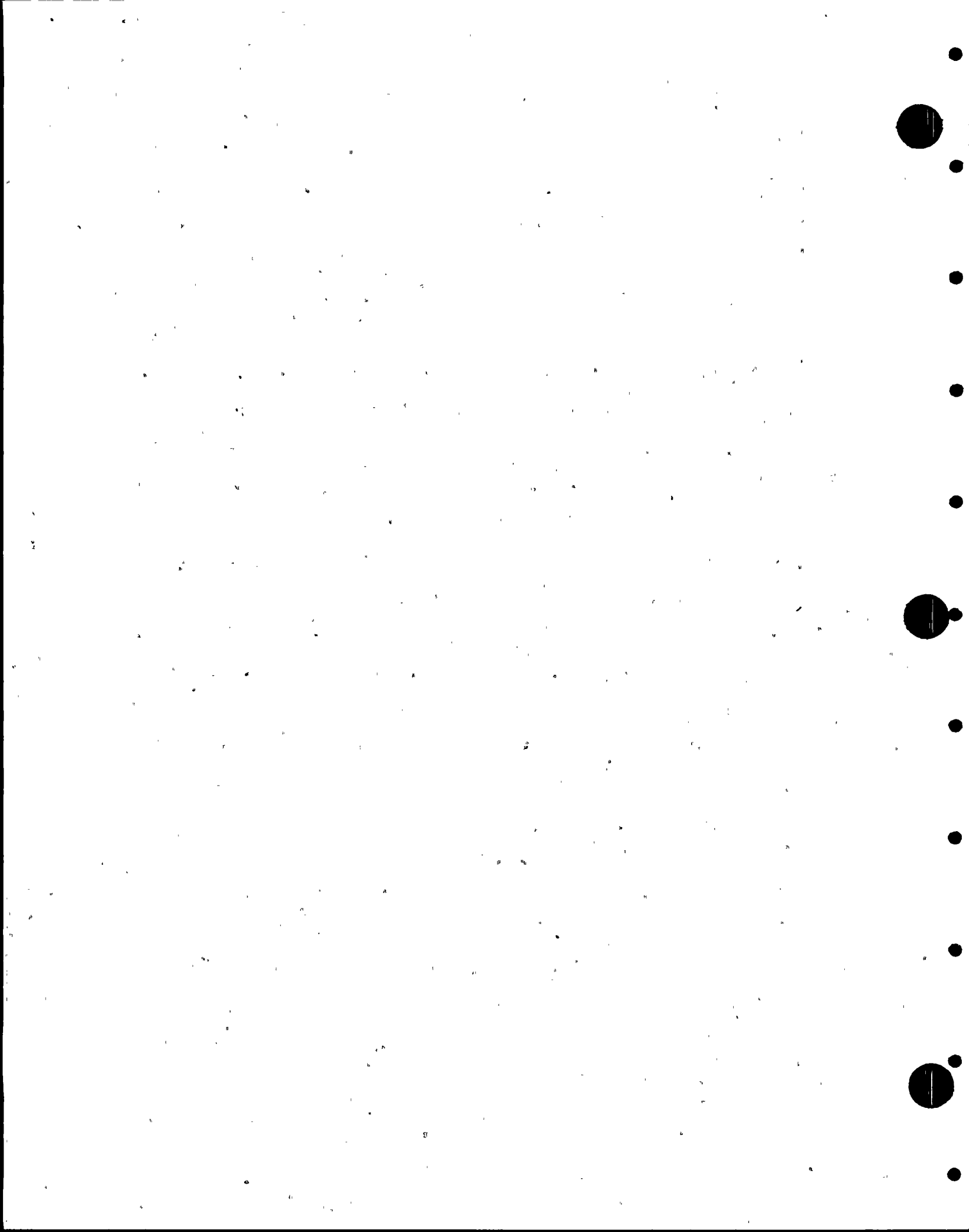
7 Exhibit 2C1-13 also indicates the rest of the
8 auxiliary feedwater instrumentation, and the ESF status
9 panel indicates system availability. This we will discuss
10 as part of the SESS in the following presentation.

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

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

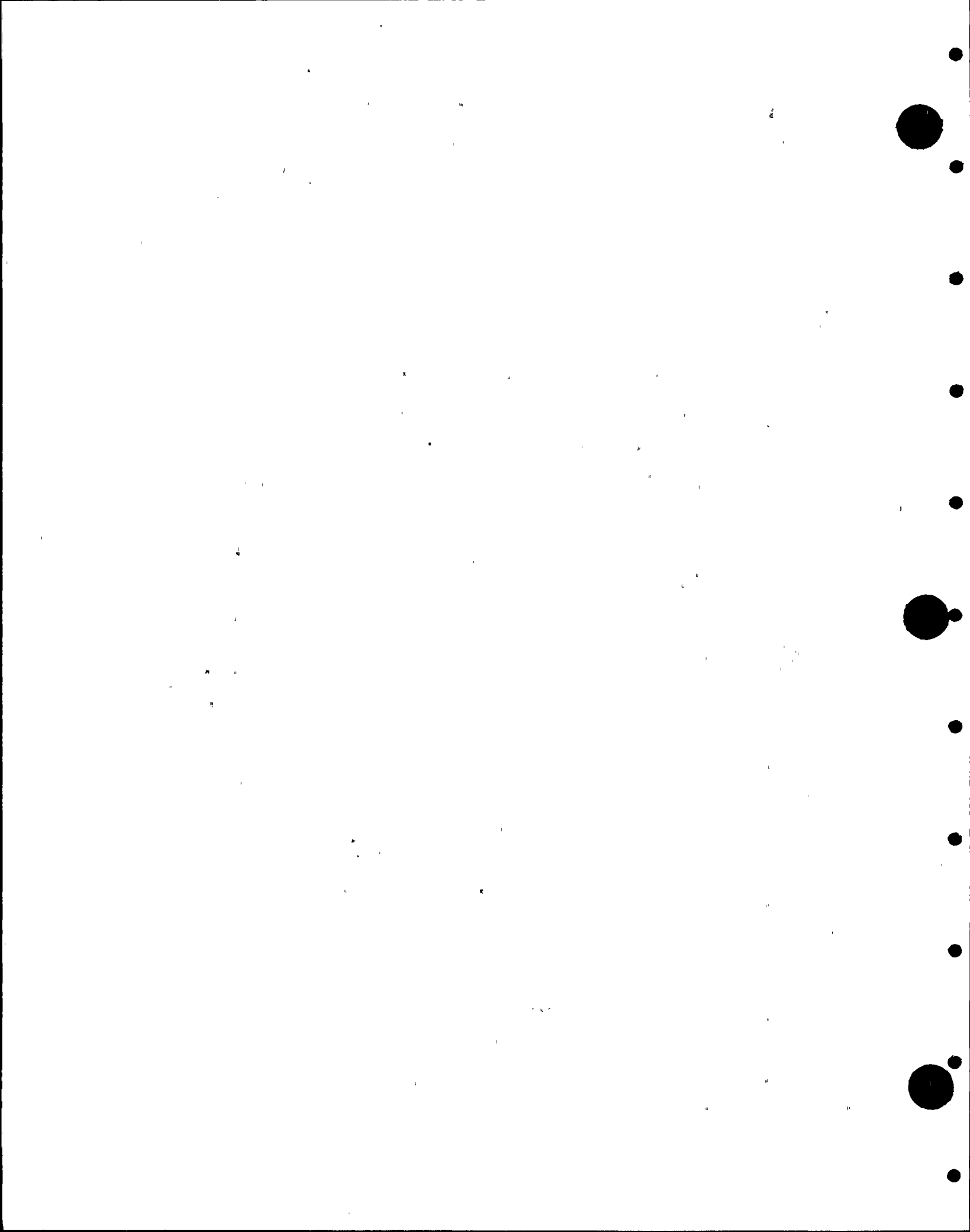


1 Exhibit 2C2-2. The system shall consist of two portions,
2 one reporting the status of safety Train A equipment, the
3 other reporting the status of Safety Train B equipment.
4 The system shall accept channelized Class IE associated
5 inputs. The system inputs are Class IE associated; therefore
6 the system shall be powered from Class IE 125 volt-DC power
7 supplies. Status contacts shall continuously monitor the
8 availability of control power and the position of circuit
9 breakers of all automatically actuated ESF devices. A loss
10 of control power or deliberate racking out of a breaker
11 shall automatically indicate at the component level the
12 device which has been rendered inoperable. Simultaneously,
13 a system level indication with audible alarm shall be
14 initiated. Proceeding with the design criteria, Exhibit
15 2C2-3. The capability for initiating a manual bypass
16 indication and alarm is provided to indicate the bypass
17 condition to the operator for those manual valves and other
18 components which are not automatically monitored. The
19 initiation and removal of manual bypass indication will be
20 under administrative control. A system of status contacts
21 shall monitor the safe operating position of all automatically
22 actuated ESF devices during an ESFAS. These status contacts
23 shall automatically indicate at the component level the
24 device which has failed to automatically complete the
25 transition to the safe operating position within a normal



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

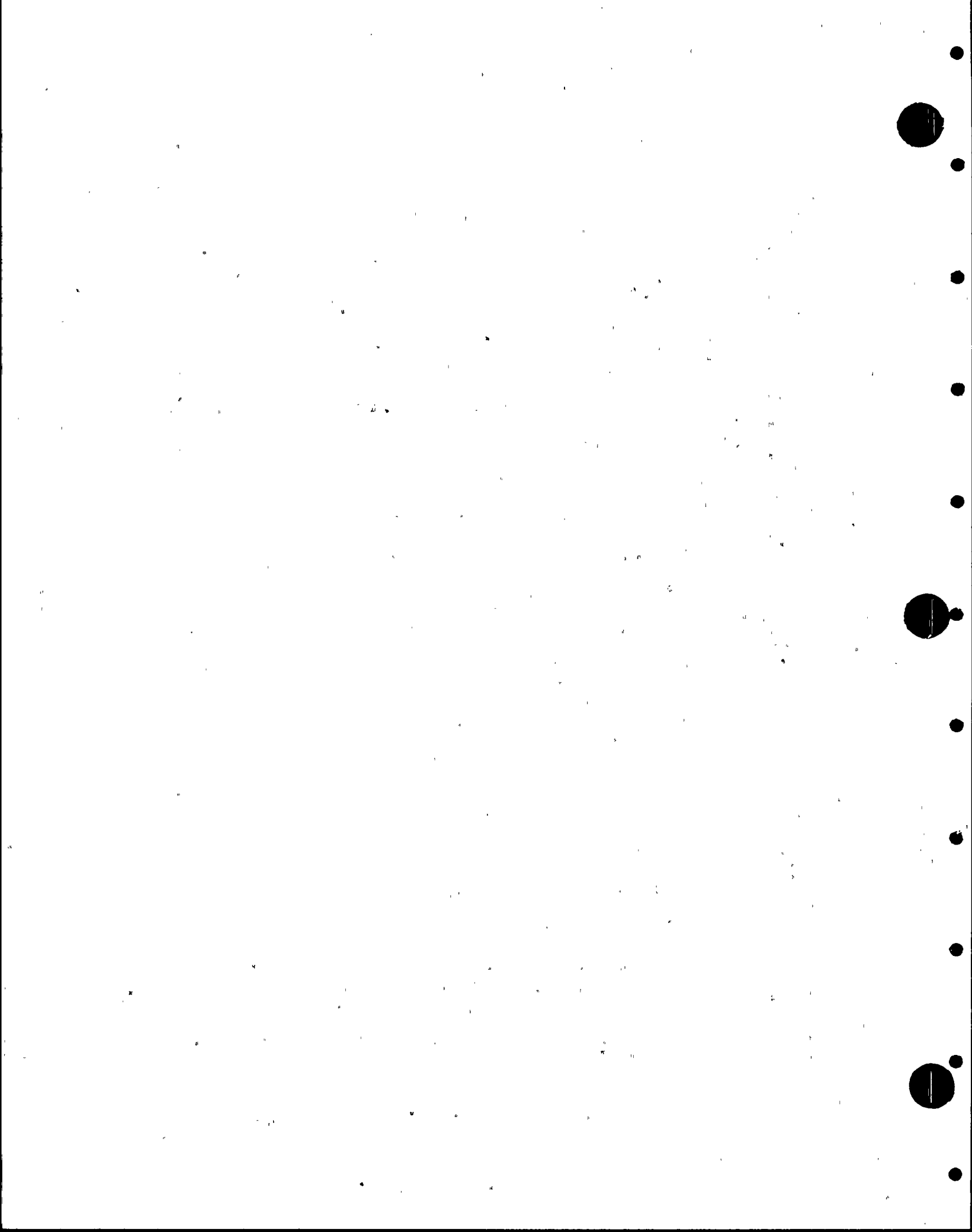
12 Exhibit 2C2-4. All components, including Solid-
13 State devices, transformers, resistors, and relays, shall
14 be of a quality and shall be used in the system in a way
15 that will ensure high reliability, minimum maintenance
16 requirements, and low failure rates. Ease of maintenance
17 shall be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



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

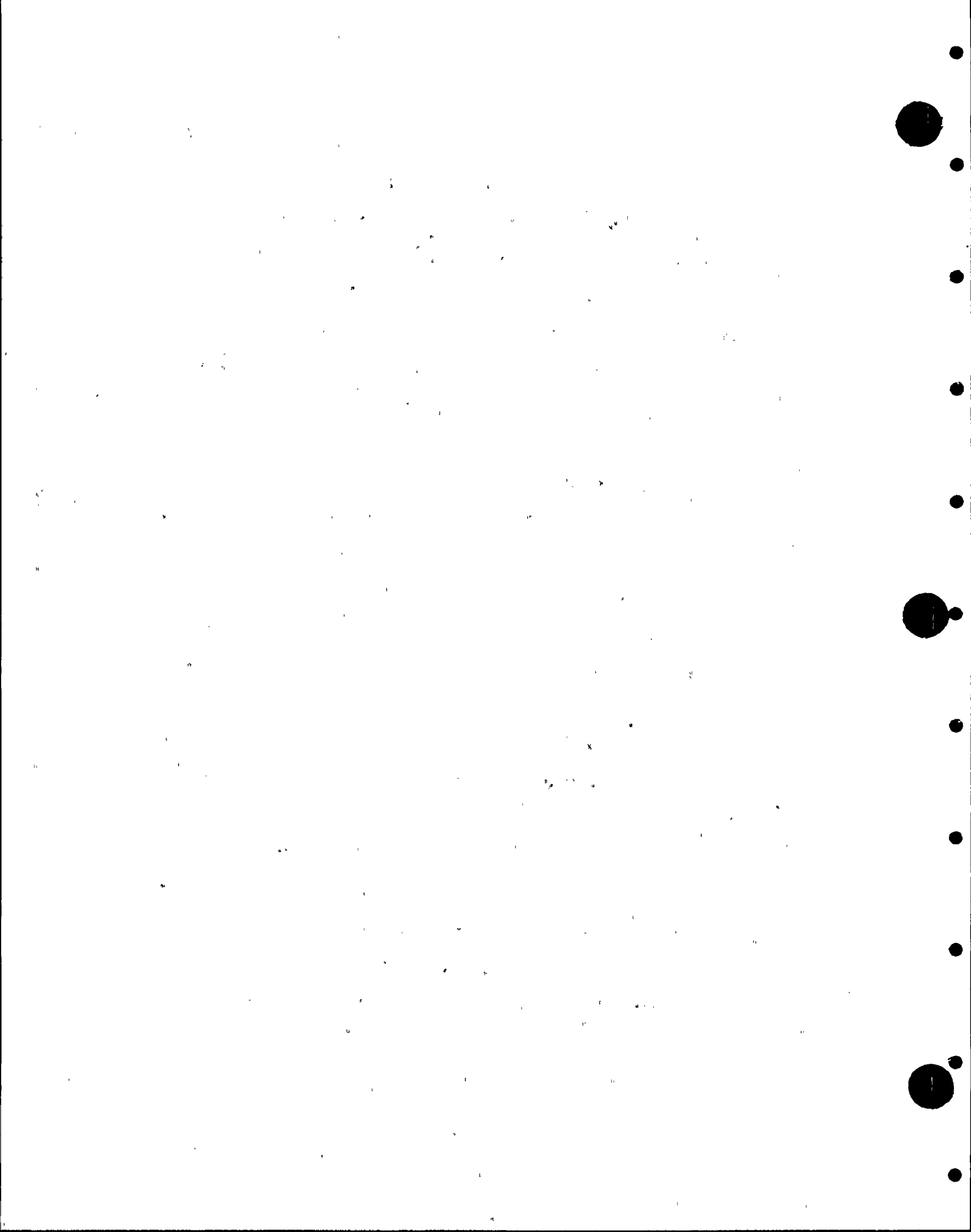
6 We will now go into the Safety Equipment Status
7 System Description starting with Exhibit 2C2-5 and referring
8 to Figure 2C-1A on the system arrangement of the safety
9 equipment status system. The safety equipment status system
10 consists of two physically separate systems shown here
11 (indicating).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

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



1 logic is shown in Figure 2C2.

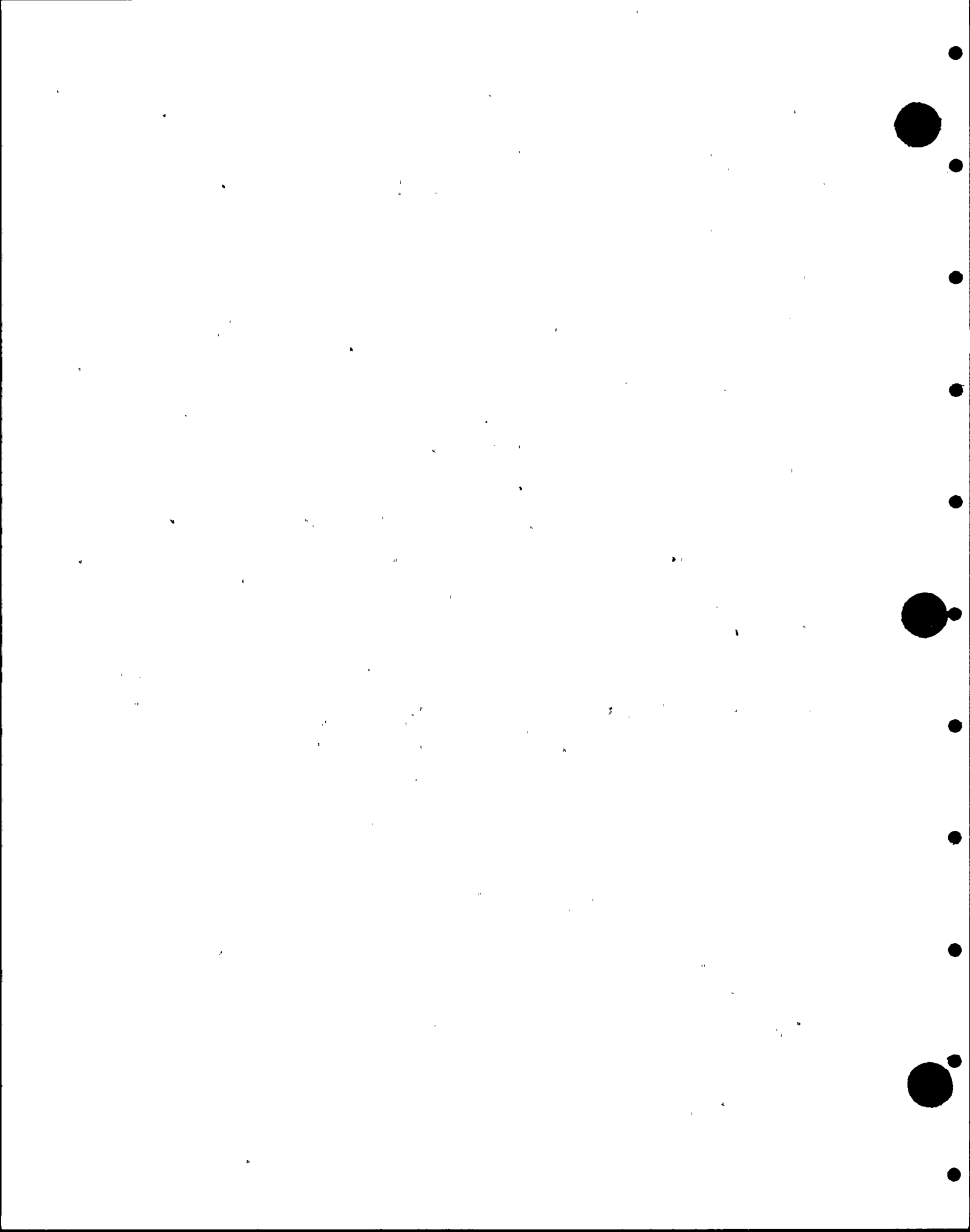
2 Exhibit 2C2-7. The SEAS logic continuously
3 monitors the operating status of ESF and ESF support
4 system actuated devices, continuously monitors the status
5 of ESFAS signals down here on the bottom of the figure
6 (indicating), provides "failure to automatically actuate"
7 annunciation if all actuated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



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

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

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



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

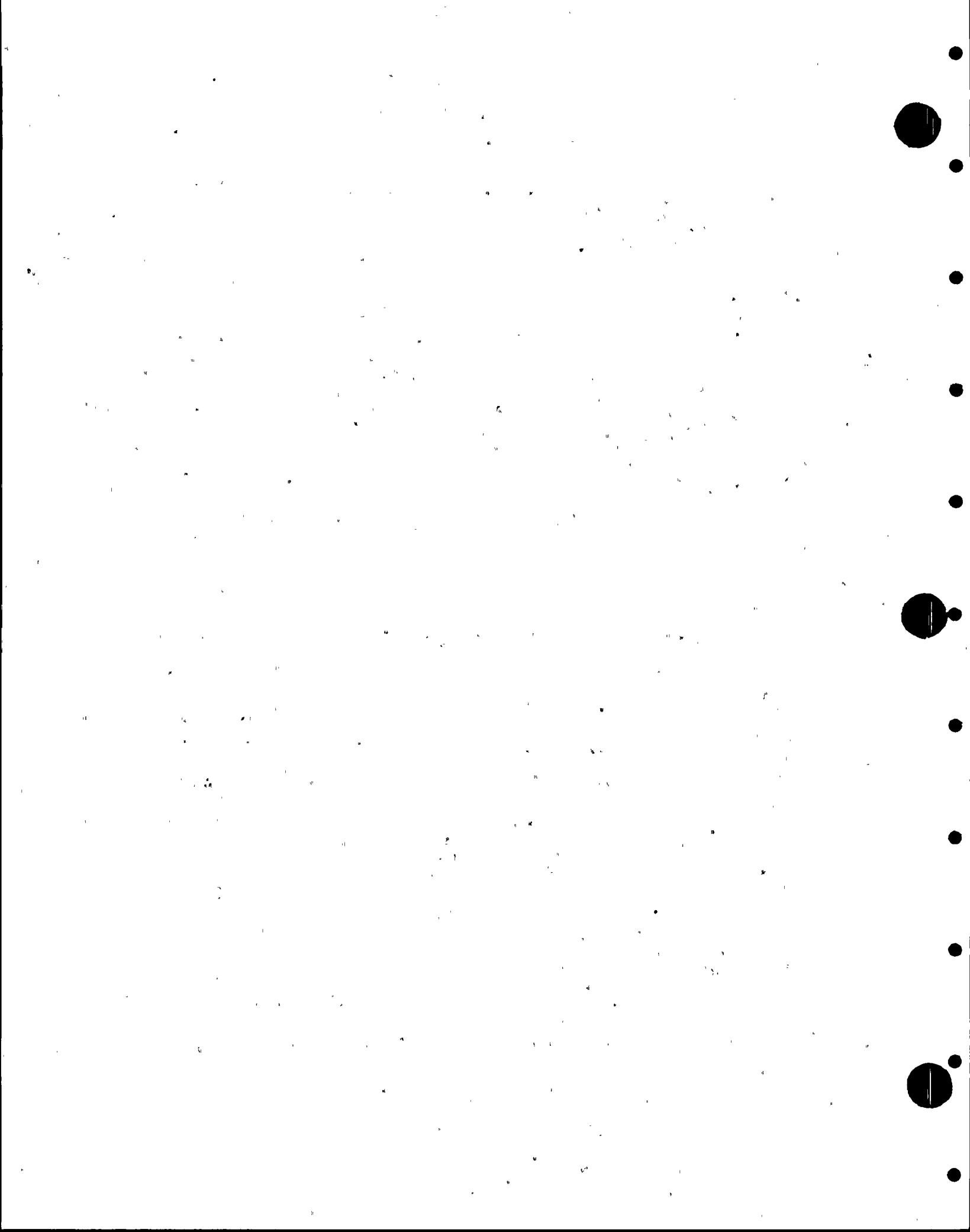
4 Figure 2C-5 is the control panel where the operator
5 may manually initiate "inoperable status" of a manual valve
6 that is used less than once a year is rendered inoperable.
7 It is under administrative control. This (indicating) is
8 also the test pushbuttons to perform system tests.

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

11 We have some slides of these. This slide is a
12 photograph of the safety equipment status system B02 or
13 the ESF panel on the simulator, which is identical to the
14 one in the main control room. These two windows up at the
15 top of the slide, one for Train A, one for Train B, are
16 the system level alarms. The panels right below them, one
17 for Train A and one for Train B, are the component level
18 windows. Directly below that on the lower portion of the
19 control panel are the two control panel inserts for the
20 SESS.

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

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



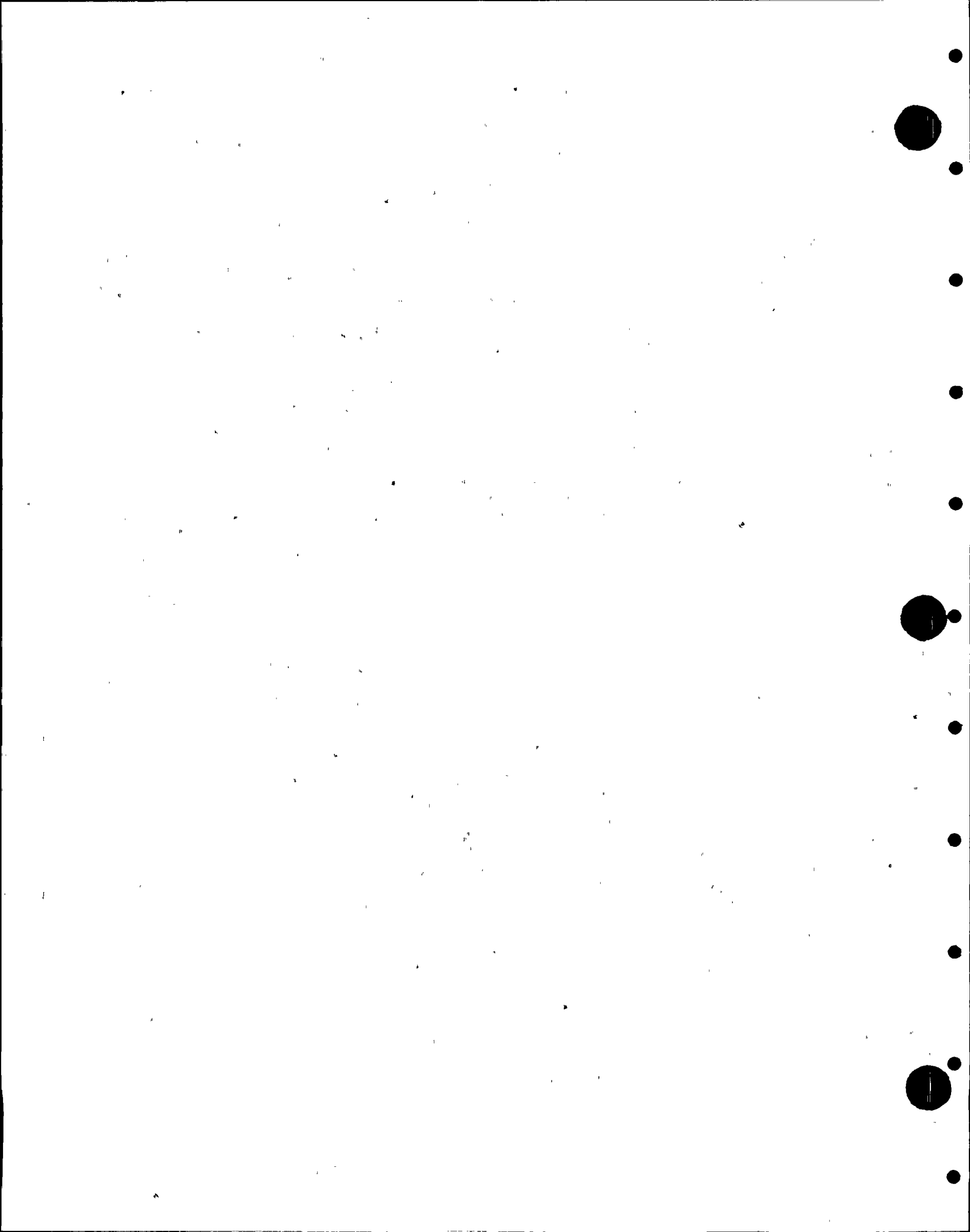
1 On the annunciator panel and on the indicating light panel,
2 the white light is in the upper half of the annunciator
3 or in the component level, and this indicates inoperable
4 status. There is a blue lamp, two sets actually, in the
5 lower half of each component window in each annunciator
6 panel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

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

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

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

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



1 indicating power availability.

2 MR. BINGHAM: Any questions?

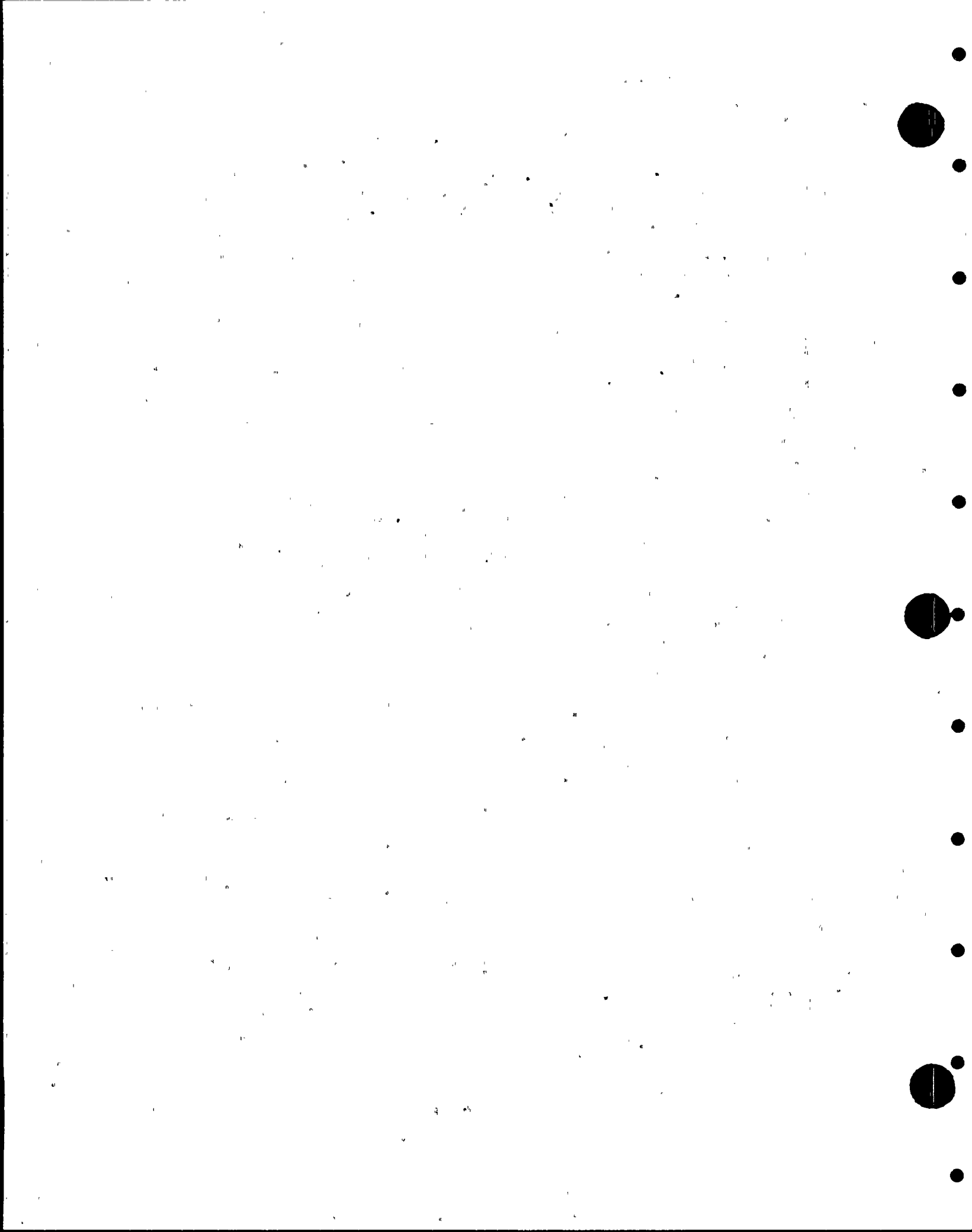
3 MR. STERLING: At the Combustion IDR, there was
4 some concern over what indication the operator would
5 receive from this instrumentation in the control room or
6 the indicators upon loss of power. Could you briefly
7 discuss what happens to the indicators when the power goes
8 out?

9 MRS. MORETON: The PVNGS displays are Foxboro Model
10 270 indicators. On a loss of power to the rack, the
11 indicators will completely go out. They do require 120 volts
12 to illuminate them, and it will just extinguish. On loss
13 of power to the recorders, the small light you saw at the
14 bottom of the recorder will go out.

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

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

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



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

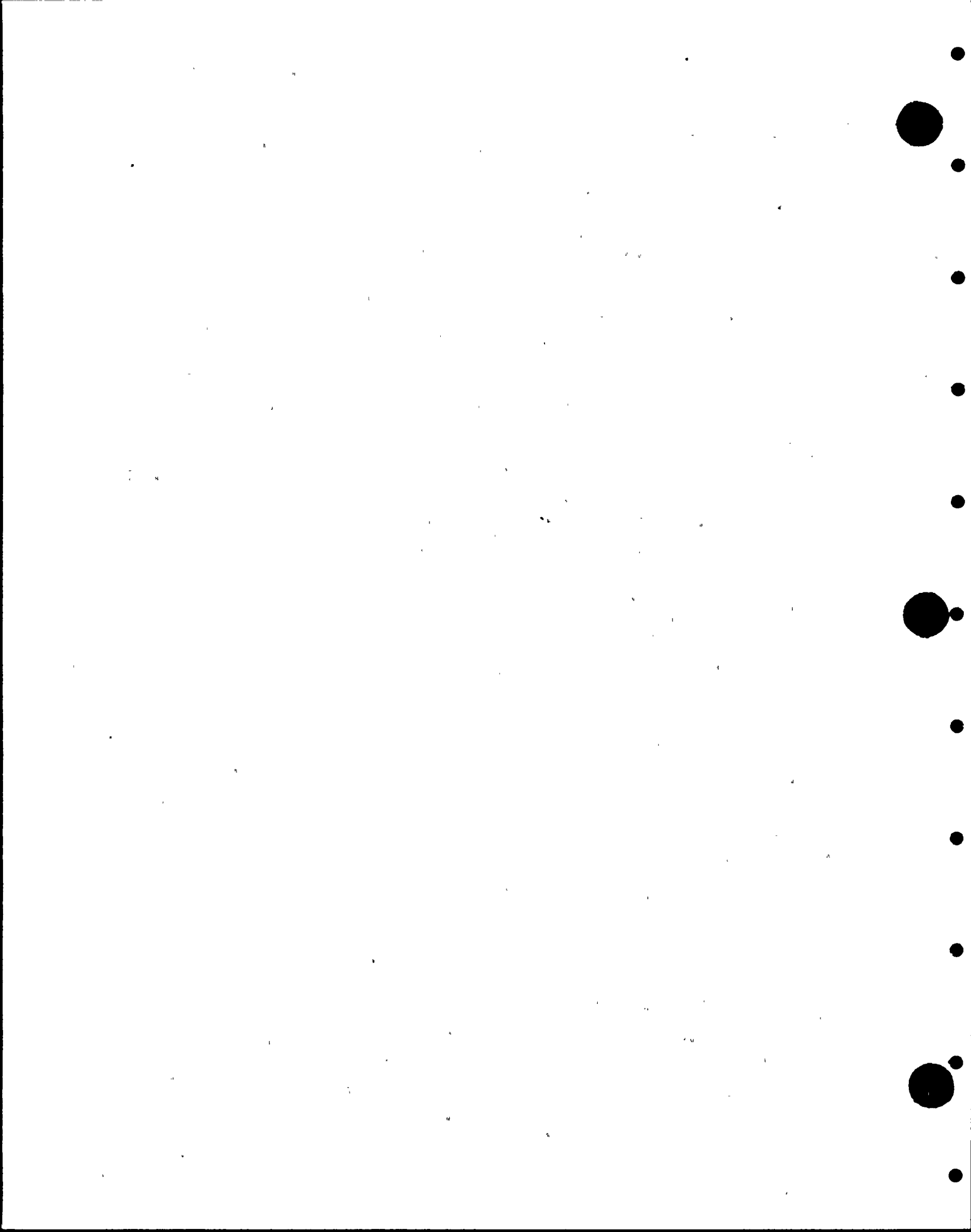
3 MR. STERLING: No, I understand that. That problem
4 has been fixed. What I am trying to get at is the operator
5 going to be misled by some failure in these Foxboros either
6 in the power supplies to the indicators or to the loops
7 that they sit in that is going to mislead the operator?

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

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

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

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



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

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

8 MR. ALLEN: Any questions?

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

13 MRS. MORETON: It may be necessary.

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

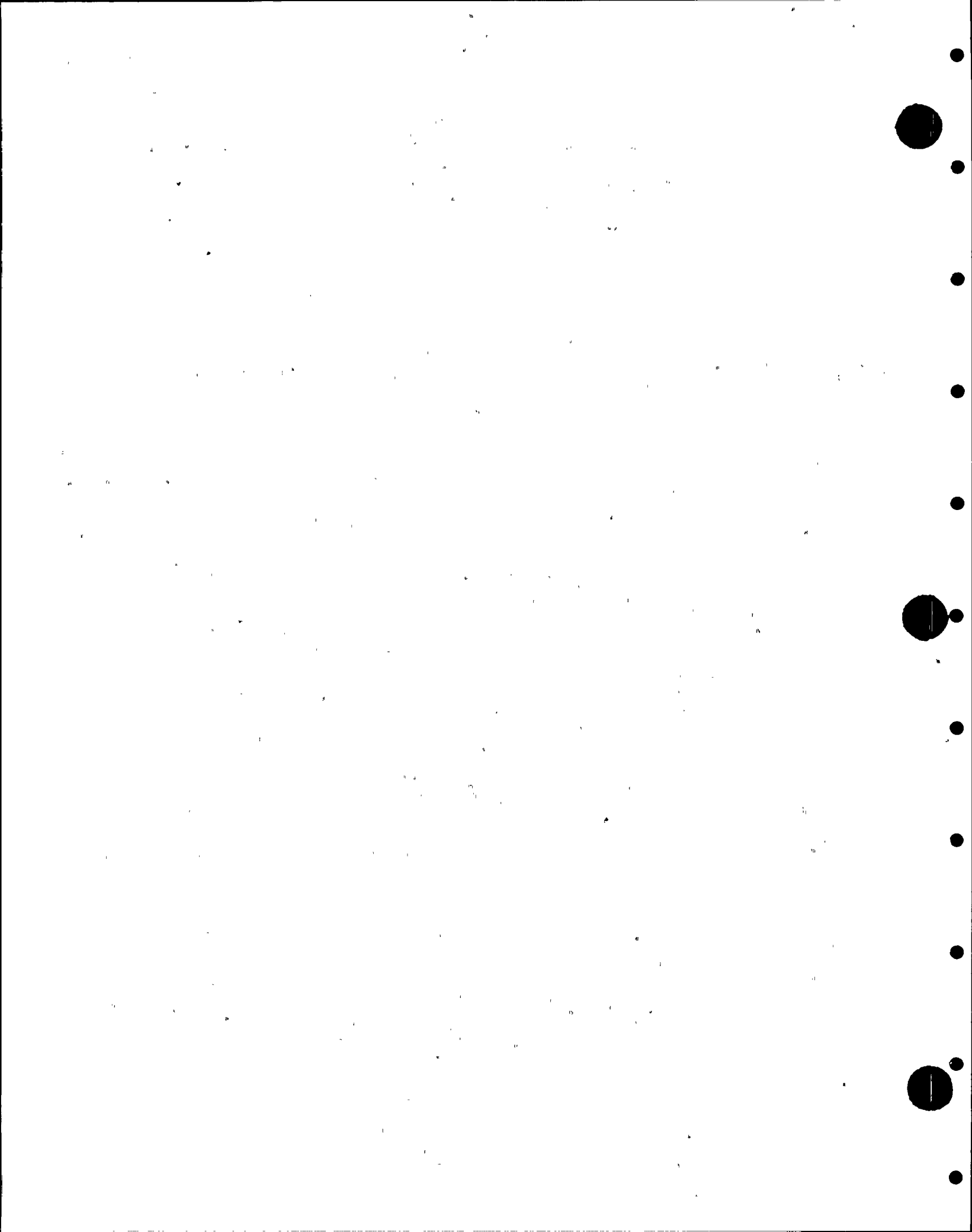
17 MR. ALLEN: Could you identify the standard you are
18 talking about?

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

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

22 MR. MECH: I have one more little question.

23 MR. ROSENTHAL: Let me hit it right now. Reg. Guide
24 1.118, which was issued after the date of your CP, speaks
25 about periodic testing of electrical power and protection.



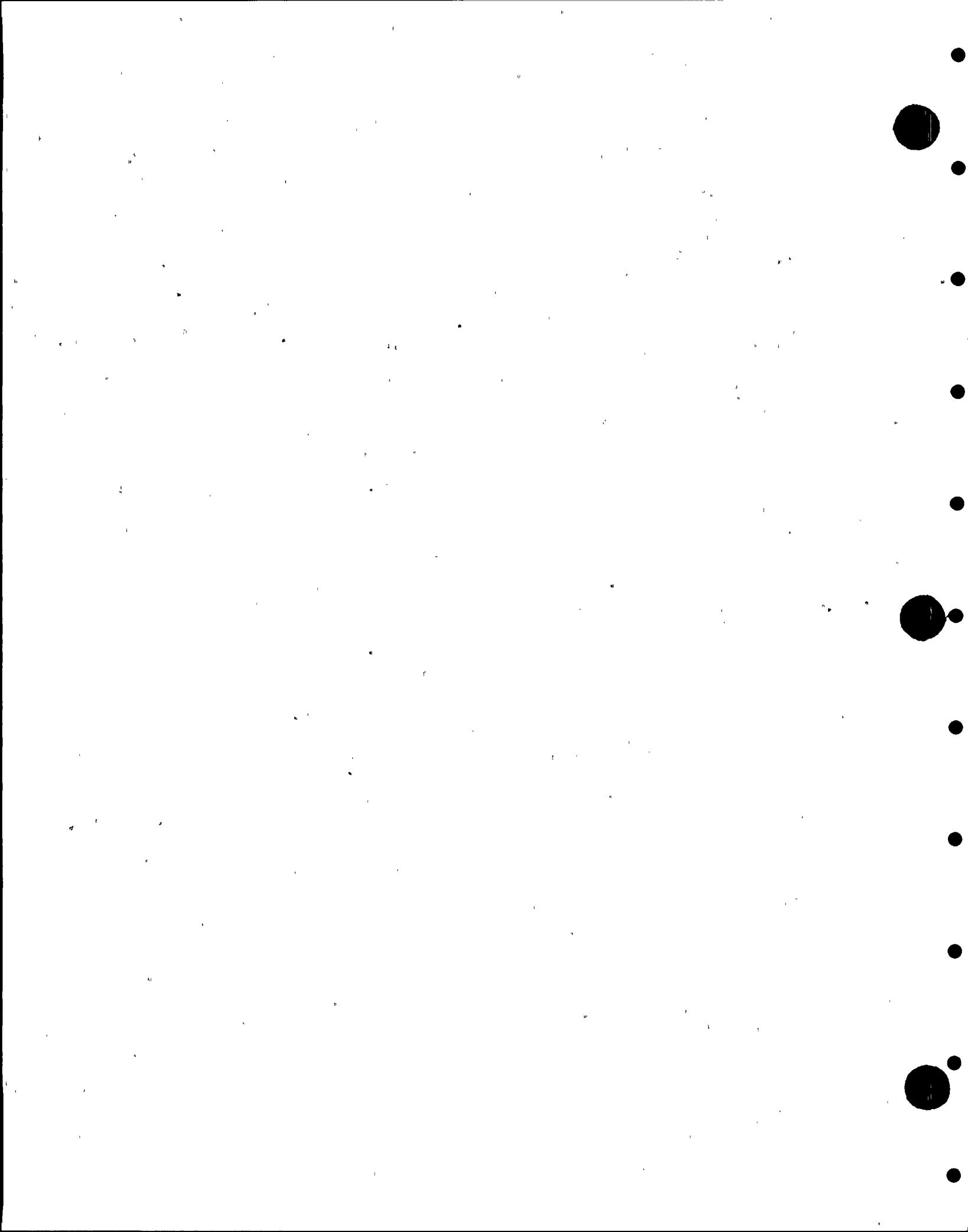
1 systems and Section C-6 discourages the use of jumpers and
2 pulling fuses, et cetera. Within the context that this
3 Reg. Guide is for protection systems and within the context
4 that the Reg. Guide was published Rev. 02, June, '78, after
5 the date of your CP date, will you identify where your
6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

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

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

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

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



1 MR. ROSENTHAL: And that will be documented where?

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

4 MR. ALLEN: Any further questions?

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

7 MR. KEITH: The figures or exhibits?

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

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

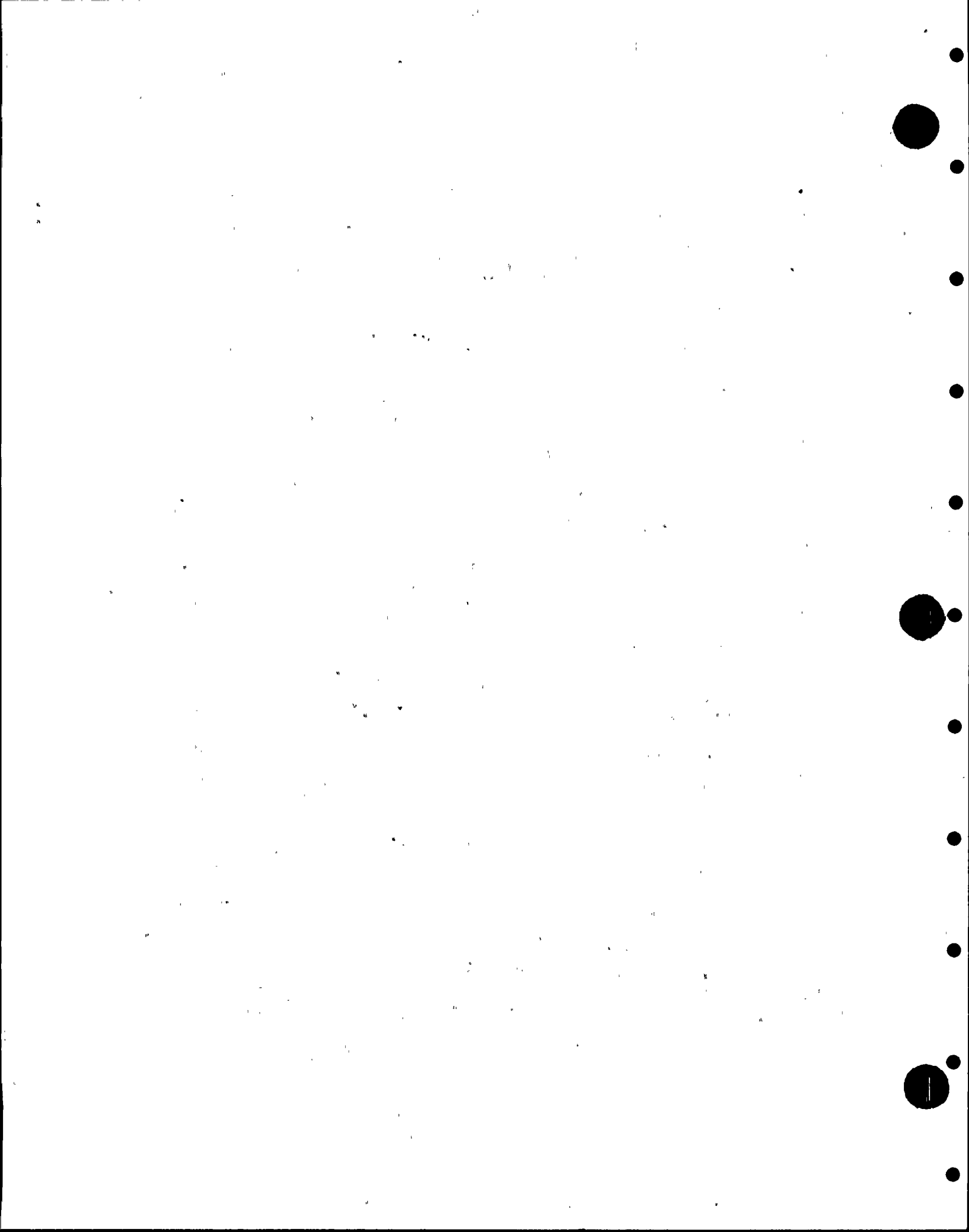
12 MR. MECH: Five shows a small panel at the bottom and
13 4 does not. Is Figure 4 supposed to have one, also, a
14 similar panel?

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

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

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

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



1 Train B will have its little panel?

2 MRS. MORETON: Correct.

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

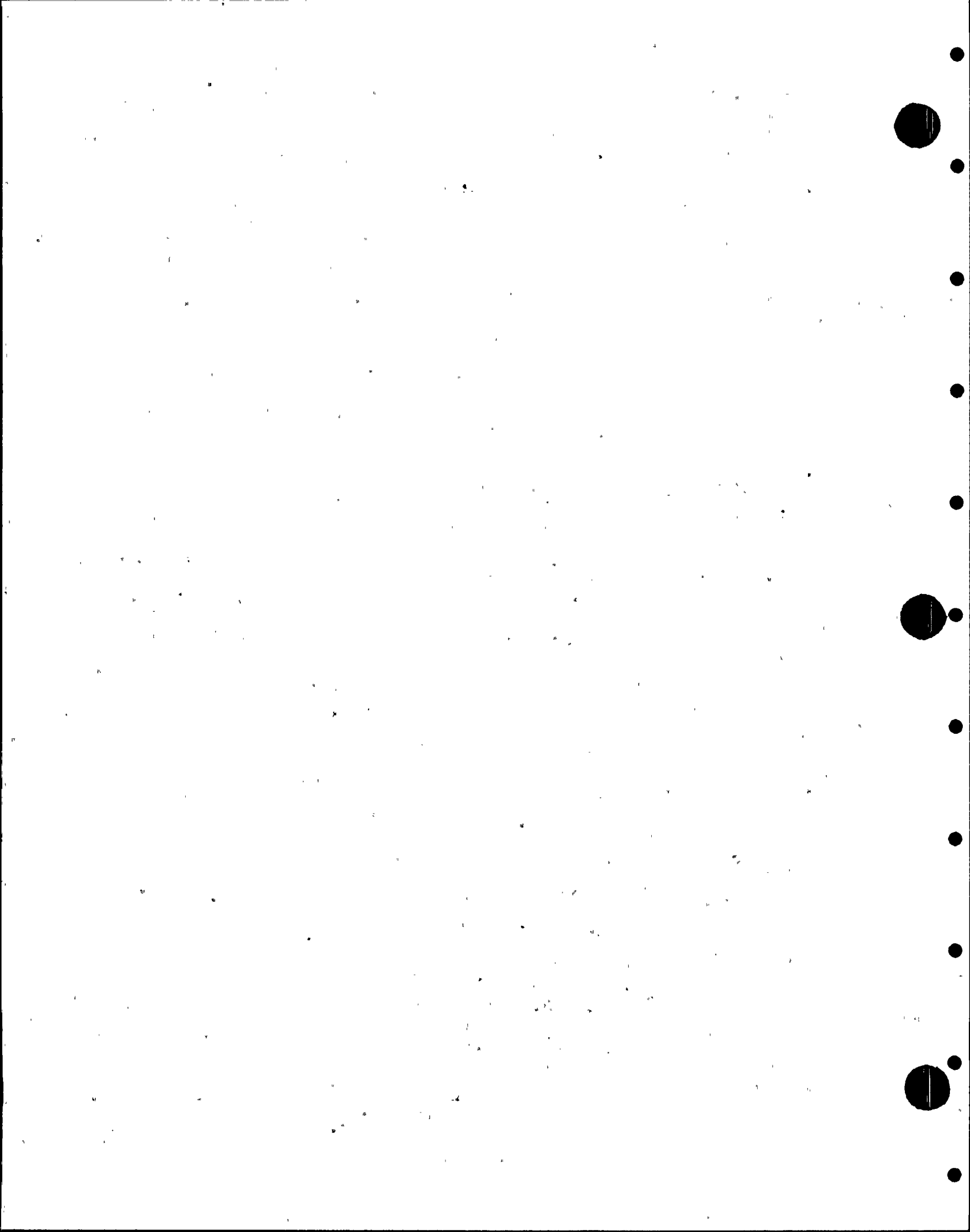
4 MR. ALLEN: Mary, I've got a question. On Figure 2C-3
5 you indicated the SESS input logic from support systems.
6 Could you touch on it, just give me an example?

7 MR. MORETON: An example of where you will see this
8 kind of feeding from system to system, you could take the
9 safety injection system, which depends on the essential HVAC,
10 which depends on the essential cooling water system, which
11 depends on the essential spray pond system. You will see
12 an input, as an example, on the essential cooling water
13 system, an input from the essential spray pond system to the
14 essential cooling water system, and one from the essential
15 cooling water system to, as an example, the essential chilled
16 water system.

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

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

25 MR. STERLING: Since they are coming from limits which



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

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

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

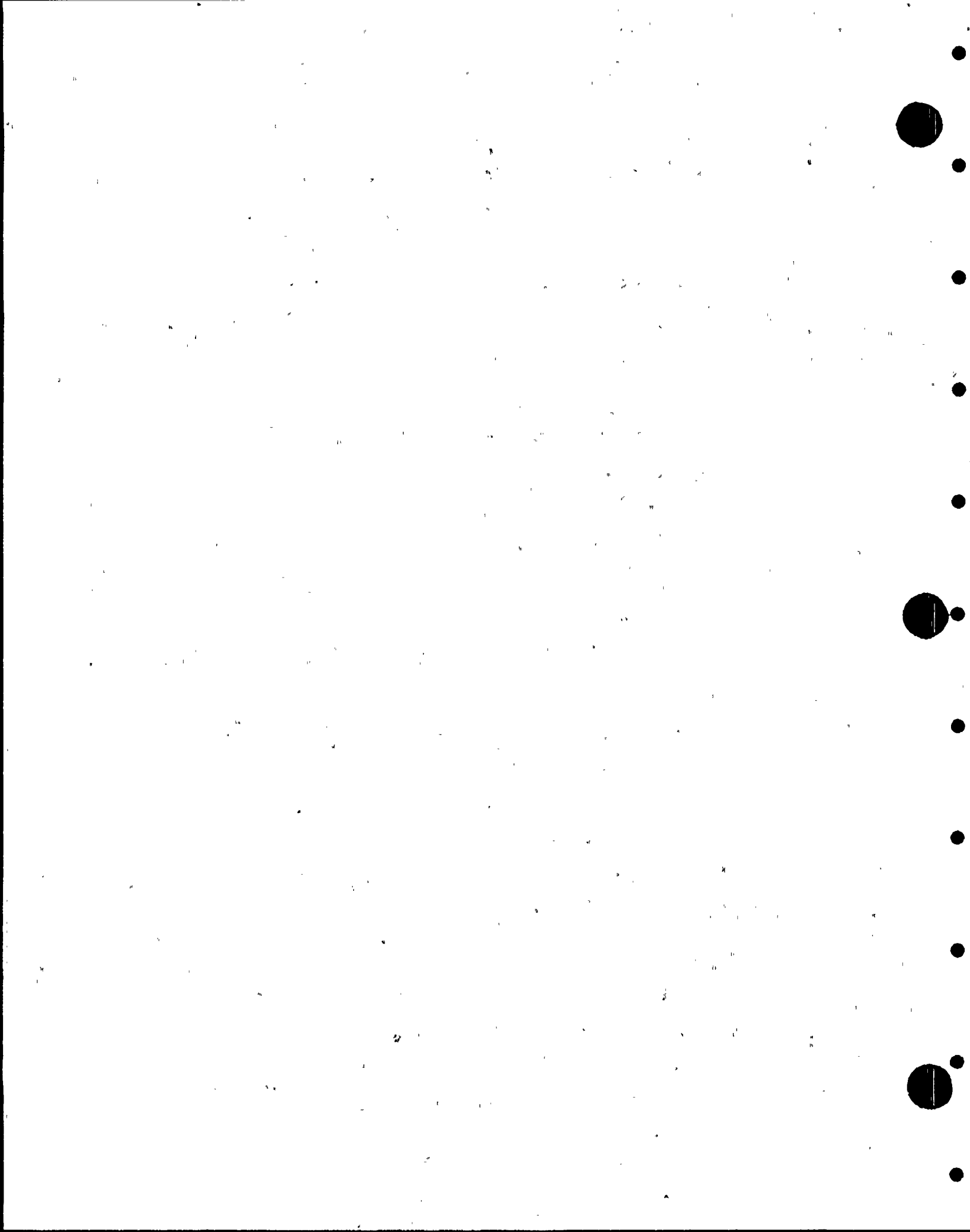
15 MR. STERLING: So that is at the input point to the
16 SESS. It would be the same input point as the limit switch
17 from the source device.

18 MRS. MORETON: Yes.

19 MR. STERLING: The status test does the same?

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

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



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

4 MRS. MORETON: That's correct.

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

7 MRS. MORETON: That's correct.

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

11 MRS. MORETON: That's correct.

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

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

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

19 MRS. MORETON: No.

20 MR. ALLEN: Any other questions?

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

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

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

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

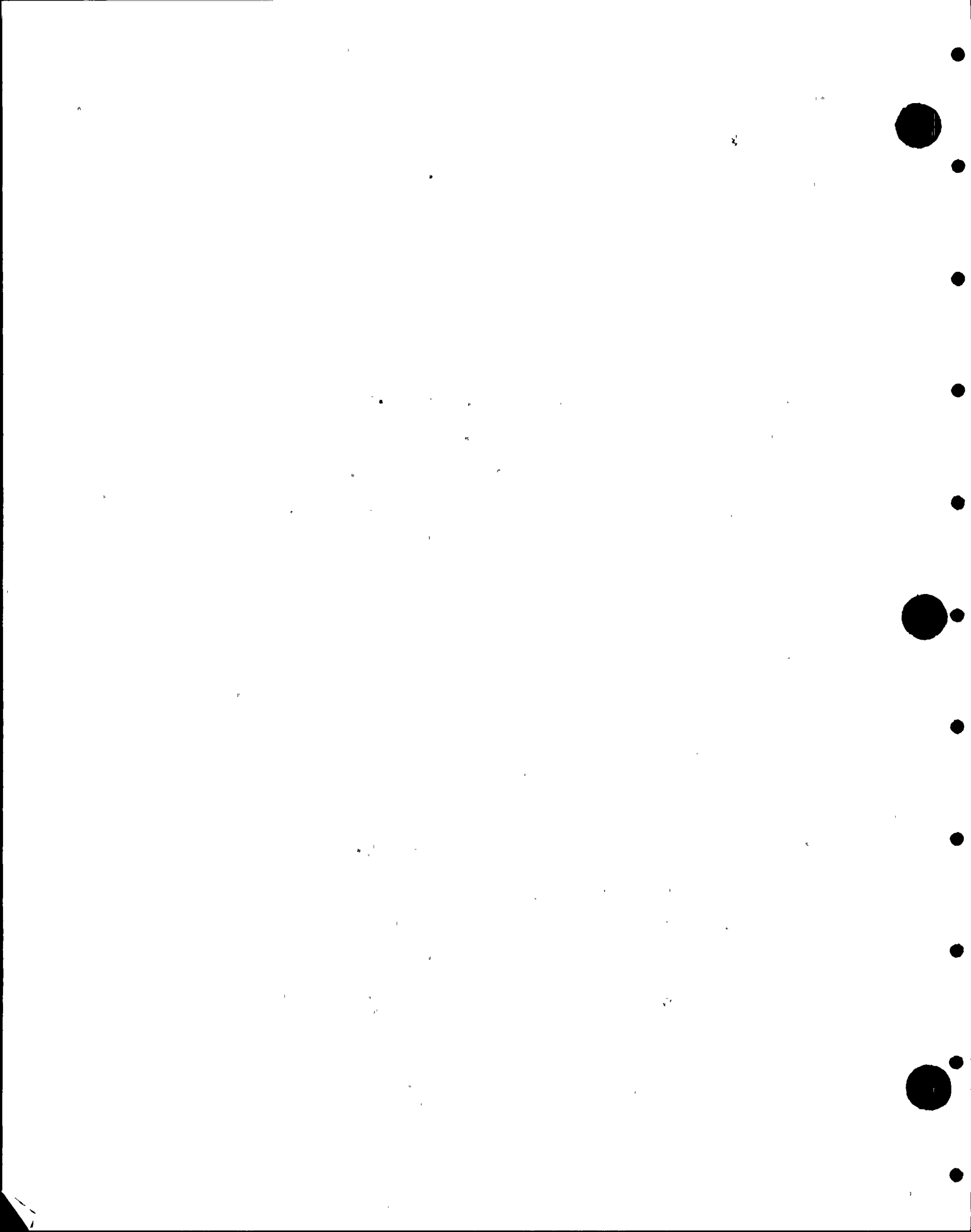
10 MR. SOTEROPOULOUS: Every time you trip the breaker,
11 the motor will wind up the spring for the next closure,
12 at which time the limit switch will close and there will
13 be a white light that monitors that contact at the switchgear
14 panel.

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

18 MR. SOTEROPOULOUS: Yes.

19 MR. ALLEN: Any other questions?

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

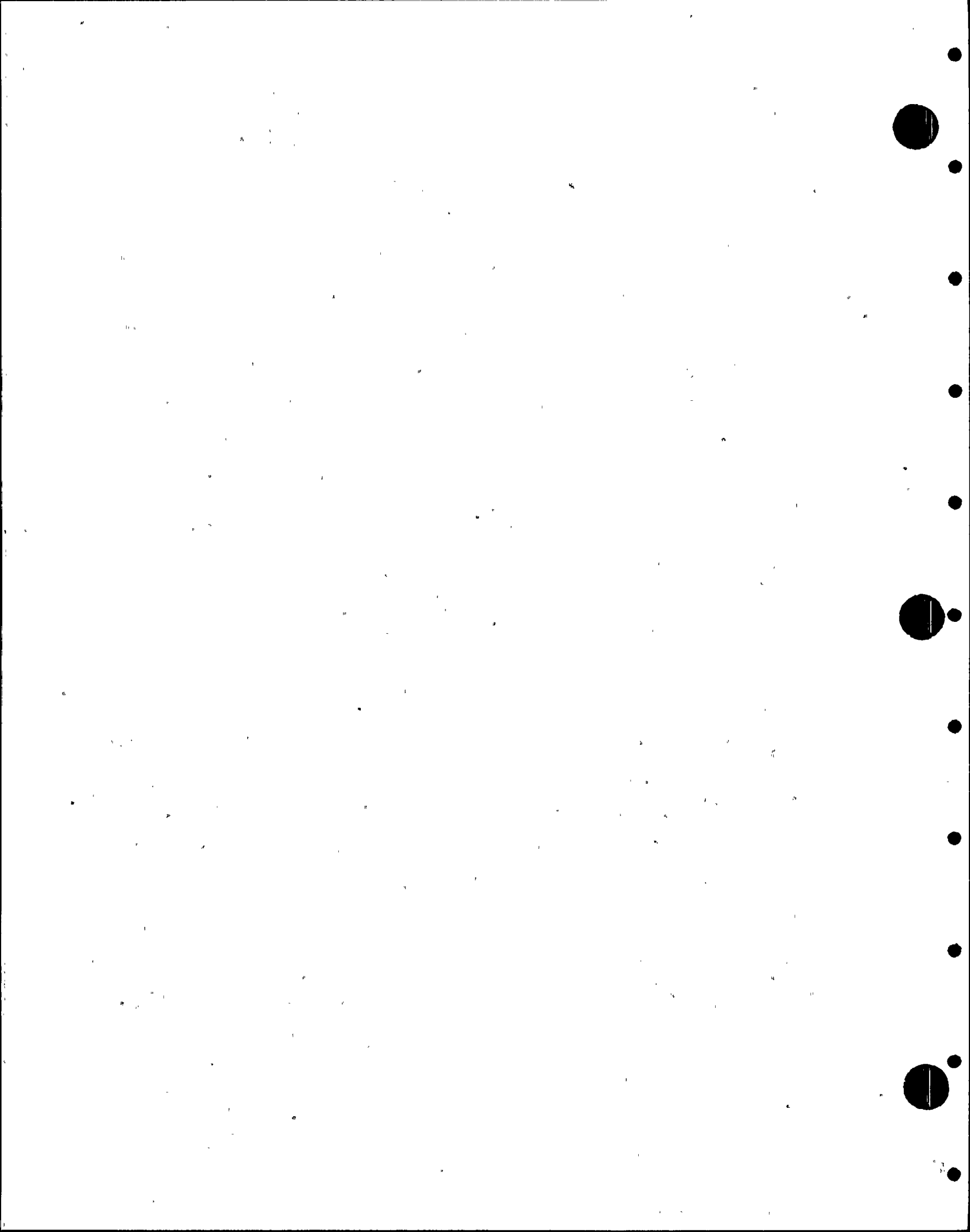


1 MRS. MORETON: The purpose of having two panels is
2 to monitor the two separate systems. The Train A panel
3 monitors the Train A components and the Train B panel monitors
4 the Train B components, so the operator would know if he
5 had annunciation in one train that that train was not
6 available.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

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

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

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



1 have isolation on that line?

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

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

9 MRS. MORETON: Right.

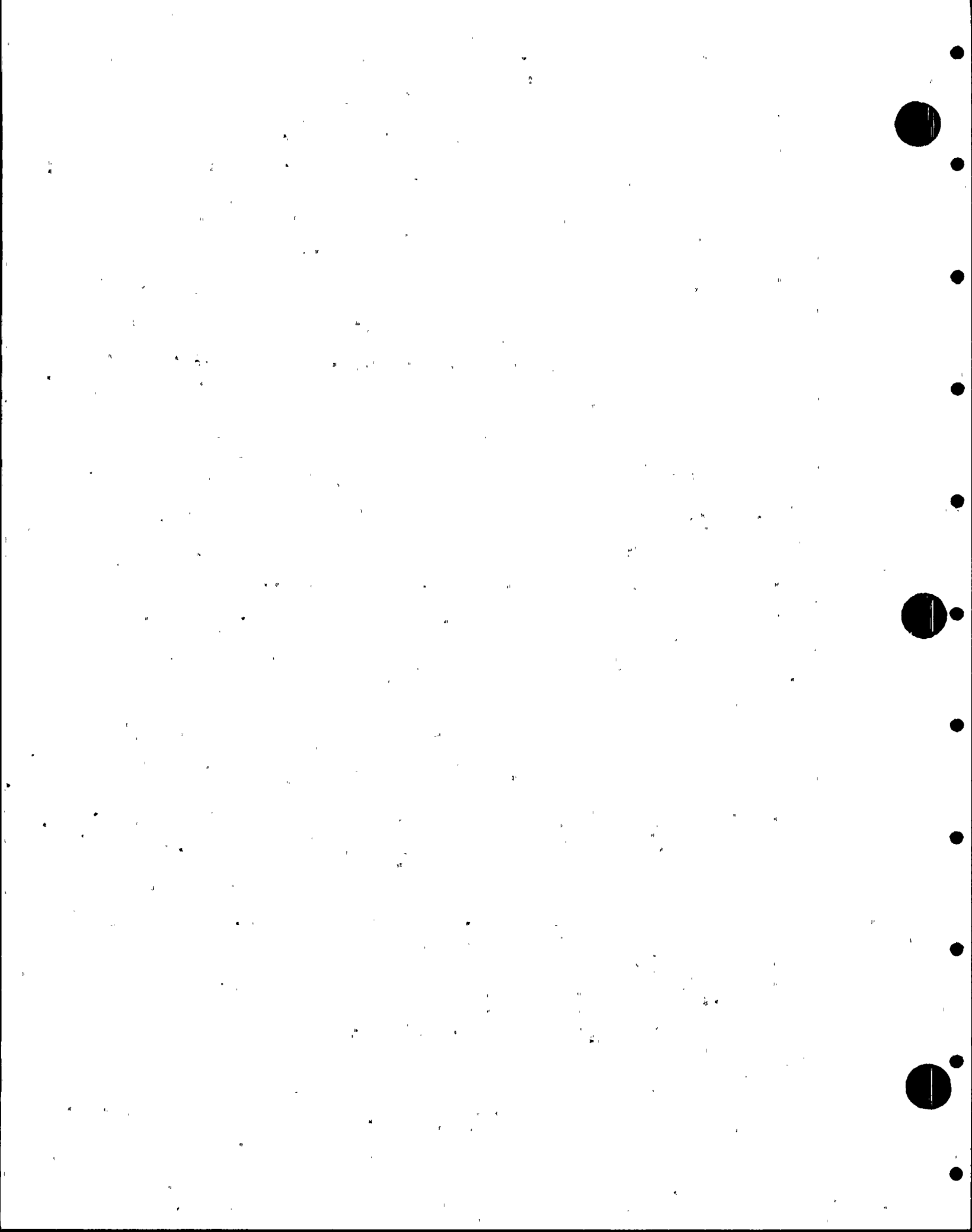
10 MISS KERRIGAN: I have a logistical question. A lot
11 of the information that we are discussing like that on the
12 control room panel display, will that be reproduced in the
13 control room design presentation that is coming up in a few
14 weeks?

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

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

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

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



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

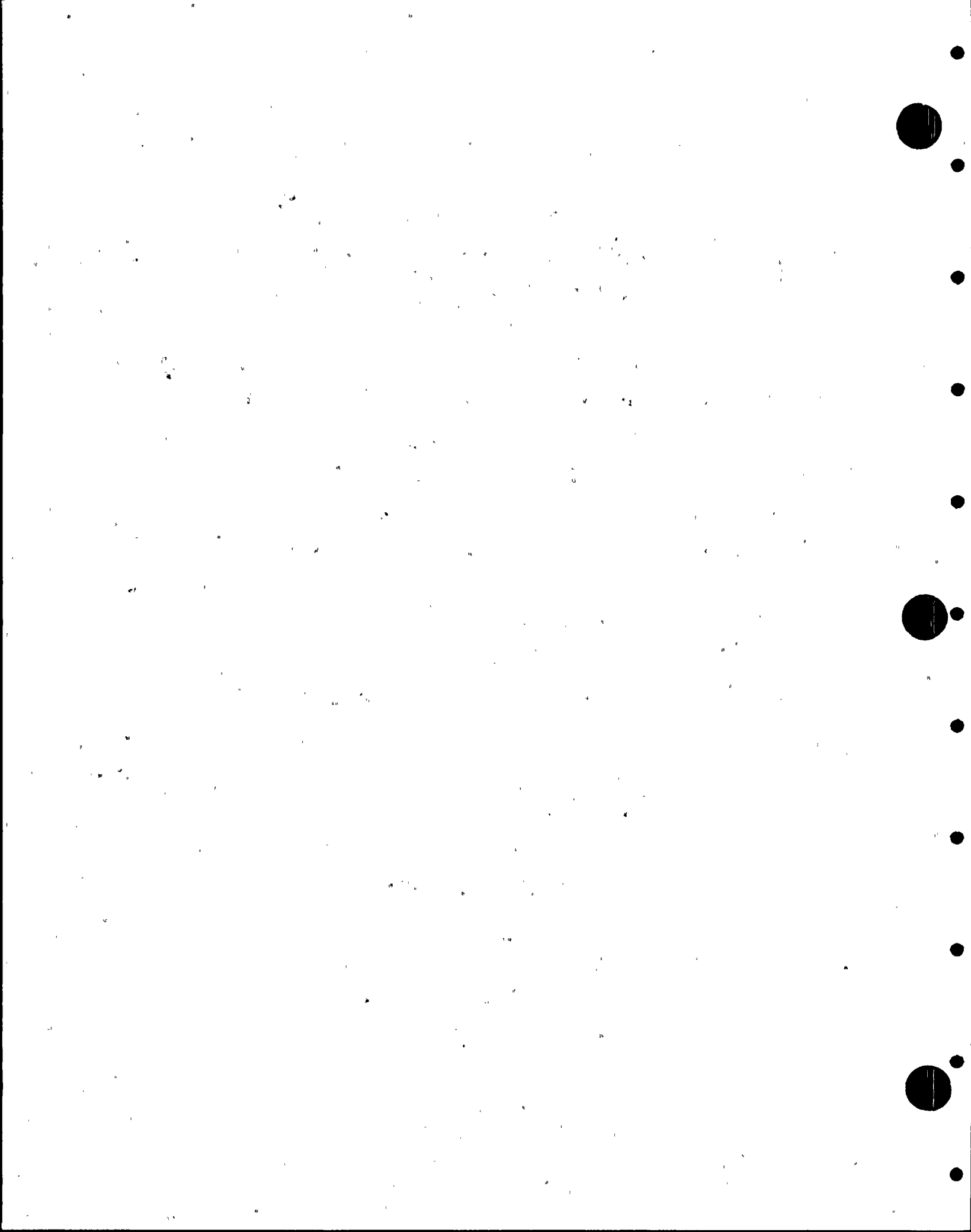
3 MR. ALLEN: Anything further? Jack.

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

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

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

22 MR. ROSENTHAL: Bearing in mind that our Reg. Guide
23 1.47 has no requirements on the quality of the hardware,
24 can you tell us if this is a computer based system or is
25 it a hard wired?



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

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

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

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

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

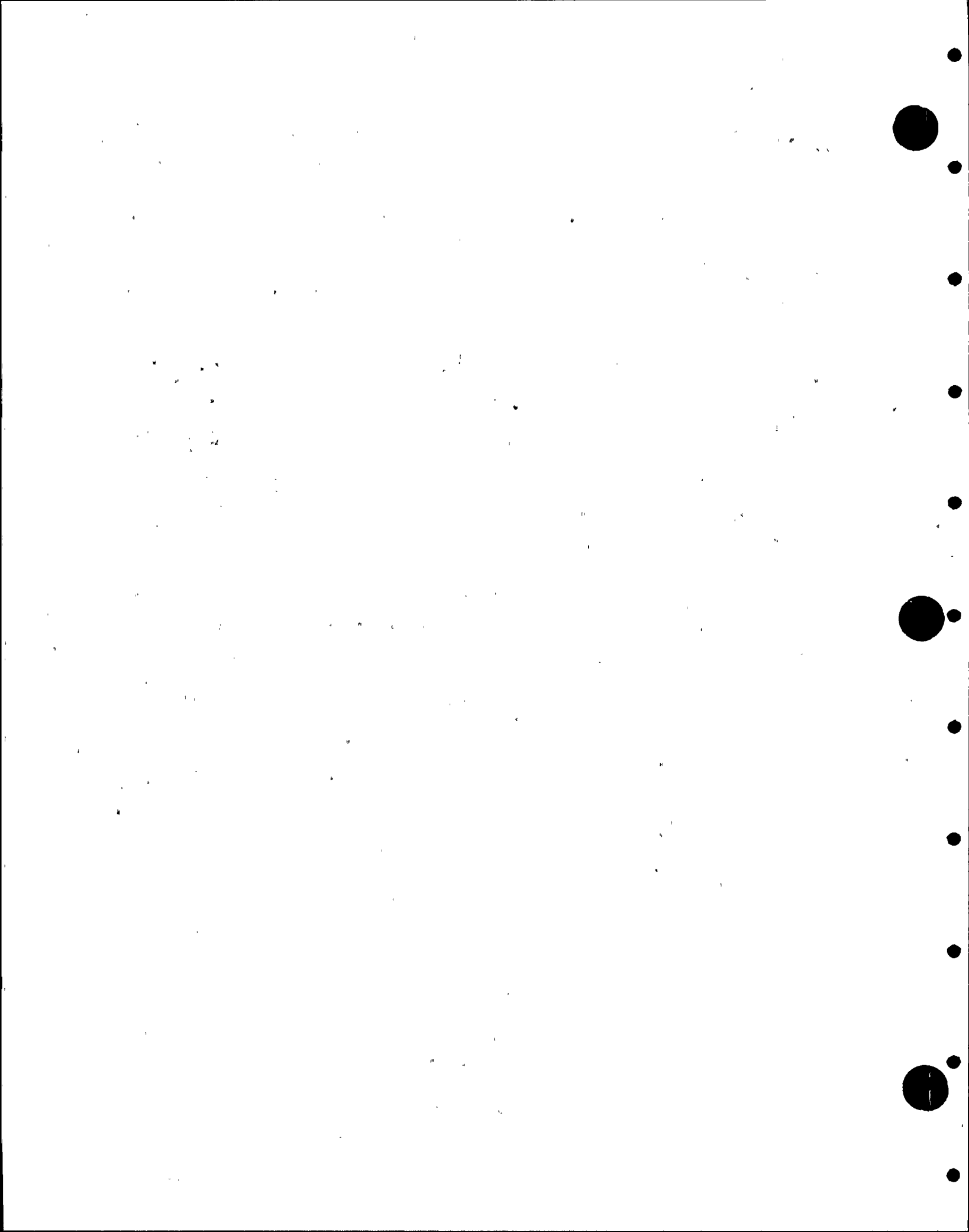
18 MR. ROSENTHAL: The last thing is the operator's
19 procedures and training, especially his training, does that
20 include a description of this panel and the interrelation-
21 ships that are being displayed by the panel?

22 MR. ALLEN: Yes.

23 MR. STERLING: Yes.

24 MR. BINGHAM: Yes, it does.

25 MR. SOTEROPOULOUS: The system sort of evolved



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

9 MR. BINGHAM: Any other questions?

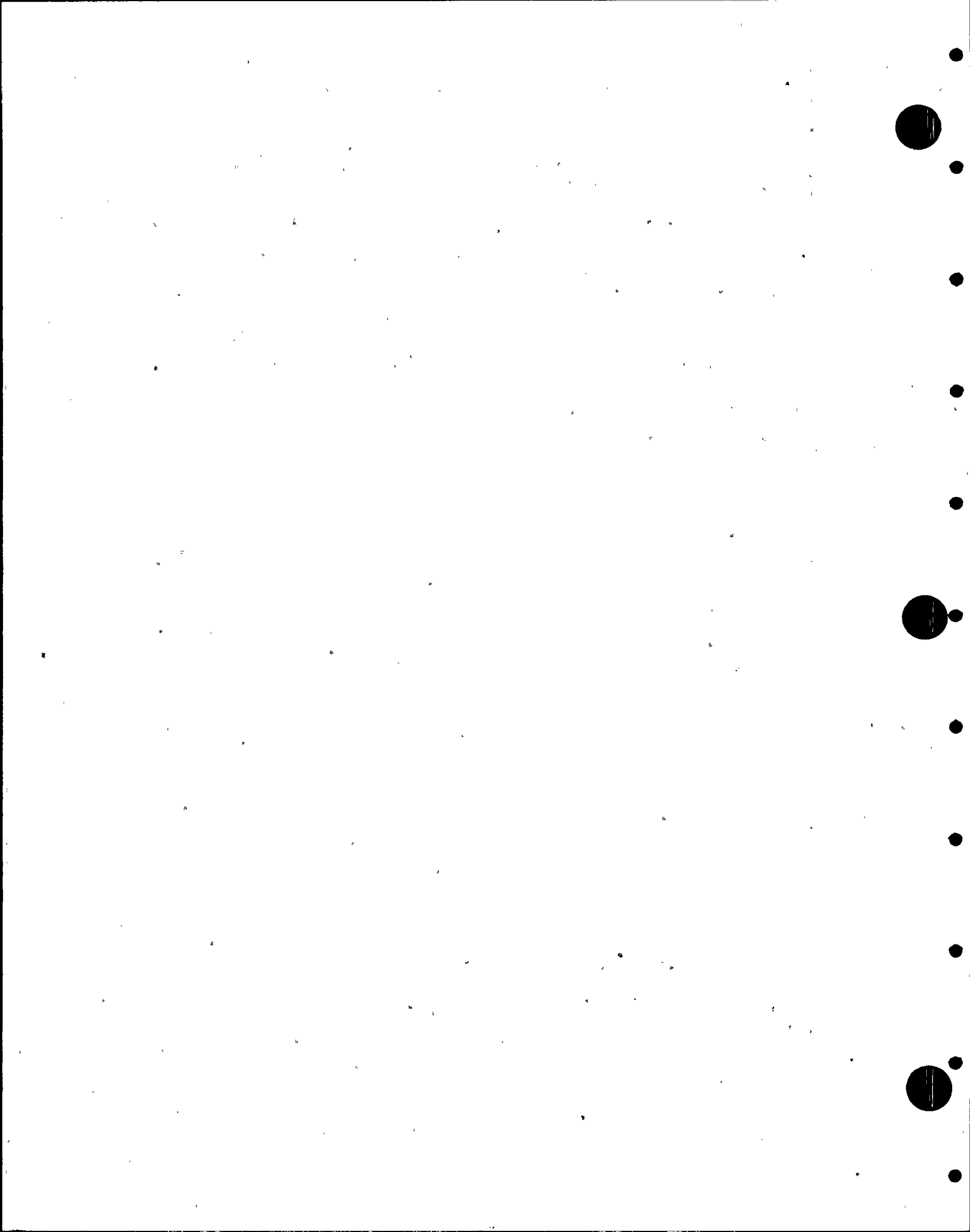
10 MR. MECH: Are any of these annunciators that you
11 showed the first-in type?

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

14 MR. ALLEN: Our schedule called for taking a break
15 at 3:00. It is now ten after. Why don't we take about a
16 15-minute break.

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

19 MR. BINGHAM: There was a question about the under-
20 voltage setpoints. The drop out is at 68% and the pick up
21 is at 75%. Let's proceed then with 2C3, Post-Accident
22 Monitoring. John, I think in the interests of time, we won't
23 go through the criteria in as much detail as we have, because
24 you can read it from the exhibit. If there are some particular
25 clarifications, we will come back and pick those up.



1 MR. ALLEN: Bill, could you indicate what you would
2 like to try to go through tonight?

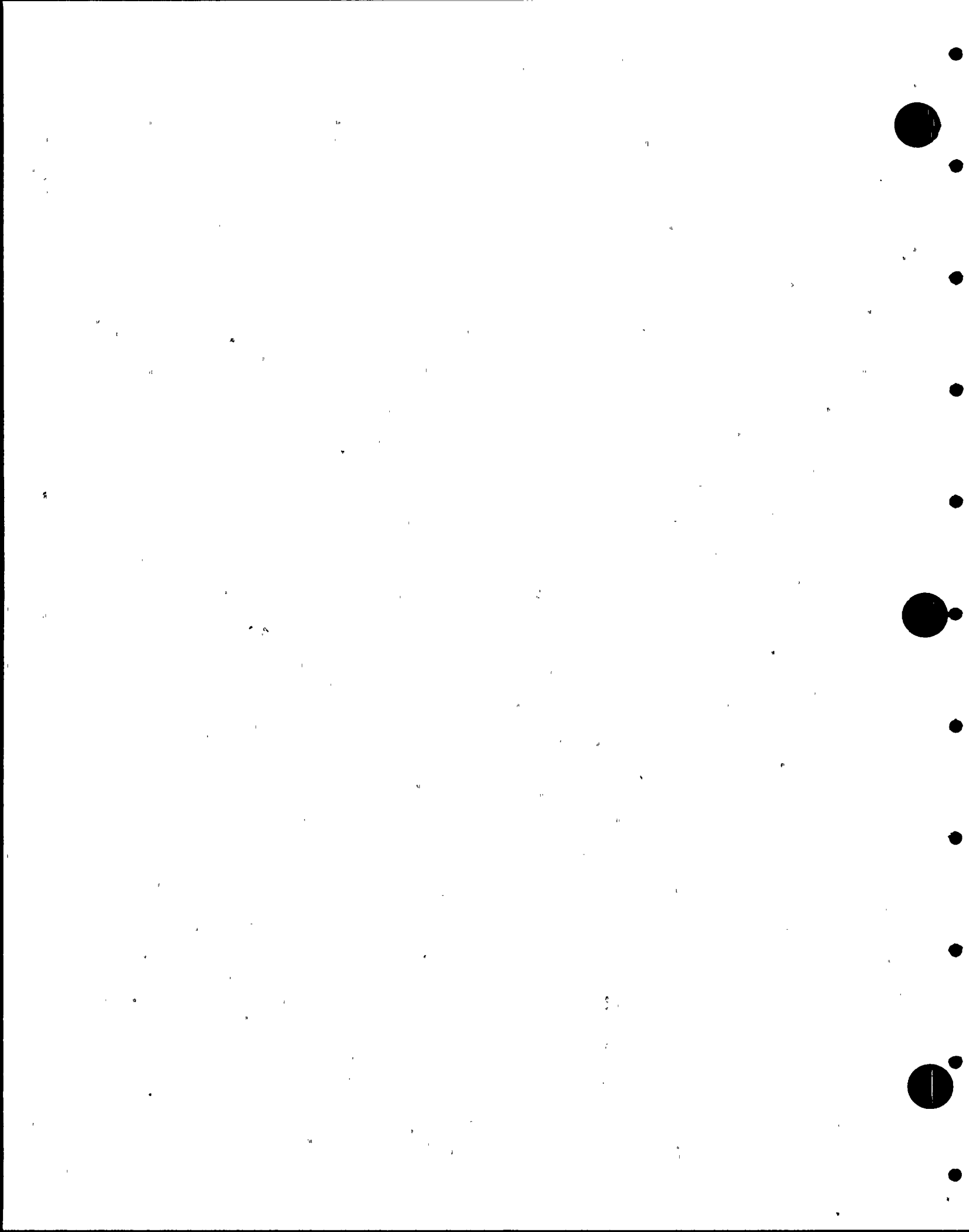
3 MR. BINGHAM: Yes. We would like to get through 3.F.

4 MRS. MORETON: Exhibit 2C3-1, Post-Accident Monitoring
5 Design Criteria. These are the design criteria and the
6 entire post-accident monitoring sections not currently in
7 the PVNGS FSAR. These are the design criteria the Project
8 is adopting and this information will be provided in the
9 FSAR when it is finalized.

10 Design criteria for post-accident monitoring
11 come from Regulatory Guide 1.97, Revision 2. The design
12 and qualification criteria categories are unique definitions
13 to PVNGS to sort of put it in the design framework that we
14 use for the different categories. These are our interpreta-
15 tions of the requirements out of Reg. Guide 1.97, Revision 2,
16 for the various categories.

17 Category 1. Instrumentation is qualified in
18 accordance with Reg. Guide 1.89 and Reg. Guide 1.100.
19 Instrumentation is designed to accommodate single failure.
20 Instrumentation is powered from Class IE. Instrumentation is
21 available prior to the accident as required by the Tech.
22 Specs. or IEEE 279, Paragraph 4.11. Instrumentation is
23 Quality Class Q.

24 Exhibit 2C3-2. Continuous indication is provided.
25 Recording shall be provided on one channel. Transmission of



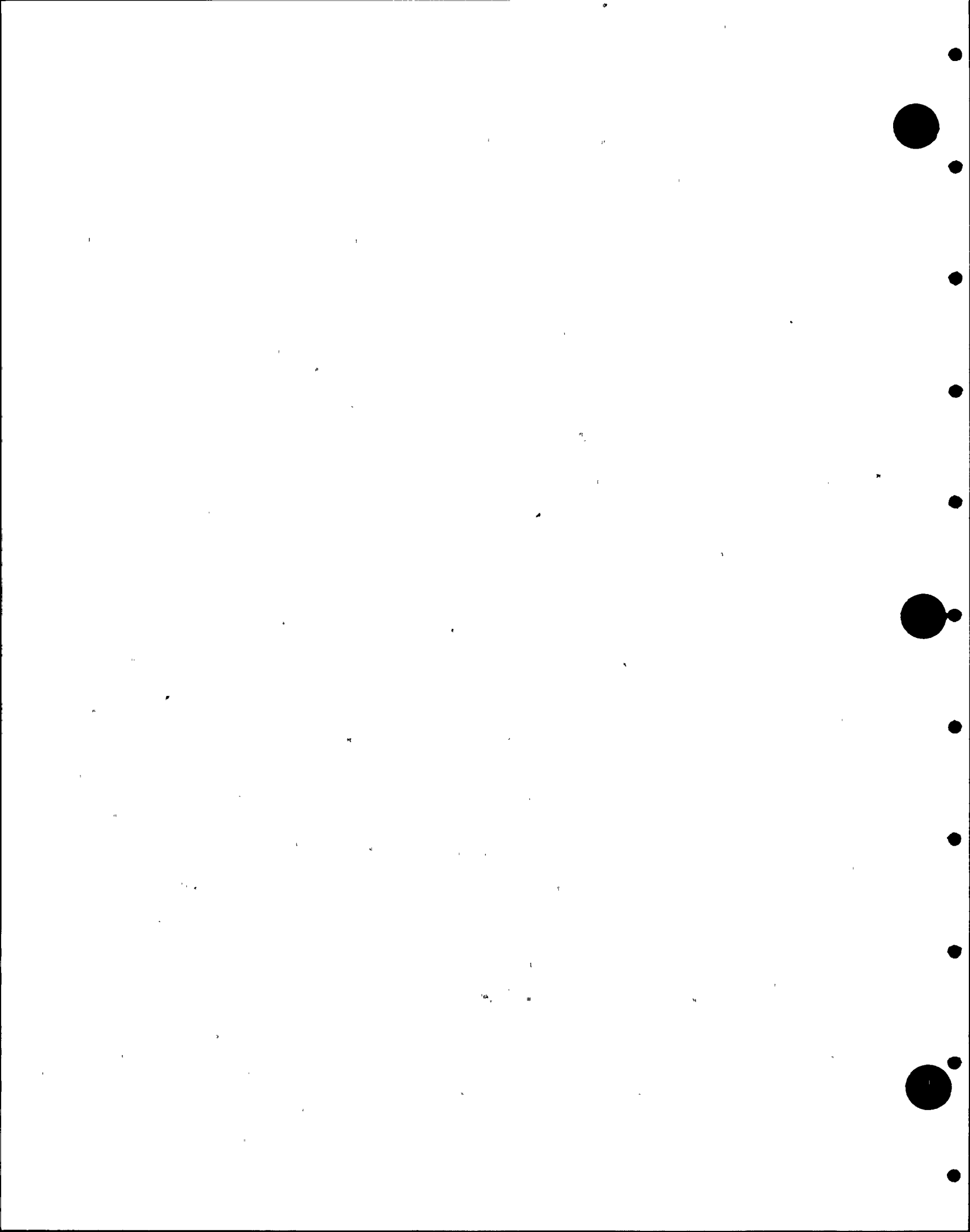
1 signals for use other than post-accident monitoring shall
2 be through isolation devices. Types A, B, and C instruments
3 shall be specifically identified on the control panels.

4 Category 2. Sensors shall be qualified in
5 accordance with Reg. Guide 1.89. Seismic qualifications
6 will be provided when instrumentation is part of the
7 safety-related system. Instrumentation is powered from a
8 non-Class IE instrument bus which has Class IE power as
9 a backup, or they may be powered from Class IE power. The
10 out-of-service interval is based on the Tech. Specs. The
11 sensors shall be Quality Class Q. There are some cases
12 where Quality Class R sensors are used. Displays shall be
13 Quality Class R.

14 Exhibit 2C3-3, continuing on Category 2. Display
15 shall be on an individual instrument or on demand on a
16 CRT. Data recording is provided for effluent radioactivity
17 monitors, area radiation monitors and meteorology monitors.
18 Transmission of signals for use other than the post-accident
19 monitoring shall be through isolation devices. Again
20 Types A, B, and C instruments are specifically identified.

21 Category 3. Instrumentation shall be of high
22 quality commercial grade and shall be selected to withstand
23 the service environment. In Category 3, the display shall
24 be on individual instrument or on demand on a CRT.

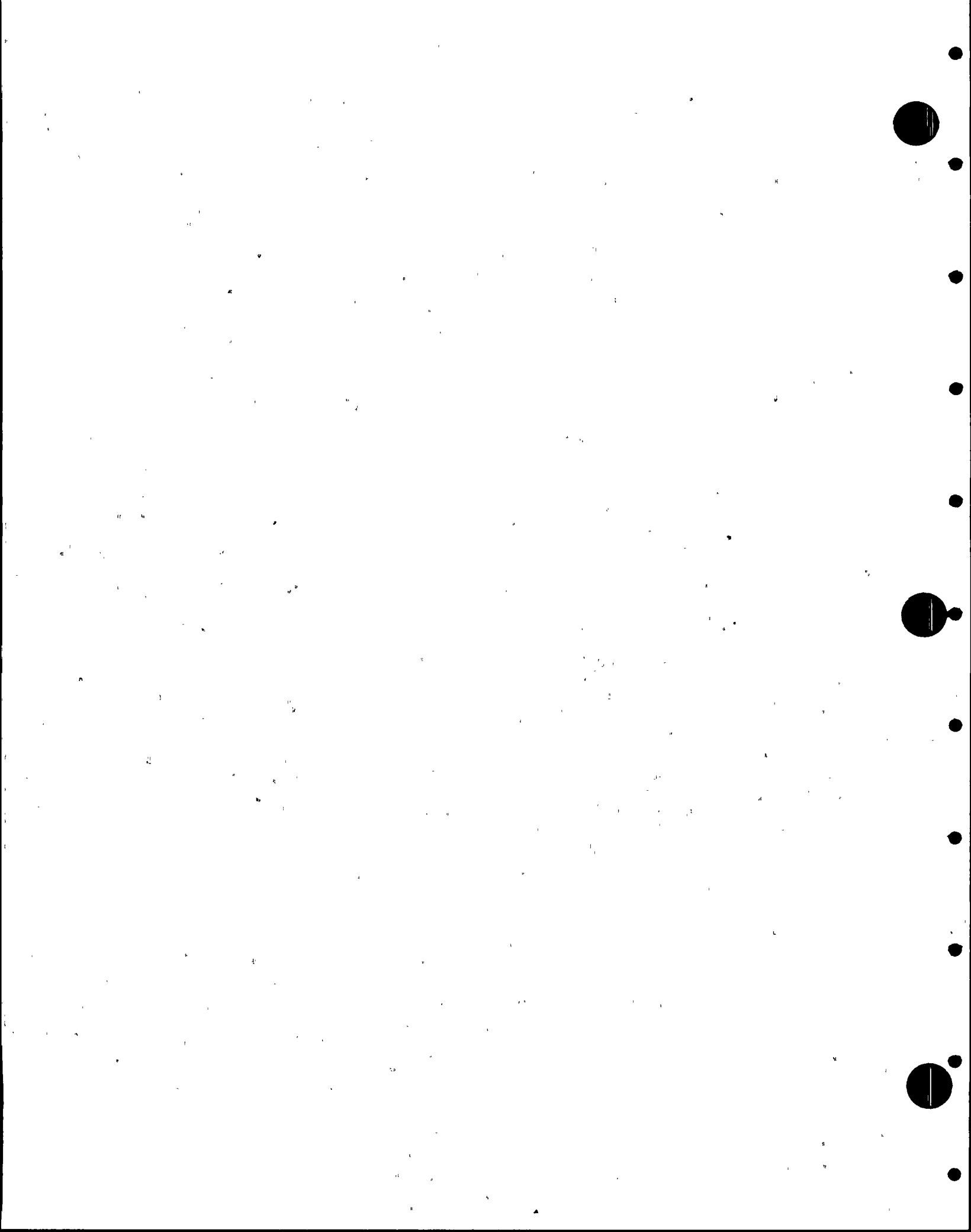
25 Exhibit 2C3-4. These are more General Design



1 Criteria. Servicing, testing, and calibration programs shall
2 be provided. Whenever means for removing channels from
3 service are included in the design, the design shall
4 facilitate administrative control. The design shall facilitate
5 administrative control of access to all setpoint adjustments,
6 module calibration adjustments and test points. The
7 monitoring instrumentation design shall minimize development
8 of conditions which would cause meters, annunciators,
9 recorders, or alarms to give anomalous indications potentially
10 confusing to the operator. The instrumentation shall be
11 designed to facilitate recognition, location, replacement,
12 repair, or adjustment of malfunctioning components or modules.
13 To the extent practicable, monitoring instrumentation inputs
14 shall be from sensors that directly measure the desired
15 variables.

16 Exhibit 2C3-5. The same instruments shall be used
17 practicable for accident monitoring as are used for normal
18 operations of the plant. Periodic testing shall be in
19 accordance with the applicable portions of Reg. Guide 1.118.

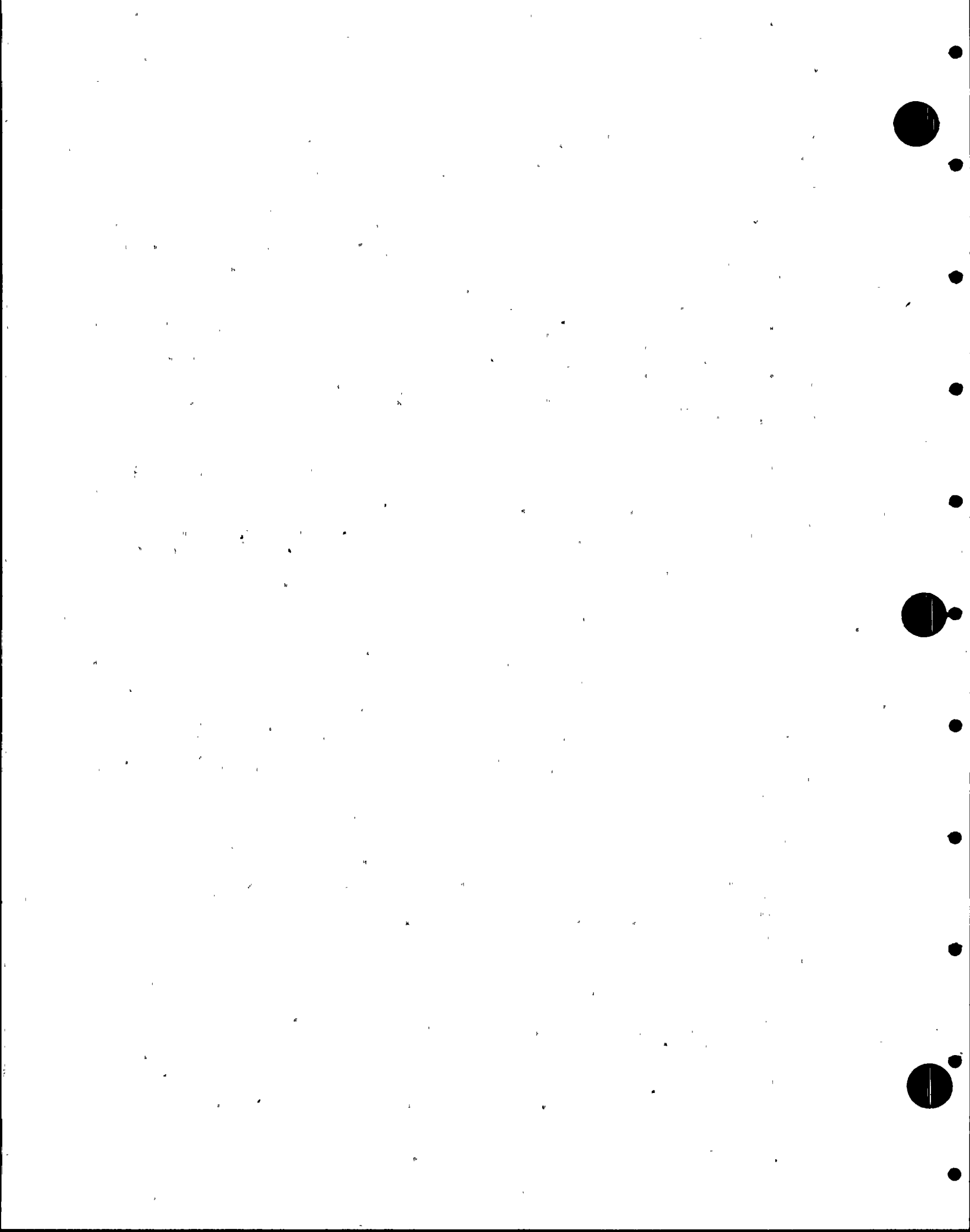
20 Proceeding on with the Post-Accident Monitoring
21 System Description, Exhibit 2C3-6, Type A variables are those
22 variables to be monitored that provide the primary information
23 required to permit the control room operator to take
24 specific manually controlled actions for which no automatic
25 control is provided and which are required for safety



1 systems to accomplish their safety function for design basis
2 accident events. For the Type A variables, Combustion
3 Engineering is providing a review of emergency guidelines
4 to identify if each event required manual action, instrument
5 consulted, required range and accuracy, and the qualification
6 status. Completion of this activity is expected in November,
7 1981. In addition, a review of the emergency procedures
8 after they are developed will be performed to ensure the
9 required variables have been identified.

10 Exhibit 2C3-7 lists the Type B variables, which
11 are variables required to provide information to indicate
12 whether the plant safety functions are being accomplished.
13 These functions include reactivity control, core cooling,
14 maintaining reactor coolant system integrity, and maintaining
15 containment integrity. Category 1 variables in the balance
16 of plant design include coolant level in the reactor. The
17 only part that is in the balance of plant design is the
18 display, which will be two channels Class IE. Containment
19 sump water level, wide range. Requirement, to monitor to
20 bottom of containment to 600,000 gallon equivalent. We have
21 provided sensors in the 11-foot range. Display is two
22 channels, Class IE, with recording on one channel.

23 Exhibit 2C3-8, continuing on with Type B Category 1
24 variables. For containment pressure, two requirements exist,
25 one to measure from zero to design pressure, the other to



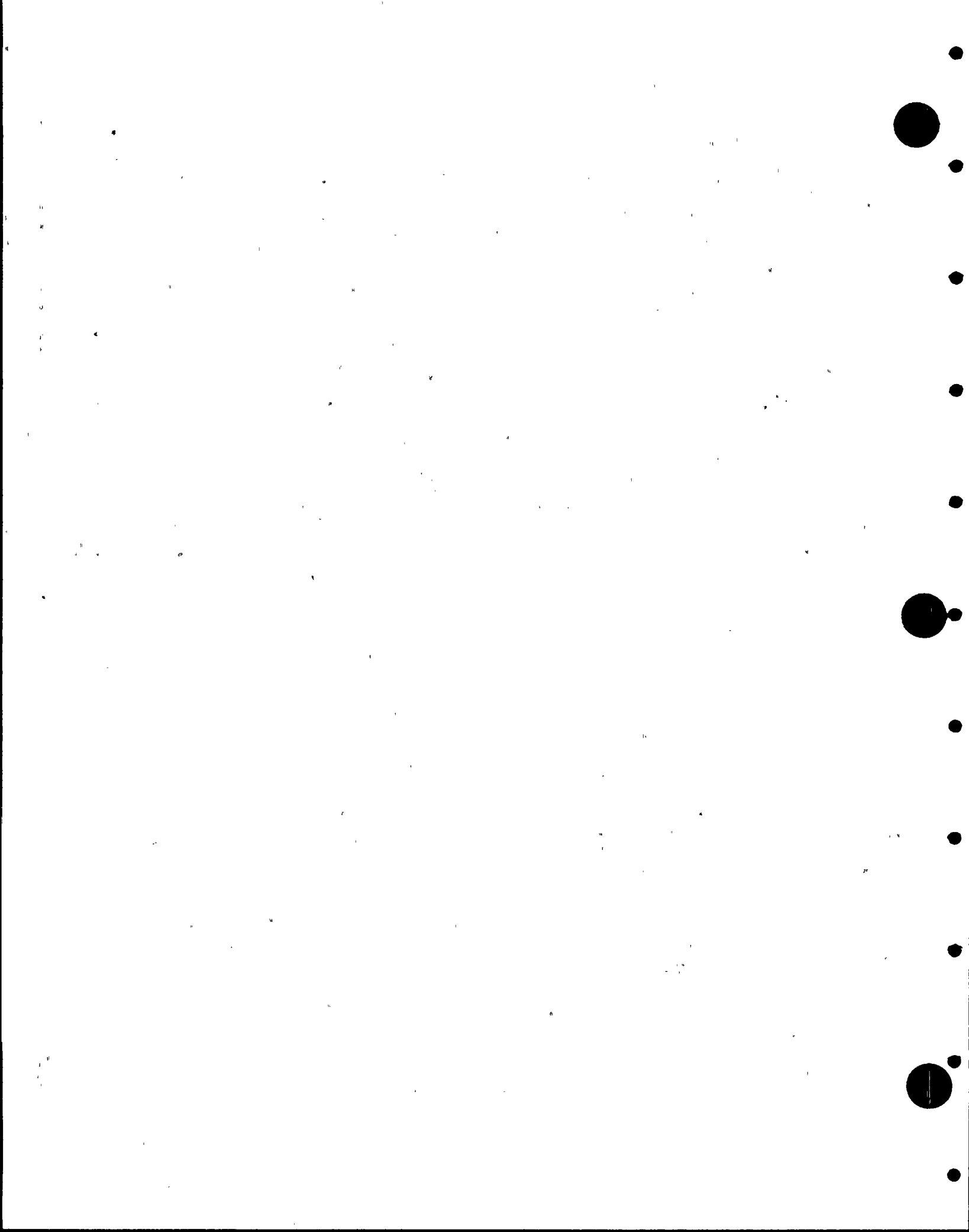
1 measure from 10 psia to design pressure. Sensors provided
2 will be from minus 5 psig to 180 psig. Display is in
3 two channels, Class IE, with recording on one channel.
4 Containment isolation valve position, excluding check valves.
5 Display is provided for valve status for all automatic or
6 remote manual containment isolation valves.

7 Category 2. Degrees of subcooling. Balance of
8 plant on this is the display only, which will be two channels
9 Class IE. Containment sump water level, narrow range. The
10 requirement is to monitor the sump. Sensors are provided
11 one per sump. That measures the sump from 6 inches above
12 the bottom of the sump to 6 inches above the top of the sump
13 to provide overlap with the wide-range detector. There is
14 one display per sump, since the sensor is qualified to the
15 post-LOCA environment.

16 Exhibit 2C3-9, continuing on with the Type B
17 Category 3 variables. Requirement, to measure RCS soluble
18 boron concentration from zero to 6,000 ppm. This is
19 accomplished in the post-accident sampling system. The range
20 is from zero to 6,000 ppm, remote sample, in-line automatic
21 with a grab sample backup.

22 Core exit temperature. The balance of plant
23 provisions here are for display only, which will be two
24 channels, Class IE.

25 Exhibit 2C3-10 covers Type C variables, which are



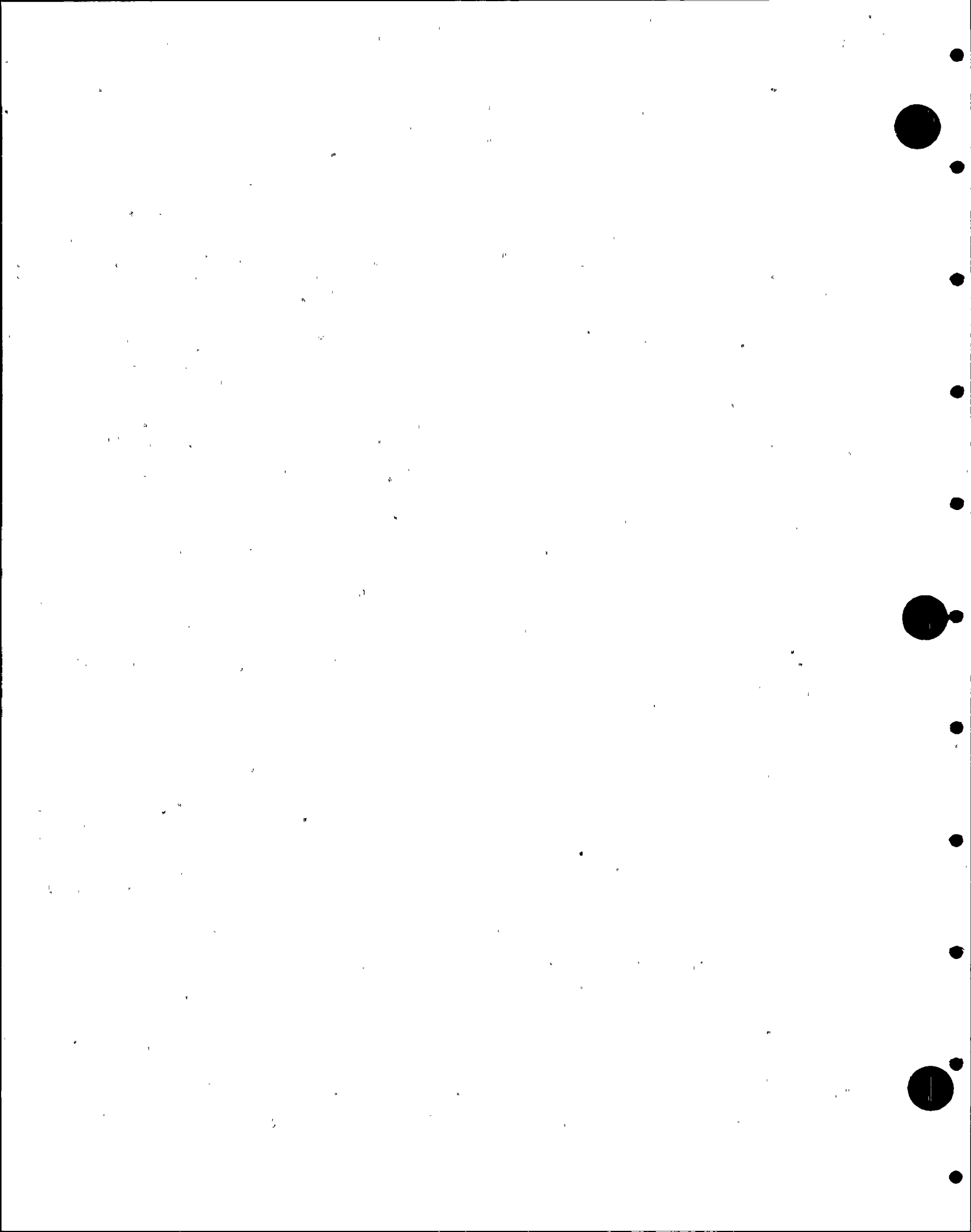
1 variables which provide information to indicate the potential
2 for being breached or the actual breach of the barriers to
3 fission product releases. The barriers are fuel cladding,
4 primary coolant pressure boundary, and containment.

5 Category 1 variables include the core exit
6 temperature, which we have discussed previously. Radioactivity
7 concentration or radiation level in circulating primary
8 coolant, the requirement is to monitor from one-half Tech.
9 Spec. limit to 100 times Tech. Spec. limit in R per hour.
10 Sensor range is provided to cover a range from 1R per hour
11 to 10^5 R per hour. Display is via a CRT, non-Class IE, and
12 two safety-related channel displays at the radiation monitor-
13 ing cabinet, which are Class IE and recording on one channel.

14 Containment pressure. The design requirements
15 here for Type C variables include an additional requirement
16 to measure from 10 psia to three times design pressure.
17 Sensor provided covers that range, as discussed before.

18 Exhibit 2C3-11, continuing on with Type C Category
19 1. Containment sump water level, wide range, is provided
20 as discussed before.

21 Containment hydrogen concentration. The requirement
22 is to measure from zero to 10%, capable of operating from
23 10 psia to maximum design pressure. Sensor provided does
24 measure from zero to 10%. It is available 30 minutes after
25 initiation of safety injection, which is in conformance with



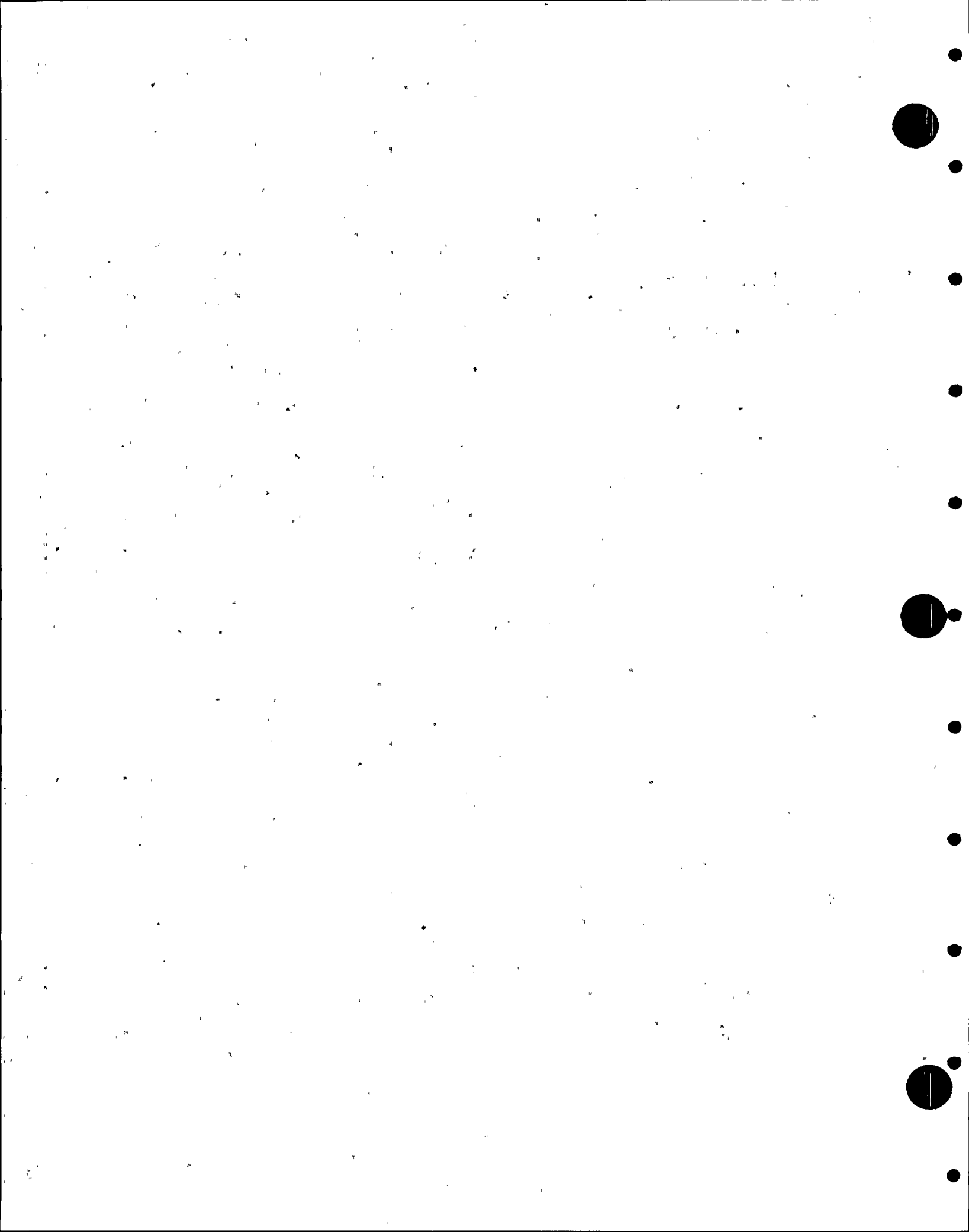
1 NUREG-0737. It is capable of operating from minus 5 psig
2 to 60 psig. Display is on two channels, Class IE, with
3 recording on one channel.

4 Exhibit 2C3-12, continuing on with Type C variables
5 Category 2. Containment sump water level, narrow range.
6 Display is provided, as discussed before.

7 Containment effluent radioactivity - noble gases
8 from identified release points. The requirement is to monitor
9 from 10^{-6} microcuries per cc to 10^{-2} microcuries per cc.
10 Sensor provided at the plant vent responds to 10^{-6} to 10^{-2}
11 microcuries per cc. Display in the control room is via CRT.
12 The sensor is qualified to post-accident environment.

13 Radiation exposure rate (inside buildings or areas
14 which are in direct contact with primary containment where
15 penetrations and hatches are located.) The requirement is
16 to monitor from 10^{-1} R per hour to 10^4 R per hour. PVNGS
17 design will incorporate 13 monitors with sensor range of
18 10^{-1} R per hour to 10^4 R per hour. Display is in the control
19 room via CRT. Sensors will be qualified to post-accident
20 environment.

21 Exhibit 2C3-13, continuing with Type C Category 2
22 variables. Effluent radioactivity - noble gases from
23 buildings, as indicated above. The requirement is to monitor
24 from 10^{-6} microcuries per cubic centimeter to 10^3 microcuries
25 per cubic centimeter. It has a sensor off the fuel building



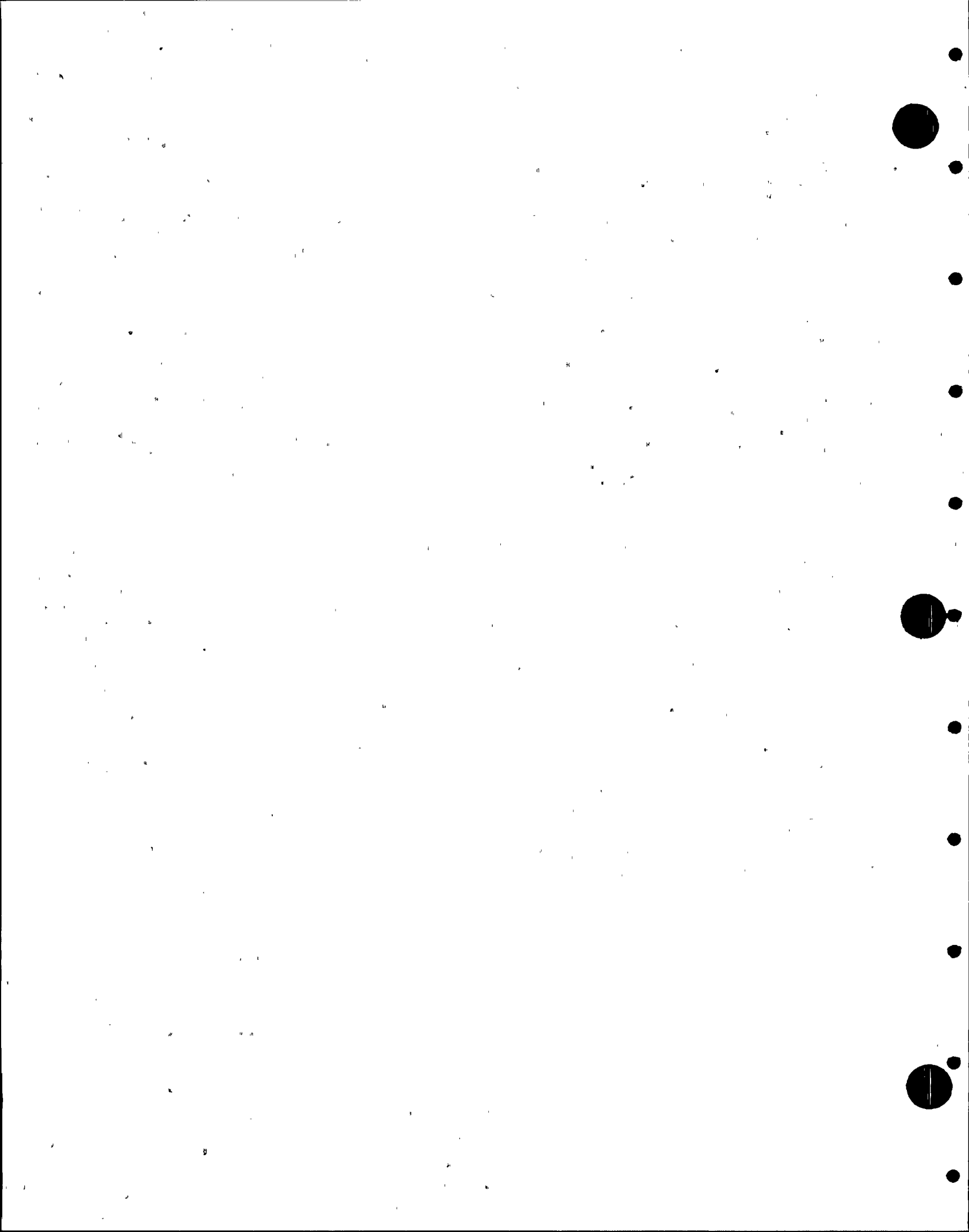
1 vent with a range of 10^{-6} microcuries per cubic centimeter
2 to 10^5 microcuries per cubic centimeter. It has a sensor
3 off the fuel building vent with a range of 10^{-6} microcuries
4 per cc to 10^5 . Display is via CRT. Sensor qualified to
5 post-accident environment.

6 Type C Category 3 variables. Analysis of primary
7 coolant (Gamma Spectrum). The requirement is to monitor
8 10 microcuries per gram to 10 curies per gram or TID-14844
9 source term in coolant volume. The PVNGS design incorporates
10 a post-accident sampling system, which is a remote sample.
11 An in-line automatic isotopic sampling is done over a range
12 of 10^{-3} microcuries per cc to 10 curies per cc.

13 Containment area radiation. The requirement is to
14 monitor from 1, R per hour to 10^4 R per hour. Sensor provided
15 monitors over that range and display via CRT.

16 Exhibit 2C3-14, continuing with Type C Category 3
17 variables. Effluent radioactivity - noble gas effluent
18 from condenser air removal system exhaust. The requirement
19 is to monitor from 10^{-6} microcuries per cc to 10^{-2} microcuries
20 per cc. Sensor provided monitors from 10^{-6} microcuries per
21 cc to 10^3 microcuries per cc. Display via CRT, with sensor
22 qualified to post-accident environment.

23 We will now go to the Type D variables that provide
24 information to indicate the operation of individual safety
25 systems and other systems important to safety. These



1 variables are to help the operator make appropriate decisions
2 in using the individual systems important to safety in
3 mitigating the consequences of an accident. The Category 1
4 variable included here is the condensate storage tank level.
5 PVNGS design has a sensor from zero to 50 feet with display
6 on two channels, Class IE, recording on one channel.

7 Exhibit 2C3-15, Type D Category 2 variables. The
8 primary system safety relief valve positions, closed - not
9 closed. PVNGS will comply with this requirement. This is
10 on the table in this form because the design is not far
11 enough along to give any specific information.

12 Pressurizer heater status. The requirement is to
13 monitor electric current. PVNGS will comply.

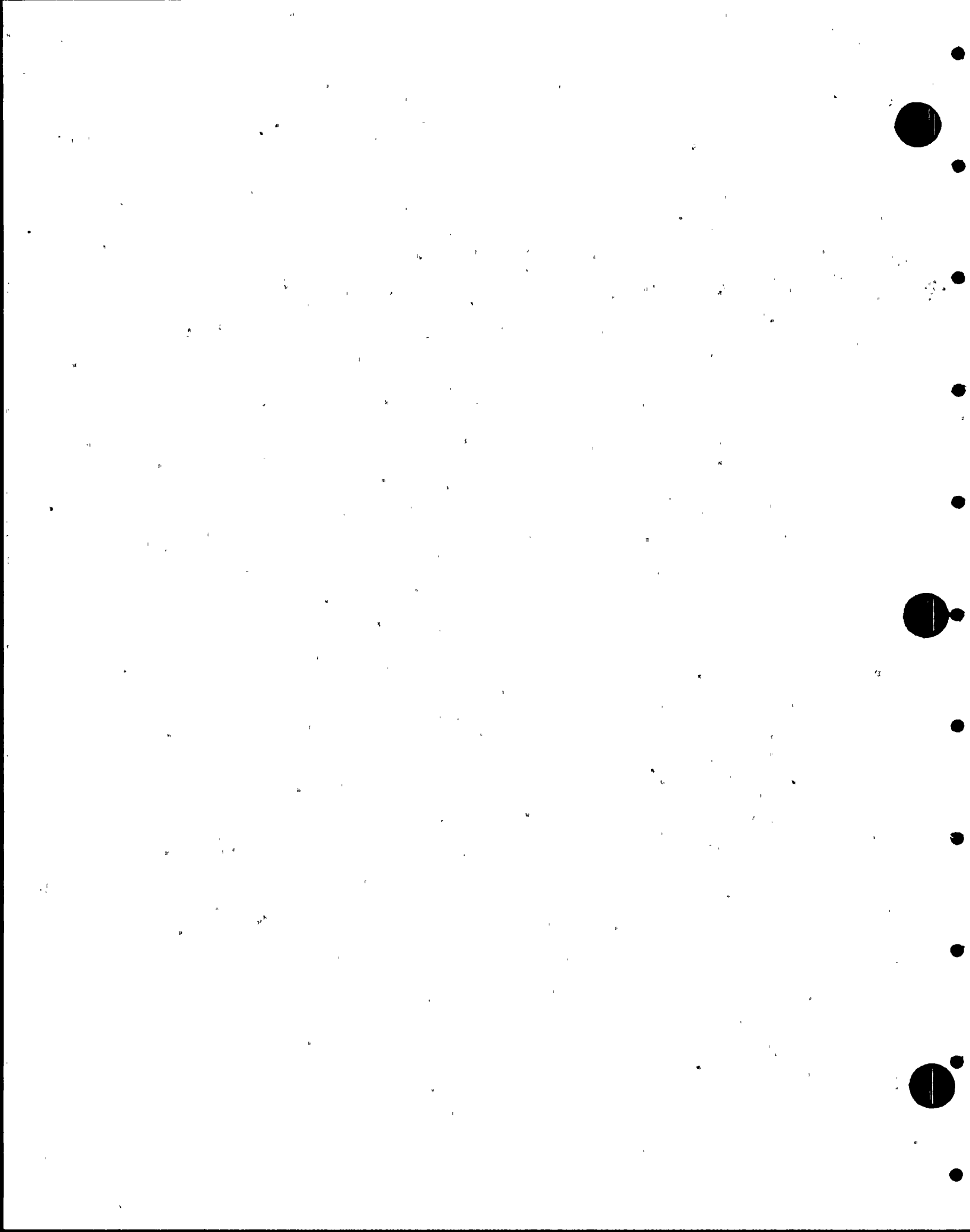
14 The safety/relief valve positions or main steam
15 flow, closed - not closed. PVNGS will comply.

16 Auxiliary feedwater flow. The requirement is from
17 zero to 110% design flow. Sensor provided from zero to
18 2,000 gpm. Display, two channels, Class IE.

19 Containment atmosphere temperature. The requirement
20 is to monitor from 40 to 400 degrees F. PVNGS will comply.

21 Containment sump water temperature. The requirement
22 is to monitor from 50 to 250 degrees F. This design
23 implementation is still under review.

24 Exhibit 2C3-16, continuing with Type D variables
25 Category 2. Essential cooling water system temperature.



1 The requirement is to monitor from 32 to 200 degrees F.
2 Sensor provided is from zero to 200 degrees F, with display
3 provided for each train.

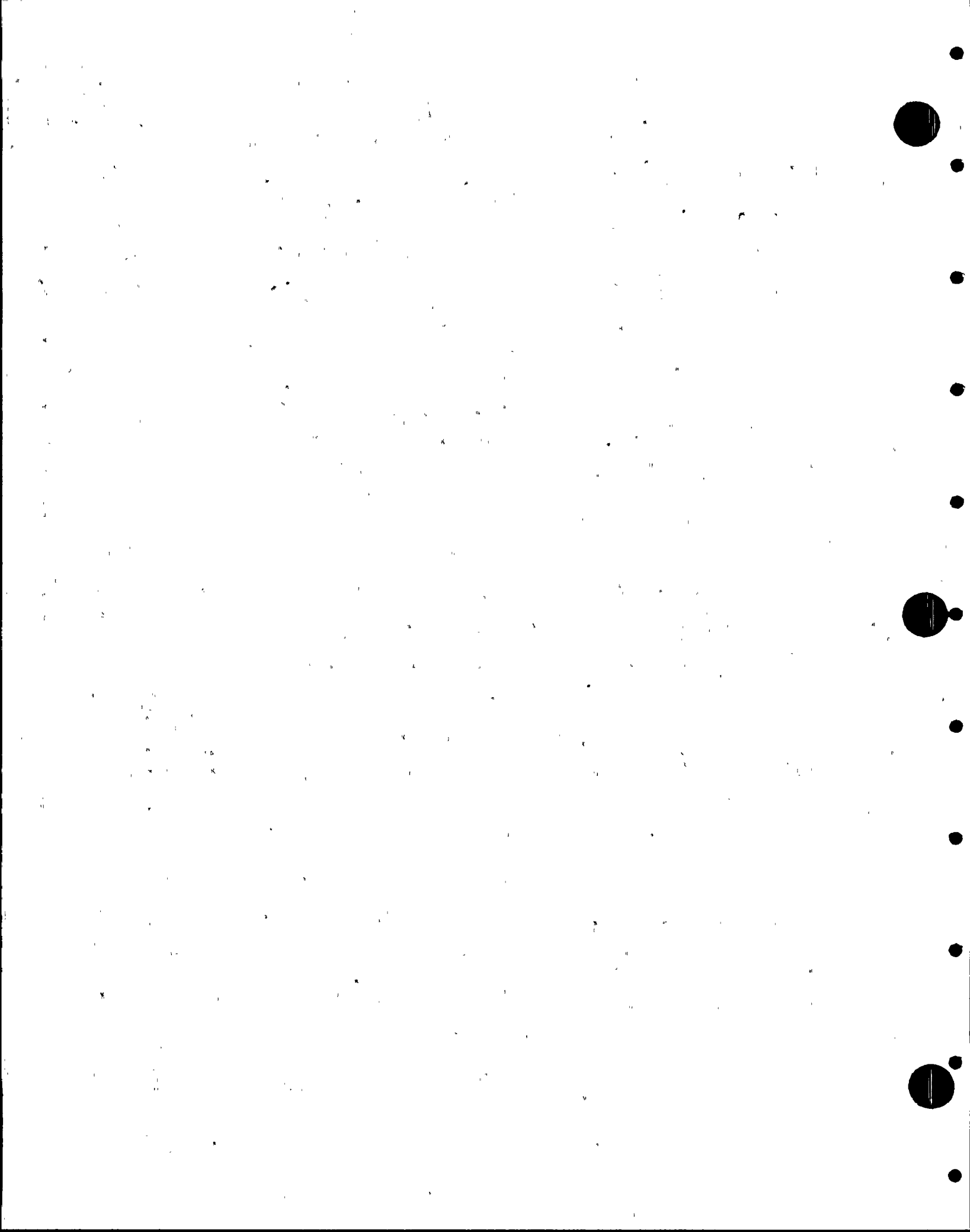
4 Essential cooling water system flow. The require-
5 ment is to monitor from zero to 110% design flow. Sensor
6 provided monitors from zero to 20,000 gpm, with the display
7 on each train.

8 Emergency ventilation damper position. The
9 requirement is to monitor open-closed status. Control room
10 display includes damper status for all automatic or remote
11 manual emergency ventilation dampers.

12 Status of standby power and other energy sources.
13 The requirement is to monitor voltages, currents, and
14 pressures. Display is provided in the control room of all
15 ESF voltages and currents. The displays are Class IE.
16 Low pressure alarms are provided on the accumulators for the
17 MSIV, MFIV, and atmospheric dump valves.

18 Exhibit 2C3-17, Type D Category 3. Reactor coolant
19 pump status. The requirement is to display motor current.
20 This is provided.

21 High-level radioactive liquid tank level. The
22 requirement is to monitor from top to bottom. Main control
23 room alarm is provided of the radwaste system trouble. The
24 radwaste systems are normally controlled from the radwaste
25 control room in the main control room.



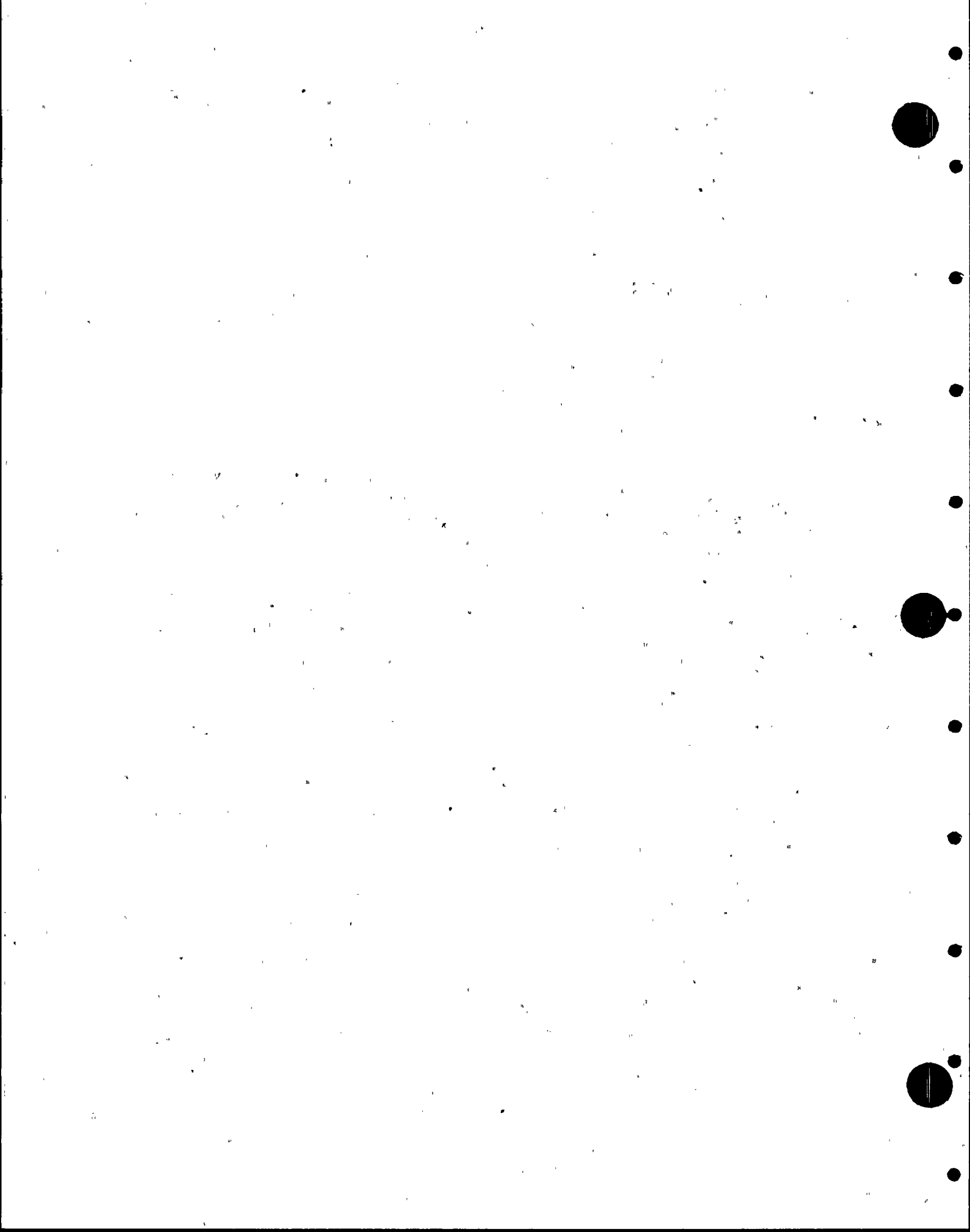
1 Radioactive gas holdup tank pressure. The
2 requirement is to monitor from zero to 150% design pressure.
3 Display is provided via control room alarm of radwaste
4 system trouble. Again, the radwaste systems are normally
5 controlled from the radwaste control room.

6 Exhibit 2C3-18, Type E variables. Those variables
7 are to be monitored as required for use in determining the
8 magnitude of the release of radioactive materials and
9 continually assessing such releases.

10 Category 1 variable includes the containment area
11 radiation-high range. The requirement is to monitor from
12 1 R per hour to 10^7 R per hour. The sensor is provided over
13 that range with a nonsafety-related CRT display and two
14 safety-related display channels at the radiation monitoring
15 cabinet, which are Class IE. Recording is provided on one
16 channel.

17 Exhibit 2C3-19, Type E Category 2 variables.
18 Radiation exposure rate (inside buildings or areas where
19 access is required to service equipment important to safety).
20 The requirement is to monitor from 10^{-1} R per hour to 10^4 R
21 per hour. PVNGS design incorporates 10 monitors with a
22 sensor range over the required range. Display is via CRT.
23 Sensors are qualified to the post-accident environment, and
24 local display and annunciation at the monitors is provided.

25 Containment or purge effluent, - noble gases and



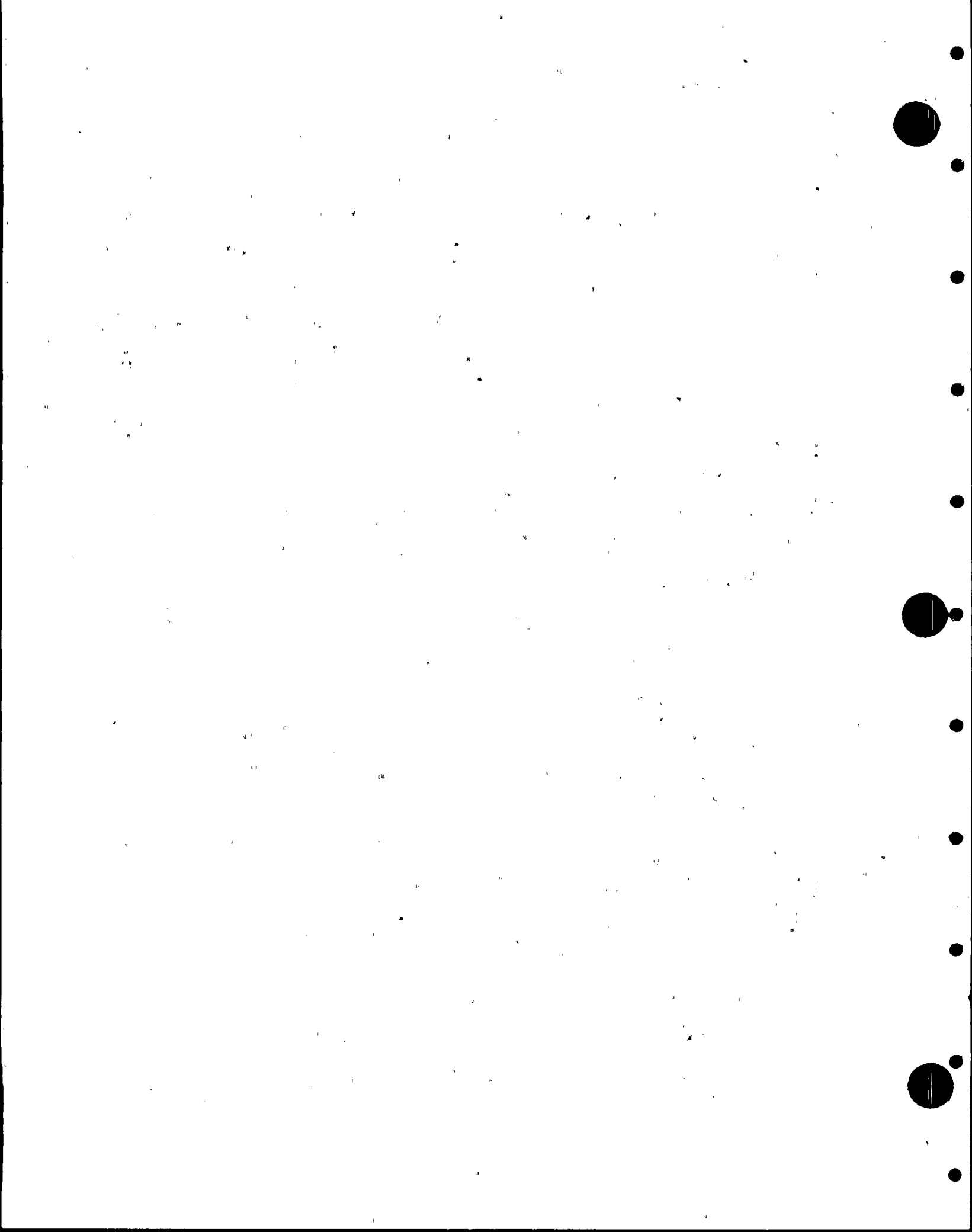
1 vent flow rate. The requirement is to monitor from 10^{-6}
2 microcuries per cc to 10^5 microcuries per cc and from zero
3 to 110% vent design flow. These releases are through the
4 plant vents. We will be discussing that on the next slide.

5 Common plant vent - noble gases and vent flow rate.
6 The requirement is 10^{-6} microcuries per cc to 10^3 microcuries
7 per cc and zero to 110% design flow. This again will be
8 discussed on the next slide.

9 Exhibit 2C3-20. Auxiliary building - noble gases
10 and vent flow rate. This is the plant vent. The requirement
11 is from 10^{-6} microcuries per cc to 10^3 microcuries per cc
12 and zero to 110% vent design flow. The PVNGS design has
13 a sensor monitoring from 10^{-9} microcuries per cc to 10^5
14 microcuries per cc at the plant vent. Display is via CRT.
15 Sensor is qualified to post-accident environment, and flow
16 measurement will be provided.

17 Condenser air removal system exhaust - noble gases
18 and vent flow rate. The requirement is 10^{-6} microcuries per
19 cc to 10^5 microcuries per cc and zero to 110% vent design
20 flow. Sensor is provided over that range with a CRT display.
21 Flow measurement will be provided.

22 Vent from steam generators' safety relief valves
23 or atmospheric dump valves - noble gases and vent flow rate.
24 The requirement is 10^{-1} microcuries per cc to 10^3 microcuries
25 per cc. Duration of releases in seconds and mass of steam



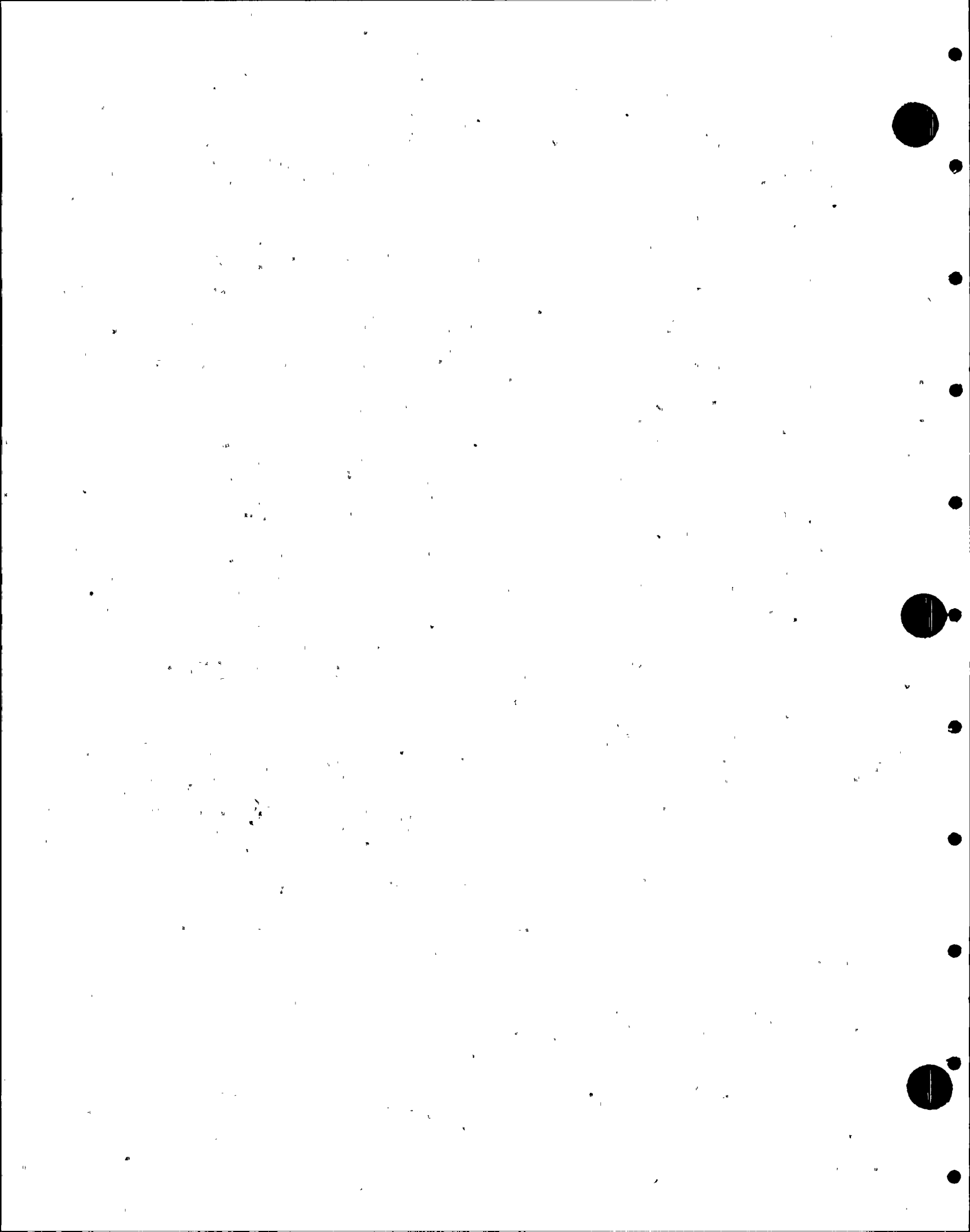
1 per unit time. Flow monitor is provided per steam line
2 over the range required. Display is CRT. Sensors qualified
3 to post-accident environment.

4 Exhibit 2C3-21, continuing with Type E Category 2
5 variables. Fuel building vent - noble gases and vent flow.
6 The requirement is 10^{-6} microcuries per cc to 10^2 microcuries
7 per cc, zero to 110% vent design flow. Sensor is provided
8 over that range, with the display via CRT.

9 Exhibit 2C3-22, Type 3 variables Category 3.
10 Particulates and halogens at all identified release points
11 (except steam generator safety relief valves or atmospheric
12 steam dump valves and condenser air removal system exhaust)
13 sampling, with onsite analysis capability. The requirement
14 is over the range of 10^{-3} microcuries per cc to 10^2 microcuries
15 per cc, zero to 110% vent design flow. Monitors are provided
16 over that range at the fuel building vent and at the main
17 condenser air removal exhaust. Flow measurement will be
18 provided.

19 Exhibit 2C3-23, continuing with Type E Category 3
20 variables. Radiation exposure meters, continuous indication
21 at fixed locations per NUREG-0654. PVNGS will comply.

22 Airborne radio-halogens and particulates (portable
23 sampling with onsite analysis capability) over the range of
24 10^{-9} microcuries per cc to 10^{-3} microcuries per cc. PVNGS
25 will comply.



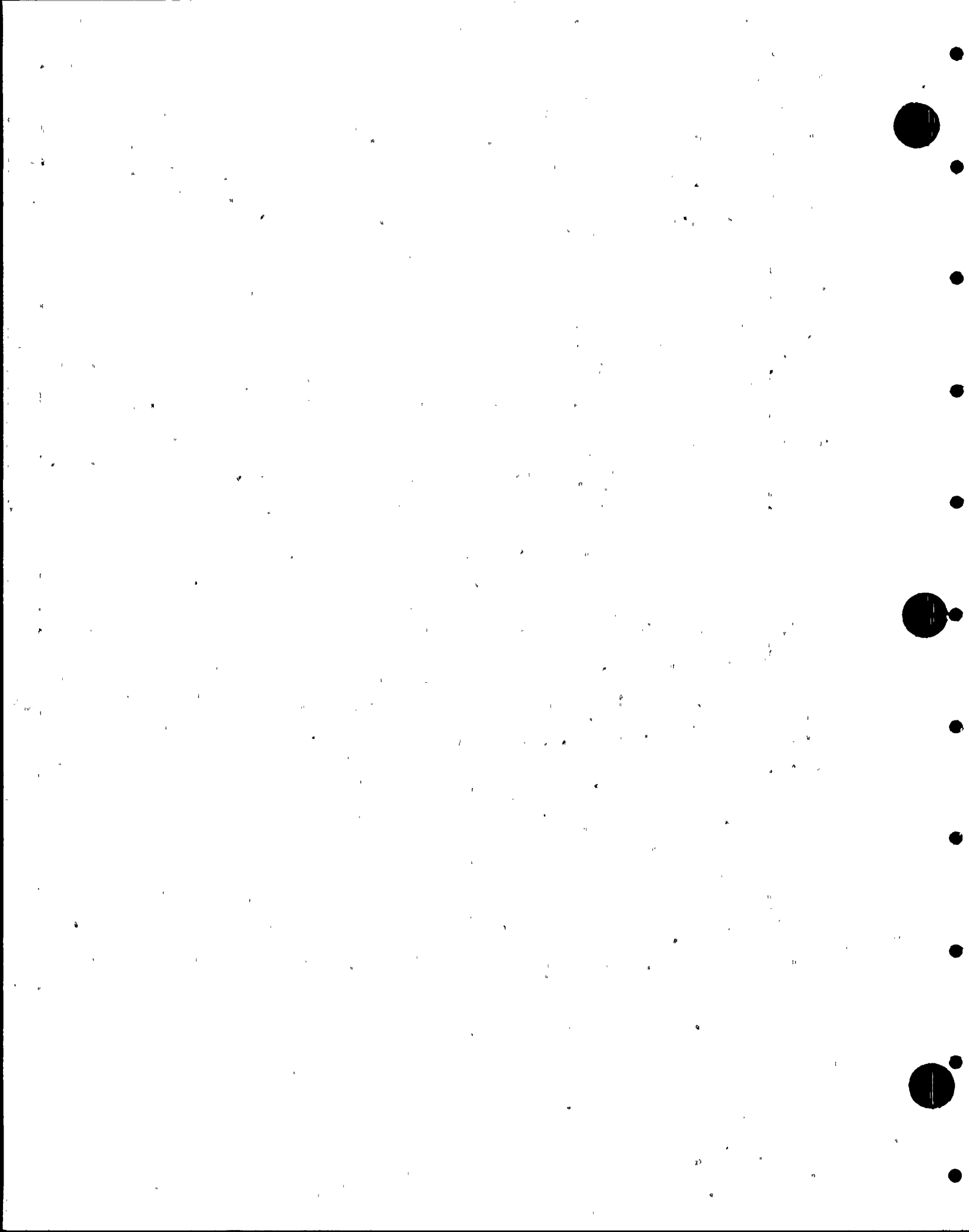
1 Exhibit 2C3-24, continuing with Type E Category 3
2 variables. Plant and environs radiation via portable
3 instrumentation. The requirement is to monitor 10^{-3} R per
4 hour to 10^4 R per hour, photons 10^{-3} rads per hour to 10^4
5 rads per hour, Beta radiations and low energy photons.
6 PVNGS will comply.

7 Plant and environs radioactivity (portable
8 instrumentation). The requirement is multichannel Gamma-Ray
9 spectrometer. PVNGS will comply.

10 Exhibit 2C3-25, Type E Category 3 variables
11 continues. Wind direction. The requirement is over a range
12 of zero to 360 degrees, starting speed of one mile per hour,
13 damping ratio between .4 and .6, distance constant of 2 meters.
14 PVNGS has sensors monitoring from zero to 540 degrees plus
15 or minus 5 degrees accuracy, a starting threshold of .75 miles
16 per hour, damping ratio .4, distance constant 3.3 feet.

17 Wind speed. The requirement is zero to 30 meters
18 per second or minus .22 meters per second. Accuracy for wind
19 speeds less than 11 meters per second, with a starting
20 threshold of less than .45 meters per second. PVNGS
21 design has a wind speed from zero to 50 miles per hour plus
22 or minus 1% or .15 miles per hour, whichever is greater, with
23 a starting threshold of .6 miles per hour.

24 Exhibit 2C3-26, continuing with Type E Category 3
25 variables. Estimation of atmospheric stability. The



1 requirement is based on vertical temperature difference from
2 primary system over a minus 5 degree C to 10 degree C or
3 minus .15 degrees, the accuracy per 50 meter interval or
4 analogous range for alternative stability estimates. PVNGS
5 design provides based on a vertical difference of 160 feet
6 plus or minus 6 degrees F analog and digital, plus 18 to
7 minus 6 degrees F analog and .18 degrees F accuracy.

8 Exhibit 2C3-27, continuing with Type E Category 3
9 variables. On the accident sampling capability, primary
10 coolant and sump via a grab sample, the requirement is for
11 gross activity 10 microcuries per milliliter to 10 curies
12 per milliliter. PVNGS monitors from 10^{-3} microcuries per cc
13 to 10 curies per cc.

14 Gamma Spectrum via isotopic analysis is in
15 compliance.

16 Boron content from zero to 6,000 ppm, in compliance

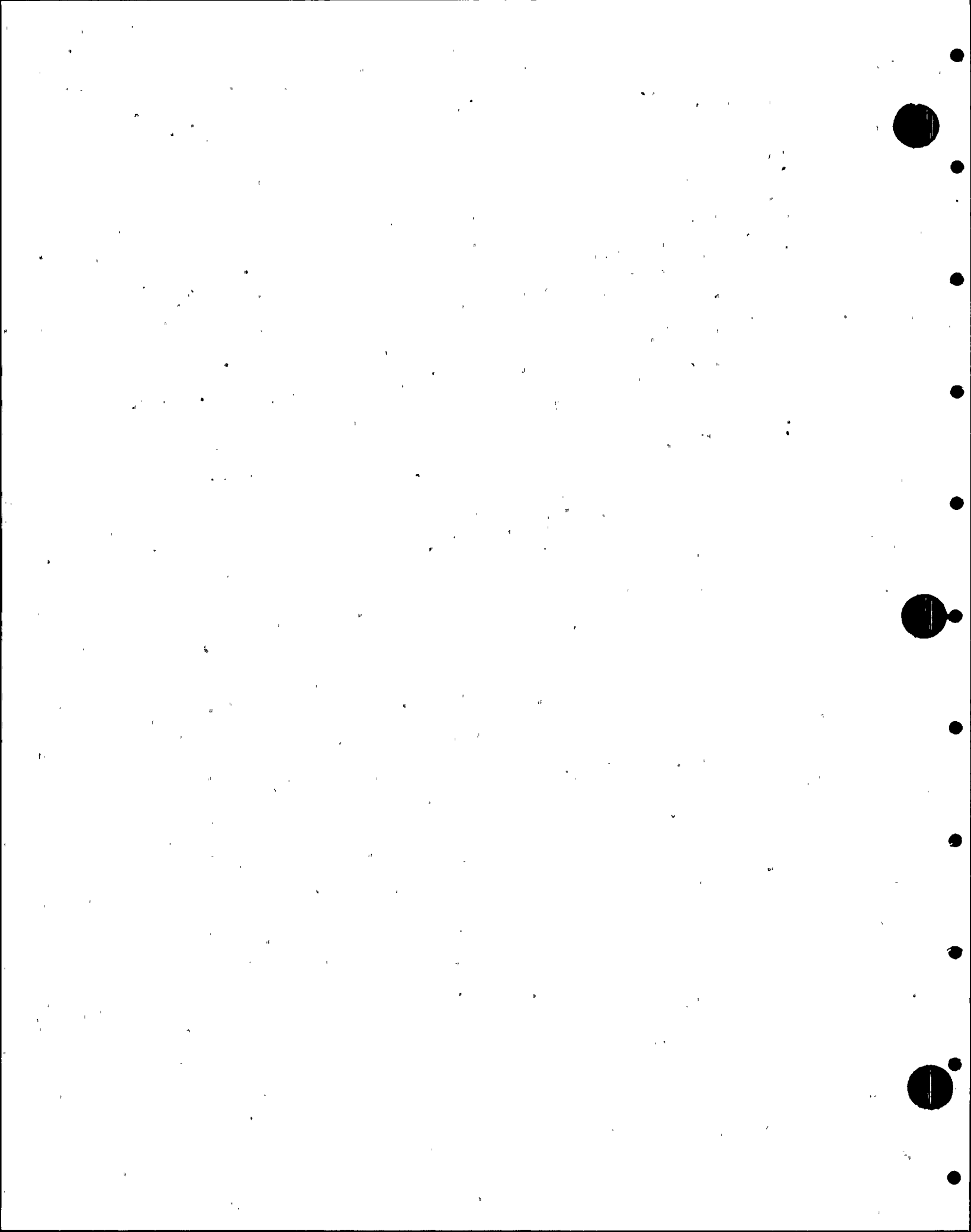
17 Chloride content zero to 20 ppm, in compliance.

18 Dissolved hydrogen from zero to 2,000 cc STP per
19 kilogram, in compliance.

20 Dissolved oxygen from zero to 20 ppm, in compliance

21 pH from 1 to 13, in compliance.

22 Exhibit 2C3-28, continuing with the Type E
23 Category 3 variables for accident sampling capability of
24 containment air. Hydrogen content from zero to 10%, in
25 compliance.



1 Oxygen content from zero to 30%, in compliance.
2 Gamma Spectrum via isotopic analysis. PVNGS
3 design provides isotopic analysis from 10^{-7} microcuries per
4 cc to 10^5 microcuries per cc.

5 MR. BINGHAM: Any questions?

6 MR. BARNOSKI: I have a couple questions. After
7 going through all that, I would like to try to summarize
8 what you said, because my eyes weren't quick enough to
9 compare all the numbers and make sure of everything. I gather
10 your intent is to comply with Reg. Guide 1.97, Rev. 2.

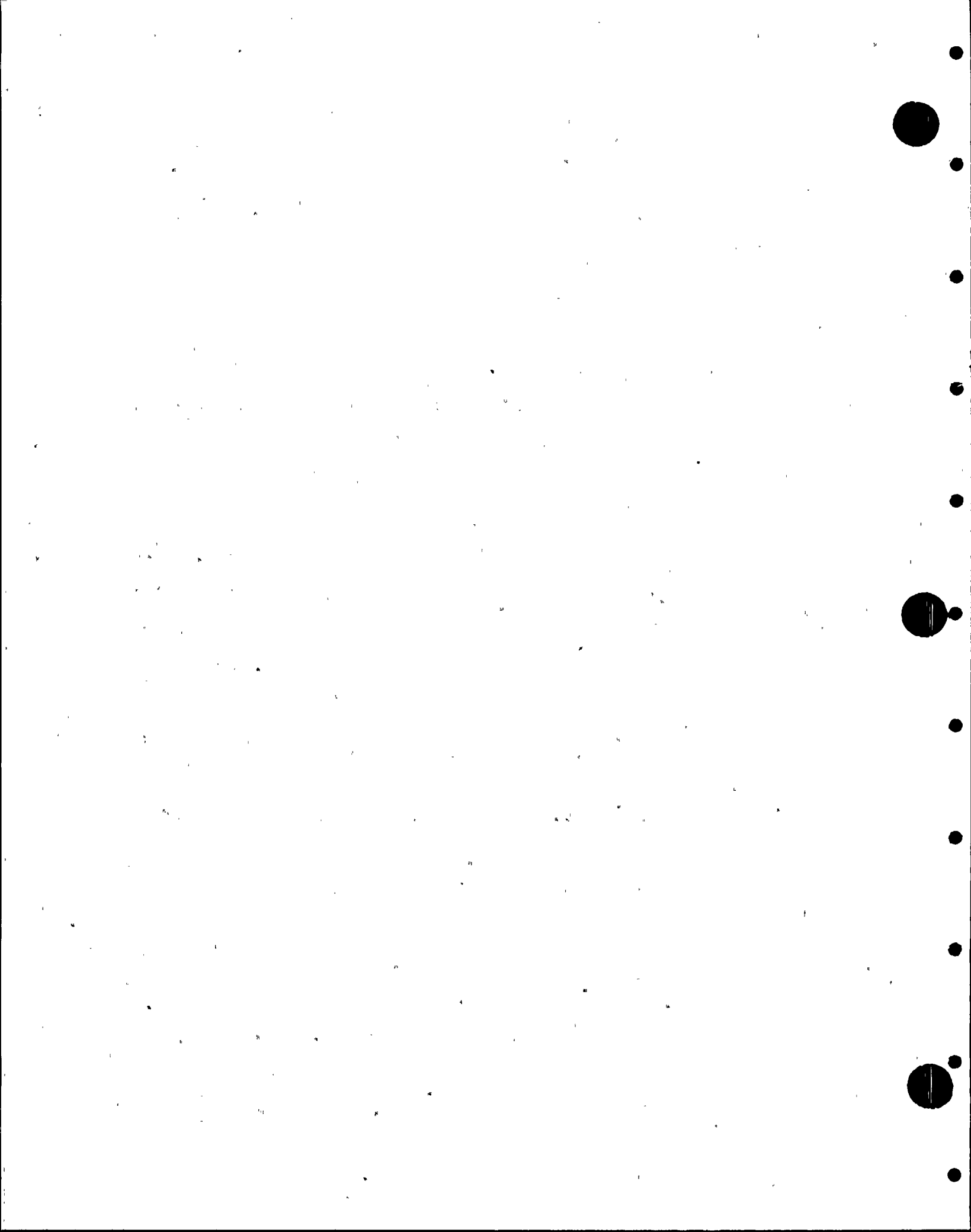
11 MR. BINGHAM: That's correct.

12 MR. BARNOSKI: On the Type A variables, you say the
13 expected completion date is November, '81. I believe there
14 is a considerable amount of work that needs to be done on
15 a plant specific basis for the BOP to support a Type A
16 analysis. I know the CESSAR schedule was November for the
17 NSSS portion. Is the BOP going to be done on that same
18 schedule, also?

19 MR. BINGHAM: I believe we were led to believe that.
20 We can recheck that date if you would like.

21 MR. STERLING: I believe we led Bechtel to believe it
22 was November, '81.

23 MR. BARNOSKI: I just have one other question, and I
24 realize this is relatively new, but on the Type B, C, D, and
25 E, some of the variables which were addressed during the



1 CESSAR review appear here. Others do not. Was that just
2 because of time? Specifically, I'll take the first one.
3 Coolant level in the reactor was addressed. However, ^THot,
4 ^TCold, and RCS pressure were not. Could you clarify what
5 your intent is, if you have gotten that far, as to what you
6 would be referencing CESSAR for?

7 MR. BINGHAM: I think you're right. It was a matter
8 of timing. Once those are included in CESSAR, we will pick
9 them up.

10 MR. BARNOSKI: Fine. That's all.

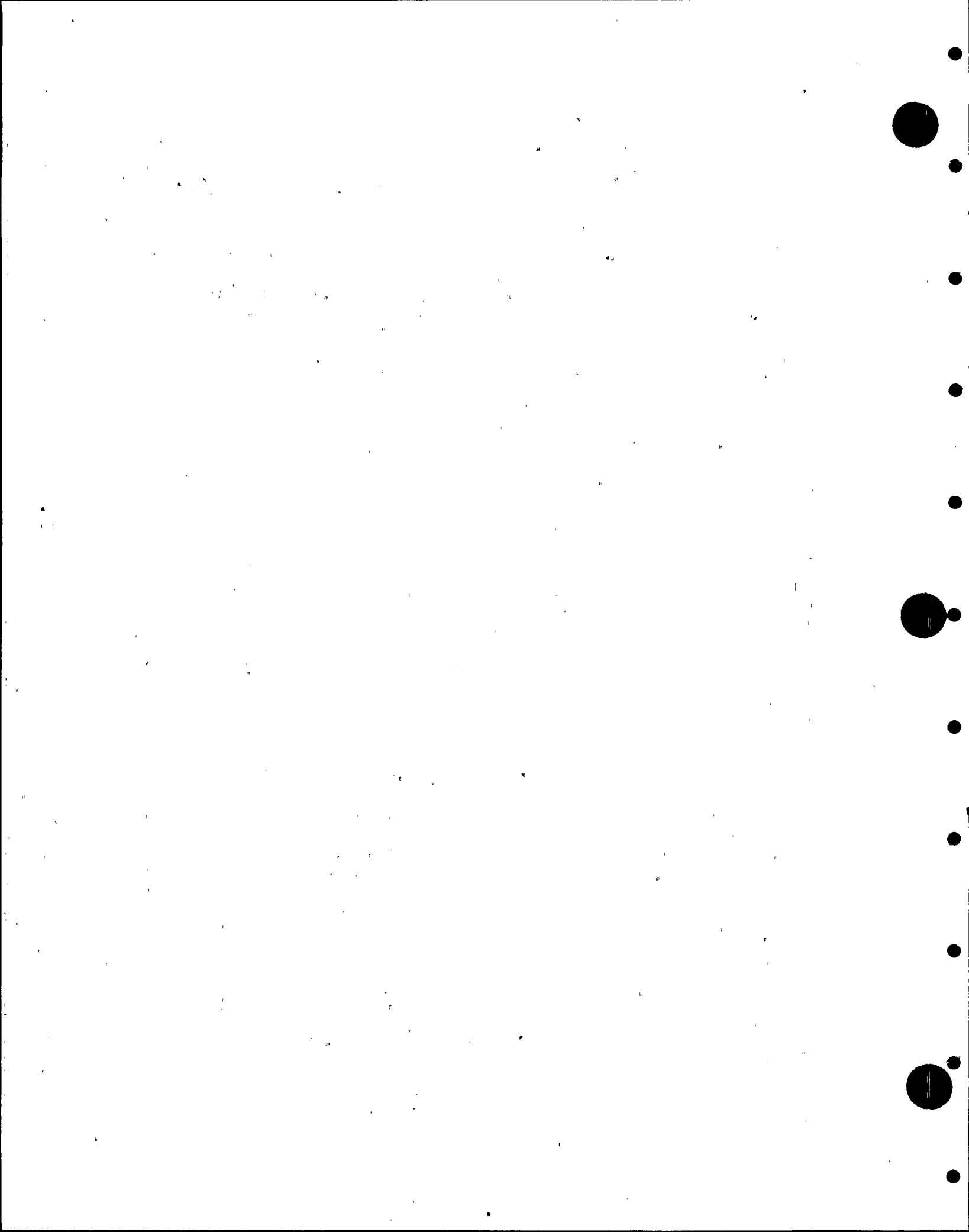
11 MISS KERRIGAN: I have just some very general
12 questions. I can't really tell from this table what is
13 in now and what you are planning to put in and when you plan
14 to put it in. Is it only the places where you have called
15 out PVNGS will comply? Are those the only instrumentation
16 that is not in now?

17 MR. ALLEN: Janis, what do you mean by not in?

18 MISS KERRIGAN: Installed or bought, purchased.

19 MR. BINGHAM: When we have the ranges specified,
20 that means we have enough information to procure it. It may not
21 yet be installed, but it will be installed. Where we say
22 we will comply, it generally means that we have not yet
23 developed enough information to give all the particulars
24 and that when we have it, we will meet the requirements.

25 MISS KERRIGAN: So you still really can't tell whether



1 you would be running into procurement problems later down
2 the road. There is still a potential for running into
3 procurement problems with some of these instruments where
4 you have specified the ranges and things. Is it your intent
5 to have everything installed prior to licensing or by June,
6 '83?

7 MR. BINGHAM: Was June, '83 the correct date? I
8 believe June, '83, but remember, Janis, we are getting behind
9 the line of all the other utilities that are buying the
10 same instruments in front of us.

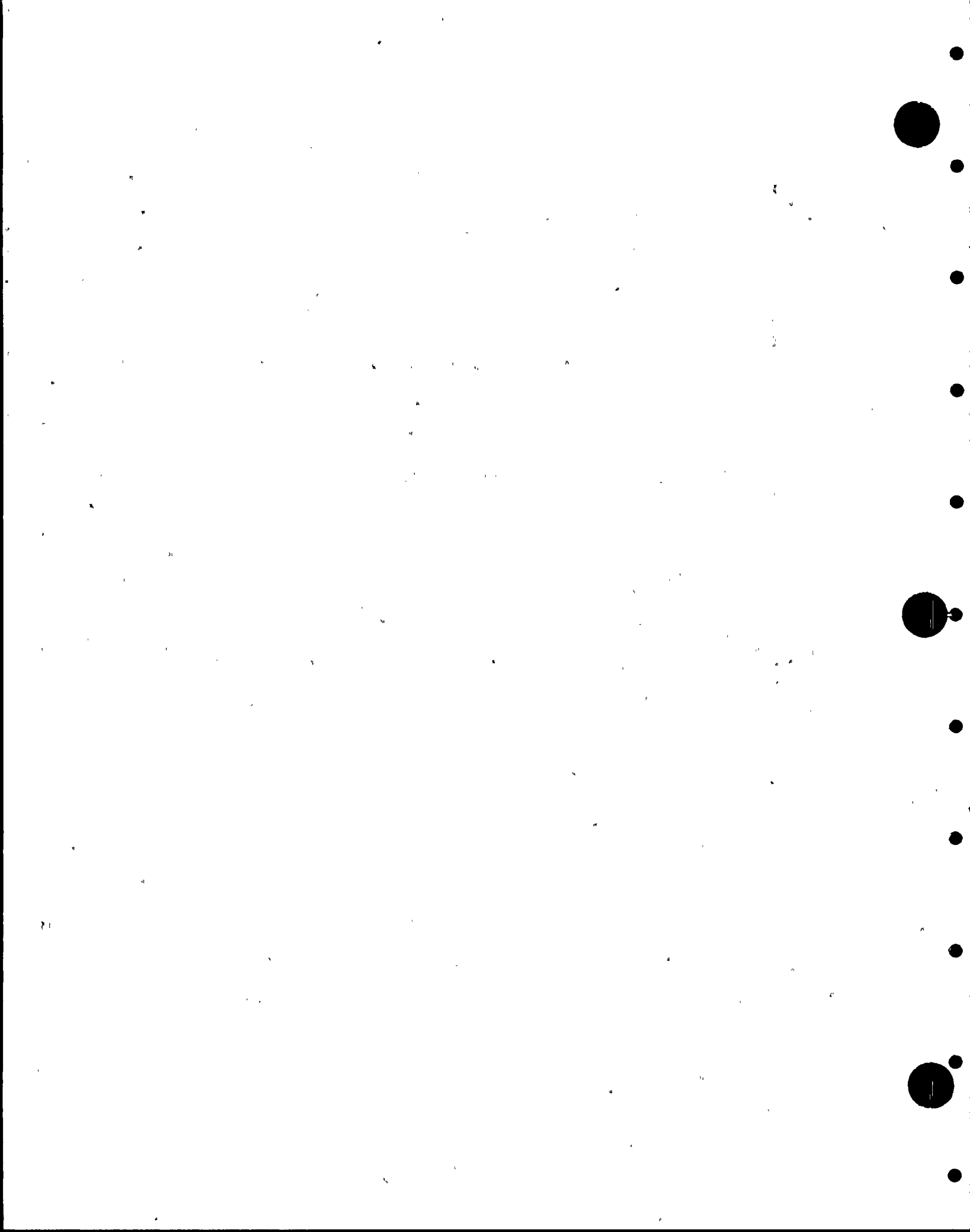
11 MISS KERRIGAN: That's right.

12 MR. BINGHAM: I would hope that the industry can
13 supply the equipment in a timely manner, but we still have
14 one constraint.

15 MISS KERRIGAN: But you will keep the NRC apprised of
16 any procurement problems and a separation of which of the
17 instrumentation will be installed by licensing and which
18 will be deferred until the June, '83, required date.

19 MR. BINGHAM: We will apprise APS. APS I am sure will
20 keep you informed.

21 MISS KERRIGAN: The second question that I have is
22 it looks like you are taking at least some exceptions to
23 Reg. Guide 1.97, Rev. 2, and will those exceptions be
24 discussed in the LLIR update and a basis provided for any
25 deviation from the criteria?



1 MR. STERLING: I believe that those are already
2 addressed in the LLIR.

3 MISS KERRIGAN: Okay, and a basis provided for the
4 exceptions in the LLIR instead of hashing that out in this
5 meeting?

6 MR. STERLING: I don't remember the exact words, but
7 I believe that's correct.

8 MISS KERRIGAN: Maybe Bill can help us out.

9 MR. QUINN: I don't really believe that we have
10 discussed thoroughly any such exceptions. We have provided
11 the information.

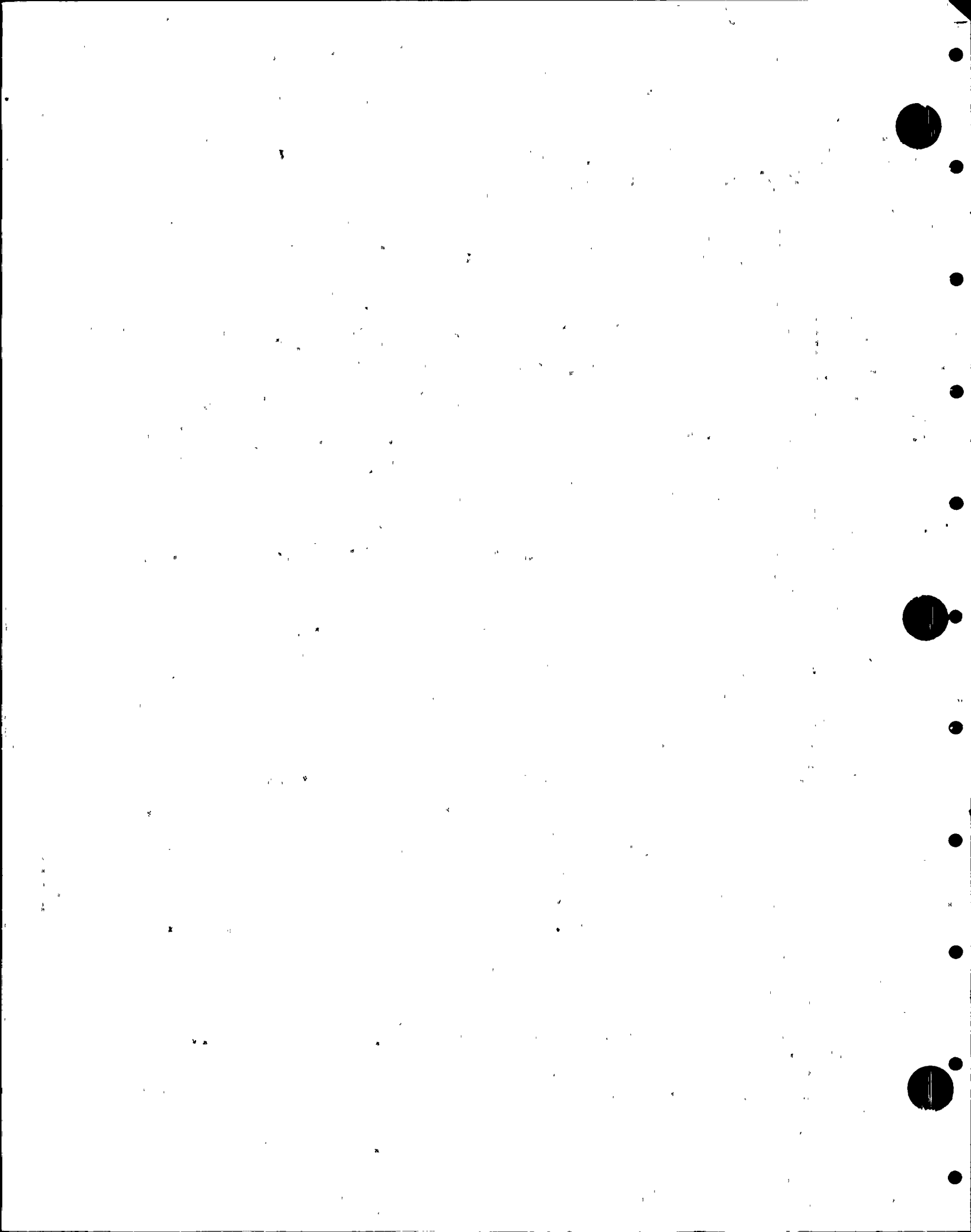
12 MISS KERRIGAN: We would need that, and rather than
13 address it in a meeting of this type, because we would be
14 here for the rest of our lives, it would be acceptable to
15 put it in the next LLIR, which is due when, Bill?

16 MR. QUINN: Well, we would like to shoot for August
17 1st.

18 MR. ROSENTHAL: Mr. Allen, the needs of the NRC with
19 respect to this may be different than the needs of the
20 Review Board, so you should determine whether this is an
21 appropriate forum for discussion.

22 MISS KERRIGAN: I think probably what we will do is
23 defer NRC's questions on this whole area until the LLIR
24 submittal.

25 MR. KOPCHINSKI: Can I ask a procedural question?



1 The LLIR just covers NUREG-0737. Are you asking that we
2 include a response to 1.97 in there?

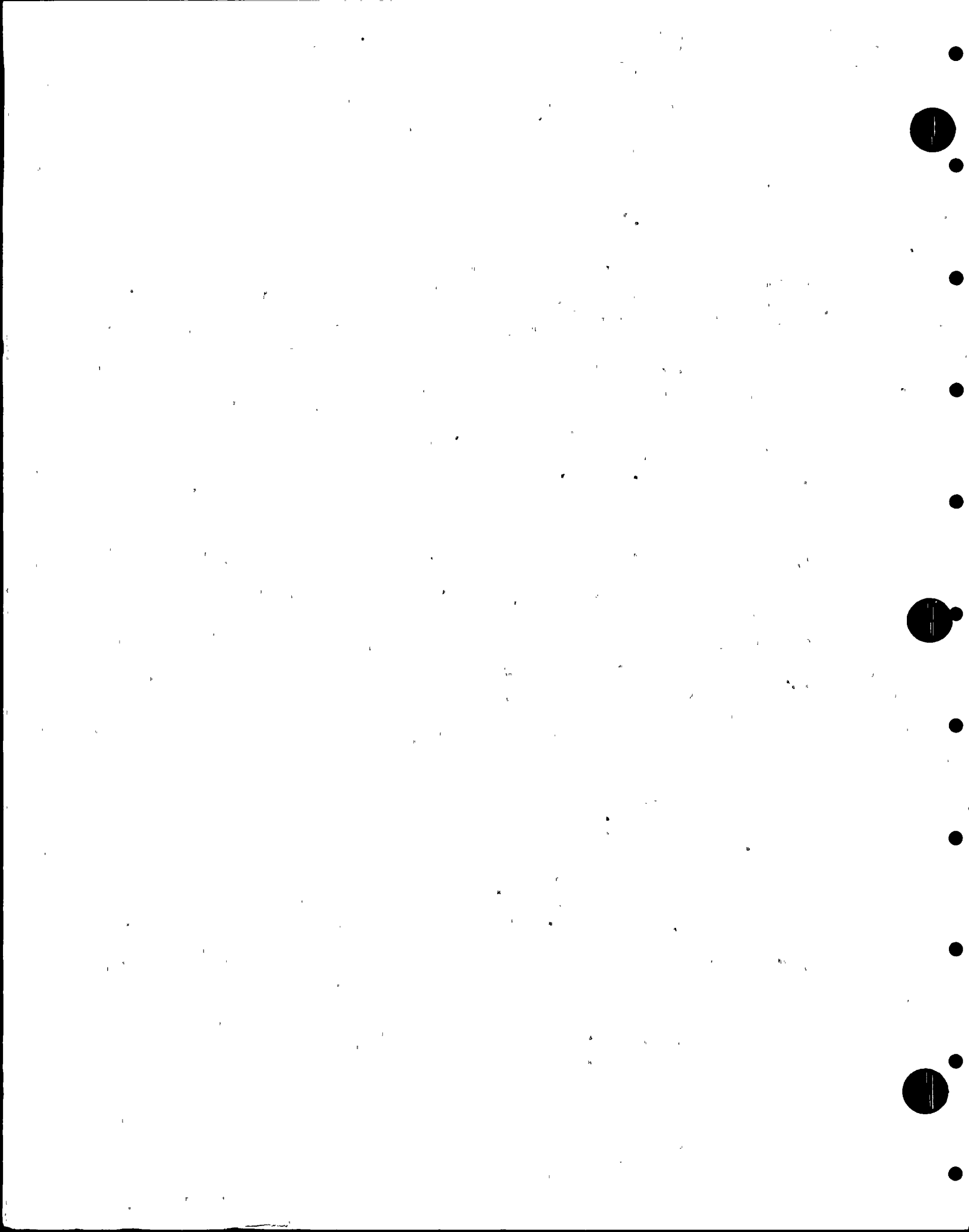
3 MISS KERRIGAN: No.

4 MR. ROSENTHAL: We are asking all of the industry to
5 comply with Reg. Guide 1.97, Rev. 2, by June, '83, and we
6 would ask you to do the same thing. I would like to see
7 as strong a commitment as you can make that you intend to
8 conform by the implementation date. Next, you want to get
9 a license before the implementation date of this plant, and
10 if the Reg. Guide has never been published, we would still
11 have to review in some depth the post-accident monitoring
12 instrumentation. I think what I would like to do is go into
13 the SER or the SSER stage with a clear understanding of what
14 equipment is in as of that time, and I would consider your
15 interim post-accident monitoring system and look for
16 compliance by June, '83.

17 MR. KOPCHINSKI: Which document would you like us to
18 provide?

19 MR. STERLING: Could I offer a suggestion? Maybe we
20 could mark on these exhibits the ones that are in procurement,
21 the ones that are being installed now, and maybe as an open
22 item to explain for those areas where we have an exception
23 the basis for it, because I know there are not that many
24 exceptions.

25 MISS KERRIGAN: Yes, that would be acceptable.



1 MR. BINGHAM: All right. The intention of this whole
2 section was to put everything out so that we could see where
3 we are, and if that would help for us to do that, we will.

4 MISS KERRIGAN: Maybe a little bit more detail as an
5 open item.

6 MR. ROSENTHAL: If you chose to discuss it for another
7 ten minutes, it is up to you. My branch is the one who will
8 review this conformance and I am one of the co-authors.

9 MR. BINGHAM: Well, why don't we discuss it for
10 another ten minutes, and if there are some issues that we
11 need to get out, let's get them out.

12 MR. ROSENTHAL: I saw under Category 2 variables
13 seismic qualification --

14 MR. BINGHAM: What exhibit are you on?

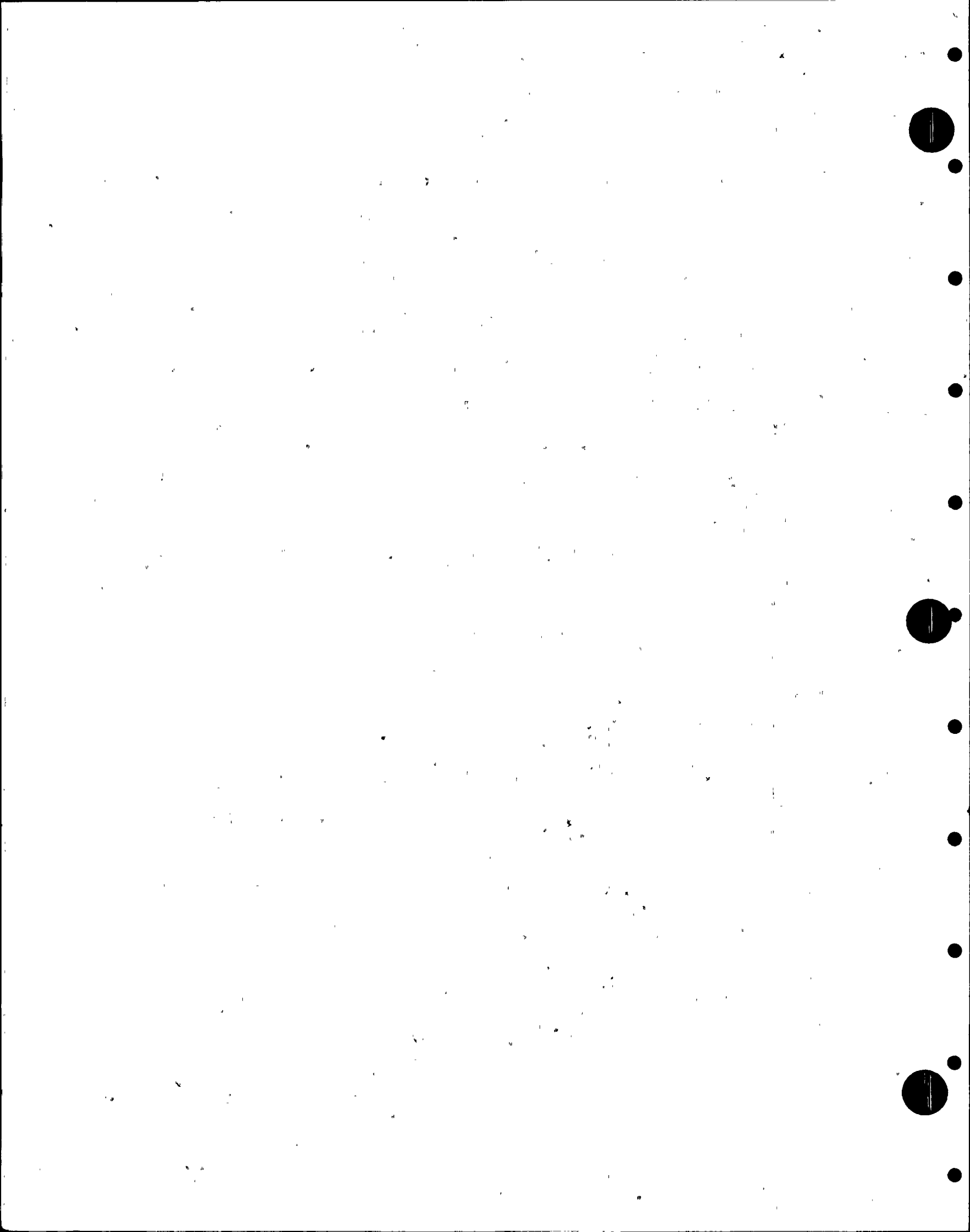
15 MR. ROSENTHAL: It is way up in the front.

16 MR. STERLING: 2C3-2.

17 MR. ROSENTHAL: Seismic qualification in accordance
18 with Regulatory Guide 1.100 shall be provided when the
19 instrumentation is part of a safety-related system. It was
20 clearly our intent that all Category 2 instruments be
21 seismically qualified whether they were hung on seismic stuff
22 or not.

23 MR. BINGHAM: Could you explain the rationale for
24 doing that?

25 MR. ROSENTHAL: One, we wanted to keep the operator

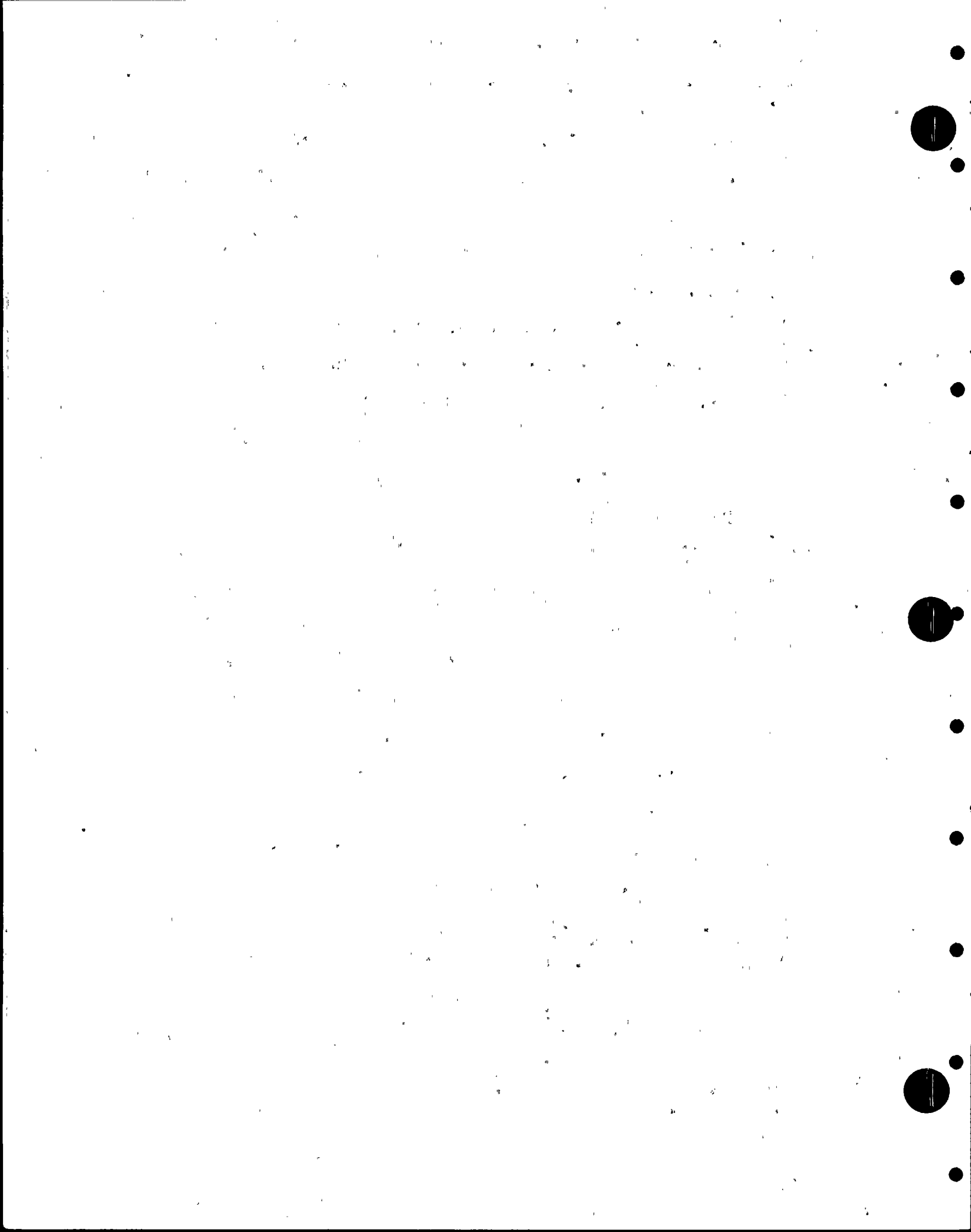


1 informed of whether that system was functioning or not.
2 Two, there is a good probability that a nonseismically
3 qualified system will continue to function post a seismic
4 event, and it seemed prudent that he had reliable indication
5 of its status.

6 MR. BINGHAM: The reason I asked is that, of course,
7 we like to keep the power plant intact as well for seismic
8 events, and there are certain things that we do. Dennis
9 discussed a qualification program that we implement that
10 gives us some good assurance, but yet we don't go with the
11 Appendix B type program and the very long lead time in order
12 to get some of this equipment to implement. So if we were
13 looking at early implementation, we would be much better off
14 to specify only those parameters that give us the assurance
15 that we will have some indication later on rather than
16 specify quite a pedigree and wait a very long time to get
17 it in the plant.

18 MR. ROSENTHAL: I would find it convenient if you
19 could just indicate which of the Category 2 variables will
20 have full seismic pedigree and which won't. This is a very
21 prescriptive Reg. Guide, and we will treat it as a Reg. Guide
22 and not as a regulation and we will permit exceptions, but
23 I would like you to identify them.

24 Then if I go all the way up to 2C3-27, and just
25 using this as an example, I look at gross activity, the



1 high range of your ability to analyze grab sample cross-
2 sections is off by a factor of thousands. Is that a typo,
3 10 microcuries per milliliter versus 10 curies -- I'm sorry,
4 same thing.

5 MR. KEITH: You are getting more than you asked for.
6 Right?

7 MR. ROSENTHAL: Yes, you're right.

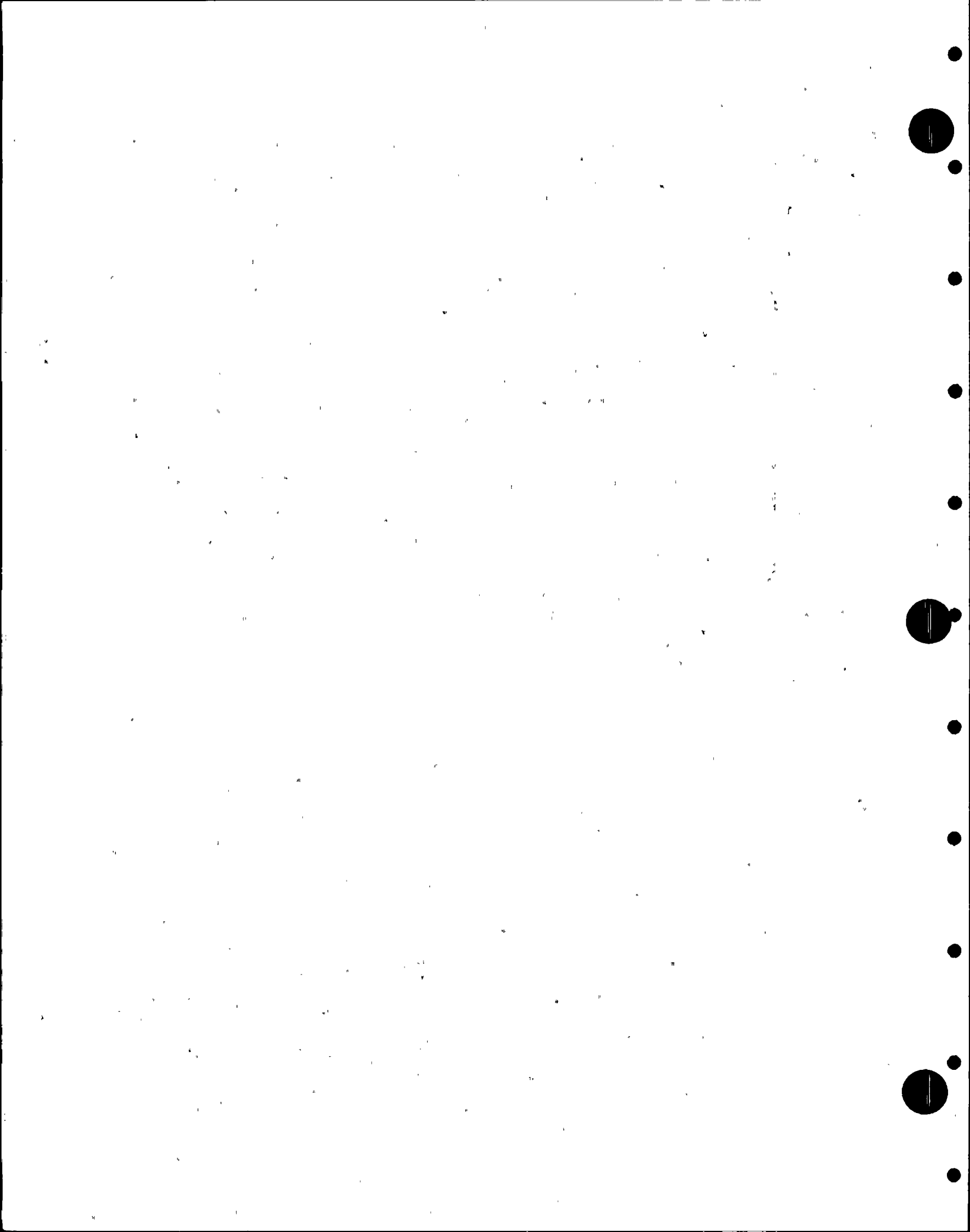
8 MISS KERRIGAN: I guess as an open item, though, I
9 think the point that Jack was trying to make is any places
10 where you did take exceptions to requirements, please provide
11 a basis. That would be the open item. The other open item
12 would be, as he had suggested, what is in now, what you
13 plan to put in, and what in the future is to be put in, a
14 strong commitment to Reg. Guide 1.97 on the schedule specified
15 in 1.97.

16 MR. BINGHAM: Fine. We will do that, Janis.

17 MR. ALLEN: Ned, did you have a question?

18 MR. KONDIC: I have two questions. One pertains to
19 the table again. We understand this is like a checklist,
20 and for most of the properties or items, the requirements
21 do mesh with design features, but in some places, we have
22 more verbal or qualitative explanation. Can we assume that
23 you imply that everything checks?

24 MISS KERRIGAN: They will document any places where
25 they do not meet the requirements.



1 MR. KONDIC: The second question, to come back to
2 this morning where we decided to postpone that chemical
3 spray effect and water effect of the containment spray on
4 the instrumentation, we decided to discuss this later this
5 afternoon. Are there some instruments in the containment
6 which may be adversely affected by water per se, in addition
7 by chemicals in that water?

8 MR. BINGHAM: I thought we had discussed that in the
9 morning, but, as I recall --

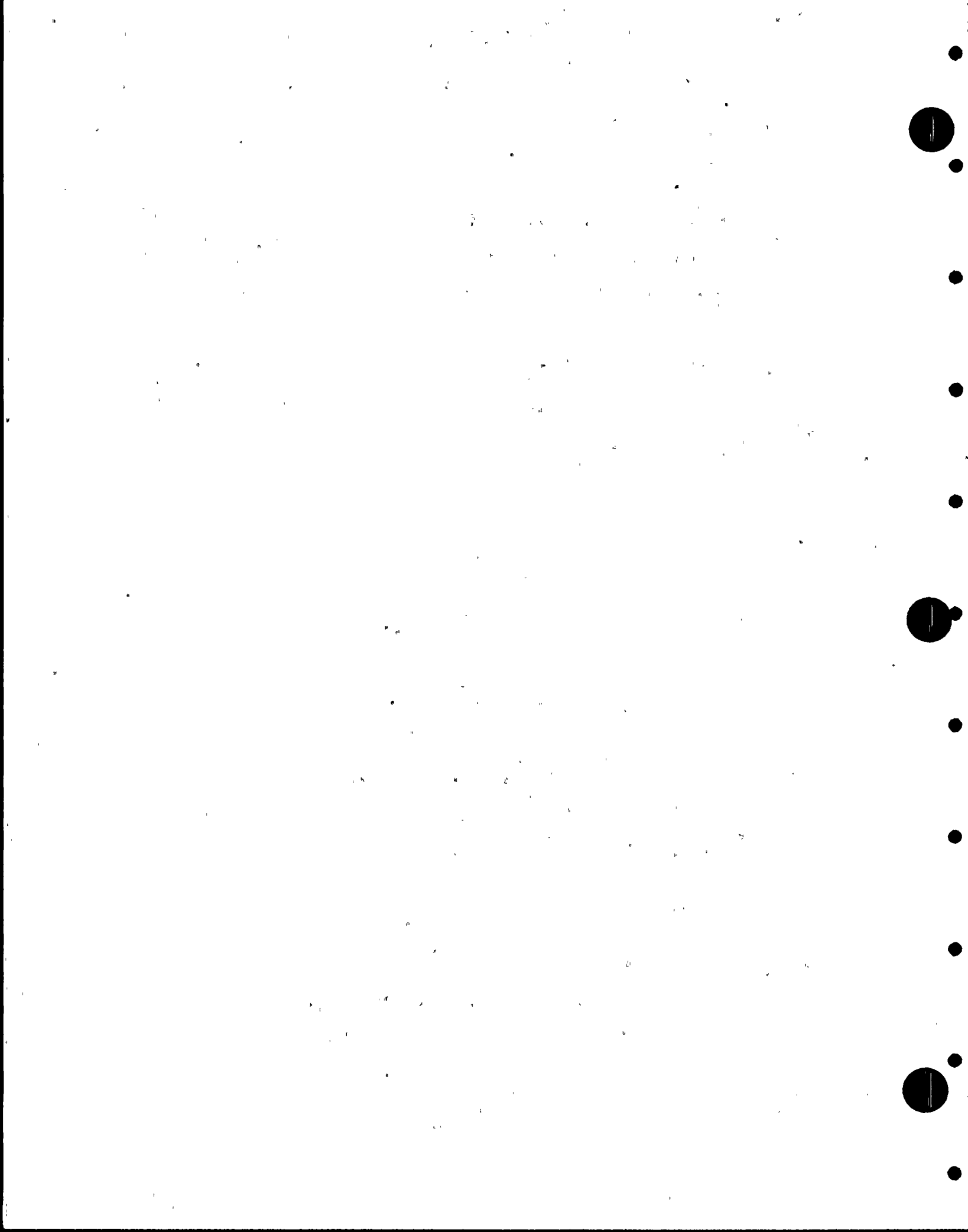
10 MR. KEITH: First, we said there were no safety-
11 related --

12 MR. BINGHAM: Yes, no safety-related components.

13 MR. KONDIC: But then we discussed that maybe spray
14 on some of those instruments may be involved in the judgment
15 of the operator.

16 MR. ROSENTHAL: Let's take a specific example, a
17 pressurizer pressure. Those transistors are not required to
18 function to perform a safety function after some very short
19 period of time, but those sensors also provide a long-term
20 indication to the operator of what the primary pressure is,
21 so with respect to the post-accident monitoring function,
22 which will continue for months and months and months, you
23 would like to know that it hadn't deteriorated.

24 MR. BINGHAM: I understand, and in the qualification
25 program that Combustion Engineering has, they do look at,



1 what I guess they call non-IE devices to make sure that they
2 are properly qualified. There is a category for that
3 particular type instrument.

4 MR. KEITH: This particular one is IE, but the whole
5 equipment qualification thing is being addressed.

6 MISS KERRIGAN: Is that in the 255?

7 MR. KEITH: Yes, that particular one would be.

8 MR. KONDIC: Another example, we had the preamps in
9 the containment. Are the preamps waterproof?

10 MR. BINGHAM: That example falls in the same category
11 as the previous one.

12 MR. ALLEN: Any other questions? Ralph.

13 MR. PHELPS: You've got a lot of your variables
14 reading out on indication in the control room, and I think
15 in NUREG-0696 for emergency support facilities, they have
16 suggested that they want all the Reg. Guide 1.97 variables
17 displayed in the technical support center and the EOF as
18 well. Are you making any provisions for that type of thing?

19 MR. BINGHAM: Yes.

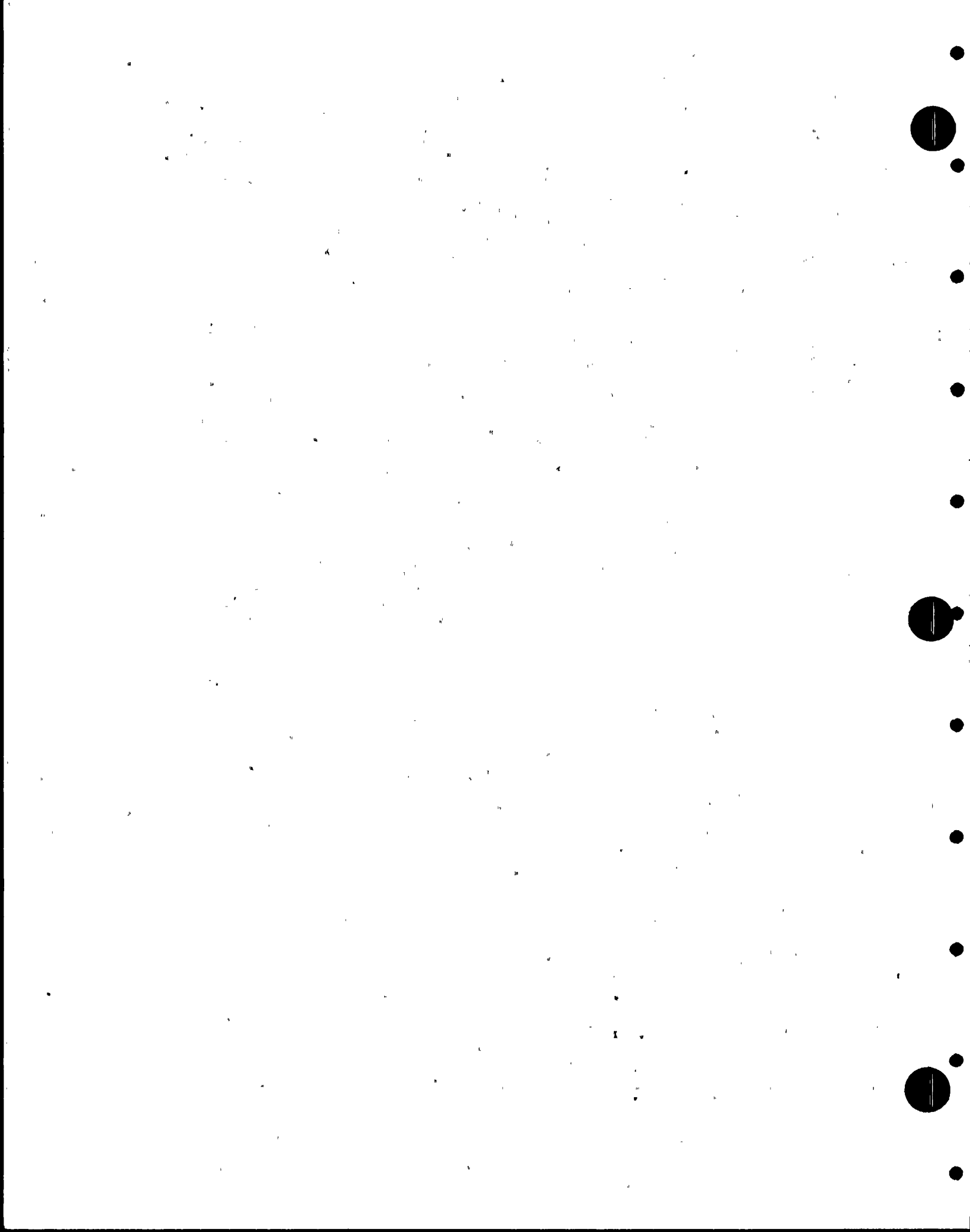
20 MISS KERRIGAN: Are you going to do it or not?

21 MR. BINGHAM: Yes, we are.

22 MISS KERRIGAN: So all the Reg. Guide 1.97 variables
23 would be displayed both in the TSC and the EOF?

24 MR. BINGHAM: That is our intent.

25 MR. ALLEN: Further questions?



1 MR. MARSH: It is perhaps a small point. I wanted to
2 clarify on Exhibit 2C3-17 regarding the radwaste liquid
3 level. That annunciation is provided in the control room and
4 indicators are provided in the radwaste control room. Do the
5 indicators that are provided there meet the requirements of
6 1.97? You didn't explicitly state that.

7 MR. BINGHAM: We may not have heard the question
8 correctly. Would you repeat it, please?

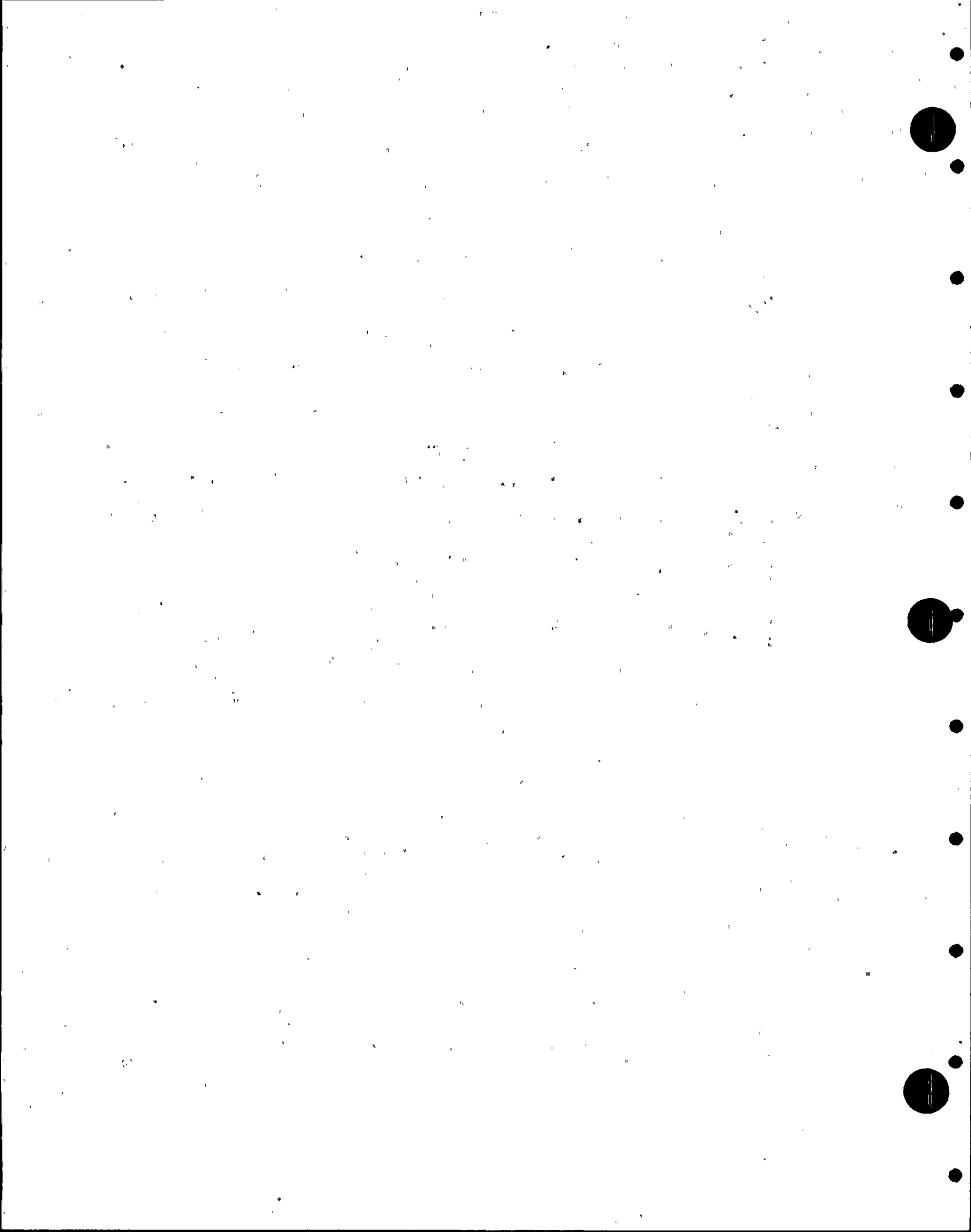
9 MR. MARSH: As I understand the table, Reg. Guide 1.97
10 requires an indication, for example, on the liquid tank
11 level in the high level radioactive waste, top to bottom
12 level indication. The design feature described there does
13 not explicitly state whether the indicators or the radwaste
14 control room panel meet that, provide an indicator from top
15 to bottom or not. All it states is that there is an alarm
16 in the main control room, an indicator in the radwaste control
17 panel.

18 MRS. MORETON: There are indicators in the radwaste
19 control room for high level radioactive liquid tank level
20 and for radioactive gas holdup tank pressure. At this time,
21 the pressure indicator does not meet the 150% design pressure
22 requirement and it is under review.

23 MR. MARSH: How about the level?

24 MRS. MORETON: That meets the level requirement.

25 MR. ALLEN: Carter, have you got a question?



1 MR. ROGERS: I have a similiar type of a question
2 on Exhibit 2C3-16. On essential cooling water system flow,
3 the requirement is zero to 110% of design flow. You do not
4 tell us what the design flow is, but you say that the high
5 range is 20,000 gallons per minute. Does that meet the
6 requirement?

7 MR. KEITH: We will have to check.

8 MR. STERLING: In addition, you might check on 2C3-15
9 the auxiliary feedwater flow, also.

10 MR. BINGHAM: I think we are going to be going
11 through this and adding the columns. We will pick up those
12 generic questions.

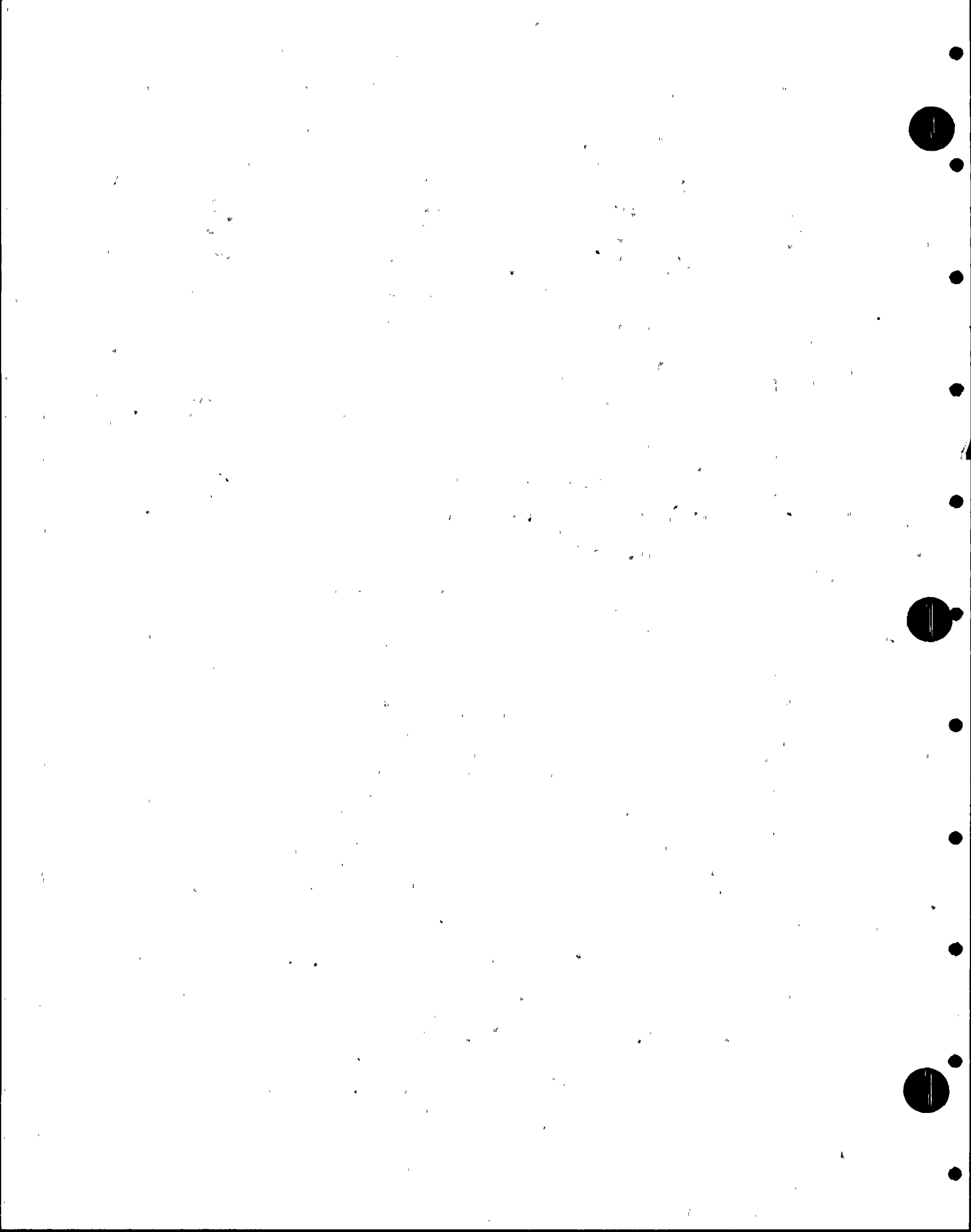
13 MR. ROGERS: That is satisfactory for me.

14 MR. ALLEN: Any additional questions before we move
15 on?

16 MR. BINGHAM: Let's go on with 2.D., All Other
17 Instrumentation Systems Required for Safety.

18 MRS. MORETON: Figure 2D-1 identifies all other
19 instrumentation systems that are required for safety, which
20 are those instrumentation systems designed to protect other
21 vital systems from potentially damaging transients. For the
22 purposes of this review, this does not include fire protection.

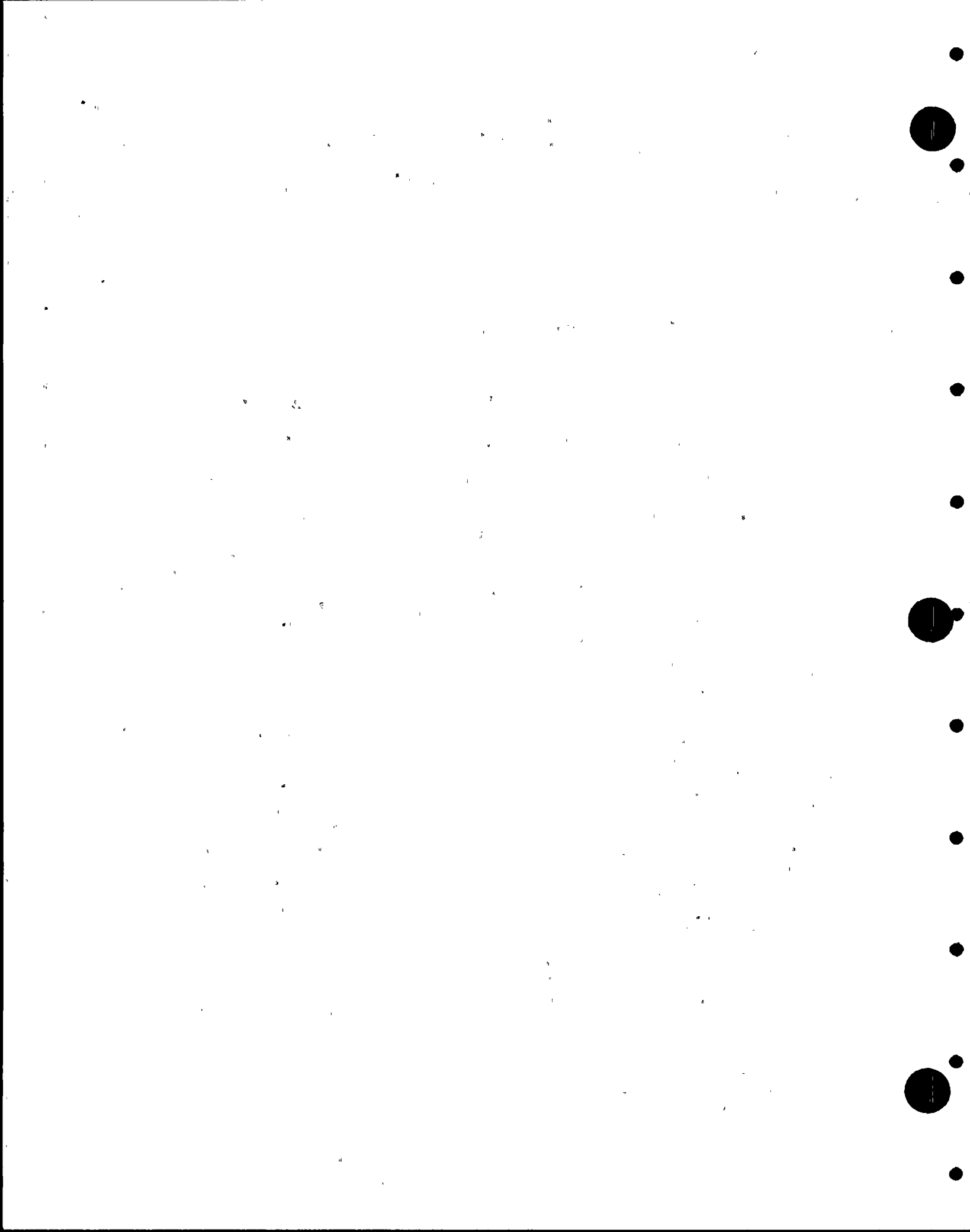
23 The NSSS features are the shutdown cooling system
24 high injection valve interlocks and the safety injection
25 tank isolation valve interlocks. In the balance of plant,



1 we will be discussing the Class IE alarm system and the
2 safety parameter display system.

3 Exhibit 2D1-1 are the Class IE Alarm System Design
4 Criteria. The Class IE alarm system is provided for a
5 limited number of operational occurrences for which no
6 specific automatic acutation of a safety system is required.
7 The system alerts the operator to keep the plant operating
8 within Technical Specification limits and aids in precluding
9 equipment damage. The Class IE alarm system shall be
10 designed in compliance with the standards listed on Exhibit
11 2D1-1 and continued at the top of Exhibit 2D1-2. Power for
12 each redundant Class IE annunciator shall be supplied from
13 a separate Class IE 125 volt-DC distribution bus. Each
14 Class IE annunciator is an independent unit from the plant
15 annunciator. The annunciation sequence for operation and
16 testing for the Class IE annunciators shall be the same as
17 the plant annunciator with the exceptions that the Class IE
18 annunciator shall have a key locked alarm acknowledge
19 function and the Class IE annunciator does not have a
20 return-to-normal audible. The Class IE alarm system shall
21 be designed to the requirements for nuclear safety-related
22 systems such that the devices must maintain their safety-
23 related functional capability under all normal and abnormal
24 plant operating conditions.

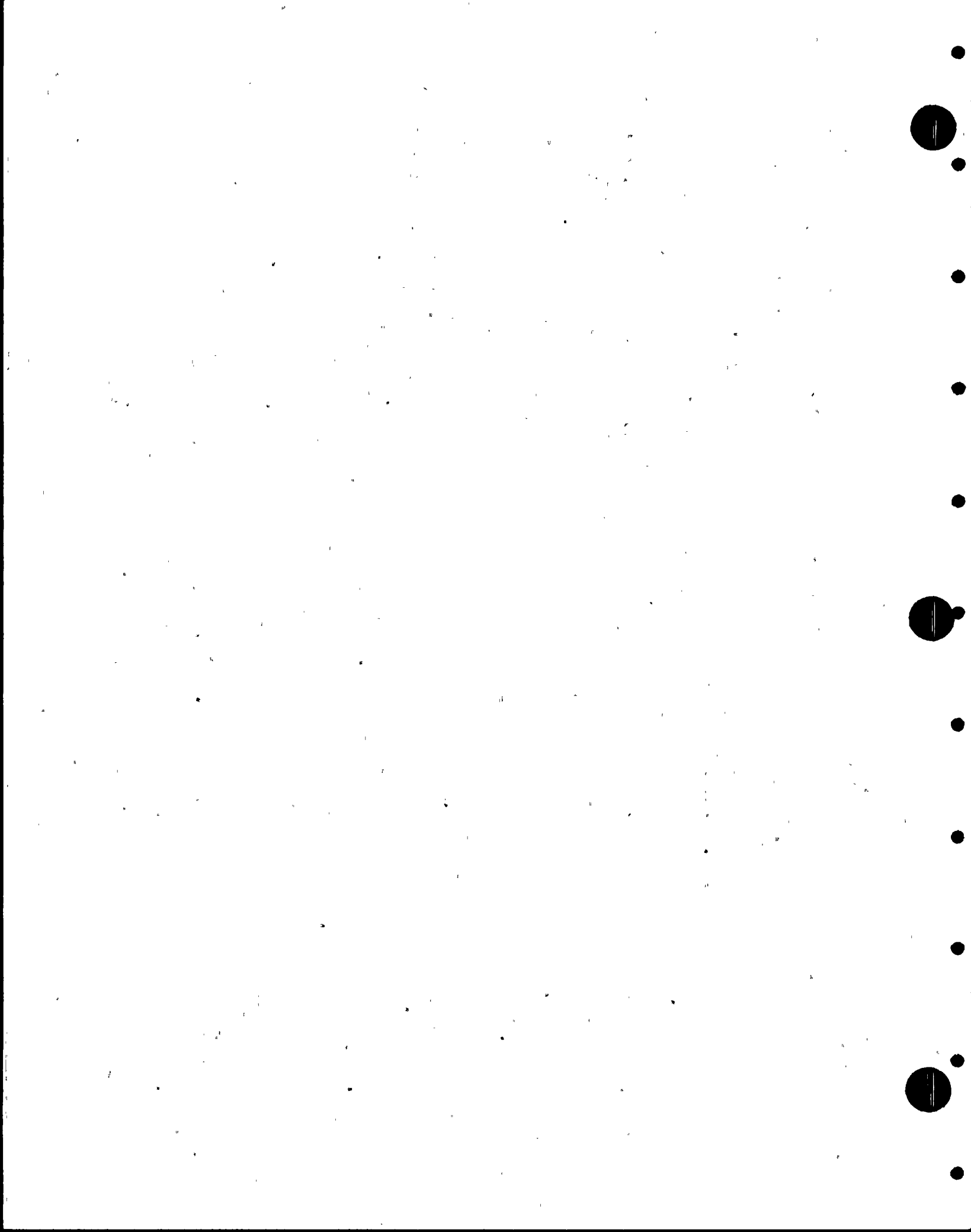
25 Exhibit 2D1-3. This is our system description of



1 the Class IE alarm system. Class IE alarms are provided to
2 alert the operator in the event of a loss of nuclear cooling
3 water to the reactor coolant pumps seal coolers, inadequate
4 safety injection tank pressure, and high water level in an
5 ECCS pump room. Silencing of the alarm audible is provided
6 by a key locked alarm acknowledge switch. Four Class IE
7 annunciators are provided, two in instrument Channel A and
8 two in instrument Channel B. The Channel A annunciators are
9 physically separate and independent of the Channel B
10 annunciators. The annunciators are supplied from separate
11 125 volt-DC Class IE distribution buses.

12 Exhibit 2D1-4 identifies the four Class IE
13 annunciators. An annunciator is provided for inadequate
14 safety injection tank pressure of Tanks 3 and 4, high water
15 level in ECCS Train A pump rooms, one annunciator window
16 per pump room. The same is provided on Channel B for safety
17 injection Tanks 1 and 2 and for the ECCS Train B pump rooms.
18 An additional annunciator is provided on loss of nuclear
19 cooling water to the reactor coolant pumps seal coolers, one
20 window per pump, and a redundant annunciator is provided on
21 Channel B.

22 Exhibit 2D1-5. Each Class IE annunciator is a unit
23 with integral windows, horn, power supply, and annunciator
24 logic cards mounted in the annunciator section of the main
25 control boards. Separate switches exist for alarm acknowledge,



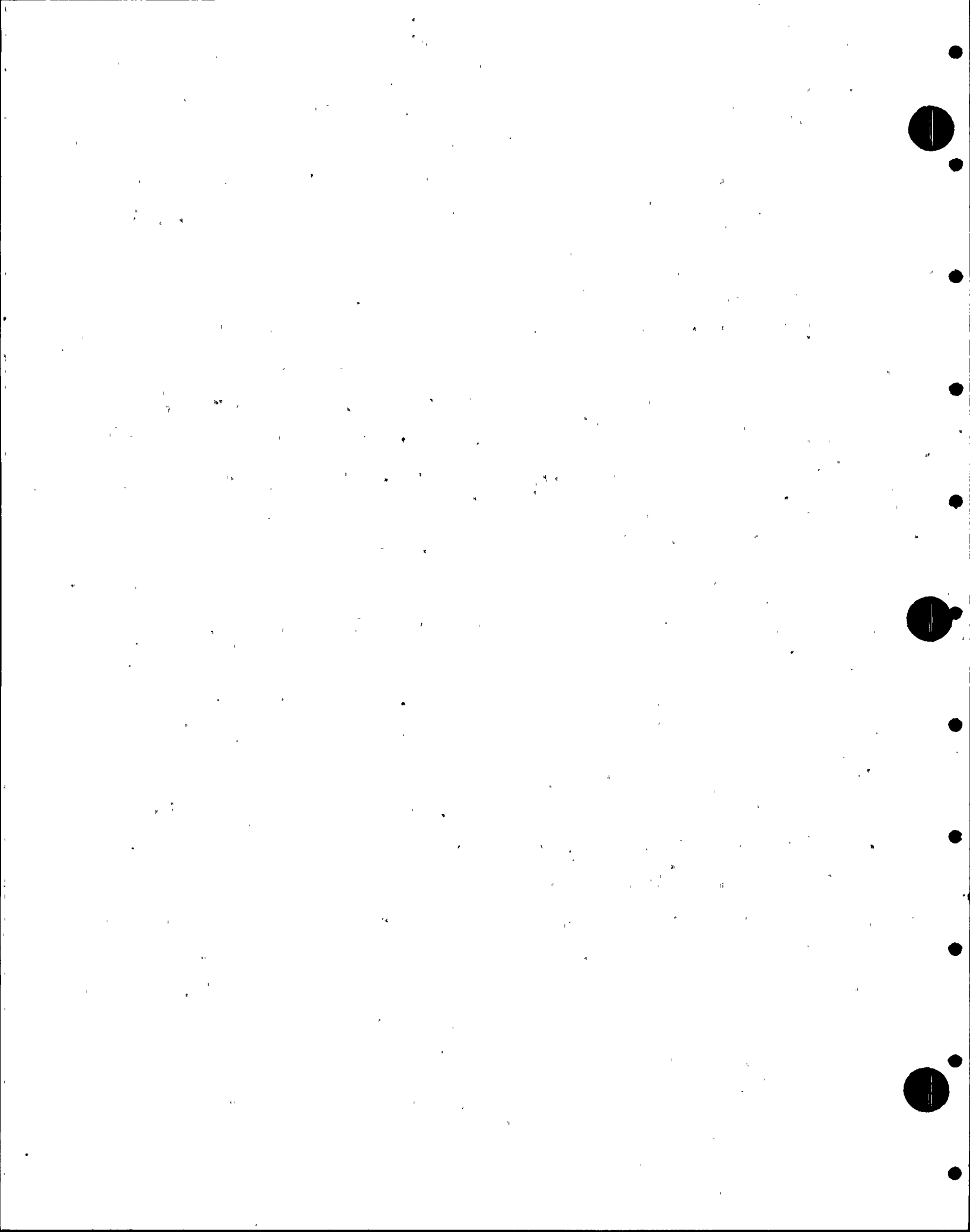
1 flasher reset, lamp reset, and test.

2 Class IE alarm functions include the loss of
3 nuclear cooling water to the reactor coolant pumps seal
4 coolers. Redundant safety grade instrument channels are
5 provided to continuously monitor nuclear cooling water flow
6 to the seal coolers for each reactor coolant pump. Annuncia-
7 tion is provided if the nuclear cooling water flow rate is
8 reduced below the minimum required for pump operation.

9 Inadequate safety injection tank pressure alarm.
10 Safety grade instrument channels monitor the pressure in each
11 safety injection tank and the pressurizer. Annunciation is
12 provided if the pressure in a safety injection tank falls
13 below 600 psig while pressurizer pressure is above 700 psig,
14 indicating the unavailability of the safety injection tank.

15 Exhibit 2D1-6. A Class IE alarm is provided on
16 high water level in an ECCS pump room. Safety grade
17 instrument channels monitor level in the drain basin in the
18 rooms for the low pressure safety injection pumps, high
19 pressure safety injection pumps, and the containment spray
20 pumps. Annunciation is provided on a high level signal
21 indicating leakage in a pump room.

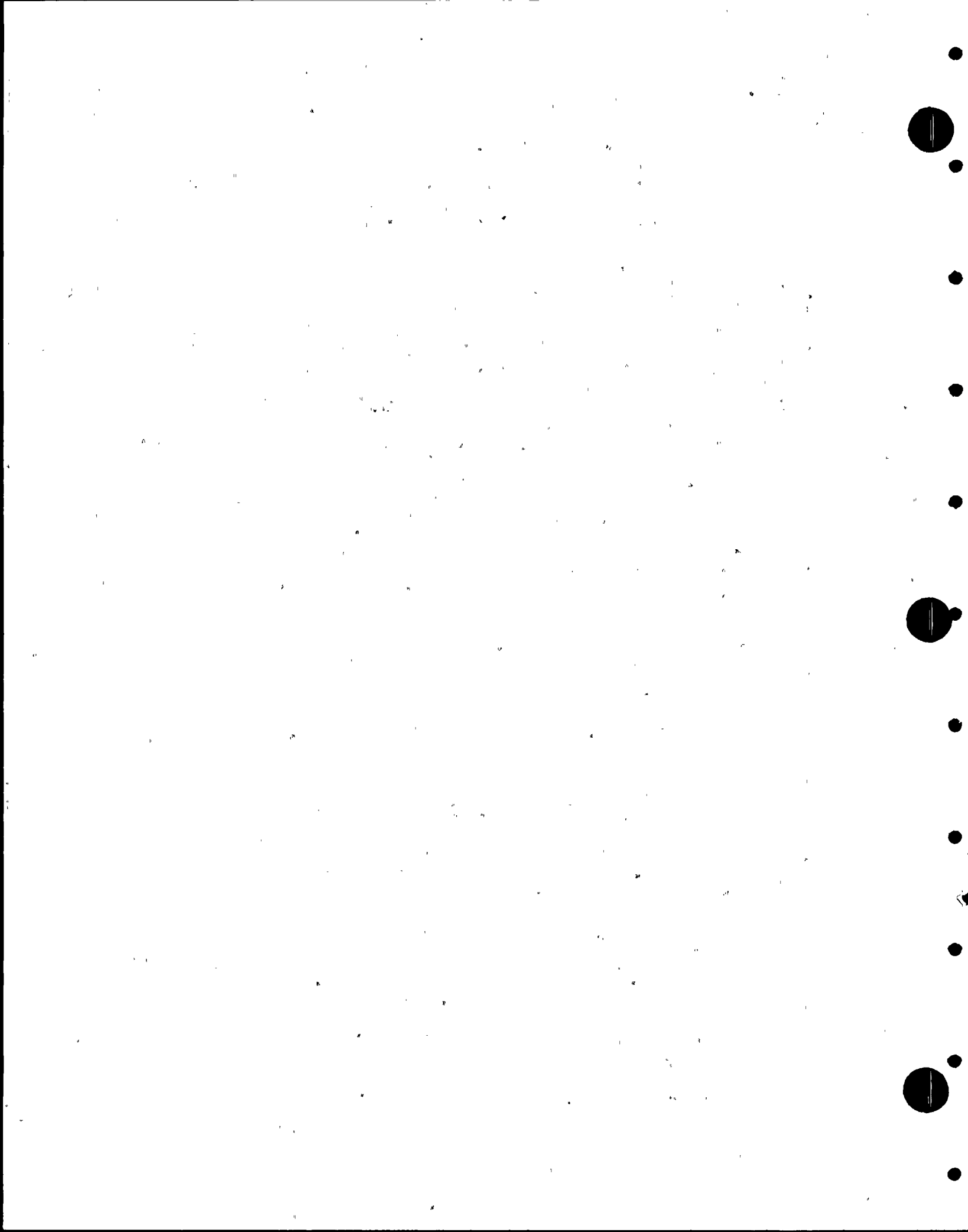
22 We will proceed now to the Safety Parameter Display
23 System Design Criteria. This system is still in the design
24 implementation and procurement phases. These are the design
25 criteria that have been adopted by the project.



1 The safety parameter display system shall be
2 provided to assist control room personnel in evaluating the
3 safety status of the plant. The primary function of the
4 SPDS is to aid the operator in rapid detection of abnormal
5 operating conditions. The SPDS shall be designed to 10CFR50,
6 Appendix A, General Design Criteria, IEEE 344 for seismic
7 qualification, and NUREG-0696.

8 Exhibit 2D2-2, continuing with the safety parameter
9 display system. The important plant functions related to
10 the primary SPDS display while the plant is generating power
11 shall include but not be limited to the reactivity control,
12 reactor core cooling, heat removal from the primary system,
13 reactor coolant system integrity, radioactivity control,
14 and containment integrity. The SPDS function in the control
15 room shall be provided during and following all events
16 expected to occur during the life of the plant, including
17 SSE. The SPDS display shall take account of human factors
18 and the man-machine interface. The SPDS display shall be
19 incorporated into the main control room with a location that
20 will allow the displays to be easily observed by the operations
21 staff. The SPDS display shall reflect and be capable of
22 supporting all operating modes.

23 Exhibit 2D2-3. The SPDS display shall also be
24 available in the TSC, the satellite TSC, and EOF. The
25 SPDS shall be designed to an operational unavailability goal



1 as defined in NUREG-0696 of 0.01 for the data display
2 function at each facility when the reactor is above cold
3 shutdown status. In addition, the SPDS display function in
4 the control room shall be designed to an operational
5 unavailability goal of 0.2 for cold shutdown status including
6 the refueling mode.

7 The SPDS System Description is provided on Exhibit
8 2D2-4. It is very brief, because the system has not yet been
9 procured. The SPDS consists of two display systems located
10 in the control room: a full-color CRT display driven from
11 the technical support center computer system, and a seismically
12 qualified display system driven from a separate control room
13 processor system. Plant functions included in the SPDS
14 displays are those that were defined in the design criteria.

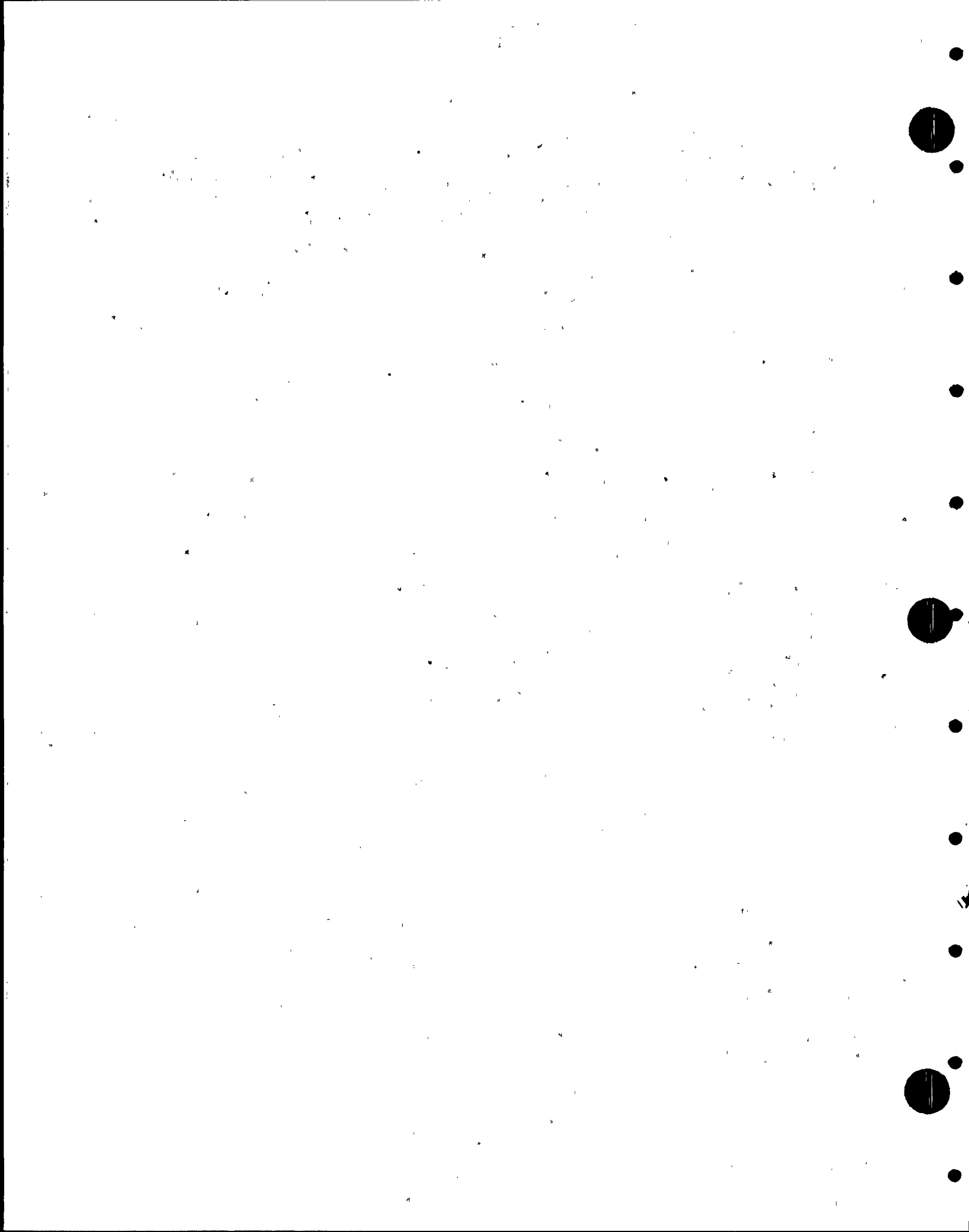
15 MR. BINGHAM: Any questions?

16 MR. ROSENTHAL: By when do you intend to install the
17 SPDS?

18 MR. BINGHAM: Our present schedule is to have it
19 installed prior to November of '82.

20 MR. HELMAN: I have a question on 2D2-3, Item 7). My
21 question concerns the EOF and post-EOF. Could you explain
22 a little further about the location of the current EOF and
23 its compliance with 0696?

24 MR. BINGHAM: I'm sorry, when you say the location
25 and its compliance, what did you have in mind, Norm?



1 MR. HELMAN: The current requirement, correct me if
2 I am wrong, is if we have a close-in EOF, which we do
3 currently, we are also required to have an alternate EOF
4 at some further location with specific SPDS and TSC type
5 displays in that location. I notice in here that you
6 indicate that the SPDS display will be available in the TSC,
7 satellite TSC, and EOF. I am concerned about addressing the
8 alternate EOF.

9 MR. BINGHAM: I think, John, I would prefer that APS
10 respond to that particular issue. That is the alternate
11 EOF.

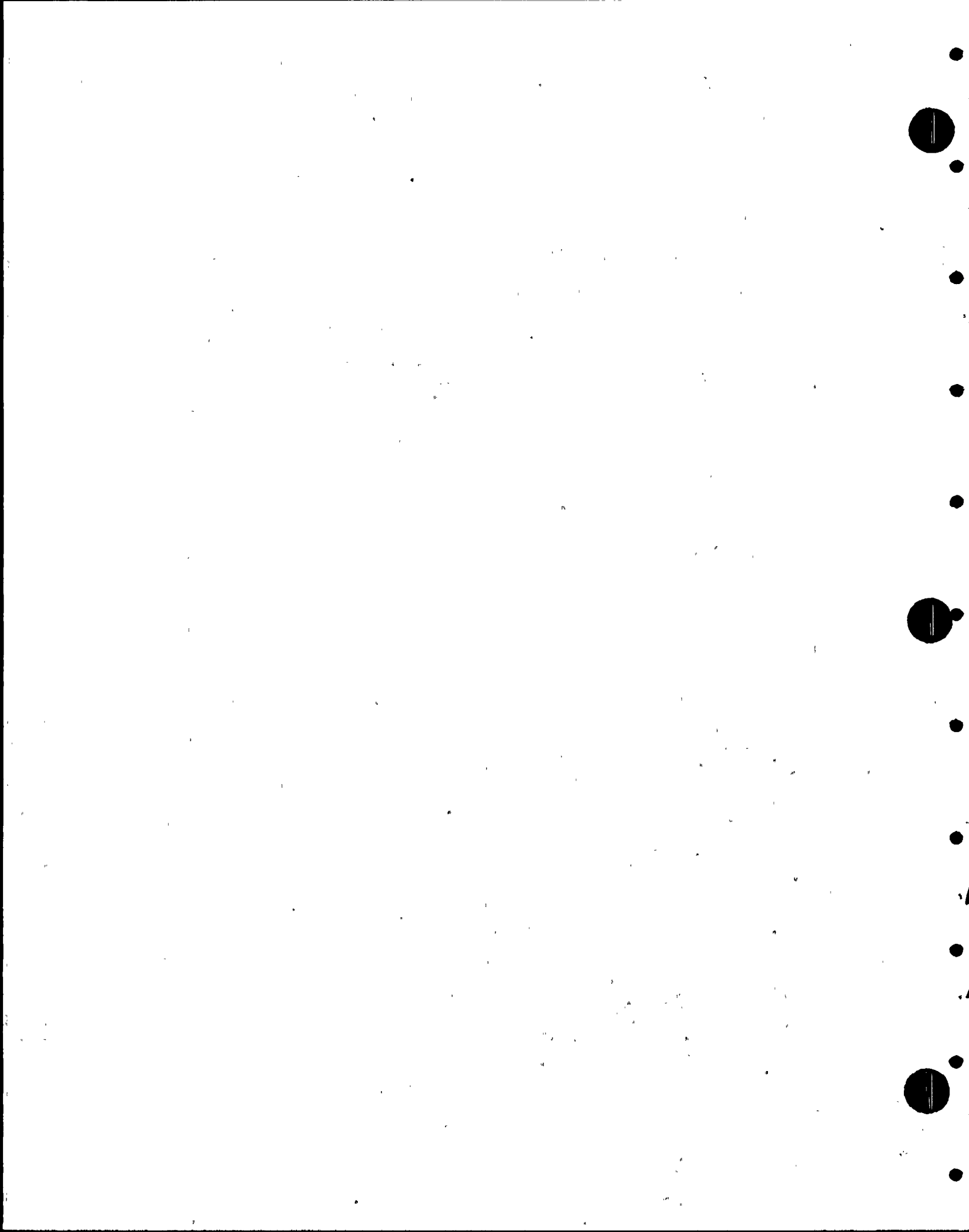
12 MR. ALLEN: Run that by one more time, Norm. You are
13 saying explain why we've got a satellite TSC?

14 MR. HELMAN: No, I am asking about the possibility of
15 an alternate EOF, because 0696 requires that if you have
16 a close-in EOF, you must also have in addition an alternate
17 EOF that is greater than ten miles.

18 MR. BINGHAM: There is a letter that APS has sent to
19 NRC stating the position regarding the alternate EOF. I
20 don't recall there being a response.

21 MR. ALLEN: We had met with the NRC a few weeks back,
22 and at that time, they had indicated to us that they felt
23 that our EOF location was satisfactory. However, they
24 would verify that and let us know by letter.

25 MISS KERRIGAN: That's right.



1 MR. ALLEN: That is still in process, Janis?

2 MISS KERRIGAN: That's right. There has been a
3 Commission paper prepared to propose to the Commission your
4 design along with a few other plants and we have not yet
5 gotten feedback on that from the Commission.

6 MR. HELMAN: Is there a specific commitment date for
7 receipt of that letter?

8 MISS KERRIGAN: No.

9 MR. HELMAN: I wanted to hear that.

10 MISS KERRIGAN: We hope to get it out shortly.

11 MR. ALLEN: Any other questions?

12 MR. PHELPS: I've got a question regarding the
13 monitoring of the cooling water flow to the pump seals. Are
14 those transmitters placed in a portion of the line where
15 they also monitor the cooling water to the pump motors?

16 MRS. MORETON: The flow transmitters are located in
17 the nuclear cooling water lines that service all the coolers
18 for the reactor coolant pump.

19 MR. PHELPS: Is that seismically designed for DBE?

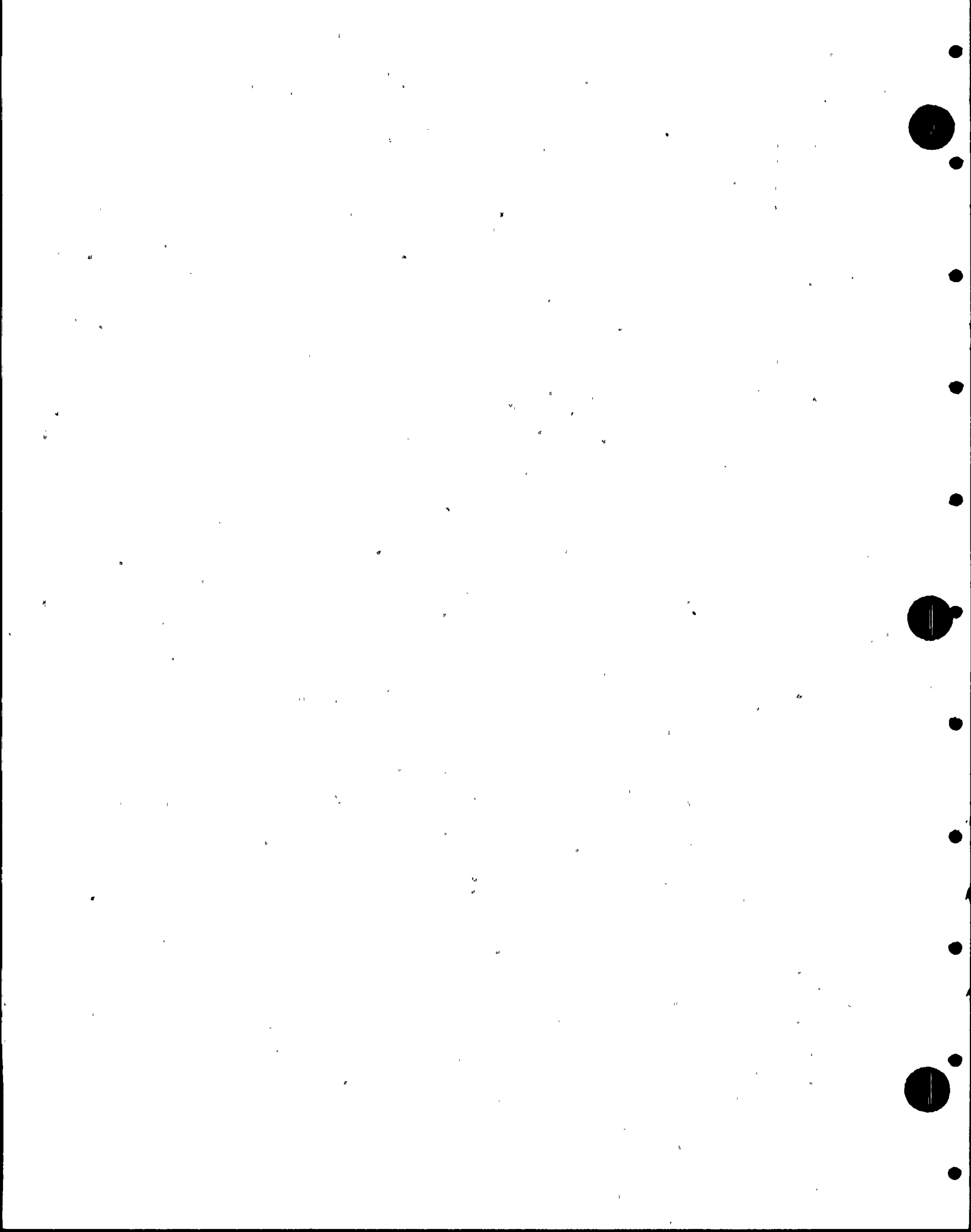
20 MRS. MORETON: The nuclear cooling water lines?

21 MR. PHELPS: Yes.

22 MRS. MORETON: No.

23 MR. PHELPS: Then how do you meet your criteria for
24 that event?

25 MR. KEITH: The nuclear cooling water lines to the



1 pumps are not Seismic Category I. The flow transmitters are
2 Seismic Category I and seismically mounted. These trans-
3 mitters were installed because of the concern that we had
4 non-Seismic Category I cooling water going to the reactor
5 coolant pumps. CE has done testing on these pumps showing
6 that the pumps are fine for at least 30 minutes without any
7 cooling water. The 30 minutes plus the alarm that we would
8 get if we lost cooling water flow to the reactor coolant
9 pumps, we would then have 30 minutes to shut down the reactor
10 in an orderly fashion and stop the reactor coolant pumps.

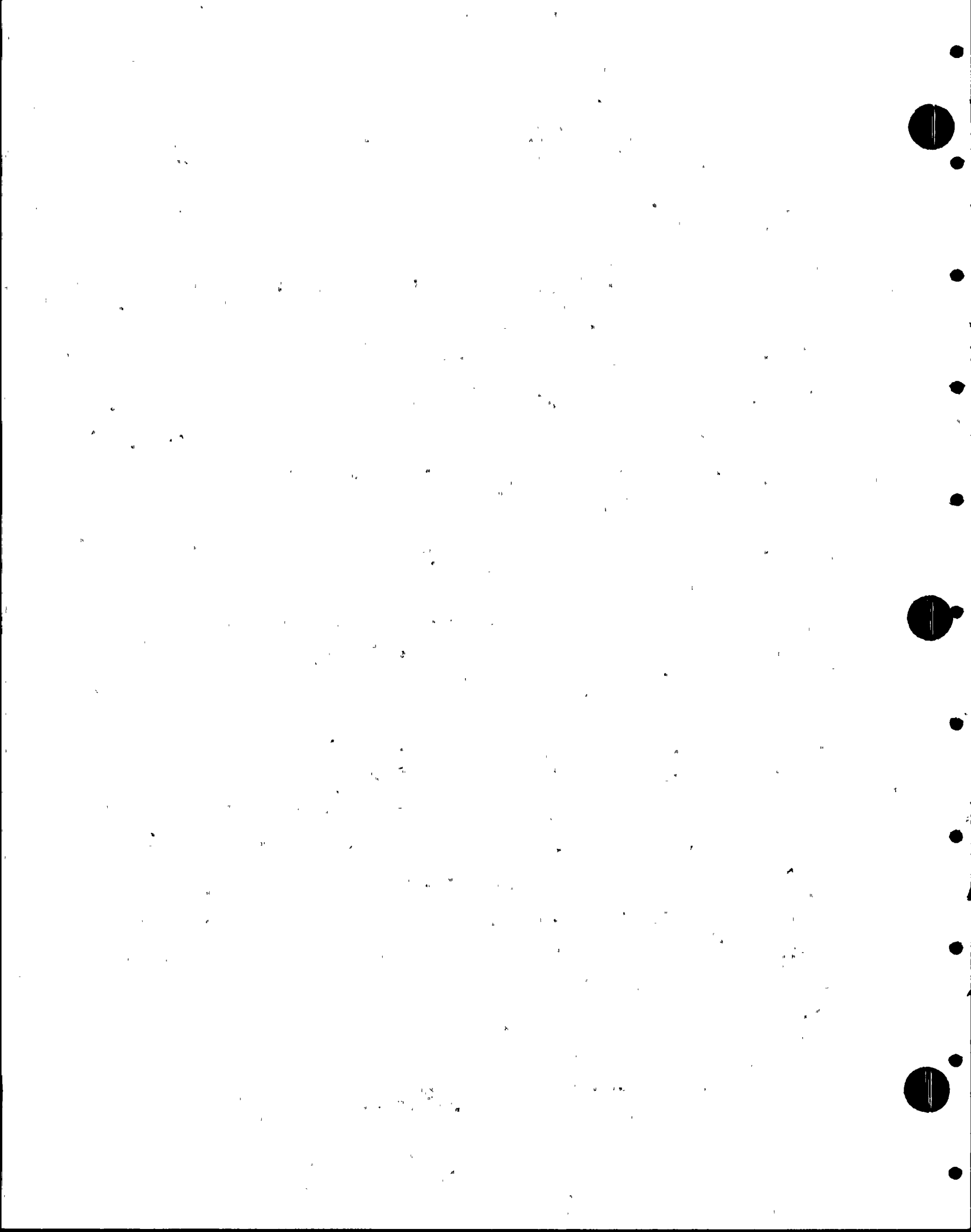
11 MR. PHELPS: What type of flow meters are they?

12 MRS. MORETON: They are differential pressure
13 transmitters.

14 MR. PHELPS: And you've got the orifice plate portion
15 of that mounted seismically, so that even if a line breaks,
16 they will still receive a no-flow signal?

17 MRS. MORETON: The orifice plate is not seismically
18 mounted. Only the transmitters are seismically mounted.
19 If the line ruptured, the impulse lines or sensing lines
20 would also break, indicating no flow. The transmitter would
21 fail to its no-flow position and cause the alarm.

22 MR. KONDIC: Are those flow meters checked and
23 recalibrated because of numerous possibilities with time to
24 give a different reading? You buy them and that's it, or
25 is there any way to find out whether that orifice has, for



1 example, accumulated dirt? A Delta P is not a measure of
2 the flow rate any more. This is something new.

3 MR. ALLEN: Jim, would you like to say what you
4 intend to do on those orifices, if anything? Nothing.
5 Is that satisfactory?

6 MR. KONDIC: The silence?

7 MR. ALLEN: No, there is no check of the orifices
8 or anything after they are installed.

9 MR. KONDIC: Thank you.

10 MR. MECH: I have a question which might throw some
11 light on that, perhaps. I am a little confused. On Exhibits
12 2D1, 5 and 6, you list the sensors used for the Class IE
13 alarm functions. Now, let me get this straight. There are
14 four annunciator panels.

15 MRS. MORETON: Yes.

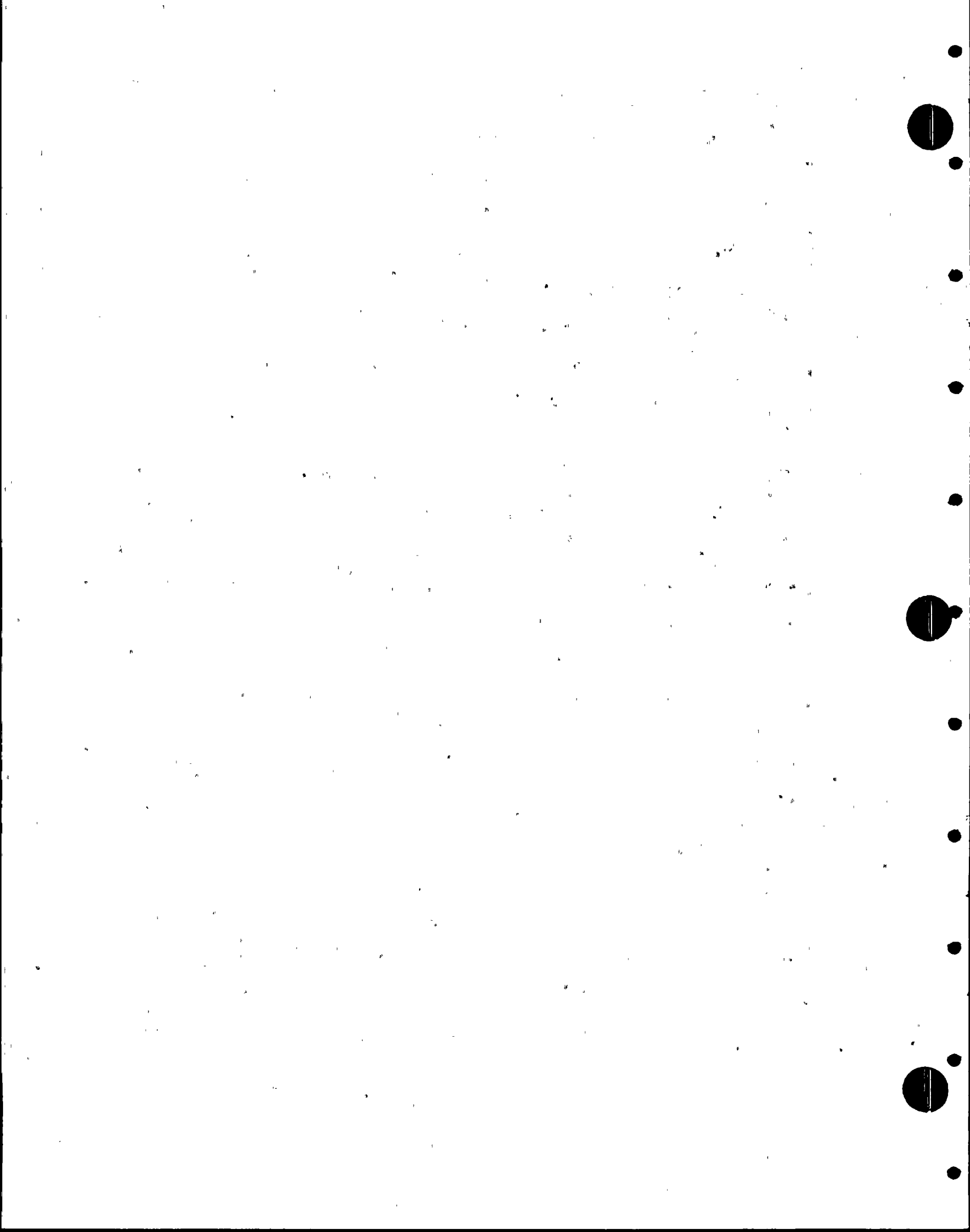
16 MR. MECH: A, B, C, D.

17 MRS. MORETON: A, B, A, B, two A's and two B's.

18 MR. MECH: All right. Then the sensors that are
19 involved with the safety injection tank, are they the same
20 sensors that are involved with the safety injection tank
21 interlocks?

22 MR. BINGHAM: We will have to look at the drawings to
23 answer that question.

24 MR. MECH: Well, let me ask another question then
25 that might help. From reading the FSAR, I find words like



1 on Exhibit 6, high water level in an ECCS pump room, I find
2 words like one independent level sensor is used to monitor
3 the level. What does that mean? What is that one indepen-
4 dent level sensor?

5 MRS. MORETON: The Train A pump room, as an example,
6 the containment spray pump room, has a Channel A sensor
7 that supplies monitoring or annunciation only to this
8 annunciator, to nowhere else. The Train B pump room would
9 have a Channel B sensor.

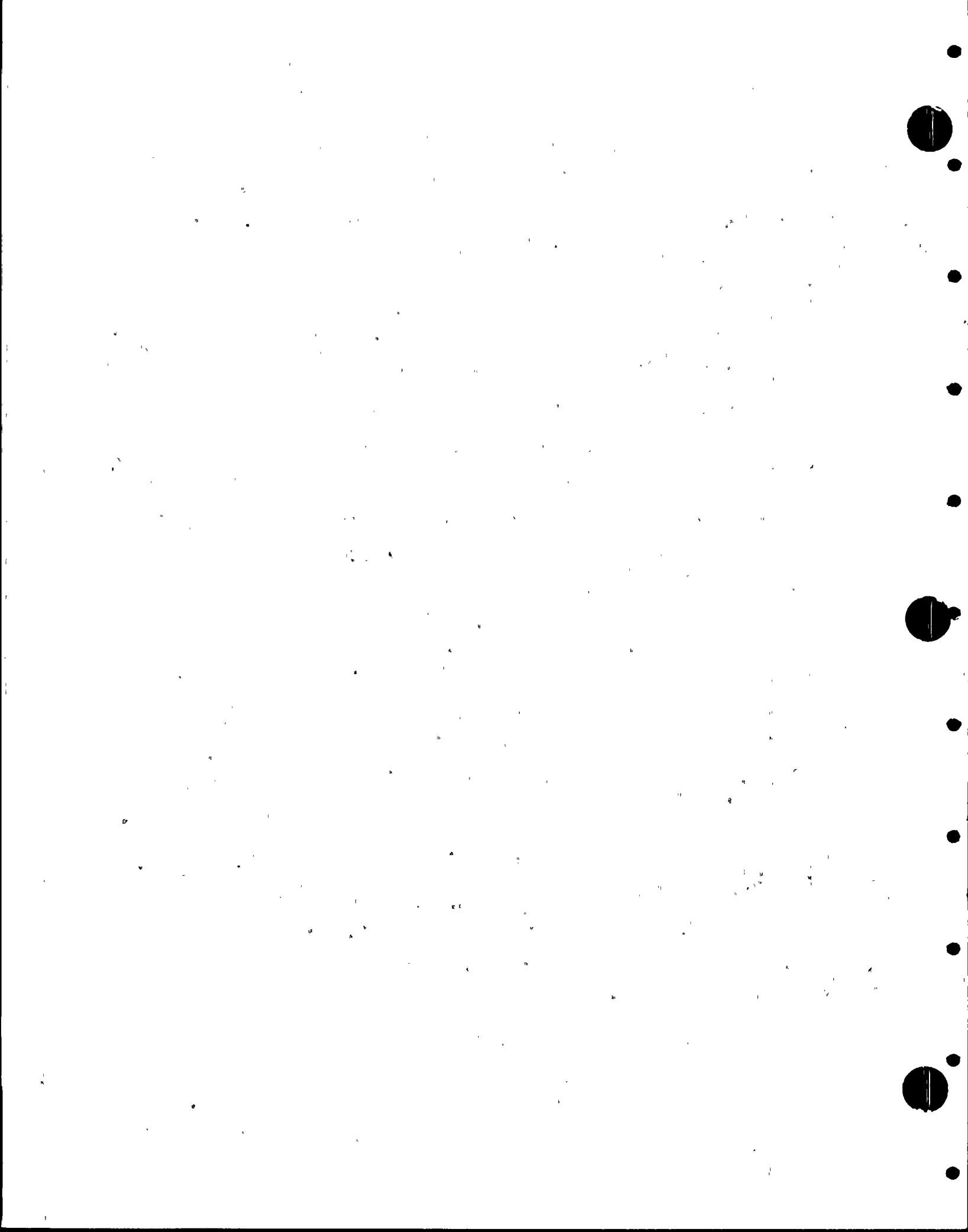
10 MR. MECH: And this is a second sensor that is put in
11 in addition to the one that is there for other reasons?

12 MRS. MORETON: Not in the same room. In a separate
13 room.

14 MR. ALLEN: Any further questioning on that section?

15 MR. MECH: I asked what an independent level sensor
16 was.

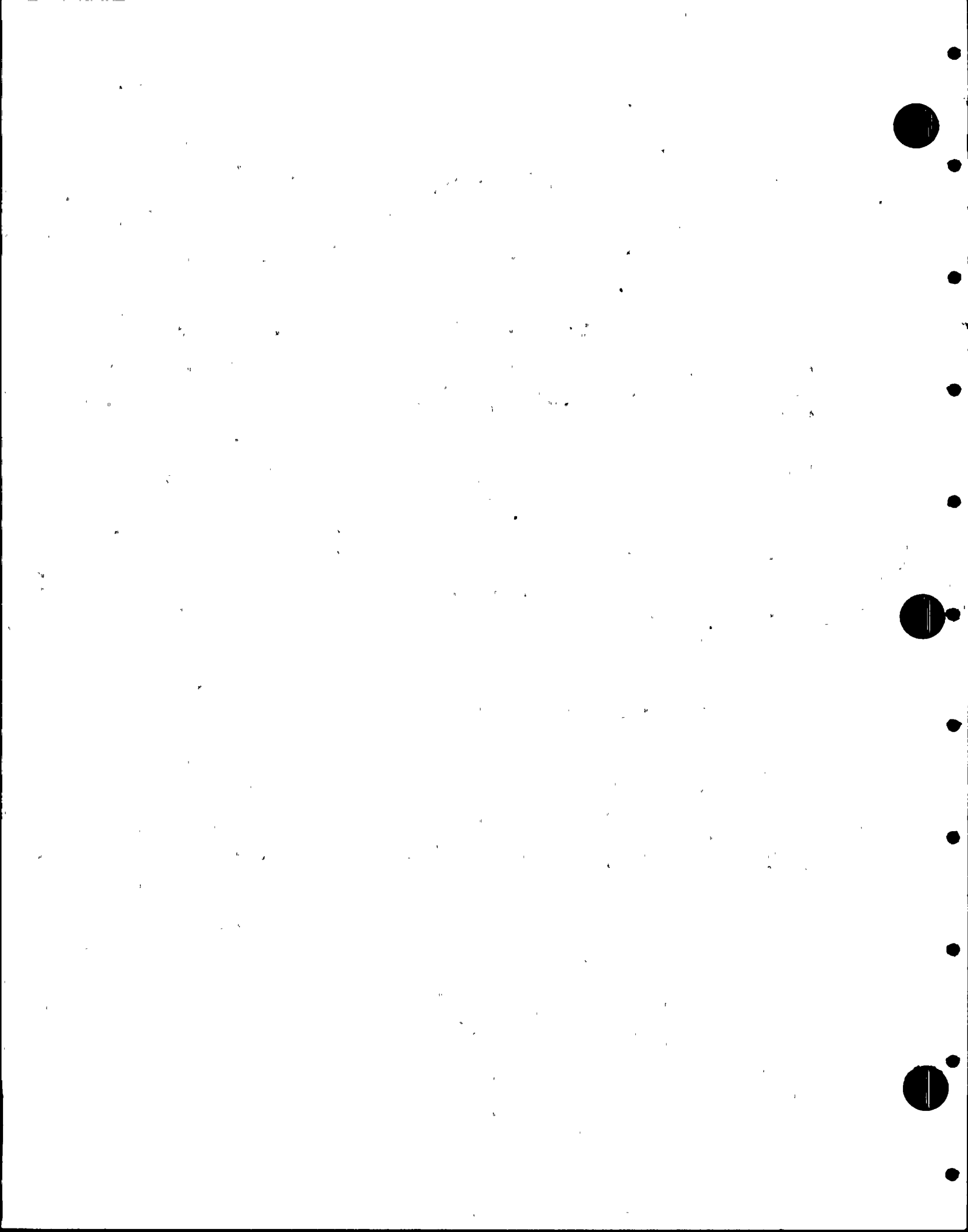
17 MR. ROSENTHAL: You lose CCW to the RCP's on a
18 containment isolation actuation signal by design. The
19 containment isolation actuation signal comes from lower
20 pressurizer pressure as well as high containment pressure, so
21 one expects that simple anticipated operational occurrences
22 will generate a containment isolation and, in turn, isolate
23 CCW to the RCT's, so with some frequency, you will isolate
24 CCW to the CRP's, more than once a year. What is the
25 rationale for not modifying the system such that you don't



1 CCW on a CIAS.

2 MR. BINGHAM: Let me see if I understand. You are
3 saying during normal operating transients that you would
4 expect containment isolation to occur at least once or more
5 a year.

6 MR. ROSENTHAL: Yes. The containment isolation
7 actuation signal some years past was on only high containment
8 pressure and would happen hopefully very infrequently, while
9 SIAS is induced by any overcooling event that drops the
10 pressurizer pressure below 1,600. Now that you have added
11 diversity to CIAS such that you pick up lower pressurizer
12 pressure, any overcooling event, and we see even undercooling
13 events which ten minutes later become overcooling events,
14 will cause SIAS and CIAS, they are logically one and the
15 same, and then by design, you isolate those lines in order
16 to fulfill the classical containment function of buttoning
17 everything up at this time, so now we have a situation in
18 which the pumps have been tested and can withstand, based
19 on limited testing, loss of CCW, and yet we expect a
20 relatively high frequency due to simple plant transients
21 to be challenging those pump seals, and loss of those pump
22 seals gives you a small break LOCA. Given that, why did you
23 decide to isolate CCW on containment isolation rather than
24 choosing to take an exception to the normal containment
25 isolation?

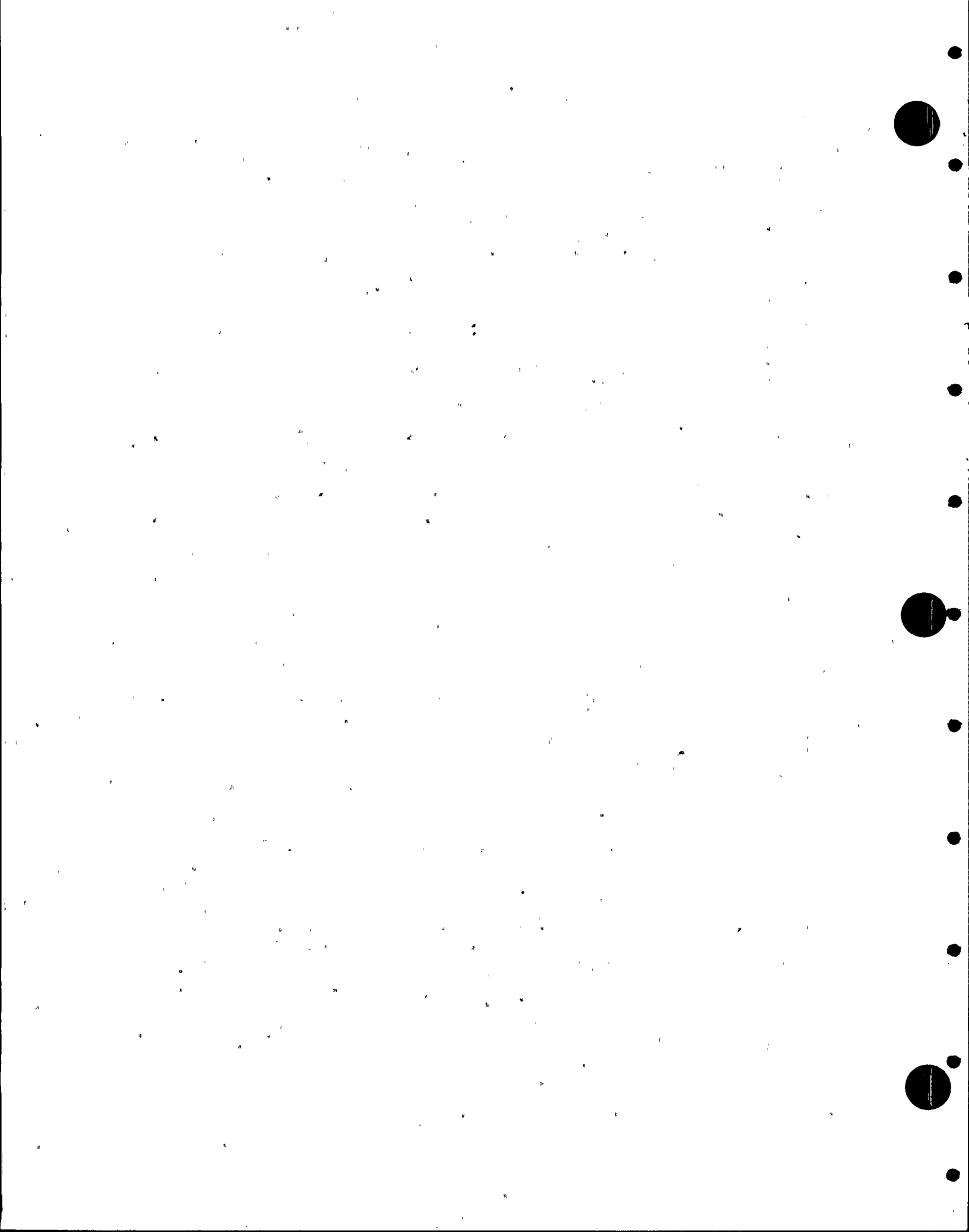


1 MR. BINGHAM: Regardless of whether it is seismic or
2 not, the issue is there. Let us confer for just a second.

3 MR. KEITH: First, I am not convinced that we are
4 going to have low pressure transients that often. I don't
5 know how good the data is on that, but, anyhow, it doesn't
6 seem to me like we should have them more often than once a
7 year. But, at any rate, because we felt we could live with
8 isolating these valves on a containment isolation actuation
9 signal, we went ahead and did it that way. I am not sure
10 that not doing it would be acceptable to your Containment
11 Systems Branch. If it were, I think there is some rationale
12 on not to shut them off on a CIAS. I would agree with your
13 observations.

14 MR. ROSENTHAL: I have had discussions with the
15 Containment Systems Branch, Auxiliary Systems Branch,
16 Reactor Safety Branch myself on this issue. The design as
17 you approach it seems to meet the requirements of the
18 regulations in the area of equipment unavailability, which
19 is a commercial concern which we wouldn't involve ourselves
20 in, although this Board might. We weren't fully happy that
21 we were sure we were doing the prudent thing, so I would
22 appreciate an explanation of the rationale, and this is an
23 area in which we would surely be anxious to hear your
24 rationale one way or the other.

25 MISS KERRIGAN: I guess what Jack is saying is we

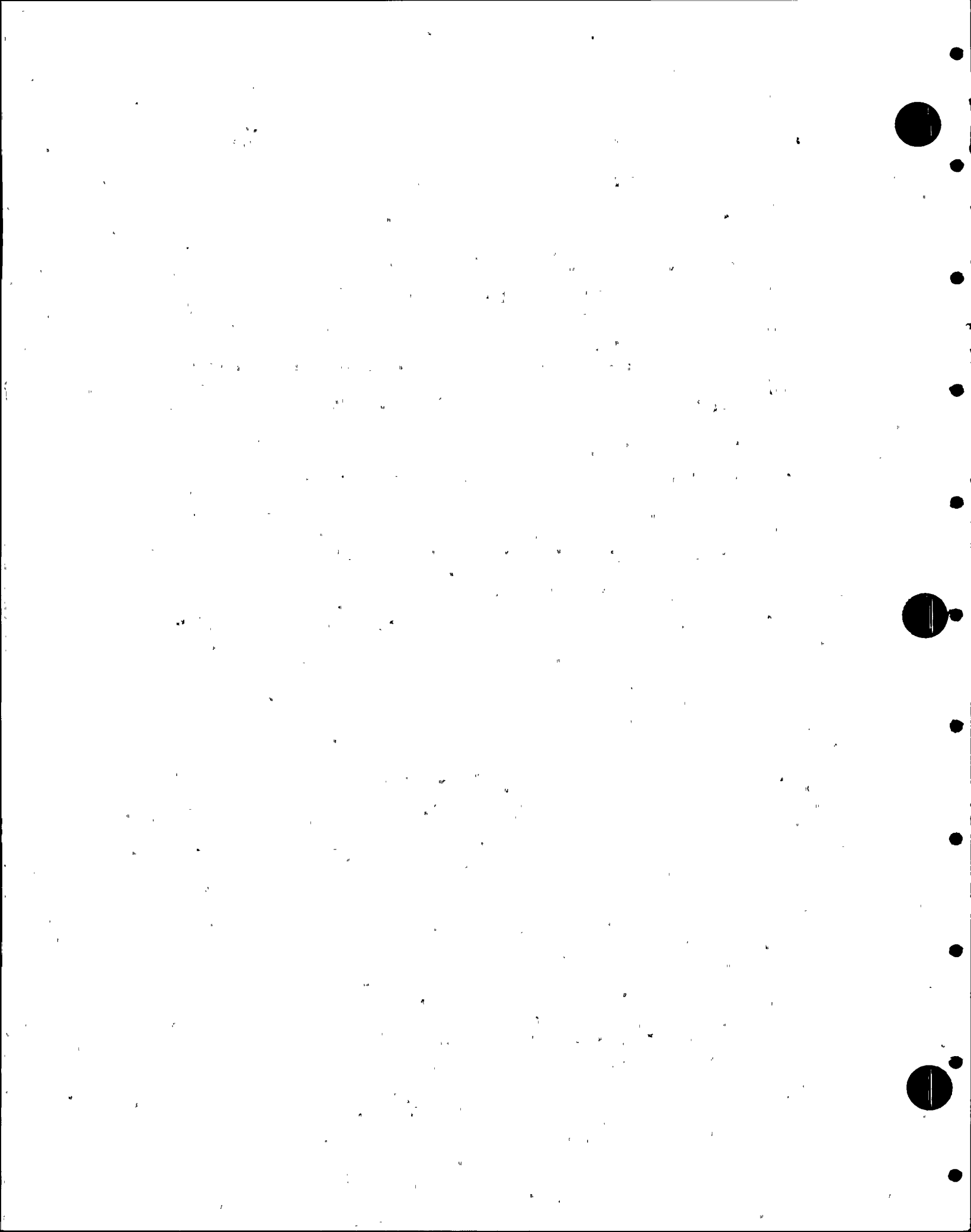


1 don't like to hear a rationale being used "because NRC told
2 us to." The responsibility of safety of the plant is yours,
3 not NRC's.

4 MR. BINGHAM: I don't believe that was the impression
5 Dennis was trying to give you, Janis. This system has been
6 the way it is since 1976 and it continues and remains to be
7 that way until there is other evidence that there should be
8 some change. What I guess I understand that Jack is saying
9 is that there is some rethinking going on about the desir-
10 ability of isolating that particular system.

11 MISS KERRIGAN: All right. I think that was back
12 into one of the TMI concerns, the old lessons-learned
13 concern about essential versus nonessential systems, and
14 that was part of the responsibility of the vendors and
15 utilities to rethink that, so we assume you have done that.
16 And now have a very strong basis for defining that CCW is
17 nonessential, and that is what we would like to hear.

18 MR. KEITH: I kind of alluded to that. Our evaluation
19 based on the work that CE has done and assuming for most
20 accidents, although it was beneficial at times at Three Mile
21 Island to run the reactor coolant pumps, generally the
22 reactor coolant pumps are not considered essential and needed,
23 so, based on that, we have classified this as a nonessential
24 system. Admittedly, it is borderline and I think we could
25 go back and take another look at it.



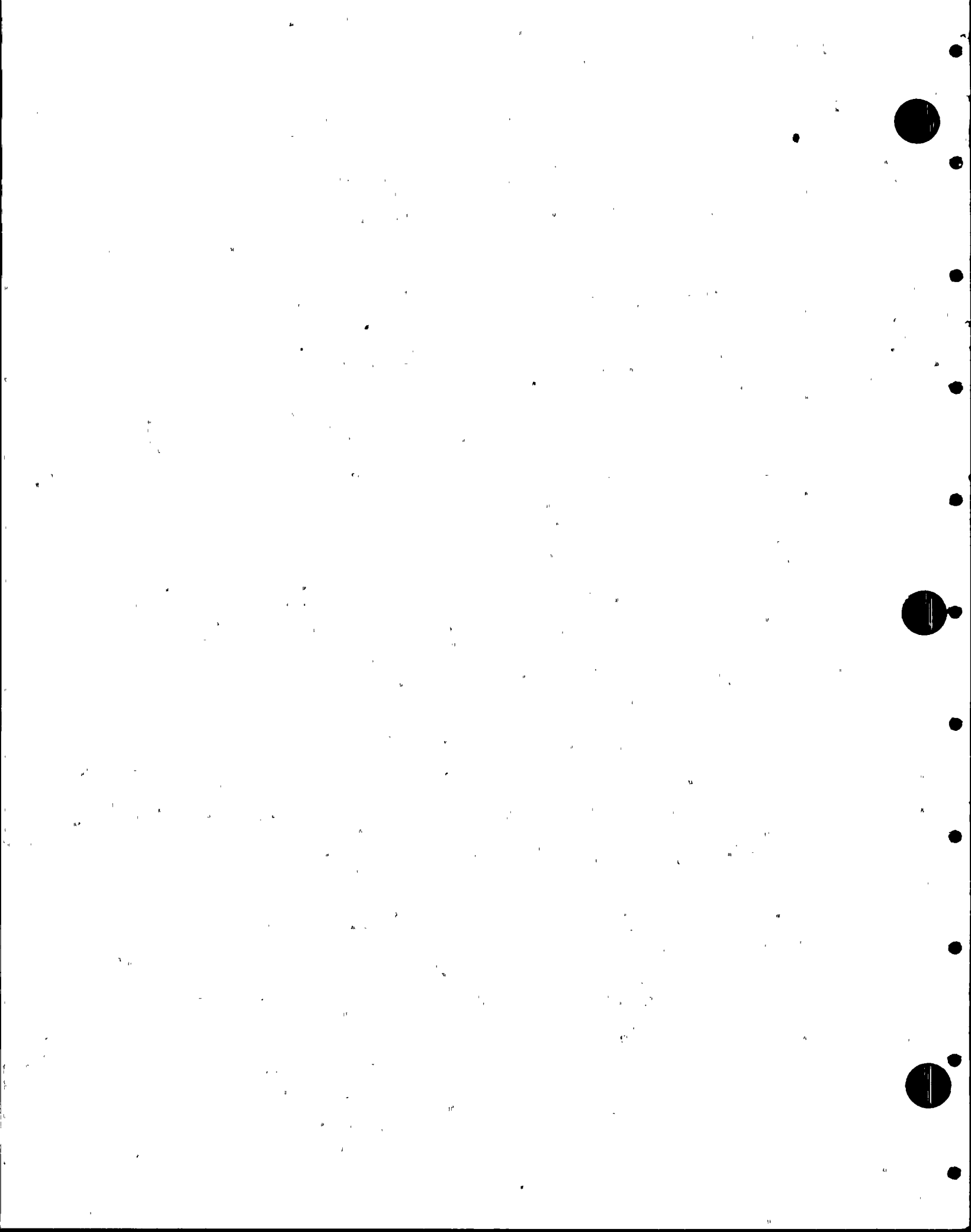
1 MR. ROGERS: Let me ask a question before you get off
2 into that. Is not the seal injection system which is
3 connected with the charging system, which is not isolated
4 in the case of a containment isolation signal, doesn't that
5 provide secondary cooling to the seals on the reactor coolant
6 pumps?

7 MR. KEITH: That's correct. There is that for the
8 seals.

9 MR. PHELPS: I just wanted to make one additional
10 point. If your original concern was correcting the low
11 pressure safety injection actuation signal terminating
12 recoolant water flow because of some of the TMI work while
13 waiting for the loss to come back, CE's operating guidelines
14 require the reactor coolant pumps to be tripped on the low
15 pressure safety injection setpoint, so that concern goes
16 away for the time being.

17 MR. ROSENTHAL: Excuse me, tripping of the pumps
18 doesn't totally protect the seals, which are quite Delta T
19 dependent. Yes, it would help, but I don't know if I am
20 bordering on an equipment concern or a safety concern. That
21 helps.

22 MR. ROGERS: The same system is a backup for the seals
23 and will keep the seals intact if you lose cooling water.
24 It is redundant in that sense to the component cooling water
25 system as I understand it.



1 MR. BINGHAM: And that valve we don't shut. We leave
2 that one open, so there is that, Jack. You might want to
3 look at that particular feature.

4 MR. ROSENTHAL: Yes, we have.

5 MISS KERRIGAN: Were you going to go back and look at
6 it or not? It's up to you.

7 MR. BINGHAM: It is up to the Board, of course. If
8 you like, I believe we will have to go to Combustion to get
9 their review.

10 MR. ALLEN: I think from our standpoint we are fairly
11 well satisfied. If you would like us to look into it --

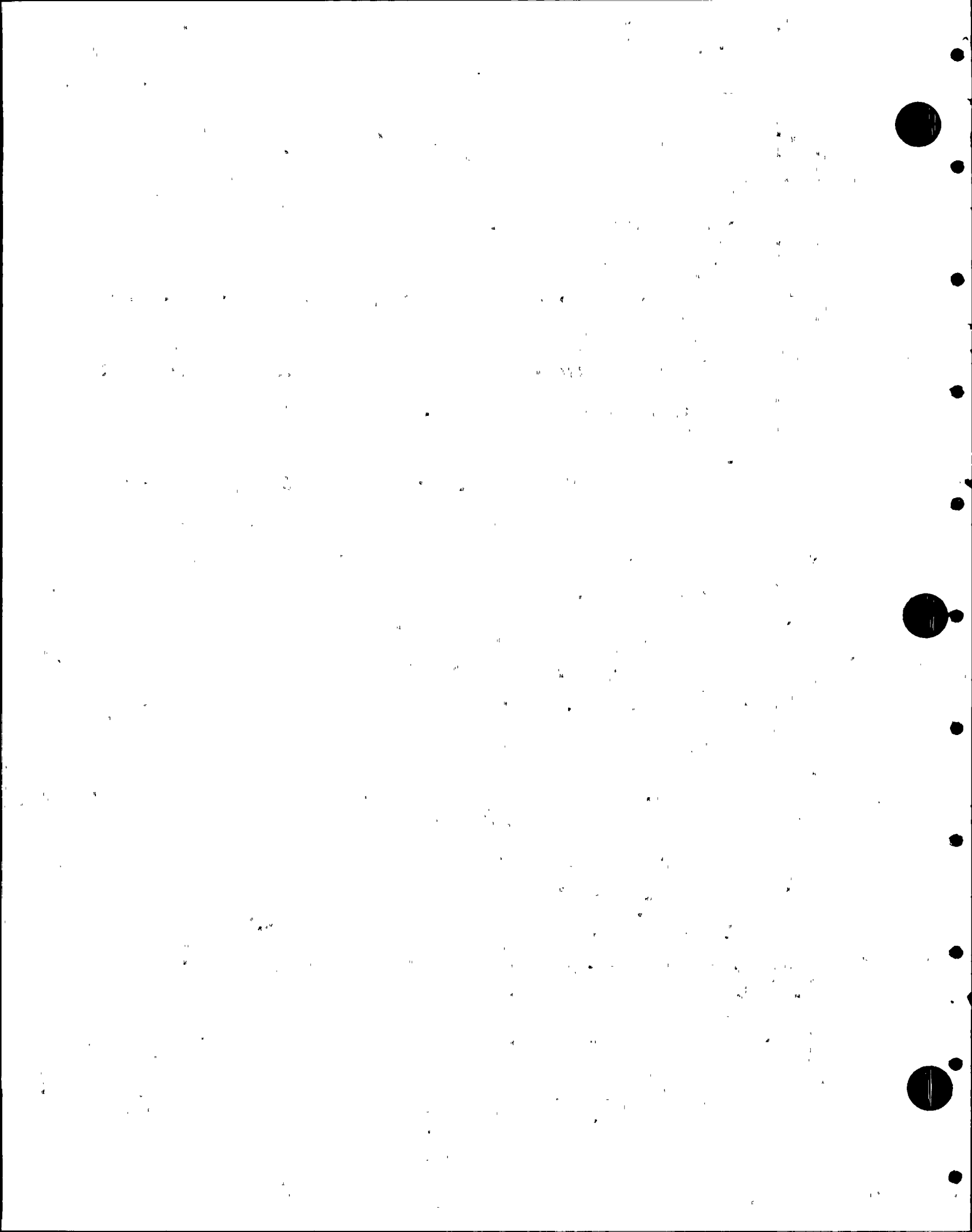
12 MISS KERRIGAN: No, it is the Board's decision.
13 I think we have the position on record and that served our
14 purposes.

15 MR. ALLEN: That position was discussed at the last
16 IDR, also, on the containment system. Unless someone else
17 on the Board has a desire to look at it, I would just as soon
18 close it.

19 MR. BINGHAM: Any more questions?

20 MR. ALLEN: Any questions left?

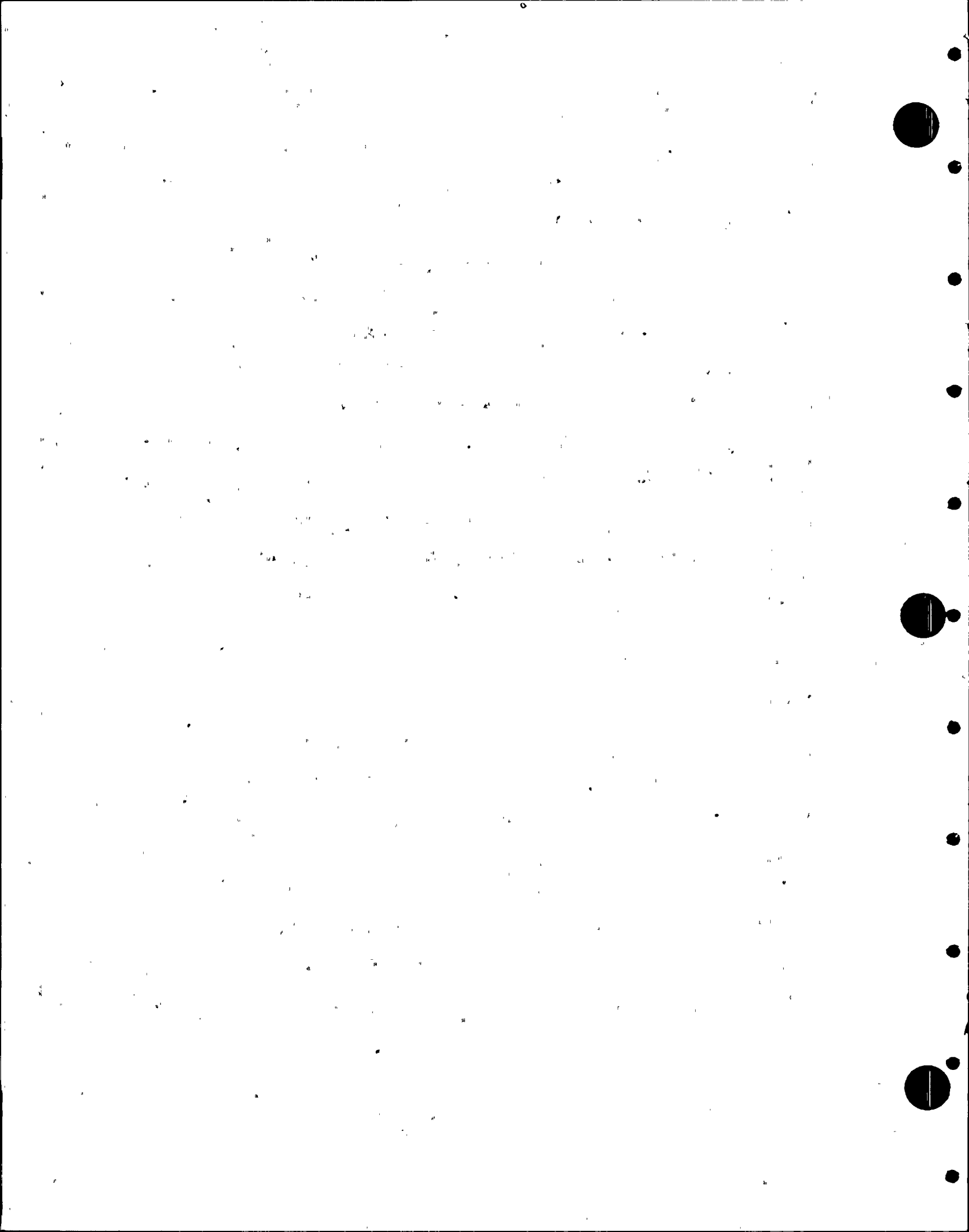
21 MR. BINGHAM: Due to the lateness of the hour, we
22 will present 2.E., Control Systems Not Required for Safety,
23 and then end the day's work with that section. Then
24 tomorrow morning, as I recall, we are convening at 8:00.
25 I would like a few minutes to bring the open items that we



1 can from today and then we will move into Section 3, which is
2 Compliance With Regulatory Requirements, if that is
3 satisfactory to the Board.

4 MRS. MORETON: Figure 2E-1. Control systems not
5 required for safety are those electrical and mechanical
6 devices and circuitry required for plant operation but whose
7 functions are not essential for the safety of the plant.
8 Most of these systems are NSSS systems which were discussed
9 in CESSAR. There are two NSSS systems that are outside the
10 CESSAR scope, including the steam bypass control system
11 option with two valves to atmosphere and the extended range
12 feedwater control system that provides control from zero to
13 15% power. The balance of plant system is the loose parts
14 monitoring system.

15 The design criteria for the control systems not
16 required for safety are, on Exhibit 2E-1, the feedwater
17 control system - extended range. For operation between
18 zero and 15% power, the feedwater control system shall
19 automatically control the steam generator downcomer water
20 level. Steam generator level will be controlled during the
21 following condition, assuming that all other control systems
22 are operating in automatic: steady state operations, 1% per
23 minute turbine load ramps between 0 and 15% NSSS power,
24 loss of one of two operating feedwater pumps, and load
25 rejection of any magnitude.

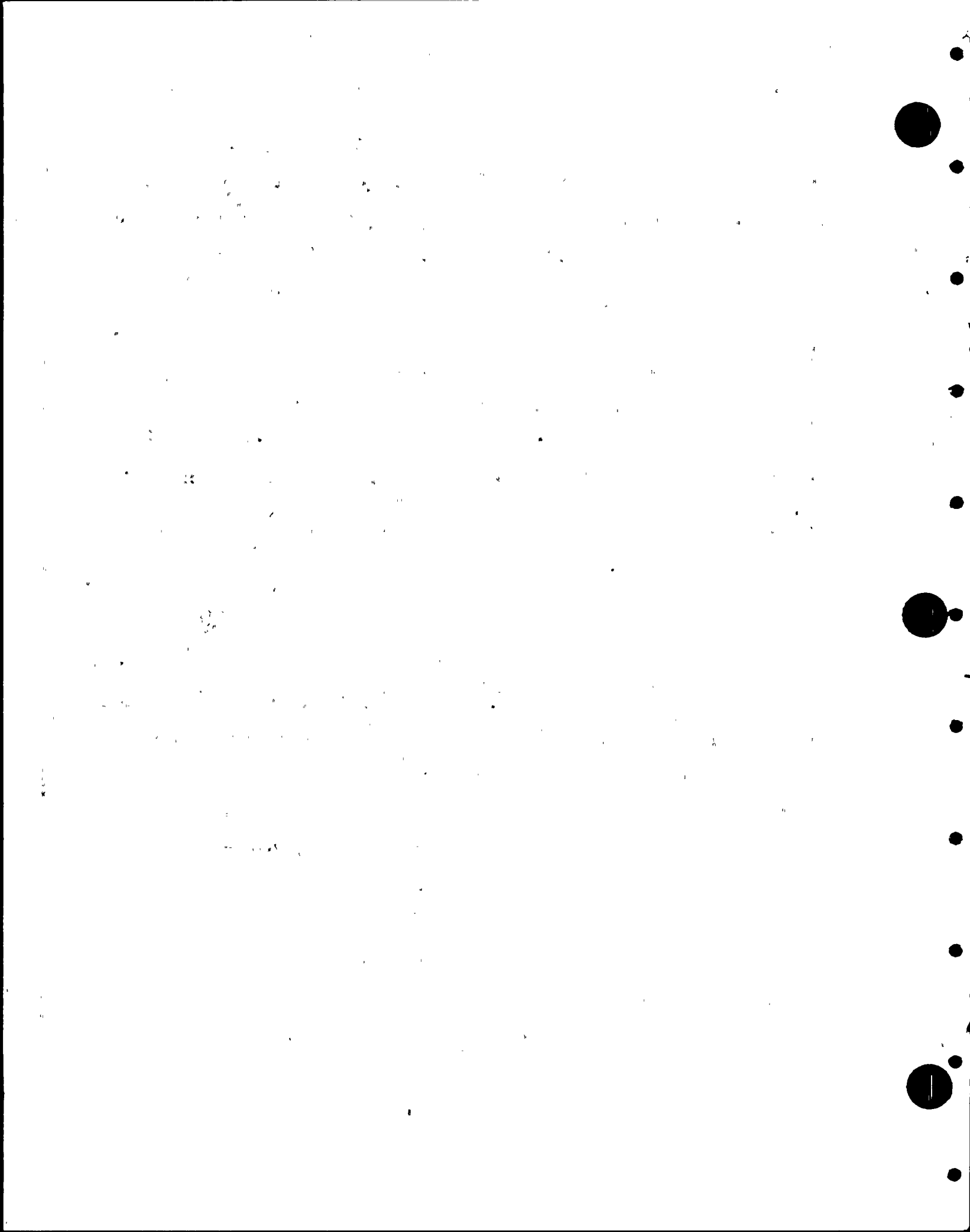


1 Design criteria for the steam bypass control
2 system option, Exhibit 2E-2. The CESSAR system is modified
3 for PVNGS to dump steam to atmosphere through two of the
4 turbine bypass valves. These valves shall be the last to
5 open and first to close during steam bypass operation.

6 Design criteria for the loose parts monitoring
7 system on Exhibit 2E-3. A loose parts monitoring system
8 shall be provided to detect and record signals resulting
9 from impacts occurring within the reactor coolant system.

10 I will now proceed with the system description.
11 Exhibit 2E-4, feedwater control system - extended range.
12 Below 15% NSSS power, referring to Figure 2E-2, the feedwater
13 control system performs dynamic compensation on the level
14 signal to generate an Alpha signal indicative of the
15 required feedwater flow. The Alpha signal is used to generate
16 the downcomer valve position demand signal. When in this
17 control mode, the economizer valve will be closed and the
18 pump speed setpoint will be at its minimum value. You see
19 the signal coming to the downcomer program. When we are
20 below 15% power, the economizer valve is closed and the
21 feedwater pump is set to minimum.

22 Exhibit 2E-5, steam bypass control system descrip-
23 tion. The CESSAR system is modified from four valve groups
24 to five valve groups. Valve Group 5 contains the seventh
25 and eighth steam bypass valves which discharge to atmosphere.

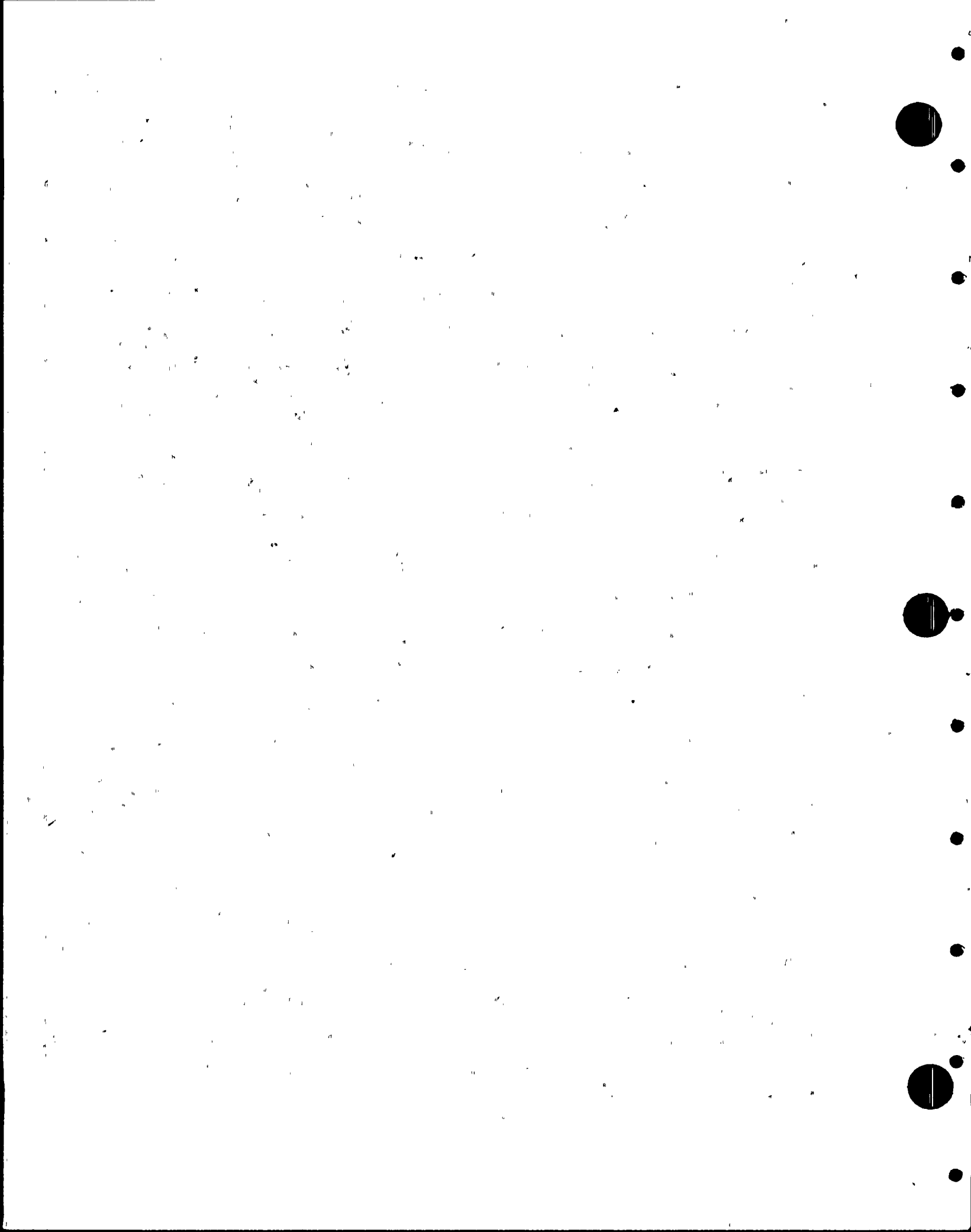


1 Valve Group 5 is the last group to sequence open and is not
2 interlocked with a loss of condenser vacuum signal.

3 Figure 2E-3 is a simply block diagram of the
4 steam bypass control system which is identical to the control
5 system provided in CESSAR, still eight valves. The only
6 change is that six go to the condenser and two to the
7 atmosphere. Those two that go to the atmosphere do not
8 receive condenser interlock signals.

9 Exhibit 2E-6, system description of the loose
10 parts monitoring system. Eight high temperature piezoelectric
11 accelerometers (transducers) will be located in the areas
12 where loose parts are most likely to become entrapped. Two
13 redundant transducers are clamp mounted on the in-core
14 instrument guide tubes on the reactor vessel lower head.
15 These are diametrically opposed. Two redundant transducers
16 will be stud mounted on the reactor vessel upper head service
17 structure flange, also diametrically opposed, and two
18 redundant transducers on the lower head region of each steam
19 generator. One transducer will be clamped to the primary
20 inlet pipe and the other will be clamped to the primary outlet
21 pipe.

22 Exhibit 2E-7, continuing on with the loose parts
23 system description. A data acquisition panel is located in
24 the control room area which contains alarm modules that
25 continually monitor the incoming signals from the preamplifier



1 for the presence of impacting. The occurrence of a loose
2 part impacting on the inside of the structure causes bursts
3 of signals that exceed the alarm setpoint and trigger the
4 alarm. The data acquisition panel includes tape recorders
5 with playback and an audio monitor.

6 MR. BINGHAM: Questions?

7 MR. MECH: One little question. You don't list in the
8 systems here the gross failed fuel monitor, which is generally
9 considered desirable. In Chapter 9 of the FSAR, you have
10 what you call a process radiation monitor, which appears to
11 do the same function. Is this true?

12 MR. BINGHAM: That's true.

13 MR. MECH: Thank you.

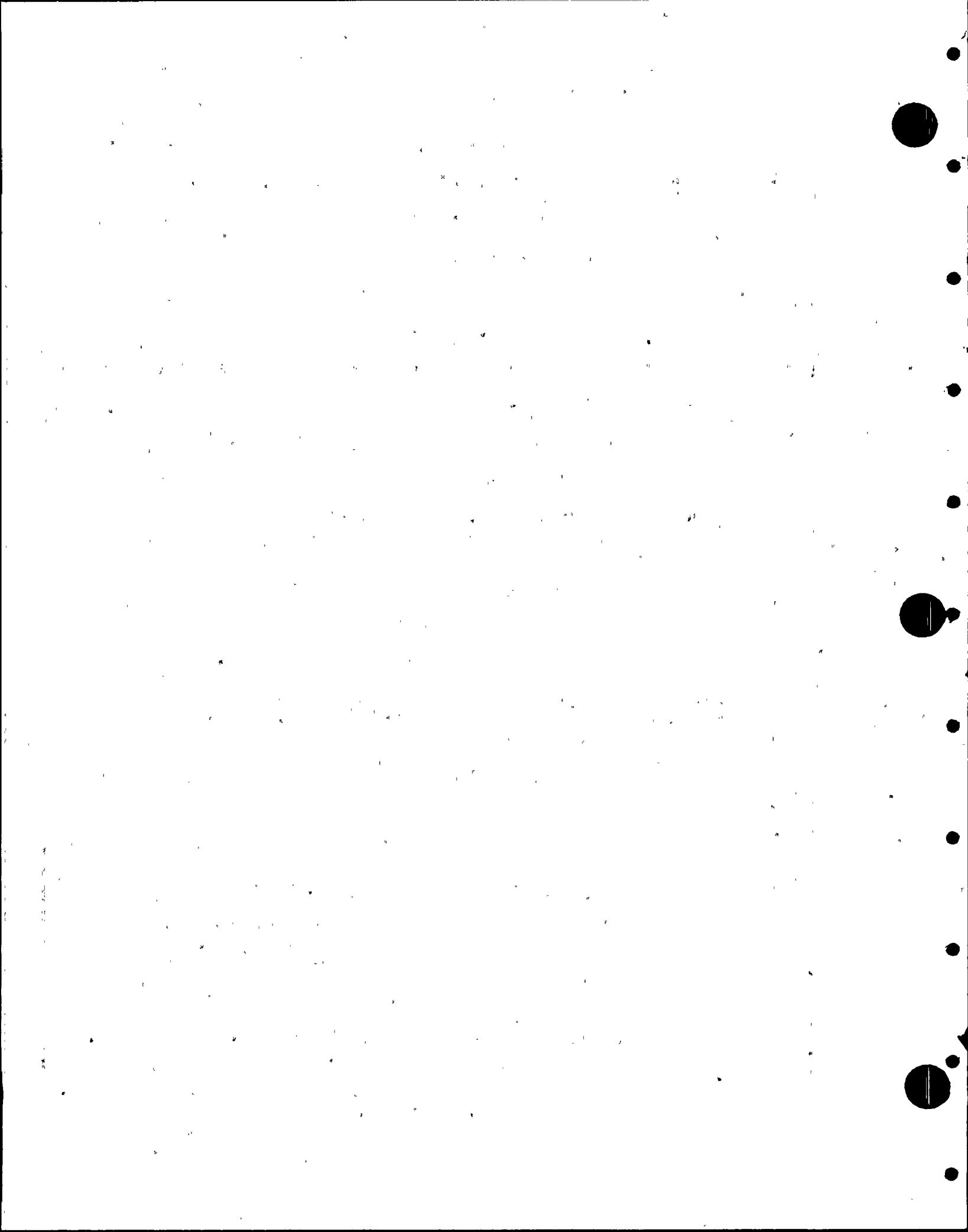
14 MR. ALLEN: Jack, I think you had one.

15 MR. ROSENTHAL: Yes. Do you have a control grade
16 reactor power cutback system? I assume that is part of the
17 standard System 80 scope of supply.

18 MR. BINGHAM: We have it. Is it part of the standard
19 System 80?

20 MR. BARNOSKI: Yes.

21 MR. ROSENTHAL: That system in some sense is in lieu
22 of the anticipatory trip of the reactor on a turbine trip,
23 which is a safety grade system and which we have required
24 on other than CE NSSS plants. Would it be appropriate to
25 have some requirements with respect to availability of that



1 system? It is no great scheme and one does have turbine
2 trip. I believe that the Chapter 15 analysis shows it
3 lifts the safeties, which is an undesirable characteristic.

4 MR. BINGHAM: I'm not sure that Bechtel is the one
5 that that question should be directed to. Maybe, John, you
6 could help us. If I understand, the question is, since that
7 is a control grade system, should there be some other
8 requirements on its availability to perform when required.
9 Is that correct?

10 MR. ROSENTHAL: Yes.

11 MR. ALLEN: That sounds like a question that would
12 have to be coordinated with Combustion. We can take it as an
13 open item.

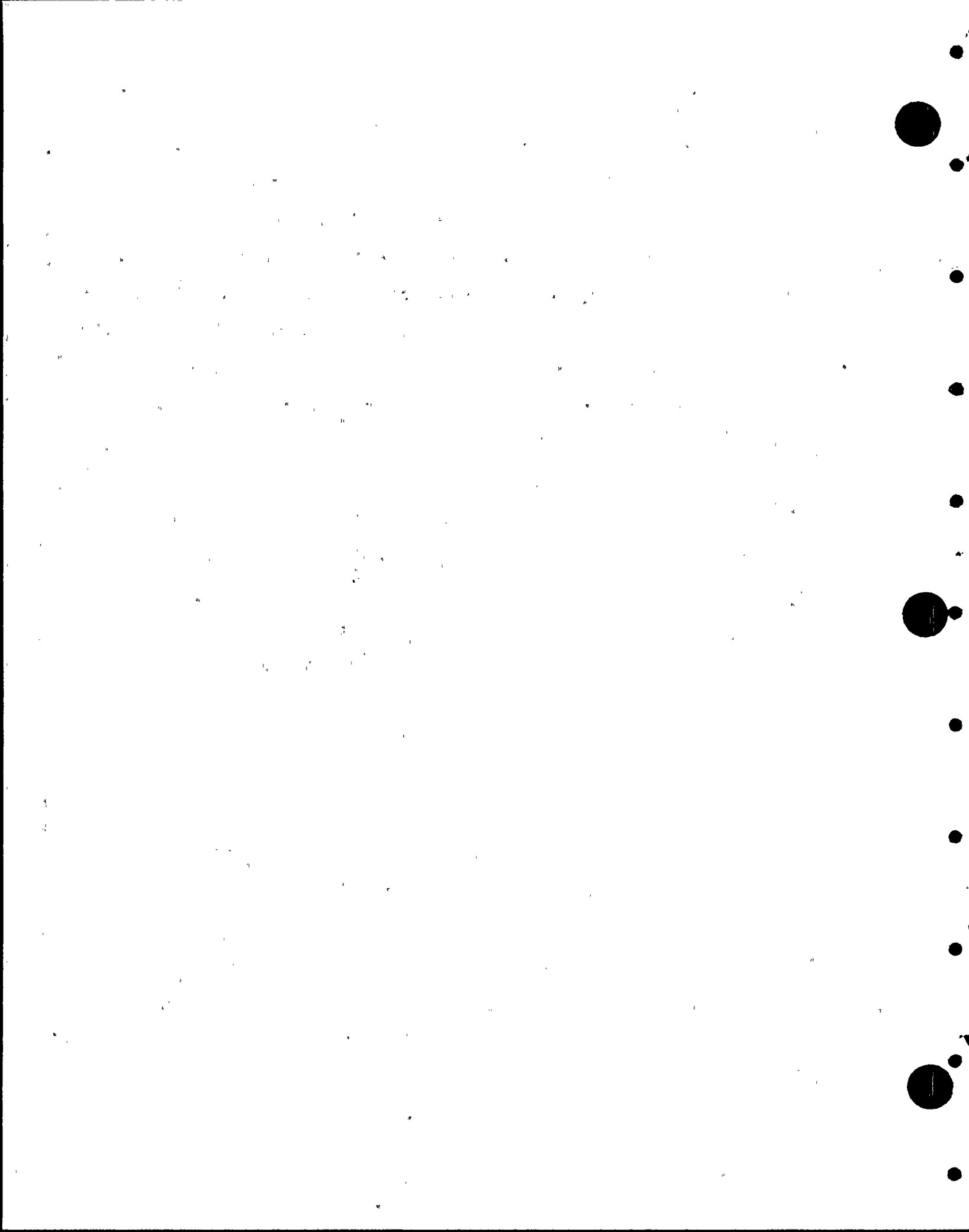
14 MR. BARNOSKI: If I might make a suggestion, I guess
15 from our point of view, that is a CESSAR question as opposed
16 to a question for these folks. We have noted it and we will
17 be prepared to discuss that at the upcoming meeting in July.

18 MR. ROSENTHAL: Okay, fine.

19 MR. BINGHAM: Does that take care of it?

20 MR. ALLEN: A clarification on that. Some System 80
21 plants don't have that like Yellow Creek.

22 MR. BESSETTE: Let me clarify. All System 80 plants
23 do have reactor power cutback. Some of the functions of
24 the reactor power cutback on Yellow Creek, for example,
25 aren't included because they have a third feed pump. Therefore,



1 there is no reactor power cutback initiated on a loss of a
2 feed pump, because they still have 100% feed pump capability,
3 but the reactor power cutback itself doesn't exist.

4 MR. ROSENTHAL: Another control grade system that
5 you have is called COLSS. That system was discussed at
6 Combustion and the level of QA of that system to the point
7 that the software leaves Combustion's doors was discussed.
8 That software now arrives at Palo Verde. Can you describe
9 the quality assurance of it and protection of that COLSS
10 software package?

11 MR. ALLEN: We will have to take that one as an open
12 item. We don't have the people here to do that.

13 MR. BINGHAM: Maybe I could add enough, John, to get
14 this before these folks.

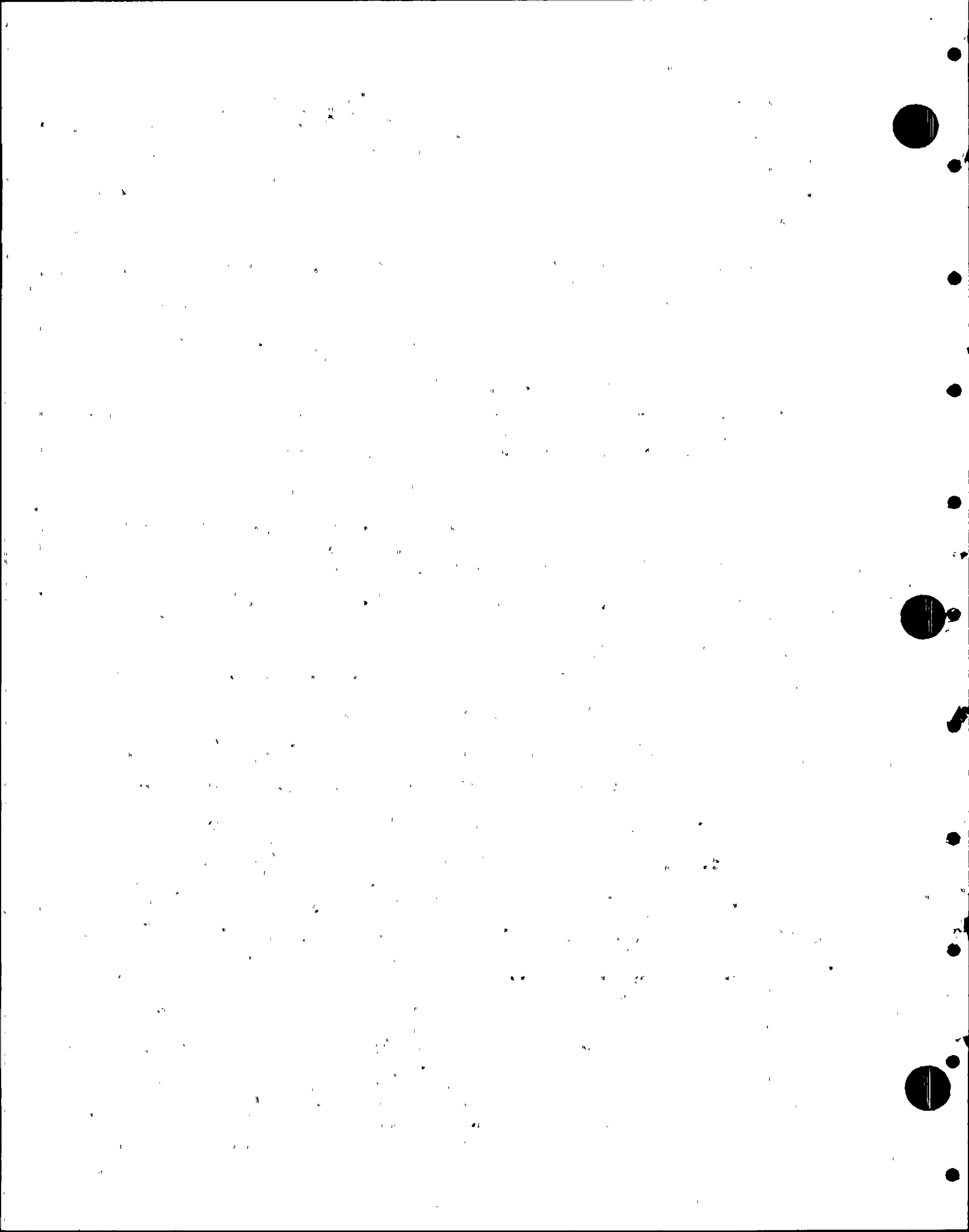
15 MR. ALLEN: That is an Operations QA problem and I
16 would like to see it addressed by Operations.

17 MR. BINGHAM: Fine.

18 MR. ROSENTHAL: Similarly, the reactor power cutback
19 system, control grade system, does get some input from
20 information which is stored on the plant computer. There
21 should be some commensurate level of QA of the software
22 for this control grade system performed by Palo Verde, We
23 would like to discuss that.

24 MR. ALLEN: We will take that as an open item, also.

25 MR. SIMKO: There were some questions from the NRC



1 addressing these already. I can't remember where. A couple
2 of months ago, they talked about this and I know our
3 Licensing Group is addressing this type of question.

4 MISS KERRIGAN: In other words, they could have spent
5 time with that first set of Q1's under the QA set of questions.

6 MR. SIMKO: You can leave it an open item, but I know
7 we have addressed that.

8 MISS KERRIGAN: It could be that your response would
9 be referring us to your Q1 response.

10 MR. ALLEN: Any further questions?

11 MR. BINGHAM: No more questions?

12 MR. ALLEN: I guess then we will adjourn for the day
13 and meet back at this room at 8:00 sharp tomorrow morning.

14 (Thereupon the meeting was at recess.)
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