PSE&G Public Service Electric and Gas Company

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Robert L. Mittl General Manager
Nuclear Assurance and Regulation

September 26, 1984

Director of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, MD 20814

Attention: Mr. Albert Schwencer, Chief
Licensing Branch 2
Division of Licensing

Gentlemen:

HOPE CREEK GENERATING STATION
DOCKET NO. 50-354
DRAFT SAFETY EVALUATION REPORT
OPEN ITEM STATUS

Attachment 1 is a current list which provides a status of the open items identified in Section 1.7 of the Draft Safety Evaluation Report (SER). Items identified as "complete" are those for which PSE&G has provided responses and no confirmation of status has been received from the staff. We will consider these items closed unless notified otherwise. In order to permit timely resolution of items identified as "complete" which may not be resolved to the staff's satisfaction, please provide a specific description of the issue which remains to be resolved.

Attachment 2 is a current list which identifies Draft SER Sections not yet provided.

Enclosed for your review and approval (see Attachment 4) are the resolutions to the Draft SER open items and FSAR Question listed in Attachment 3.

In addition, enclosed (see Attachment 5) is a copy of FSAR Section 13.4 revised to reflect the proposed HCGS Technical Specifications transmitted on September 21, 1984.

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Also, enclosed (see Attachment 6) is a copy of the resolutions to the Draft SER open items and modifications to FSAR Section 17.2 and SRAI (1) previously transmitted on September 24, 1984, and (see Attachment 7) a copy of the resolution to Power System Branch Questions previously transmitted on September 25, 1984.

Also, enclosed (see Attachment 8) for your information is one copy of the A.D. Little report entitled, "An Update on the Analysis of Potential Effects of Water Borne Traffic on the Control Room and Water Intakes at the Hope Creek Generating Station," March 1983.

Pursuant to the DSER License Condition contained in Section 4.4.4, PSE&G will evaluate the analytical results for thermal hydraulic stability for operations beyond Cycle 1 core and will submit the results for NRC review and approval if the calculated core stability margin is less than that for the existing core.

A signed original of the required affidavit is provided to document the submittal of these items.

Should you have any questions or require any additional information on these items, please contact us.

Very truly yours,

R L Mittl

Attachments/Enclosure

C D. H. Wagner
USNRC Licensing Project Manager (w/attach.)

W. H. Bateman
USNRC Senior Resident Inspector (w/attach.)

J. Spraul
USNRC Quality Assurance Branch

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
DOCKET NO. 50-354

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Public Service Electric and Gas Company hereby submits the enclosed responses to DSER open items and FSAR Questions, and revised FSAR Section 13.4, 17.2, and SRAI(1) for the Hope Creek Generating Station.

The matters set forth in this submittal are true to the best of my knowledge, information, and belief.

Respectfully submitted,

Public Service Electric
and Gas Company

By: Thomas J. Martin
Thomas J. Martin
Vice President -
Engineering and Construction

Sworn to and subscribed
before me, a Notary Public
of New Jersey, this 26th day
of September 1984.

David K. Burd

DAVID K. BURD
NOTARY PUBLIC OF NEW JERSEY
My Comm. Expires 10-23-85

MC 28 02

DATE: 9/26/84

ATTACHMENT 1

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
1	2.3.1	Design-basis temperatures for safety-related auxiliary systems	Complete	8/15/84
2a	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 1)
2b	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 1)
2c	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 2)
2d	2.3.3	Accuracies of meteorological measurements	Complete	8/15/84 (Rev. 2)
3a	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/15/84 (Rev. 2)
3b	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/15/84 (Rev. 2)
3c	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	NRC Action	
4	2.4.2.2	Ponding levels	Complete	8/03/84
5a	2.4.5	Wave impact and runup on service Water Intake Structure	Complete	9/13/84 (Rev. 3)
5b	2.4.5	Wave impact and runup on service water intake structure	Complete	9/13/84 (Rev. 3)
5c	2.4.5	Wave impact and runup on service water intake structure	Complete	7/27/84
5d	2.4.5	Wave impact and runup on service water intake structure	Complete	9/13/84 (Rev. 3)
6a	2.4.10	Stability of erosion protection structures	Complete	8/20/84
6b	2.4.10	Stability of erosion protection structures	Complete	8/20/84
6c	2.4.10	Stability of erosion protection structures	Complete	8/03/84

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ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
7a	2.4.11.2	Thermal aspects of ultimate heat sink	Complete	8/3/84
7b	2.4.11.2	Thermal aspects of ultimate heat sink	Complete	8/3/84
8	2.5.2.2	Choice of maximum earthquake for New England - Piedmont Tectonic Province	Complete	8/15/84
9	2.5.4	Soil damping values	Complete	6/1/84
10	2.5.4	Foundation level response spectra	Complete	6/1/84
11	2.5.4	Soil shear moduli variation	Complete	6/1/84
12	2.5.4	Combination of soil layer properties	Complete	6/1/84
13	2.5.4	Lab test shear moduli values	Complete	6/1/84
14	2.5.4	Liquefaction analysis of river bottom sands	Complete	6/1/84
15	2.5.4	Tabulations of shear moduli	Complete	6/1/84
16	2.5.4	Drying and wetting effect on Vincentown	Complete	6/1/84
17	2.5.4	Power block settlement monitoring	Complete	6/1/84
18	2.5.4	Maximum earth at rest pressure coefficient	Complete	6/1/84
19	2.5.4	Liquefaction analysis for service water piping	Complete	6/1/84
20	2.5.4	Explanation of observed power block settlement	Complete	6/1/84
21	2.5.4	Service water pipe settlement records	Complete	6/1/84
22	2.5.4	Cofferdam stability	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
23	2.5.4	Clarification of FSAR Tables 2.5.13 and 2.5.14	Complete	6/1/84
24	2.5.4	Soil depth models for intake structure	Complete	6/1/84
25	2.5.4	Intake structure soil modeling	Complete	8/10/84
26	2.5.4.4	Intake structure sliding stability	Complete	8/20/84
27	2.5.5	Slope stability	Complete	6/1/84
28a	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28b	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28c	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28d	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28e	3.4.1	Flood protection	Complete	8/30/84 (Rev. 1)
28f	3.4.1	Flood protection	Complete	7/27/84
28g	3.4.1	Flood protection	Complete	7/27/84
29	3.5.1.1	Internally generated missiles (outside containment)	Complete	8/3/84 (Rev. 1)
30	3.5.1.2	Internally generated missiles (inside containment)	Closed (5/30/84-Aux.Sys.Mtg.)	6/1/84
31	3.5.1.3	Turbine missiles	Complete	7/18/84
32	3.5.1.4	Missiles generated by natural phenomena	Complete	7/27/84
33	3.5.2	Structures, systems, and components to be protected from externally generated missiles	Complete	7/27/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
34	3.6.2	Unrestrained whipping pipe inside containment	Complete	7/18/84
35	3.6.2	ISI program for pipe welds in break exclusion zone	Complete	6/29/84
36	3.6.2	Postulated pipe ruptures	Complete	6/29/84
37	3.6.2	Feedwater isolation check valve operability	Complete	8/20/84
38	3.6.2	Design of pipe rupture restraints	Complete	8/20/84
39	3.7.2.3	SSI analysis results using finite element method and elastic half-space approach for containment structure	Complete	8/3/84
40	3.7.2.3	SSI analysis results using finite element method and elastic half-space approach for intake structure	Complete	8/3/84
41	3.8.2	Steel containment buckling analysis	Complete	6/1/84
42	3.8.2	Steel containment ultimate capacity analysis	Complete	8/20/84 (Rev. 1)
43	3.8.2	SRV/LOCA pool dynamic loads	Complete	6/1/84
44	3.8.3	ACI 349 deviations for internal structures	Complete	6/1/84
45	3.8.4	ACI 349 deviations for Category I structures	Complete	8/20/84 (Rev. 1)
46	3.8.5	ACI 349 deviations for foundations	Complete	8/20/84 (Rev. 1)
47	3.8.6	Base mat response spectra	Complete	8/10/84 (Rev. 1)
48	3.8.6	Rocking time histories	Complete	8/20/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
49	3.8.6	Gross concrete section	Complete	8/20/84 (Rev. 1)
50	3.8.6	Vertical floor flexibility response spectra	Complete	8/20/84 (Rev. 1)
51	3.8.6	Comparison of Bechtel independent verification results with the design-basis results	Complete	8/20/84 (Rev. 2)
52	3.8.6	Ductility ratios due to pipe break	Complete	8/3/84
53	3.8.6	Design of seismic Category I tanks	Complete	8/20/84 (Rev. 1)
54	3.8.6	Combination of vertical responses	Complete	8/10/84 (Rev. 1)
55	3.8.6	Torsional stiffness calculation	Complete	6/1/84
56	3.8.6	Drywell stick model development	Complete	8/20/84 (Rev. 1)
57	3.8.6	Rotational time history inputs	Complete	6/1/84
58	3.8.6	"O" reference point for auxiliary building model	Complete	6/1/84
59	3.8.6	Overturning moment of reactor building foundation mat	Complete	8/20/84 (Rev. 1)
60	3.8.6	BSAP element size limitations	Complete	8/20/84 (Rev. 1)
61	3.8.6	Seismic modeling of drywell shield wall	Complete	6/1/84
62	3.8.6	Drywell shield wall boundary conditions	Complete	6/1/84
63	3.8.6	Reactor building dome boundary conditions	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
64	3.8.6	SSI analysis 12 Hz cutoff frequency	Complete	8/20/84 (Rev. 1)
65	3.8.6	Intake structure crane heavy load drop	Complete	6/1/84
66	3.8.6	Impedance analysis for the intake structure	Complete	8/10/84 (Rev. 1)
67	3.8.6	Critical loads calculation for reactor building dome	Complete	6/1/84
68	3.8.6	Reactor building foundation mat contact pressures	Complete	6/1/84
69	3.8.6	Factors of safety against sliding and overturning of drywell shield wall	Complete	6/1/84
70	3.8.6	Seismic shear force distribution in cylinder wall	Complete	6/1/84
71	3.8.6	Overturning of cylinder wall	Complete	6/1/84
72	3.8.6	Deep beam design of fuel pool walls	Complete	6/1/84
73	3.8.6	ASHSD dome model load inputs	Complete	6/1/84
74	3.8.6	Tornado depressurization	Complete	6/1/84
75	3.8.6	Auxiliary building abnormal pressure	Complete	6/1/84
76	3.8.6	Tangential shear stresses in drywell shield wall and the cylinder wall	Complete	6/1/84
77	3.8.6	Factor of safety against overturning of intake structure	Complete	8/20/84 (Rev. 1)
78	3.8.6	Dead load calculations	Complete	6/1/84
79	3.8.6	Post-modification seismic loads for the torus	Complete	8/20/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
80	3.8.6	Torus fluid-structure interactions	Complete	6/1/84
81	3.8.6	Seismic displacement of torus	Complete	8/20/84 (Rev. 1)
82	3.8.6	Review of seismic Category I tank design	Complete	8/20/84 (Rev. 1)
83	3.8.6	Factors of safety for drywell buckling evaluation	Complete	6/1/84
84	3.8.6	Ultimate capacity of containment (materials)	Complete	8/20/84 (Rev. 1)
85	3.8.6	Load combination consistency	Complete	6/1/84
86	3.9.1	Computer code validation	Complete	8/20/84
87	3.9.1	Information on transients	Complete	8/20/84
88	3.9.1	Stress analysis and elastic-plastic analysis	Complete	6/29/84
89	3.9.2.1	Vibration levels for NSSS piping systems	Complete	6/29/84
90	3.9.2.1	Vibration monitoring program during testing	Complete	7/18/84
91	3.9.2.2	Piping supports and anchors	Complete	6/29/84
92	3.9.2.2	Triple flued-head containment penetrations	Complete	6/15/84
93	3.9.3.1	Load combinations and allowable stress limits	Complete	6/29/84
94	3.9.3.2	Design of SRVs and SRV discharge piping	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
95	3.9.3.2	Fatigue evaluation on SRV piping and LOCA downcomers	Complete	6/15/84
96	3.9.3.3	IE Information Notice 83-80	Complete	8/20/84 (Rev. 1)
97	3.9.3.3	Buckling criteria used for component supports	Complete	6/29/84
98	3.9.3.3	Design of bolts	Complete	6/15/84
99a	3.9.5	Stress categories and limits for core support structures	Complete	6/15/84
99b	3.9.5	Stress categories and limits for core support structures	Complete	6/15/84
100a	3.9.6	10CFR50.55a paragraph (g)	Complete	6/29/84
100b	3.9.6	10CFR50.55a paragraph (g)	Complete	9/12/84 (Rev. 1)
101	3.9.6	PSI and ISI programs for pumps and valves	Complete	9/12/84 (Rev. 1)
102	3.9.6	Leak testing of pressure isolation valves	Complete	9/12/84 (Rev. 1)
103a1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
103a5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103a7	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103b6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
103c4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Complete	8/20/84
104	3.11	Environmental qualification of mechanical and electrical equipment	NRC Action	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
105	4.2	Plant-specific mechanical fracturing analysis	Complete	8/20/84 (Rev. 1)
106	4.2	Applicability of seismic andd LOCA loading evaluation	Complete	8/20/84 (Rev. 1)
107	4.2	Minimal post-irradiation fuel surveillance program	Complete	6/29/84
108	4.2	Gadolina thermal conductivity equation	Complete	6/29/84
109a	4.4.7	TMI-2 Item II.F.2	Complete	8/20/84
109b	4.4.7	TMI-2 Item II.F.2	Complete	8/20/84
110a	4.6	Functional design of reactivity control systems	Complete	8/30/84 (Rev. 1)
110b	4.6	Functional design of reactivity control systems	Complete	8/30/84 (Rev. 1)
111a	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
111b	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
111c	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84
112a	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112b	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
112c	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112d	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
112e	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	8/30/84 (Rev. 1)
113	5.3.4	GE procedure applicability	Complete	7/18/84
114	5.3.4	Compliance with NB 2360 of the Summer 1972 Addenda to the 1971 ASME Code	Complete	7/18/84
115	5.3.4	Drop weight and Charpy v-notch tests for closure flange materials	Complete	9/5/84 (Rev. 1)
116	5.3.4	Charpy v-notch test data for base materials as used in shell course No. 1	Complete	7/18/84
117	5.3.4	Compliance with NB 2332 of Winter 1972 Addenda of the ASME Code	Complete	8/20/84
118	5.3.4	Lead factors and neutron fluence for surveillance capsules	Complete	8/20/84
119	6.2	TMI item II.E.4.1	Complete	6/29/84
120a	6.2	TMI Item II.E.4.2	Complete	8/20/84
120b	6.2	TMI Item II.E.4.2	Complete	8/20/84
121	6.2.1.3.3	Use of NUREG-0588	Complete	7/27/84
122	6.2.1.3.3	Temperature profile	Complete	7/27/84
123	6.2.1.4	Butterfly valve operation (post accident)	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
124a	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
124b	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
124c	6.2.1.5.1	RPV shield annulus analysis	Complete	8/20/84 (Rev. 1)
125	6.2.1.5.2	Design drywell head differential pressure	Complete	6/15/84
126a	6.2.1.6	Redundant position indicators for vacuum breakers (and control room alarms)	Complete	8/20/84
126b	6.2.1.6	Redundant position indicators for vacuum breakers (and control room alarms)	Complete	8/20/84
127	6.2.1.6	Operability testing of vacuum breakers	Complete	8/20/84 (Rev. 1)
128	6.2.2	Air ingestion	Complete	7/27/84
129	6.2.2	Insulation ingestion	Complete	6/1/84
130	6.2.3	Potential bypass leakage paths	Complete	9/13/84 (Rev. 1)
131	6.2.3	Administration of secondary containment openings	Complete	7/18/84
132	6.2.4	Containment isolation review	Complete	6/15/84
133a	6.2.4.1	Containment purge system	Complete	8/20/84
133b	6.2.4.1	Containment purge system	Complete	8/20/84
133c	6.2.4.1	Containment purge system	Complete	8/20/84

DATE: 9/26/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
134	6.2.6	Containment leakage testing	Complete	6/15/84
135	6.3.3	LPCS and LPCI injection valve interlocks	Complete	8/20/84
136	6.3.5	Plant-specific LOCA (see Section 15.9.13)	Complete	8/20/84 (Rev. 1)
137a	6.4	Control room habitability	Complete	8/20/84
137b	6.4	Control room habitability	Complete	8/20/84
137c	6.4	Control room habitability	Complete	8/20/84
138	6.6	Preservice inspection program for Class 2 and 3 components	Complete	6/29/84
139	6.7	MSIV leakage control system	Complete	6/29/84
140a	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140b	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140c	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
140d	9.1.2	Spent fuel pool storage	Complete	9/7/84 (Rev. 2)
141a	9.1.3	Spent fuel cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141b	9.1.3	Spent fuel cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141c	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)

DATE: 9/26/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
141d	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141e	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141f	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
141g	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/30/84 (Rev. 1)
142a	9.1.4	Light load handling system (related to refueling)	Complete	8/15/84 (Rev. 1)
142b	9.1.4	Light load handling system (related to refueling)	Complete	8/15/84 (Rev. 1)
143a	9.1.5	Overhead heavy load handling	Complete	9/7/84
143b	9.1.5	Overhead heavy load handling	Complete	9/13/84
144a	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
144b	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
144c	9.2.1	Station service water system	Complete	8/15/84 (Rev. 1)
145	9.2.2	ISI program and functional testing of safety and turbine auxiliaries cooling systems	Closed (5/30/84-Aux.Sys.Mtg.)	6/15/84
146	9.2.6	Switches and wiring associated with HPCI/RCIC torus suction	Closed (5/30/84-Aux.Sys.Mtg.)	6/15/84

DATE: 9/26/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
147a	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147b	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147c	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
147d	9.3.1	Compressed air systems	Complete	9/21/84 (Rev. 2)
148	9.3.2	Post-accident sampling system (II.B.3)	Complete	9/12/84 (Rev. 1)
149a	9.3.3	Equipment and floor drainage system	Complete	7/27/84
149b	9.3.3	Equipment and floor drainage system	Complete	7/27/84
150	9.3.6	Primary containment instrument gas system	Complete	8/3/84 (Rev. 1)
151a	9.4.1	Control structure ventilation system	Complete	8/30/84 (Rev. 1)
151b	9.4.1	Control structure ventilation system	Complete	8/30/84 (Rev. 1)
152	9.4.4	Radioactivity monitoring elements	Closed (5/30/84-Aux.Sys.Mtg.)	6/1/84
153	9.4.5	Engineered safety features ventilation system	Complete	8/30/84 (Rev 2)
154	9.5.1.4.a	Metal roof deck construction classificiation	Complete	6/1/84
155	9.5.1.4.b	Ongoing review of safe shutdown capability	NRC Action	
156	9.5.1.4.c	Ongoing review of alternate shutdown capability	NRC Action	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
157	9.5.1.4.e	Cable tray protection	Complete	8/20/84
158	9.5.1.5.a	Class B fire detection system	Complete	6/15/84
159	9.5.1.5.a	Primary and secondary power supplies for fire detection system	Complete	6/1/84
160	9.5.1.5.b	Fire water pump capacity	Complete	8/13/84
161	9.5.1.5.b	Fire water valve supervision	Complete	6/1/84
162	9.5.1.5.c	Deluge valves	Complete	6/1/84
163	9.5.1.5.c	Manual hose station pipe sizing	Complete	6/1/84
164	9.5.1.6.e	Remote shutdown panel ventilation	Complete	6/1/84
165	9.5.1.6.g	Emergency diesel generator day tank protection	Complete	6/1/84
166	12.3.4.2	Airborne radioactivity monitor positioning	Complete	9/13/84 (Rev. 2)
167	12.3.4.2	Portable continuous air monitors	Complete	7/18/84
168	12.5.2	Equipment, training, and procedures for inplant iodine instrumentation	Complete	6/29/84
169	12.5.3	Guidance of Division B Regulatory Guides	Complete	7/18/84
170	13.5.2	Procedures generation package submittal	Complete	6/29/84
171	13.5.2	TMI Item I.C.1	Complete	6/29/84
172	13.5.2	PGP Commitment	Complete	6/29/84
173	13.5.2	Procedures covering abnormal releases of radioactivity	Complete	6/29/84

DATE: 9/26/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
174	13.5.2	Resolution explanation in FSAR of TMI Items I.C.7 and I.C.8	Complete	6/15/84
175	13.6	Physical security	Open	
176a	14.2	Initial plant test program	Complete	8/13/84
176b	14.2	Initial plant test program	Complete	8/13/84
176c	14.2	Initial plant test program	Complete	7/27/84
176d	14.2	Initial plant test program	Complete	8/24/84 (Rev. 2)
176e	14.2	Initial plant test program	Complete	7/27/84
176f	14.2	Initial plant test program	Complete	8/13/84
176g	14.2	Initial plant test program	Complete	8/20/84
176h	14.2	Initial plant test program	Complete	8/13/84
176i	14.2	Initial plant test program	Complete	7/27/84
177	15.1.1	Partial feedwater heating	Complete	8/20/84 (Rev. 1)
178	15.6.5	LOCA resulting from spectrum of postulated piping breaks within RCP	NRC Action	
179	15.7.4	Radiological consequences of fuel handling accidents	NRC Action	
180	15.7.5	Spent fuel cask drop accidents	NRC Action	
181	15.9.5	TMI-2 Item II.K.3.3	Complete	6/29/84
182	15.9.10	TMI-2 Item II.K.3.18	Complete	6/1/84
183	18	Hope Creek DCRDR	Complete	8/15/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
184	7.2.2.1.e	Failures in reactor vessel level sensing lines	Complete	8/1/84 (Rev 1)
185	7.2.2.2	Trip system sensors and cabling in turbine building	Complete	6/1/84
186	7.2.2.3	Testability of plant protection systems at power	Complete	8/13/84 (Rev. 1)
187	7.2.2.4	Lifting of leads to perform surveillance testing	Complete	8/3/84
188	7.2.2.5	Setpoint methodology	Complete	8/1/84
189	7.2.2.6	Isolation devices	Complete	8/1/84
190	7.2.2.7	Regulatory Guide 1.75	Complete	6/1/84
191	7.2.2.8	Scram discharge volume	Complete	6/29/84
192	7.2.2.9	Reactor mode switch	Complete	8/15/84 (Rev. 1)
193	7.3.2.1.10	Manual initiation of safety systems	Complete	8/1/84
194	7.3.2.2	Standard review plan deviations	Complete	8/1/84 (Rev 1)
195a	7.3.2.3	Freeze-protection/water filled instrument and sampling lines and cabinet temperature control	Complete	8/1/84
195b	7.3.2.3	Freeze-protection/water filled instrument and sampling lines and cabinet temperature control	Complete	8/1/84
196	7.3.2.4	Sharing of common instrument taps	Complete	8/1/84
197	7.3.2.5	Microprocessor, multiplexer and computer systems	Complete	8/1/84 (Rev 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
198	7.3.2.6	TMI Item II.K.3.18-ADS actuation	Complete	8/20/84
199	7.4.2.1	IE Bulletin 79-27-Loss of non-class IE instrumentation and control power system bus during operation	Complete	8/24/84 (Rev. 1)
200	7.4.2.2	Remote shutdown system	Complete	8/15/84 (Rev 1)
201	7.4.2.3	RCIC/HPCI interactions	Complete	8/3/84
202	7.5.2.1	Level measurement errors as a result of environmental temperature effects on level instrumentation reference leg	Complete	8/3/84
203	7.5.2.2	Regulatory Guide 1.97	Complete	8/3/84
204	7.5.2.3	TMI Item II.F.1 - Accident monitoring	Complete	8/1/84
205	7.5.2.4	Plant process computer system	Complete	6/1/84
206	7.6.2.1	High pressure/low pressure interlocks	Complete	7/27/84
207	7.7.2.1	HELBs and consequential control system failures	Complete	8/24/84 (Rev. 1)
208	7.7.2.2	Multiple control system failures	Complete	8/24/84 (Rev. 1)
209	7.7.2.3	Credit for non-safety related systems in Chapter 15 of the FSAR	Complete	8/1/84 (Rev 1)
210	7.7.2.4	Transient analysis recording system	Complete	7/27/84
211a	4.5.1	Control rod drive structural materials	Complete	7/27/84
211b	4.5.1	Control rod drive structural materials	Complete	7/27/84
211c	4.5.1	Control rod drive structural materials	Complete	7/27/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
211d	4.5.1	Control rod drive structural materials	Complete	7/27/84
211e	4.5.1	Control rod drive structural materials	Complete	7/27/84
212	4.5.2	Reactor internals materials	Complete	7/27/84
213	5.2.3	Reactor coolant pressure boundary material	Complete	7/27/84
214	6.1.1	Engineered safety features materials	Complete	7/27/84
215	10.3.6	Main steam and feedwater system materials	Complete	7/27/84
216a	5.3.1	Reactor vessel materials	Complete	7/27/84
216b	5.3.1	Reactor vessel materials	Complete	7/27/84
217	9.5.1.1	Fire protection organization	Complete	8/15/84
218	9.5.1.1	Fire hazards analysis	Complete	6/1/84
219	9.5.1.2	Fire protection administrative controls	Complete	8/15/84
220	9.5.1.3	Fire brigade and fire brigade training	Complete	8/15/84
221	8.2.2.1	Physical separation of offsite transmission lines	Complete	8/1/84
222	8.2.2.2	Design provisions for re-establishment of an offsite power source	Complete	9/14/84 (Rev. 1)
223	8.2.2.3	Independence of offsite circuits between the switchyard and class IE buses	Complete	9/26/84 (Rev. 3)
224	8.2.2.4	Common failure mode between onsite and offsite power circuits	Complete	9/26/84 (Rev. 2)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
225	8.2.3.1	Testability of automatic transfer of power from the normal to preferred power source	Complete	9/21/84 (Rev. 1)
226	8.2.2.5	Grid stability	Complete	8/13/84 (Rev. 1)
227	8.2.2.6	Capacity and capability of offsite circuits	Complete	8/1/84
228	8.3.1.1(1)	Voltage drop during transient conditions	Complete	8/1/84
229	8.3.1.1(2)	Basis for using bus voltage versus actual connected load voltage in the voltage drop analysis	Complete	8/1/84
230	8.3.1.1(3)	Clarification of Table 8.3-11	Complete	8/1/84
231	8.3.1.1(4)	Undervoltage trip setpoints	Complete	8/1/84
232	8.3.1.1(5)	Load configuration used for the voltage drop analysis	Complete	8/1/84
233	8.3.3.4.1	Periodic system testing	Complete	9/21/84 (Rev. 2)
234	8.3.1.3	Capacity and capability of onsite AC power supplies and use of administrative controls to prevent overloading of the diesel generators	Complete	8/1/84
235	8.3.1.5	Diesel generators load acceptance test	Complete	9/21/84 (Rev. 2)
236	8.3.1.6	Compliance with position C.6 of RG 1.9	Complete	8/1/84
237	8.3.1.7	Decription of the load sequencer	Complete	9/21/84 (Rev. 1)
238	8.2.2.7	Sequencing of loads on the offsite power system	Complete	9/21/84 (Rev. 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
239	8.3.1.8	Testing to verify 80% minimum voltage	Complete	8/15/84
240	8.3.1.9	Compliance with BTP-PSB-2	Complete	8/1/84
241	8.3.1.10	Load acceptance test after prolonged no load operation of the diesel generator	Complete	9/21/84 (Rev. 3)
242	8.3.2.1	Compliance with position 1 of Regulatory Guide 1.128	Complete	9/13/84 (Rev. 1)
243	8.3.3.1.3	Protection or qualification of Class 1E equipment from the effects of fire suppression systems	Complete	9/13/84 (Rev. 1)
244	8.3.3.3.1	Analysis and test to demonstrate adequacy of less than specified separation	Complete	9/26/84 (Rev. 3)
245	8.3.3.3.2	The use of 18 versus 36 inches of separation between raceways	Complete	9/26/84 (Rev. 3)
246	8.3.3.3.3	Specified separation of raceways by analysis and test	Complete	8/1/84
247	8.3.3.5.1	Capability of penetrations to withstand long duration short circuits at less than maximum or worst case short circuit	Complete	9/13/84 (Rev. 1)
248	8.3.3.5.2	Separation of penetration primary and backup protections	Complete	8/1/84
249	8.3.3.5.3	The use of bypassed thermal overload protective devices for penetration protections	Complete	8/1/84
250	8.3.3.5.4	Testing of fuses in accordance with R.G. 1.63	Complete	8/1/84

DATE: 9/26/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
251	8.3.3.5.5	Fault current analysis for all representative penetration circuits	Complete	9/24/84 (Rev. 3)
252	8.3.3.5.6	The use of a single breaker to provide penetration protection	Complete	9/21/84 (Rev. 2)
253	8.3.3.1.4	Commitment to protect all Class 1E equipment from external hazards versus only class 1E equipment in one division	Complete	9/24/84 (Rev. 2A)
254	8.3.3.1.5	Protection of class 1E power supplies from failure of unqualified class 1E loads	Complete	9/14/84 (Rev. 1)
255	8.3.2.2	Battery capacity	Complete	8/1/84
256	8.3.2.3	Automatic trip of loads to maintain sufficient battery capacity	Complete	9/13/84 (Rev. 1)
257	8.3.2.5	Justification for a 0 to 13 second load cycle	Complete	9/13/83 (Rev. 1)
258	8.3.2.6	Design and qualification of DC system loads to operate between minimum and maximum voltage levels	Complete	8/1/84
259	8.3.3.3.4	Use of an inverter as an isolation device	Complete	9/26/84 (Rev. 2)
260	8.3.3.3.5	Use of a single breaker tripped by a LOCA signal used as an isolation device	Complete	9/13/84 (Rev. 1)
261	8.3.3.3.6	Automatic transfer of loads and interconnection between redundant divisions	Complete	9/13/84 (Rev. 1)
262	11.4.2.d	Solid waste control program	Complete	8/20/84

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ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
263	11.4.2.e	Fire protection for solid radwaste storage area	Complete	8/13/84
264	6.2.5	Sources of oxygen	Complete	8/20/84
265	6.8.1.4	ESF Filter Testing	Complete	8/13/84
266	6.8.1.4	Field leak tests	Complete	8/13/84
267	6.4.1	Control room toxic chemical detectors	Complete	8/13/84
268		Air filtration unit drains	Complete	9/13/84 (Rev. 1)
269	5.2.2	Code cases N-242 and N-242-1	Complete	8/20/84
270	5.2.2	Code case N-252	Complete	8/20/84
TS-1	2.4.14	Closure of watertight doors to safety-related structures	Open	
TS-2	4.4.4	Single recirculation loop operation	Open	
TS-3	4.4.5	Core flow monitoring for crud effects	Complete	6/1/84
TS-4	4.4.6	Loose parts monitoring system	Open	
TS-5	4.4.9	Natural circulation in normal operation	Open	
TS-6	6.2.3	Secondary containment negative pressure	Open	
TS-7	6.2.3	Inleakage and drawdown time in secondary containment	Open	
TS-8	6.2.4.1	Leakage integrity testing	Open	
TS-9	6.3.4.2	ECCS subsystem periodic component testing	Open	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
TS-10	6.7	MSIV leakage rate		
TS-11	15.2.2	Availability, setpoints, and testing of turbine bypass system	Open	
TS-12	15.6.4	Primary coolant activity		
LC-1	4.2	Fuel rod internal pressure criteria	Complete	6/1/84
LC-2	4.4.4	Stability analysis submitted before second-cycle operation	Open	

M P84 80/12 25- gs

ATTACHMENT 2 DATE: 9/26/84

DRAFT SER SECTIONS AND DATES PROVIDED

SECTION	DATE	SECTION	DATE
3.1			
3.2.1		11.4.1	See Notes 1&5
3.2.2		11.4.2	See Notes 1&5
5.1		11.5.1	See Notes 1&5
5.2.1		11.5.2	See Notes 1&5
6.5.1	See Notes 1&5	13.1.1	See Note 4
8.1	See Note 2	13.1.2	See Note 4
8.2.1	See Note 2	13.2.1	See Note 4
8.2.2	See Note 2	13.2.2	See Note 4
8.2.3	See Note 2	13.3.1	See Note 4
8.2.4	See Note 2	13.3.2	See Note 4
8.3.1	See Note 2	13.3.3	See Note 4
8.3.2	See Note 2	13.3.4	See Note 4
8.4.1	See Note 2	13.4	See Note 4
8.4.2	See Note 2	13.5.1	See Note 4
8.4.3	See Note 2	15.2.3	
8.4.5	See Note 2	15.2.4	
8.4.6	See Note 2	15.2.5	
8.4.7	See Note 2	15.2.6	
8.4.8	See Note 2	15.2.7	
9.5.2	See Note 3	15.2.8	
9.5.3	See Note 3	15.7.3	See Notes 1&5
9.5.7	See Note 3	17.1	8/3/84
9.5.8	See Note 3	17.2	8/3/84
10.1	See Note 3	17.3	8/3/84
10.2	See Note 3	17.4	8/3/84
10.2.3	See Note 3		
10.3.2	See Note 3		
10.4.1	See Note 3		
10.4.2	See Notes 3&5		
10.4.3	See Notes 3&5		
10.4.4	See Note 3		
11.1.1	See Notes 1&5		
11.1.2	See Notes 1&5		
11.2.1	See Notes 1&5		
11.2.2	See Notes 1&5		
11.3.1	See Notes 1&5		
11.3.2	See Notes 1&5		

Notes:

1. Open items provided in letter dated July 24, 1984 (Schwencer to Mittl)

2. Open items provided in June 6, 1984 meeting

3. Open items provided in April 17-18, 1984 meeting

4. Open items provided in May 2, 1984 meting

5. Draft SER Section provided in letter dated August 7, 1984 (Schwencer to Mittl)

CT:db

Date: 9/26/84

Attachment 3

DSER ITEM	DSER SECTION	SUBJECT
223	8.2.2.3	Independence of offsite circuits between the switchyard and Class 1E buses
224	8.2.2.4	Common failure mode between onsite and offsite power circuits
244	8.3.3.3.1	Analysis and test to demonstrate adequacy of less than specified separation
245	8.3.3.3.2	The use of 18 versus 36 inches of separation between raceways
259	8.3.3.3.4	Use of an inverter as an isolation device

ATTACHMENT 4

Rev. 3

DSER Open Item No. 223 (DSER Section 8.2.2.3)

INDEPENDENCE OF OFFSITE CIRCUITS BETWEEN THE SWITCHYARD AND THE CLASS 1E BUSSES

The Hope Creek design provides two immediate access offsite circuits between the switchyard and the 4.16 kV Class 1E busses. It is the staff position that these two circuits be physically separate and independent such that no single event can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from beng exceeded. The physical separation and independence of these two circuits from and including station service transformers 1AX501 and 1BX501 to the 4.16 kV Class 1E busses has not been described or analyzed in the FSAR.

By Amendment 4 to the FSAR, the applicant implied, in response to a request for information, that the offsite circuits are non-Class 1E and thus do not have to be physically separated in accordance with the requirements of Criterion 17 of Appendix A of 10CFR50. The staff finds this interpretation to be unacceptable.

RESPONSE

FSAR Section 8.2.2.2 has been added to provide a discussion of the physical separation and independence of the two offsite power circuits from the station service transformers to the 4.16 kV Class 1E buses.

QUESTION 430.4 (Section 8.2)

The Hope Creek design provides two immediate access offsite circuits between the switchyard and the 4.16 kV Class 1E buses. It is the staff position that these two circuits be physically separate and independent such that no single event can simultaneously affect both circuits in such a way that neither can be returned to service in time to prevent fuel design limits or design conditions of the reactor coolant pressure boundary from being exceeded. The physical separation and independence of transformers 1AX501 and 1BX501 to the 4.16 kV Class 1E buses has not been described or analyzed in the FSAR. Provide the description and analysis and justify areas of noncompliance with the above staff position. The analysis should include separation and independence of control and protective relaying circuits as well as the power circuits.

RESPONSE

FSAR Section 8.2.2.2 has been added to provide the required information.

8.2.2.2 SEPARATION OF OFFSITE POWER SUPPLIES WITHIN THE PLANT

The circuits for the offsite power supply located within the plant are designed to comply with the requirements of GDC 17. Refer to FSAR Section 8.3.1.2.1 for a detailed description.

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groups remain intact to provide for 1. and 2. above.

→ INSERT A

Each 4.16-kV Class 1E bus has access to the two physically independent offsite power sources. Upon LOP, the Class 1E system is automatically isolated from the offsite power system and the onsite non-Class 1E distribution system. The isolation of the offsite and Class 1E onsite power systems is accomplished by tripping of the incoming offsite source breakers to the 4.16-kV Class 1E buses. This tripping is accomplished through the undervoltage relays connected on the source side of these breakers. The tripping of these incoming offsite source breakers to the 4.16-kV Class 1E buses also isolates one power supply channel from redundant power supply channels. The combination of these factors considered in the design of the electric power system minimizes the probability of losing electric power from the onsite power supplies as a result of the loss of power from the offsite sources or any disturbances of the non-Class 1E ac system.

The voltage analysis performed in accordance with Branch Technical Position PSB-1, Item 3, indicates that the onsite distribution system voltages are adequate to support Class 1E loads within the equipment ratings during LOCA and plant shutdown with the offsite system voltages at anticipated minimum or maximum voltage and with only the offsite source being considered available. The analysis also confirmed that the setting of the undervoltage relays on the source side of the incoming offsite source breakers on the Class 1E 4.16-kV buses will protect Class 1E loads from degraded voltages resulting from sustained low offsite system voltage condition.

The voltage analysis is based on the simplified single line diagram shown on Figure 8.3-15 which represents one half of station distribution buses and one of the two offsite sources. Because of similarity in the redundant Class 1E buses and similarity of non-Class 1E buses, the voltage analysis conducted is applicable to all of the station distribution buses. This single line

Insert A

Figure 8.3-5 shows that each of the four 4.16 kV Class 1E switchgear buses is supplied from two offsite (preferred) power sources and one onsite standby diesel generator (SDG). The offsite power to these buses is supplied from station service transformers 1AX501 and 1BX501 by non-segregated phase buses that are enclosed in metallic ducts. The non-segregated phase buses from the station service transformers to the 4.16 kV Class 1E switchgear are designated as non-Class 1E.

Figure 8.3-16 shows the routing of these non-segregated phase bus ducts from station service transformers 1AX501 and 1BX501 to 4.16 kV switchgear.

Station service transformers 1AX501 and 1BX501 are provided with individual water spray systems and are separated from each other by a 1-hour fire barrier. Each transformer has a collection dike and drainage outlet for collecting transformer oil spills and fire suppression system water and draining it to the oily waste drainage system. The drainage outlet for each transformer is designed to drain the entire volume of oil from the transformer plus the maximum flow of water from the automatic water spray system.

The non-segregated phase buses are run outside the turbine building wall up to the point where they enter the building. An extension of the station service transformers' water spray sprinkler system provides additional protection in the area of the common bus support and the limited area of crossover of the two non-segregated buses.

The non-segregated bus ducts are designed and constructed for adverse outdoor weather conditions (rain, ice, etc). The bus ducts are designed per ANSI Standard C37.20-1969/C37.20C-1974, Section 8.2.2.4, Watertight Tests, and, therefore, water from the sprinkler system of one transformer will not endanger the operation of the non-segregated bus of the other transformer.

These design features ensure that a station service transformer fire can not damage the bus duct from the other transformer and cause a loss of both offsite sources of power.

Within the turbine building the offsite buses are routed through common areas. Separate supports are provided for the non-segregated phase buses in non-seismic plant areas. In Seismic Class I plant areas Seismic Class I supports are provided for the non-segregrated phase buses. The buses are physically separated from each other and their steel duct enclosures minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident environmental conditions.

The onsite power feeds to the 4.16 kV Class 1E switchgear are routed in rigid steel conduit from the standby diesel generator rooms. Each train of onsite Class 1E power is compartmentalized such that the four trains are separated from each other by two-hour fire rated concrete walls and each diesel is separated from its associated offsite power bus by a three-hour fire rated wall.

The circuit breakers that connect a 4.16 kV Class 1E switchgear bus to the two offsite power supplies and its associated onsite standby power supply are Class 1E and are qualified to the HCGS seismic and environmental parameters for any design basis event. These breakers are electrically interlocked to prevent the automatic paralleling of the onsite and offsite power supplies.

The only control interface between the onsite Class 1E and offsite power systems is the station service transformer differential relay current transformer (CT) leads in the Class 1E switchgear. The CT leads are classified as non-Class 1E and are enclosed in armored cable or conduit to comply with Regulatory Guide 1.75.

Each of the four SDGs are located in separate rooms of a Seismic Class 1 structure. The SDGs and the associated control panels are qualified for HCGS seismic and environmental parameters for all design basis events. The control panels, power, and control cables for all the four SDGs are separated to comply with Regulatory Guide 1.75 requirements.

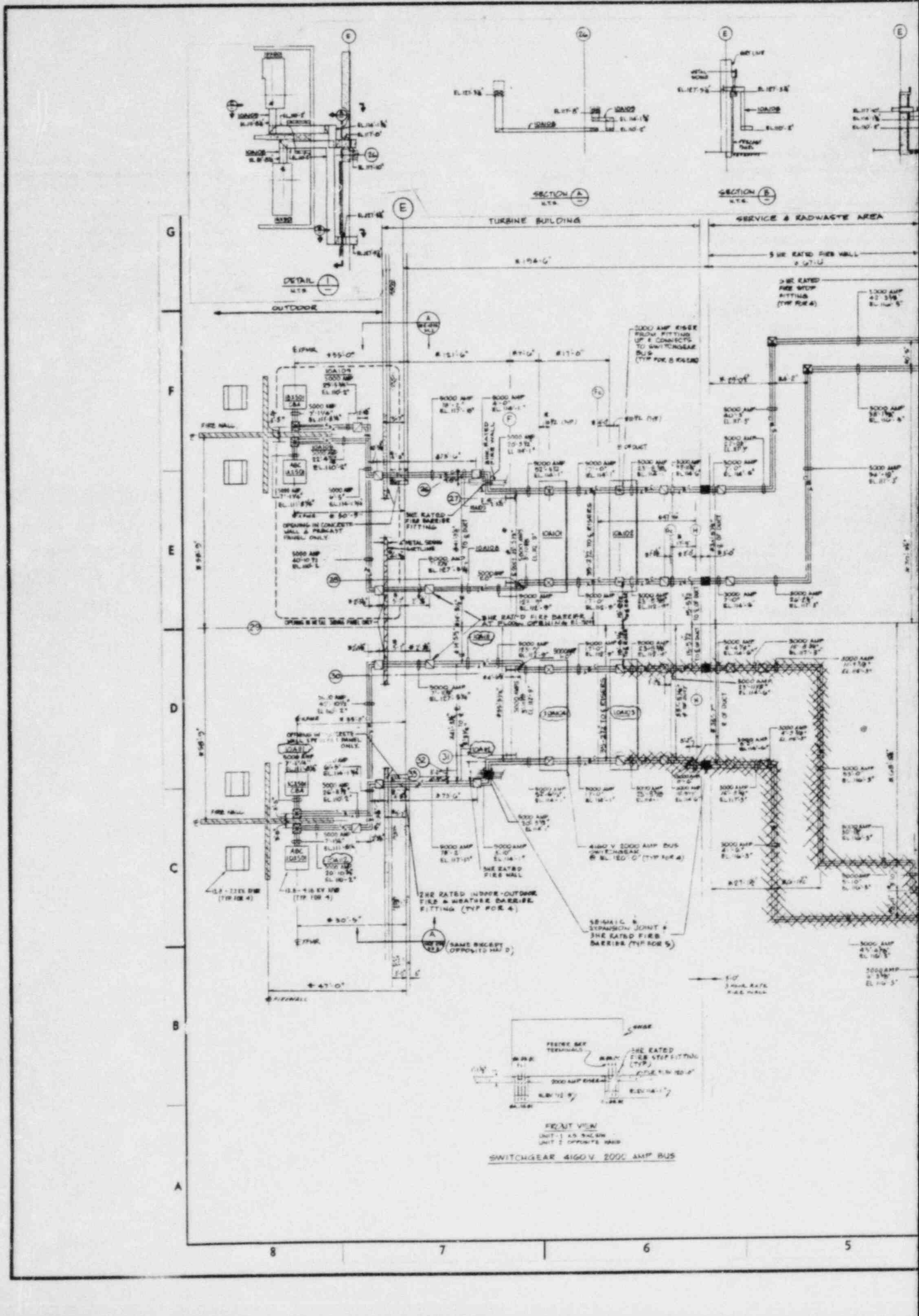
Each of the four Class 1E 4.16 kV switchgear buses has its own independent protective relaying schemes. The failure of a protective relay in the 13.8 kV and/or 500 kV systems does not impact any of the four onsite power sources.

The control power supplies for both the offsite and onsite Class 1E infeed breakers are from a 125V dc distribution panel of the same Class 1E channel. Cables of the same Class 1E channel are routed in common raceways but these raceways are separated from their redundant counterpart by two-hour fire rated concrete walls from the switchgear room to the cable spreading room. Within the cable spreading room the redundant Class 1E control raceways are provided with Regulatory Guide 1.75 separation as well as automatic fire suppression systems. Figures 9.5-1 to 9.5-5 show these features.

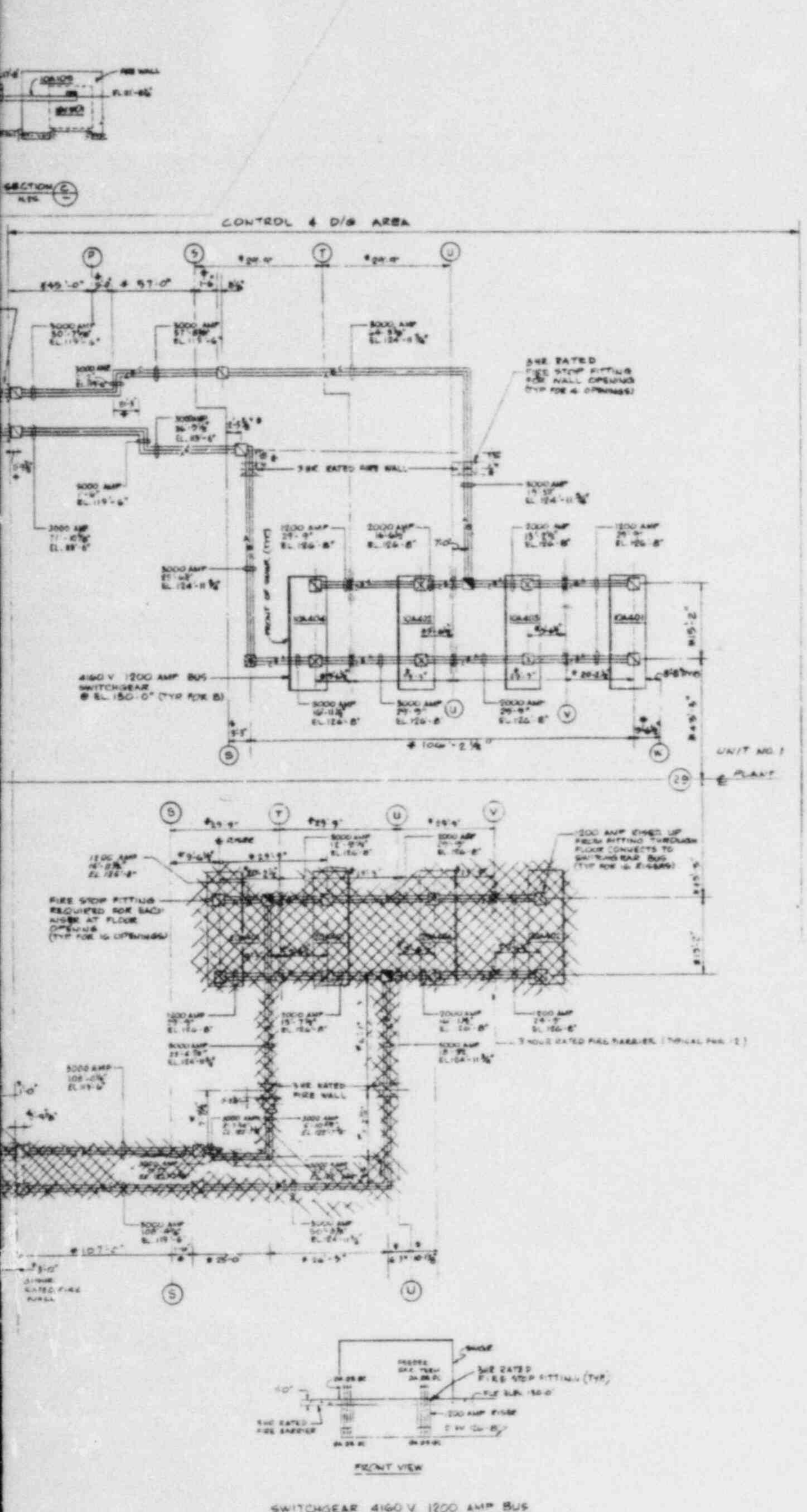
Common control room panels, where both onsite and offsite control cables terminate, have separation or barriers provided, in accordance with Regulatory Guide 1.75, to eliminate common mode failures between onsite and offsite breaker control.

Protection against common mode fire induced failure of the onsite power trains is addressed as part of the Hope Creek fire protection analysis in Section 9.5.1, and Appendix 9A.

These design features minimize the probability of losing electric power from any of the required Class 1E electrical power systems as a result of, or coincident with, loss of the power generated by the main generator, loss of the power from the offsite transmission network, or loss of the power from the onsite electric power supplies, as required by GDC 17.



TURBINE BUILDING
SERVICE & RADWASTE AREA
OUTDOOR
SECTION A
SECTION B
DETAIL 1
FIRE WALL
3HR RATED INDOOR-OUTDOOR FIRE & WEATHER BARRIER FITTING (TYP FOR 4)
SEISMIC & EXPANSION JOINT & 3HR RATED FIRE BARRIER (TYP FOR 5)
4160 V 2000 AMP BUS SWITCHGEAR
FRONT VIEW
SWITCHGEAR 4160V 2000 AMP BUS
G
F
E
D
C
B
A
8
7
6
5



NOTES

1. ALL DIMENSIONS ARE TO CENTER LINE OF BUS DUCT OR FITTING.
2. ALL ELEVATIONS ARE TO BOTTOM OF BUS DUCT.

SYMBOLS

- SQUARE ELBOW FITTING.
- ELBOW FITTING RISER
- SQUARE FITTING
- EXPANSION FITTING
- VERTICAL 90° FITTING
- TEE FITTING RISER
- BUS PHASE SEQUENCE TRANSITION FITTING
- 4.16 KV BUS DUCT SHOWING PHASE SEQUENCE ARRANGEMENT (ØA, ØB, ØC)
- FIRE WALL
- * REFERENCE DIMENSION

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HOPE CREEK
GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

4.16 KV, 3Ø, 60 Hz
NON-SEGRAGATED BUS DUCT

FIGURE 8.3-16 AMENDMENT 8, 10/84

8410010290-01

Rev. 2

DSER Open Item No. 224 (DSER Section 8.2.2.4)

COMMON FAILURE MODE BETWEEN ONSITE AND OFFSITE POWER CIRCUITS

Each of the 4.16 kv Class 1E busses at Hope Creek is supplied power from preferred offsite and standby onsite circuits. It is the staff position that these circuits should not have common failure modes. Physical separation and independence of these circuits has not been described or analyzed in the FSAR. By Amend. 4 to the FSAR, the applicant, in response to a request for information, indicated that a single event can not cause common failure of both onsite and offsite power source circuits because they are separated in accordance with the requirements of Regulatory Guide 1.75. The staff disagrees. Separation in accordance with Regulatory Guide 1.75 by itself is not sufficient for the staff to conclude that there are no common failure modes or to conclude that the probability of coincident loss of both onsite and offsite power sources has been minimized in accordance with the requirements of Criterion 17 of Appendix A to 10 CFR 50.

RESPONSE

FSAR Section 8.3.1.2.1 has been revised to include the results of an analysis to show compliance of the onsite and offsite power systems to GDC 17. FSAR Figure 8.3-16 is attached to DSER Open Item 223.

QUESTION 430.5 (SECTION 8.2)

Each of the 4.16 kV Class 1E busses at Hope Creek is supplied power from preferred offsite and standby onsite circuits. It is the staff position that these circuits should not have common failure modes. Physical separation and independence of these circuits has not been described or analyzed in the FSAR. Provide a description and analysis in accordance with Section 5.2.1(5) of IEEE Standard 308-1974.

RESPONSE

FSAR Section 8.3.1.2.1 has been revised to provide the requested information.

groups remain intact to provide for 1. and 2. above.

→ INSERT A

Each 4.16-kV Class 1E bus has access to the two physically independent offsite power sources. Upon LOP, the Class 1E system is automatically isolated from the offsite power system and the onsite non-Class 1E distribution system. The isolation of the offsite and Class 1E onsite power systems is accomplished by tripping of the incoming offsite source breakers to the 4.16-kV Class 1E buses. This tripping is accomplished through the undervoltage relays connected on the source side of these breakers. The tripping of these incoming offsite source breakers to the 4.16-kV Class 1E buses also isolates one power supply channel from redundant power supply channels. The combination of these factors considered in the design of the electric power system minimizes the probability of losing electric power from the onsite power supplies as a result of the loss of power from the offsite sources or any disturbances of the non-Class 1E ac system.

The voltage analysis performed in accordance with Branch Technical Position PSB-1, Item 3, indicates that the onsite distribution system voltages are adequate to support Class 1E loads within the equipment ratings during LOCA and plant shutdown with the offsite system voltages at anticipated minimum or maximum voltage and with only the offsite source being considered available. The analysis also confirmed that the setting of the undervoltage relays on the source side of the incoming offsite source breakers on the Class 1E 4.16-kV buses will protect Class 1E loads from degraded voltages resulting from sustained low offsite system voltage condition.

The voltage analysis is based on the simplified single line diagram shown on Figure 8.3-15 which represents one half of station distribution buses and one of the two offsite sources. Because of similarity in the redundant Class 1E buses and similarity of non-Class 1E buses, the voltage analysis conducted is applicable to all of the station distribution buses. This single line

Insert A

Figure 8.3-5 shows that each of the four 4.16 kV Class 1E switchgear buses is supplied from two offsite (preferred) power sources and one onsite standby diesel generator (SDG). The offsite power to these buses is supplied from station service transformers 1AX501 and 1BX501 by non-segregated phase buses that are enclosed in metallic ducts. The non-segregated phase buses from the station service transformers to the 4.16 kV Class 1E switchgear are designated as non-Class 1E.

Figure 8.3-16 shows the routing of these non-segregated phase bus ducts from station service transformers 1AX501 and 1BX501 to 4.16 kV switchgear.

Station service transformers 1AX501 and 1BX501 are provided with individual water spray systems and are separated from each other by a 1-hour fire barrier. Each transformer has a collection dike and drainage outlet for collecting transformer oil spills and fire suppression system water and draining it to the oily waste drainage system. The drainage outlet for each transformer is designed to drain the entire volume of oil from the transformer plus the maximum flow of water from the automatic water spray system.

The non-segregated phase buses are run outside the turbine building wall up to the point where they enter the building. An extension of the station service transformers' water spray sprinkler system provides additional protection in the area of the common bus support and the limited area of crossover of the two non-segregated buses.

The non-segregated bus ducts are designed and constructed for adverse outdoor weather conditions (rain, ice, etc). The bus ducts are designed per ANSI Standard C37.20-1969/C37.20C-1974, Section 8.2.2.4, Watertight Tests, and, therefore, water from the sprinkler system of one transformer will not endanger the operation of the non-segregated bus of the other transformer.

These design features ensure that a station service transformer fire can not damage the bus duct from the other transformer and cause a loss of both offsite sources of power.

Within the turbine building the offsite buses are routed through common areas. Separate supports are provided for the non-segregated phase buses in non-seismic plant areas. In Seismic Class I plant areas Seismic Class I supports are provided for the non-segregrated phase buses. The buses are physically separated from each other and their steel duct enclosures minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident environmental conditions.

The onsite power feeds to the 4.16 kV Class 1E switchgear are routed in rigid steel conduit from the standby diesel generator rooms. Each train of onsite Class 1E power is compartmentalized such that the four trains are separated from each other by two-hour fire rated concrete walls and each diesel is separated from its associated offsite power bus by a three-hour fire rated wall.

The circuit breakers that connect a 4.16 kV Class 1E switchgear bus to the two offsite power supplies and its associated onsite standby power supply are Class 1E and are qualified to the HCGS seismic and environmental parameters for any design basis event. These breakers are electrically interlocked to prevent the automatic paralleling of the onsite and offsite power supplies.

The only control interface between the onsite Class 1E and offsite power systems is the station service transformer differential relay current transformer (CT) leads in the Class 1E switchgear. The CT leads are classified as non-Class 1E and are enclosed in armored cable or conduit to comply with Regulatory Guide 1.75.

Each of the four SDGs are located in separate rooms of a Seismic Class 1 structure. The SDGs and the associated control panels are qualified for HCGS seismic and environmental parameters for all design basis events. The control panels, power, and control cables for all the four SDGs are separated to comply with Regulatory Guide 1.75 requirements.

Each of the four Class 1E 4.16 kV switchgear buses has its own independent protective relaying schemes. The failure of a protective relay in the 13.8 kV and/or 500 kV systems does not impact any of the four onsite power sources.

The control power supplies for both the offsite and onsite Class 1E infeed breakers are from a 125V dc distribution panel of the same Class 1E channel. Cables of the same Class 1E channel are routed in common raceways but these raceways are separated from their redundant counterpart by two-hour fire rated concrete walls from the switchgear room to the cable spreading room. Within the cable spreading room the redundant Class 1E control raceways are provided with Regulatory Guide 1.75 separation as well as automatic fire suppression systems. Figures 9.5-1 to 9.5-5 show these features.

Common control room panels, where both onsite and offsite control cables terminate, have separation or barriers provided, in accordance with Regulatory Guide 1.75, to eliminate common mode failures between onsite and offsite breaker control.

Protection against common mode fire induced failure of the onsite power trains is addressed as part of the Hope Creek fire protection analysis in Section 9.5.1, and Appendix 9A.

These design features minimize the probability of losing electric power from any of the required Class 1E electrical power systems as a result of, or coincident with, loss of the power generated by the main generator, loss of the power from the offsite transmission network, or loss of the power from the onsite electric power supplies, as required by GDC 17.

Rev. 2A #25

DSER Open Item No. 244 (DSER Section 8.3.3.3.1)

ANALYSIS AND TEST TO DEMONSTRATE ADEQUACY OF LESS THAN SPECIFIED SEPARATION

The applicant, by Amendment 4 to the FSAR, provided a description of physical separation between redundant enclosed raceways (covered trays and open top raceways, and between non-Class 1E trays and Class 1E conduit, as follows:

1. In the cable spreading rooms, the main control room, relay room, and control equipment room, the separation is twelve inches (12") horizontal, and eighteen inches (18") vertical.

2. In all other plant areas, the separation is three feet horizontal and five feet vertical.

The applicant further stated that where the separation distances specified above can not be maintained, cable trays shall either be covered with metal tray covers or an analysis, based on test results, will be performed.

The staff concludes that the above separation meets the guidelines of Regulatory Guide 1.75 and is acceptable except for the following:

(1) The use of 18 versus 36 inches of separation between raceways is evaluated in Section 8.3.3.3.2 of this report, and

(2) The use of an analysis to justify less than specified separation will be pursued with the applicant.

RESPONSE

The response to Question 430.52 has been revised to provide the requested analysis. One copy of each of the following reports were attached for your use: on August 30, 1984

1) Wyle Laboraties, Test Report No. 5-6719, Dated November 20, 1980, prepared for Susquehanna Steam Electric Station for electrical wire and cable isolation barrier ~~test~~ materials test.

2) Franklin Institute Research Laboratories, ~~[illegible]~~ Dated March 30, 1977, prepared for Toledo Edison Company for Conduit Separation test Program.

DSER 244
Rev. 2A
Item 25

QUESTION 430.52 (SECTION 8.3.1 and 8.3.2)

Provide a description of separation between redundant enclosed raceways or conduit and open top raceways and between Non Class 1E trays and Class 1E conduit.

RESPONSE

Refer to Section 8.1.4.14 and revised Section 1.8.1.75 for a description of HCGS separation provisions and a discussion of HCGS compliance to Regulatory Guide 1.75.

1.8.1.74 Conformance to Regulatory Guide 1.74, Revision 0, February 1974: Quality Assurance Terms and Definitions

HCGS complies with ANSI N45.2.10-1973, as interpreted in Regulatory Guide 1.74.

See Section 17.2 for further discussion of quality assurance and Section 1.8.2 for the NSSS assessment of this Regulatory Guide.

1.8.1.75 Conformance to Regulatory Guide 1.75, Revision 2, September 1978: Physical Independence of Electric Systems

HCGS complies with IEEE 384-1974, as modified and endorsed by Regulatory Guide 1.75, with the clarifications and exceptions outlined below.

Position C.1 separation is accomplished in general by supplying non-Class 1E loads connected to a Class 1E bus through a single breaker with a shunt trip device tripped by a LOCA signal. All non-Class 1E loads will be tripped automatically by LOCA signal. Provisions for restoring certain of these loads from the main control room are provided.

Insert A

Position C.12 states that redundant cable spreading areas should be provided. HCGS has only a single cable spreading area.

Position C.12 endorses IEEE 384-1974, Paragraph 5.1.3, which indicates that in cable spreading areas the minimum separation distance between redundant Class 1E cable trays should be 1 foot between trays separated horizontally and 3 feet between trays separated vertically. The separation criteria used on HCGS for cable spreading areas is a minimum of 1-foot horizontal distance and 18-inch vertical distance between redundant Class 1E cable trays. The configurations, for which the redundant cable trays can not be separated by distances specified above, will either be analyzed or tested tc demonstrate the compliance with the intent of Regulatory Guide 1.75.

Position C.15 specifies that redundant Class 1E batteries be located in separate safety class structures and be served by independent ventilation systems. The 250-V Class 1E batteries for electrical divisions A and B, located on elevation 163 feet of the auxiliary building, are served by a common ventilation

(Question 430.52/Item 25)

INSERT A

Position C.6 states that all analyses to justify lesser separation distances shall be identified. The following are the HCGS exceptions to the IEEE 384 separation distances.

There are only three generic cases where analysis is used to justify lesser separation distances. These are identified and analyzed as follows:

- Conduit-to-conduit less than one (1) inch apart.

  Because of space limitations in some areas of the plant, the minimum separation distance of one inch between rigid steel conduits can not be maintained. The use of the conduits is limited to instrumentation to instrumentation control to control, and instrumentation to power feeder with maximum 120 Vac or 125 Vdc cables only. Wyle Test Report No. 56719, prepared for Susquehanna Steam Electric Station, showed that rigid steel conduits in contact with each other are acceptable barriers. The testing demonstrated that shorting of conductors in one conduit until failure did not affect the performance of the conductors in the other conduit or damage the conduit. In addition, Franklin Institute Research Laboratories (FIRL) performed similar testing for the Toledo Edison Company in 1977 with successful results. The test configuration and cables used conservatively bound the HCGS conditions; therefore, the limited cases where the HCGS separation has not been met in the installation are justified. The two reports referenced have been submitted under separate cover, by letter from R. L. Mittl, PSE&G, to A. Schwencer, NRC, dated August 30, 1984.

  Based on the results of this test and analysis program, separation criteria for Class 1E conduit has been established which assures that (1) any failure or occurrence in a Class 1E conduit will not degrade a redundant essential Class 1E circuit in adjacent Class 1E conduits, (2) a failure or occurrence in a non-Class 1E conduit will not degrade redundant essential Class 1E circuits in adjacent Class 1E conduits.

  The criteria established are as follows:

  1. Circuits carrying control, instrumentation, or power

Insert A (Cont'd)

cable (where the power cable is limited to 480 volt or lower and No. 12 AWG or smaller) are allowed to touch each other.

2. Conduit carrying essential Class 1E 4.16 kV power cables or 480 volt load center power cables will have a one inch minimum separation from conduits carrying Class 1E circuits of a redundant channel.

3. Conduit carrying non-essential 13.8 kV, 4.16 kV, or 480 volt load center cables that bridge conduits carrying essential Class 1E circuits of redundant channels will be separated from conduit carrying circuits of the redundant channel to give a minimum separation of one inch.

4. Conduit carrying essential Class 1E power cable of 480 volt or lower voltage with conductor size larger than number 12 AWG, and not covered by 2. above, will meet the following criteria:

   a. Will have a minimum of 1/8-inch separation from the surface of any conduit crossing above which contains an essential Class 1E circuit of the redundant channel.

   b. Are allowed to touch conduits containing an essential Class 1E circuit of the redundant channel when installed in a horizontal, side-by-side configuration.

   c. Will have a minimum separation of one inch from conduits containing an essential Class 1E circuit of the redundant channel mounted directly above and running parallel.

5. Conduit carrying non-essential power cable of 480 volt or lower voltage with conductor size larger than number 12 AWG, and not covered by 3. above, that bridge conduits carrying essential Class 1E circuits of redundant channels will be treated as in 4.a, b, and c for proper separation from the redundant channel.

- Non-Class 1E conduit separation from Class 1E tray.

In safety-related areas of the plant there are non-Class 1E rigid steel conduits within one inch of Class 1E tray. The non-Class 1E conduit contains only control, instrumentation or 120 Vac/125 Vdc power cables. The testing performed

Insert A (Cont'd)

for the above projects demonstrated that the rigid steel conduit is an effective barrier for protection of any cabling. Therefore, the HCGS cases where the non-Class 1E conduit is not installed as required is justified by the previous testing.

- Metal-clad cable separation from Class 1E raceways.

  Metal-clad cables, type MC, are used in non-Class 1E circuits only. The minimum separation between the metal-clad cable and Class 1E raceways (open top trays or conduits) is one (1) inch. The type MC cable is a factory assembly of one or more conductors, each individually insulated, covered with an overall insulating jacket and all enclosed in a metallic sheath of interlocking galvanized steel. The cable has passed the vertical flame test of IEEE 383-1974.

The above analysis identified the cases on a generic level. The installation and inspection of raceways are ongoing and the specific cases where the analysis appoes are documented on nonconformance reports that are part of the QA/QC program.

Rev. 2A [NT]
#26

DSER Open Item No. 245 (DSER Section 8.3.3.3.2)

THE USE OF 18 VERSUS 36 INCHES OF SEPARATION BETWEEN RACEWAYS

In Sections 1.8.1.75 and 8.1.4.14.3.1 of the FSAR it is stated that separation between redundant cable trays in the cable spreading area, control equipment room,, relay room, and main control room are separated by 18 inches vertically as opposed to the recommended 36 inches of separation required by IEEE Standard 384-1974.

The applicant, by Amendment 4 to the FSAR, indicated that this 18 inches of separation was approved by the staff during the preliminary design review of the Hope Creek plant. The staff's preliminary safety evaluation report for this item states that:

> "The applicant claims these separation distances are adequate because a high grade type cabling will be specified and results of extensive testing show that no cable degradation or flame propagation occurs when the lower tray, separated by 12 inches from the upper tray, is exposed to a gas flame for 15 minutes."

The results of these tests, that demonstrate no degradation to cables located in the trays 12 inches above the tray exposed to the gas flame, will be pursued with the applicant.

RESPONSE

Section 8.1.4.14.3.1 and the response to Question 430.51 have been revised to provide additional justification for the separation distance.

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HCGS FSAR

QUESTION 430.51 (SECTION 8.3.1 and 8.3.2)

In Sections 1.8.1.75 and 8.1.4.14.3.1 of the FSAR you state that separation between redundant cable trays in the cable spreading area, control equipment room, relay room, and main control room are separated by 18 inches of separation required by IEEE Standard 384-1974. Provide analysis substantiated by test that demonstrates the adequacy of 18 inches of separation.

RESPONSE

The HCGS PSAR was approved with 18 inch vertical separation between redundant cable trays.

A copy of the test report that substantiated the use of this vertical separation has been submitted under separate cover (letter from R. L. Mitt, PSE&G, to A. Schwencer, NRC, dated August 15, 1984).

Revised section 8.1.4.14.3.1 provides the analysis based on this test to demonstrate the adequacy of 18 inches separation.

In addition to the above test, an additional cable tray test will be performed that tests electrical shorting of electrical cabling utilizing the 18 inch vertical separation. This test plan is being submitted under separate cover.

If the test is unsuccessful, then cable tray covers will be added to the trays in accordance with IEEE Std 384-1974.

NT

Rev. 2A

8.1.4.14.3.1 Cable Spreading Area, Control Equipment Room and ~~Relay Room~~ Mezzanine, and Main Control Room

The cable spreading area, control equipment room and mezzanine ~~relay room~~, and main control room do not contain high energy equipment such as switchgear, transformer, rotating equipment, or potential sources of missiles or pipe whip, and are not used for storing flammable materials. Power supply circuits are limited to those serving these areas and their instrument systems. These 208/120-V power cables are installed in conduits. Conduits containing redundant cables are separated by a minimum of 1 inch. Conduit couplings, clamps, locknuts, bushings, etc, shall not be considered in determining the required separation distances. For conduits carrying redundant neutron monitoring cables, boxes also shall not be considered in determining the required separation. Redundant cable trays are separated by at least 18 inches vertically and 12 inches horizontally. The configurations, for which the redundant ~~cable trays~~ raceways can not be separated by distances specified above, will either be analyzed or tested to demonstrate the compliance with the intent of Regulatory Guide 1.75. Separation distance requirements between Class 1E and non-Class 1E raceways are the same as for the separation among redundant channels.

INSERT A

Strict administrative control of operations and maintenance activities is developed to control and limit the introduction of potential hazards into these areas.

8.1.4.14.3.2 Limited Hazard Areas

Limited hazard areas are the general plant areas from which potential nonelectrical hazards such as missiles, pipe whip, and exposure fires are excluded. The hazards in this area are limited to failures or faults internal to the electrical equipment or cables. These areas include elevations 77, 102, 124, 130, and 137 feet in the auxiliary building wing areas and elevation 87 feet in the radwaste area. Minimum separation in these ~~nonhazardous~~ areas is as follows:

a. Conduits containing redundant cables are separated by a minimum of 1 inch, unless consideration of hazards indicates greater separation is required. Conduit couplings, clamps, locknuts, bushings, etc, shall not be considered in determining the required separation distances. For conduits carrying redundant neutron

INSERT A TO 8.1.4.14.3.1

IEEE 384-1974 requires a minimum vertical separation of 3 feet between trays. The HCGS minimum vertical separation distance is 18 inches. The following analysis provides the justification for the lesser separation distance:

A. All cables are flame retardant and meet or exceed the flame test specified in IEEE 383-1974 as demonstrated by tests. Cable test reports are on file and available for audit.

B. As indicated in the above paragraph, high energy equipment and potential sources of missiles or pipe whip are excluded from the areas. Power circuits in the areas are installed in conduits that qualify as barriers; the maximum potential of the power circuits is limited to 208/120 volts ac or 125 volts dc. There are no power cables of higher potential serving equipment in the areas.

C. The cable tray test report performed for Salem showed that a fire in a cable tray located 12" directly below another tray did not propagate to the upper cable tray nor degrade the cables in the upper cable tray. The test configuration and cables were representative of the HCGS design and installation except that the test configuration used a 12 inch vertical separation. Because the Salem test demonstrated that the 12 inch vertical separation was adequate, the HCGS separation distance is justified. The Salem test report, ~~entitled,~~ "Basis for Cable System Design Power Generating Stations", dated July 16, 1971, has been submitted under separate cover (letter from R.L. Mittl, PSE&G, to A. Schwencer, NRC, dated August 15, 1984).

ABSTRACT-PHYSICAL SEPARATION TEST PLAN

1.0 SCOPE

This document is a test plan for the purpose of testing physical separation between redundant Class 1E cables and Class 1E and non-Class 1E cables with respect to electrical faults in configurations representative of HCGS.

1.1 OBJECTIVE

The purpose of this procedure is to present the requirements, procedures, and sequence for testing the design adequacy of the Hope Creek cable tray-to-cable tray separation. Figure 1 identifies the tray-to-tray separation test configuration.

1.2 APPLICABLE DOCUMENTS

- IEEE Std 384-1981
- IPCEA S19-81
- HCGS FSAR Section 8.1

1.3 EQUIPMENT DESCRIPTION

This test procedure encompasses testing of control cable and instrumentation cable as described below:

Item No.	Description
1.0	Okonite 600VAC, two conductor, size # 14 AWG (HCGS No. C02)
2.0	Okonite 600VAC, two conductor, size # 12 AWG (HCGS No. P12)
3.0	Eaton 600VAC, two conductor, size # 16 AWG (HCGS No. I02)

2.0 TEST REQUIREMENTS

2.1 Acceptance Criteria

2.1.1 Insulation Resistance Test

Measured insulation resistance on all "target" cables and any other cable, in the target raceway, that might sustain significant damage to its insulation system shall be greater than 1.6×10^6 ohms with an applied potential of 500 VDC for sixty seconds.

2.1.2 High Potential Test

There shall be no evidence of insulation breakdown or flashover with an applied potential of 2200 VAC for sixty seconds on all "target" cables and any other cable, in the target raceway, that might sustain significant damage to its insulation system.

2.1.3 Cable Continuity Test

Energized non-fault specimens in the "target" raceway shall conduct 100% rated current at 120 VAC throughout the overcurrent test.

2.1.4 Cable Temperature

The cabling in the upper cable tray shall be monitored for cable jacket temperature and it shall not exceed the qualified parameter in the environmental qualification of the cable.

3.0 TEST PROGRAM

3.1 Test Configuration

These tests shall consist of a series of tests with two vertically separated horizontal cable trays (see Figure 1). The test setup shall be identical for each test with the exception of the location of the faulted cable.

3.1.1 Purpose

The purpose of the tests is to demonstrate the adequacy of design where two horizontal cable trays are physically separated by eighteen inches vertically when an electrical fault occurs in the lower cable tray.

3.1.2 Test Specimen Preparation

The test specimens shall be placed in the cable tray assembly as shown in Figure 1. This apparatus shall be assembled to the indicated dimensions. The following guidelines shall be observed with regard to the materials and construction of the cable tray assembly:

1. The cable trays shall be ladder rung trays 72" by 24" by 4" (horizontal tray) from PSE&G stock.

2. The cable trays shall be supported with unistrut hangers and shall be mounted such that the bottom of the upper horizontal cable tray is eighteen inches above the top of the upper horizontal cable tray.

3. The upper and lower cable trays shall be filled to a 50% fill level (by area) using an assortment of six ft unpowered control and instrumentation cables from PSE&G stock.

4. One energized 2/C Size 16 AWG cable and one energized 3/C Size 14 AWG cable shall be placed inside the cable trays that do not have the faulted cable. The energized "target" cables shall be located in the worst case locations (directly above, underneath or next to the faulted cable) as shown in Figure 1. (NOTE: Figure 1 shows the fault and "target" cable locations for the two tests).

3.1.3 Instrumentation Setup

3.1.3.1 Thermocouple Locations

For the test, five thermocouples are to be mounted to the upper and lower cable tray on the edge closest to the faulted cable in the horizontal cable tray.

These thermocouples shall be monitored by a Fluke Datalogger feeding a high-speed printer. The datalogger shall be operated at its maximum rate throughout the overcurrent test.

3.1.3.2 Electrical Monitoring -- All voltages and phase currents of the energized cables and the fault cable current shall be fed to oscillograph recorders. The oscillographs shall be operated at the 0.1 inch per minute rate throughout the overcurrent test. The oscillograph channels shall be as specified below:

Oscillograph #1 Channels

Channel No.	Test No.	Signal	Location
1	1	Current	16 AWG Upper Cable Tray
1	2	Current	14 AWG Lower Cable Tray
2	1	Current	12 AWG Upper Cable Tray
2	2	Current	16 AWG Lower Cable Tray
3	1	Current	16 AWG Upper Cable Tray
3	2	Current	14 AWG Lower Cable Tray
4	1	Voltage	16 AWG Upper Cable Tray
4	2	Voltage	12 AWG Lower Cable Tray
5	1	Voltage	12 AWG Upper Cable Tray
5	2	Voltage	16 AWG Lower Cable Tray
6	1	Voltage	16 AWG Upper Cable Tray
6	2	Voltage	14 AWG Lower Cable Tray

Oscillograph #2 Channels

Channel No.	Test No.	Signal	Location
1	1,2	Current	Faulted Cable

A digital multimeter shall be utilized to measure all phase-to-phase voltages and all phase currents prior to, during, and after the overcurrent test. These data shall be recorded to provide accurate evidence of the energized specimens' ability to conduct rated current and 120 VAC throughout the overcurrent test.

3.1.4 Baseline Functional Tests for Cabling in Upper Tray

The baseline functional tests shall consist of insulation resistance and high potential tests on the "target" cables.

3.1.4.1 Insulation Resistance Test

1. Using a megohmmeter, apply a potential of 500 VDC and record the minimum insulation resistance indicated over a period of 60 seconds on the "target" cables.

2. Perform a high potential test on the "target" cable.

3.1.5 Overcurrent Test

1. Connect the worst case cable (WCC) size to the copper bus bars per Figure 3.

2. Energize the two 3/C Size 14 AWG cables with 120 VAC and 15 amperes.

3. Energize the two 3/C Size 12 AWG cables with 120 VAC and 90 amperes.

4. Energize the worst case cable size with rated current (90 amps).

5. Record "target" cable voltages and currents and the fault cable current.

6. Allow the worst case cable size to conduct rated current for 15 minutes.

7. Increase the Multi-Amp Test Set output to 660 amperes.

8. Record "target" cable voltages and currents and the fault cable current and temperatures.

9. Allow the WCC to conduct 660 amperes until cable failure occurs or until thermocouple readings stabilize for a period of five minutes.

10. De-energize the Multi-Amp Test Set output.

11. Record Multi-Amp Test Set time to failure of the faulted cable.

12. Record "target" cable voltages and currents.

13. De-energize the "target" cables.

14. Photograph the post-test damage.

15. Remove the faulted cable and any other cables that were significantly damaged.

16. Repeat the applicable portions of Paragraphs 3.1.2 (Test Specimen Preparation, 3.1.3 (Instrumentation Setup) and 3.1.4 (Baseline Functional Tests).

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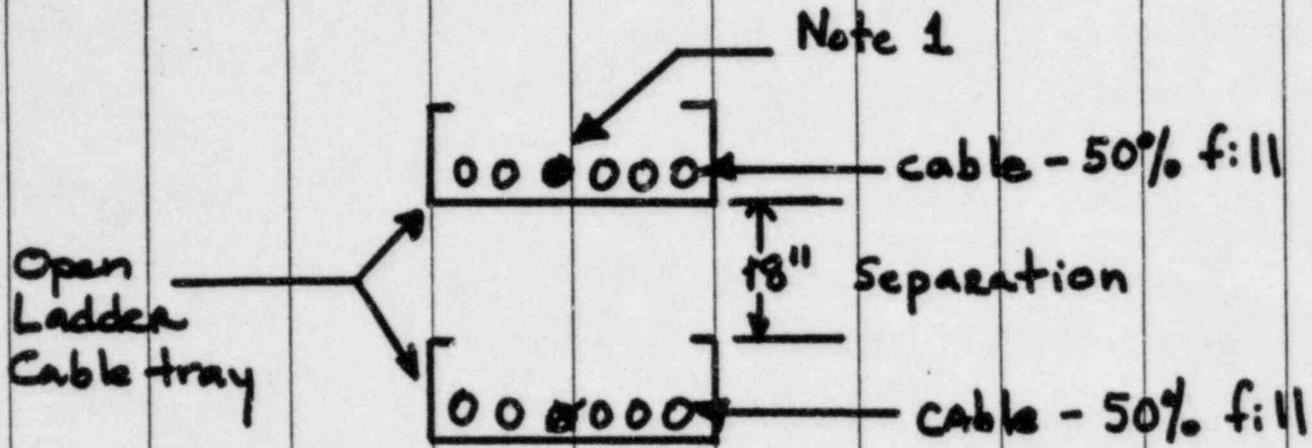
(Item 26)

FIGURE 1 - TEST SETUP FOR TRAY-TO-TRAY SEPARATION



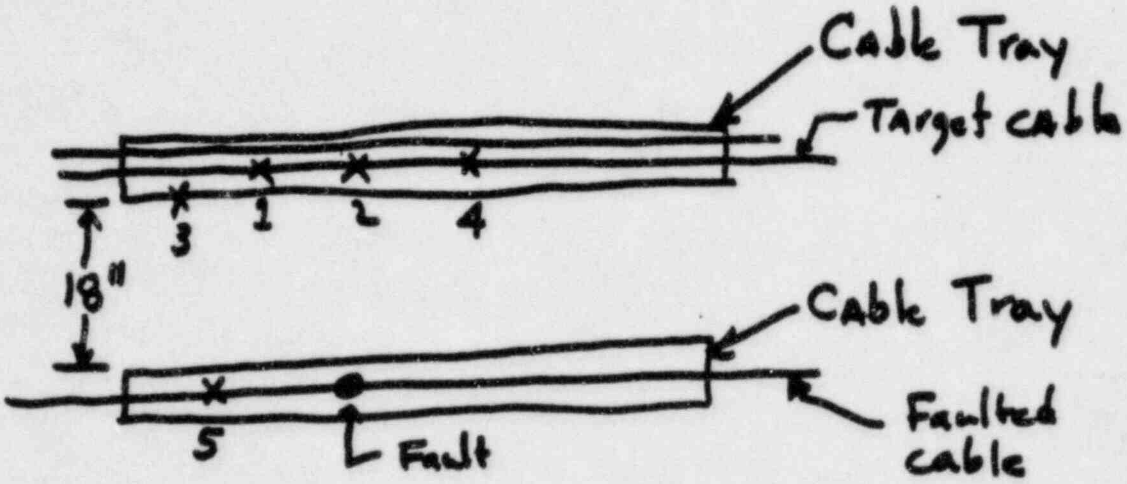
● Denotes Target Cable Location

⊗ Denotes Fault Cable Location

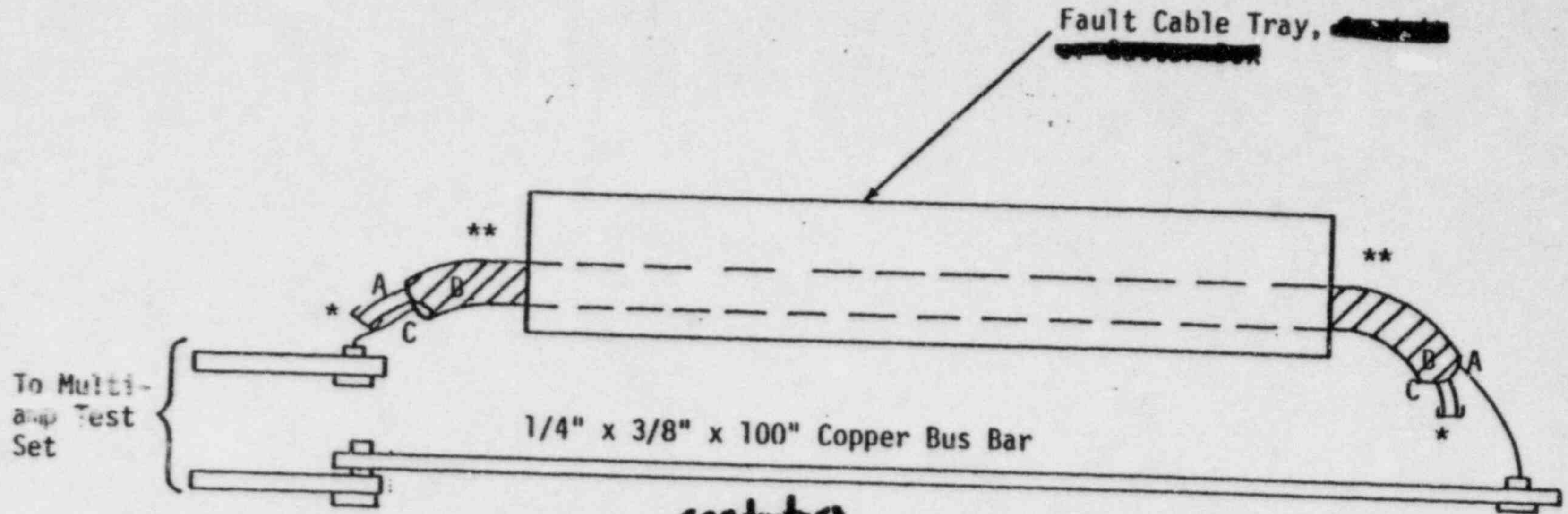
Note 1 - Target cable will be energized during the faulted test condition

(NT)

Figure 2 - Thermocouple Locations



X - Type "K" thermocouple mounted on the target cable jacket and cable adjacent to the target ~~$~~cable and the cable rungs.



* The three conductors of the fault cable shall be connected in series.

** The fault cable shall be wrapped with a single layer of siltemp wide tape No. 65 from the edge of the test area to the bus bar.

FIGURE 3. TYPICAL FAULT CABLE CONNECTIONS

DSER Open Item No. 259 (DSER Section 8.3.3.3.4)

USE OF AN INVERTER AS AN ISOLATION DEVICE

By Amendment 4 to the FSAR, the applicant indicated that the non-Class 1E public address system distribution panel shown on sheet 2 of Figure 8.3-11 of the FSAR is supplied power from the Class 1E dc system through an inverter. The applicant further stated that this inverter is an acceptable isolation device per IEEE-384-1981, Section 7.1.2.3. The staff does not agree. Test and analysis to demonstrate the adequacy of an inverter as an isolation device will be pursued with the applicant.

RESPONSE

The response to Question 430.33 has been revised to state that the inverter will be tested as an isolation device. In the event that the tests are not successful, the non Class 1E loads will be removed or the cables will be re-routed.

QUESTION 430.33 (SECTION 8.3.1 and 8.3.2)

Section 8.3.1.1.2 of the FSAR indicates that the Class 1E system provides power to non-Class 1E loads. Non-Class 1E loads are connected to the Class 1E system through a single breaker that is tripped automatically by a LOCA signal. The single breaker tripped by a LOCA signal provides acceptable isolation between Class 1E and Non-Class 1E circuits for the design basis accident - LOCA. However, for other design basis accidents or operating occurrances that do not generate a LOCA signal (such as loss of offsite power, design basis exposure fire, seismic events, etc), it is the staff concern that a single breaker may not provide acceptable isolation. Provide an analysis, in accordance with the guidelines of Section 4.9 of IEEE Standard 308-1974, that demonstrates that failure of anyone or simultanous combined failure of all non Class 1E loads will not prevent any of the four channels of Class 1E power from performing its safety function. The analysis should consider, but not be limited to, (1) capacity and capability of onsite and offsite power supplies and their associated distribution system to supply power to Class 1E loads within their design ratings for all modes of plant operation, (2) the guidelines of Section 7.1.2.1 of IEEE standard 384-1981, (3) an analysis of diesel generator loadings for loss of offsite power similiar to that presented in Tables 8.3-2 through 8.3-6 of the FSAR, (4) the failure of the Non Class 1E dc system that supplies control power to the subject non Class 1E loads, and (5) a similiar analysis of the Class 1E dc system if non-Class 1E loads are connected.

RESPONSE

The following discussion demonstrates the adequacy of employing a single circuit breaker tripped by a LOCA signal as an isolation device between a Class 1E power bus and a non-Class 1E load for design base event that do not generate LOCA signals.
is

x

Figure 430.33-1 shows the two configurations that employ a circuit breaker tripped by a LOCA signal as an isolation device. The two configurations are:

a. A Class 1E unit substation supplies a non-Class 1E motor control center (MCC) or a motor load through Class 1E circuit breaker B.

b. A Class 1E motor control center supplies through Class 1E circuit breaker D, a non-Class 1E distribution panel.

The Class 1E circuit breakers B and D are qualified to operate for HCGS seismic and environmental parameters for all design basis events. These circuit breakers will trip to isolate their

DSER OPEN ITEM 260

respective Class 1E power supply buses from the non-Class 1E loads in the event the non-Class 1E loads fail. This applies whether the plant is supplied from an offsite source or an onsite source. Thus, the failure of the non-Class 1E loads supplied from Class 1E power supply buses will not prevent any of the four channels of Class 1E power supplies from performing its safety function. INSERT A FROM PAGE 430.33-2A

COMPLIANCE WITH GUIDELINES OF SECTION 7.1.2.1 OF IEEE 384-1981

Protective device coordination studies for devices shown in Figure 430.33-1 have shown that the time-overcurrent trip characteristics of circuit breakers A, B, C, and D are such that:

a. Circuit breaker B will trip to clear a fault current prior to initiation of a trip of circuit breaker A.

b. Circuit breaker D will trip to clear a fault current prior to initiation of a trip of circuit breaker C.

Both the onsite and offsite powers supply sources are separately capable of supplying the necessary fault current for sufficient time to ensure the proper protective device coordination without loss of function of Class 1E loads. INSERT B FROM PAGE 430.33-2A

STANDBY DIESEL GENERATOR LOADINGS FOR LOSS OF OFFSITE POWER

Table 8.3-1 tabulates the loads, their KW ratings, and loading sequences for design basis accident (DBA) and loss of offsite power (LOP) scenarios. It can be verified by inspecting Table 8.3-1 that DBA loading of the SDGs is the limiting case with respect to the loading capability of the SDGs.

FAILURE OF THE NON-CLASS 1E DC SYSTEM THAT SUPPLIES CONTROL POWER TO THE SUBJECT NON-CLASS 1E LOADS

For configuration (a) (described above) the circuit breaker B supplying a Non-Class 1E MCC or a motor load is controlled by Class 1E 125 V dc control power supply. For a non-Class 1E motor load, a non-Class 1E circuit breaker is provided downstream of circuit breaker B. This non-Class 1E circuit breaker (GE-AKR type) is controlled by a non-Class 1E 125 V dc control power. GE-AKR type circuit breakers are directly acting trip devices and do not require external control power supply for tripping for electrical fault conditions. Therefore, the failure of the dc control power supply does not prevent the circuit breaker ~~to~~ tripping from in response to the failure of non-Class 1E motor load.

INSERT C FROM PAGES 430.33-2B

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INSERT A

The Class 1E onsite ac sources and the offsite power sources and their distribution system are of sufficient capacity and capability to supply power to both Class 1E and non-Class 1E loads during all plant conditions. In the event of a LOCA the non-Class 1E loads are automatically tripped from the class 1E buses in accordance with Position C.1 of Regulatory Guide 1.75. IN ADDITION, CABLES FROM THE CLASS IE BUSES TO THE NON-CLASS IE LOADS ARE ROUTED IN RIGID STEEL CONDUITS OR TRAYS. WHERE TRAY ROUTING IS USED, NON-CLASS IE CABLES ASSOCIATED WITH OTHER IE CHANNE ARE NOT RUN TOGETHER IN THE SAME TRA

FP→ AN OPERATION DESIGN CHANGE CONTROL PROGRAM WILL BE IN EFFECT AT THE HOPE CREEK PLANT TO ASSURE THAT FUTURE ADDITIONS / MODIFICATIONS WILL COMPLY WITH THIS REQUIREMENT. ADDITIONALLY, THE PERTINENT DESIGN DOCUMENTS WILL BE PROVIDED WITH A NOTATIONS TO REFLECT THIS REQUIREMENT.

INSERT B

Periodic testing of the breaker time-overcurrent trip characteristics will be performed to demonstrate that the circuit breaker trip function remains within required limits. Table 430.33-1 identifies the non-Class 1E loads that are supplied through circuit breakers B and D of Figure 430.33-1.

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Rev. 1A

QUESTION 430.33 Insert "C"

ANALYSIS FOR SUPPLYING NON-CLASS 1E FROM CLASS 1E DC SYSTEMS

Figure 8.3.11 shows non-Class 1E public address system distribution panel 10J496 supplied from a Class 1E dc power bus 10D410 through a Class 1E inverter in UPS unit 10D496. The inverter is an acceptable isolation device per IEEE-384-1981, Section 7.1.2.3. Therefore, a failure in the non-Class 1E distribution panel 10J496 will not degrade Class 1E dc system bus 10D410.

The HCGS UPS system will be tested to demonstrate the adequacy of an inverter being applied as an isolation device. The test will demonstrate that voltage, current, and frequency on the Class 1E side of the UPS are not degraded below acceptable levels when maximum credible voltage or current transient is applied on the non-Class 1E side of the UPS system. The tests to be performed will simulate all operating modes for which the HCGS UPS system is designed. The tests will include the following types of faults at the UPS output location:

a. Phase to ground
b. Neutral to ground
c. Phase to neutral without ground
d. Hot short (460 Vac)

A test plan is submitted separately for the staff's review. The test report and any associated analysis of the test results will be submitted in December 1984.

An analysis has been performed to support the values used for the acceptance criteria for voltages. This analysis shows that the voltages specified will not cause misoperation or loss of any electrical equipment connected to the supply buses.

The results of this analysis for the ac systems is stated in FSAR Section 8.3.1.2.1 and the calculated results are shown in Table 8.3-11. The results of the dc analysis are contained in FSAR Section 8.3.2. These results indicate that the 125 volt dc system has an acceptable operating capability with battery voltage variations of 35 volts (140 volts dc to 105 volts dc). The test acceptance criterion limits the bus voltage variation to 105-135 volts.

In addition, the acceptance values for the test currents are well below the level that would cause the infeed breakers to the UPS supply buses to trip. These values are as follows:

Circuit	Acceptance Current	Infeed breaker Setting
Normal 480 VAC Supply	0-55 amperes continuous with a maximum peak not to exceed 132 amperes and no value above 55 amperes shall persist for longer than 10 mS	600 amperes Pick-up

Rev. 1A

Insert "C"
Page two

Circuit	Acceptance Current	Infeed breaker Setting
Back-up 480 VAC Supply	0-78 amperes continuous with a maximum peak not to exceed 500 amperes and no value above 78 amperes shall persist for longer than 10 mS	600 amperes Pick-up
Alternate 125 VDC Supply	0-180 amperes continuous with a maximum peak of 364 amperes and no value above 180 amperes shall persist for longer than 500 mS	2000 ampere fuse

If the testing can not demonstrate adequacy of the UPS as an isolation device, than an isolation transformer will be added between the inverter and the distribution panel. The test plan for the isolation transformer is also submitted separately for the staff's review.

In the event of failure of both tests the non-Class 1E loads associated with the UPS system will be removed from the Class 1E buses or the cables to these loads will be re-routed so as to be separated from Class 1E cables associated with other Class 1E channels.

TABLE 430.33-1

NON-CLASS 1E LOADS CONNECTED TO CLASS 1E BUSES THROUGH CIRCUIT BREAKER TRIPPED BY LOCA SIGNAL

LOAD NO.	NON-CLASS 1E LOAD DESCRIPTION	CLASS 1E BUS	CLASS 1E CIRCUIT BREAKER NO.
1	Reactor Auxiliary Cooling System Pump 1AP209	10B410	52-41011
2	Radwaste and Service Area MCC 10B313	10B410	52-41014
3	Reactor Building Supply Air Handling Unit 1BVH300	10B410	52-41024
4	Reactor Auxiliary Cooling System Pump 1BP209	10B420	52-42011
5	Radwaste and Service Area MCC 10B323	10B420	52-42014
6	Reactor Building Exhaust Fan 1BV301	10B420	52-42024
7	Reactor Building Supply Air Handling Unit 1CVH300	10B430	52-43024
8	Control Rod Drive Pump 1AP207	10B430	52-43014
9	Control Rod Drive Pump 1BP207	10B440	52-44014
10	Reactor Building Supply Air Handling Unit 1AVH300	10B440	52-44024
11	Radwaste Area Supply Fan 0BV316	10B440	52-44034
12	Reactor Area MCC 10B252	10B450	52-45011
13	Radwaste Area Exhaust Fan 0AV305	10B450	52-45014
14	Emergency Instrument Air Compressor 10K100	10B450	52-45024
15	Reactor Building Exhaust Fan 1CV301	10B450	52-45034
16	Reactor Area MCC 10B262	10B460	52-46011
17	Radwaste Area Exhaust Fan 0BV305	10B460	52-46014
18	Reactor Area MCC 10B272	10B470	52-47011
19	Radwaste Area Exhaust Fan 0CV305	10B470	52-47014
20	Radwaste Area Supply Fan 0AV316	10B470	52-47024
21	Technical Support Center MCC 00B474	10B470	52-47031

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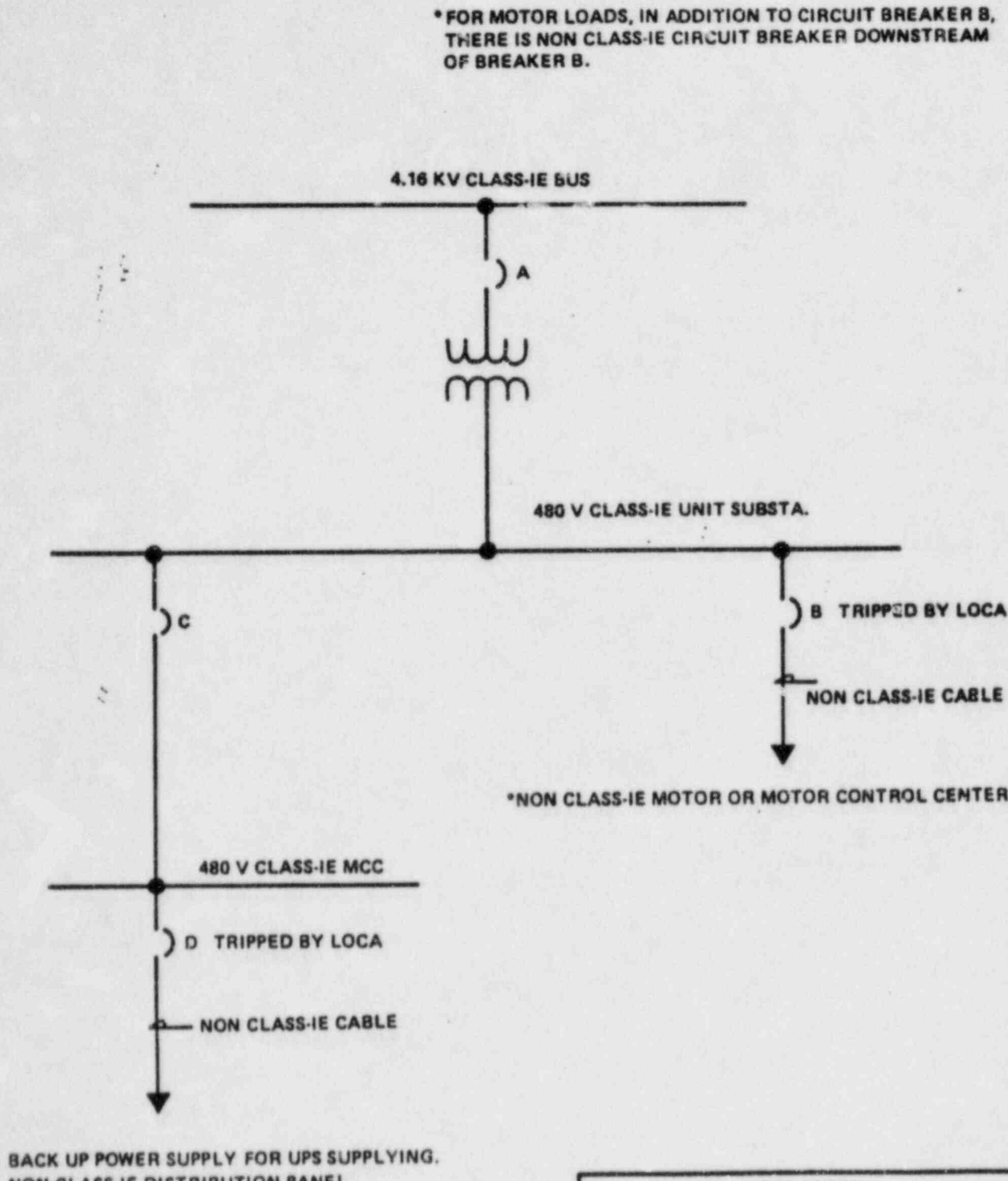
TABLE 430.33-1
CONTINUED

22	Reactor Area MCC 1OB282	1OB480	52-48011
23	Reactor Building Exhaust Fan 1AV301	1OB480	52-48029
~~24~~	~~NSSS Computer Inverter 1OD485~~	~~1OB441~~	~~52-441023~~
25	Public Address System Inverter 1OD496	1OB451	52-451023
~~26~~	~~BOP Computer Inverter 1AD492~~	~~1OB461~~	~~52-461023~~
27	Security System Inverter OAD495	1OB471	52-471023
~~28~~	~~BOP Computer Inverter 1BD492~~	~~1OB481~~	~~52-481023~~

DSER OPEN ITEM 260



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

ISOLATION BETWEEN CLASS-IE POWER SUPPLIES AND NON CLASS-IE LOADS— TRIPPING CIRCUIT BREAKER

FIGURE 430.33-1 AMENDMENT 4, 1/84

TEST PROCEDURE, ISOLATION VERIFICATION

S/N 9743 1E 20KVA UPS (INSTRUMENTATION AC POWER SUPPLY)

FOR PUBLIC SERVICE ELECTRIC & GAS CO.
HOPE CREEK GENERATING STATION
PO. 10855-E-154 (Q)-AC

OBJECTIVE:

TESTING TO ESTABLISH THE UPS SYSTEM AS A CIRCUIT ISOLATION SYSTEM.

PASS CRITERIA:

DEFINITION OF ISOLATION DEVICE OR SYSTEM: A DEVICE OR SYSTEM IS CONSIDERED TO BE A CIRCUIT ISOLATION DEVICE IF IT IS APPLIED SUCH THAT THE MAXIMUM CREDIBLE VOLTAGE OR CURRENT TRANSIENT APPLIED TO THE NON CLASS 1E SIDE OF THE DEVICE WILL NOT DEGRADE THE CLASS 1E CIRCUIT ON THE OTHER SIDE OF THAT DEVICE.

CIRCUIT	NORMAL VARIATION
ALT. DC. SUPPLY	105-135 VDC 0-364 ADC
NORMAL AC SUPPLY	480+10% V(L-L) 3 PHASE 0-55A, 0-132AP FOR 10MSEC
BACK UP AC SUPPLY	480+10% V 1 PHASE 0-78A, 0-500AP FOR 10MSEC

ANY VARIATIONS OUTSIDE OF NORMAL VARIATIONS SPECIFIED, WILL BE ANALYZED ON A CASE BY CASE BASIS.

FAULT LOCATION AND TYPE

FAULTS WILL BE APPLIED TO UPS SYSTEM OUTPUT TERMINALS BY CLOSING A SWITCH AS REQUIRED.

FAULT TYPES:

1. PHASE (HOT) TO GROUND
2. NEUTRAL TO GROUND
3. PHASE TO NEUTRAL W/O GROUND
4. 480VAC APPLIED ACROSS UPS OUTPUT W/O GROUND (HOT SHORT)

THE CONDITION OF THE THREE CLASS 1E SOURCES WILL BE MONITORED THROUGH SUITABLE SIGNAL CONDITIONERS, BY GOULD INC., 2000W SERIES HIGH FREQUENCY RECORDING SYSTEM.

TEST PROCEDURES

1.0 GENERAL NOTES

1.1 BEFORE STARTING TEST DETERMINE AND RECORD ALL SIGNAL CONDITIONER TRANSFER RATIO (MULTIPLIER) VALUES.

1.2 NORMAL SYSTEM OPERATION DURING EACH TEST

A. CONNECTION PER FIG. 1.
B. OUTPUT LOAD 10KVA @ .08PF (66.7 AMP RESISTIVE AND 50 AMP INDUCTIVE) @ 120VAC NOMINAL.
C. UPS POWERED BY "ALTERNATE" DC SOURCE (BATTERY) AND ONE OR BOTH AC SOURCES, "NORMAL" & "BACK-UP".
D. STATIC SWITCH IN "PREFERRED" POSITION.
E. ALL BREAKERS & SWITCHES CLOSED, BOTH BYPASS SWITCHES IN "NORMAL" POSITION
"TEST" SWITCH - CENTERED
"RETURN MODE" SWITCH - IN "AUTO" POSITION
"ISOLATION" TOGGLE SWITCHES - ON
"SYNC" TOGGLE SWITCH - ON

1.3 TEST INSTRUMENTATION

A. GOULD INC., MODEL 2800W HIGH FREQUENCY RECORDING SYSTEM. EIGHT CHANNEL, INDEPENDENT SCALE SELECT ±.050 TO ±500 VOLTS FULL SCALE.
B. POTENTIAL TRANSFORMER 480V, 60HZ PRIMARY 120V SECONDARY (4:1 RATIO).
C. CURRENT TRANSFORMER 1000:1 RATIO WITH 10 OHM BURDEN RESISTOR. (.01V/A).
D. WIDEBAND DC ISOLATION AMPLIFIER, GOULD INC. MODEL 13-4615-10 OR EQUIVALENT.

1.4 TEST FACILITY AND EQUIPMENT

A. DC SUPPLY - C&D 4LCW-15 BATTERY (60 CELLS, 80KW FOR 30 MIN.) AND BATTERY CHARGER.
B. AC SUPPLY - 480V, 3 PHASE, 4W, 60 HZ, 1200A GROUNDED NEUTRAL.
C. AC LOAD BANK - 0-30KW OR 0-30KVA @ 0.8PF.
D. FAULT APPLICATION DEVICE - G.E. CIRCUIT BREAKER TJC 36400G 400A, 3P. MAGNETIC ONLY.
E. HOT FAULT SOURCE - TRANSFORMER, 1 PH 480:120V 30KVA OR LARGER.

2.0 TEST PROCEDURE

2.1 BASE LINE DATA

START UP THE UPS WITH ALL SOURCES AVAILABLE. SET UP "NORMAL OPERATION" PER 1.2 AND ALLOW SYSTEM TO WARM UP FOR AT LEAST 30 MINUTES.

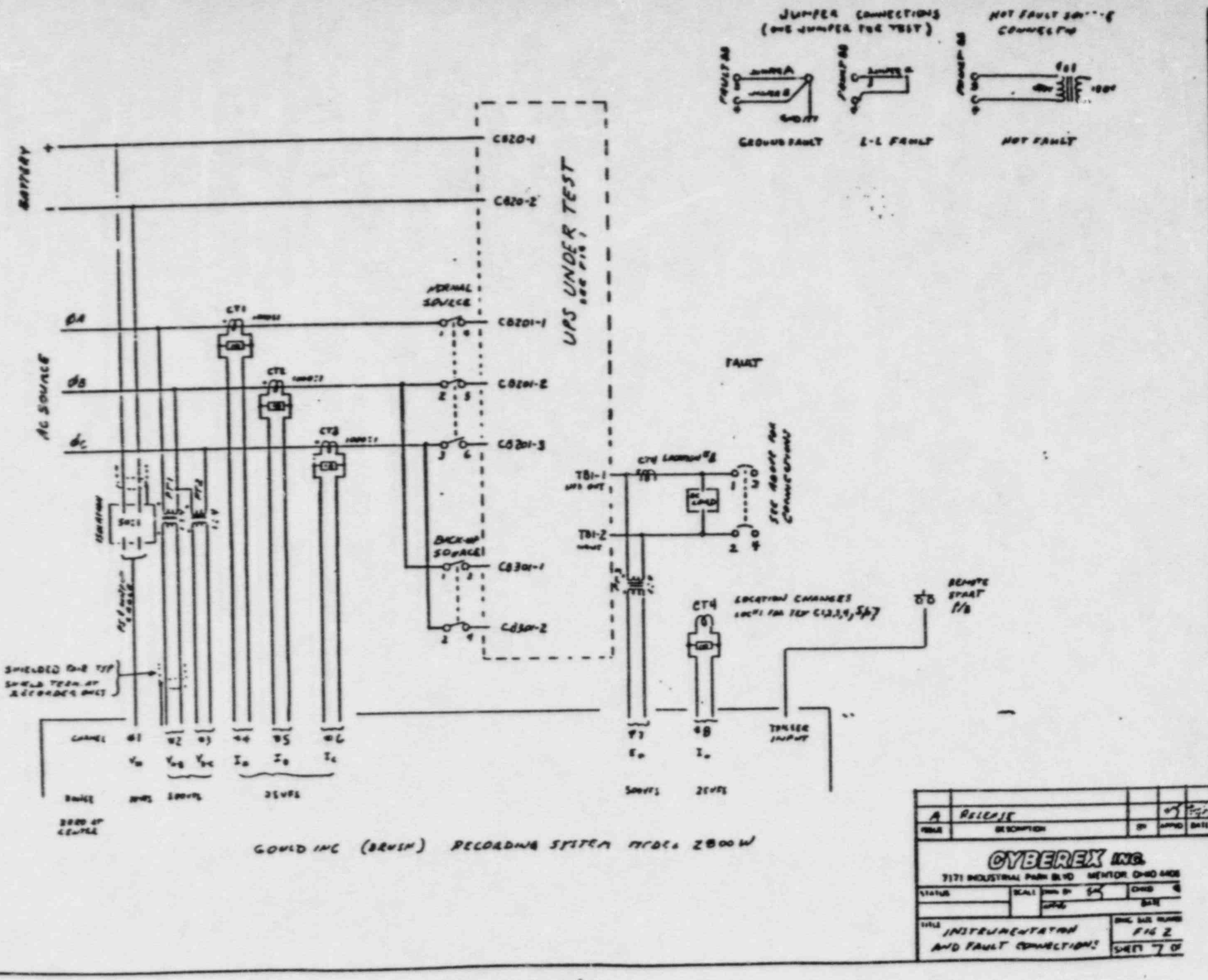
A1. METERING AND CONNECTIONS PER FIG. 2 AND "BACKUP SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
A2. REPEAT A1 EXCEPT USE 500HZ TIME BASE.
B1. WITH METERING AND CONNECTIONS PER FIG. 2 AND "NORMAL SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
B2. REPEAT B1 EXCEPT STATIC SWITCH TRANSFERRED TO BACKUP.
B3. REPEAT B1 EXCEPT USE 500HZ TIME BASE.
B4. REPEAT B2 EXCEPT USE 500HZ TIME BASE.

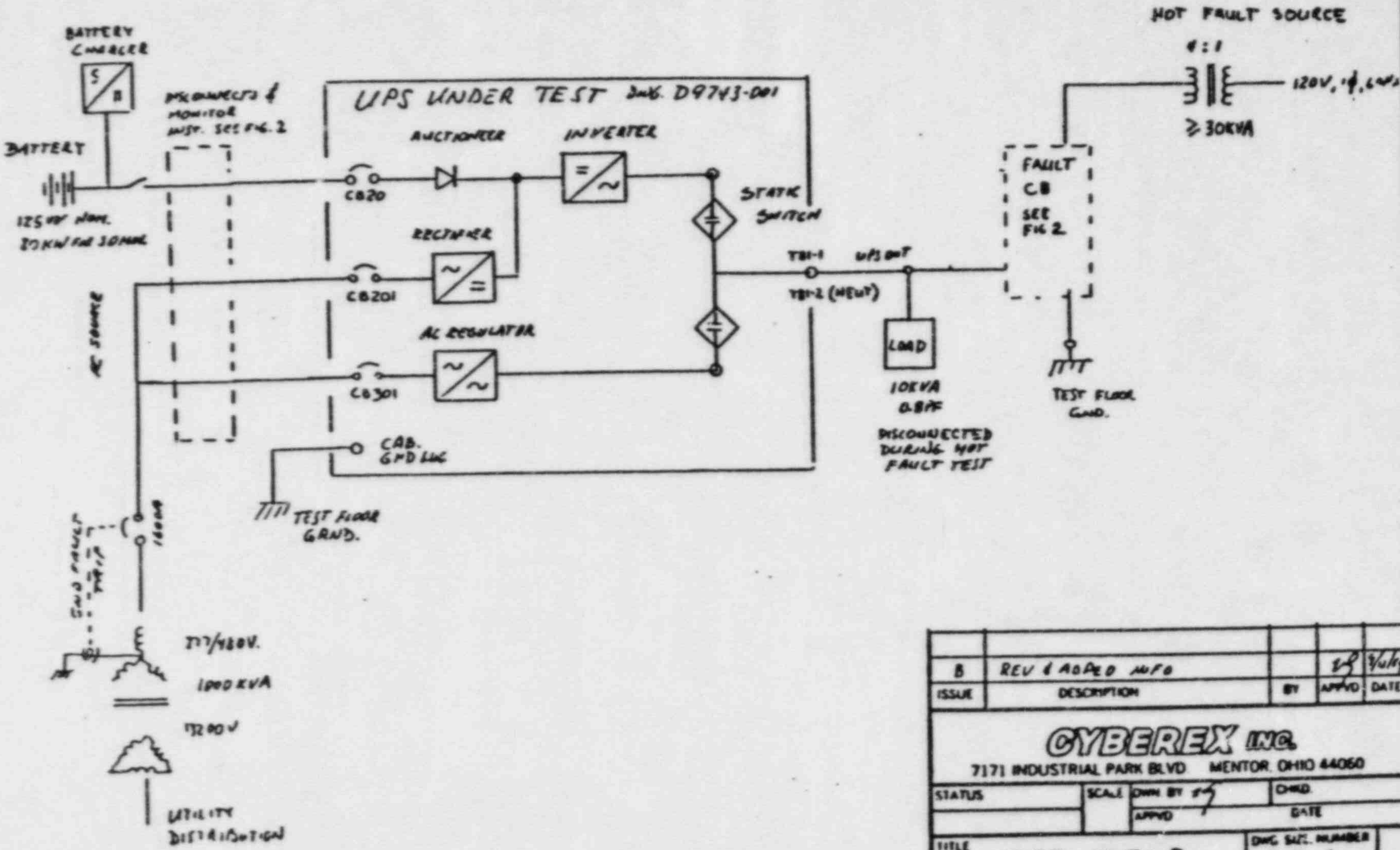
2.2 FAULT TESTING

C0. METERING AND CONNECTIONS PER FIG 2, RECORDER IN MANUAL TRIGGER MODE. APPLY FAULT BY CLOSING "FAULT" CB AND AT THE SAME TIME (OR 0 TO 10 MILLISECONDS BEFORE) TRIGGER THE RECORDER IN "STORE" MODE. REMOVE THE FAULT AND RECORD THE MEMORY TO PAPER.
AFTER EACH FAULT APPLICATION CHECK THE UPS FOR DAMAGE. REPAIR THE UPS IF REQUIRED BEFORE PROCEEDING.

C1. INSTALL JUMPER "A" TO "FAULT" CB WITH "BACKUP SOURCE" CB OPEN WITH RECORDER AT 20KHZ TIME BASE APPLY FAULT PER C0.
C2. REPEAT C1 EXCEPT WITH 500HZ TIME BASE.
C3. OPEN "NORMAL SOURCE" CB AND CLOSE "BACKUP" WITH RECORDER 20KHZ TIME BASE APPLY FAULT PER C0.
C4. REPEAT C3 EXCEPT WITH 500HZ TIME BASE.
C5. REPEAT C1, C2, C3 & C4 WITH JUMPER "B" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C6. REPEAT C1, C2, C3, & C4 WITH JUMPER "C" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C7. REPEAT C1, C2, C3, & C4 WITH CONNECTIONS TO HOT FAULT SOURCE (UPS RUNNING AT NO LOAD).

2.3 COMPLETE TEST SUMMARY SHEET FOR EACH TEST OR TEST GROUP.


JUMPER CONNECTIONS
(ONE JUMPER FOR TEST)
GROUND FAULT
L-L FAULT
HOT FAULT
BATTERY
CB20-1
CB20-2
UPS UNDER TEST
SEE FIG 1
NORMAL SOURCE
CB201-1
CB201-2
CB201-3
BACK-UP SOURCE
CB301-1
CB301-2
AC SOURCE
CT1
CT2
CT3
CT4
FAULT
TB1-1
UPS OUT
TB1-2
SEE ABOVE FOR CONNECTIONS
LOCATION CHANGES
REMOTE START
SHIELDED TWIST TYP
SHIELD TERM AT RECORDER ONLY
TRIGGER INPUT
GOULD INC (BRUSH) RECORDING SYSTEM MODEL 2800W
A RELEASE
CYBEREX INC.
7171 INDUSTRIAL PARK BLVD MENTOR OHIO
INSTRUMENTATION AND FAULT CONNECTIONS
FIG 2



B	REV & ADDED INFO		[illegible]	[illegible]
ISSUE	DESCRIPTION	BY	APPVD	DATE

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD MENTOR, OHIO 44060

STATUS	SCALE	DWN BY [illegible]	CHKD.
		APPVD	DATE
TITLE TEST SETUP ONE LINE DIAGRAM		DWG SIZE NUMBER FIG. 1	
		SHEET 6 OF 8	

TEST SUMMARY

TEST # ____________ CHART # ____________ CHART SPEED ____________

BY ________ DATE ________ APR'D BY ________ DATE ________

TEST DESCRIPTION :

CHAN #	CHART SCALE units/mm	CHANGE DURING TEST		REMARKS
1				
2				
3				
4				
5				
6				
7				
8				

CHART TIME BASE ____________

DAMAGED PARTS :

UPS BREAKER TRIPPED DURING TEST : ____________

UPS FUSE CLEARED DURING TEST : ____________

REMARKS :

ISSUE	DESCRIPTION	BY	APP'D	DATE

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD. MENTOR, OHIO 44060

TITLE	STATUS	SCALE	DWN BY	CHK'D	APP'D	DATE	DWG. SIZE, NUMBER	SHEET
								8 OF 8

TEST PROCEDURE, ISOLATION VERIFICATION

S/N 9743 1E 20KVA UPS (INSTRUMENTATION AC POWER SUPPLY) IN SERIES WITH A POWER CONVERSION PRODUCTS ISOLATING TRANSFORMER MODEL # RTF-120/120-30

FOR PUBLIC SERVICE ELECTRIC & GAS CO.
HOPE CREEK GENERATING STATION
PO. 10855-E-154 (Q)-AC

OBJECTIVE:

TESTING TO ESTABLISH THE ISOLATING TRANSFORMER IN SERIES WITH A UPS SYSTEM AS A CIRCUIT ISOLATION SYSTEM.

PASS CRITERIA:

DEFINITION OF ISOLATION DEVICE OR SYSTEM: A DEVICE OR SYSTEM IS CONSIDERED TO BE A CIRCUIT ISOLATION DEVICE IF IT IS APPLIED SUCH THAT THE MAXIMUM CREDIBLE VOLTAGE OR CURRENT TRANSIENT APPLIED TO THE NON CLASS 1E SIDE OF THE DEVICE WILL NOT DEGRADE THE CLASS 1E CIRCUIT ON THE OTHER SIDE OF THAT DEVICE.

CIRCUIT	NORMAL VARIATION
ALT. DC. SUPPLY	105-135 VDC 0-364 ADC
NORMAL AC SUPPLY	480+10% V(L-L) 3 PHASE 0-55A, 0-132AP FOR 10MSEC
BACK UP AC SUPPLY	480+10% V 1 PHASE 0-78A, 0-500AP FOR 10MSEC

ANY VARIATIONS OUTSIDE OF NORMAL VARIATIONS SPECIFIED, WILL BE ANALYZED ON A CASE BY CASE BASIS.

FAULT LOCATION AND TYPE

FAULTS WILL BE APPLIED TO ISOLATING TRANSFORMER OUTPUT TERMINALS BY CLOSING A SWITCH AS REQUIRED.

FAULT TYPES:

1. PHASE (HOT) TO GROUND
2. NEUTRAL TO GROUND
3. PHASE TO NEUTRAL W/O GROUND
4. 480VAC APPLIED ACROSS UPS OUTPUT W/O GROUND (HOT SHORT)

THE CONDITION OF THE THREE CLASS IE SOURCES WILL BE MONITORED THROUGH SUITABLE SIGNAL CONDITIONERS, BY GOULD INC., 2000W SERIES HIGH FREQUENCY RECORDING SYSTEM.

TEST PROCEDURES

1.0 GENERAL NOTES

1.1 BEFORE STARTING TEST DETERMINE AND RECORD ALL SIGNAL CONDITIONER TRANSFER RATIO (MULTIPLIER) VALUES.

1.2 NORMAL SYSTEM OPERATION DURING EACH TEST

A. CONNECTION PER FIG. 1.
B. OUTPUT LOAD 10KVA @ .08PF (66.7 AMP RESISTIVE AND 50 AMP INDUCTIVE) @ 120VAC NOMINAL.
C. UPS POWERED BY "ALTERNATE" DC SOURCE (BATTERY) AND ONE OR BOTH AC SOURCES, "NORMAL" & "BACK-UP".
D. STATIC SWITCH IN "PREFERRED" POSITION.
E. ALL BREAKERS & SWITCHES CLOSED, BOTH BYPASS SWITCHES IN "NORMAL" POSITION
"TEST" SWITCH - CENTERED
"RETURN MODE" SWITCH - IN "AUTO" POSITION
"ISOLATION" TOGGLE SWITCHES - ON
"SYNC" TOGGLE SWITCH - ON

1.3 TEST INSTRUMENTATION

A. GOULD INC., MODEL 2800W HIGH FREQUENCY RECORDING SYSTEM. EIGHT CHANNEL, INDEPENDENT SCALE SELECT ±.050 TO ±500 VOLTS FULL SCALE.
B. POTENTIAL TRANSFORMER 480V, 60HZ PRIMARY 120V SECONDARY (4:1 RATIO).
C. CURRENT TRANSFORMER 1000:1 RATIO WITH 10 OHM BURDEN RESISTOR. (.01V/A).
D. WIDEBAND DC ISOLATION AMPLIFIER, GOULD INC. MODEL 13-4615-10 OR EQUIVALENT.

9-13

1.4 TEST FACILITY AND EQUIPMENT

A. DC SUPPLY - C&D 4LCW-15 BATTERY (60 CELLS, 80KW FOR 30 MIN.) AND BATTERY CHARGER.
B. AC SUPPLY - 480V, 3 PHASE, 4W, 60 HZ, 1200A GROUNDED NEUTRAL.
C. AC LOAD BANK - 0-30KW OR 0-30KVA @ 0.8PF.
D. FAULT APPLICATION DEVICE - G.E. CIRCUIT BREAKER TJC 36400G 400A, 3P. MAGNETIC ONLY.
E. HOT FAULT SOURCE - TRANSFORMER, 1 PH 480:120V 30KVA OR LARGER.

2.0 TEST PROCEDURE

2.1 BASE LINE DATA

START UP THE UPS WITH ALL SOURCES AVAILABLE. SET UP "NORMAL OPERATION" PER 1.2 AND ALLOW SYSTEM TO WARM UP FOR AT LEAST 30 MINUTES.

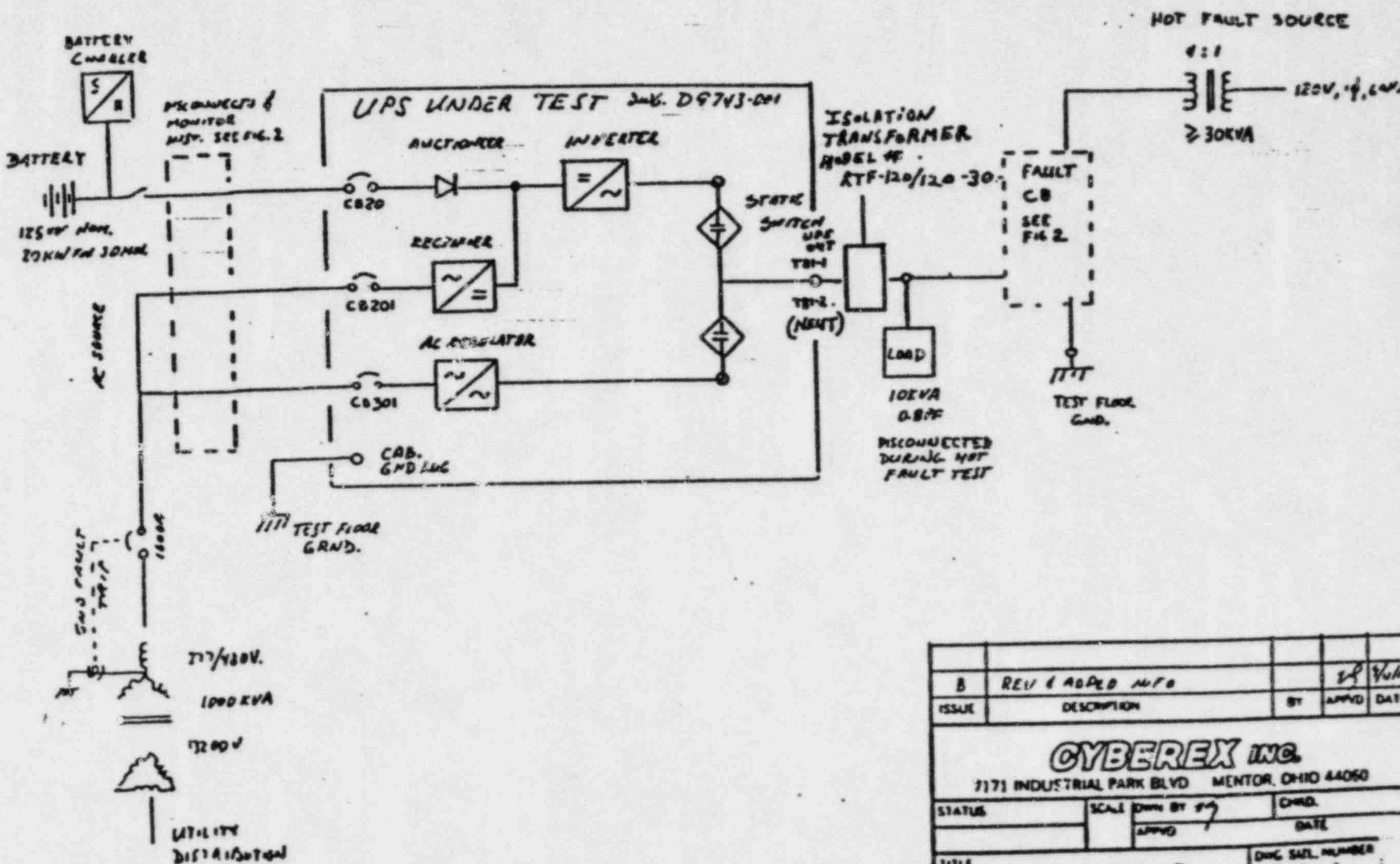
A1. METERING AND CONNECTIONS PER FIG. 2 AND "BACKUP SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
A2. REPEAT A1 EXCEPT USE 500HZ TIME BASE.
B1. WITH METERING AND CONNECTIONS PER FIG. 2 AND "NORMAL SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
B2. REPEAT B1 EXCEPT STATIC SWITCH TRANSFERRED TO BACKUP.
B3. REPEAT B1 EXCEPT USE 500HZ TIME BASE.
B4. REPEAT B2 EXCEPT USE 500HZ TIME BASE.

2.2 FAULT TESTING

C0. METERING AND CONNECTIONS PER FIG 2, RECORDER IN MANUAL TRIGGER MODE. APPLY FAULT BY CLOSING "FAULT" CB AND AT THE SAME TIME (OR 0 TO 10 MILLISECONDS BEFORE) TRIGGER THE RECORDER IN "STORE" MODE. REMOVE THE FAULT AND RECORD THE MEMORY TO PAPER.
AFTER EACH FAULT APPLICATION CHECK THE UPS FOR DAMAGE. REPAIR THE UPS IF REQUIRED BEFORE PROCEEDING.

C1. INSTALL JUMPER "A" TO "FAULT" CB WITH "BACKUP SOURCE" CB OPEN WITH RECORDER AT 20KHZ TIME BASE APPLY FAULT PER C0.
C2. REPEAT C1 EXCEPT WITH 500HZ TIME BASE.
C3. OPEN "NORMAL SOURCE" CB AND CLOSE "BACKUP" WITH RECORDER 20KHZ TIME BASE APPLY FAULT PER C0.
C4. REPEAT C3 EXCEPT WITH 500HZ TIME BASE.
C5. REPEAT C1, C2, C3 & C4 WITH JUMPER "B" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C6. REPEAT C1, C2, C3, & C4 WITH JUMPER "C" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C7. REPEAT C1, C2, C3, & C4 WITH CONNECTIONS TO HOT FAULT SOURCE (UPS RUNNING AT NO LOAD).

2.3 COMPLETE TEST SUMMARY SHEET FOR EACH TEST OR TEST GROUP.



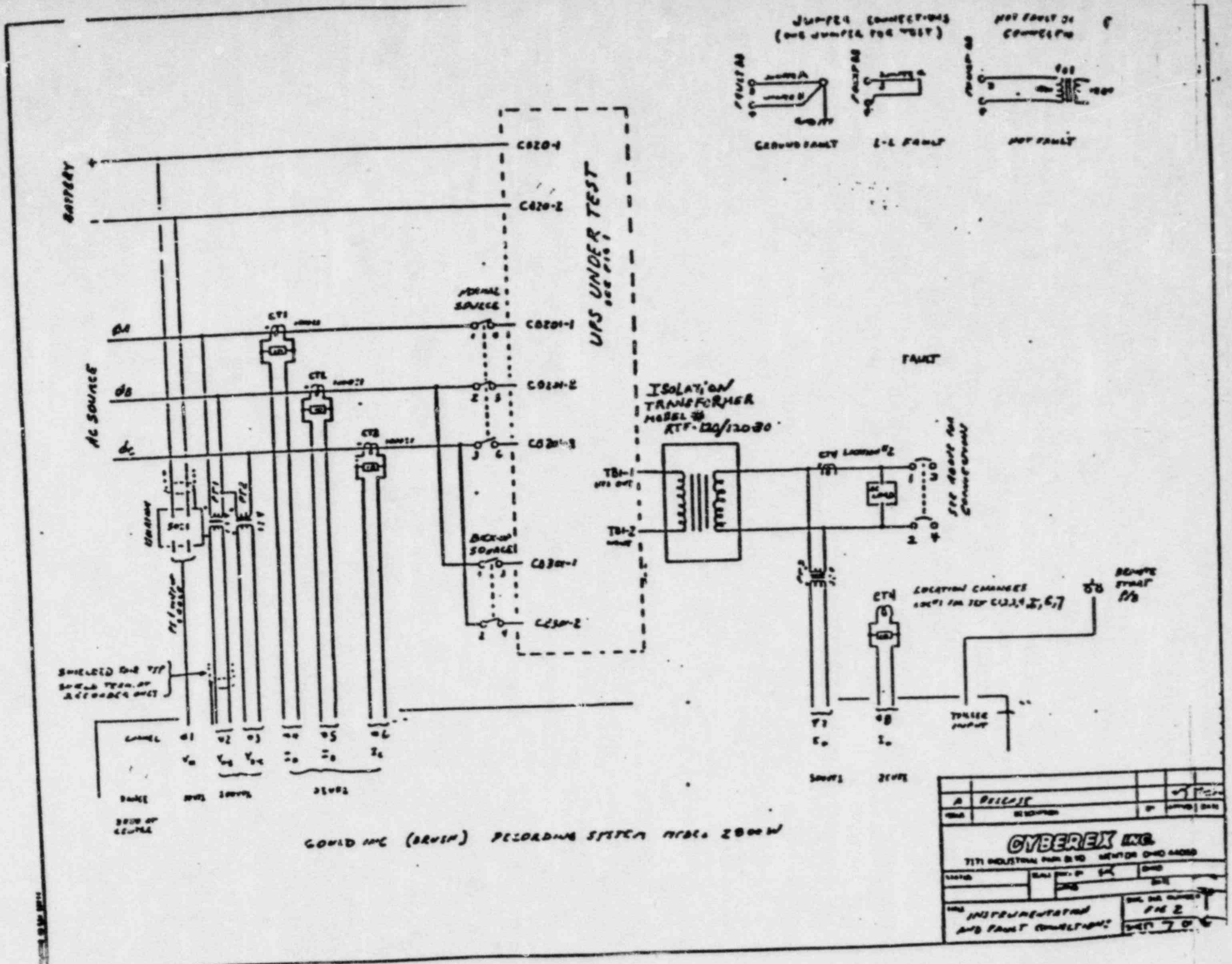
ISSUE	DESCRIPTION	BY	APPVD	DATE
B	REV & ADDED INFO			

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD MENTOR, OHIO 44060

STATUS | SCALE | DWN BY | CHKD. | APPVD | DATE

TITLE: TEST SETUP
ONE LINE DIAGRAM

DWG SIZE, NUMBER: FIG. 1
SHEET 6 OF 8


JUMPER CONNECTIONS
(ONE JUMPER FOR TEST)
GROUND FAULT
L-L FAULT
BATTERY
AC SOURCE
C820-1
C820-2
NORMAL SOURCE
BACK-UP SOURCE
UPS UNDER TEST
FAULT
ISOLATION TRANSFORMER
MODEL #
RTF-120/12080
TB1-1
TB1-2
CT4
TRIGGER INPUT
GOULD INC (BRUSH) RECORDING SYSTEM MODEL 2800W
A RELEASE
CYBEREX INC.
INSTRUMENTATION AND FAULT CONNECTIONS
FIG 2

TEST SUMMARY

TEST # ______ CHART # ______ CHART SPEED ______

BY ______ DATE ______ APR'D BY ______ DATE ______

TEST DESCRIPTION :

CHAN #	CHART SCALE UNITS/mm	CHANGE DURING TEST		REMARKS
1				
2				
3				
4				
5				
6				
7				
8				

CHART TIME BASE ______

DAMAGED PARTS :

UPS BREAKER TRIPPED DURING TEST : ______

UPS FUSE CLEARED DURING TEST : ______

REMARKS :

TITLE	STATUS	SCALE	DWN BY	CHKD.
			APPVD	DATE
CYBEREX INC. 7171 INDUSTRIAL PARK BLVD. MENTOR, OHIO 44060				
ISSUE	DESCRIPTION	BY	APPVD	DATE
DWG SIZE NUMBER				
SHEET 8 OF 8				

ATTACHMENT 5

13.4 REVIEW AND AUDIT

The independent review and audit functions of ANSI-N-18.7 will be performed by the Station Operations Review Committee which reports to the General Manager - Hope Creek Operations, and the General Manager - Nuclear Safety Review who reports to the Vice President - Nuclear. Reporting to the General Manager - Nuclear Safety Review are two groups, namely the On-Site Safety Review Group (SRG) and the Off-Site Review Group (OSR). Since the Nuclear Department is located on Artificial Island site the terms on-site and off-site are intended to convey the distinction between inside and outside the Station fence. The Nuclear Safety Review (NSR) Department organization is indicated in Fig. 13.1-6a. The equivalency to review groups identified in standard Technical Specifications is indicated below:

PSE&G	Equivalent Commonly Used Standard Technical Specification Terms
Station Operations Review Committee (SORC)	SORC or PORC or PRC or Unit Review Group (URG)
On-Site Safety Review Group (SRG)	ISEG
Off-Site Review Group (OSR)	Nuclear Review Board (NRB) or Off-Site Safety Review Committee or Safety Review and Audit Board or Company Nuclear Review and Audit Group (CNRAG)

The nuclear safety review process will be further strengthened in the organization by the establishment of an advisory board called the Nuclear Safety Advisory Board reporting to the Vice President - Nuclear.

senior management and

The Nuclear Safety Advisory Board (NSAB) fulfills the role of an oversight committee from the standpoint of nuclear safety with participation by outside members. The NSAB will be an advisory board to the Vice President - Nuclear and will not be governed by any Technical Specification requirements. Its primary responsibility is to consider potentially significant nuclear and radiation safety issues and related management matters from a programmatic and policy level viewpoint and advise the Vice President - Nuclear.

13.4.1 STATION OPERATIONS REVIEW COMMITTEE

The Station Operations Review Committee (SORC) will be established and functional before the initial fuel loading. Its purpose, throughout the life of the plant, is to advise the General Manager - Hope Creek Operations on all operational matters related to nuclear safety by reviewing plant operations, procedures, and tests that have nuclear safety significance.

12.4.1.1 Organization

Membership of the SORC will consist of, but not be limited to, the following:

a. Chairman - Assistant General Manager - Hope Creek Operations

b. Members:

1. Technical Manager - Vice Chairman
2. Operations Manager - Vice Chairman
3. Maintenance Manager - Vice Chairman
4. Operating Engineer
5. Maintenance Engineer
6. Instrument and Control Engineer
7. Chemistry Engineer
8. Technical Engineer
9. Radiation Protection Engineer
10. Senior Nuclear Shift Supervisor
11. Manager, On-Site Safety Review Group

13.4.1.1.1 Alternates

All alternate members shall be appointed in writing by the Chairman to serve on a temporary basis.

13.4.1.1.2 Quorum

A quorum of the SORC shall consist of the Chairman or his designated alternate and five members including alternates. However, no more than two alternates shall participate as voting members in SORC activities at any one time.

13.4.1.2 Meetings

The SORC will meet at least once per calendar month and as convened by the Chairman or Vice Chairman. Minutes of all formal meetings shall be maintained. Copies of minutes from SORC meetings are sent to the Manager - Off-Site Review, the General Manager - Nuclear Safety Review and the Vice President - Nuclear.

13.4.1.3 Responsibility

The SORC is responsible for:

a. Review of: (1) Station Administrative Procedures and changes thereto and (2) Newly created procedures or changes to existing procedures that involve a significant safety issue.

b. Review of all proposed tests and experiments that affect nuclear safety.

c. Review of all proposed changes to Appendix A, Technical Specifications.

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety

e. Review of the safety evaluations that have been completed under the provisions of 10CFR50.59.

f. Review of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, to the Vice President - Nuclear and to the General Manager - Nuclear Safety Review.

g. Review of all REPORTABLE EVENTS

h. Review of facility operations to detect potential nuclear safety hazards.

i. Performance of special reviews, investigations, or analyses and reporting thereon, as requested, by the General Manager - Hope Creek Operations or the General Manager - Nuclear Safety Review.

j. Review of the Emergency Plan and implementing procedures including revisions

k. Review of the Security Plan and implementing procedures including revisions.

l. Review of the Fire Protection Program and implementing procedures.

m. Review of all unplanned on-site releases of radioactivity to the environs including the preparation of reports covering evaluation, recommendations, and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the Vice President - Nuclear and to the General Manager - Nuclear Safety Review.

n. Review of changes to the PROCESS CONTROL MANUAL and the OFF-SITE DOSE CALCULATION MANUAL.

13.4.1.4 SORC Review Process

A technical review and control system will be established to perform the reviews generally required by SORC in accordance with standard Technical Specifications. This system will focus the SORC effort on those areas where the collective expertise of the committee members can have the most substantial contribution to the safety review effort. Important elements of such system would include:

1. Routine periodic review of procedures and changes thereto will be performed within the station organization, and only those items that have a safety significance will be referred to SORC for review.

2. SORC reviews will concentrate on consideration of safe and reliable operation of the station. Independent reviews for determination or verification of USQ will be performed by NSR and the results of NSR reviews will be provided to SORC.

3. A system of qualified reviewers within the station organization will be established to assist SORC review effort.

Reviews and approval of temporary changes to procedures is described in Section 13.5.

The SORC will review all events that require 24-hour notification to the NRC, violations of Technical Specifications, and any other unplanned events that may have nuclear safety significance. A report will be submitted to the SORC by a designated staff member. The conclusions and recommendations reached by the SORC will be recorded in the minutes of the meeting and forwarded to the General Manager - Hope Creek Operations and the General Manager - Nuclear Safety Review. Any unreviewed safety questions will be reported to the General Manger - Nuclear Safety Review for further action.

13.4.1.5 Authority

The SORC shall:

a. Recommend to the General Manager - Hope Creek Operations written approval or disapproval of items a. through e. under Section 13.4.1.3.

b. Provide written notification within 24 hours to the General Manager - Nuclear Safety Review of any disagreement between the SORC and the General Manager - Hope Creek Operations; The General Manager - Hope Creek Operations will have the responsibility for resolutions of such disagreements.

13.4.2 NUCLEAR SAFETY REVIEW

The Nuclear Safety Review Department (NSR) will be responsible for the independent safety review program consisting of the ISEG functions and the standard technical specification functions that are generally performed by a company nuclear review board. NSR consists of a General Manager, a Manager of the On-Site Safety Review Group (SRG) supported by at least four dedicated, full-time engineers located on-site at Hope Creek, and a Manager of the Off-Site Review Group (OSR) supported by at least four dedicated, full-time engineers located off-site. The SRG will be primarily responsible for ISEG functions and the OSR will be primarily responsible for functions that are generally performed by a Nuclear Review Board. However, depending on the need the resources of both SRG and OSR will be utilized, without organizational restrictions, in discharging overall review responsibilities of NSR. The staff will possess experience and competence in the general areas listed in Section 13.4.2.1. NSR shall establish a system of qualified reviewers from other technical organizations to augment its expertise in the disciplines of Section 13.4.2.1. Such qualified reviewers will meet the same qualification requirements as the NSR members; and will not have been involved with performance of the original work.

Establishment of the Manager, Off-Site Review and Staff is guided by the provisions for independent review of Section 4.3 of ANSI N18.7 (ANS-3.2), and the qualification requirements for the review staff will meet or exceed those described in Section 4.7 of ANS-3.1.

13.4.2.1 OFF-SITE REVIEW GROUP

The Off-site Review Group (OSR) will become effective upon the initial fuel loading of the unit and will function to provide independent review and audit of designated activities in the areas of:

a. Nuclear power plant operations

b. Nuclear engineering

c. Chemistry and radiochemistry

d. Metallurgy

e. Instrumentation and control

f. Radiological safety

g. Mechanical engineering

h. Electrical engineering

i. Quality Assurance

j. Nondestructive testing

k. Emergency preparedness

It will also function to examine plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources which may assist in performing its reviews.

13.4.2.1.1 Review

The OSR will review:

a. The safety evaluations for:

1) Changes to procedures, equipment, or systems and
2) tests or experiments completed under the provision of 10CFR50.59, to verify that such actions did not constitute an unreviewed safety question.

b. Proposed changes to procedures, equipment, or systems that involve an unreviewed safety question as defined in 10CFR50.59.

c. Proposed test or experiments that involve an unreviewed safety question as defined in 10CFR50.59.

d. Proposed changes to Technical Specifications or to the Operating License.

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or internal procedures or instructions having nuclear safety significance.

f. Significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety.

g. All REPORTABLE EVENTS.

h. All recognized indications of an unanticipated deficiency in some aspects of design or operation of safety-related structures, systems, or components.

i. Reports and meeting minutes of the SORC.

13.4.2.1.2 Audits

Audits of facility activities that generally are required to be performed under the cognizance of OSR, in accordance with the Standard Technical Specifications are listed below:

a. The conformance of facility operations to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months.

b. The performance, training, and qualifications of the entire facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety at least once per 6 months.

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10CFR50, at least once per 24 months

e. The Facility Emergency Plan and implementing procedures at least once per 12 months

f. The Facility Security Plan and implementing procedures at least once per 12 months

g. Any other area of facility operation considered appropriate by the General Manager - Nuclear Safety Review or the Vice President - Nuclear.

h. The Facility Fire Protection Program and implementing procedures at least once per 24 months.

i. An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing either qualified off-site licensee personnel or an outside fire protection firm.

j. An inspection and audit of the fire protection and loss prevention program shall be performed by a qualified outside fire consultant at least once per 36 months.

k. The radiological environmental monitoring program and the results thereof at least once per 12 months.

The above audits will be conducted by the Quality Assurance Department. Audit results and recommendations will be reviewed by NSR.

13.4.2.1.3 Consultants

Consultants may be used as determined by the General Manager - NSR to provide expert advice to the NSR. Other support groups within the Nuclear Department will also be available to provide technical expertise.

13.4.2.1.4 Authority

NSR will report to and advise the Vice President - Nuclear on those areas of responsibility specified in Sections 13.4.2.1.1 and 13.4.2.1.2

13.4.2.1.5 Records

Records of NSR activities will be prepared and maintained. Reports of reviews and audits will be distributed as follows:

a. Reports of reviews encompassed by Section 13.4.2.1.1 above, will be forwarded to the Vice President - Nuclear within 14 days following completion of the review.

b. Audit reports encompassed by Section 13.4.2.1.2 above will be forwarded to the Vice President - Nuclear and to the management positions responsible for the areas audited within 30 days after completion of the audit.

13.4.2.2 ON-SITE SAFETY REVIEW GROUP

The On-Site Safety Review Group (SRG) will be established and functioning prior to initial fuel load. The functions of the SRG include: the review of plant design and operating experience for potential opportunities for improving plant safety; the evaluation of plant operations and maintenance activities; and advice to management on the overall quality and safety of plant operations.

13.4.2.2.1 Organization

The SRG will consist of the Manager - On-Site Safety Review Group and dedicated, full-time engineers, located on site. Four such dedicated engineers will be at the Hope Creek site.

13.4.2.2.2 Qualifications

SRG members will meet or exceed the qualifications described in Section 4.4 of ANS 3.1 with a bachelor's degree in engineering and 2-4 years' experience in their field, including 1-2 years' nuclear experience.

13.4.2.2.3 Responsibility

The SRG will be responsible for:

a. Review of selected plant operating characteristics, NRC issuances, industry advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety.

b. Review of selected facility features, equipment, and systems.

c. Review of selected procedures and plant activities including maintenance, modifications, operational problems, and operational analysis.

d. Surveillance of selected plant operations and maintenance activities to provide independent verification* that they are performed correctly and that human errors are reduced to as low as reasonably achievable.

13.4.2.2.4 Authority

The SRG will make recommendations for revised procedures, equipment modifications, or other means of improving plant safety to appropriate station/corporate management.

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*Not responsible for sign-off function.

ATTACHMENT 6

Date: 9/24/84

DSER ITEM	DSER SECTION	SUBJECT
245	8.3.3.3.2	The use of 18 versus 36 inches of separation between raceways
251	8.3.3.5.5	Fault current analysis for all representative penetration circuits
253	8.3.3.1.4	Commitment to protect all Class 1E equipment from external hazards versus only Class 1E equipment in one division
259	8.3.3.3.4	Use of an inverter as an isolation device

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#26

DSER Open Item No. 245 (DSER Section 8.3.3.3.2)

THE USE OF 18 VERSUS 36 INCHES OF SEPARATION BETWEEN RACEWAYS

In Sections 1.8.1.75 and 8.1.4.14.3.1 of the FSAR it is stated that separation between redundant cable trays in the cable spreading area, control equipment room,, relay room, and main control room are separated by 18 inches vertically as opposed to the recommended 36 inches of separation required by IEEE Standard 384-1974.

The applicant, by Amendment 4 to the FSAR, indicated that this 18 inches of separation was approved by the staff during the preliminary design review of the Hope Creek plant. The staff's preliminary safety evaluation report for this item states that:

> "The applicant claims these separation distances are adequate because a high grade type cabling will be specified and results of extensive testing show that no cable degradation or flame propagation occurs when the lower tray, separated by 12 inches from the upper tray, is exposed to a gas flame for 15 minutes."

The results of these tests, that demonstrate no degradation to cables located in the trays 12 inches above the tray exposed to the gas flame, will be pursued with the applicant.

RESPONSE

Section 8.1.4.14.3.1 and the response to Question 430.51 have been revised to provide additional justification for the separation distance.

DH/em
. F70(8)

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Rev. 2

HCGS FSAR

QUESTION 430.51 (SECTION 8.3.1 and 8.3.2)

In Sections 1.8.1.75 and 8.1.4.14.3.1 of the FSAR you state that separation between redundant cable trays in the cable spreading area, control equipment room, relay room, and main control room are separated by 18 inches of separation required by IEEE Standard 384-1974. Provide analysis substantiated by test that demonstrates the adequacy of 18 inches of separation.

RESPONSE

The HCGS PSAR was approved with 18 inch vertical separation between redundant cable trays.

A copy of the test report that substantiated the use of this vertical separation has been submitted under separate cover (letter from R. L. Mitt, PSE&G, to A. Schwencer, NRC, dated August 15, 1984).

Revised section 8.1.4.14.3.1 provides the analysis based on this test to demonstrate the adequacy of 18 inches separation.

In addition to the above test, an additional cable tray test will be performed that tests shorting of electrical cabling utilizing the 18 inch vertical separation. This test plan is being submitted under separate cover.

Rev. 2

8.1.4.14.3.1 Cable Spreading Area, Control Equipment Room, and ~~Relay Room~~ Mezzanine, and Main Control Room

The cable spreading area, control equipment room and mezzanine, ~~relay room~~, and main control room do not contain high energy equipment such as switchgear, transformer, rotating equipment, or potential sources of missiles or pipe whip, and are not used for storing flammable materials. Power supply circuits are limited to those serving these areas and their instrument systems. These 208/120-V power cables are installed in conduits. Conduits containing redundant cables are separated by a minimum of 1 inch. Conduit couplings, clamps, locknuts, bushings, etc, shall not be considered in determining the required separation distances. For conduits carrying redundant neutron monitoring cables, boxes also shall not be considered in determining the required separation. Redundant cable trays are separated by at least 18 inches vertically and 12 inches horizontally. The configurations, for which the redundant ~~cable trays~~ raceways can not be separated by distances specified above, will either be analyzed or tested to demonstrate the compliance with the intent of Regulatory Guide 1.75. Separation distance requirements between Class 1E and non-Class 1E raceways are the same as for the separation among redundant channels.

> INSERT A

Strict administrative control of operations and maintenance activities is developed to control and limit the introduction of potential hazards into these areas.

8.1.4.14.3.2 Limited Hazard Areas

Limited hazard areas are the general plant areas from which potential nonelectrical hazards such as missiles, pipe whip, and exposure fires are excluded. The hazards in this area are limited to failures or faults internal to the electrical equipment or cables. These areas include elevations 77, 102, 124, 130, and 137 feet in the auxiliary building wing areas and elevation 87 feet in the radwaste area. Minimum separation in these ~~nonhazardous~~ areas is as follows:

a. Conduits containing redundant cables are separated by a minimum of 1 inch, unless consideration of hazards indicates greater separation is required. Conduit couplings, clamps, locknuts, bushings, etc, shall not be considered in determining the required separation distances. For conduits carrying redundant neutron

INSERT A TO 8.1.4.14.3.1

IEEE 384-1974 requires a minimum vertical separation of 3 feet between trays. The HCGS minimum vertical separation distance is 18 inches. The following analysis provides the justification for the lesser separation distance:

A. All cables are flame retardant and meet or exceed the flame test specified in IEEE 383-1974 as demonstrated by tests. Cable test reports are on file and available for audit.

B. As indicated in the above paragraph, high energy equipment and potential sources of missiles or pipe whip are excluded from the areas. Power circuits in the areas are installed in conduits that qualify as barriers; the maximum potential of the power circuits is limited to 208/120 volts ac or 125 volts dc. There are no power cables of higher potential serving equipment in the areas.

C. The cable tray test report performed for Salem showed that a fire in a cable tray located 12" directly below another tray did not propagate to the upper cable tray nor degrade the cables in the upper cable tray. The test configuration and cables were representative of the HCGS design and installation except that the test configuration used a 12 inch vertical separation. Because the Salem test demonstrated that the 12 inch vertical separation was adequate, the HCGS separation distance is justified. The Salem test report, ~~entitled~~ "Basis for Cable System Design Power Generating Stations", dated July 16, 1971, has been submitted under separate cover (letter from R.L. Mittl, PSE&G, to A. Schwencer, NRC, dated August 15, 1984).

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ABSTRACT-PHYSICAL SEPARATION TEST PLAN

1.0 SCOPE

This document is a test plan for the purpose of testing physical separation between redundant Class 1E cables and Class 1E and non-Class 1E cables with respect to electrical faults in configurations representative of HCGS.

1.1 OBJECTIVE

The purpose of this procedure is to present the requirements, procedures, and sequence for testing the design adequacy of the Hope Creek cable tray-to-cable tray separation. Figure 1 identifies the tray-to-tray separation test configuration.

1.2 APPLICABLE DOCUMENTS

- IEEE Std 384-1981
- IPCEA S19-81
- HCGS FSAR Section 8.1

1.3 EQUIPMENT DESCRIPTION

This test procedure encompasses testing of control cable and instrumentation cable as described below:

Item No.	Description
1.0	Okonite 600VAC, two conductor, size # 14 AWG (HC No. C02)
2.0	Okonite 600VAC, two conductor, size # 12 AWG (HC No. P12)
3.0	Eaton 600VAC, two conductor, size # 16 AWG (HC No. I02)

2.0 TEST REQUIREMENTS

2.1 Acceptance Criteria

2.1.1 Insulation Resistance Test

Measured insulation resistance on all "target" cables and any other cable, in the target raceway, that might sustain significant damage to its insulation system shall be greater than 1.6×10^6 ohms with an applied potential of 500 VDC for sixty (60) seconds.

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(Item 26)

2.1.2 High Potential Test

There shall be no evidence of insulation breakdown or flashover with an applied potential of 2200 VAC for sixty (60) seconds on all "target" cables and any other cable, in the target raceway, that might sustain significant damage to its insulation system.

2.1.3 Cable Continuity Test

Energized non-fault specimens in the "target" raceway shall conduct 100% rated current at 120 VAC throughout the overcurrent test.

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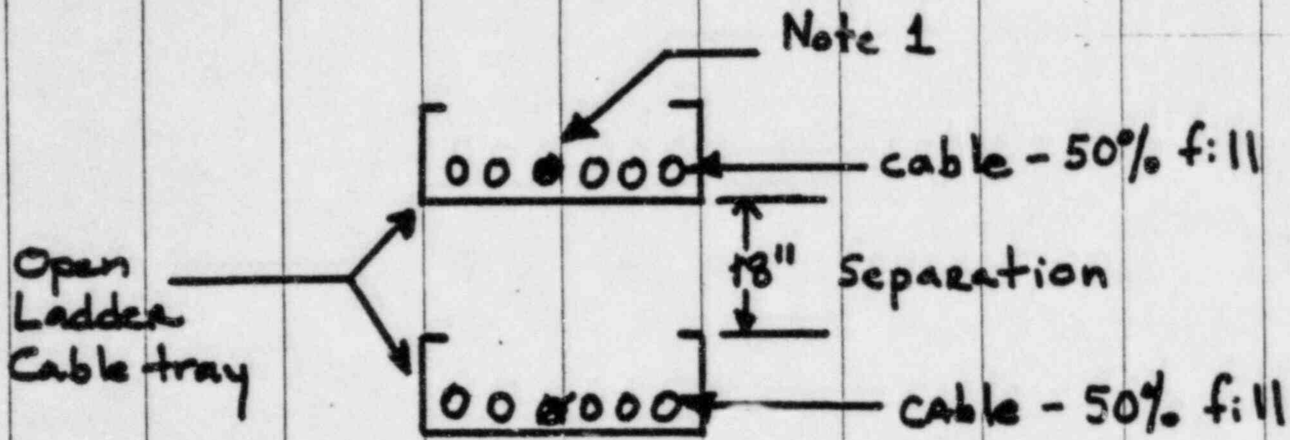
(Item 26)

FIGURE 1 - TEST SETUP FOR TRAY-TO-TRAY SEPARATION



● Denotes Target Cable Location

⊗ Denotes Fault Cable Location

Note 1 - Target cable will be energized during the faulted test condition

#32

N7

Rev. 3

DSER Open Item No. 251 (DSER Section 8.3.3.5.5)

FAULT CURRENT ANALYSIS FOR ALL REPRESENTATIVE PENETRATION CIRCUITS

By Amendment 4 to the FSAR, the applicant indicated that coordinated fault-current versus time curves for representative penetration conductors and their protective devices are included in Figures 420.46-1 of the FSAR. Based on a review of these figures, the staff concludes that representative curves for motor differential relay, current transformer, and instrumentation circuits were not included in Figure 430.46-1. Inclusion of these circuits as well as other circuits such that the coordinated fault-current versus time curves is representative of all penetration circuits will be pursued with the applicant.

RESPONSE

FSAR Section 8.1.4.12 has been revised in response to Question 430.46, and to address this concern.

NT

QUESTION 430.46 (SECTION 8.3.1 and 8.3.2)

Section 8.1.4.12 of the FSAR simplies, through the use of the term "penetration conductor", that primary and backup circuit protection is provided to protect the circuit conductor versus the penetration. This design for containment electrical penetration protection does not meet the guidelines of position 1 of Regulatory Guide 1.63. Position 1 requires primary and backup protection where maximum available fault-current exceeds the current-carrying capability of the penetration versus capability of the conductors.

a. Provide justification for noncompliance with the guidelines of position 1 of Regulatory Guide 1.63.

b. Provide coordinated fault-current versus time curves for each representative type cable that penetrates primary containment. For each cable, the curves must show the relationship of the fault carrying capability between the electric penetrations, the primary overcurrent protective device, and the backup overcurrent protective device.

c. Provide the test report with results that substantiates the capability of the electrical penetration to withstand the total range of time versus fault current without seal failure for worst case environmemental conditions.

RESPONSE

FSAR Section 8.1.4.12 has been revised to provide the requested information.

NT

Figure 430.46-1

Sheets 1 to 15

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NT

8.1.4.10 Regulatory Guide 1.53, Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems, June 1973

The electric power system is designed to comply with Regulatory Guide 1.53 as discussed in Section 1.8. All four Class 1E power system channels are designed and located in accordance with the separation criteria for the plant. Routing of cables and location of equipment is designed so that a failure of any kind in any channel cannot propagate to any other redundant channel. Consistent with the single failure criterion, only one failure is assumed to occur in the system following a DBA.

8.1.4.11 Regulatory Guide 1.62, Manual Initiation of Protective Actions, October 1973

HCGS complies with Regulatory Guide 1.62 as discussed in Section 1.8.

8.1.4.12 Regulatory Guide 1.63, Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants, July 1978

Design of HCGS penetration assembly systems is in compliance with Regulatory Guide 1.63, with the exceptions indicated in g, h, and i below. X

The types of circuits that go through penetration assemblies are as follows:

a. Power feeders for medium voltage 3.92-kV motors

b. Power feeders for 480-V ac motors

c. 480-V ac and 208-V ac miscellaneous power feeders

d. 120-V ac control circuits

e. 125-V dc control circuits

f. 120-V ac lighting circuits

g. Motor differential relay current transformer circuits

h. Low voltage instrumentation circuits

i. Communication circuits.

The following system features are provided to ensure compliance with the Regulatory Guide position on single random failures of circuit overload protection devices:

a. Medium voltage penetration assemblies: The only medium voltage circuits routed through the penetration are the 3.92-kV circuits for the two reactor recirculation pump motors. Each motor is supplied from a variable frequency motor-generator set. The maximum fault current available for a fault inside the containment is limited by the generator contribution and the circuit resistance. PRIMARY AND BACKUP PROTECTION FOR THE 1000 Kcmil PENETRATION IS PROVIDED BY TWO CLASS 1E CIRCUIT BREAKERS IN SERIES AS SHOWN IN FSAR FIGURE 8.3-4. EACH CIRCUIT BREAKER IS PROVIDED WITH AN OVERCURRENT RELAY. THESE RELAYS ARE SET TO TRIP THEIR RESPECTIVE CIRCUIT-BREAKERS. Figure 8.3-17, SHEET 11, SHOWS THAT THE TIME-CURRENT CAPABILITY OF THE 1000 Kcmil PENETRATION IS GREATER THAN ANY MAXIMUM SHORT CIRCUIT CURRENT VS. TIME CONDITION THAT COULD OCCUR.

DSER OPEN ITEM 351

b. 480-V ac motor feeder circuits: The 480-V ac loads inside the containment consist of Class 1E and non-Class 1E motor-operated valves and non-Class 1E continuous-duty motors. All these loads are supplied from 480-V motor control centers (MCCs).

The magnetic-only circuit breaker used in the combination starter for the motor provides primary protection for penetration conductors. A thermal-magnetic breaker in series with the starter breaker provides backup protection for these penetration conductors. These primary and backup breakers used for the protection of penetration conductors are both located in the same cubicle of the MCC. The primary breaker is set to provide only short circuit protection. It does not provide locked-rotor protection, which is provided by overload relays in the MCCs for non-Class 1E motor-operated valves and continuous-duty motors.

For Class 1E motor-operated valves (MOVs), the overload relay is bypassed for emergency plant operation to increase the availability of these valves in accordance with Regulatory Guide 1.106. For these Class 1E MOVs, the backup breakers are selected to allow for sustained locked rotor current and penetration conductors are selected to ensure that the thermal limits of the penetration are not exceeded during this condition.

The thermal-magnetic backup breaker has a nonadjustable trip setting, which is rated on the following basis:

1. The time-current characteristic curve remains under the thermal damage curve of the penetration conductor over the range of postulated temperatures so that the breaker trips on overcurrent before the thermal limit of the penetration conductor is reached.

2. The breaker allows locked rotor current of non-Class 1E motors for at least 10 seconds and 1000 seconds for Class 1E motors. These breaker settings prevent nuisance tripping of non-Class 1E motors during starting and allows ample time for the motors to start.

c. 480-V and 208-V miscellaneous feeders: Non-Class 1E 480-V MCCs provide power for hoists, reactor recirculation pump motor space heaters, and welding outlets in the drywell. The primary and backup protections for these feeders are provided by two thermal magnetic breakers in series. Both the breakers have the same ratings and are located in the same cubicle of the MCC. The ratings of both the breakers

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are selected so that on overcurrent, the breakers trip before the thermal limit of associated penetration conductor is reached.

208-V ac miscellaneous feeders from a 208/120-V ac power panel provide power for source range monitoring (SRM) and intermediate range monitoring (IRM) systems. The primary protection for the 208-V ac circuit is provided by fuses in each circuit conductor. These fuses are located in GE control panels. The main 20-ampere thermal-magnetic breaker, located in the power panel, provides the backup protection for these circuits. The time-current characteristics of both the fuses and circuit breakers are selected so that both the devices trip before the thermal limit of the associated penetration conductor is reached.

d. 120-V ac control circuits: 120-V ac circuits are powered from 480/120-V ac control transformers located in the MCC cubicles. Two fuses, with the same rating in series for each circuit, located in the associated cubicles of MCCs, provide both the primary and backup protection. For a fault, the fuses blow before the thermal limit of the associated penetration conductor is reached.

120-V ac control circuits fed from uninterruptible power supply (UPS) distribution panels are provided with two fuses in series for each circuit. Primary protection is provided by the fuses located in GE control panels. Backup protection is provided by the main fuse with a rating higher than the primary fuse located in the UPS panel. For a fault, the fuses blow before the thermal limit of the penetration conductor is reached.

e. 125-V dc control circuits: Each circuit powered from the 125-V dc control bus in the switchgear is provided with two fuses of the same rating located in the associated switchgear cubicle. These two fuses wired in series provide both primary and backup protection for the associated penetration conductor.

Each circuit powered from the control bus in the GE control panels is provided with a fuse in that panel to ensure primary protection for the penetration

NT

conductor. Backup protection is provided by the feeder breaker supplying the control bus.

In both cases above, either the primary or backup protection is capable of clearing the fault before the thermal limit of the associated penetration conductor is reached.

f. 120-V ac lighting circuits: All lighting circuits going through the penetrations are 120-V ac. Each circuit is provided with two thermal-magnetic breakers in series. The primary protection for the penetration conductor is provided by breakers located in breaker panels. Breakers located in the lighting panels wired in series circuit with breaker panels provide the backup protection for the penetration conductor.

Both the primary and backup protection are capable of clearing the fault before the thermal limit of the penetration conductor is reached.

g. Motor differential relay current transformer circuits: The only circuits in this category are the current transformer circuits for differential protection of the reactor recirculation pump motors. No protection is necessary for the penetration conductors associated with these current transformer leads because the maximum possible relay current for a sustained fault in the medium voltage cable is only 37 amperes. The ampacity of the penetration conductor is 41 amperes. Furthermore, the relay current decays to 1.7 amperes after 80 seconds because of the fault current decrement. These current transformer circuit cables are designated control cables and are routed in separate raceways from power cables. This eliminates the possibility of a short circuit between power and control cables.

INSERT "A"

h. Instrumentation circuits: Instrument circuits are all low-energy circuits carrying only a few milliamperes. Also, these circuits are routed in separate raceways from power cables to eliminate the possibility of a short between power and instrument circuits. The SHORT CIRCUIT current in the instrument circuits CAN not exceed the ampacity of penetration conductors under any faulted condition. In addition,

NT

Insert A

The differential relay fails safe for shorts or opens in the current transformer circuits. If the differential leads were to short while carrying their normal load of 3.17 amperes, the differential relay would operate and trip the generator drive motor in 144 milliseconds and the 3.17 amperes load would drop down to 1.7 amperes in 80 seconds. The penetration is rated for 41 amperes continuously.

NT

the instrumentation circuits are protected from overloads by primary overcurrent protective devices which are integral with their power supply and by backup overcurrent protective devices located upstream of the power supplies.

INSERT "B"

i. Communication circuits - Communication circuits consist of 120-V ac power and signal circuits. Each power circuit has two fuses in series. One located in the distribution panel provides the primary protection, and another located in a terminal box near the penetration provides backup protection for the associated penetration conductors. Both of these are capable of clearing the fault before the penetration conductor reaches its thermal limit.

INSERT "C"

8.1.4.13 Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants, January 1974

HCGS complies with Regulatory Guide 1.73 as discussed in Section 1.8.

8.1.4.14 Regulatory Guide 1.75, Physical Independence of Electric Systems, September 1978

HCGS complies with Regulatory Guide 1.75. Clarifications and exceptions are noted in Section 1.8.

8.1.4.14.1 General Separation Criteria

Electrical equipment and wiring for the engineered safety feature systems (ESF), reactor protection system (RPS), and neutron monitoring system (NMS) are segregated into separated channels/divisions as shown in Table 8.1-1, so that under DBAs no single credible event is capable of disabling sufficient equipment to prevent reactor shutdown, decay heat removal from the core, or mitigation of accidents. The ESF systems, RPS, and NMS are separated electrically and physically from one another, and each is further separated into four channels. The degree of separation provided is commensurate with the potential hazards in a given area.

Insert B

The only penetrations with instrument class circuits that are protected by a single circuit breaker or fuse are as follows:

1. Vibration Monitoring

   (a) Circuit breaker is 7 amperes.
   (b) Maximum short circuit current is 0.8 amperes.
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 18 times the maximum short circuit current they may be expected to experience.

2. Neutron Monitoring System

   (a) Circuit protected by a 1/4 ampere fuse.
   (b) Maximum short circuit current is 0.2 amperes.
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 75 times the maximum short circuit current they may be expected to experience.

3. Acoustical Monitoring System

   (a) Circuit protected by a 2.5 ampere fuse.
   (b) Maximum short circuit current <0.1 ampere. (The 330KΩ resistor would limit the short circuit to 0.1 ampere even if the rest of the circuit impedance was zero.)
   (c) Penetration is #16 AWG wire with a continuous rating of 15 amperes.
   (d) These penetrations have a continuous rating in excess of 150 times the maximum short circuit current they may be expected to experience.

4. Thermocouple Circuits

   (a) Thermocouples cannot generate any conceivable short circuit challenge to a penetration.

Insert C

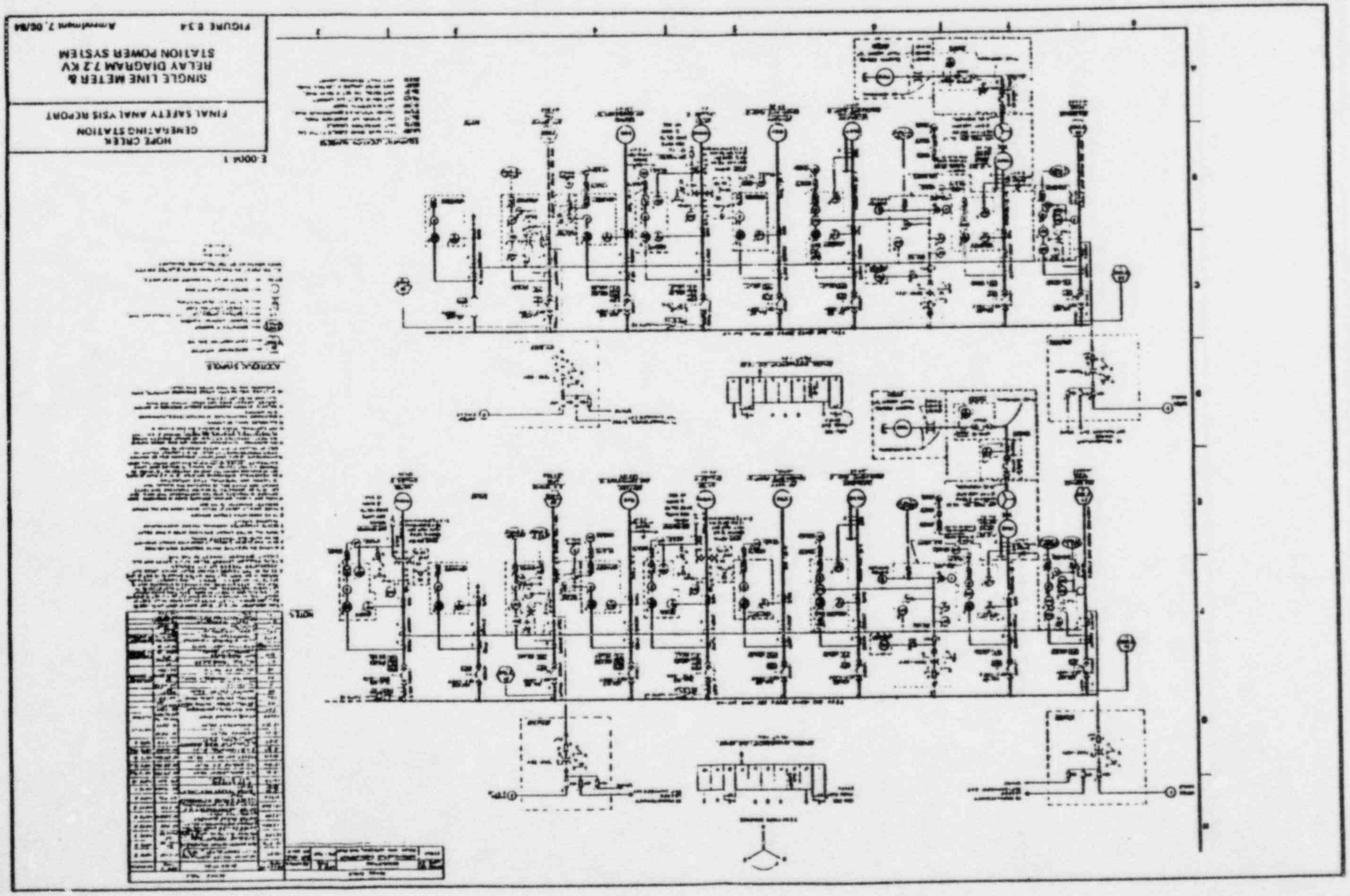
The P.A. voice circuits carry millivolt signals only when they are actually transmitting a voice communication. The system cannot generate any conceivable short circuit challenge to a penetration.

In addition, the penetration assemblies are designed to withstand, without loss of mechanical integrity, the maximum short-circuit current vs. time conditions that could occur, given single random failures of circuit overload protection devices. Time current characteristic curves, based on tests, of the penetration conductors have been established by the penetration supplier; these curves show the maximum duration of symmetrical short circuit current. Based on these curves the primary and backup protective devices are selected to ensure that the mechanical integrity of the penetrations is maintained. Coordinated fault-current versus time curves for representative penetration conductors and the protective devices are shown in Figures 8.3-17, Sheets 1 to 22.

The test report that substantiates the capability of the electrical penetration to withstand fault current without seal failure for worst case environmental conditions has been submitted under a separate cover.

The testing of all penetration over-current protective devices will be incorporated in the HCGS Technical Specifications.

DSER OPEN ITEM 251



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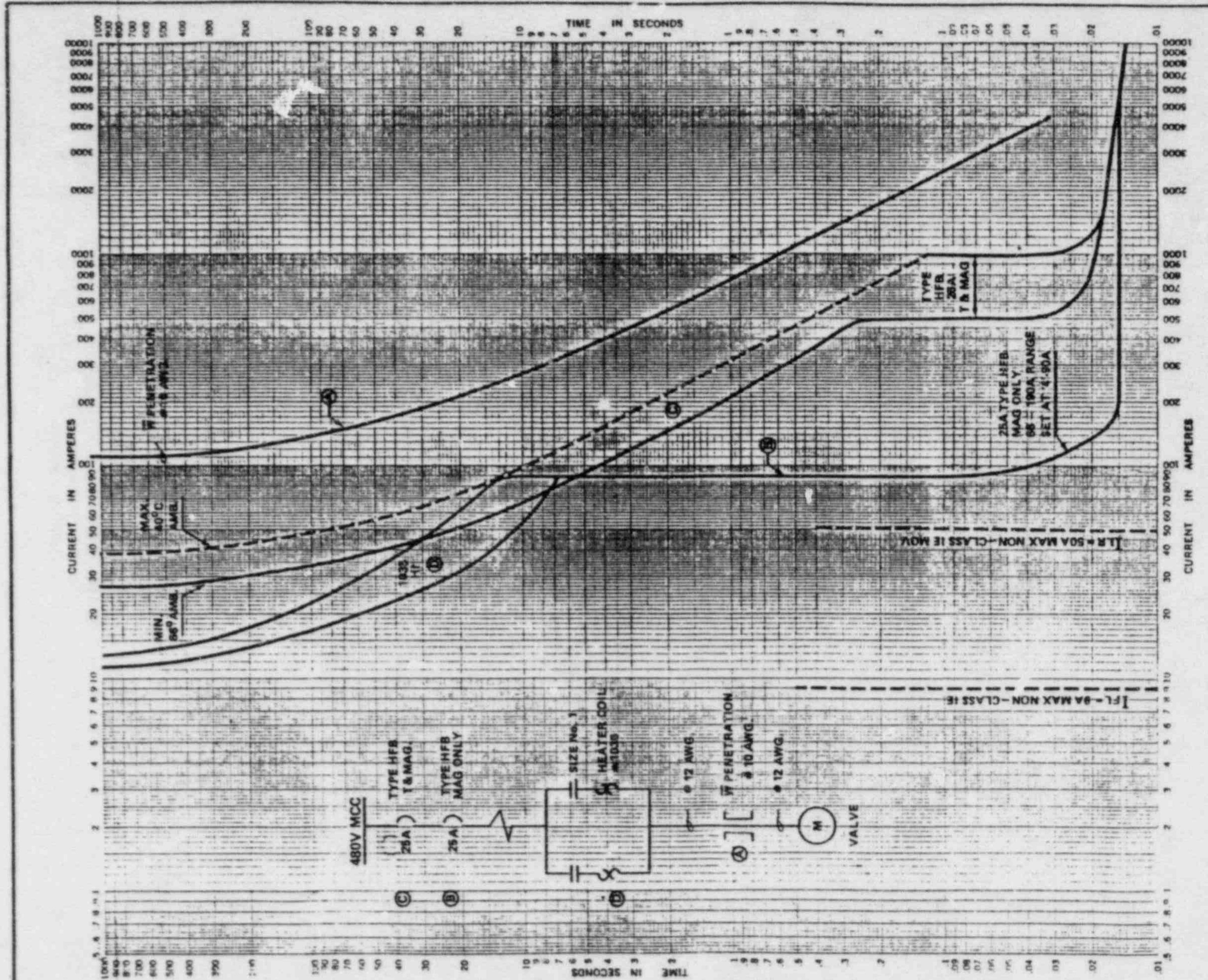
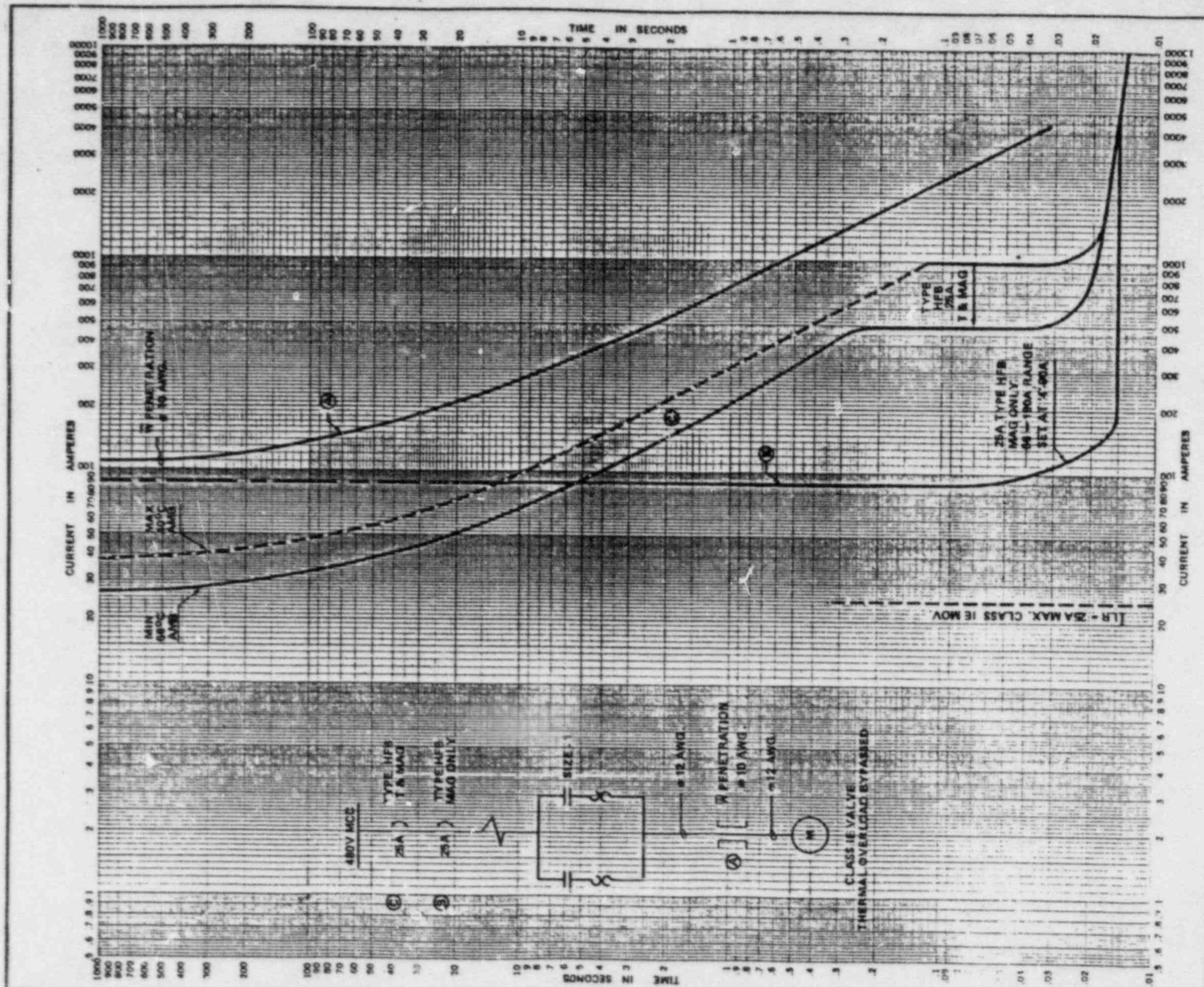


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 1 OF 22

~~AMENDMENT~~ 10/84

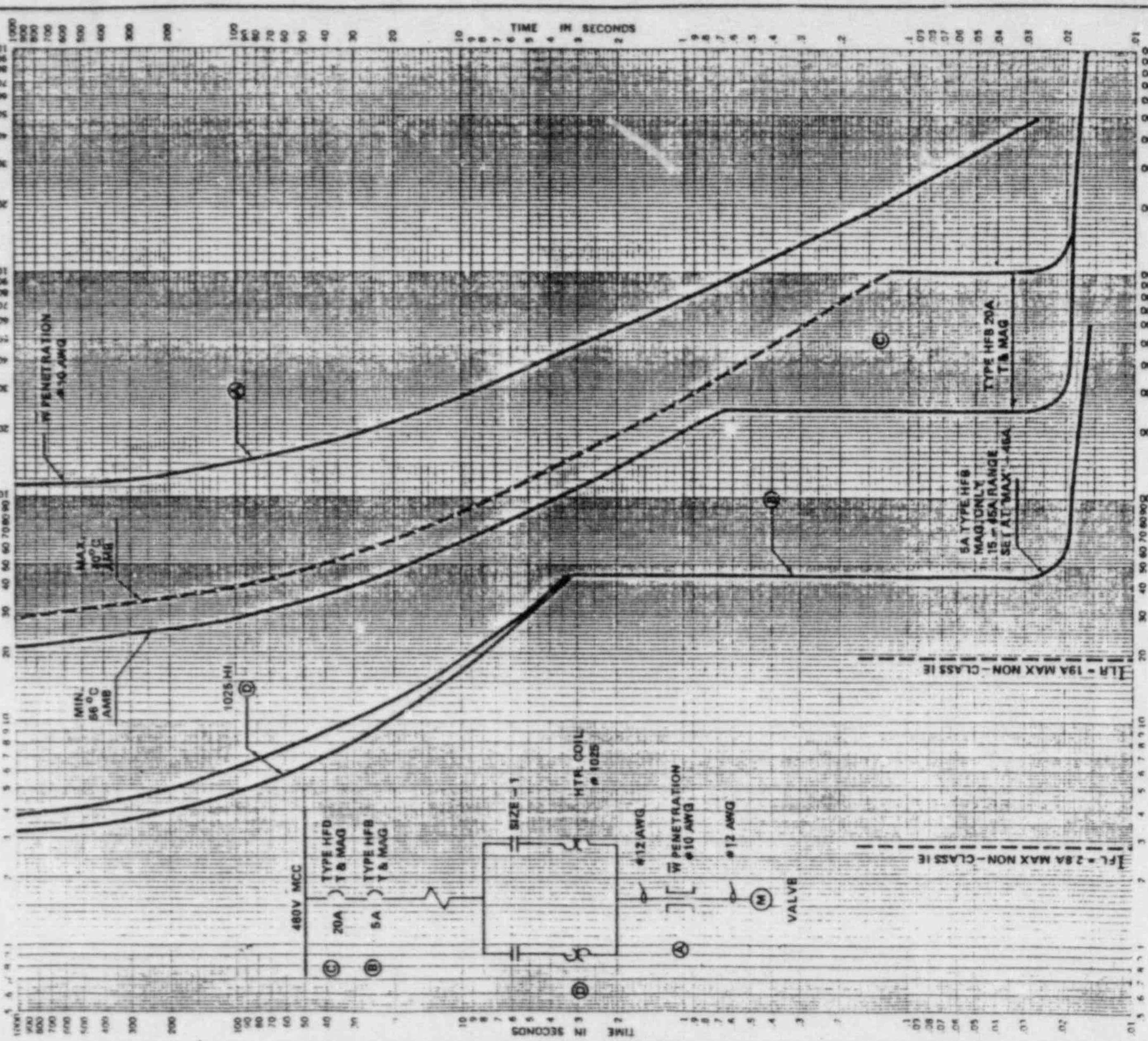


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 2 OF 22

~~AMENDMENT 8~~, 10/84

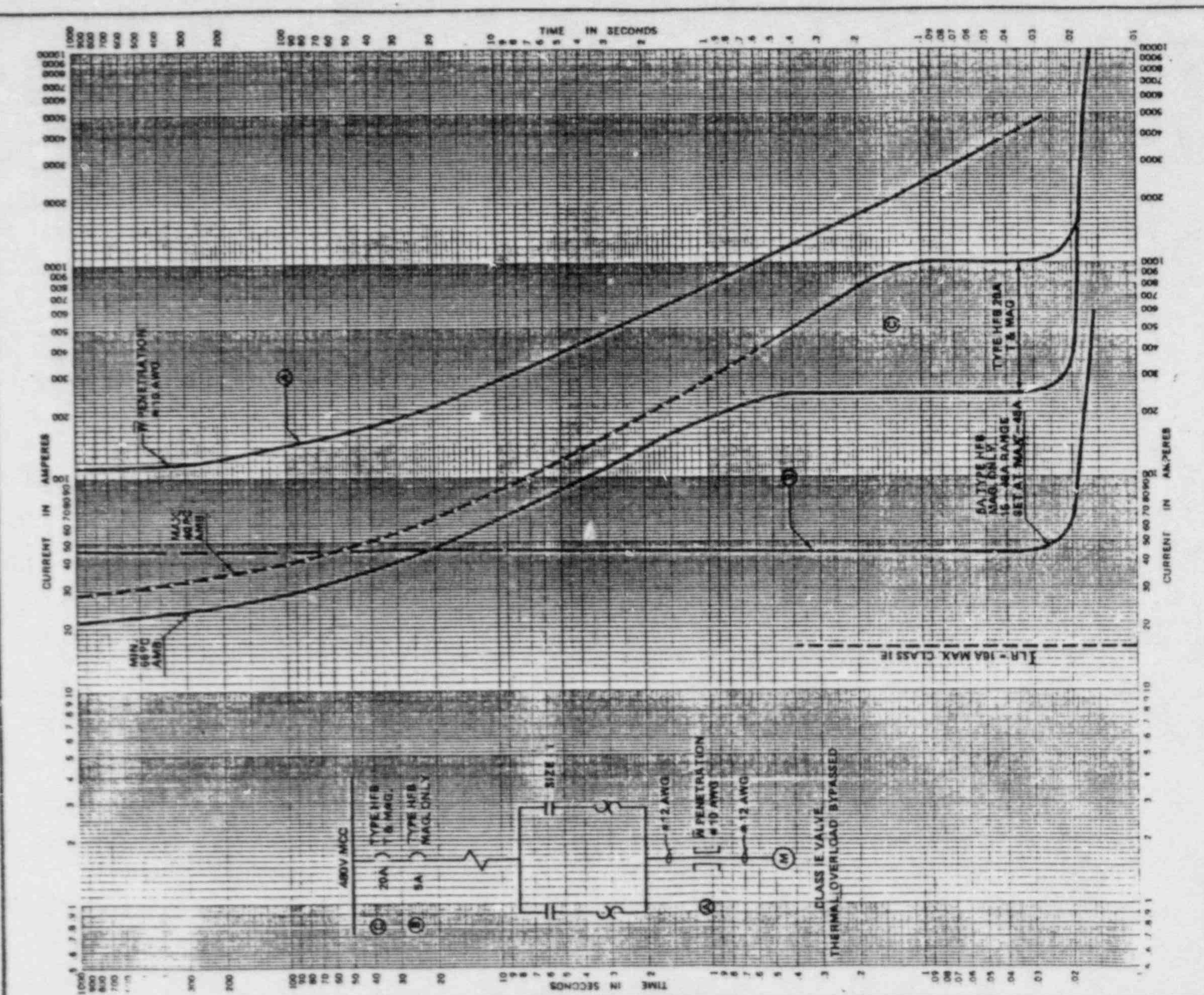


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 3 OF 22

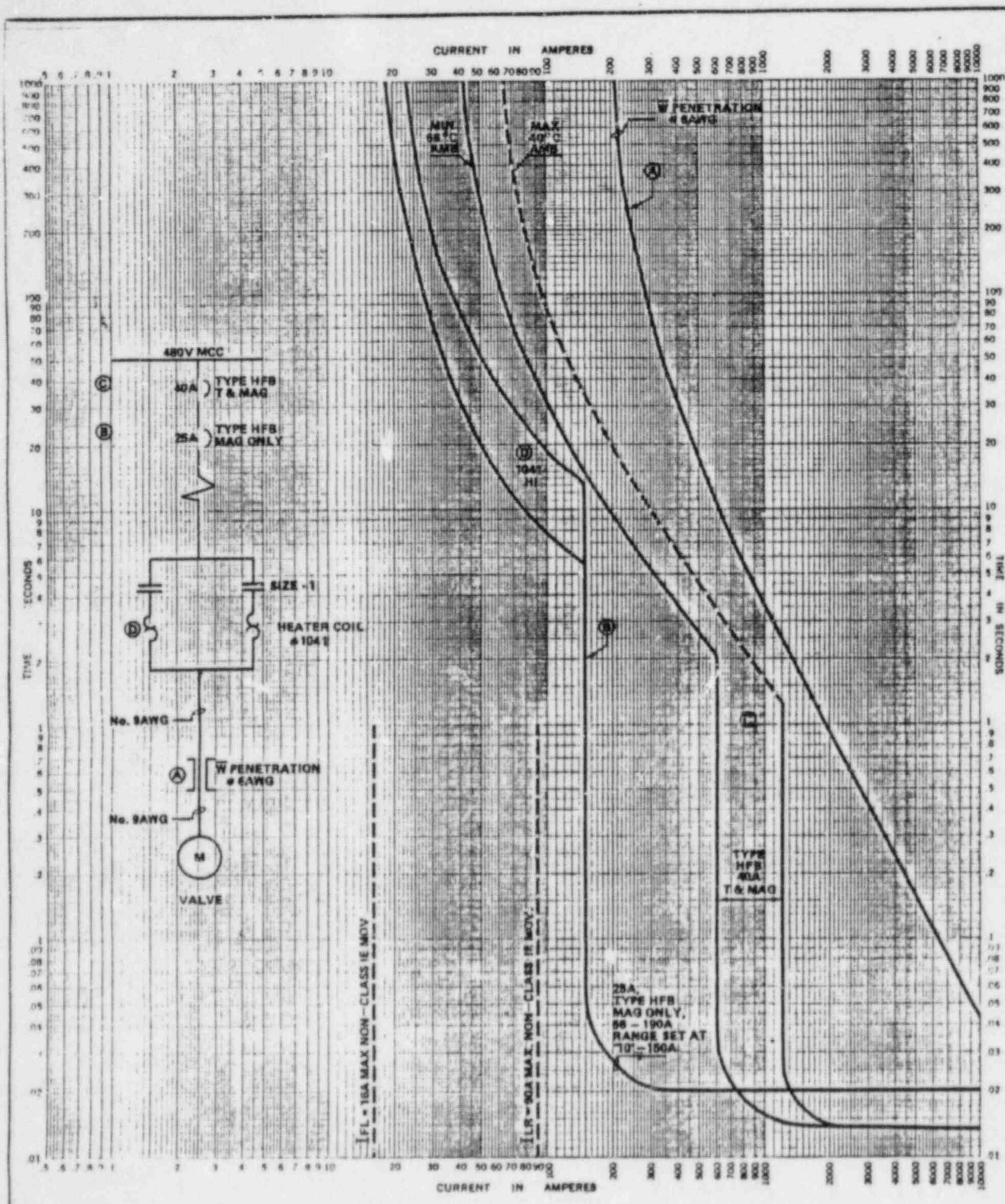
~~[illegible]~~ 10/84



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

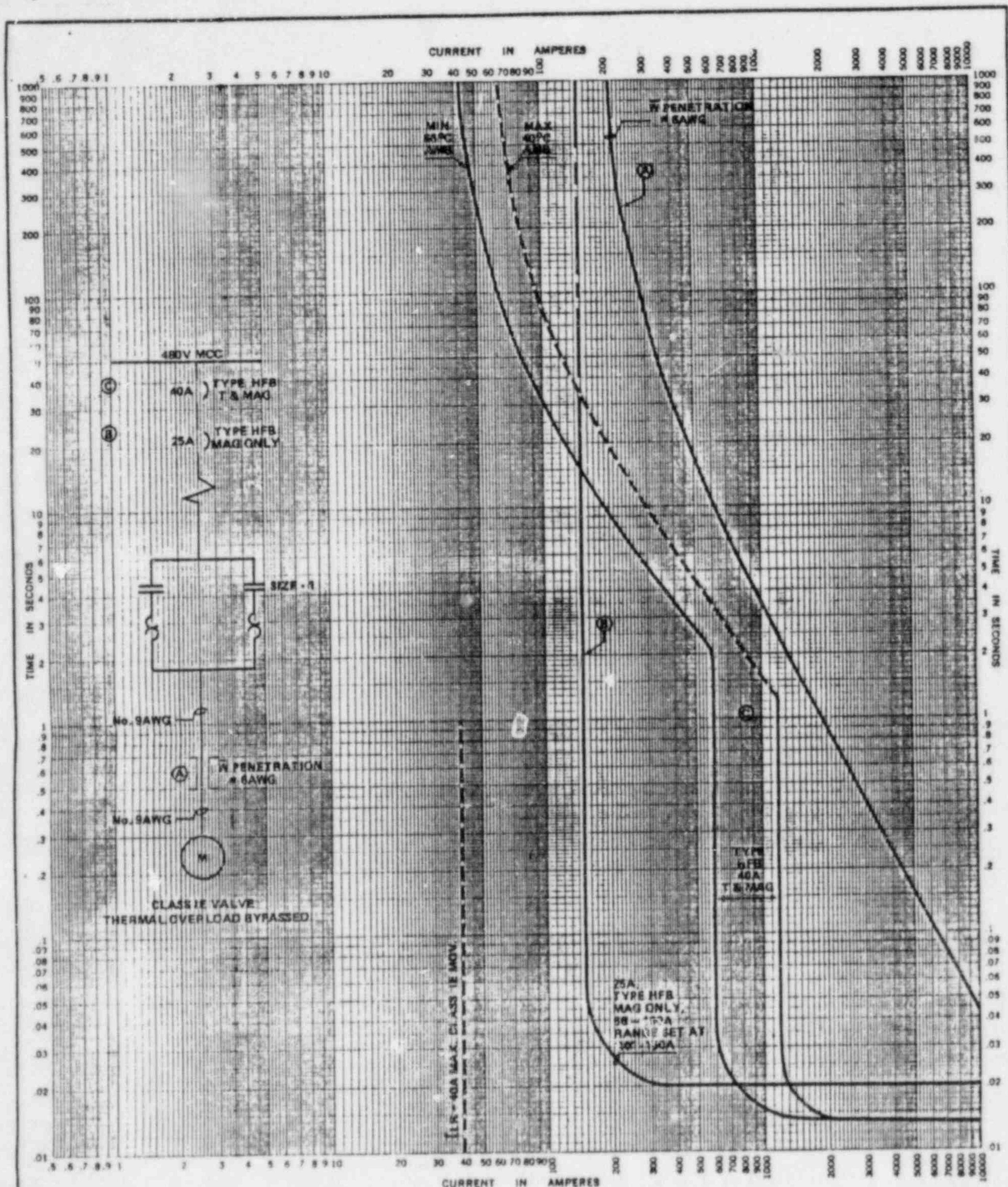
FIGURE 8.3-17
SHEET 4 OF 22
, 10/84



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 5 OF 22

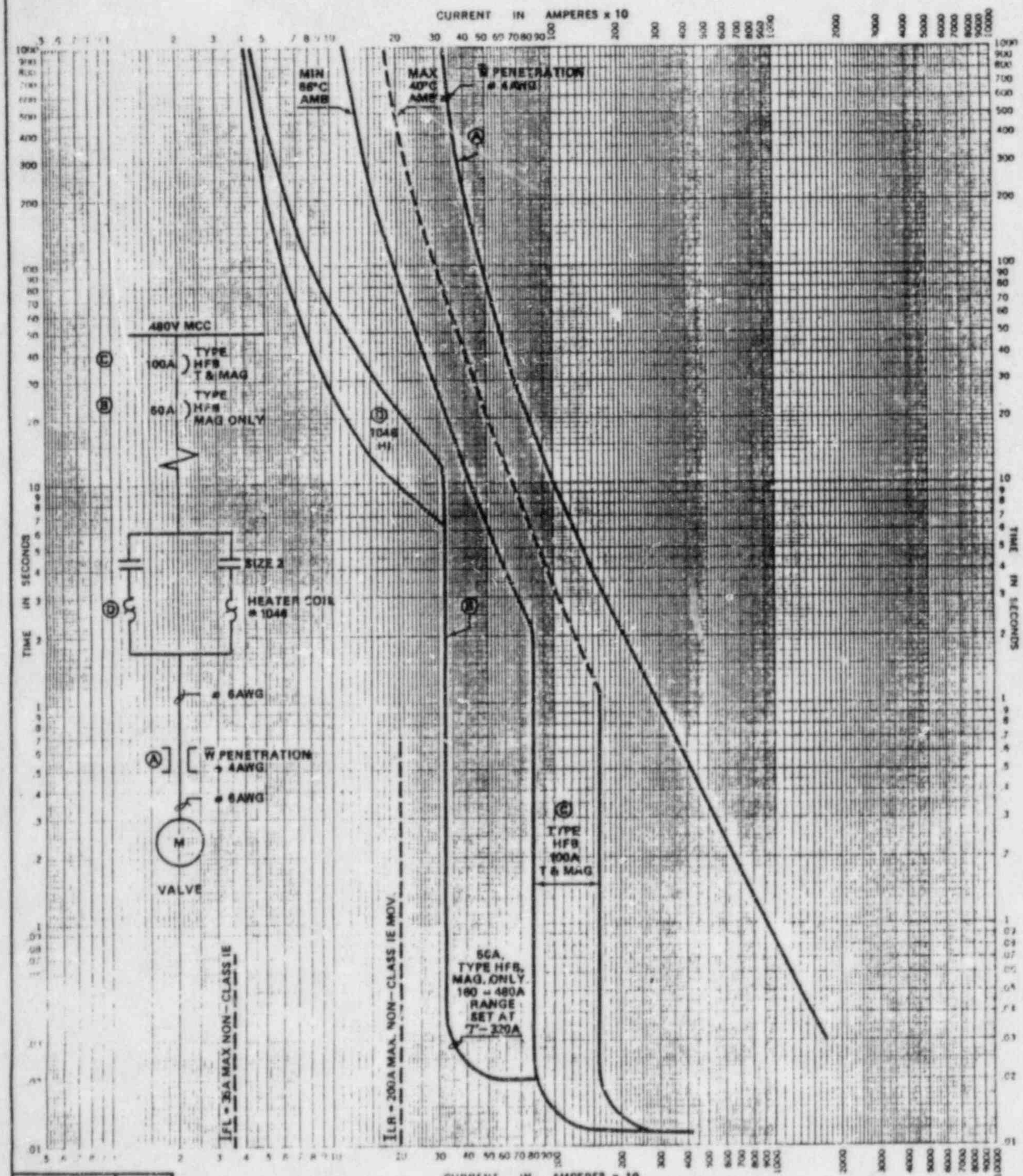


HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 6 OF 22

10/84

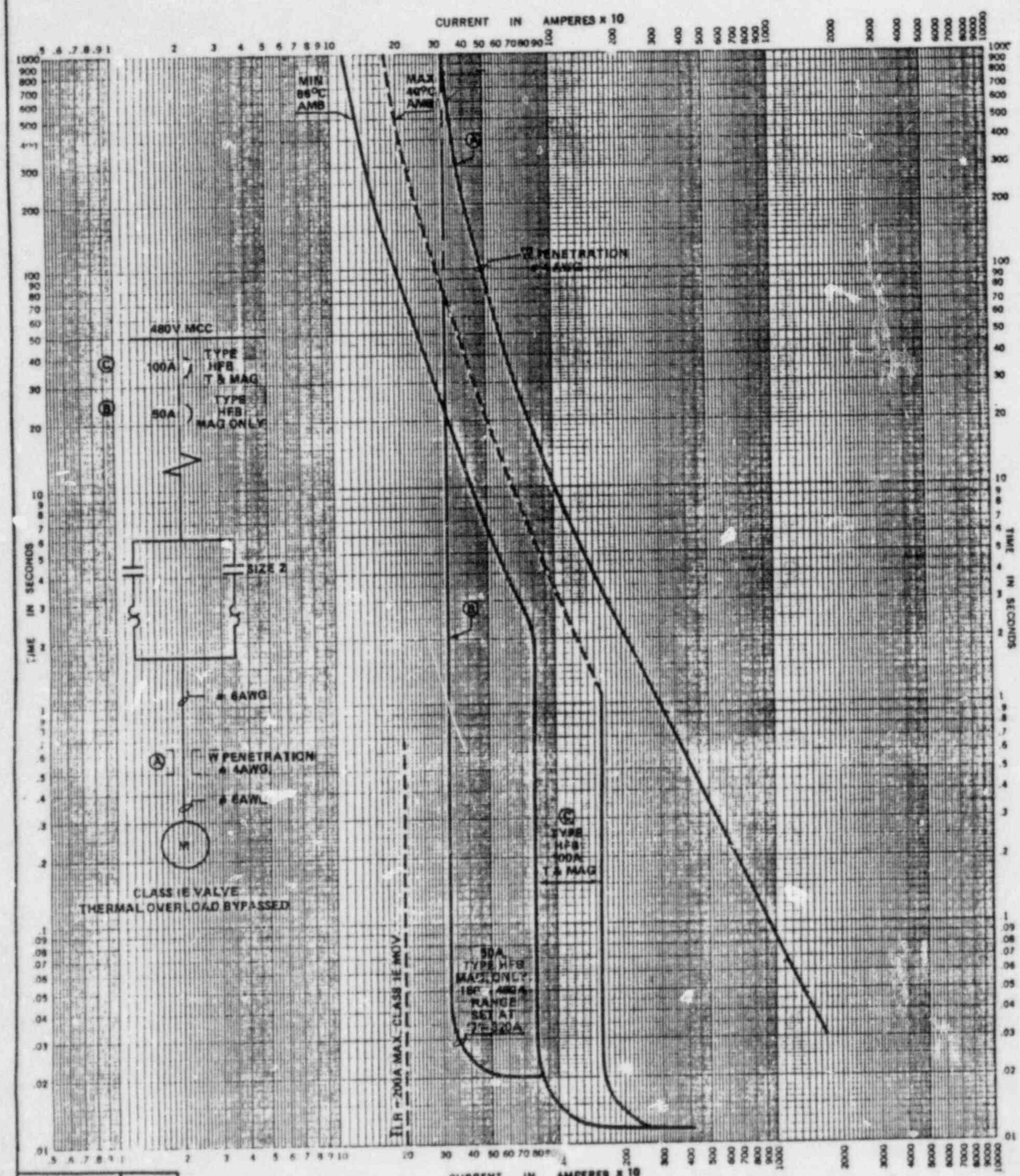


HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.1-17
SHEET 7 OF 22

10/84

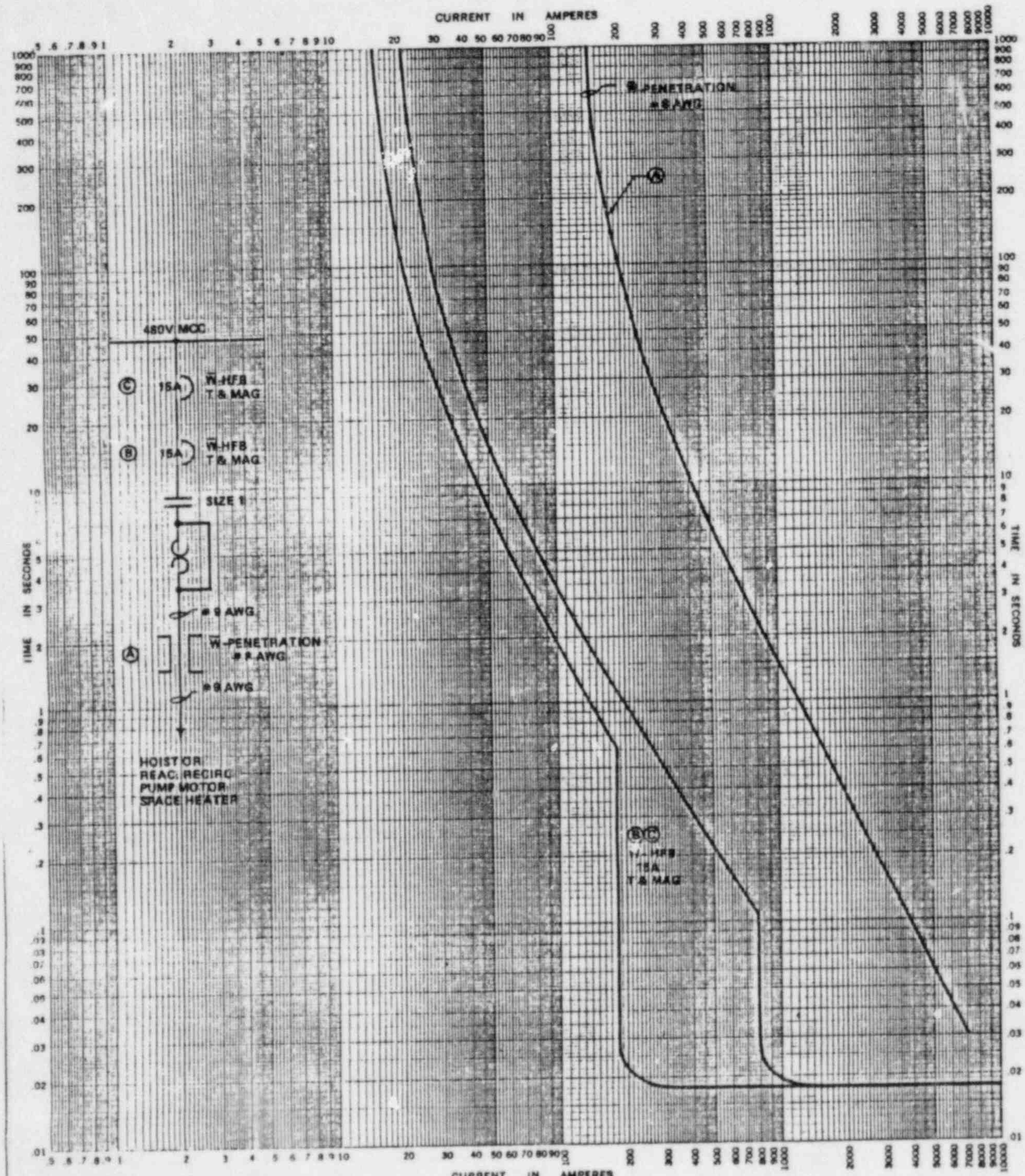


HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 8 OF 22

10/84

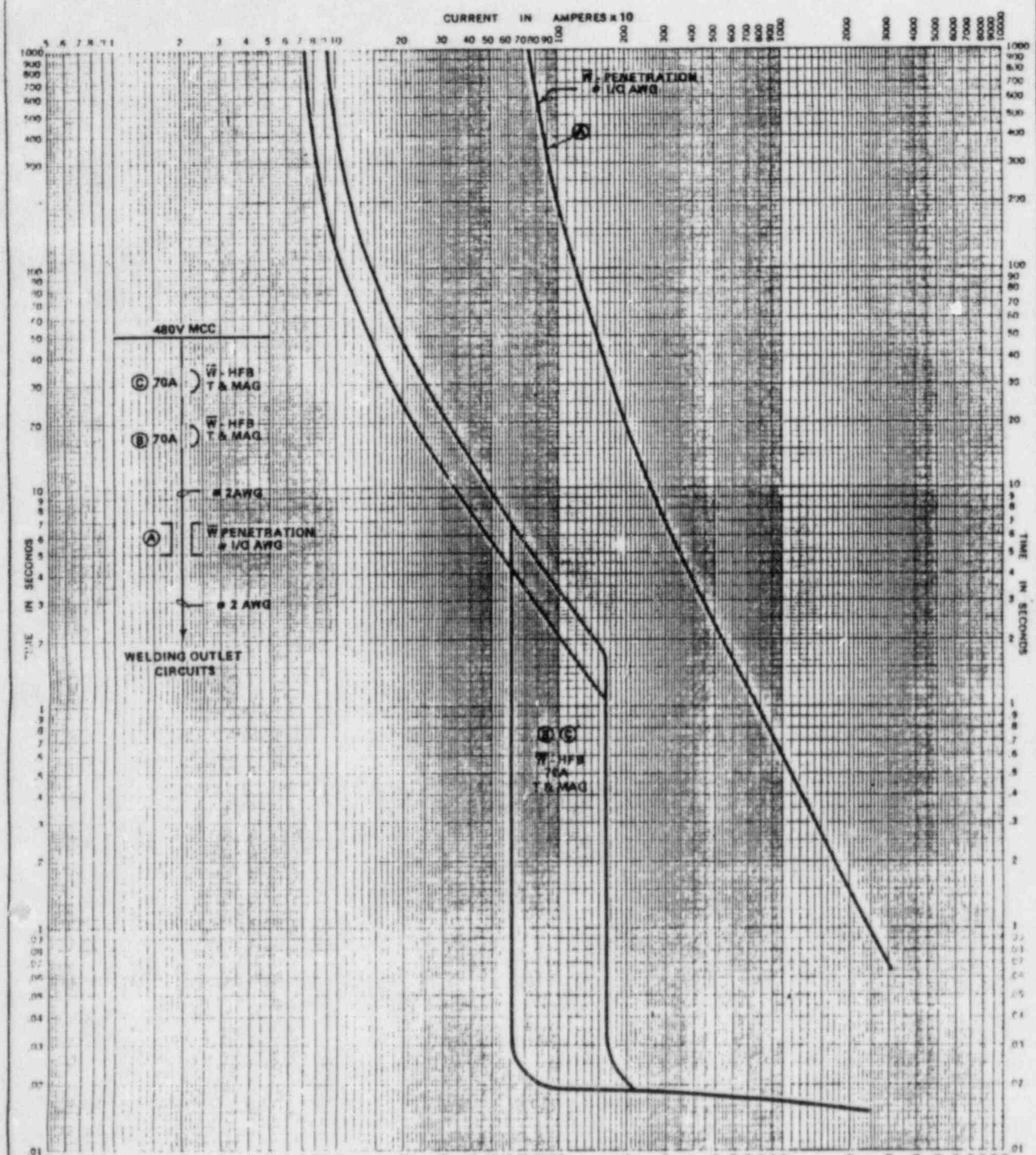


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 9 OF 22

[redacted] 10/84



HOPE CREEK
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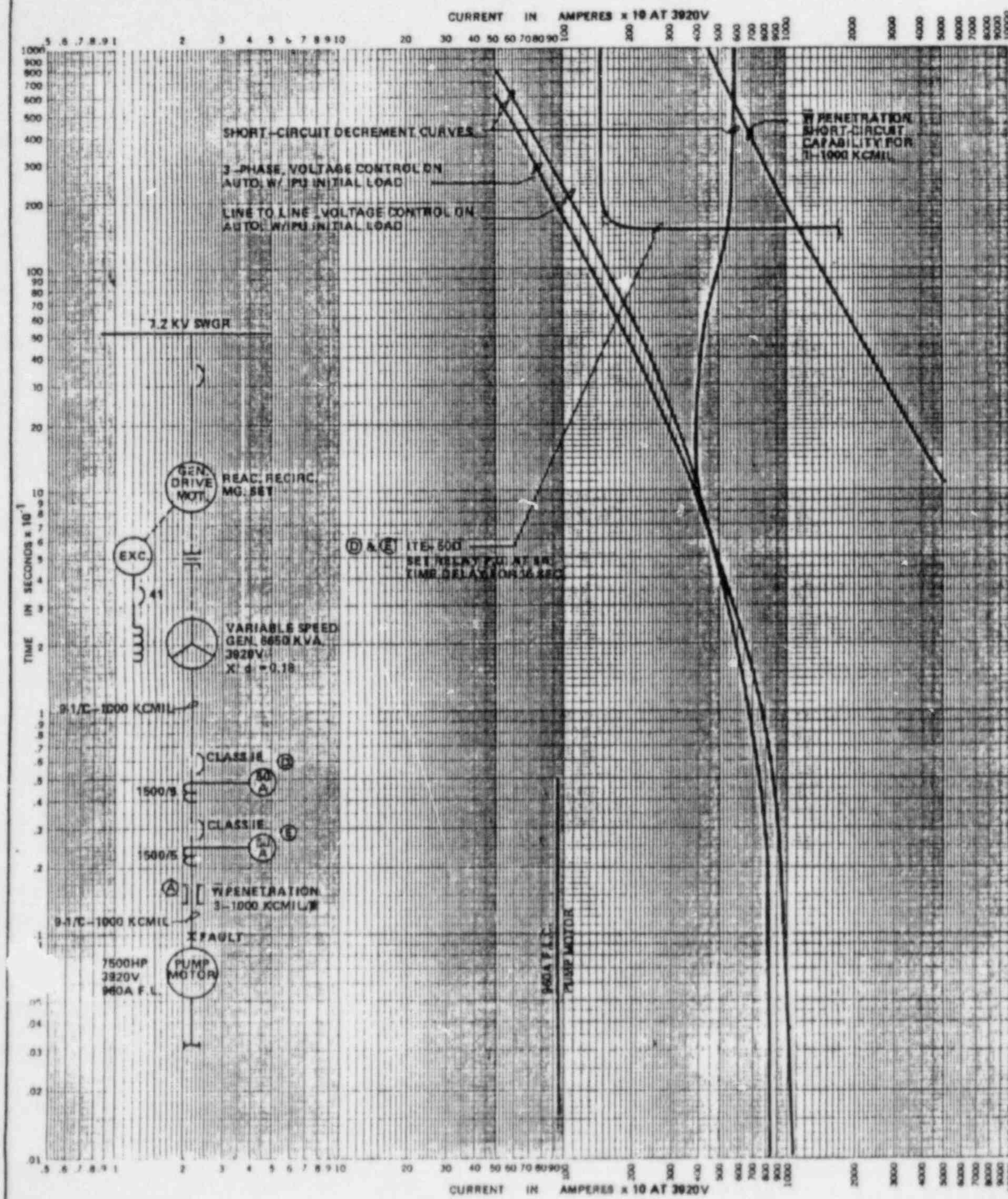
PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 10 OF 22

[redacted], 10/84

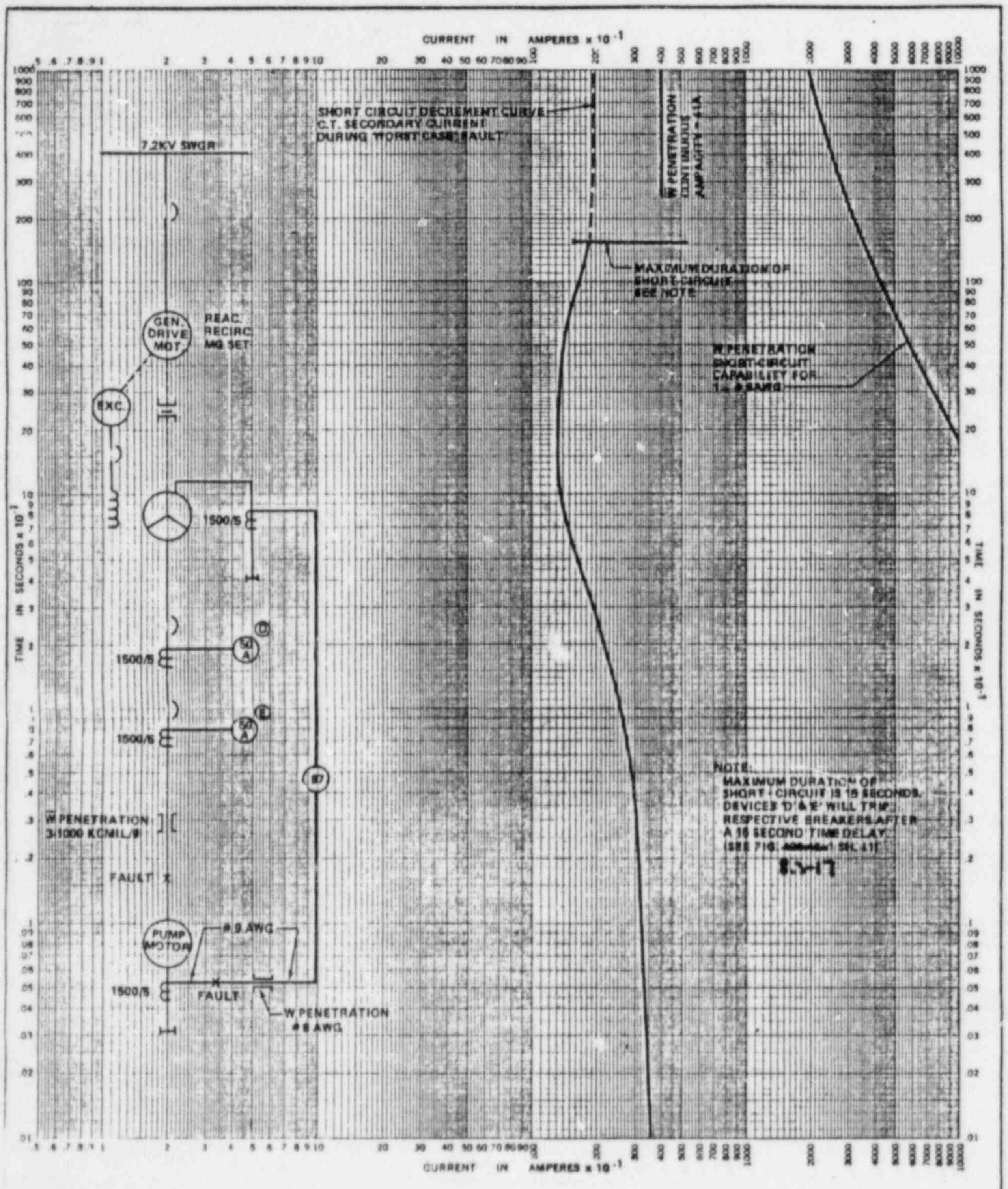


HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 11 OF 22

[redacted] 10/84



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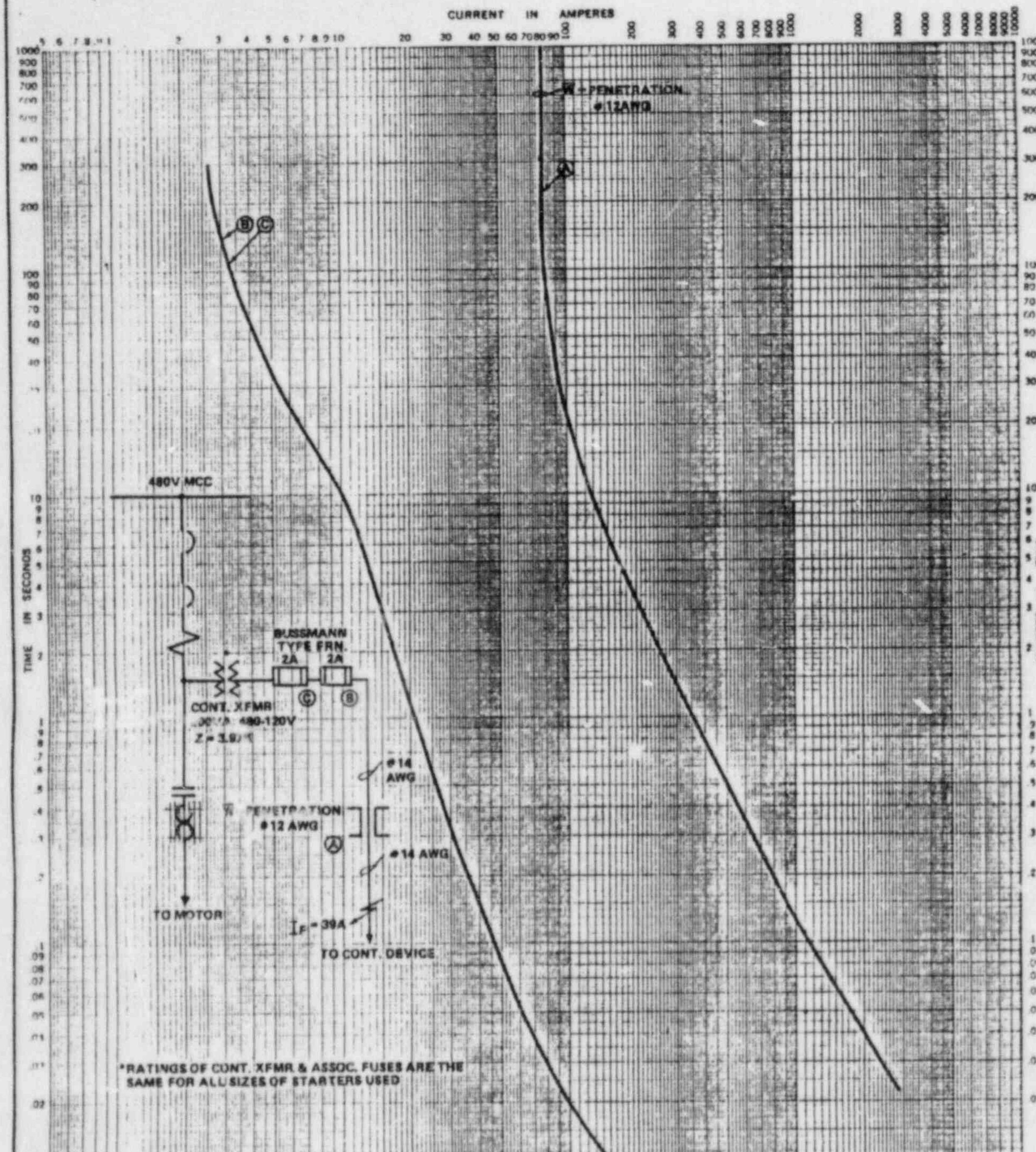
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE [redacted] 8.3-17
SHEET 12 OF 22

[redacted] 10/84



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
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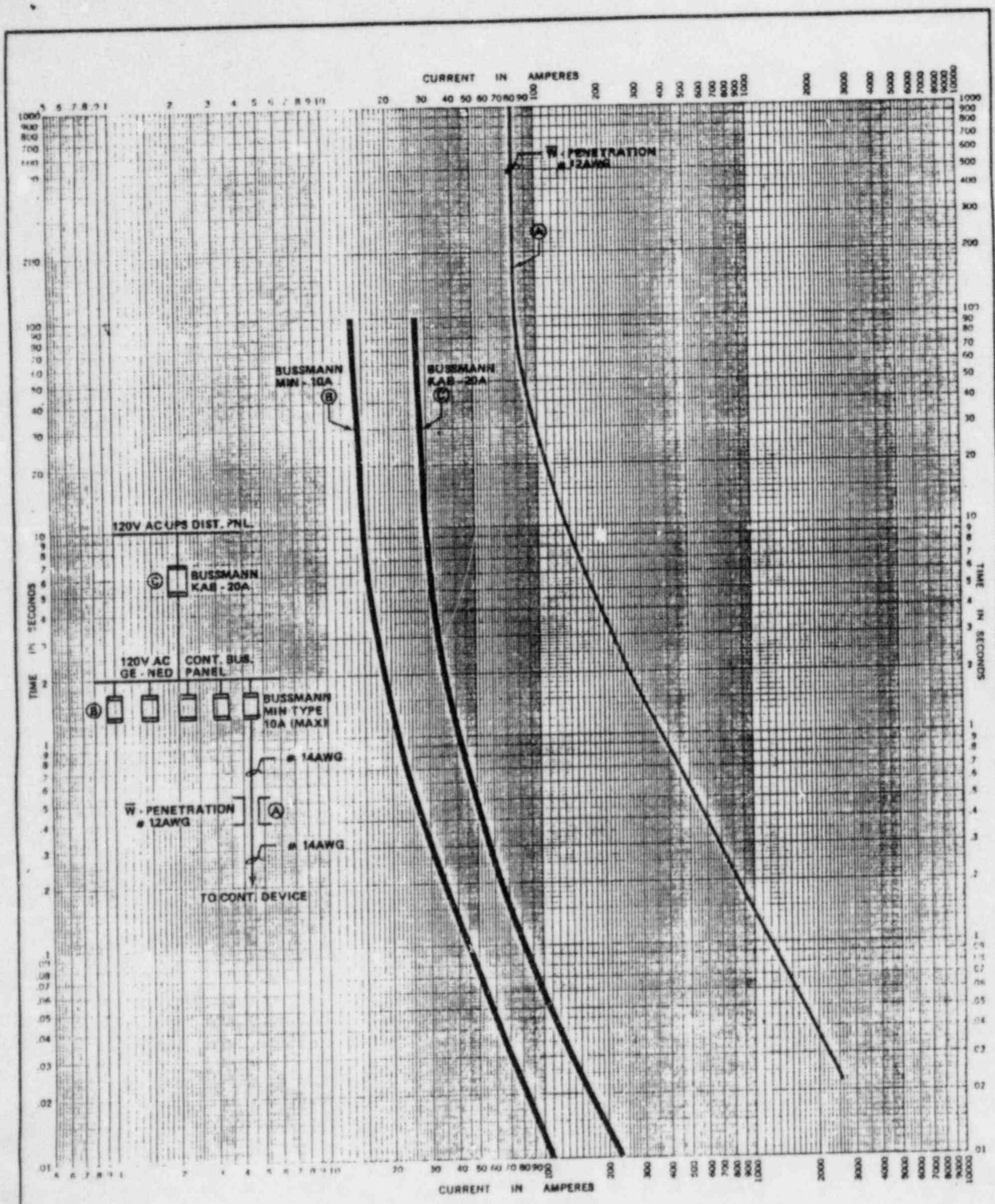
FIGURE 8.1-17
SHEET 13 OF 22

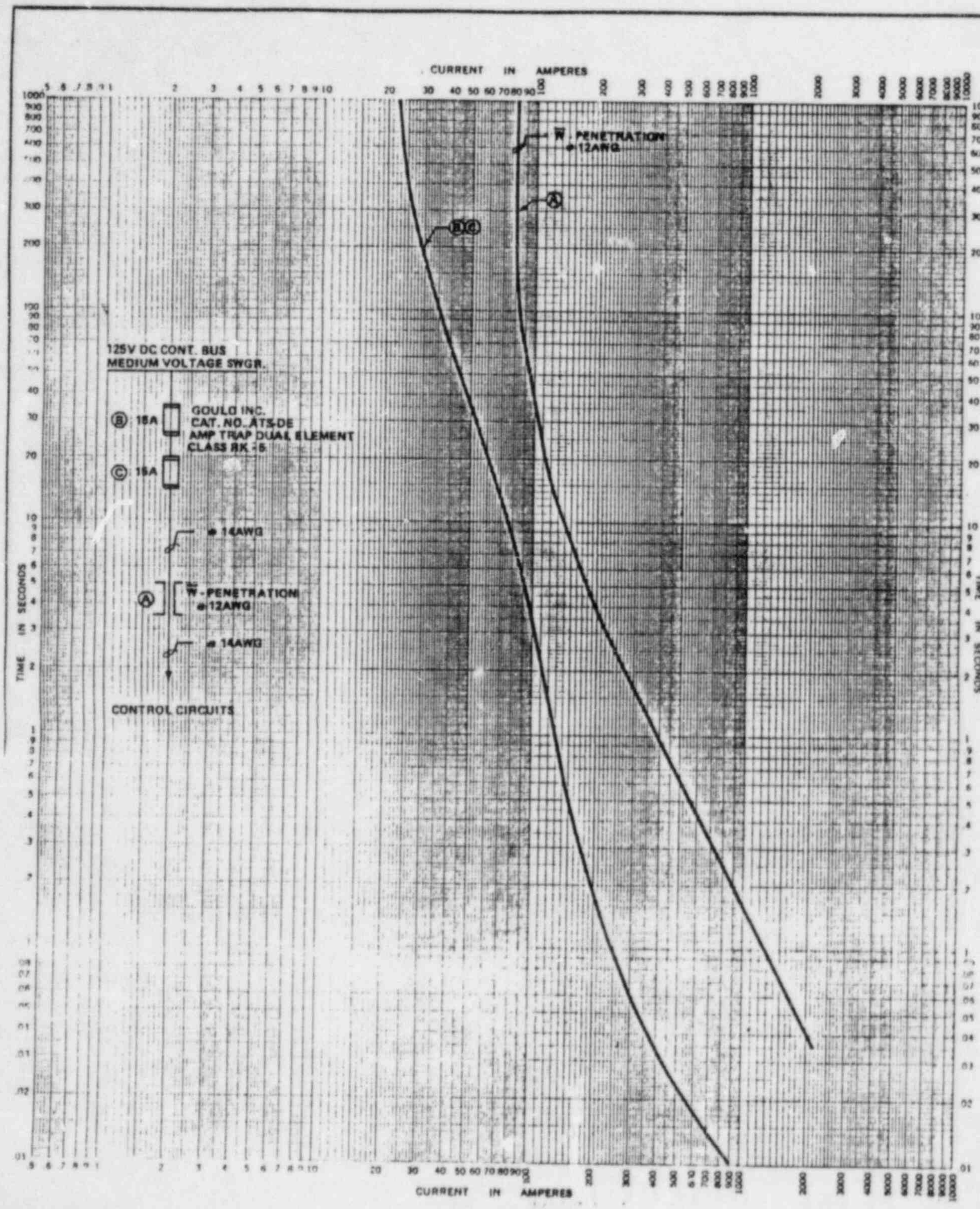
10/84



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

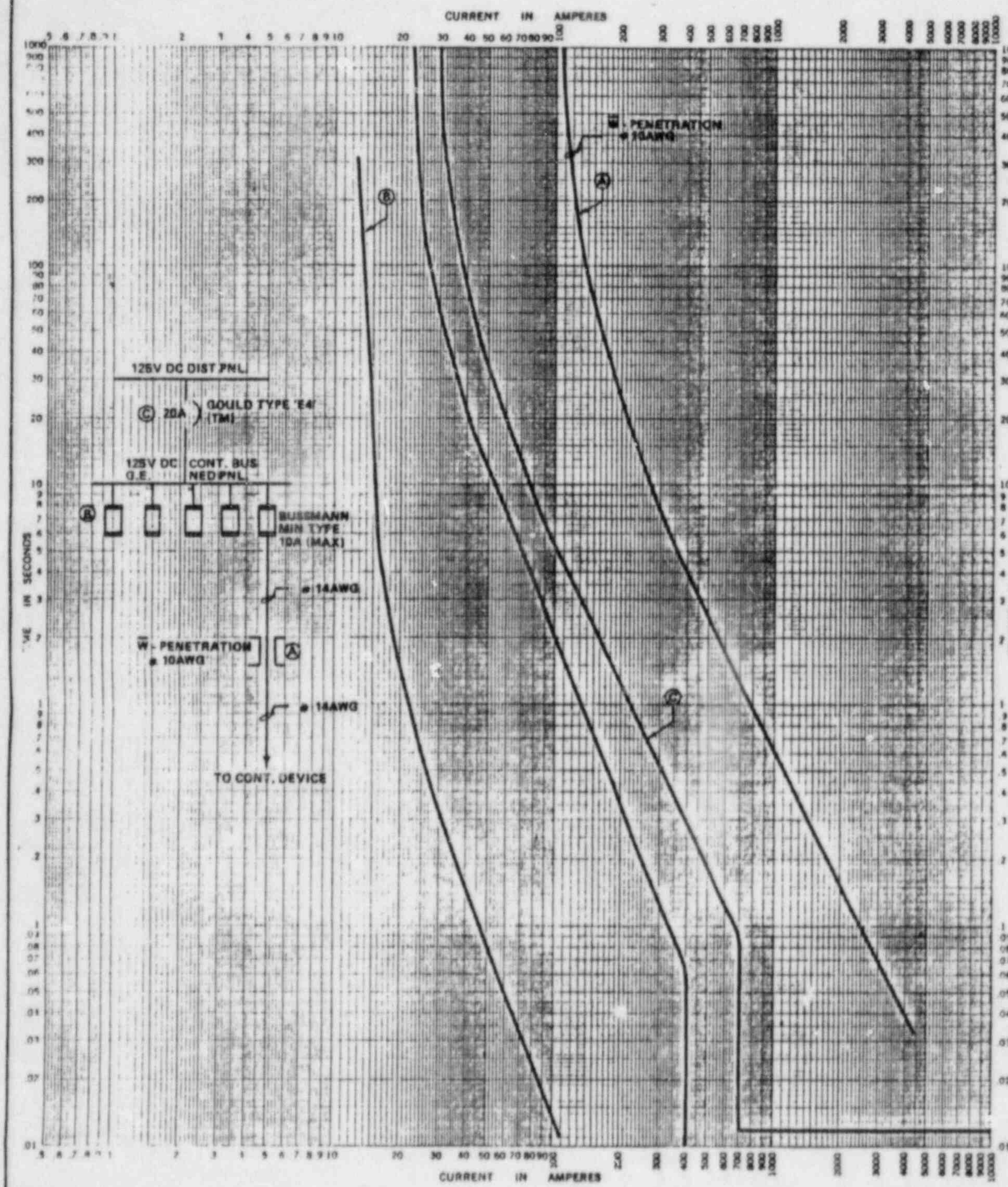
FIGURE 8.3-17
SHEET 14 OF 22



HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.3-17



HOPE CREEK
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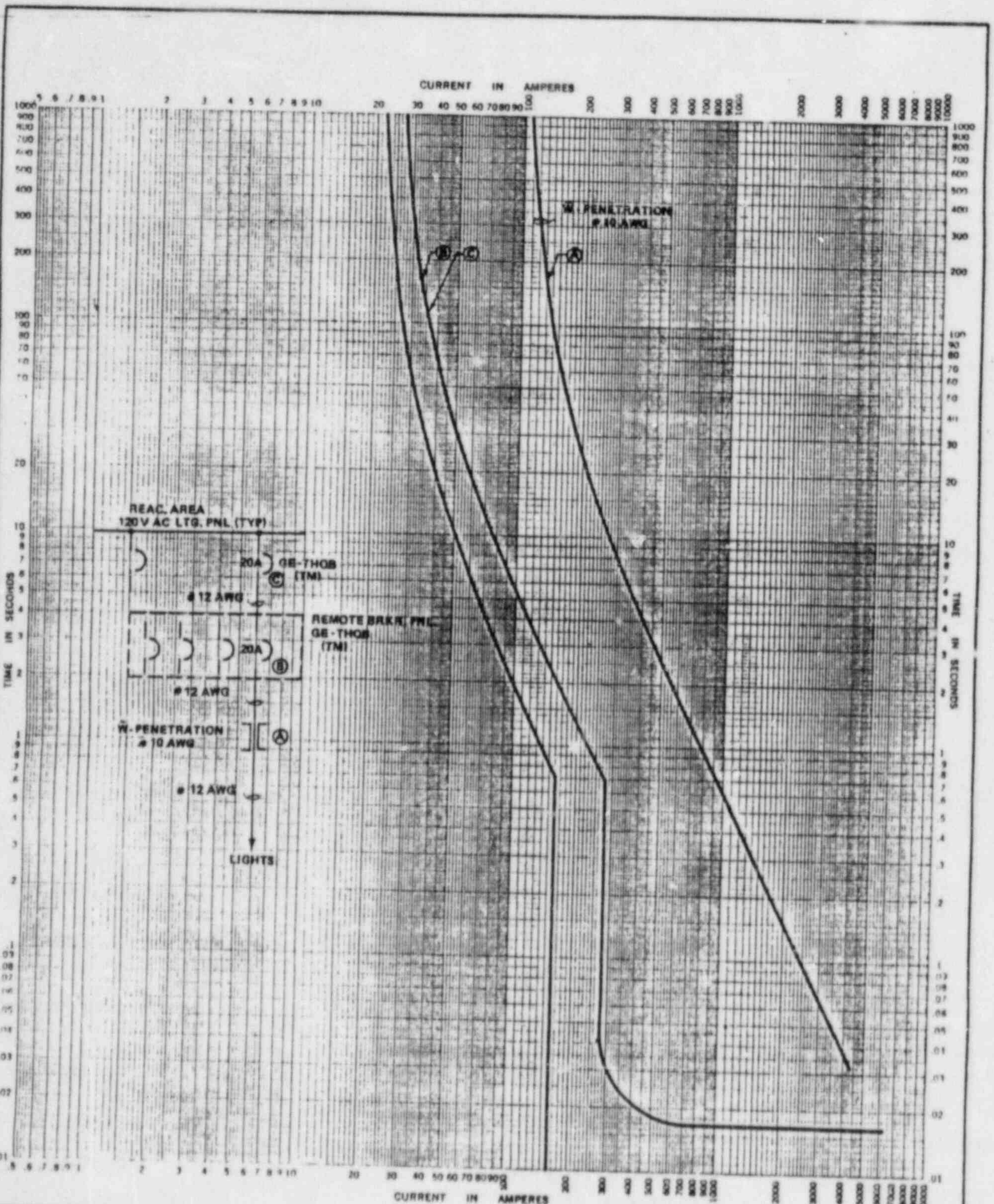
PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE [redacted]3-17
SHEET 16 OF 22

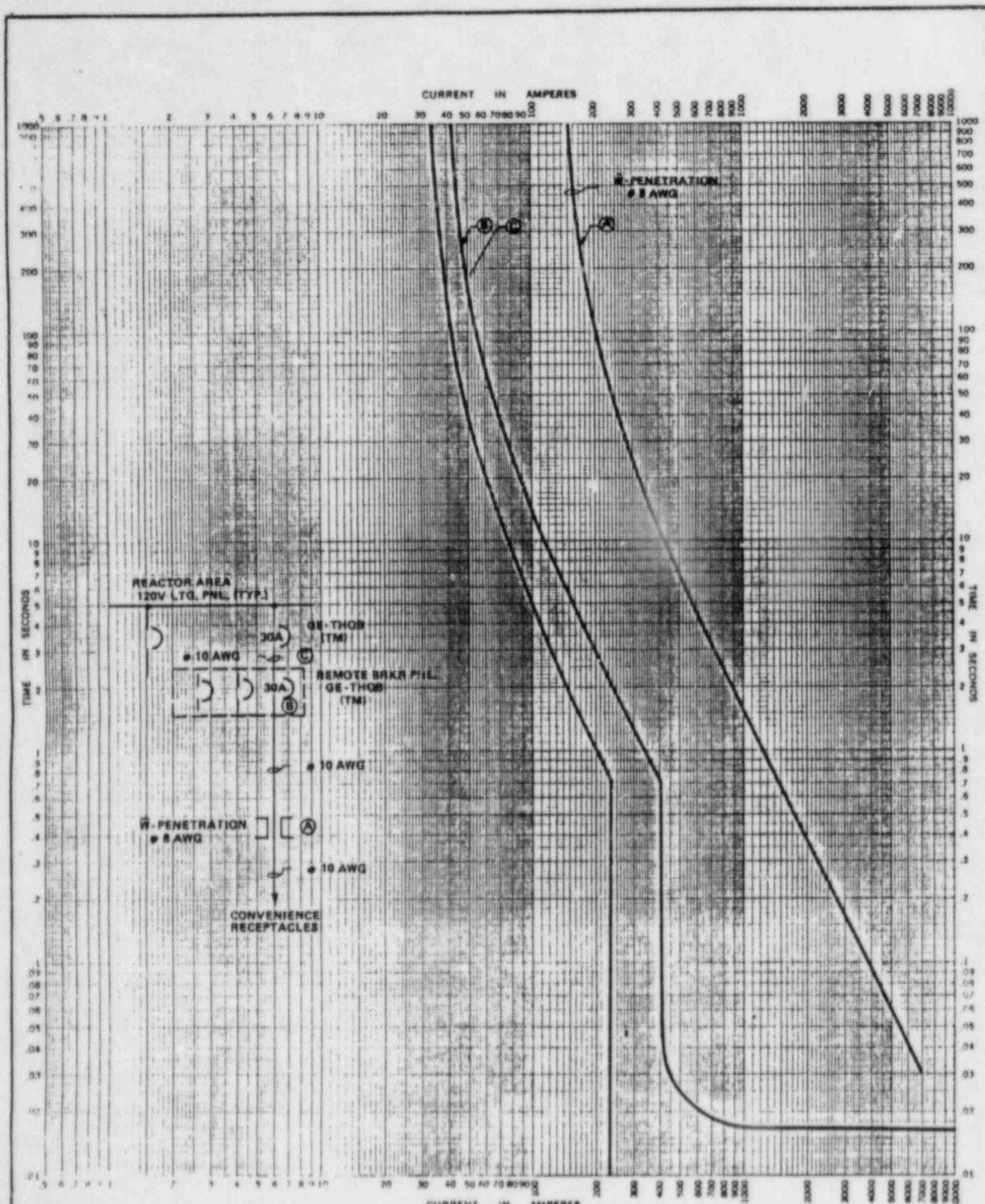
[redacted], 10/84



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

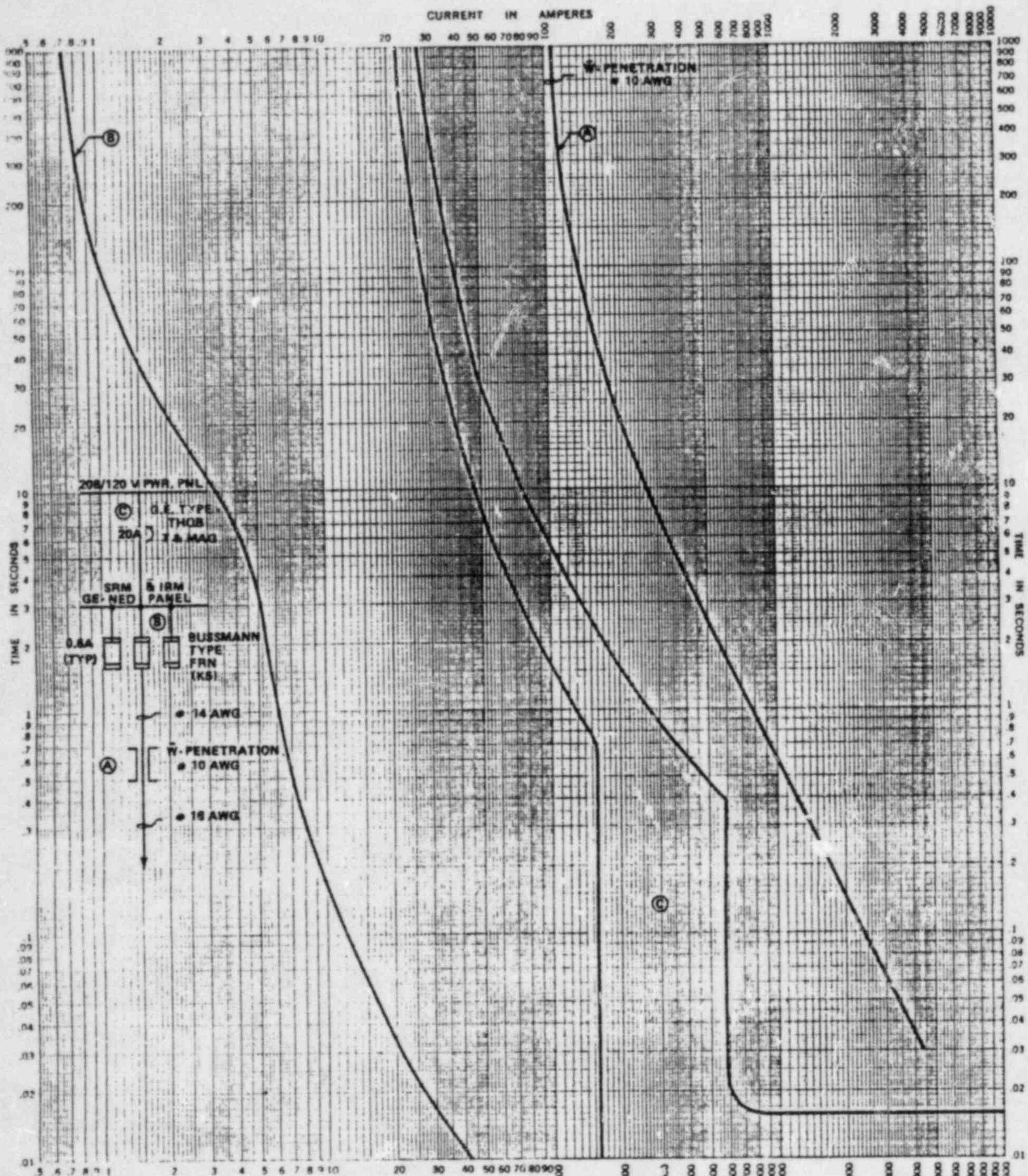
FIGURE 8.3-17
SHEET 17 OF 22



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 18 OF 22

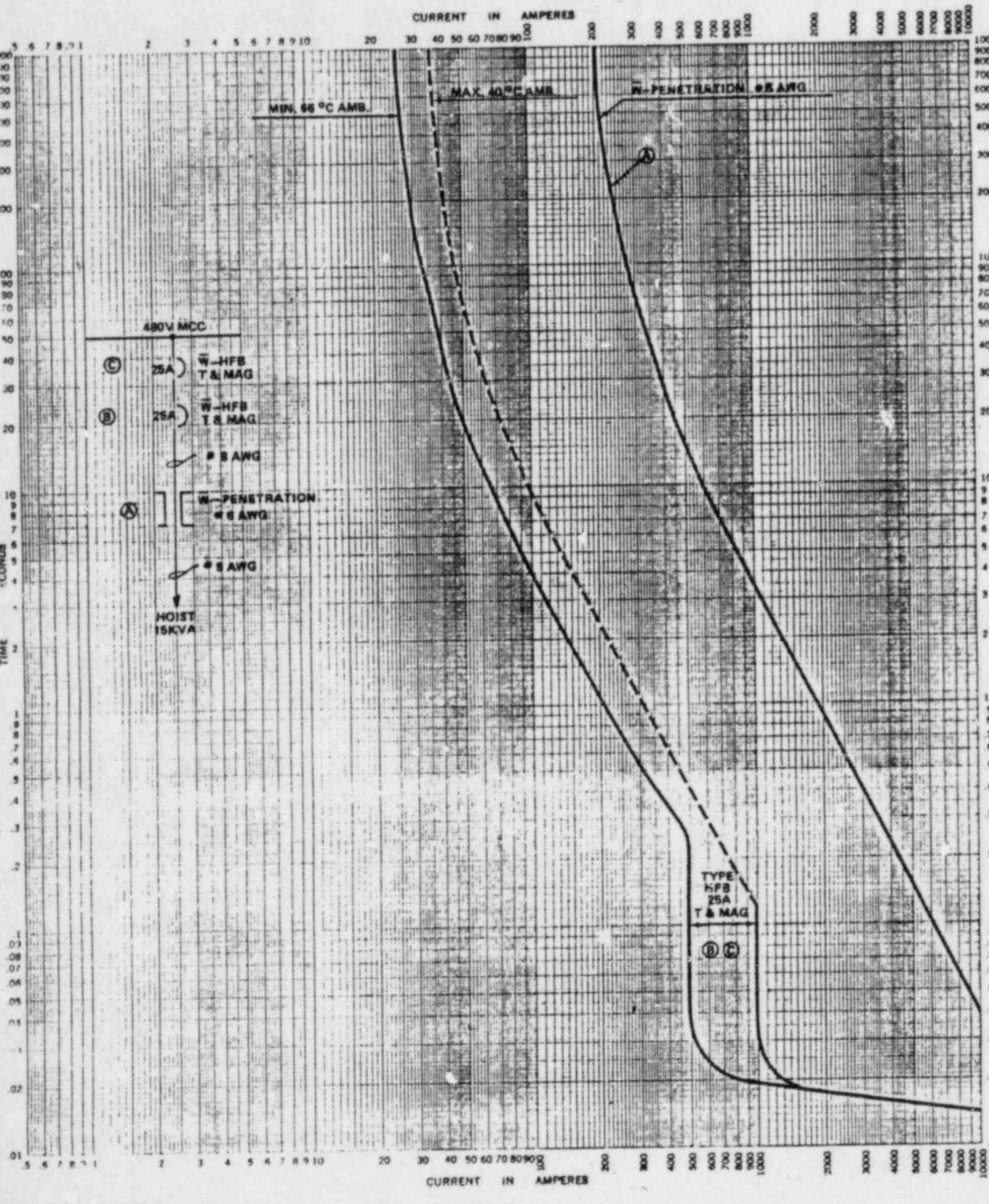


HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

FIGURE 8.3-17
SHEET 19 OF 22

[redacted], 10/84



HOPE CREEK
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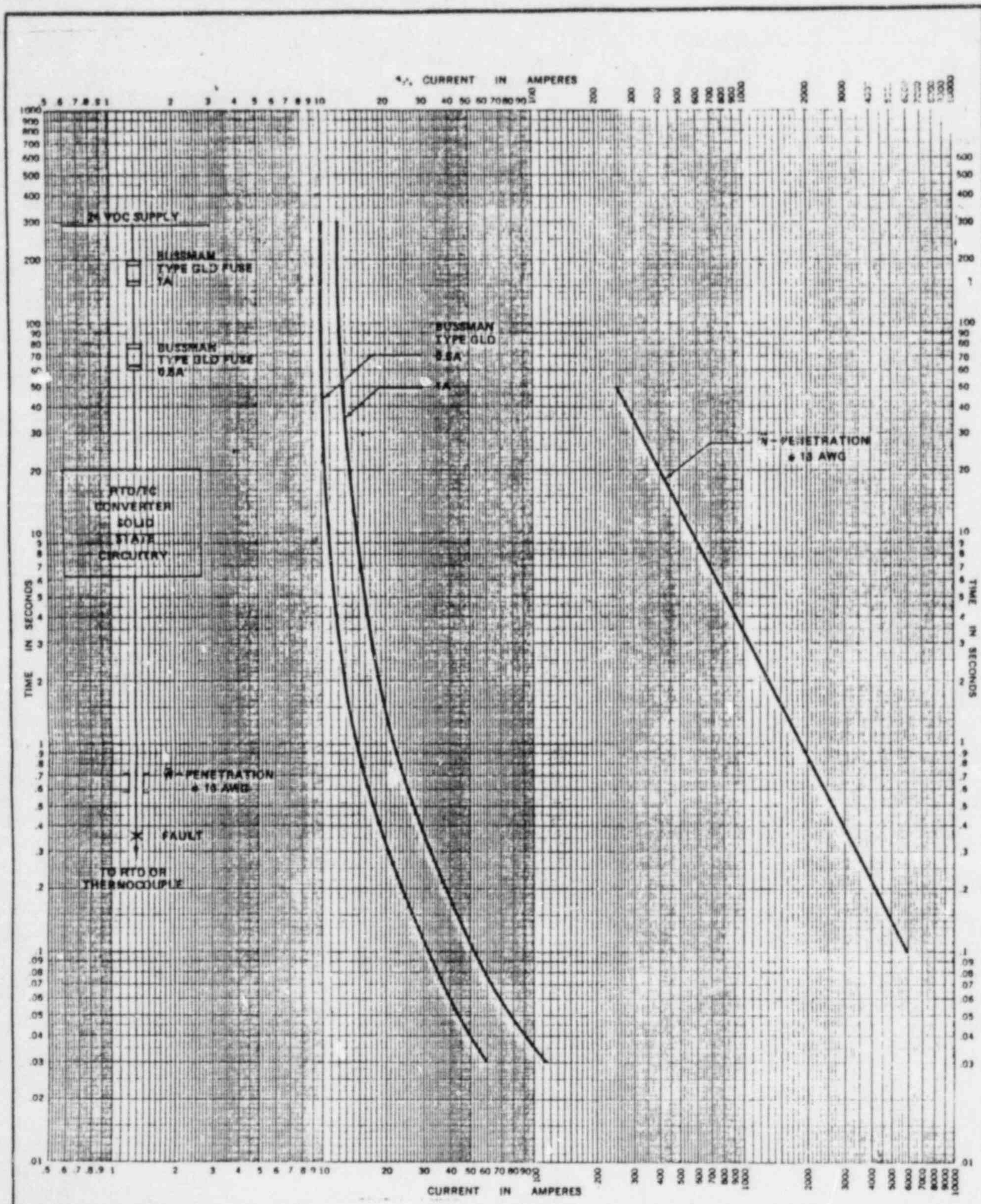
PENETRATION CONDUCTOR
OVERCURRENT PROTECTION

[redacted] 8.3-7
SHEET 20 OF 22

[redacted] 10/84

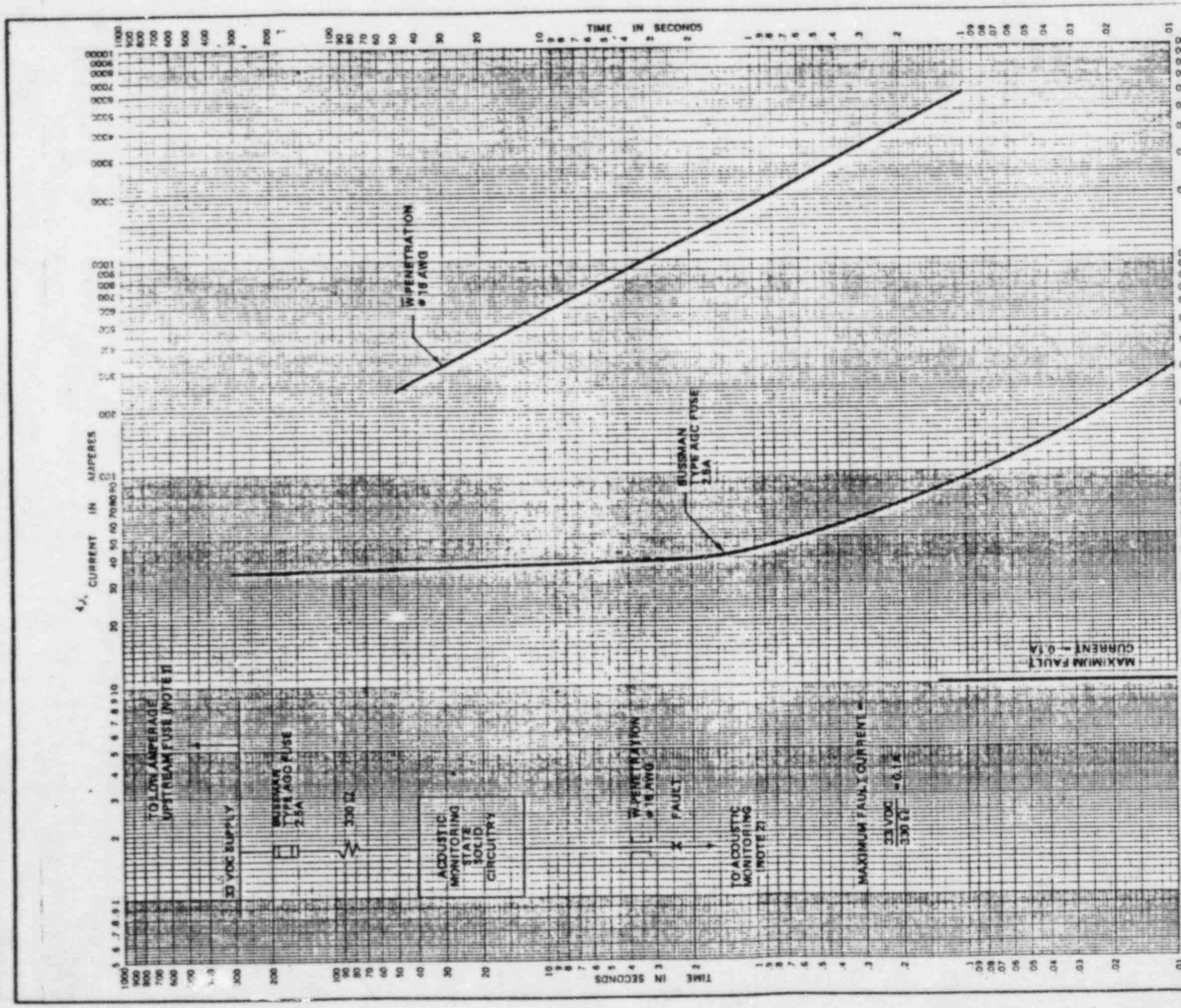


HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.1-17
SHEET 21 OF 22

[redacted], 10/84



NOTES:

1) THE UPSTREAM FUSE PROVIDES OVERCURRENT PROTECTION OF THIS POWER SUPPLY AND OTHER POWER SUPPLIES OF THIS SYSTEM.

2) THIS CIRCUIT IS SIMILAR TO OTHER INSTRUMENTATION CIRCUITS THAT HAVE LOW ENERGY POWER SUPPLIES AND LOW SIGNALS LEVELS.

HOPE CREEK GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

PENETRATION CONDUCTOR OVERCURRENT PROTECTION

FIGURE 8.1-17

SHEET 22 OF 22

[redacted], 10/84

Rev 2A

DSER Open Item No. 253 (DSER Section 8.3.3.1.4)

COMMITMENT TO PROTECT ALL CLASS 1E EQUIPMENT FROM EXTERNAL HAZARDS VERSUS ONLY CLASS 1E EQUIPMENT IN ONE DIVISION

In Section 8.1.14.3.3 of the FSAR, it is stated that where neither compartmentalization nor the construction of barriers is possible (to protect Class 1E circuits or equipment from hazards such as pipe break, flooding, missiles, and fires) an analysis is performed to demonstrate that none of the hazards disables redundant equipment, conduits, or trays. Based on this statement, the staff concludes that at least one of the redundant Class 1E systems and components at Hope Creek need not be protected from external hazards. The design, thus, does not meet the protection requirement of Criteria 2 and 4, nor the single failure requirement of Criterion 17 of Appendix A to 10 CFR 50. Justification for non-compliance with Criteria 2, 4, and 17 will be pursued with the applicant.

RESPONSE

The response to Question 430.38, and Section 8.1.4.14.3.3, have been revised to provide a discussion of protection of Class 1E systems and components against external hazards.

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Rev. 2A

QUESTION 430.38 (SECTION 8.3.1 and 8.3.2)

In Sections 8.1.4.14.3.3 of the FSAR you state that where neither compartmentalization nor the construction of barriers is possible (to protect Class 1E circuits or equipment from hazards such as pipe break, flooding, missiles, and fires) an analysis is performed to demonstrate that none of the hazards disables redundant equipment, conduits, or trays. Based on this statement it appears that at least one of the redundant Class 1E systems and components at Hope Creek may not be protected from external hazards. The design, thus, does not meet the protection requirement of Criteria 2 and 4 nor the single failure requirement of Criterion 17 of Appendix A to 10CFR50. Justify non-compliance with Criteria 2, 4, and 17.

RESPONSE

Section 3.5 indicates that Class 1E equipment is protected from postulated missiles by use of plant arrangement or suitable physical barriers such that a single missile cannot simultaneously damage a critical system component and its backup system. This is accomplished by locating redundant systems in different areas of the plant or separation by missile-proof walls. There are no Class 1E electrical equipment and components that can be damaged by missiles generated externally to the plant.

Section 3.6.1.1 indicates that, as part of the design basis for protection against dynamic effects associated with the postulated rupture of piping, a single active component failure is assumed to occur in systems used to mitigate the consequences of the postulated piping rupture and to shut down the reactor. A thorough review of the plant using the design bases provided in Section 3.6.1.1 was conducted and no cases were found where the piping failure would prevent safe shutdown (Reference: Question/Response 410.23).

Section 8.1.4.14.3.3 has been revised to INCLUDE THE FOLLOWING STATEMENT:

The HCGS separation review (hazard analysis) confirms that no external hazard originating in a non-safety related system or component can prevent safe shutdown of the plant, even when the loss of offsite power and the worst single active failure of any safety related system or component is assumed.

INSERT "A"

#34
Rev. 2A

(DSER 253/QUESTION 430.38)

Insert "A" INTO QUESTION 430.38

The design of the Class 1E electrical power and control systems is such that two or more Class 1E current interrupting devices are provided for primary and back-up protection for all Class 1E cable or equipment. Should an external missile or hazard cause a shorting failure of an electrical cable(s) or device(s) (as a result of an impact on a cable raceway or electrical component) the Class 1E protective devices will operate to isolate that specific cable or component. This design feature enables HCGS to accommodate a failure of a Class 1E electrical component due to an external hazard with a single failure in a redundant Class 1E train. The diesel generators, 4.16 kV Class 1E switchgear, 480V Class 1E unit sutstations and the 125V dc switchgear and distribution cabinets are located in areas protected from external hazards. Only the following types of Class 1E isolation devices are required to operate to isolate failed components:

1. 70 ampere fuses in 125V dc distribution cabinets.

2. AKR - 30 breakers in 125V dc switchgear.

3. Molded case breakers in 480V motor control centers.

4. AKR - 50 breakers in 480V ac unit substations.

5. 20 ampere fuses in instrument distribution cabinents.

6. 300 ampere fuses in 20kVA uninterruptible power source (UPS) systems.

7. 200 ampere fuses in 10kVA UPS systems.

To insure that the above Class 1E overcurrent protective devices required to ensure this capability will operate correctly, HCGS will include surveillance testing of these devices in the Technical Specifications.

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monitoring cables, boxes also shall not be considered in determing the required separation.

b. In case of open ventilated trays, redundant trays are separated by 3 feet horizontally and 5 feet vertically, respectively. If the redundant trays cannot be separated by the distances specified above, solid covers for trays are provided as designated in Section 6.1.4 of IEEE 384-1981.

Separation requirements between Class 1E and non-Class 1E circuits are the same as those required between redundant circuits.

8.1.4.14.3.3 Hazardous Areas

These are areas where one or more of hazards such as pipe break, flooding, missile, and fire can be postulated.

Routing of redundant Class 1E circuits or the locating of redundant Class 1E equipment in hazardous areas is avoided. The preferred separation between redundant Class 1E circuits or equipment in these areas is by a wall, floor, or barrier that is structurally adequate to shield redundant raceways from potential hazards in the area.

Where neither compartmentalization nor the construction of barriers is possible, an analysis is performed to demonstrate that no missile, fire, jet stream impingement, or pipe whip hazard disables redundant equipment, conduits, or trays. In no case, regardless of the distance of physical separation, are redundant equipment cable trays located in the direct line of sight of the same potential missile source.

The plant design for fire protection separation of electrical cables and equipment is reviewed against 10 CFR 50, Appendix R, which is discussed in Section 9.5.1.

The HCGS separation review (hazard analysis) confirms that no external hazard originating in a non-safety related system or component can prevent safe shutdown of the plant, even when the loss of offsite power and the worst single active failure of any safety related system or component is assumed.

INSERT "A"

#34
Rev. 2A

(DSER 253/QUESTION 430.38)

Insert "A" INTO SECTION 8.1.4.14.3.3

The design of the Class 1E electrical power and control systems is such that two or more Class 1E current interrupting devices are provided for primary and back-up protection for all Class 1E cable or equipment. Should an external missile or hazard cause a shorting failure of an electrical cable(s) or device(s) (as a result of an impact on a cable raceway or electrical component) the Class 1E protective devices will operate to isolate that specific cable or component. This design feature enables HCGS to accommodate a failure of a Class 1E electrical component due to an external hazard with a single failure in a redundant Class 1E train. The diesel generators, 4.16 kV Class 1E switchgear, 480V Class 1E unit sutstations and the 125V dc switchgear and distribution cabinets are located in areas protected from external hazards. Only the following types of Class 1E isolation devices are required to operate to isolate failed components:

1. 70 ampere fuses in 125V dc distribution cabinets.
2. AKR - 30 breakers in 125V dc switchgear.
3. Molded case breakers in 480V motor control centers.
4. AKR - 50 breakers in 480V ac unit substations.
5. 20 ampere fuses in instrument distribution cabinents.
6. 300 ampere fuses in 20kVA uninterruptible power source (UPS) systems.
7. 200 ampere fuses in 10kVA UPS systems.

To insure that the above Class 1E overcurrent protective devices required to ensure this capability will operate correctly, HCGS will include surveillance testing of these devices in the Technical Specifications.

DSER Open Item No. 259 (DSER Section 8.3.3.3.4)

USE OF AN INVERTER AS AN ISOLATION DEVICE

By Amendment 4 to the FSAR, the applicant indicated that the non-Class 1E public address system distribution panel shown on sheet 2 of Figure 8.3-11 of the FSAR is supplied power from the Class 1E dc system through an inverter. The applicant further stated that this inverter is an acceptable isolation device per IEEE-384-1981, Section 7.1.2.3. The staff does not agree. Test and analysis to demonstrate the adequacy of an inverter as an isolation device will be pursued with the applicant.

RESPONSE

The response to Question 430.33 has been revised to state that the inverter will be tested as an isolation device. In the event that the tests are not successful, the non Class 1E loads will be removed or the cables will be re-routed.

QUESTION 430.33 (SECTION 8.3.1 and 8.3.2)

Section 8.3.1.1.2 of the FSAR indicates that the Class 1E system provides power to non-Class 1E loads. Non-Class 1E loads are connected to the Class 1E system through a single breaker that is tripped automatically by a LOCA signal. The single breaker tripped by a LOCA signal provides acceptable isolation between Class 1E and Non-Class 1E circuits for the design basis accident - LOCA. However, for other design basis accidents or operating occurrances that do not generate a LOCA signal (such as loss of offsite power, design basis exposure fire, seismic events, etc), it is the staff concern that a single breaker may not provide acceptable isolation. Provide an analysis, in accordance with the guidelines of Section 4.9 of IEEE Standard 308-1974, that demonstrates that failure of anyone or simultanous combined failure of all non Class 1E loads will not prevent any of the four channels of Class 1E power from performing its safety function. The analysis should consider, but not be limited to, (1) capacity and capability of onsite and offsite power supplies and their associated distribution system to supply power to Class 1E loads within their design ratings for all modes of plant operation, (2) the guidelines of Section 7.1.2.1 of IEEE standard 384-1981, (3) an analysis of diesel generator loadings for loss of offsite power similiar to that presented in Tables 8.3-2 through 8.3-6 of the FSAR, (4) the failure of the Non Class 1E dc system that supplies control power to the subject non Class 1E loads, and (5) a similiar analysis of the Class 1E dc system if non-Class 1E loads are connected.

RESPONSE

The following discussion demonstrates the adequacy of employing a single circuit breaker tripped by a LOCA signal as an isolation device between a Class 1E power bus and a non-Class 1E load for design base event that do not generate LOCA signals.

is

X

Figure 430.33-1 shows the two configurations that employ a circuit breaker tripped by a LOCA signal as an isolation device. The two configurations are:

a. A Class 1E unit substation supplies a non-Class 1E motor control center (MCC) or a motor load through Class 1E circuit breaker B.

b. A Class 1E motor control center supplies through Class 1E circuit breaker D, a non-Class 1E distribution panel.

The Class 1E circuit breakers B and D are qualified to operate for HCGS seismic and environmental parameters for all design basis events. These circuit breakers will trip to isolate their

DSER OPEN ITEM 260

respective Class 1E power supply buses from the non-Class 1E loads in the event the non-Class 1E loads fail. This applies whether the plant is supplied from an offsite source or an onsite source. Thus, the failure of the non-Class 1E loads supplied from Class 1E power supply buses will not prevent any of the four channels of Class 1E power supplies from performing its safety function. INSERT A FROM PAGE 430.33-2A

COMPLIANCE WITH GUIDELINES OF SECTION 7.1.2.1 OF IEEE 384-1981

Protective device coordination studies for devices shown in Figure 430.33-1 have shown that the time-overcurrent trip characteristics of circuit breakers A, B, C, and D are such that:

a. Circuit breaker B will trip to clear a fault current prior to initiation of a trip of circuit breaker A.

b. Circuit breaker D will trip to clear a fault current prior to initiation of a trip of circuit breaker C.

Both the onsite and offsite powers supply sources are separately capable of supplying the necessary fault current for sufficient time to ensure the proper protective device coordination without loss of function of Class 1E O loads. INSERT B FROM PAGE 430.33-2A

STANDBY DIESEL GENERATOR LOADINGS FOR LOSS OF OFFSITE POWER

Table 8.3-1 tabulates the loads, their KW ratings, and loading sequences for design basis accident (DBA) and loss of offsite power (LOP) scenarios. It can be verified by inspecting Table 8.3-1 that DBA loading of the SDGs is the limiting case with respect to the loading capability of the SDGs.

FAILURE OF THE NON-CLASS 1E DC SYSTEM THAT SUPPLIES CONTROL POWER TO THE SUBJECT NON-CLASS 1E LOADS

For configuration (a) (described above) the circuit breaker B supplying a Non-Class 1E MCC or a motor load is controlled by Class 1E 125 V dc control power supply. For a non-Class 1E motor load, a non-Class 1E circuit breaker is provided downstream of circuit breaker B. This non-Class 1E circuit breaker (GE-AKR type) is controlled by a non-Class 1E 125 V dc control power. GE-AKR type circuit breakers are direct ~~ing~~ acting trip devices and do not require external control power supply for tripping for electrical fault conditions. Therefore, the failure of the dc control power supply does not prevent the circuit breaker ~~to~~ trip ping in response to the failure of non-Class 1E motor load. from

INSERT C FROM PAGES 430.33-2B

DSER OPEN ITEM 260

INSERT A

The Class IE onsite ac sources and the offsite power sources and their distribution system are of sufficient capacity and capability to supply power to both Class IE and non-Class IE loads during all plant conditions. In the event of a LOCA the non-Class IE loads are automatically tripped from the class IE buses in accordance with Position C.1 of Regulatory Guide 1.75. IN ADDITION, CABLES FROM THE CLASS IE BUSES TO THE NON-CLASS IE LOADS ARE ROUTED IN RIGID STEEL CONDUITS OR TRAYS. WHERE TRAY ROUTING IS USED, NON-CLASS IE CABLES ASSOCIATED WITH OTHER IE CHANNE ARE NOT RUN TOGETHER IN THE SAME TRA

AN OPERATION DESIGN CHANGE CONTROL PROGRAM WILL BE IN EFFECT AT THE HOPE CREEK PLANT TO ASSURE THAT FUTURE ADDITIONS/MODIFICATIONS WILL COMPLY WITH THIS REQUIREMENT. ADDITIONALLY, THE PERTINENT DESIGN DOCUMENTS WILL BE PROVIDED WITH A NOTATIONS TO REFLECT THIS REQUIREMENT.

INSERT B

Periodic testing of the breaker time-overcurrent trip characteristics will be performed to demonstrate that the circuit breaker trip function remains within required limits. Table 430.33-1 identifies the non-Class IE loads that are supplied through circuit breakers B and D of Figure 430.33-1.

DSER OPEN ITEM 260

QUESTION 430.33 INSERT "C"

ANALYSIS FOR SUPPLYING NON-CLASS 1E FROM CLASS 1E DC SYSTEMS

Figure 8.3-11 shows non-Class 1E public address system distribution panel 10J496 supplied from a Class 1E dc power bus 10D410 through a Class 1E inverter in UPS unit 10D496. The inverter is an acceptable isolation device per IEEE-384-1981, Section 7.1.2.3. Therefore, a failure in the non-Class 1E distribution panel 10J496 will not degrade Class 1E dc system bus 10D410.

The HCGS UPS system will be tested to demonstrate the adequacy of an inverter being applied as an isolation device. The test will demonstrate that voltage, current, and frequency on the Class 1E side of the UPS are not degraded below acceptable levels when a maximum credible voltage or current transient is applied on the non-Class 1E side of the UPS system. The tests to be performed will simulate all operating modes for which the HCGS UPS system is designed. The tests will include the following types of faults at the UPS output location:

a. Phase to ground
b. Neutral to ground
c. Phase to neutral without ground
d. Hot short (460 Vac)

A test plan is submitted separately for the staff's review. The test report and any associated analysis of the test results will be submitted in December 1984.

An analysis has been performed to support the values used for the acceptance criteria for voltages. This analysis shows that the voltages specified will not cause misoperation or loss of any electrical equipment connected to the supply buses.

In addition, the acceptance values for the test currents are well below the level that would cause the infeed breakers to the UPS supply buses to trip. These values are as follows:

Circuit	Acceptance Current	Infeed breaker Setting
Normal 480 VAC Supply	0-55 amperes continuous with a maximum peak of 132 amperes for not longer than 10 mS	600 amperes Pick-up
Back-up 480 VAC Supply	0-78 amperes continuous with a maximum peak of 500 amperes for not longer than 10 mS	600 amperes Pick-up
Alternate 125 VDC Supply	0-364 amperes	2000 ampere Fuse

INSERT "C"

Page two

If the testing can not demonstrate adequacy of the UPS as an isolation device, then an isolation transformer will be added between the inverter and the distribution panel. The test plan for the isolation transformer is also submitted separately for the staff's review.

In the event of failure of both tests the non-Class 1E loads associated with the UPS system will be removed from the Class 1E buses or the cables to these loads will be re-routed so as to be separated from Class 1E cables associated with other Class 1E channels.

TABLE 430.33-1

NON-CLASS 1E LOADS CONNECTED TO CLASS 1E BUSES THROUGH CIRCUIT BREAKER TRIPPED BY LOCA SIGNAL

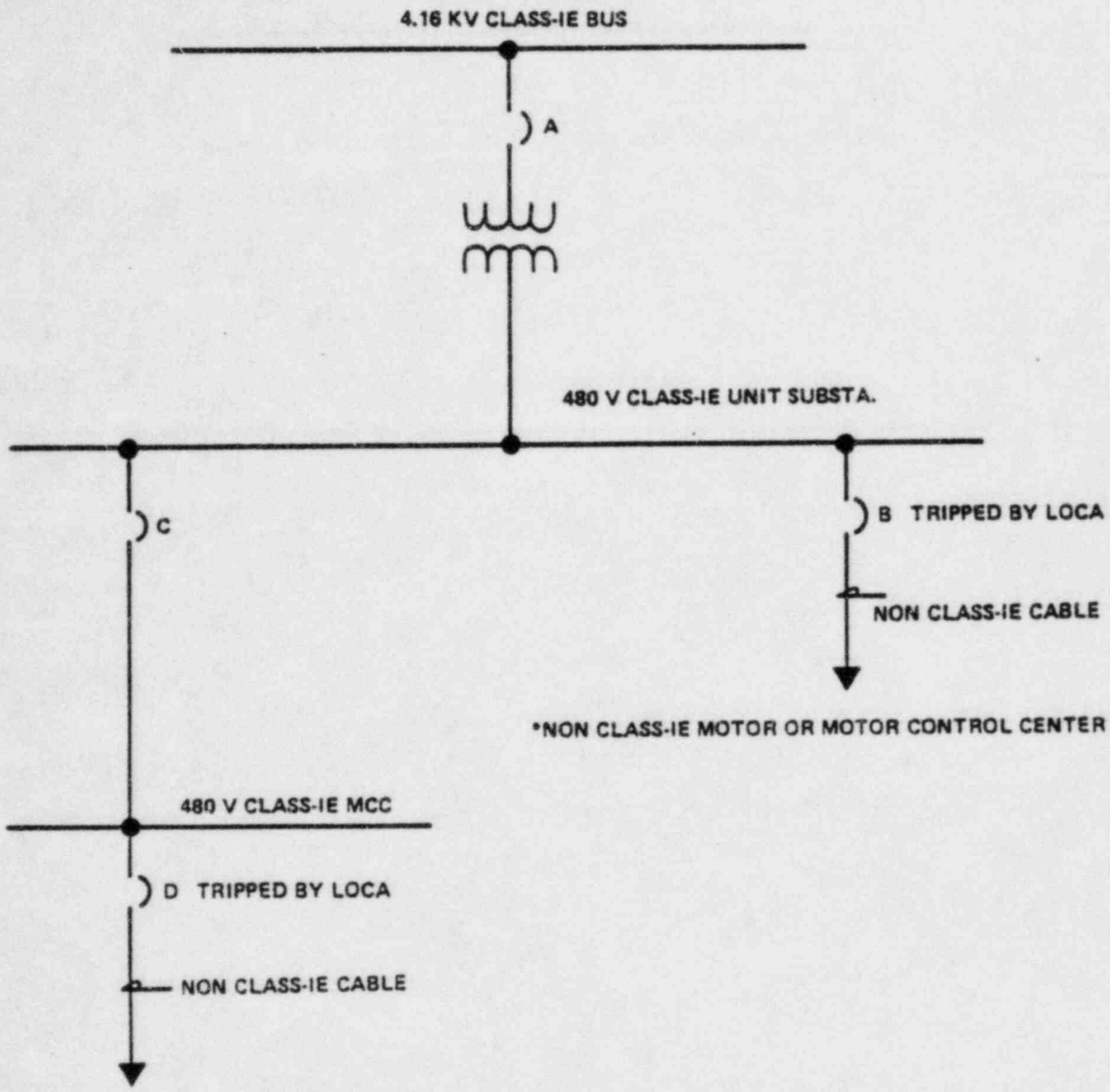
LOAD NO.	NON-CLASS 1E LOAD DESCRIPTION	CLASS 1E BUS	CLASS 1E CIRCUIT BREAKER NO.
1	Reactor Auxiliary Cooling System Pump 1AP209	10B410	52-41011
2	Radwaste and Service Area MCC 10B313	10B410	52-41014
3	Reactor Building Supply Air Handling Unit 1BVH300	10B410	52-41024
4	Reactor Auxiliary Cooling System Pump 1BP209	10B420	52-42011
5	Radwaste and Service Area MCC 10B323	10B420	52-42014
6	Reactor Building Exhaust Fan 1BV301	10B420	52-42024
7	Reactor Building Supply Air Handling Unit 1CVH300	10B430	52-43024
8	Control Rod Drive Pump 1AP207	10B430	52-43014
9	Control Rod Drive Pump 1BP207	10B440	52-44014
10	Reactor Building Supply Air Handling Unit 1AVH300	10B440	52-44024
11	Radwaste Area Supply Fan 0BV316	10B440	52-44034
12	Reactor Area MCC 10B252	10B450	52-45011
13	Radwaste Area Exhaust Fan 0AV305	10B450	52-45014
14	Emergency Instrument Air Compressor 10K100	10B450	52-45024
15	Reactor Building Exhaust Fan 1CV301	10B450	52-45034
16	Reactor Area MCC 10B262	10B460	52-46011
17	Radwaste Area Exhaust Fan 0BV305	10B460	52-46014
18	Reactor Area MCC 10B272	10B470	52-47011
19	Radwaste Area Exhaust Fan 0CV305	10B470	52-47014
20	Radwaste Area Supply Fan 0AV316	10B470	52-47024
21	Technical Support Center MCC 00B474	10B470	52-47031

DSER OPEN ITEM 260

TABLE 430.33-1
CONTINUED

22	Reactor Area MCC 10B282	10B480	52-48011
23	Reactor Building Exhaust Fan 1AV301	10B480	52-48024
~~24~~	~~NSSS Computer Inverter 10D485~~	~~10B441~~	~~52-441023~~
25	Public Address System Inverter 10D496	10B451	52-451023
~~26~~	~~BOP Computer Inverter 1AD492~~	~~10B461~~	~~52-461023~~
27	Security System Inverter 0AD495	10B471	52-471023
~~28~~	~~BOP Computer Inverter 1BD492~~	~~10B481~~	~~52-481023~~

DSER OPEN ITEM 260



HOPE CREEK
GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

ISOLATION BETWEEN CLASS-IE POWER SUPPLIES AND NON CLASS-IE LOADS—TRIPPING CIRCUIT BREAKER

FIGURE 430.33-1 AMENDMENT 4, 1/84

TEST PROCEDURE, ISOLATION VERIFICATION

S/N 9743 1E 20KVA UPS (INSTRUMENTATION AC POWER SUPPLY)

FOR PUBLIC SERVICE ELECTRIC & GAS CO.
HOPE CREEK GENERATING STATION
PO. 10855-E-154 (Q)-AC

OBJECTIVE:

TESTING TO ESTABLISH THE UPS SYSTEM AS A CIRCUIT ISOLATION SYSTEM.

PASS CRITERIA:

DEFINITION OF ISOLATION DEVICE OR SYSTEM: A DEVICE OR SYSTEM IS CONSIDERED TO BE A CIRCUIT ISOLATION DEVICE IF IT IS APPLIED SUCH THAT THE MAXIMUM CREDIBLE VOLTAGE OR CURRENT TRANSIENT APPLIED TO THE NON CLASS 1E SIDE OF THE DEVICE WILL NOT DEGRADE THE CLASS 1E CIRCUIT ON THE OTHER SIDE OF THAT DEVICE.

CIRCUIT	NORMAL VARIATION
ALT. DC. SUPPLY	150-140 VDC 0-364 ADC
NORMAL AC SUPPLY	480+10% V(L-L) 3 PHASE 0-55A, 0-132AP FOR 10MSEC
BACK UP AC SUPPLY	480+10% V 1 PHASE 0-78A, 0-500AP FOR 10MSEC

ANY VARIATIONS OUTSIDE OF NORMAL VARIATIONS SPECIFIED, WILL BE ANALYZED ON A CASE BY CASE BASIS.

FAULT LOCATION AND TYPE

FAULTS WILL BE APPLIED TO UPS SYSTEM OUTPUT TERMINALS BY CLOSING A SWITCH AS REQUIRED.

FAULT TYPES:

1. PHASE (HOT) TO GROUND
2. NEUTRAL TO GROUND
3. PHASE TO NEUTRAL W/O GROUND
4. 480VAC APPLIED ACROSS UPS OUTPUT W/O GROUND (HOT SHORT)

THE CONDITION OF THE THREE CLASS 1E SOURCES WILL BE MONITORED THROUGH SUITABLE SIGNAL CONDITIONERS, BY GOULD INC., 2000W SERIES HIGH FREQUENCY RECORDING SYSTEM.

TEST PROCEDURES

1.0 GENERAL NOTES

1.1 BEFORE STARTING TEST DETERMINE AND RECORD ALL SIGNAL CONDITIONER TRANSFER RATIO (MULTIPLIER) VALUES.

1.2 NORMAL SYSTEM OPERATION DURING EACH TEST

A. CONNECTION PER FIG. 1.
B. OUTPUT LOAD 10KVA @ .08PF (66.7 AMP RESISTIVE AND 50 AMP INDUCTIVE) @ 120VAC NOMINAL.
C. UPS POWERED BY "ALTERNATE" DC SOURCE (BATTERY) AND ONE OR BOTH AC SOURCES, "NORMAL" & "BACK-UP".
D. STATIC SWITCH IN "PREFERRED" POSITION.
E. ALL BREAKERS & SWITCHES CLOSED, BOTH BYPASS SWITCHES IN "NORMAL" POSITION
"TEST" SWITCH - CENTERED
"RETURN MODE" SWITCH - IN "AUTO" POSITION
"ISOLATION" TOGGLE SWITCHES - ON
"SYNC" TOGGLE SWITCH - ON

1.3 TEST INSTRUMENTATION

A. GOULD INC., MODEL 2800W HIGH FREQUENCY RECORDING SYSTEM. EIGHT CHANNEL, INDEPENDENT SCALE SELECT ±.050 TO ±500 VOLTS FULL SCALE.
B. POTENTIAL TRANSFORMER 480V, 60HZ PRIMARY 120V SECONDARY (4:1 RATIO).
C. CURRENT TRANSFORMER 1000:1 RATIO WITH 10 OHM BURDEN RESISTOR. (.01V/A).
D. WIDEBAND DC ISOLATION AMPLIFIER, GOULD INC. MODEL 13-4615-10 OR EQUIVALENT.

1.4 TEST FACILITY AND EQUIPMENT

A. DC SUPPLY - C&D 4LCW-15 BATTERY (60 CELLS, 80KW FOR 30 MIN.) AND BATTERY CHARGER.
B. AC SUPPLY - 480V, 3 PHASE, 4W, 60 HZ, 1200A GROUNDED NEUTRAL.
C. AC LOAD BANK - 0-30KW OR 0-30KVA @ 0.8PF.
D. FAULT APPLICATION DEVICE - G.E. CIRCUIT BREAKER TJC 36400G 400A, 3P. MAGNETIC ONLY.
E. HOT FAULT SOURCE - TRANSFORMER, 1 PH 480:120V 30KVA OR LARGER.

2.0 TEST PROCEDURE

2.1 BASE LINE DATA
START UP THE UPS WITH ALL SOURCES AVAILABLE. SET UP "NORMAL OPERATION" PER 1.2 AND ALLOW SYSTEM TO WARM UP FOR AT LEAST 30 MINUTES.

A1. METERING AND CONNECTIONS PER FIG. 2 AND "BACKUP SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
A2. REPEAT A1 EXCEPT USE 500HZ TIME BASE.
B1. WITH METERING AND CONNECTIONS PER FIG. 2 AND "NORMAL SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
B2. REPEAT B1 EXCEPT STATIC SWITCH TRANSFERRED TO BACKUP.
B3. REPEAT B1 EXCEPT USE 500HZ TIME BASE.
B4. REPEAT B2 EXCEPT USE 500HZ TIME BASE.

2.2 FAULT TESTING

C0. METERING AND CONNECTIONS PER FIG 2, RECORDER IN MANUAL TRIGGER MODE. APPLY FAULT BY CLOSING "FAULT" CB AND AT THE SAME TIME (OR 0 TO 10 MILLISECONDS BEFORE) TRIGGER THE RECORDER IN "STORE" MODE. REMOVE THE FAULT AND RECORD THE MEMORY TO PAPER.
AFTER EACH FAULT APPLICATION CHECK THE UPS FOR DAMAGE. REPAIR THE UPS IF REQUIRED BEFORE PROCEEDING.

C1. INSTALL JUMPER "A" TO "FAULT" CB WITH "BACKUP SOURCE" CB OPEN WITH RECORDER AT 20KHZ TIME BASE APPLY FAULT PER C0.

C2. REPEAT C1 EXCEPT WITH 500HZ TIME BASE.

C3. OPEN "NORMAL SOURCE" CB AND CLOSE "BACKUP" WITH RECORDER 20KHZ TIME BASE APPLY FAULT PER C0.

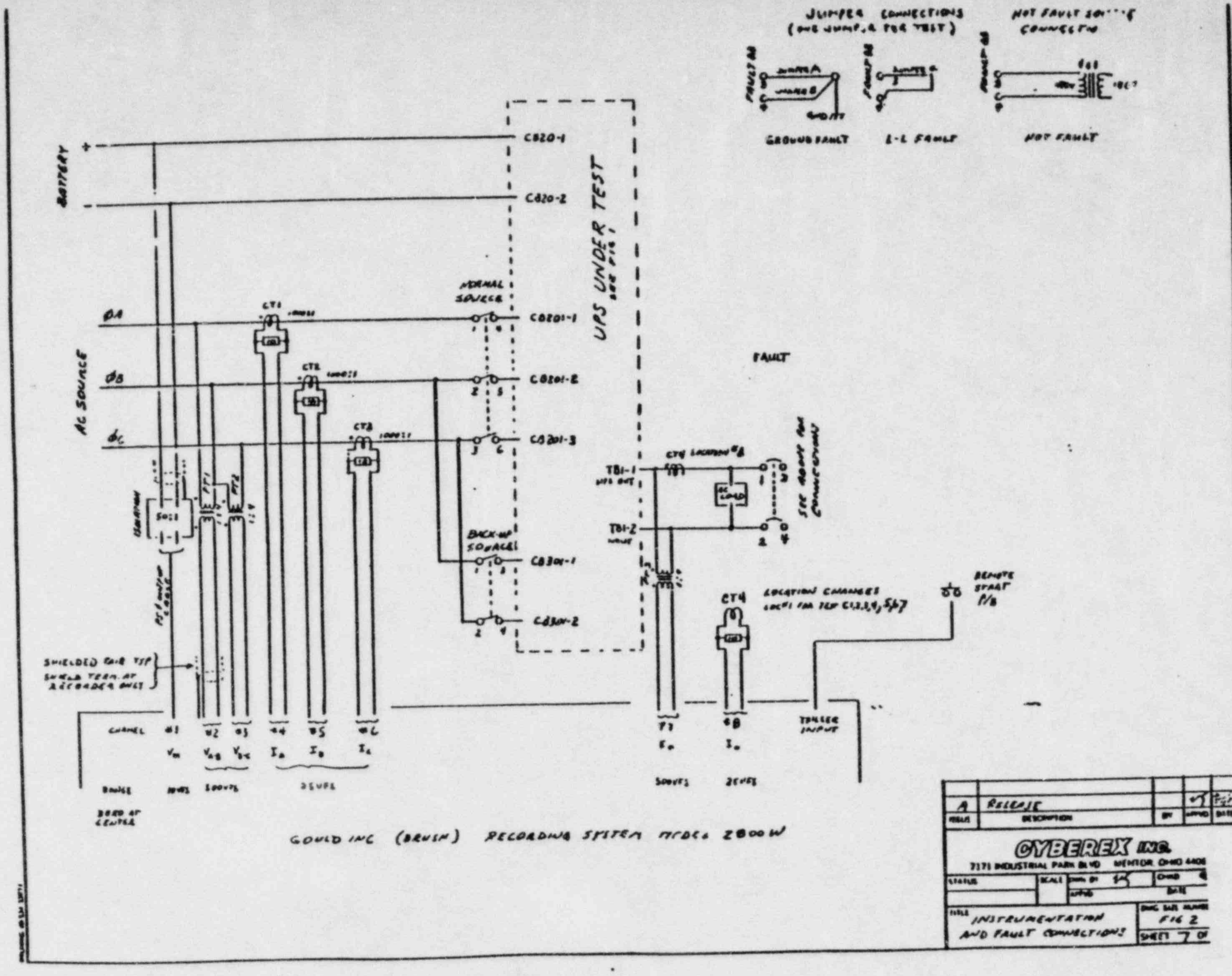
C4. REPEAT C3 EXCEPT WITH 500HZ TIME BASE.

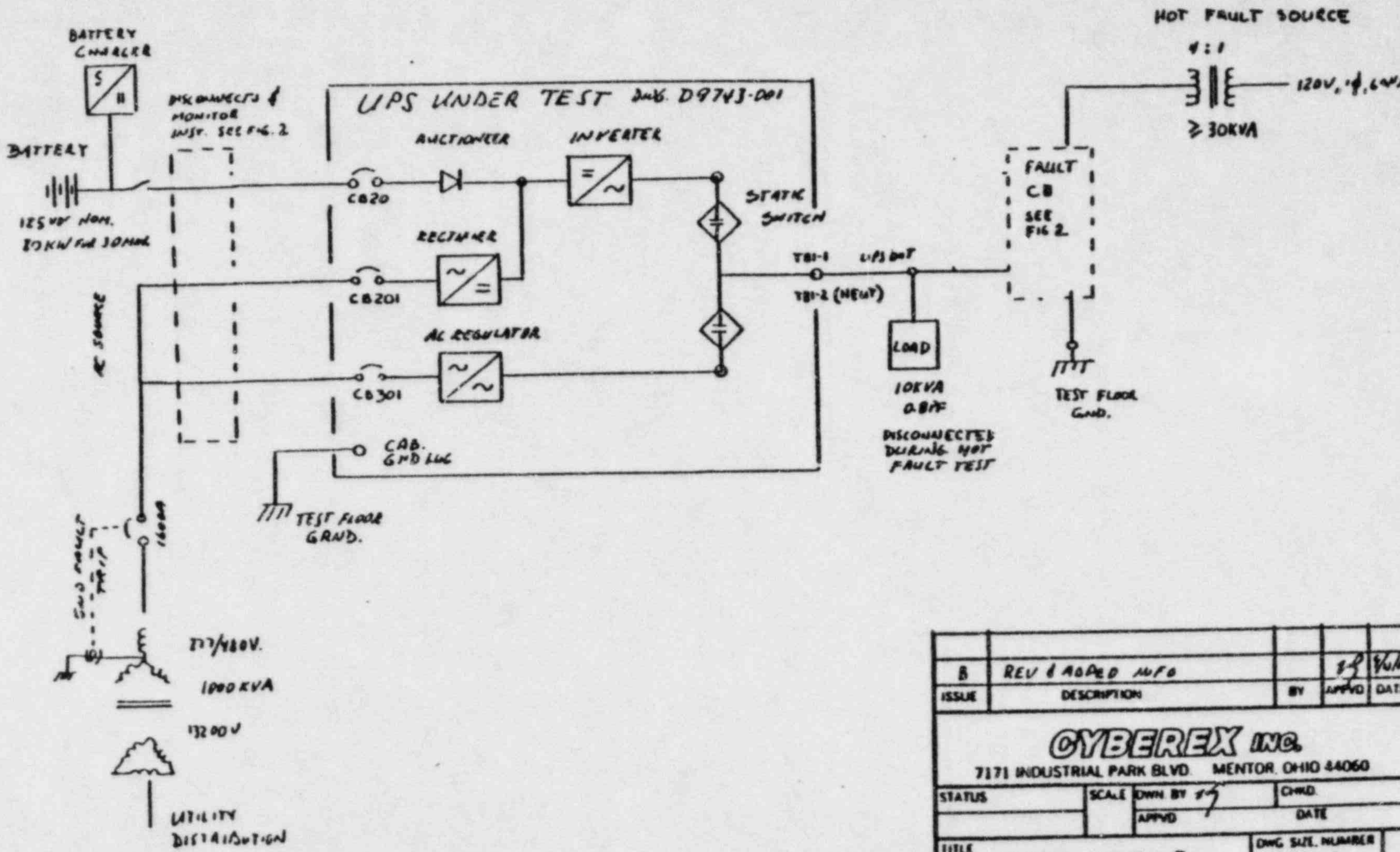
C5. REPEAT C1, C2, C3 & C4 WITH JUMPER "B" INSTEAD OF "A" CONNECTED TO "FAULT" CB.

C6. REPEAT C1, C2, C3, & C4 WITH JUMPER "C" INSTEAD OF "A" CONNECTED TO "FAULT" CB.

C7. REPEAT C1, C2, C3, & C4 WITH CONNECTIONS TO HOT FAULT SOURCE (UPS RUNNING AT NO LOAD).

2.3 COMPLETE TEST SUMMARY SHEET FOR EACH TEST OR TEST GROUP.


JUMPER CONNECTIONS
(ONE JUMP, A FOR TEST)
HOT FAULT
GROUND FAULT
L-L FAULT
HOT FAULT
BATTERY
C820-1
C820-2
UPS UNDER TEST
AC SOURCE
ØA
ØB
ØC
NORMAL SOURCE
CB201-1
CB201-2
CB201-3
BACK-UP SOURCE
CB301-1
CB301-2
CT1
CT2
CT3
PT1
PT2
FAULT
TB1-1
TB1-2
SEE ABOVE FOR CONNECTIONS
CT4
REMOTE START P/B
TRIGGER INPUT
SHIELDED PAIR TYP
SHIELD TERM AT RECORDER ONLY
CHANNEL
#1
#2
#3
#4
#5
#6
#7
#8
V_m
V_{AB}
V_{BC}
I_A
I_B
I_C
RANGE
ZERO AT CENTER
GOULD INC (BRUSH) RECORDING SYSTEM MODEL 2800W
A
RELEASE
CYBEREX INC.
7171 INDUSTRIAL PARK BLVD MENTOR, OHIO
INSTRUMENTATION AND FAULT CONNECTIONS
FIG 2
SHEET 7



B	REV & ADDED INFO			
ISSUE	DESCRIPTION	BY	APP'D	DATE

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD. MENTOR, OHIO 44060

STATUS	SCALE	DWN BY	CHKD.
		APP'D	DATE

TITLE: TEST SETUP ONE LINE DIAGRAM	DWG SIZE NUMBER: FIG. 1
	SHEET 6 OF 8

TEST SUMMARY

TEST # ______ CHART # ______ CHART SPEED ______

BY ______ DATE ______ APR'D BY ______ DATE ______

TEST DESCRIPTION:

CHAN #	CHART SCALE UNITS/mm	CHANGE DURING TEST		REMARKS
1				
2				
3				
4				
5				
6				
7				
8				

CHART TIME BASE ______

DAMAGED PARTS:

UPS BREAKER TRIPPED DURING TEST: ______

UPS FUSE CLEARED DURING TEST: ______

REMARKS:

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD. MENTOR, OHIO 44060

TITLE	STATUS	SCALE	DWN BY	APPVD	CHKD	DATE	DWG. SIZE NUMBER	SHEET 8 OF 8

ISSUE	DESCRIPTION	BY	APPVD	DATE

TEST PROCEDURE, ISOLATION VERIFICATION

S/N 9743 1E 20KVA UPS (INSTRUMENTATION AC POWER SUPPLY) IN SERIES WITH A POWER CONVERSION PRODUCTS ISOLATING TRANSFORMER MODEL # RTF-120/120-30

FOR PUBLIC SERVICE ELECTRIC & GAS CO.
HOPE CREEK GENERATING STATION
PO. 10855-E-154 (Q)-AC

OBJECTIVE:

TESTING TO ESTABLISH THE ISOLATING TRANSFORMER IN SERIES WITH A UPS SYSTEM AS A CIRCUIT ISOLATION SYSTEM.

PASS CRITERIA:

DEFINITION OF ISOLATION DEVICE OR SYSTEM: A DEVICE OR SYSTEM IS CONSIDERED TO BE A CIRCUIT ISOLATION DEVICE IF IT IS APPLIED SUCH THAT THE MAXIMUM CREDIBLE VOLTAGE OR CURRENT TRANSIENT APPLIED TO THE NON CLASS 1E SIDE OF THE DEVICE WILL NOT DEGRADE THE CLASS 1E CIRCUIT ON THE OTHER SIDE OF THAT DEVICE.

CIRCUIT	NORMAL VARIATION
ALT. DC. SUPPLY	150-140 VDC 0-364 ADC
NORMAL AC SUPPLY	480+10% V(L-L) 3 PHASE 0-55A, 0-132AP FOR 10MSEC
BACK UP AC SUPPLY	480+10% V 1 PHASE 0-78A, 0-500AP FOR 10MSEC

ANY VARIATIONS OUTSIDE OF NORMAL VARIATIONS SPECIFIED, WILL BE ANALYZED ON A CASE BY CASE BASIS.

FAULT LOCATION AND TYPE

FAULTS WILL BE APPLIED TO ISOLATING TRANSFORMER OUTPUT TERMINALS BY CLOSING A SWITCH AS REQUIRED.

FAULT TYPES:

1. PHASE (HOT) TO GROUND
2. NEUTRAL TO GROUND
3. PHASE TO NEUTRAL W/O GROUND
4. 480VAC APPLIED ACROSS UPS OUTPUT W/O GROUND (HOT SHORT)

THE CONDITION OF THE THREE CLASS IE SOURCES WILL BE MONITORED THROUGH SUITABLE SIGNAL CONDITIONERS, BY GOULD INC., 2000W SERIES HIGH FREQUENCY RECORDING SYSTEM.

TEST PROCEDURES

1.0 GENERAL NOTES

1.1 BEFORE STARTING TEST DETERMINE AND RECORD ALL SIGNAL CONDITIONER TRANSFER RATIO (MULTIPLIER) VALUES.

1.2 NORMAL SYSTEM OPERATION DURING EACH TEST

A. CONNECTION PER FIG. 1.
B. OUTPUT LOAD 10KVA @ .08PF (66.7 AMP RESISTIVE AND 50 AMP INDUCTIVE) @ 120VAC NOMINAL.
C. UPS POWERED BY "ALTERNATE" DC SOURCE (BATTERY) AND ONE OR BOTH AC SOURCES, "NORMAL" & "BACK-UP".
D. STATIC SWITCH IN "PREFERRED" POSITION.
E. ALL BREAKERS & SWITCHES CLOSED, BOTH BYPASS SWITCHES IN "NORMAL" POSITION
"TEST" SWITCH - CENTERED
"RETURN MODE" SWITCH - IN "AUTO" POSITION
"ISOLATION" TOGGLE SWITCHES - ON
"SYNC" TOGGLE SWITCH - ON

1.3 TEST INSTRUMENTATION

A. GOULD INC., MODEL 2800W HIGH FREQUENCY RECORDING SYSTEM. EIGHT CHANNEL, INDEPENDENT SCALE SELECT ±.050 TO ±500 VOLTS FULL SCALE.
B. POTENTIAL TRANSFORMER 480V, 60HZ PRIMARY 120V SECONDARY (4:1 RATIO).
C. CURRENT TRANSFORMER 1000:1 RATIO WITH 10 OHM BURDEN RESISTOR. (.01V/A).
D. WIDEBAND DC ISOLATION AMPLIFIER, GOULD INC. MODEL 13-4615-10 OR EQUIVALENT.

1.4 TEST FACILITY AND EQUIPMENT

A. DC SUPPLY - C&D 4LCW-15 BATTERY (60 CELLS, 80KW FOR 30 MIN.) AND BATTERY CHARGER.
B. AC SUPPLY - 480V, 3 PHASE, 4W, 60 HZ, 1200A GROUNDED NEUTRAL.
C. AC LOAD BANK - 0-30KW OR 0-30KVA @ 0.8PF.
D. FAULT APPLICATION DEVICE - G.E. CIRCUIT BREAKER TJC 36400G 400A, 3P, MAGNETIC ONLY.
E. HOT FAULT SOURCE - TRANSFORMER, 1 PH 480:120V 30KVA OR LARGER.

2.0 TEST PROCEDURE

2.1 BASE LINE DATA

START UP THE UPS WITH ALL SOURCES AVAILABLE. SET UP "NORMAL OPERATION" PER 1.2 AND ALLOW SYSTEM TO WARM UP FOR AT LEAST 30 MINUTES.

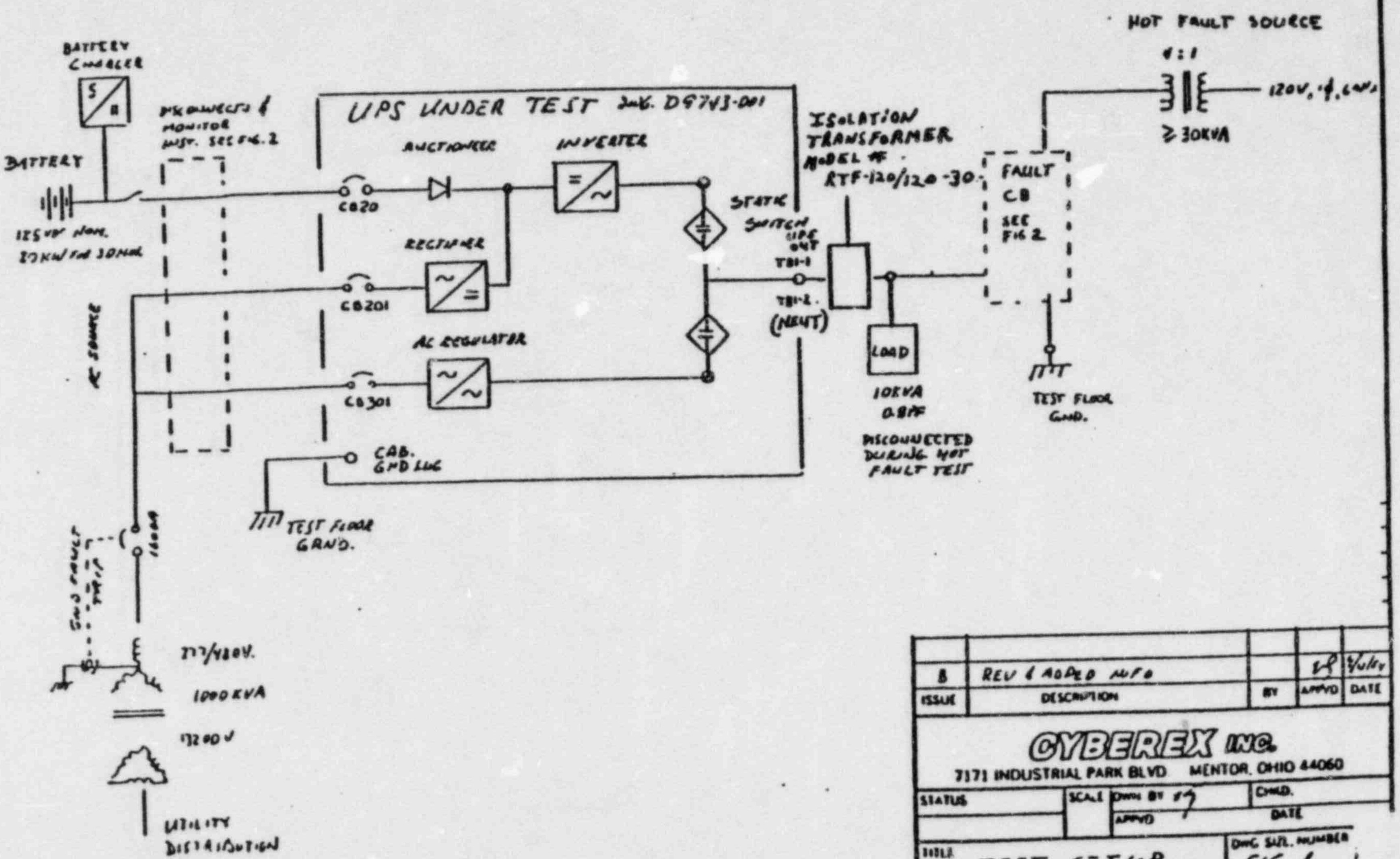
A1. METERING AND CONNECTIONS PER FIG. 2 AND "BACKUP SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
A2. REPEAT A1 EXCEPT USE 500HZ TIME BASE.
B1. WITH METERING AND CONNECTIONS PER FIG. 2 AND "NORMAL SOURCE" BREAKER OPEN. RECORD IN "STORE" MODE AT 20KHZ TIME BASE. COPY MEMORY TO PAPER.
B2. REPEAT B1 EXCEPT STATIC SWITCH TRANSFERRED TO BACKUP.
B3. REPEAT B1 EXCEPT USE 500HZ TIME BASE.
B4. REPEAT B2 EXCEPT USE 500HZ TIME BASE.

2.2 FAULT TESTING

C0. METERING AND CONNECTIONS PER FIG 2, RECORDER IN MANUAL TRIGGER MODE. APPLY FAULT BY CLOSING "FAULT" CB AND AT THE SAME TIME (OR 0 TO 10 MILLISECONDS BEFORE) TRIGGER THE RECORDER IN "STORE" MODE. REMOVE THE FAULT AND RECORD THE MEMORY TO PAPER.
AFTER EACH FAULT APPLICATION CHECK THE UPS FOR DAMAGE. REPAIR THE UPS IF REQUIRED BEFORE PROCEEDING.

C1. INSTALL JUMPER "A" TO "FAULT" CB WITH "BACKUP SOURCE" CB OPEN WITH RECORDER AT 20KHZ TIME BASE APPLY FAULT PER C0.
C2. REPEAT C1 EXCEPT WITH 500HZ TIME BASE.
C3. OPEN "NORMAL SOURCE" CB AND CLOSE "BACKUP" WITH RECORDER 20KHZ TIME BASE APPLY FAULT PER C0.
C4. REPEAT C3 EXCEPT WITH 500HZ TIME BASE.
C5. REPEAT C1, C2, C3 & C4 WITH JUMPER "B" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C6. REPEAT C1, C2, C3, & C4 WITH JUMPER "C" INSTEAD OF "A" CONNECTED TO "FAULT" CB.
C7. REPEAT C1, C2, C3, & C4 WITH CONNECTIONS TO HOT FAULT SOURCE (UPS RUNNING AT NO LOAD).

2.3 COMPLETE TEST SUMMARY SHEET FOR EACH TEST OR TEST GROUP.



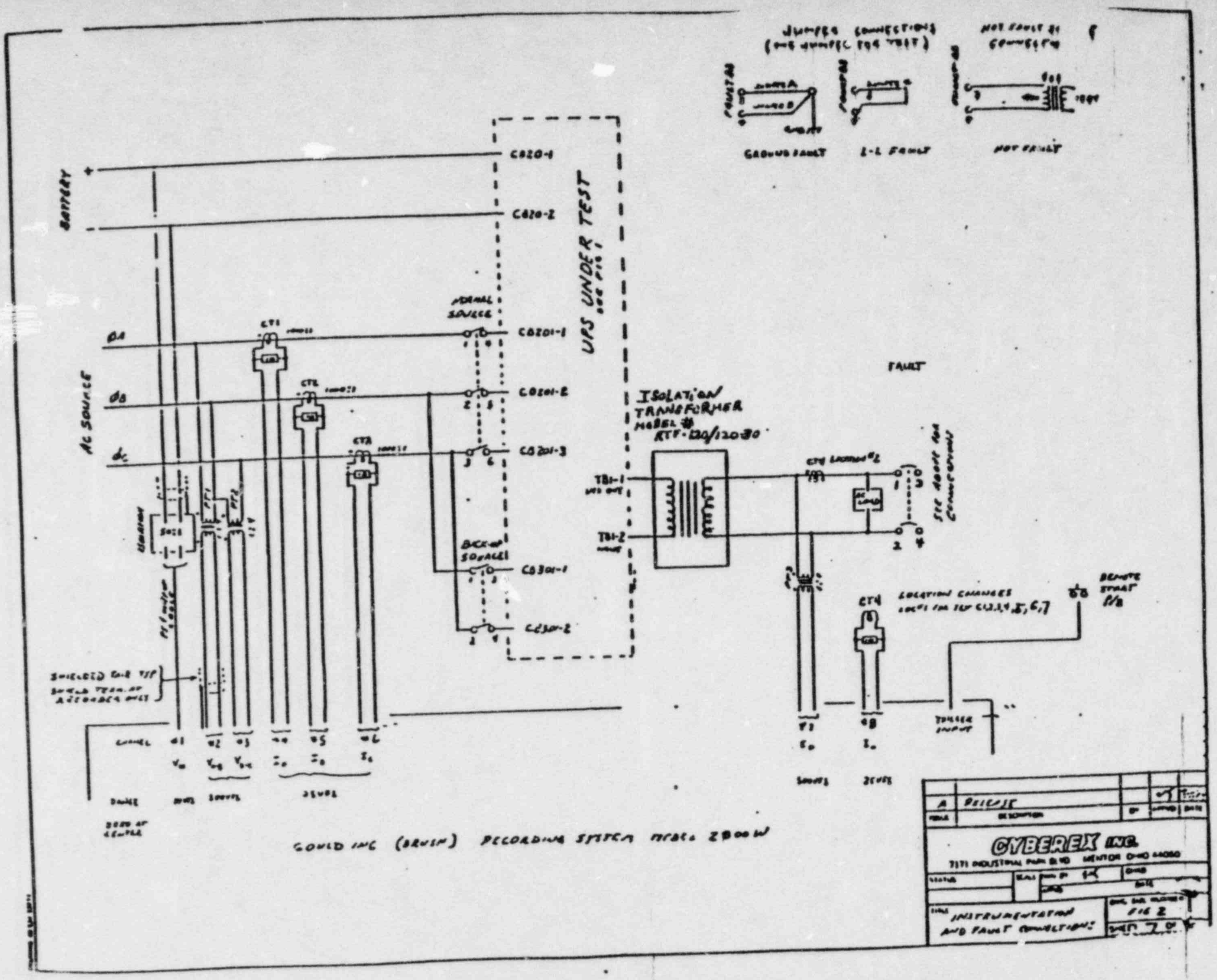
ISSUE	DESCRIPTION	BY	APPVD	DATE
B	REV & ADDED INFO			

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD MENTOR, OHIO 44060

STATUS	SCALE	DWN BY	CHKD.
		APPVD	DATE

TITLE: TEST SETUP
ONE LINE DIAGRAM

DWG SIZE NUMBER: FIG. 1
SHEET 6 OF


JUMPER CONNECTIONS
GROUND FAULT
L-L FAULT
HOT FAULT
BATTERY
AC SOURCE
C020-1
C020-2
C0201-1
C0201-2
C0201-3
C0301-1
C0301-2
UPS UNDER TEST
NORMAL SOURCE
BACKUP SOURCE
CT1
CT2
CT3
CT4
FAULT
ISOLATION TRANSFORMER
TB1-1
TB1-2
SEE ABOVE FOR CONNECTIONS
LOCATION CHANGES
REMOTE START
TRIGGER INPUT
SHIELDED CABLE
GOULD INC (BRUSH) RECORDING SYSTEM MODEL 2800W
CYBEREX INC.
INSTRUMENTATION AND FAULT CONNECTIONS
FIG 2

TEST SUMMARY

TEST # ______________ CHART # ______________ CHART SPEED ______________

BY ________ DATE ________ APR'D BY ________ DATE ________

TEST DESCRIPTION:

CHAN #	CHART SCALE UNITS/mm	CHANGE DURING TEST		REMARKS
1				
2				
3				
4				
5				
6				
7				
8				

CHART TIME BASE ______________

DAMAGED PARTS:

UPS BREAKER TRIPPED DURING TEST: ______________

UPS FUSE CLEARED DURING TEST: ______________

REMARKS:

ISSUE	DESCRIPTION	BY	APP'D	DATE

CYBEREX INC.
7171 INDUSTRIAL PARK BLVD. MENTOR, OHIO 44060

TITLE

STATUS | SCALE | DWN BY | CHKD
APP'D | DATE
DWG SIZE NUMBER
SHEET 8 OF 8

c.22 Activities covered by the QA program are delineated in Table 17.2-1 and include inplant I_2 radiation monitoring under "Control of Radioactivity."

c.23 The HCGS position on TMI Item II.d.3.4 is given in Section 1.10. This item is not a "structure, system or component" requiring entry in Table 3.2-1. Control of this activity is provided by appropriate procedures. Chapter 17 describes the Quality Assurance Program coverage of procedural controls.

The following information is provided for additional clarification:

a) The nonsafety-related, non-ESF internal cpmponents include the steam dryer, the shroud head and steam separator assembly, the in-core guide tubes and stabilizers, the differential-pressure and liquid-control lines inside the RPV, the fuel orifices, and the feedwater spargers. In all BWR 4, 5, and 6 designs, these components are not Q-listed because they are neither required for safe shutdown of the plant, nor would their failure jeopardize the safety functions of other safety-related internal components.

During the operating phase of the HCGS, the same high-quality design, procurement, and installation control practices, as were applied during the design and construction phase, will be applied to any changes to these components. As Section 3.2.1 and notes (13) and (50) for Table 3.2-1 indicate, the quality assurance controls for non-ESF RPV internal components and for seismic Class II/I equipment are described in Section 1.8.1.29.

In addition, the reactor pressure vessel internal structures which are accessible are included in the ISI program, which is covered by the operational QA program.

b) Reactor building penetrations are not required to be Q-listed unless the piping system is Q-listed. A non-Q piping system penetrating the reactor building is not required to have a Q-listed penetration. ~~However, most of the reactor building penetrations are Q-listed as shown in revised Table 3.2-1.~~ However reactor building penetrations are either Q-listed or classified as Seismic II/I as shown in revised Table 3.2-1.

c) The spent fuel pool liner does not perform a safety function and therefore is not Q-listed. However, the spent fuel pool does meet the quality assurance requirements of 10 CFR 50, Appendix B, and has been noted as such in Table 3.2-1, Item XIX.e.

d) Shore protection of the intake structure does not have a safety function and therefore is not Q-listed (Item XVIII.j

6. Vendor services

b. Coordinates PSE&G system/component turnover documentation review

c. Coordinates resolution of support-related problems

d. Provides test and startup technical support and assistance, as required.

In implementing this responsibility, he directs assigned group leaders and personnel.

14.2.2.2.4 Integrated Testing Coordinator

The integrated testing coordinator is responsible for providing technical expertise to the startup program. In this capacity, his responsibilities include:

a. Development and direction of the test program on integrated system tests

b. Technical procedure review

c. Acquisition of baseline data.

In implementing this responsibility, he directs assigned group leaders and personnel.

14.2.2.2.5 Quality Assurance Startup Engineer (QASE)

Quality Assurance

The quality assurance startup engineer performs a staff function to PSSUG. He is assigned to the Public Service ~~corporate quality assurance department (QAD)~~ Engineering & Construction Group, to which he is technically and administratively responsible. He will identify to the Startup Manager, or his designee, all quality related problems associated with Q/F-listed activities. His responsibilities include:

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

Public Service Electric and Gas Company (PSE&G) is responsible for assuring that the operation, maintenance, refueling and modification of Hope Creek Generating Station (HCGS) is accomplished in a manner that protects public health and safety and that is in compliance with applicable regulatory requirements. To carry out this responsibility, PSE&G has developed and implemented a comprehensive quality assurance program that is applicable to the design, construction, and testing phases. The description of the quality assurance program provided herein parallels the operational quality assurance program currently being implemented at the Salem Generating Station.

This operational quality assurance program is documented in the nuclear department manual. This description is maintained by nuclear ~~operations~~ quality assurance (NQA). The program provides measures to assure the control of activities affecting the safety-related function of structures, systems, and components. The quality assurance program encompasses fire protection of safety-related areas and other activities enumerated in Regulatory Guide 1.33. A planned monitoring and audit program assures that specified requirements of the operational quality assurance program are met. The program provides coordinated and centralized quality assurance direction, control, and documentation, as required by the NRC criteria set forth in 10 CFR 50, Appendix B. Applicable NRC Regulatory Guides, codes, and standards, as well as the policy statements contained in the Nuclear department ~~PSE&G quality assurance~~ manual, are used by PSE&G organizations performing activities affecting safety to prepare appropriate implementing procedures. To assess the effectiveness of the PSE&G quality assurance program, independent auditors from outside the company periodically audit the program for compliance with 10 CFR 50, Appendix B, and other regulatory commitments. Independent audits shall be conducted at least every two years. Reports of such audits are made directly to upper management.

QA policy statements are issued by key management representatives including the Company Board Chairman/President, by the Senior Vice President - ~~Energy Supply~~ Nuclear and Engineering and by the Vice President - Nuclear and, as such, are mandatory throughout the Company.

Key policy elements, as they apply to nuclear safety, include the following:

a. Nuclear safety is of the highest priority and shall take precedence over matters concerning power production.

b. The public's health and safety is the prime consideration in the conduct and support of Public Service Electric and Gas Company's nuclear operations and shall not be compromised. All decisions which could affect the health and safety of the public shall be made conservatively.

c. A Quality Assurance Program is an essential part of the PSE&G commitment to safe and reliable nuclear power operation. Applicable program requirements shall be strictly adhered to in the performance of activities covered by the Quality Assurance Program.

PSE&G requires its suppliers and contractors to assume responsibility for establishing and implementing QA/QC programs, as applicable, to meet 10 CFR 50, Appendix B. However, the responsibility for the overall QA program is retained and excercised by PSE&G. NQA reviews those programs and conducts appropriate monitoring and auditing as required to assure that the suppliers are properly implementing their QA/QC programs. The nuclear operations quality assurance program verifies that requirements necessary to assure quality are properly included or referenced. In addition, these suppliers' procurement documents include applicable PSE&G quality assurance requirements for items and services provided by their suppliers.

17.2.1 ORGANIZATION

The nuclear ~~operations~~ QA program, referred to hereafter as the QA program, assures that adequate administrative and management controls are established for the safe operation of the Hope Creek Generating Station.

General

Implementation is assured by ongoing review, monitoring and audit under the direction of the Manager-Nuclear ~~Operations~~ Quality Assurance who reports to the Vice President-Nuclear.

Company organization is shown on Figures 13.1-1, 13.1-2 and 17.2-1. Responsibilities for activities affecting safety are described in the following sections.

17.2.1.1 Nuclear Department

The Vice President - Nuclear is responsible for managing and directing the nuclear activities of the company. ~~Reporting to the vice president - nuclear are the general manager - nuclear services, general manager - nuclear support, general manager - Salem operations, general manager - Hope Creek operations, and manager - quality assurance nuclear operations.~~ Overall duties and responsibilities of the nuclear department are ~~included in~~ provided ~~the following sections. More detailed descriptions are contained~~ in Section 13.1. ~~The~~ General managers reporting to the Vice President - nuclear are responsible for implementation of quality assurance requirements by their staff. These QA requirements are contained in the ~~station administrative~~ nuclear ~~procedures and other department manuals.~~ department manual and in individual department manuals

The Vice President - Nuclear regularly assesses the scope, status, adequacy, and compliance of the QA program to 10 CFR 50, Appendix B through:

a. Frequent contacts in staff meetings, NQA audit reports, cooperative management audit reports, NRC inspection reports, department status reports.

b. An annual assessment of the QA program is preplanned and documented. This assessment addresses the scope, status, and adequacy of the QA program. Corrective action is identified, and tracked.

~~17.2.1.1.1 Nuclear Department - Nuclear Services~~

~~The general manager - nuclear services is responsible for providing technical support to station organizations in the areas of radiation protection; site protection, including fire, security, and emergency preparedness; site maintenance; nuclear procurements and materials control; and personnel training.~~

~~17.2.1.1.2 Nuclear Department - Nuclear Support~~

Company organization is shown on Figures 13.1-1, 13.1-2 and 17.2-1. Responsibilities for activities affecting safety are described in the following sections.

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~~17.2.1.1.2 Nuclear Department - Nuclear Support~~

~~The general manager - nuclear support is responsible for providing support to the station in the areas of reactor engineering, engineering and design, fuel management, licensing and regulatory activity, nuclear safety, and risk assessment analysis.~~

17.2.1.1.3 Nuclear Department - Hope Creek Operations

~~The general manager - Hope Creek operations is responsible for the safe and efficient operation of the plant, and for the general direction of the station operating, maintenance, radiation protection, and technical support departments. The general manager - Hope Creek operations also directs the activities of the station operations review committee (SORC) and is responsible for assuring that plant positions are staffed by fully qualified and trained personnel, as well as being responsible for the implementation of quality assurance requirements by station staff. These quality assurance requirements are contained in the station administrative procedures and other station department manuals.~~

17.2.1.1.~~4~~ 1 Nuclear ~~Operations~~ Quality Assurance

The general manager - nuclear ~~operations~~ quality assurance is responsible for defining, formulating, implementing, and coordinating the quality assurance program. He has been delegated the authority and has the independence to interpret quality requirements, identify quality problems and trends, and provide recommendations or solutions to quality problems. He is responsible for approval of the nuclear QA department manual to be used during the operations phase of Hope Creek. He also is responsible for assuring compliance with established requirements for the quality assurance program through document review, inspection, monitoring, and audit. NQA provides a centralized coordinating function for quality assurance and quality control activities applied to the operation phase.

The general manager - nuclear ~~operations~~ quality assurance has the authority and responsibility to:

a. Stop work when significant conditions adverse to quality require such action.

The PSE&G policies and organization structure assure that the General manager - ~~quality~~ Nuclear quality assurance ~~nuclear operations~~ has sufficient organizational freedom and independence to carry out his responsibilities.

17.2.1.1.4.1 Nuclear ~~Operations~~ Quality Assurance Personnel Qualifications

The general manager - NQA and engineers reporting directly to him must each have a combination of 6 years of experience in the field of quality assurance and operations. At least 1 of these 6 years of experience must be in the overall implementation of a nuclear power plant quality assurance program and must be obtained within the quality assurance organization. A minimum of 1 year and a maximum of 4 of the 6 years of experience may be fulfilled by related technical or academic training. Personnel performing inspections, examinations, and test activities (i.e., to verify conformance) are certified as Level I, Level II, Level III as appropriate to their responsibilities, also in accordance with Regulatory Guide 1.58, as noted.

The general manager - nuclear ~~operations~~ quality assurance fulfills the above qualifications with the addition of the following:

a. Knowledge and experience in quality assurance,

b. High level of leadership with the ability to command the respect and cooperation of company personnel, vendors, and construction forces

c. Initiative and judgment to establish related policies to attain high achievements and economy of operations.

17.2.1.1.5 ~~Independent Review Groups~~ Operational Review

Three advisory groups, {the station operations review committee (SORC), the on-site safety review group (SRG), and the off-site safety review group (OSR)} are responsible for reviewing and evaluating items related to nuclear safety. The overall responsibilities of these groups are ~~included in the following sections. More detailed descriptions are contained~~ provided in Section 13.4.

~~The SORC is an in station advisory group. Composed of key station personnel, its responsibilities include review of plant~~

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~~The SORC is an in station advisory group. Composed of key station personnel, its responsibilities include review of plant~~

~~erations, reportable occurrences, investigation of Technical Specification violations (with recommendations to preclude recurrence), and procedure reviews for activities affecting nuclear safety. Recommendations of this advisory group are forwarded to the general manager - Hope Creek operations, with copies to the chairman of the nuclear review board (NRB)~~. The SQAE is invited to all SORC meetings and receives the minutes of the meetings. He attends the meetings periodically as part of the planned surveillance program.

~~The second advisory group is the safety review group (SRG). This group, whose primary responsibility is to improve plant safety, reviews sources of plant design and operating experience information, and performs surveillance of plant operations and maintenance activities. Results of these reviews and surveillance are reported to the appropriate general manager.~~

As part its independent review functions, the OSR

~~The third advisory group is the NRB, which advises the vice president - nuclear in matters affecting nuclear safety or relating to plant operation or modification to the plant design. The NRB is responsible for performing an independent review of plant activities. In addition, NRB~~ is responsible for selected preplanned, independent audits of plant operations in accordance with Technical Specification requirements. These audits are generally conducted by the NQA under ~~NRB~~ OSR cognizance. ~~The manager - NQA is a member of this board.~~

17.2.1.2 Research and Testing Laboratory

The Research and Testing Laboratory is a part of the PSE&G Research Corporation, which is an independent entity.

The Research and Testing Laboratory performs calibrations, analyses, and evaluations on systems, equipment, and materials, as requested by PSE&G departments, and maintains compliance with is quality assurance program.

17.2.1.3 Fuel Supply Department

The general manager - fuel supply reports to executive the vice president - fuel supply who, in turn, reports to the ~~senior~~ vice president - operations ~~energy supply and engineering~~. The fuel supply department is responsible for arranging for procurement of uranium ore, conversion and enrichment services, and fuel assembly fabrication

Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants.

q. Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

r. Regulatory Guide 1.137, Fuel-Oil Systems for Standby Diesel Generators

~~s~~. t Regulatory Guide 1.144, Auditing Quality Assurance Programs for Nuclear Power Plants

~~t~~. u Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

~~u~~. v BTP 9.5-1, Appendix A, Guidelines for Fire Protection for Nuclear Plants Docketed Prior to July 1, 1976.

Commitments to Regulatory Guides, with respect to revision level, exceptions, etc, are contained in Section 1.8.

Substantive changes to the quality assurance program described herein will be submitted to the NRC within 30 days of implementation. Nonsubstantive changes will be identified in the annual FSAR updates.

The overall quality assurance program is described in the nuclear department manual. This description is prepared and maintained by nuclear ~~operations~~ quality assurance.

PSE&G organizations performing activities affecting nuclear safety prepare and maintain implementing procedures and instructions. These procedures and instructions, and subsequent revisions thereto, are subject to NQA review and approval to the extent necessary to verify compliance with the quality assurance program and the applicable quality-related Regulatory Guides and standards identified above. NQA will monitor the preparation and issuance of required procedures to assure that they are in place at least six months prior to fuel load.

The general manager - Hope Creek operations has instituted and will maintain an administrative procedures (AP) manual for Hope Creek Generating Station (HCGS).

The station administrative procedures and all subsequent revisions thereto are prepared by the technical staff, are reviewed by the Technical Engineer, Technical Manager, NQA and SORC, and are approved by the General Manager-Hope Creek Operations.

Regulatory Guide 1.33 requires that plant activities affecting quality-related items and services be conducted in accordance with written administrative controls prepared by management. The procedures and instructions by which plant activities are performed are prepared by the responsible station organization as required by station APs, ~~received~~ reviewed by the organization responsible for the activity, reviewed by NQA for quality requirements, reviewed by the SORC (for procedures affecting safety), and approved by the department manager. In the absence of a department manager, procedures will be approved by the assistant general manager or his designee. Procedures cannot be implemented unless the review/approval process is accomplished. Station administrative procedures provide a means to accommodate on-the-spot changes to subtier implementing procedures. The routine practice for revising a procedure is to repeat the original review and approval sequence.

Implementation of the quality assurance program is verified by means of independent inspections, monitoring, and audits conducted by NQA.

NQA reviews and analyzes problems affecting safety that occur during the operational phase. Items subject to review include:

a. Documented nonconformances occurring at the vendor's facility and those during receiving, storage, installation, test, and operation, e.g., Deficiency Reports, Nonconformance Reports, Licensee Event Reports, etc

b. Documented corrective actions taken on significant noncompliances and on audit findings

c. NRC inspection findings, notifications, bulletins, etc.

The general manager - nuclear ~~operations~~ quality assurance, or his designee, has the authority to stop work through the issuance of a stop work order where continuance of an activity would seriously compromise safety or constitute a persistent and deliberate failure to correct a serious deficiency. Designees include the station quality assurance engineer for activities conducted at the station and the engineering and procurement engineer for supplier activities.

NQA reports significant problems affecting the quality assurance program to respective management along with:

a. Measures taken to improve quality assurance program controls

b. Appropriate recommendations to achieve compliance with applicable requirements.

Management policy and implementing procedures provide all personnel awareness and direction for reporting of defects and noncompliance pursuant to 10 CFR 21.

The quality assurance program requires that activities affecting nuclear safety, including activities affecting the fire protection of safety-related areas, be accomplished under suitably controlled conditions. The program takes into consideration the need for procedures, special controls, cleanliness, special processes, test equipment, tools, and skills to obtain the required quality and the verification of quality by inspection, test, examination, monitoring, and independent review and audit. These activities include, but are not limited to, designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying.
reworking

Personnel who have the responsibility to implement the nuclear ~~operations~~ quality assurance program also have the responsibility and authority to escalate unresolved quality problems to the level of management necessary to effect a resolution of the problem. Escalation is applied by NQA personnel to increasingly higher levels of management, up to the vice president - nuclear, as required.

Personnel performing Q- and F-designated activities are trained and/or indoctrinated as necessary to assure that suitable proficiency is achieved and maintained. Personnel outside the QA organization performing inspection and test are trained and

and Maintenance ~~Department~~ personnel who perform visual inspection as part of the Inservice Inspection program

Personnel requiring certification are evaluated to establish their qualifications for their respective level and discipline. Recertification is based upon demonstrated continued proficiency or requalification, if necessary. Personnel requiring certification in accordance with Regulatory Guide 1.58 are limited to NQA personnel who perform inspection and test activities, ~~and~~ members of the Operational Test Group (OTG) who perform post-design modification testing. ~~NQA and OTG and calibration~~ These personnel receive a periodic training needs assessment to identify additional supportive training needs as well as to evaluate individual post-training performance. The assessment period is three years or less. Inspection and test activities not requiring personnel certification per Regulatory Guide 1.58 include Technical Specification surveillances and periodic inspection and test of fire protection equipment. These personnel are qualified and retrained in accordance with applicable requirements of Regulatory Guide 1.8.

Training programs of supporting organizations are described in their manuals, which are required to comply with the quality assurance program.

The Nuclear Training Center is responsible for the licensed operator training and retraining, in addition to other technical and supervisory training programs, including General Employee Indoctrination, which is required for all personnel having access to the station.

17.2.3 DESIGN CONTROL

The design control program includes activities such as field design engineering, associated computer programs, compatibility of materials, and accessibility for inservice inspection, maintenance, and repair.

During the operations phase, issuance of new drawings and revisions to existing drawings require the implementation of a design change.

The nuclear general ~~support division~~ engineering procedures, approved by the manager - nuclear ~~operations~~ QA, provide implementation guidance for the intent of Regulatory Guide 1.64 "Quality Assurance Requirements for the Design of Nuclear Power Plants." ~~Within that division,~~ The nuclear engineering section has the following responsibilities:

The scope of the design control program includes design activities associated with the preparation and review of design documents, including the correct translation of applicable regulatory requirements into design modification, procurement and procedural documents.

a. Prepare and update detailed engineering and design documents, including drawings and specifications, for all systems, components, and structures

b. Specify applicable codes, standards, regulatory and quality requirements acceptance standards, and other design input in design documents

c. Identify systems, components, and structures that are covered by the quality assurance program

d. Perform design verification for systems, components, and structures

e. Perform safety evaluations of proposed design changes

f. Prepare documents for procurement of equipment, materials, and components

g. Recommend engineering consultants and laboratories for procurement services and coordinate their activities

h. Review design documents submitted by suppliers (including the nuclear steam supply system (NSSS) supplier) and contractors

i. Specify, or approve as required, inspections and/or tests

j. Designate whether they will seek the service of other qualified engineering organizations

The cognizant engineer is responsible for the identification and completion of design analyses. The purpose of design analyses is to assure that the technical design is accomplished in a planned, controlled, and correct manner. Types of design analyses include, but are not limited to, reactor physics, stress, seismic, thermal, hydraulic, radiation, and accident.

In the event that the verification method for design modifications is only by test, procedures and instructions will be written which include measures to ensure that:

a. Criteria are provided to specify when verification should be by test.

b. Where applicable, prototype, component or feature testing will be performed prior to installation of plant equipment. In those cases where this cannot be met, the testing will be deferred but not beyond the point when the installation would be irreversible.

c. Tests will be performed under conditions that simulate the most adverse design conditions, as determined by analysis.

Drawings are prepared by, or under the supervision of a designer from information received from the responsible engineer, manufacturer's drawings, etc. The drawings are reviewed and initialed as being checked by another designer or design supervisor. The drawings are approved by the Chief Designer or his assistants.

Specifications and changes thereto for items covered by the quality assurance program are prepared by nuclear engineering and are reviewed and approved by NQA for quality assurance content.

The NQA review assures that the documents are prepared, reviewed, and approved in accordance with company procedures and that the documents contain the necessary QA requirements such as inspection and test requirements, acceptance requirements, and the extent of documenting inspection and test results .

The station operations review committee (SORC) reviews proposed changes affecting nuclear safety and makes recommendations concerning implementation of the change to the general manager - Hope Creek operations. The design change process provides for sign-off of the design change by station department heads for the purpose of identifying required procedure change. If the proposed modification involves a Technical Specification change, or is considered by the SORC to involve an unreviewed safety question (10 CFR 50.59), the matter is submitted to the ~~nuclear~~
off-site safety review group

(OSR)
~~review board (NRB)~~ for a determination of its safety implication before a license change request is submitted for NRC approval.

NQA reviews design changes for quality content both before and after implementation. Design changes are reviewed prior to implementation for adequacy of inspection, test, and supplier requirements, as applicable. The design change package is reviewed following implementation for acceptability of documentation.

During the development of a design, nuclear engineering section, i.e., electrical, mechanical, controls, structural/civil, design, is identified as the sponsor. The sponsor is responsible for the interface with affected disciplines within nuclear engineering, manufacturers, consultants, and PSE&G organizations outside of nuclear engineering, identified in documents such as contracts, specifications, purchase orders, design data sheets, and drawings. The primary interface between nuclear engineering and external organizations is through the cognizant engineering section head or his assigned representative.

Updating of records, including drawings, blueprints, instructions and technical manuals, and specifications resulting from design changes, is the responsibility of the general manager - nuclear ~~support~~. Design change procedures provide for the timely update of affected drawings following design change implementation to reflect as-built configuration.

17.2.4 PROCUREMENT DOCUMENT CONTROL

Procurement documents and changes thereto for the purchase of Q- and F-designated material, equipment, or services are reviewed and approved by NQA prior to issuance by the purchasing department to the prospective supplier. NQA review assures that spare and replacement parts are procured using controls which are commensurate with current operational QA program requirements.

The review also assures that procurement documents adequately and correctly:

a. Identify applicable quality assurance program requirements

b. Reference applicable regulatory requirements, codes, and standards the station operations review committee (SORC) for technical content, by NQA for quality assurance requirements, and are approved by the responsible station department manager or his designee.

The general manager - nuclear ~~support~~ engineering is responsible for issuing specifications, drawings, blueprints, and instruction and technical manuals associated with Q- and F-designated structures, systems, and components. Approved and implemented modifications and design changes are incorporated to these reference documents for the life of the station. Master lists of current editions or revisions of these documents are periodically issued by the general manager - nuclear ~~support~~ engineering to the general manager - Hope Creek operations to periodically assure that only current and approved referenced documents are used at the station.

NQA reviews and approves station inspection plans and procedures that implement the quality assurance program, including testing, calibration, maintenance, modification, and repair. Changes to these documents are also reviewed and approved. In addition, NQA is responsible for review and approval of PSE&G specifications, test procedures, and results of testing. rework

17.2.6 DOCUMENT CONTROL

Instructions, procedures, drawings, and changes thereto are reviewed for inclusion of appropriate quality assurance requirements and are approved by appropriate levels of management of the PSE&G organizations producing such documents, and distributed on a timely basis to using locations. Measures are provided for the timely removal of obsoleted or superseded documents from the using location. Supplier documents are controlled according to contractual agreements with suppliers.

The following is a generic minimum listing of key documents for the operational phase, showing organization responsibility for review and or approval, including changes thereto:

a. Design specification - Nuclear ~~Support~~ engineering, NQA

b. Design, modification manufacturing, construction, and installation drawings - Nuclear ~~Support~~ engineering, nuclear services Hope Creek operations, NQA

d. Satisfactory past history of providing similar items

e. Survey of supplier's facility.

The evaluations of the prospective suppliers are conducted using standard checklist form designed to include the 18 quality criteria of 10 CFR 50, Appendix B, as appropriate.

Surveys of suppliers' capabilities include evaluation of management systems manufacturing processes and adherence to QA/QC procedures. The results of supplier evaluations are documented by the appropriate checklist form and filed.

Supplier control is maintained through a planned inspection, monitoring, and audit program by NQA

NQA and the responsible engineer conduct a review of the manufacturing process for complex manufactured items, such as pumps, valves, heat exchangers, vessels, electrical panels, etc. This review establishes critical inspection points and establishes a notification point program for the identified inspection or surveillance activities. The established inspection or surveillance activities are implemented by qualified NQA personnel or NQA agents. Commercial grade items are not normally included in the notification point program. Receipt inspection and subsequent installation and test controls provide the basis for acceptability of commercial grade items.

Monitoring of suppliers/contractors during fabrication, installation, modification, rework, repair, inspection, testing, and shipment of Q- and F-designated materials, equipment, and services, is conducted by qualified NQA personnel or NQA agents at the supplier's/contractor's facility or at the generating station. Surveillances are conducted in accordance with written procedures and are designed to assure conformance with procurement requirements, in accordance with the safety significance of the item or service.

Periodic evaluations of the supplier/contractor quality program are also conducted, consistent with the importance or complexity of the item or service. Dependent upon the evaluation, additional audits or corrections by the supplier/contractor may be required. Supplier's certificates of conformance are periodically evaluated by audit, inspection, or test to assure

Material identification and traceability is maintained for rework repairs, ~~replacement~~, and modifications throughout operation.

Organizations which implement requirements for the identification and control of materials parts and components include Nuclear Services, Nuclear Engineering ~~Support~~, Hope Creek Operations and NQA for procurement document controls, and Nuclear Services, Hope Creek Operations and NQA for receipt, storage, installation, inspection and test activities.

17.2.9 CONTROL OF SPECIAL PROCESSES

Special process controls provide for the use of qualified procedures, equipment, personnel, and documentation of satisfactory completion of an activity. Special processes are generally those processes where direct inspection is impossible or disadvantageous.

Procedures have been established for special processes such as welding, brazing, soldening, concreting, protective coating, cleaning, heat treating, and nondestructive examination (NDE) to assure compliance with codes and design specifications. The general manager - nuclear support is responsible for preparing special process specifioations. These specifications are reviewed and approved by NQA for necessary quality content. NQA monitoring and audits assure that qualification of special processes, equipment and personnel have been satisfactorily performed.

Procedures for implementing the requirements of the specifications are prepared either by the nuclear department or by supplier personnel, ~~and~~ are approved by the ~~assistant~~ general manager - nuclear engineering ~~Support~~ or his designee, (with the exception of special process procedures prepared by code suppliers holding an "N" stamp). Procedures prepared by suppliers are also reviewed and approved by NQA.

Qualification records of procedures, equipment, and personnel associated with special processes are retained as stated in Section 17.2.17.

17.2.10 INSPECTION

A planned inspection program is conducted and documented by personnel appropriately qualified in accordance with Section 17.2.2. The inspection program verifies conformance to the established procedure, code, or standard, consistent with the item's or activity's importance to safety.

Inspection instructions include, as required, characteristics to be inspected, method of inspection, acceptance rejection criteria, required measuring and test equipment, and required reference documents. Documentation includes inspection identification and results of inspection operation.

When required, inspection hold points are included in the procedure or instruction and performed by NQA personnel.

Station department heads are also responsible for inserting inspection hold points for critical activities in procedures they approve. These inspection hold points are witnessed by NQA. The station operations review committee (SORC) may recommend additional or different hold points to the general manager - Hope Creek operations as a result of their review. Safety-related procedures are reviewed by NQA prior to issuance and additional inspection hold points may be added to a procedure. The inspection hold points cannot be passed without authorization from the applicable QA/QC (NQA) representative. Typical critical activities include:

a. Visual inspection and NDE of ASME pressure boundary welds

b. Verification of cleanliness prior to closing safety-related systems

c. Verification of reactor trip and engineered safety feature (ESF) initiation setting after adjustment

d. Packaging and loading of radioactive material for shipment

e. Hydrostatic testing of Q- and F-designated systems

f. Acceptance testing of major modifications, rework, and repairs to Q- and F-designated structures, systems, and components.

Periodic inspection may be performed by qualified individuals other than those who performed or directly supervised the activity being inspected. These typically include periodic inspections of:

a. Storage areas

b. Housekeeping (general)

c. Fire protection equipment

d. Special handling tools and equipment

e. NDE visual inspection required by the inservice inspection program

Inspection of operating activities, i.e., work functions associated with the normal operation of the plant, routine maintenance, and certain technical services, may be conducted by second line supervisory personnel or other qualified personnel not assigned first-line supervisory responsibilities for conduct of the work. When inspections are so conducted and the activity involves breaching a pressure retaining boundary, the quality of the work is demonstrated through appropriate testing unless restrictions, such as ALARA considerations, prevent such testing.

rework,

The applicable inspection and retest requirements necessary to assure that modifications, or repairs have been accomplished correctly are included in the design change package, work order, or procedure. The inspection and retest requirements for

rework

modification, and repair are based on the original inspection and test program, as well as the nature and scope of the modification or repair activity.

Evaluation and review of inspection results are conducted by Level II individuals.

A planned and documented monitoring program is conducted for Q- and F-designated activities. Monitoring of the implementation of the quality assurance program by station and site contractor personnel is conducted by NQA. NQA conducts ~~monitoring~~ surveillance of supplier and (~~onsite~~) off-site contractor activities.

Discrepancies found during the conduct of monitoring are brought to the attention of the management responsible for the activity.

station quality assurance engineer

The (SQAE) or his designee routinely attends and participates in plant work schedule and status meetings to assure that they are kept abreast of day-to-day work assignments throughout the plant and that there is adequate QA/QC coverage relative to procedural and inspection controls, acceptance criteria, and QA/QC staffing and qualification of personnel to carry out QA assignments.

17.2.11 TEST CONTROL

Q- and F-designated equipment and components that must be tested periodically to assure satisfactory performance, or have been replaced, modified, or repaired, are tested by qualified personnel in accordance with written procedures that provide acceptance criteria based on requirements contained in applicable design and procurement documents.

Provisions are implemented that assure that nonconformances are corrected or resolved prior to the initiation of the preoperational test program on the item.

Retest requirements are provided by engineering specifications and/or the responsible engineer, as were the original test requirements. The operational test group is responsible for preparation of test procedures incorporating the engineering parameters. Nuclear engineering reviews applicable test procedures; NQA reviews test procedures and test results.

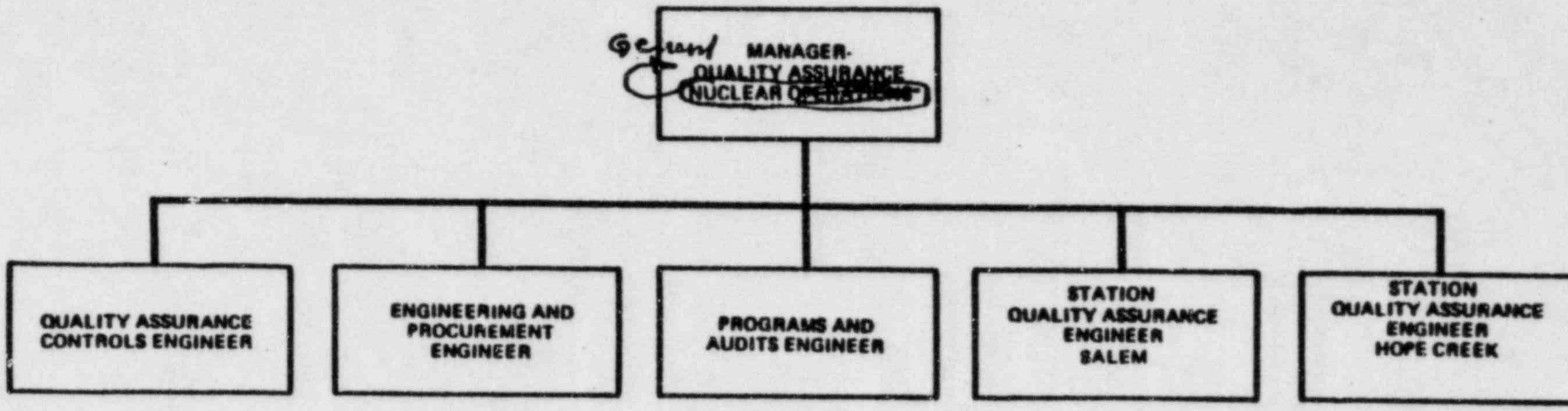
Test procedures prescribe, as applicable:

a. Prerequisites, including completeness of test item(s)

b. Instructions for performing the test

c. Instrumentation and equipment for conduct of the test adequate to the test objective

d. Suitable environmental conditions and adequate test methods



HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

QUALITY ASSURANCE
NUCLEAR ~~OPERATIONS~~

FIGURE 17.2-1

AMENDMENT 8, 4/84

ATTACHMENT 7

#16
9-25-84
Rev 2

QUESTION 430.62 (SECTION 8.3)

Periodic testing and test loading of an emergency diesel generator in a nuclear power plant is a necessary function to demonstrate the operability, capability and availability of the unit on demand. Periodic testing coupled with good preventive maintenance practices will assure optimum equipment readiness and availability on demand. This is the desired goal.

To achieve this optimum equipment readiness status the following requirements should be met:

1. The equipment should be tested with a minimum loading of 25 percent of rated load. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequences of no load or light load operation are potential equipment failure due to the gum and varnish deposits and fire in the engine exhaust system.

2. Periodic surveillance testing should be performed in accordance with the applicable NRC guidelines (R.G. 1.108), and with the recommendations of the engine manufacturer. Conflicts between any such recommendations and the NRC guidelines, particularly with respect to test frequency, loading and duration, should be identified and justified.

3. Preventive maintenance should go beyond the normal routine adjustments, servicing and repair of components when a malfunction occurs. Preventive maintenance should encompass investigative testing of components which have a history of repeated malfunctioning and require constant attention and repair. In such cases consideration should be given to replacement of those components with other products which have a record of demonstrated reliability, rather than repetitive repair and maintenance of the existing components. Testing of the unit after adjustments or repairs have been made only confirms that the equipment is operable and does not necessarily mean that the root cause of the problem has been eliminated or alleviated.

4. Upon completion of repairs or maintenance and prior to an actual start, run, and load test a final equipment check should be made to assure that all electrical circuits are functional, i.e., fuses are in place, switches and circuit breakers are in their proper position, no loose wires, all test leads have been removed, and all valves are in the proper position to permit a manual start of the equipment. After the unit has been satisfactorily started and load

tested, return the unit to ready automatic standby service and under the control of the control room operator.

Provide a discussion of how the above requirements have been implemented in the emergency diesel generator system design and how they will be considered when the plant is in commercial operation, i.e., buy what means will the above requirements be enforced. (SRP 8.3.1, Parts II & III).

RESPONSE

1. Minimum load requirements for SDG testing will be identified in OP-SO.KJ-001, Diesel Generator Operation. *Add Insert 1*

2. See response to Question 430.15.

3. A comprehensive preventive maintenance (PM) program *for the SDG incorporates* ~~is currently being developed and this program will consist of~~ the latest vendor recommendations and the requirements of Chapter 16. One SDG can be taken out of service, in accordance with 8.3.1.1.3, enabling periodic maintenance and/or rework to be performed. ~~in a timely manner. Additionally, a reliability monitoring program will be~~ *sert B →* ~~implemented to monitor and trend repetitive equipment and/or component failures.~~ In this manner, the root causes of system *or component* malfunctions can be more readily identified and corrective actions taken as necessary.

4. The supervisor in charge of the work will verify for completeness, and administrative controls will be implemented to ensure the system is restored to its operable condition prior to any start, run, or load test on the SDG.

The following procedures will reference this topic:

MD-PM.KJ-001(Q)	Diesel Engine PM
MD-PM.KJ-002(Q)	Starting Air System PM
MD-PM.KJ-003(Q)	Generator PM
MD-CM.KJ-001(Q)	Diesel Engine Overhaul and Repair
MD-CM.KJ-002(Q)	Starting Air Compressor Overhaul, Repair and Replacement
MD-CM.KJ-003(Q)	Generator Overhaul and Repair

Station Administrative Procedures 17, 21, 22, 23, and 26, as discussed in Section 13.5.

Add insert A.

Insert 1

Loading requirements will incorporate the diesel engine manufacturers' recommendations to preclude gum and varnish deposits on engine components or the engine exhaust system. See also the response to Question 430.22 for further information on no load and light load operation of the HCGS diesel generators.

Insert ~~I~~ B 430.62

Additionally, a reliability monitering program will be implemented at HCGS.

The HCGS reliability program enhances SDG reliability by:

1. Analyzing machinery history record for recurring problems or failures of the SDG or supporting auxiliary systems or components.
2. Tracking operating experience reports, circulars, letters and notices of failure or problems given to all diesel generators.
3. Use of the NPRDS data base system.
4. Analyzing surveilliance testing results.

These functions are an ongoing and continuous responsibility of the Technical Department. Items which may adversely impact the safety function of the diesel engines at the station will receive immediate attention to determine a plan of action. Routine feedback issues are reviewed as received. All material reviewed as part of the feedback program is tracked on a computerized tracking system to ensure material is reviewed and dispositioned.

INSERT A 430.62

These maintenance procedures will require that after a cumulative four hours of operation at light load, i.e., less than 20% of rated, on any diesel, that diesel will be operated for one hour at a minimum of 50% rated load as per the diesel manufacturer's recommendations.

9-25-84 #1

1/4

Rev.2

QUESTION 430.65 (SECTION 9.5.2)

The information regarding the onsite communications system (Section 9.5.2) does not adequately cover the system capabilities during transients and accidents. Provide the following information:

a. Identify all working stations on the plant site where it may be necessary for plant personnel to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents (including fires) in order to mitigate the consequences of the event and to attain a safe cold plant shutdown.

b. Indicate the maximum sound levels that could exist at each of the above identified working stations for all transients and accident conditions.

c. Indicate the types of communication systems available at each of the above identified working stations.

d. Indicate the maximum background noise level that could exist at each working station and yet reliably expect effective communication with the control room using:

   1. the page party communiations systems, and

   2. any other additional communication system provide that working station.

e. Describe the performance requirements and tests that the above onsite working stations communication system will be required to pass in order to be assured that effective communication with the control room or emergency shutdown panel is possible under all conditions.

f. Identify and describe the power source(s) provided for each of the communications systems. (SRP 9.5.2; Parts II & III).

RESPONSE

Insert A

a. ~~The identification of all working stations where it may be necessary for plant personnel to communicate with the control room during and/or following transients and/or accidents is not provided because all necessary plant shutdown controls and indications are located within the control room which precludes necessity of having plant personnel located at any particular station. If, however, plant shutdown is controlled~~

Insert A

~~from the emergency shutdown panel, then it may be necessary to have plant personnel able to communicate from three working stations which have backup controls and indications. These three stations are at the diesel generator remote control panels rooms (4 total), the Class 1E switchgear rooms (4 total), and at the reactor protection system (RPS) motor generator set area. In the event of fires, the fire brigade reports to the affected area(s) and the areas are listed in Section 9.5.1.2.15.~~

b. ~~Maximum sound levels have not been defined for the above working stations. The effectiveness of the communication system(s) will be demonstrated during the preoperational and power ascension test programs of Chapter 14.~~ Insert B

c. The page party communication system is available at or nearby the above working stations. In addition, a two-way radio communication system is available as a backup system. Insert C

d. ~~The maximum background noise level that could exist at the stations for communicating with the control room has not been established.~~ The communications systems provided on HCGS are of proven design as used in previously approved plants. In addition, the communication system will be tested as described in Part (e) of this response. Insert D

e. See response to Question 430.68, communication systems performance requirements and tests. In-plant communication tests are also described in Section 14.2.12.1.38. The test method states that communication is checked between the control room and the remote shutdown panel. Insert E

f. The power source to the page party communication system is from an uninterruptible power supply feeding the public address system distribution panel 10D496 which in turn supplies the public address system cabinet 10C685, as shown on Sheet 2 of Figure 8.3-11. Insert F

Q430.65

Insert A

Table 9.5-17 identifies all necessary working stations where it may be necessary for plant personnel to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents (including fires) in order to mitigate the consequences of the event and to attain a safe cold plant shutdown. The identified working stations or areas in this table are selected from the Fire Hazard Analysis presented in Appendix 9A wherein all areas containing safe shutdown equipment and cables are evaluated for effect of fire on the ability to achieve and maintain cold shutdown. The areas shown on Table 9.5-17 are those which contain equipment required for shutdown, areas containing only raceways and cables are not shown.

Insert B

The locations of public address loudspeakers and handset/speaker amplifier are selected to provide effective communications and to accommodate areas with high noise levels during normal plant operation and accident condition, including fire. The design of these public address components includes provisions for volume control of the loudspeakers, adjustment in loudspeaker mounting to provide maximum coverage, and special noise-cancelling handset which are effective in high ambient noise areas without use of acoustic booths. As indicated in Section 14.2.12.1.38, the public address system will be tested with area equipment running. Any relocation and adjustment of the public address components will be provided as necessary as result a of the testing. Estimates of maximum sound levels are provided as indicated on Table 9.5-17. These estimates are based on equipment being energized or running and based on no sound level attenuation which would result from accounting for room constant and distance and location of the noise source(s).

Insert C

Table 9.5-17 also shows for each of the safety-related rooms the types of communication system components available with the associated maximum sound levels within the room. All of the communication components have the capability to function in the sound environments that are listed in the Table 9.5-17. The table 9.5-17 defines the maximum sound level capability for each communication component.

Insert D

As part of Table 9.5-17, the maximum noise levels are estimated for the areas where personnel will be communicating with the control room or remote shutdown panel room. Generally, PA handsets and telephones are not located in areas with high noise levels. The maximum noise levels are estimated based on the type of operating equipment in the area with the sound defined by industry standards, such as NEMA Publication MG I and IEEE standards. If several types of equipment are in the same area, then the noise level associated with the noisiest equipment is shown on this table.

Q430.-;

Insert E

The communication systems are preoperationally tested to demonstrate that the public address system is effective in areas with high noise levels and that other communication systems are effective between the control room or emergency shutdown panel and working stations as indicated in Table 9.5-17.

Insert F

This uninterruptible power supply (UPS) is fed from Class 1E, Channel A, distribution buses. The UHF radio system is also supplied with a non-class 1E uninterruptible power supply. The design of each UPS, as shown on Figure 8.3-11, is such that there are three input power feeders - two from 480V ac motor control centers and one from a 125V dc switchgear. In the case of the UHF radio system, the non-class 1E 480V ac motor control centers, which are connected to Class 1E 480V load centers, are tripped on a LOCA signal. The radio system will be powered from the non-class 1E batteries (4 hour rated) through the UPS under all accident cases. After a LOCA the operator can manually reconnect the non class 1E UPS to the Class 1E load center that is powered from the stand-by diesel generator. The UHF radio system will be powered at all times during any power distribution transfers. The non-class 1E UPS, batteries, and associated electrical distribution equipment that supply power to the radio system were purchased under the same technical specifications as the Class 1E equipment and are located in Seismic Category I structures.

#1

Question 430.65 Table

Notes for Table 9.5-1

1. These lighting levels are at the panel or equipment surface.

2. The following are the maximum sound levels (db) that the communication components are capable of producing or operating in.

Component	Sound Level
PA speaker (driven by 30w amplifier)	120
PA headset	110
UHF radio portable set	80
Telephone	70

3. In these rooms the UHF radio sets' sound capability is below the maximum sound level that could be experienced in the room. In these rooms the adjacent hallway can be utilized for communication with the UHF radio set.

4. The work stations identified on the table are areas that may be required to be manned during design basis accidents or during the improbable event of a loss of all ac power.

5. These rooms have a PA handset for two way communication in the adjacent hallway, corridor or room (within approximately 50 ft of these rooms).

6. All Class 1E batteries are passive electrical components and do not require any inspection during a station blackout per the HCGS station blackout procedures. The electrical status of the Class 1E batteries is available in the control room.

7. All Class 1E dc switchgear (HPCI, RCIC, etc), inverters and battery chargers can be monitored at the control room and require no local control per the HCGS station blackout procedures.

8. These rooms and equipment are not required to be locally monitored or are not required during the station blackout condition per the HCGS procedures.

9. The 2 ft candle lighting level is a design intent which will cover a sufficient area of the corridor to provide safe ingress and egress routes. Any hazards within the corridor will be lighted to provide safe passage.

10. In addition to areas of the plant which have at least 10 ft candles of emergency lighting, trouble shooting during a station blackout may be required in the diesel fuel oil storage tank and pump rooms and the diesel generator battery rooms. Sufficient portable lighting will be stored in the corridors near each of these areas.

[illegible] EXISTING
TABLE [illegible] (AMEND. 4)
WITH THIS

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TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: WORK STATION (See note 4)	APPROXIMATE FOOTCANDLES AT EQUIPMENT AREA: ESSENTIAL AC	APPROXIMATE FOOTCANDLES AT EQUIPMENT AREA: 8-HOUR BATTERY PACK
(See note 2)	LEGEND: 1 = PA HANDSET; 2 = PA SPEAKER; 3 = TELEPHONE; 4 = RADIO	LEGEND: dBA = DECIBEL, A-WEIGHTED; < = LESS THAN			
AUXILIARY BUILDING					
ROOM 3576, EL. 137 REMOTE SHUTDOWN PANEL	1, 2, 3, 4	<60	YES	30	10 (see note 1)
ROOM 5104 EL 54 HPCI BATTERIES	2, 4 (SEE NOTE 5)	<30	NOTE 6, 8	3	1
ROOM 5105, EL. 54 RPS MG SET	1, 2, 4	<80	NOTE 8	3	1
ROOM 5106, EL. 54 CORRIDOR	2, 4, 1	<50	NOTE 8	5	3 (SEE NOTE 9)
ROOM 5107, EL. 54 DIESEL FUEL OIL STORAGE TANKS AND PUMPS	2, 4 (SEE NOTE 5)	<80	NOTE 10	3	1 (SEE NOTE 10)
ROOM 5108, EL. 54 DIESEL FUEL OIL STORAGE TANKS AND PUMPS	2, 4 (SEE NOTE 5)	<80	NOTE 10	3	1 (SEE NOTE 10)
ROOM 3504, EL. 137 CORRIDOR	2, 4, 1	<50	NOTE 8	3	3 (SEE NOTE 9)

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TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA		EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA-: ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA-: 8-HOUR BATTERY PACK
AUXILIARY BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN	WORK STATION		
ROOM 5109, EL. 54 DIESEL FUEL OIL STORAGE TANKS AND PUMPS	2, 4 (SEE NOTE 5)	<80	— NOTE 10	3	1 (SEE NOTE 10)
ROOM 5110, EL. 54 DIESEL FUEL OIL STORAGE TANKS AND PUMPS	2, 4 (SEE NOTE 5)	<80	— NOTE 10	3	1 (SEE NOTE 10)
ROOM 5111, EL. 54 CORRIDOR	1, 2 (SEE NOTE 5)	<50	— NOTE 8	3	≥2 (SEE NOTE 9)
ROOM 5112, EL. 54 CORRIDOR	1 (IN ADJACENT VESTIBULE), 2, 4	<50	— NOTE 8	5	≥2 (SEE NOTE 9)
ROOM 5128, EL. 54 RCIC BATTERIES	2, 4 (SEE NOTE 5)	<50	— NOTE 6, 8	3	1
ROOM 5129, EL. 54 HPCI BATTERY CHARGER AND DC SWITCHGEAR	1, 2 (SEE NOTE 5)	<70	— NOTE 7	10	1
ROOM 5101, EL. 137 STAIRWAY	2, 4	<50	— NOTE 8	3	3 (SEE NOTE 9)

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

	COMMUNICATION FEATURES		EMERGENCY LIGHTING SYSTEM FEATURES		
			APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA-		
AREA / EQUIPMENT	COMPONENTS AVAILABLE AT AREA	ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	ESSENTIAL AC	WORK STATION	8-HOUR BATTERY PACK
AUXILIARY BUILDING (CONTINUED)	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5130, EL.54 RCIC BATTERY CHARGER AND DC SWITCHGEAR	2, 4 (SEE NOTE 5)	< 70	NOTE 7	3	1
ROOM 5208, EL.77 D/G ROOM HVAC COOLER AND RECIRCULATION FAN	2, 4 (SEE NOTE 3) AND 5	< 100	NOTE 8	3	1
ROOM 5209, EL.77 D/G ROOM HVAC COOLER AND RECIRCULATION FAN	2, 4 (SEE NOTE 3) AND 5	< 100	NOTE 8	3	1
ROOM 5210, EL.77 D/G ROOM HVAC COOLER AND RECIRCULATION FAN	2, 4 (SEE NOTE 3) AND 5	< 100	NOTE 8	3	1
ROOM 5211, EL.77 D/G ROOM HVAC COOLER AND RECIRCULATION FAN	2, 4 (SEE NOTE 3) AND 5	< 100	NOTE 8	3	1
ROOM 5217 EL. 77 CORRIDOR	1 (IN ADJACENT VESTIBULE), 2, 4	< 50	NOTE 8	5	x2 (See Note 9)

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION: ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION: 8-HOUR BATTERY PACK
AUXILIARY BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5301, EL. 102 CORRIDOR	2, 4, 1	<50	NOTE 8	5	≥2
ROOM 5302, EL. 102 CONTROL PANELS	2, 4 (SEE NOTE 5)	<65	NOTE	3	1
ROOM 5304, EL. 102 D/G AND CONTROL PANELS	2, 4 (see note 3) and 5	<110	Yes	3	≥10
ROOM 5305, EL. 102 D/G AND CONTROL PANELS	2, 4 (see note 3) and 5	<110	Yes	3	≥10
ROOM 5306, EL. 102 D/G AND CONTROL PANELS	2, 4 (see note 3) AND 5	<110	Yes	3	≥10
ROOM 5307 EL. 102 D/G AND CONTROL PANELS	2, 4 (see note 3) and 5	<110	Yes	3	≥10
ROOM 5313, EL. 102 CORRIDOR	1 (IN ADJACENT VESTIBULE), 2, 4	<50	NOTE 8	4	≥2 (see NOTE 9)

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION — ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION — 8-HOUR BATTERY PACK
AUXILIARY BUILDING CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5401, EL. 124 CORRIDOR/ACCESS AREA	2, 4 (See NOTE 5)	<50	NOTE 6	3	2
ROOM 5402, EL. 117-6 ~~CABLE SPREAD~~ ROOM	1, 2, 4	<65	NOTE 7	3	2
ROOM 5404, EL. 124 CORRIDOR	1, 2, 4	<50	NOTE 8	3	2
ROOM 5409, EL. 124 CORRIDOR	1, 2, 4	<50	NOTE 8	3	2
ROOM 5410, EL. 130 D/G REMOTE CONTROL PANELS AND SEQUENCER	1, 2, 4	<65	YES	≥10	≥10 (see note 1)
ROOM 5411, EL. 130 SWITCHGEAR, LOAD CENTERS, MCCs AND DIST PANELS	1, 2, 4	<70	YES	≥10	≥10 (see note 1)
ROOM 5412, EL. 130 D/G REMOTE CONTROL PANELS AND SEQUENCER	1, 2, 4	<65	YES	≥10	≥10 (see note 1)
ROOM 5413, EL. 130 SWITCHGEAR, LOAD CENTERS, MCCs AND DIST. PANELS	1, 2, 4	<70	YES	≥10	≥10 (see note 1)

TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: WORK STATION	APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM: ESSENTIAL AC	APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM: 8-HOUR BATTERY PACK
AUXILIARY BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5414, EL. 130 D/G REMOTE CONTROL PANELS AND SEQUENCER	1, 2, 4	<65	YES	≥10	≥10 (see NOTE 1)
ROOM 5415, EL. 130 SWITCHGEAR, LOAD CENTERS, MCCs AND DIST. PANELS	1, 2, 4	<70	YES	≥10	≥10 (see NOTE 1)
ROOM 5416, EL. 130 D/G REMOTE CONTROL PANELS AND SEQUENCER	1, 2, 4	<65	YES	≥10	≥10 (see NOTE 1)
ROOM 5417, EL. 130 SWITCHGEAR, LOAD CENTERS, MCCs AND DIST. PANELS	1, 2, 4	<70	YES	≥10	≥10 (see Note 1)
ROOM 5447, EL. 124 FRVS CONTROL PANELS	2, 4 (See NOTE 8)	<65	NOTE 8	3	1
ROOM 5448, EL. 124 INVERTERS AND DIST. PANELS	1 (IN ADJACENT VESTIBULE), 2, 4	<70	NOTE 7	3	1
ROOM 5501 EL. 137 INVERTERS AND DIST. PANELS	2, 3 (IN ADJACENT ROOM), 4	<70	NOTE 7	3	2

TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA-: ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA-: 8-HOUR BATTERY PACK
AUXILIARY BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5502, EL. 137 CORRIDOR	2, 3 (IN ADJACENT ROOM), 4	<50	NOTE 8	8	2 (see NOTE 9)
ROOM 5510, EL. 137 CONTROL ROOM PANELS AND CONSOLES	1, 2, 3, 4	<60	YES	30	15
ROOM 5537, EL. 137 CORRIDOR	1 (IN ADJACENT VESTIBULE), 2, 4	<50	NOTE 8	3	2 (see note 9)
ROOM 5538, EL. 137 BATTERY CHARGERS, FUSE BOX AND BATT. MONITOR	4 (see NOTE 5)	<65	NOTE [illegible]	3	2 (see note 10)
ROOM 5539, EL. 137 BATTERIES	2, 4 (see NOTE 5)	<50	NOTE 10	3	2 (see NOTE 10)
ROOM 5540, EL. 137 BATTERY CHARGERS, FUSE BOX AND BATT. MONITOR	4 (see NOTE 5)	<65	NOTE [illegible]	3	2 ~~(see note 10)~~
ROOM 5541, EL. 137 BATTERIES	4 (see NOTE 5)	<50	NOTE 10	3	2 (see NOTE 10)
ROOM 5542, EL. 137 BATTERY CHARGERS FUSE BOX AND BATT. MONITOR	2, 4 (see NOTE 5)	<65	NOTE [illegible]	3	2 ~~(see note 10)~~

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TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICA- WORK STATION: ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: 8-HOUR BATTERY PACK
AUXILIARY BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN		
ROOM 5513, EL. 137 BATTERIES	2, 4 (SEE NOTE 5)	<50	— 3 NOTE 10	2 (SEE NOTE 10)
ROOM 5511, EL. 137 BATTERY CHARGERS, FUSE BOX AND BATT. MONITOR	2, 4 (SEE NOTE 5)	<65	— 3 NOTE 6	2
ROOM 5515, EL. 137 BATTERIES	4 (SEE NOTE 5)	<50	— 3 NOTE 10	2 (SEE NOTE 10)
ROOM 5602, EL. 155-3 CONTROL AREA WATER CHILLER, CONTROL ROOM AIR HANDLING UNIT AND RETURN AIR FAN, AND HVAC CONTROL PANEL	1 (LOCATED AWAY FROM LARGEST NOISE SOURCE), 2, 1 (SEE NOTE 3) AND 5	<110	— 3 NOTE 8	2
ROOM 5604, EL. 163-6 CORRIDOR	1, 2, 4	<50	— 3 NOTE 8	2 (SEE NOTE 9)
ROOM 5605, EL. 163-6 CONTROL PANELS	1, 2 (SEE NOTE 5)	<65	— 3 NOTE 8	2
ROOM [illegible], EL 163-6 CORRIDOR	2, 1 (SEE NOTE 5)	<50	— 3 NOTE 8	2 (SEE NOTE 9)

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM 8-HOUR BATTERY PACK
Auxiliary Building (continued)	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5606, EL. 163-6 SWITCHGEAR ROOM COOLERS AND D/G BATTERY ROOM EXHAUST FANS	2, 4 (see NOTE 5)	<90	NOTE 7	5	2
ROOM 5607, EL. 163-6 INVERTER, DC SWITCHGEAR, BATTERY CHARGER AND FUSE BOX	4 (see NOTE 5)	<70	NOTE 7	3	1
ROOM 5608, EL. 163-6 CORRIDOR	1, 2 (IN ADJACENT CORRIDOR), 4	<50	NOTE 8	5	2 (see NOTE 9)
ROOM 5609, EL. 163-6 BATTERIES	4 (see NOTE 5)	<50	NOTE 6	4	2
ROOM 5610, EL. 163-6 CORRIDOR	4, 1	<50	NOTE 8	9	≥2 (see Note 9)
ROOM 5612, EL. 163-6 CORRIDOR	4, 1	<50		8	≥2 (see Note 9)
ROOM 5629, EL. 163-6 SWITCHGEAR ROOM COOLERS AND D/G BATTERY ROOM EXHAUST FANS	1, 2, 4 (see NOTE 3)	<90	NOTE 7	5	2
ROOM 5630 EL. 163-6 CONTROL AREA WATER CHILLER, CONTROL ROOM AIR HANDLING UNIT AND RETURN AIR FAN, AND [illegible]	2, 4 (see NOTE 3) AND 5	<110	NOTE 8	3	2

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION, ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT INDICATION, 8-HOUR BATTERY PACK
AUXILIARY BUILDING CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 5702, EL. 172 CORRIDOR	1, 2 (IN ADJACENT ROOM), 4	<70	NOTE 8	5	2 (SEE NOTE 9)
ROOM 5704, EL. 178 CONTROL AND DIESEL AREA HVAC EQUIPMENT	1 (LOCATED AWAY FROM NOISIEST EQUIPMENT), 2, 4 (SEE NOTE 7)	<105	— NOTE 7	3	2
REACTOR BUILDING					
ROOM 4104, EL. 54 CORE SPRAY PUMP AND UNIT COOLERS	1 (IN ADJACENT VESTIBULE), 2, 4 (SEE NOTE 7)	<106	— NOTE 8	15	2
ROOM 4102, EL. 54 TO 101 VALVES	2, 4 (SEE NOTE 5)	<70	— NOTE 8	3	1
ROOM 4105, EL. 54 CORE SPRAY PUMP AND UNIT COOLERS	1 (IN ADJACENT VESTIBULE), 2, 4 (SEE NOTE 7)	<106	— NOTE 8	15	2
ROOM 4107, EL. 54 RHR PUMP, JOCKEY PUMP, UNIT COOLER AND INSTRUMENT RACK	1 (IN ADJACENT ELECTRICAL ROOM), 2, 4 (SEE NOTE 7)	<108	— NOTE 8	3	1

TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT [illegible]- ESSENTIAL AC (WORK STATION)	EMERGENCY LIGHTING SYSTEM FEATURES: 8-HOUR BATTERY PACK
REACTOR BUILDING CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN		
ROOM 4108, EL. 54 RCIC-MCC AND INSTRUMENT RACKS	1, 2, 4	<65	NOTE 7 10	2
ROOM 4109, EL. 54 RHR PUMP, HX AND UNIT COOLER	1 (IN ADJACENT ELECTRICAL ROOM), 2, 4 (SEE NOTE 3)	<108	NOTE 8 3	2
ROOM 4110, EL. 54 RCIC PUMP, TURBINE, GLAND STEAM CONDENSER, VACUUM PUMP, CONDENSATE PUMP, JOCKEY PUMP AND UNIT COOLERS	2, 4 (SEE NOTE 1) AND 5	<110	NOTE 7 3	2
ROOM 4111, EL. 54 HPCI PUMP, TURBINE, GLAND STEAM CONDENSER VACUUM PUMP, [illegible] PUMP, VALVES AND UNIT COOLERS	2, 4 (SEE NOTE 1) AND 5	<110	NOTE 7 3	1
ROOM 4112, EL. 54 HPCI MCC AND INSTR[illegible] RACKS	1, 2, 4	<65	NOTE 7 3	2

TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT [illegible]: ESSENTIAL AC (WORK STATION)	ESSENTIAL AC	8-HOUR BATTERY PACK
REACTOR BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN	WORK STATION		
ROOM 4113, EL. 54 RHR PUMP, HX AND UNIT COOLER	1 (IN ADJACENT ELECTRICAL ROOM), 2, 4 (SEE NOTE 3)	<108	— NOTE 8	3	2
ROOM 4114, EL. 54 RHR PUMP, JOCKEY PUMP, INSTRUMENT RACK, UNIT COOLERS	1 (IN ADJACENT ELECTRICAL ROOM), 2, 4 (SEE NOTE 3)	<108	— NOTE 8	5	2
ROOM 4116, EL. 54 CORE SPRAY PUMP AND UNIT COOLERS	1 (IN ADJACENT VESTIBULE), 2, 4 (SEE NOTE 3)	<106	— NOTE 8	25	2
ROOM 4118, EL. 54 CORE SPRAY PUMP AND UNIT COOLERS	1 (IN ADJACENT VESTIBULE), 2, 4 (SEE NOTE 3)	<106	— NOTE 8	5	2
ROOM 4201, EL. 77 MCCs	1 (IN ADJACENT ROOM), 2, 4	<65	— NOTE 8	3	2
ROOM 4202, EL. 77 INSTRUMENT RACKS	1, 2, 4 (SEE NOTE 3)	<100	— NOTE 8	3	2
ROOM 4203, EL. 77 INSTRUMENT RACK	2, 4 (SEE NOTE 5)	<65	— NOTE 8	3	2

TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM - ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM - 8-HOUR BATTERY PACK
REACTOR BUILDING - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 4208, EL. 77 RHR HX AND UNIT COOLER	2, 4 (see NOTE 5)	<85	NOTE 8	3	2
ROOM 4209, EL. 77 VALVES AND INSTRUMENTS	1 (IN ADJACENT VESTIBULE), 2, 4 (see NOTE 5)	<100	NOTE 8	3	1
ROOM 4210, EL. 77 INSTRUMENTS	2, 4 (see NOTE 5)	<65	NOTE 8	3	2
ROOM 4214, EL. 77 RHR HX	2, 4 (see NOTE 5)	<85	NOTE 8	3	2
ROOM 4215, EL. 77 INSTRUMENT RACK	2, 4 (see NOTE 5)	<65	NOTE 8	3	2
ROOM 4216, EL. 77 CORRIDOR	2, 4 (see NOTE 5)	<50	NOTE 8	3	~~1~~ 2
ROOM 4218, EL. 77 INSTRUMENT RACK	1, 2, 4	<65	NOTE 8	3	2
ROOM 4219, EL. 77 INSTRUMENTS	2, 4 (see NOTE 5)	<65	NOTE 8	3	2

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TABLE 9.5-17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA/EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM- ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM- 8-HOUR BATTERY PACK
REACTOR BUILDING, CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 4301, EL. 102 CORRIDOR	1, 2, 4	<65	NOTE 8	3	2 (see note 9)
ROOM 4303, EL. 102 MCC	1, 2, 4	<65	NOTE 8	3	2
ROOM 4307, EL. 102 SACS PUMPS AND HXs, CONTROL PANELS, VALVES AND UNIT COOLERS	2, 4 (see NOTE 3) AND 5	<106	NOTE 7	3	2
ROOM 4339, EL. 102 SACS PUMPS AND HXs, CONTROL PANELS, VALVES AND UNIT COOLERS	1 (LOCATED AWAY FROM NOISIEST EQUIPMENT), 2, 4 (see NOTE 3)	<106	NOTE 7	3	1
ROOM 43[illegible], EL. 102 CORRIDOR	2 (NEARBY), 4	<65	NOTE 8	3	2 (see note 9)
ROOM 43[illegible], EL. 102 HPCI VALVES	2, 4 (see NOTE 5)	<80	NOTE 7	3	2
ROOM 4329, EL. 102 RHR VALVES	2, 4 (see NOTE 5)	<80	NOTE 8	3	2
ROOM 4317, EL. 102 RCIC VALVE	2, 4 (see NOTE 5)	<80	NOTE 7	3	2
ROOM 43[illegible], EL. 102 RHR VALVE	2, 4 (see NOTE 5)	<80	NOTE 8	3	2

TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

	COMMUNICATION FEATURES		EMERGENCY LIGHTING SYSTEM FEATURES		
			APPROXIMATE FOOTCANDLES AT EQUIPMENT INDIA-		
AREA / EQUIPMENT	COMPONENTS AVAILABLE AT AREA	ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	WORK STATION	ESSENTIAL AC	8-HOUR BATTERY PACK
INTAKE STRUCTURE	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN			
ROOM 107, EL. 79-8 VALVES	2, 4 (SEE NOTE 5)	< 80	NOTE 8	3	2
ROOM 110, EL. 79.8 VALVES	2, 4 (SEE NOTE 5)	< 80	NOTE 8	3	2
ROOM 203, EL. 93 MCCs	1 (IN ADJACENT ROOM), 2, 4	< 65	NOTE 8	10	2
ROOM 204, EL. 93 PUMPS, VALVES AND CONTROL PANELS	1 (IN ADJACENT ROOM), 2, 4 (SEE NOTE 3)	< 108	NOTE 8	5	2
ROOM 207, EL. 93 MCCs	1, 2 (IN ADJACENT ROOM), 3, 4	< 65	NOTE 8	10	2
ROOM 208, EL. 93 PUMPS, VALVES AND CONTROL PANELS	1, 2 (IN ADJACENT ROOM), 4 (SEE NOTE 3)	< 108	NOTE 8	5	2
EL. 107 TRAVELLING SCREEN CONTROL PANELS	2, 4 (SEE NOTE 5)	< 80	NOTE 8	10	1
EL. 114 TRAVELLING SCREEN MOTOR ROOM FANS	2, 4 (SEE NOTE 5)	< 70	NOTE 8	10	2

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TABLE 9.5 - 17

COMMUNICATIONS AND EMERGENCY LIGHTING SYSTEMS FOR SAFE SHUTDOWN AREAS

AREA / EQUIPMENT	COMMUNICATION FEATURES: COMPONENTS AVAILABLE AT AREA	COMMUNICATION FEATURES: ESTIMATED MAXIMUM NOISE LEVEL AT AREA, dBA	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM - ESSENTIAL AC	EMERGENCY LIGHTING SYSTEM FEATURES: APPROXIMATE FOOTCANDLES AT EQUIPMENT FROM - 8-HOUR BATTERY PACK
INTAKE STRUCTURE - CONTINUED	LEGEND 1 = PA HANDSET 2 = PA SPEAKER 3 = TELEPHONE 4 = RADIO	LEGEND dBA = DECIBEL, A-WEIGHTED < = LESS THAN	WORK STATION	
ROOM 305, 306, EL.122 FANS	1, 2, 4 (see NOTE 3)	<90	NOTE 8 10	1
ROOM 311, 312, EL.122 FANS	1, 2, 4 (see NOTE 3)	<90	NOTE 8 10	1
STAIRWELLS IN Control, Diesel, Reactor Bldgs	2 (see NOTE 5)	<50	NOTE 8 5	10

QUESTION 430.73 (SECTION 9.5.3)

You state in Sections 9.5.3.1 and 9.5.3.3 of the FSAR that illumination levels provided in the various areas of the plant either conform to or exceed that required in the Illumination Engineering Society Handbook. This statement is too general particularly for emergency lighting. The staff has determined that a minimum of 10 foot candles at the work station is required to adequately control, monitor and/or maintain safety related equipoment during accident and transient conditions and a minimum of 5 foot candles in the corridors which provide access to and egress from these areas. For those safety related areas listed in requests 430.65 and 430.70 above and illuminated by the dc lighting systems only verify that the minimum of 10 foot candles at the work station is being met. Also verify that the 10 foot candles minimum at the work station is being met by those safety related areas illuminated by the ac emergency system. Verify that the access and egress corridors are illuminated by a minimum of 5 foot candles. Modify your design as necessary. (SRP 9.5.3, Part I & II).

RESPONSE

Revised Table 9.5-17 identifies areas that are manned work stations during design basis accidents or during a loss of all ac power at the plant. At these particular locations (control room, remote shutdown panel room, and each diesel generator switchgear room) the lighting levels will be 10 ft candles from either the essential ac lighting system or the emergency 8-hour battery pack system. These particular work stations are areas where specific equipment require manual operation or monitoring of instrumentation meters.

The other safety-related areas that contain safety-related equipment have lighting levels less than 10 ft candles as identified on Table 9.5-17. If safety-related equipment in areas that have less than 10 ft candles of emergency ac lighting require repair or maintenance during or after an accident, portable lighting will be utilized to accommodate the repair to be the equipment. The portable lighting will be stored onsite for such emergencies and will be maintained and tested in accordance with the manufacturers recommended procedures and frequencies. This portable lighting will provide a minimum of 10 ft candles to the safety-related area.

The Hope Creek ingress and egress routes are listed in the Table 9.5-17. These ingress and egress routes have a lighting level of from 2 to 5 ft candles when the lighting is powered from the essential ac lighting system. During a station blackout, all station ac power is not available. In this condition, the HCGS ingress and egress routes have lighting from the 8-hour battery pack units and emergency lighting in the stairwells powered from the standby dc lighting system. The minimum illumination levels in the ingress and egress areas will be approximately 2 ft candles. This level of lighting within the ingress and egress areas is the design intent. The preoperational testing of the lighting system will determine whether the lighting is sufficient.

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QUESTION 430.75 (SECTION 9.5.3)

In Section 9.5.2.4 of the FSAR you state that inservice inspection tests, preventative maintenance, and operability checks are performed periodically to prove the availability of the communication systems. However no description is provided for the inservice inspection tests, preventative maintenance and operability checks to prove the availability of the emergency lighting systems. Describe the tests and checks that will be performed on the emergency lighting systems and their frequency. (SRP 9.5.3, Parts I & II).

RESPONSE

The emergency lighting systems will be demonstrated operable by energizing the lighting systems. Visual inspections will be performed: (1) Semiannually for those areas of the plant that are accessible; and (2) Within 72 hours of achieving cold shutdown for those areas of the plant that are not accessible during plant operation, unless emergency lighting operability has been demonstrated in those areas within the past six months.

Testing of the Class 1E feed will be performed in conjunction with the standby diesel generator load testing.

Additionally the dc emergency battery pack lighting units, as well as stored onsite portable dc lighting packs, will be tested on an 18 month interval in accordance with manufacturers recommendations to insure that rated illumination is available. As a minimum this will include the following:

a. Check of battery voltmeter.
b. Functional test of the unit by an installed push button to verify lamp operation, power transfer, and battery operability.

The lighting pack consists of two sealed, 6 volt, lead acid, rechargeable batteries with automatic, continuous float charge operation. There is no need for a battery discharge test because the inplace voltmeter indicates the battery voltage. If the voltage drops below the manufacturers requirements, the batteries will be replaced. The batteries have a 5 year warranteed life and will be replaced in accordance with manufacturers recommendations or after four and one-half years of service.

QUESTION 430.83 (SECTION 3.2)

The FSAR text and Table 3.2-1 indicates that the components and piping systems for the diesel generator auxiliaries (fuel oil system, cooling water, lubrication, air starting, and intake and combustion system) that are mounted on the auxiliary skids are designed seismic Category I and are ASME Section III, Class 3. The engine mounted components and piping and certain other components listed in the various Sections of 9.5 and Table 3.2-1 are designed and manufactured to DEMA standards and/or manufacturer's standards and are seismic Category I. This is not in accordance with Regulatory Guide 1.26 which requires the entire diesel generator auxiliary systems be designed to ASME Section III Class 3 or Quality Group C. You also state that the figures in Section 9.5 show where quality group classification changes are. The figures do not provide this information. Provide the following: (a) the industry standards that were used in the design, manufacture, and inspection of the engine mounted piping and components, (b) show on the appropriate P&ID's where the Quality Group Classification changes from Quality Group C, and where the Seismic Category I portions of the system are located. Sections 9.5.4 through 9.5.8 and Table 3.2-1 define certain pumps, filters, strainers, valves, and subsystems in the diesel generator auxiliary systems as Quality Group D or not applicable with regards to Quality Group Classification. It is our position that all components and piping in the diesel generator auxiliary systems be designed to Seismic Category I ASME Section III Class 3 requirements. Comply with this position or justify noncompliance. (SRPs 9.5.4 - 9.5.8, Part III)

RESPONSE

a. The engine mounted piping systems (such as the lube oil headers, water headers, cylinder heads, etc) are manufactured to the manufacturer's proprietary design requirements which do not necessarily meet the requirements of ASME Section III or ANSI B.31. The components used are pressure tested and the manufacturing processes are monitored as part of the supplier's approved QA program. The major components are included in the seismic analysis.

   The diesel engine and piping integral to the engine (mounted on the engine and provided with the engine) are designed to Seismic Category I requirements and proven designs based on the manufacturer's knowledge and experience. Regulatory guide 1.26 states that "other systems not covered by this guide, such as... diesel engine and its generators and auxiliary support systems, fuel oil... should be designed, fabricated, erected and tested to quality standards commensurate with the safety function to be performed." The desel generator engine piping is highly reliable and of proven quality and design and therefore meets the requirements of the regulatory guide. The Standard Review Plans (SRP) (Sections 9.5.4, 9.5.5, 9.5.6, 9.5.7, and 9.5.8) require review for quality group application and other features for piping, valves, and other components only up to the "engine interface". This is further clarified as being the interface "as defined by the engine manufacturer". The manufacturer for the Hope Creek Generation Station diesel generators has defined these boundaries; the piping up to this interface is designed to Qualify Group C requirements as discussed in part b below. The applicant considers that the design for the engine, including the portions of pipe that are integral to the engine as the most prudent and the safest available. The design is proven and tested and is based on the years of experience of the engine manufacturer.

Furthermore, as requested, the applicant has made a comparison of those portions of piping and tubing that are integral to the engine with the design requirements of ANSI B.31.1 and ASME Section III, Class 3, requirements for allowable design pressures. Because the allowables for materials under the ASME Section III Class 3 code are the same or greater than the allowables under the rules of ANSI B.31.1 for the same material, the more conservative (that comparison that resulted in the lower allowable design pressure) is provided in Table 430.83-1 along with the piping description. Piping integral to the engine is moderate energy pipe.

Comparing the working pressure with the maximum design pressure in the table, it is evident that the manufacturer's standards are conservative when examining the pressure retaining capability of the pipe and tube.

(It should be noted that the DEMA standard is not a design specification, but gives guidance as to what should be included in a performance type specification.)

b. The figures in Section 9.5 can be used to determine quality group classification and seismic boundaries. The diesel engine auxiliary system P&IDs (Figures 9.5-22, 25, and 28) indicate the piping line classes and the piping specification changes as defined on Figure 1.13-1, sheet 1 (P&ID legend). The third letter of the three-letter piping line class code indicates the code to which the piping and components are built. Tables 3.2-2 and 3.2-3 can then be used to determine the quality group classification based on the applicable code. The Seismic Category I boundaries are indicated by the Q-flags as indicated in Section 3.2.1.

   Section 1.8.1.26 has been revised to include a clarification of Regulatory Guide 1.26, Revision 3, position C.2.b with regard to engine mounted components and piping.

The diesel generator auxiliary systems were designed for the most part during the period from 1974 to 1977. Careful consideration was given to classifying essential system piping as ASME Section III, Class 3. This intent was reviewed at the construction permit stage and is reflected in Table 15.4-2 of the PSAR which specifies that the "diesel fuel oil pumps, piping, and valves" are Quality

Group D. In addition, paragraph 15.4.3.3 of the PSAR further clarifies that the "diesel generator fuel supply piping from seven day storage tank to engines" is to be classified as Qualify Group C. It should be noted that it does not include other piping such as the diesel generator fill line. The guidance of Regulatory Guide 1.26 stated that systems not covered by this guide [include] diesel engine and its generators and auxiliary support systems, diesel fuel,..." and that these systems should be designed to quality standards "commensurate with the safety function to be performed."

The position with respect to the diesel generator storage tank fill lines was that they were not essential in that lengths of hoses would be available to be positioned such that fuel oil could be transferred directly to the tank through the manhole or the spare flange connection (see the response to Question 430.93).

During the construction of the station, and following procurement of the piping for the fill lines (in early 1977), an evaluation was made regarding the design of the fill lines. In light of the NRC's interest in this particular fill line on other dockets, a decision was made to upgrade the emergency fill piping down to the tanks to withstand the effects of an SSE. This piping was subsequently reanalyzed and supported similar to other Seismic Category I piping. In addition, the piping support installation has been inspected by the construction quality control organization under a 10 CFR 50, Appendix B, quality assurance inspection program.

The diesel fuel oil fill line, although not designed to the requirements of ASME Section III, Class 3, is designed, fabricated, and inspected commensurate with its safety function and provides an adequate level of safety based on the following:

1. The piping is designed to the standards of ANSI B.31.1. The material specified is ASTM A106, GrB which is identical to the comparable ASME SA-106.

2. The piping is designed to withstand the effects of an SSE without loss of function.

3. Installation of the supports for the piping are inspected under an 10 CFR 50, Appendix B, quality assurance program.

4. The fill line will experience little pressure during filling operations and is not pressurized when not in use.

5. The line is not critical in the early stages of an emergency and in the unlikely event it becomes unusable, sufficient time will likely be available to effect repairs. This is justified in that a normal seven day supply of fuel will be on site and available for use for each diesel generator.

6. The capability exists to fill the tanks with hoses that can be positioned to fill the tanks directly. Procedures shall be written to detail this emergency operation which will include the requirement for a dedicated fire watch who shall periodically patrol among the spaces containing the fill hoses when in use.

7. The piping shall be visually inspected on an inspection interval equal to the requirements of ASME Section XI for ASME III, Class 3, piping.

8. The piping shall be placed under the operational QA program for the station.

Table 430.83-1

LUBE OIL SYSTEM

Working Pressure 120 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressure (PSI)(1)
3.5	.120	MT1018	681
1.625	.25	MT1018	3060
1.5	.120	MT1010	1224
1.25	.25	MT1018	3978
1.1875	.156	MT1018	2605
1	.095	MT1020	1816
.75	.065	MT1010	1326
.625	.065	MT1010	1591
.375	.065	MT1010	2652
.5	.065	MT1010	1989
.25	.049	MT1010	2998

TURBOCHARGER WATER PIPES

Working Pressure 60 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressure (PSI)(1)
4	.188	MT1018	989
2.375	.154	A120-S	862
1.646	.140	A120-S	1134
1.375	.133	A120-S	1292
1	.188	MT1018	3955

INJECTOR COOLING SYSTEM

Working Pressure 50 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressure (PSI)(1)
1.316	.179	A120-S	1816
1.125	.065	MT1010	384
.375	.065	MT1010	2652

Table 430.83-1

AIR STARTING SYSTEM

Working Pressure 250 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressure (PSI)(1)
2.375	.218	A53	1632
1.9	.145	A120XS	1015
1.875	.188	MT1020	2028
1.75	.156	A513	1360
.625	.049	A254C1	657
.375	.049	MT1010	1994

JACKET WATER SYSTEM

Working Pressure 60 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressure (PSI)(1)
4	.188	MT1018	989
.375	.095	MT1010	3876

FUEL OIL SYSTEM

Working Pressure 35 PSI

Pipe & Fittings Material

OD	Wall Thickness	Material Spec.	Max. Design Pressuire (PSI)(1)
1.5	.120	MT1018	1591
1	.065	MT304	1551
.75	.095	MT1010	1938
.5	.049	MT304	2333
.25	.035	MT304	3341

Table 430.83-1

(1) Assumptions:

a. Normalized tubing

b. Allowables are assumed to be 1/4 ultimate stress valves.

c. Weld factor = 0.85 ERW

d. Because the fluids are not capable of causing any loss of strength by corrosion, no allowance is required.

e. A 10% manufacturer's tolerance on wall thickness except as noted otherwise.

f. For metal tube products, the allowables are derived from 1/4 ultimates:

MT 1010	=	10,000 psi
MT 1020	=	12,500 psi
MT 1018	=	13,000 psi
MT 304	=	15,600 psi

g. Allowables for other materials are:

A120-S	=	9,000 psi
(mfg. tolerance = 12.5%)		
A254C1	=	5,500 psi
A53	=	13,000 psi
A513	=	10,000 psi

h. Piping temperatures are less than 200 F.

QUESTION 430.115 (SECTION 9.5.6)

Describe the instrumentation, controls, sensors and alarms provided for monitoring the diesel engine air starting system, and describe their function. Describe the testing necessary to maintain a highly reliable instrumentation, control, sensors and alarm system and where the alarms are annunciated. Identify the temperature, pressure and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe any operator actions required during alarm conditions to prevent harmful effects to the diesel engine. Discuss system interlocks provided. Revise your FSAR accordingly. (SRP 9.5.6, Part III)

RESPONSE

The instrumentation, controls, sensors and alarms are described in Sections 9.5.6.3 and 9.5.6.5.

For the testing frequency and where the alarms are annunciated see response to Question 430.104.

Only pressure controls and instrumentation are supplied air by the starting air system; temperature and level sensors are not applicable. A summary of the equipment and surveillance frequency is provided on Table 430.115-1.

As described in Section 9.5.6.3 a low pressure alarm on each of the air trains alerts the operator of system trouble in the control room. Operator response to diesel engine starting air system alarms is summarized in Table 430.115-2. Safety relief valves on the receivers/air trains protect the system from overpressure.

A high pressure alarm is not provided because the relief valves are oversized, 450 scfm, compared to the compressor output of 25 scfm, and if a compressor fails to shut off at its high pressure setpoint, the plant operations personnel would easily hear the relief valves operating to relieve the overpressure condition.

The diesel engine air starting system air compressor starts automatically when air accumulator pressure decreases to 280 psi, and shuts off the compressor at 425 psi. The system is disabled by the barring gear interlock which is used to prevent diesel engine operation during maintenance.

NT

TABLE 430.115-1

Diesel Engine
Starting & Control Air System.

System ID	INST. NO		FUNCTION		Surveillance Frequency*	
KJ	PI-7539	A-H	Air Start Receiver Tanks		P	~~P~~
KJ	PIC-7543	A-D	Cont. Air Press		P	~~P~~
KJ	PSHL-4825	A-H	Start Air Comp. Control		P	~~P~~
KJ	PI-7554	A1-D2	Start. Air Press	(ELCP)	P	~~P~~
KJ	PSL-7555	A1-D2	Start Air Press		F	~~F~~

* All above instrumentation will be calibrated on an 18 month schedule.

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Summary of Operator Actions in Response to Diesel Engine Air Starting System Alarms.

High Priority

a) STARTING AIR PRESSURE LOW

Check	Action
Air header pressure	If normal: Check valve lineup to sensor Attempt to clear alarm If low: Proceed to next step
Receiver pressure	If normal: Check valve lineup to air start distributor If low: Proceed to next step
Valve lineup to receivers	Open valves if closed
Compressor running	If stopped: Confirm valve lineup to start switch Ensure power to compressor
Piping and flex coupling	If leaks or obstructions exist; Isolate leak if possible Notify Shift Supervisor

b) START FAILURE CRANKSHAFT NOT ROTATING

Check	Action
Barring device	If engaged: Check reason for engagement
	Disengage when possible
Engine trouble shutdown	Ensure shutdown has been reset
Control power available	Ensure circuit #3 is energized
	Notify Maintenance if repairs are required
Maintenance switch position	If 43 switch is not in REMOTE:
	Check reason for position
	Return to REMOTE when possible.
Hand switch position	If HSS switch is not in NORMAL:
	Check reason for position
	Return to NORMAL when possible
If the diesel still fails to start, manually start at:	
	Control room panel
	remote engine panel
	local engine panel
	air start solenoid valve

a) START FAILURE CRANKSHAFT ROTATING

Check	Action
Fuel system	If fuel system problems exist, respond in accordance with applicable alarm response
Air intake system	Check condition of air intake filters, piping, flex connections, and intake manifolds.

TABLE 430.115-2 (Sheet 3 of 3)

Low Priority.

a) ENGINE LOCKED OUT FOR MAINTENANCE

Check	Action
Position of maintenance switch (83)	If switch is in MAINTENANCE position: Check reason for switch position Return to REMOTE when possible If switch is in REMOTE position: Attempt to clear alarm

b) DIESEL ENGINE IN LOCAL CONTROL

Check	Action
Position of maintenance switch (83)	If switch is in LOCAL position: Check reason for switch position Return to REMOTE when possible If switch is in REMOTE position: Attempt to clear alarm

c) REMOTE EMERGENCY TAKEOVER

Check	Action
Position of control switch (HSS)	If switch is in EMERGENCY TAKEOVER Check reason for switch position Return to NORMAL when possible If switch is in NORMAL: Attempt to clear alarm

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QUESTION 430.120 (SECTION 9.5.6)

Section 9.5.6.2 of the FSAR defines the air starting system for your plant as a high energy system. A high energy line pipe break in the air starting system of one diesel generator, plus any single active failure in any auxiliary system of any other diesel generator will result in loss of sufficient onsite AC power so that the plant cannot safely shutdown. This is unacceptable. Provide the following information:

a. Assuming a pipe break at any location in the high energy portion of the air start system, demonstrate that no damage from the resulting pipe whip, jet impingement, or missiles (air receivers, or engine mounted air tanks) will occur on any of the four diesel generators or their auxiliary systems.

b. Section 9.5.6.2 states that the air receivers, valves, and piping to the engine are designed in accordance with ASME Section III Class 3 (Quality Group C) requirements. This is partially acceptable. We require the entire air starting system from the compressor discharge up to and including all engine mounted air start piping, valves and components be designed to Seismic Category I, ASME Section III Class 3 (Quality Group C) requirements. Show that you comply with this position. (SRP 9.5.6, Part II and III)

RESPONSE

a. For the purposes of pipe break and jet impingement analysis the emergency diesel generator and its associated auxiliaries are considered a single system. As a single system a single failure is only required to be postulated in one system. Separation of the diesel generator rooms by 18 inch reinforced concrete walls protects other diesel generator units and auxiliaries from damage due to a pipe break in adjacent diesel generator rooms. Therefore, a pipe break in any one of the diesel generator rooms will not affect the remaining diesel generator units and their associated auxiliaries.

b. All of the air start piping, valves and receivers from the check valve on the air receiver inlet (including the check valve) to the air start solenoid valve on the engine are designed to Seismic Category I, ASME Section III, Class 3, requirements. Refer to Figure 9.5-26 for component descriptions.

The compressor, air dryer, and piping up to the air receiver inlet check valve are not built to meet ASME code requirements because they do not serve a safety-related function. The air start valves, air distributors, and the diesel engine cylinders are all pressure retaining parts downstream of the air start solenoid valves which do serve a safety-related function and are non ASME code items built to Seismic

Category I requirements. The air start solenoid pilot valves reduce the starting air pressure to approximately 250 psi, therefore these components, which are downstream of the air start solinoid pilot valves, are actually located in a moderate energy portion of the system (See the response to Question 430.83). The non-ASME III pipe in the air-start system is designed to Seismic Category 1 requirements. These are specialty items that are not available as ASME components but which are built to the SDG manufacturers own critical specifications (see Table 3.2-1, Tem XII.b.) Refer to the response to Question 430.82 for further discussion of the air start piping and the applicable design requirements.

A postulated break in the starting air system is not considered to occur concurrently with, nor to cause, a loss of offsite power. Therefore a single failure in another of the standby diesel generators is not of consequence. In addition, the effects of postulated breaks in the non-safety related compressor air dryer piping up to the ASME Section III, Class 3, air inlet check valve have been examined. The postulated failures will not effect the function of any safety related component. Also, the effect of any postulated pipe break from any of the normally pressurized safety related air start piping will not damage any component that would cause its associated engine, if running, to shutdown.

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QUESTION 430.135 (SECTION 9.5.7)

You state in Section 9.5.7.2 of the FSAR and shown in Figure 9.5-27 that lube oil is added to the diesel generator lubricating oil system from a 250 gallon lube oil make-up tank. Provide a discussion on the measures that have been taken to prevent entry of deleterious materials in the lube oil make-up tank. Also discuss what measures have been taken to prevent entry of deleterious materials into the lube oil make-up tank due to operator error during filling operation.

In addition address the following:

a. Discuss the means for detecting or preventing growth of algae in the lube oil make-up tank. If it were detected, describe the methods to be provided for cleaning the affected storage tank.

b. Provide an explicit description of proposed corrosion protection for the lube oil make-up tank. Where corrosion protective coatings are being considered for the piping and tanks (both external and internal) include the industry standards which will be used in their application.

c. Figure 9.5-27 of the FSAR shows that the diesel generator lube oil make-up tank is provided with an individual fill, vent, and emergency pressure relief vent lines. Indicate where these lines are located (indoor or outdoor) and the height these lines are terminated above finished ground grade. If these lines are located outdoors discuss the provisions made in your design to prevent entrance of water into the make-up tank during adverse environmental conditions, and the tornado missile protection provided.

d. Assume an unlikely event has occurred requiring operation of a diesel generator for a prolonged period that would require replenishment of lube oil in the sump without interruping operation of the diesel generator. What provisions have been made in the lube oil transfer system design from the lube oil make-up tank to the engine sump to prevent carryover of sediment, water, and scale that may accumulate in the clean lube oil storage tank. What provisions have been made for the removal of accumulated sediment, water, and other deleterious material that may collect at the bottom of the storage tank. (SRP 9.5.7, Parts II & III)

RESPONSE

Deleterious material is prevented from entering the diesel engine lube oil make-up tank by:

a. Procuring high quality, high purity lube oil with lubricating properties in accordance with the manufacturers' recommendations.

b. Insuring that filling operations to increase make-up tank level are performed through the installed basket strainer in the fill line.

The lube oil make-up tank conservation vent permits tank venting when required and prohibits airborne impurities from continuously entering the tank.

Make-up tank filling will be accomplished in accordance with a written procedure. A controlled copy of the procedure will be posted in the vicinity of the lube oil fill line. The lube oil fill line will be labeled to identify the fill line connection purpose and a reference to the applicable procedure.

a. Algae formation may occur due to condensate accumulation in the make-up lube oil tank. Prior to diesel engine monthly operability testing, and in accordance with plant technical specifications, the lube oil make-up tank drain will be opened to remove any water, sediment, algae or other deleterious material. If lube oil purity is degraded any of the following methods can be implemented to restore lube oil purity in the make-up tank:

   1. All deleterious material may be removed by draining lube oil through the drain line.

   2. The lube oil make-up tank can be drained, cleaned and refilled with fresh lube oil.

   3. A chemical additive can be added to remove algae or other biological growth if advised by a tribology specialist.

b. The standby diesel generator lube oil make-up tank material is carbon steel, SA 515 GR. 70. The exterior of the tank is coated using Colt Industries standard protection system. The system consists of a primer of Gordon Bartells 13409, yellow, and a finish coat of Gordon Bartells 14-811, suede grey, both applied according to the paint manufacturers recommendations. The interior of the tank is not coated because the lube oil is non-corrosive. Corrosion of the SDG lube oil make-up tank in the unfilled areas is prevented by lube oil vapor coating, normally found on unflooded sections of lube oil tanks.

Prevention of corrosion of the lower head of the SDG lube oil makeup tank due to moisture accumulation is addressed in the second paragraph to part d of this response.

c. The vent and emergency pressure relief vent are terminated indoors, directly above the tank. The fill line is routed to the outside (west) of the auxiliary building at elevation 105 feet 0 inches, 3 feet above grade. The line is capped and has a normally closed isolation valve located in the building to prevent water from entering the line. It is not protected from missiles and tornadoes because it is not safety-related.

d. In accordance with technical specifications, twenty 55-gallon drums of diesel engine lubricating oil are stored and available for use if diesel operation is required for a prolonged period. Additional information on lube oil make up requirements is provided in the response to Question 430.131.

The lube oil makeup tank bottom is hemispherical. The line to the diesel generator sump is approximately 1.75 inches above the bottom of the dish and is located ten inches off the centerline of the tank, reference figure 430.135-1. Should there be any carry over into the transfer line, it would be trapped in the strainer and/or filter after entering the engine sump.

A normally closed drain valve is provided at the low point of the tank, reference Figures 9.5-27 and 430.135-1. The drain valve will be opened in accordance with plant operating procedures to remove any deleterious sediment, water or other material that may accumulate in the bottom of the tank.

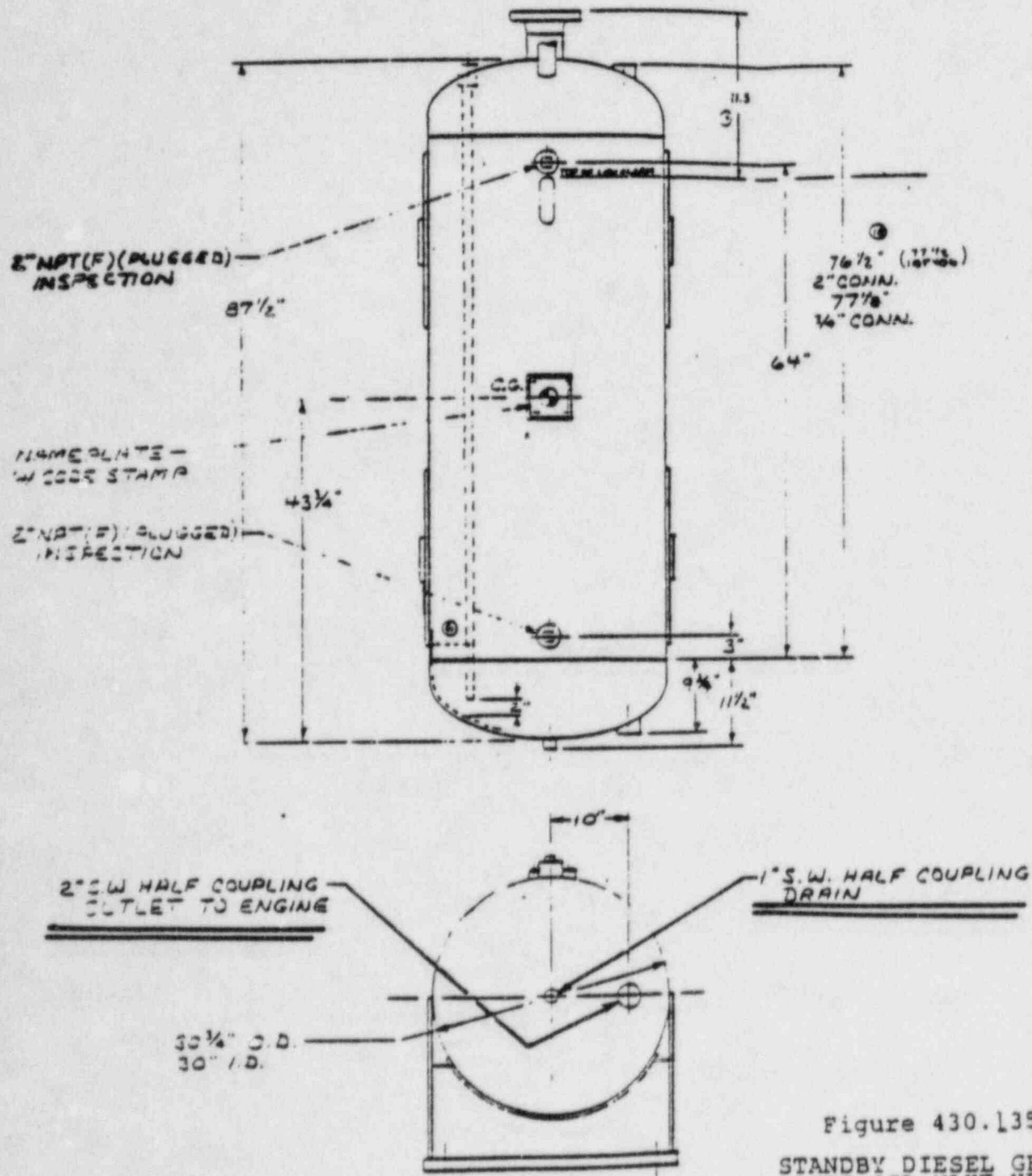

Figure 430.135-1

STANDBY DIESEL GENERATOR LUBE OIL MAKE-UP TANK

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 Rev. 2

QUESTION 430.143 (SECTION 9.5.8) Rev 2

Show by analysis that a potential fire in the diesel generator building or any of the other surrounding buildings (reactor building, control building, etc.) together with a single failure of the fire protection system for that area will not degrade the quality of the diesel combustion air so that the remaining diesels will be able to provide full rated power. (SRP 9.5.8, Parts II & III)

RESPONSE

A 3-hour-fire-barrier has been added to separate the diesel combustion air intakes by safe shutdown division. Since the divisionalized intakes are in separate rooms, a fire in one zone, and an automatic closure of the fire door will not affect the remaining diesels' combustion air. Therefore, the remaining two diesels will be able to provide full rated power. This analysis was performed as part of the Appendix R fire hazard analysis (see revised Appendix 9A).

The Appendix R analysis shows that a fire in any one fire area of the control, diesel or reactor buildings will affect no more than one division of the diesel generator intakes. Ths Appendix R analysis assumes a failure of any automatic fire protection system for that area.

The SDG HVAC systems exhaust from missile protected areas located at elevation 198'-0". The possibility of significant quantities of smoke or other combustion by-products bypassing dampers or failed dampers from any of the areas and exiting at the 198 ft elevation and consequently being drawn down to other diesel generator intakes at the 130 ft elevation is not credible.

→ INSERT 1

HCGS

430.143 - Insert 1

With a postulated failure of the automatic fire suppression system in one diesel area, the fire damper would close to contain the fire. Failure of the damper, since it is a UL listed device and uses only the physical properties of the fusible link to operate, is not considered credible. However, failure would release smoke into the large volume common corridor, but the HVAC system design would prevent any smoke from affecting more than one diesel. Section 9.4.6 describes how the system consists of 100% recirculating fan coil units with only a minimal of air exchange from the common corridor during diesel generator operation. Thus, cooling of the diesels would not be significantly affected.

During normal plant operations, thus no diesels operating, the diesel area ventilation will exhaust air from each diesel compartment and out of the roof vent. Smoke from one compartment would have to exit to the large volume common corridor through the fire damper. It could then enter the other diesel generator compartments through that compartment's fire damper. The manufacturer has stated that the diesel generator itself is insensitive to smoke in the compartment. Should the temperature rise the recirculation coil units would automatically start ~~(9.4.6.2.g)~~.

The diesel control panels are NEMA 12, dust tight, panels. The protective relays inside the panel are further encased. The panels do not contain sensitive integrated circuits. The room temperature, even if smoke filled, is maintained by the recirculation coil units as stated above. Therefore, the diesel generator panels will not be affected by smoke (either temperature or particulates) in the diesel generator room.

ATTACHMENT 8

Final Report to

Public Service Electric and Gas Company
Newark, New Jersey

March 1983

An Update on the Analysis of Potential Effects of Waterborne Traffic on the Control Room and Water Intakes at Hope Creek Generating Station

Arthur D. Little, Inc. *Reference 88536*

AN UPDATE ON THE ANALYSIS OF POTENTIAL EFFECTS OF WATERBORNE TRAFFIC ON THE CONTROL ROOM AND WATER INTAKES AT HOPE CREEK GENERATING STATION

F I N A L   R E P O R T

TO

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
80 PARK PLAZA
NEWARK, NEW JERSEY 07101

FROM

ARTHUR D. LITTLE, INC.
ACORN PARK
CAMBRIDGE, MASSACHUSETTS 02140

MARCH 1983

ADL REFERENCE 88536

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1.0 INTRODUCTION

1.1 BACKGROUND

The potential effects of waterborne traffic on the control room and water intake structure at Hope Creek Generating Station (HCGS) were analyzed by Arthur D. Little, Inc. in 1974, as described in a report [Ref. 1] to Public Service Electric and Gas Company (PSEG). This study considered risks to the intake structure and the control room from barge and ship/tanker related spills. In particular, the probabilities of spill related fire, vapor dispersion, explosion, and corrosive chemical were evaluated. Also, the probabilities of a ship or a barge blocking and ramming the intake structure were determined.

A subsequent study [Ref. 2] developed a methodology to monitor LNG and LPG shipping in the vicinity of HCGS. This methodology was applied to estimate the probabilities of an LNG or an LPG ship ramming a stationary object or colliding with a vessel in the vicinity of HCGS [Refs. 3 and 4].

Presently, PSEG is in the process of preparing the Final Safety Analysis Report (FSAR) for HCGS. In order to ensure that the FSAR reflects the current situation, PSEG approached Arthur D. Little to update the analysis presented in the earlier reports. This document presents the results of the study. Also included are the results of two small tasks performed under the same contract, one dealing with evaluating the implications of hazardous chemicals stored on-site and the other with hazardous material pipelines, if any, in the vicinity of HCGS.

1.2 OBJECTIVE OF THIS REPORT

This report addresses three major objectives:

- to update the 1974 report [Ref. 1] prepared by Arthur D. Little (on potential effects of waterborne traffic on the safety and control room and water intakes at HCGS) to reflect:

- more recent shipment and accident data on the Delaware River,
- changes in the regulations affecting shipment of hazardous material in the river,
- any recent design changes (such as building only one reactor unit instead of two),
- recent research in areas such as vapor dispersion from an LNG or LPG spill in water, and
- changes in the navigable characteristics of the Delaware River in vicinity of HCGS.

- to assess the probability of significant accidents involving storage and transport of hazardous chemicals on-site.
- to update the presence, if any, of nearby hazardous material pipelines.

The approach taken in achieving these objectives is described below.

1.3 APPROACH

In order to accomplish the objectives outlined above, we obtained and analyzed information from a large number of sources. In some cases, redundant information was obtained in order to cross check the validity of data from different sources. Table 1-1 identifies the sources approached and information obtained to accomplish the objectives of this study.

1.4 REPORT FORMAT

Section 2 discusses the implications of the hazardous material transport activity on the water intake structure and the control room. The probabilities of various accident scenarios affecting these two areas are provided. These probability calculations incorporate the effects of updated shipping and accident data, the updated regulations, the additional accident scenarios, and the updated analysis of accident consequences, all of which are described in Section 3. Finally, several appendices are provided to support the analysis and observations presented in Section 3.

TABLE 1.1

Approach Taken in Accomplishing Various Objectives

Objective	Approach
Update data on shipment of hazardous material	• Analyzed data from the most recent (1980) issue of "Waterborne Commerce of the United States," published by the Corps of Engineers.
	• Obtained the data on recent LPG shipping from Poten & Partners through PSEG.
	• Visited Philadelphia Maritime Exchange and Captain of the Port (U.S. Coast Guard) to obtain additional data.
	• Confirmed that there were no plans for LNG terminal by contacting DOE, Federal Agency Regulatory Commission.
	• Obtained correspondence conducted by PSEG with various chemical facilities regarding their future plans.
Update of Accidents on the Delaware River	• Extracted and analyzed relevant data from the most recent commercial vessel casualty data file obtained from U.S. Coast Guard.
Determine the number of rammable objects in the Delaware River, particularly in vicinity of the HCGS.	• Obtain and analyzed the most recent NOAA charts for the river.
	• Confirmed validity of the charts by flying over the river, 12 mile upstream and 12 mile downstream of the plant, in a helicopter.
	• Confirmed the absence of any major new constrictions in recent years by contacting the Delaware River Basin Commission.

TABLE 1.1 (continued)

Objective	Approach
Incorporate changes in regulations on LNG & LPG shipping	• Obtained and evaluated the most recent "Procedures for the Movement of Liquified Flammable Gas (LFG)" from the Captain of the Port, Philadelphia.
Determine status of the Explosives Anchorage in the vicinity of the HCGS	• Obtained and analyzed a copy of the Federal Register which incorporates the petition to prohibit explosive anchorage in vicinity of the plant.
Incorporate effects of design changes	• Recalculated the effects of blocking on the new configuration of the water intake structure.
	• Reevaluated the possibility of ramming of the water intake structure in light of recent dredging.
Incorporate results of recent research in vapor dispersion	• Conducted a survey of the recent literature on vapor dispersion from an LNG or LPG spill on water.
Determine location of hazardous material pipelines in the vicinity of HCGS.	• Contacted representatives of neighboring counties.
	• Contacted Getty Oil in Delaware City. • Contacted Colonial Pipeline. • Contacted South Jersey Gas Co. • Contacted Dept. of Transportation and FERC.
Assess hazards presented by the storage and transportation of chemicals on-site	• Obtained correspondence and site visit information on - type, amount and location of on-site chemicals; - frequency, method, and amount of shipment of the on-site chemicals.
	• Evaluated probability of the control room being affected by an accident involving any of these chemicals.

2.0 RESULTS

This section presents the updated probability calculations for the various accidents which could affect the water intake structure and the control room at HCGS. The implications of the effects of various accidents to water intake structure and the control room are discussed in Subsections 2.1 and 2.2, respectively. The following accident scenarios are considered.

- Accidents Affecting the Water Intake
  - the barge-related accidents; and
  - the ship/tanker related accidents
- Accidents Affecting the Control Room
  - the barge-related accidents;
  - the ship/tanker related accidents;
  - the stored chemical related accidents; and
  - the pipeline related accidents.

2.1 Accidents of Potential Concern to the Water Intake

2.1.1 Barge Related Accidents

The barge related accident scenarios which could potentially affect the water intake structure of HCGS are:

- pool fire accidents; and
- corrosive chemical accidents.

Since there is no known barge shipment of liquefied or compressed gases past Artificial Island, we have not considered vapor dispersion accidents, and since there is no known explosive shipment movement in the vicinity of Artificial Island, the effects of accidents involving explosives are also not considered.

Finally, as discussed in Section 3, the detrimental blockage of the intake structure due to barge is found to be not possible and ramming will produce slight damage but not impair the operability of the water intake system.

2.1.1.1 Pool Fire Scenario

The following calculation yields the probability of pool fire from a barge accident. The ignition of a spill of five million gallons or more of a flammable liquid within one mile of the water intake (catchment distance of 2 miles) is required to pose a potential threat to the water intake. [Ref. 1]

Annual barge trips of flammable cargo	1665 (See Table 3.3)
Catchment distance (miles)	x 2
Accidents per barge mile	x 0.42×10^{-6}
Spills per accident	x 0.45
Spills of 5×10^6 gallons or more/spill	x 1.2×10^{-3}
Ignition per barge spill	x 7×10^{-2} [Ref. 5]

Therefore:

The probability of a barge-caused large fire at water intake = 5.28×10^{-8}/yr

In this calculation, the number of accidents per barge mile was obtained from the previous ADL study. [Ref. 1]

2.1.1.2 Corrosive Chemical Accidents

The only corrosive liquid moving in barges by the Hope Creek site is dilute sulfuric acid. The catchment distance for sulfuric acid is one-half mile and the spill must occur within 200 feet of the shoreline to work its way into the intake. The calculation for corrosive liquid ingestion is as follows:

Annual barge trip (sulfuric acid)	125 (See Table 3.3)
Catchment distance (miles)	x 0.5
Correction for nearness to shoreline	x 0.02
Probability of accident per barge mile	x 0.42×10^{-6}
Spills per accident	x 0.45
Spills of 10^6 gallons or more/spill	x 7×10^{-3}

Therefore:

The probability of corrosive chemical ingestion $= 1.65 \times 10^{-9}$/yr

2.1.2 Ship/Tanker-Related Accidents

This subsection discusses two scenarios:

- fire accidents, and
- flammable vapor cloud accidents.

Accident scenarios involving corrosive chemicals or explosives are not considered since these commodities are not moved past Artificial Island in ships. Also, a toxic vapor cloud does not present any risk to water intake. Finally, as described in Section 3, ramming of a ship on the water intake structure will produce only slight damage and detrimental blockage of the intake by ship is highly improbable.

2.1.2.1 Fire Scenario

A total of 2120 loaded tankers carrying flammable liquid cargoes pass Artificial Island each year, as shown in Table 3.3. Once again, as in the case of barges, any spills and ignition of five million gallons of fuel or more are potentially threatening to the water intake. The probability of a large fire at the water intakes is calculated as follows:

Annual tanker trips	2120
Probability of tanker accidents in catchment area (per trip)	5.4×10^{-6}
Spills per accident	0.2
Spills of 5×10^6 gallons or more/spill	4×10^{-3}
Probability of ignition/large spill	1×10^{-2}

Therefore:

The probability of a ship/tanker caused large fire at water intake $= 9.16 \times 10^{-8}$/yr

In this case, the value of probability of tanker accident in the catchment distance of 2 miles is found from adding the probabilities of tanker collision with vessel and with fixed object:

Probability of Tanker Accident in Catchment
Distance per Trip

= Probability of Collision with vessel per Mile x Catchment
Distance (miles)
+ Rate of Collision per Fixed Object per
Passage x Number of Fixed Objects in the Catchment Distance
= $2.7 \times 10^{-6} \times 2 = 5.4 \times 10^{-6}$ per trip.

Since there are no objects which a large ship can ram into within the 2 mile catchment distance, the second factor in the above equation equals zero.

2.1.2.2 Flammable Vapor Cloud Accidents

Three liquefied gases, butane, propane and butadiene are shipped past Artificial Island. They constitute a total of 23 ship movements per year, as shown in Table 3.3. Based on this traffic, the risk of having a flammable vapor cloud covering the plant is calculated as follows:

Annual tanker trips	23
Probability of tanker accident in catchment distance (per trip)	55.8×10^{-6}
Spills per accident	x 0.02
Probability of cloud not having ignited prior to arrival over plant	x 0.01
Probability of lethal wind direction	$\times 2.8 \times 10^{-2}$
Probability of adverse weather condition	x 0.5

<u>Therefore</u>:

Probability of a flammable vapor cloud reaching water intake $= 3.59 \times 10^{-9}$/yr

Here again, the probability of tanker accident in catchment distance (per trip) is calculated using equation provided in Subsection 2.1.2.1:

Probability of tanker accident = probability of collision with a vessel

+ probability of collision with a fixed object

$= 2.3 \times 10^{-6} \times 22 + 2 \times 2.6 \times 10^{-6}$ per trip

$= 55.8 \times 10^{-6}$

As can be seen, the above equation includes the probability of collision with either of the two rammable objects in the catchment area (Tower 97 and a ship wreck).

The catchment distance used in this equation is 22 miles, which, according to the current research on downwind travel of vapor from large spills of LNG and LPG on water (summarized in Appendix A) is quite conservative.

Note, that unlike the gasoline products, liquefied gases are highly volatile. They vaporize rapidly and the probability of ignition due to collision itself is likely to be high. If ignition occurs at the accident site, the gas would be consumed quickly, and there would be no vapor dispersion problem. Furthermore, even if the cloud did not ignite immediately, the probability of a flammable vapor cloud igniting prior to moving any significant distance is great. Any ignition source (such as a match or a motor boat) could ignite the cloud and eliminate further downwind travel.

2.2 Accidents of Potential Concern to the Control Room

2.2.1 Barge Related Accidents

Since liquefied or compressed gases are not shipped by barge and since there is no known shipment of explosives past Artificial Island, the danger from a barge related accident involving vapor dispersion or explosion is not evaluated. Also, although there is a finite probability of fire risk due to a barge related accident, as calculated in Subsection 2.1.1., the control room is judged to be too far removed from the water to be affected by spill fires. Thus, we have found it unnecessary to evaluate any barge related accident scenarios.

2.2.2 Ship/Tanker Related Accidents

Here again, we have not evaluated the effect on control room of a spill fire arising from a ship/tanker accident because the control room is judged to be too far to be affected. However, the probabilities of accidents involving vapor dispersion (i.e., those involving flammable or toxic vapor cloud) are calculated.

2.2.2.1 Flammable Vapor Cloud

As far as the accidents resulting in flammable vapor clouds are concerned, the analysis presented in Subsection 2.1.2.2 is valid and the probability of having a flammable vapor cloud affecting the control room is 3.59×10^{-9}/yr. However, as mentioned in that Subsection, there is a very high probability that the vapor will be ignited before it reaches the control room.

2.2.2.2 Toxic Vapor Cloud

The only toxic gas shipped past Artificial Island is liquid ammonia. Sixteen loaded ships, each carrying about 7000 tons of liquid ammonia, moved past the island in 1980. The hazard presented by movements is the possible accumulation of gaseous ammonia in the control room, in the event of an accident that results in a gaseous cloud over the plant. The calculation of the probability of such an event is as follows:

Annual tanker trips	16
Tanker accident in the catchment distance (per trip)	82.4×10^{-6}
Spills per accident	$\times$ 0.02
Probability of lethal wind direction	$\times 2.8 \times 10^{-2}$
Probability of adverse weather condition	$\times$ 0.5
<u>Therefore</u>:	
Probability of a toxic vapor cloud affecting the control room	$= 3.69 \times 10^{-7}$/yr.

As discussed earlier, the probability of a tanker accident in the catchment distance (which, based on 400 ppm concentration, is 28 miles) includes the probability of the tanker colliding with a vessel and that of the tanker ramming one of the two fixed objects in the catchment distance:

Probability of tanker accident in the catchment distance per trip =

$$2.7 \times 10^{-6} \times 28 + 2 \times 3.4 \times 10^{-6} = 82.4 \times 10^{-6} \text{ per trip}$$

Note that the human nose can detect ammonia at 20 ppm, well below the 400 ppm level that is severely irritating and that would require personnel to leave the control room.

The probability calculated above is based on a realistic toxic concentration of 400 ppm.

2.2.3 Stored Chemical Related Accidents

The major hazards that may result from accidental releases of chemicals stored on site are as follows:

- Explosion and flammability hazard resulting from release of hydrogen and liquid propane;
- Thermal radiation hazard resulting from fuel oil spills; and
- Toxic vapor dispersion hazards due to release of sulfuric acid and sodium hypochlorite.

As shown in Table 2.1, hydrogen is stored in twelve bottles of 56 cubic foot capacity under a pressure of about 2000 psig. These bottles are installed horizontally in three separately manifolded banks located outside the turbine building. Approximately 200 lbs of propane is stored at a pressure of about 8 atmospheres in a 47 gallon tank. Accidental releases of hydrogen and propane pose both explosion and flammability hazards. The explosion hazard was estimated using a TNT equivalent analysis. Our analyses indicate that an overpressure of about 3 psi (sufficient to cause structural damage to concrete structures) can be generated at distances up to 40 feet from an explosion of contents of a

TABLE 2.1

HAZARDOUS CHEMICALS STORED ON-SITE AT HCGS

Chemical	Amount
Hydrogen	• Twelve bottles of 56 cu ft capacity at 2000 psig, located outside turbine building shipped by trucks, one truck a month at 600 cu ft
Propane	• Approximately 200 lbs in a 47 gallon container (located outside auxiliary boiler building)
Sodium hydroxide	• Two tanks of 16,000 gallons one of 5000 gallons
Sulfuric acid	• One tank of 20,000 gal., two of 16,000 gal.
Sodium hypochlorite	• Four tanks of 30,000 gal. Shipped in 4,000 gal. trucks, one truck per week
Nitrogen	• Two tanks of 9,300 gal.
Carbon dioxide	• Three tanks of 17, 6 and 4 ton capacity

Plus, fuel oil in a storage tank near the barge docking facility.

Source: PSEG

single hydrogen bottle. Overpressure of about 0.5 psi (sufficient to damage glass windows) can be generated at distances of about 170 feet. Instantaneous release of 200 lbs of propane can result in an explosion hazard. The 3 psi over pressure can occur at distances up to 60 feet and 0.5 psi. Overpressure can occur at distances up to 240 feet.

Upon immediate ignition, hydrogen and propane can burn in the form of a rising fireball. The hydrogen flames radiate only in the water vapor band and thermal radiation hazards of hydrogen flame are not very significant. Our calculations indicate that serious burn injuries can occur over a distance of about 25 feet from the location of the fireball. A propane fireball could result in serious burn injuries over distances of about 40 feet. In the absence of ignition, a flammable vapor dispersion hazard is present. The dispersion is governed by the prevailing atmospheric conditions and the wind speed. Hydrogen is much lighter than ambient air and therefore will result in significant plume rise. At lower wind speeds, the plume rise will be higher. The calculated ground level concentrations at neutral and stable atmospheric conditions are well below the lower flammability limit for hydrogen. Instantaneous release of pressurized propane results in flash vaporization. Our calculations indicate that nearly 37% of the liquid will vaporize instantly. The vigorous boiling process will also result in entrainment of much of the liquid fraction into the vapor cloud. The average density of the vapor cloud is greater than that of air and therefore the dispersion is dominated by the gravitational effects. The maximum radius of the propane vapor cloud reaches about 100 feet and the maximum downwind travel to reach lower flammability limit is about 220 feet.

The fuel oil tank is located in a dike. Any inadvertent spill of fuel oil will be confined by the dike. An ignition is likely to result in a pool fire of dimensions equal to that of the dike. The thermal radiation hazards for serious burn injuries are limited to about 30 feet from the dike edge.

Sulfuric acid and sodium hypochlorite are nonflammable. Therefore spills of these chemicals will result in an evaporating pool. A 5000 gallon spill of either chemical will result in a 200 foot diameter pool. The vapor may travel downwind posing a toxic vapor dispersion hazard. The suggested Immediately Dangerous to Life and Health (IDLH) level for sulfuric acid is 2 mg/m^3 for 30 minutes. The toxic vapor dispersion hazard is about 15 feet from the evaporating pool under neutral weather conditions and a wind speed of 11 mph. During stable atmospheric conditions and a wind speed of 4.5 mph, the downwind dispersion hazard extends to about 50 feet. The vapor pressure of sodium hypochlorite is very small. Further, sodium hypochlorite vapors do not pose short term inhalation hazards. However, contact with liquid sodium hypochlorite can cause severe irritation to skin and eyes. Therefore, the exposure hazard is limited to the liquid pool.

2.2.4 Pipeline Related Accidents

For the purpose of evaluating the effects of accidents from industrial, transportation and military installations, the U.S. Atomic Energy Commission Regulatory Guide [Ref. 6] defines vicinity as within a five-mile radius. The HCGS site is located in a rural area consisting of marshes, abandoned meadowland, and some farmland. Since there are no industrial activities within five miles, we have conservatively selected a ten-mile radius in evaluating the probability of HCGS being affected by an accident resulting from pipelines carrying hazardous materials.

In order to determine if there are any pipelines carrying hazardous materials within a ten-mile radius of the HCGS, we contacted:

Carl Gaskil
Elsinborough Township, New Jersey
Lower Alloways Creek Township, New Jersey
(609) 935-0688

and,

Ron Groshardt
County Engineering Department
Greenwich Township, New Jersey
Stowecreek Township, New Jersey
(609) 451-8000

According to them, there are no such pipelines in the vicinity. Also contacted was:

Ed Tonielli
General Manager of Division Operation
South Jersey Gas Company
(609) 561-9000

He disclosed that 60 psi distribution pipelines carrying natural gas exist in Salem and Shilo. In addition, there are 200 psi transmission pipelines in Salem. However, we do not consider these pipelines to be dangerous to the HCGS since buoyant methane is lighter than air and does not disperse close to the ground.

On the other side of the river (in Delaware) we contacted:

Brad Smith
State Division of Environmental Control
Delaware City
(302) 736-5726

who mentioned that while there is bulk storage of hazardous materials, no such materials are transported through pipelines.

We also talked to:

Dick Ladd
Getty Oil Refinery
(302) 834-6162

This refinery is located on the fringes of the 10 mile radius from the HCGS. They have mostly low pressure lines carrying oil, however, there are some short run high pressure (2000 psi) lines. These lines are considered too far from the plant to pose danger.

We also talked to several people in the Office of Operations and Enforcement of Material Transportation Bureau (MTB) which is a part of the Department of Transportation. (The Office of Pipeline Safety Operations does not exist any more.) This office has undertaken a survey of hazardous liquid operators in each state. Although the study is not yet complete, Mr. Frank Fulton (202-426-3046) mentioned that there is one pipeline carrying petroleum products in Salem County, which belongs to Colonial Pipeline. A subsequent conversation with Mr. Robert T. Anderson (804-282-9771) of Colonial Pipeline revealed that the pipeline actually passes through Marcus Hook and then through Gloucester County north of Salem County and at a distance of at least 15 miles from HCGS.

According to Mr. Robert K. Arvedlund, Federal Energy Regulatory Commission (202-357-9043), there are no known interstate gas pipelines in the vicinity of HCGS.

2.2.5 Resupply of Chemicals On-Site

The two chemicals stored on-site of potential concern to the safety of the control room are propane and hydrogen. The location of the storage point of these chemicals is such that an accidental release at either location would not impact the control room (see Section 2.2.3 and 3.4). These chemicals will be periodically resupplied by truck. About twelve shipments of hydrogen and six of propane are anticipated every year. The hydrogen truck will carry a total of ten bottles containing a total of 600 cu. ft. of hydrogen. The propane truck will carry up to eight bottles containing a total of 400 gallons of propane.

The probability of the trucks carrying either hydrogen or propane having an accident on site and releasing its cargo was calculated. Utilizing very conservative highway statistics the probability of a truck accident involving a collision with a fixed object or a non-collision event such as running off the road is about 1.6×10^{-7} accidents per vehicle mile [Ref. 16]. Accident statistics also indicate that for tank trucks the conditional probability of spill given an accident is about 2 percent [Ref. 17]. Tank truck accidents on highways occur at much higher speeds than would be experienced by resupply trucks on-site and the thick steel pressurized bottles of hydrogen and propane are considered far less likely to rupture than unpressurized tank trucks. As a result the applicable conditional spill probability is estimated at 1 percent. Based on the above, and a one mile round trip truck travel on-site, the annual spill probability is estimated as follows:

Number of trucks carrying hydrogen or propane		18/year
Accident rate	x	1.6×10^{-7} accidents/mile
Conditional spill probability	x	1×10^{-2} spills/accident
Round trip distance of concern	x	1.0 mile

<u>Therefore</u>:

The probability of hydrogen or propane release during resupply by truck	=	2.88×10^{-8}/year

The above estimate is a combined estimate of the probability of release of hydrogen or propane during resupply by truck at HCGS.

3.0 CHANGES/ADDITIONS TO PREVIOUS REPORT

Most of the results provided in Chapter 2 are updated versions of similar results discussed in the earlier ADL report prepared in 1974 [Ref. 1]. These results reflect changes/additions to the data base used in calculating probability values. Also changes in the shipping regulations, and in accident scenarios and their consequences have been taken into account while performing the updated safety analysis. These changes and additions are described in this chapter.

3.1 Updated Data Base

3.1.1 Traffic on Delaware River by Hope Creek

There have been some changes in the quantity of hazardous material traffic past Artificial Island on which the Hope Creek plant is located. The procedure employed in obtaining the data has essentially been the same as that used in the 1974 report by ADL. The following steps summarize this procedure.

- The annual tonnage of most hazardous commodities was obtained from "Waterborne Commerce of the U.S., 1980." [Ref. 7] The values provided in the table titled, "Delaware River, Trenton, N.J. to the Sea (Consolidated Report)", shown partly in Figure 3.1, were adjusted to accommodate internal traffic according to the procedure described in Appendix B of the 1974 report. [Ref. 1] The results of this analysis are shown in Table 3.1.
- The annual tonnage for ammonia was obtained by counting the number of vessels carrying ammonia in the Philadelphia Maritime Exchange register for year 1980 and multiplying that number by the average lot size obtained from the Captain of the Port, U.S. Coast Guard in Gloucester City (near Camden), New Jersey.
- The annual tonnage and number of vessels of butane, butadiene and propane, shown in Table 3.2, were obtained by PSEG from Poten & Partners (a maritime consulting organization) and supplied to us. The detailed breakdown of the LPG shipping is provided in Appendix B.

WATERBORNE COMMERCE OF THE UNITED STATES, 1980

PHILADELPHIA, PA., DISTRICT

DELAWARE RIVER, TRENTON, N. J., TO THE SEA
(CONSOLIDATED REPORT)

COMPARATIVE STATEMENT OF TRAFFIC

YEAR	TONS	PASSENGERS	ADDITIONAL TRAFFIC: RAILROAD FREIGHT CARS, EMPTY	ADDITIONAL TRAFFIC: RAILROAD FREIGHT CARS, LOADED	ADDITIONAL TRAFFIC: AUTOMOBILES ACCOMPANYING PASSENGERS	YEAR	TONS	PASSENGERS	ADDITIONAL TRAFFIC: RAILROAD FREIGHT CARS, EMPTY	ADDITIONAL TRAFFIC: RAILROAD FREIGHT CARS, LOADED	ADDITIONAL TRAFFIC: AUTOMOBILES ACCOMPANYING PASSENGERS
1971--	123,343,497	4,276,829	4,743	4,480	1,137,469	1976--	133,696,091	1,140,723	2,872	3,583	171,530
1972--	127,207,707	4,675,914	4,814	4,742	1,291,230	1977--	133,276,227	1,175,525	1,529	2,513	181,508
1973--	139,297,118	6,013,115	5,532	5,685	1,758,940	1978--	132,438,907	1,282,649	1,616	1,693	214,988
1974--	147,673,521	1,813,120	5,053	4928	224,705	1979--	140,463,460	1,443,570	783	938	203,936
1975--	12[illegible],819,164	1,575,524	4,063	3,987	143,063	1980--	119,349,114	1,426,211	393	418	236,261

FREIGHT TRAFFIC, 1980

OCEANGOING

(SHORT TONS)

COMMODITY	TOTAL	FOREIGN: IMPORTS	FOREIGN: EXPORTS	FOREIGN: THROUGH UPBOUND	FOREIGN: THROUGH DOWNBOUND	DOMESTIC COASTWISE: RECEIPTS	DOMESTIC COASTWISE: SHIPMENTS	DOMESTIC COASTWISE: THROUGH UPBOUND	DOMESTIC COASTWISE: THROUGH DOWNBOUND
TOTAL	93,905,786	56,039,246	6,684,874	1,946,042	2,952,737	10,848,174	9,094,549	2,807,150	3,532,928
0101 COTTON, RAW	363	-----	363	-----	-----	-----	-----	-----	-----
0103 CORN	2,643,100	-----	1,274,741	-----	1,368,359	-----	-----	-----	-----
0104 OATS	7	-----	-----	-----	7	-----	-----	-----	-----
0105 RICE	1,910	-----	1,910	-----	-----	-----	-----	-----	-----
0107 WHEAT	288,578	-----	254,037	-----	34,541	-----	-----	-----	-----
0111 SOYBEANS	578,651	-----	124,601	-----	454,050	-----	-----	-----	-----
0119 OILSEEDS, NEC	218	41	177	-----	-----	-----	-----	-----	-----
0121 TOBACCO, LEAF	18,555	18,435	94	-----	-----	26	-----	-----	-----
0129 FIELD CROPS, NEC	25,132	25,056	71	-----	5	-----	-----	-----	-----
0131 FRESH FRUITS AND TREE NUTS	147,542	18,668	200	128,144	-----	221	-----	381	-----
0133 COFFEE	987	974	13	-----	-----	-----	-----	-----	-----
0134 COCOA BEANS	48,250	40,821	323	5,602	-----	1,604	-----	-----	-----
0141 FRESH AND FROZEN VEGETABLES	2,236	1,290	771	175	-----	-----	-----	-----	-----
0151 LIVE ANIMALS	48	-----	-----	-----	-----	48	-----	-----	-----
0161 ANIMALS AND PRODUCTS, NEC	6,082	2,502	3,278	294	2	24	-----	2	-----
0191 MISCELLANEOUS FARM PRODUCTS	51	47	-----	4	-----	-----	-----	-----	-----
0841 CRUDE RUBBER AND ALLIED GUMS	1,831	1,683	112	136	-----	-----	-----	-----	-----
0861 FOREST PRODUCTS, NEC	3,103	2,395	570	67	71	-----	-----	-----	-----
0911 FRESH FISH, EXCEPT SHELLFISH	13,596	12,107	443	1,025	21	-----	-----	-----	-----
0912 SHELLFISH, EXCEPT PREPARED	1,373	1,237	51	12	16	-----	-----	57	-----
1011 IRON ORE AND CONCENTRATES	6,715,333	6,714,993	321	-----	19	-----	-----	-----	-----
1021 COPPER ORE AND CONCENTRATES	40	40	-----	-----	-----	-----	-----	-----	-----
1051 ALUMINUM ORES, CONCENTRATES	39,668	32,794	28	6,841	5	-----	-----	-----	-----
1061 MANGANESE ORES, CONCENTRATES	40,059	40,059	-----	-----	-----	-----	-----	-----	-----
1091 NONFERROUS ORES, CONCENT, NEC	54,105	26,594	15,718	8,710	3,083	-----	-----	-----	-----
1121 COAL AND LIGNITE	3,097,166	-----	2,874,880	-----	91,137	-----	62,526	1	68,622
1311 CRUDE PETROLEUM	46,124,635	42,859,379	-----	289,178	-----	2,468,649	242,674	264,759	-----
1411 LIMESTONE	934,308	626,474	15,966	267,508	24,360	-----	-----	-----	-----
1412 BUILDING STONE, UNWORKED	1,910	-----	1,910	-----	-----	-----	-----	-----	-----
1442 SAND, GRAVEL, CRUSHED ROCK	6,680	31	6,592	-----	57	-----	-----	-----	-----
1451 CLAY	59,085	36,100	22,128	-----	703	-----	-----	134	-----
1471 PHOSPHATE ROCK	4,391	-----	136	4,148	107	-----	-----	-----	-----
1491 SALT	47,327	-----	53	47,274	-----	-----	-----	-----	-----
1492 SULPHUR, DRY	879	-----	879	-----	-----	-----	-----	-----	-----
1493 SULPHUR, LIQUID	6,868	-----	-----	-----	-----	6,868	-----	-----	-----
1499 NONMETALLIC MINERALS, NEC	32,463	31,688	639	99	37	-----	-----	-----	-----
1911 ORDNANCE AND ACCESSORIES	81	17	64	-----	-----	-----	-----	-----	-----
2011 MEAT, FRESH, CHILLED, FROZEN	260,181	236,365	2,246	12,533	7,863	1,112	-----	62	-----
2012 MEAT AND PRODUCTS, NEC	21,381	20,725	434	-----	5	217	-----	-----	-----
2014 TALLOW, ANIMAL FATS AND OILS	17,684	-----	15,716	-----	1,968	-----	-----	-----	-----
2015 ANIMAL BY-PRODUCTS, NEC	340	157	183	-----	-----	-----	-----	-----	-----
2021 DAIRY PRODUCTS, NEC	22,090	20,980	20	-----	-----	1,090	-----	-----	-----
2022 DRIED MILK AND CREAM	2,122	84	1,784	-----	254	-----	-----	-----	-----
2031 FISH AND SHELLFISH, PREPARED	5,533	3,795	32	-----	-----	68	-----	1,638	-----
2034 VEGETABLES AND PREP, NEC	7,676	6,306	748	-----	24	233	-----	365	-----
2039 PREP FRUIT AND VEG JUICE, NEC	101,438	92,264	972	5,427	17	1,562	-----	1,196	-----
2042 PREPARED ANIMAL FEEDS	3,050	1,087	1,541	311	111	-----	-----	-----	-----
2049 GRAIN MILL PRODUCTS, NEC	4,353	747	3,495	-----	-----	-----	-----	111	-----
2061 SUGAR	876,520	697,138	11,415	-----	-----	167,967	-----	-----	-----
2062 MOLASSES	3,396	-----	8	-----	-----	-----	-----	3,388	-----
2081 ALCOHOLIC BEVERAGES	51,906	28,678	896	78	-----	6,024	-----	16,140	90
2091 VEGETABLE OILS, MARG, SHORT	14,348	2,154	157	-----	44	1,517	1,492	7,734	1,250
2092 ANIMAL OILS AND FATS, NEC	673	643	30	-----	-----	-----	-----	-----	-----
2099 MISCELLANEOUS FOOD PRODUCTS	111,220	98,892	8,847	2,602	405	614	-----	460	-----
2111 TOBACCO MANUFACTURES	852	52	689	-----	3	1	-----	107	-----
2211 BASIC TEXTILE PRODUCTS	30,336	11,541	14,978	2,662	128	791	-----	236	-----
2212 TEXTILE FIBERS, NEC	1,735	1,025	22	328	15	205	-----	60	-----
2311 APPAREL	4,464	3,944	507	4	1	-----	-----	8	-----
2411 LOGS	1,405	447	558	286	114	-----	-----	-----	-----
2413 FUEL WOOD, CHARCOAL, WASTES	199	199	-----	-----	-----	-----	-----	-----	-----
2416 WOOD CHIPS, STAVES, MOLDINGS	1,847	1,625	222	-----	-----	-----	-----	-----	-----
2421 LUMBER	259,616	154,144	1,906	83,748	19,818	-----	-----	-----	-----
2431 VENEER, PLYWOOD, WORKED WOOD	99,414	98,770	535	63	-----	-----	-----	46	-----
2491 WOOD MANUFACTURES, NEC	5,647	2,403	3,045	-----	69	94	-----	36	-----
2511 FURNITURE AND FIXTURES	3,481	2,384	909	6	35	62	-----	85	-----
2611 PULP	245	12	233	-----	-----	-----	-----	-----	-----
2631 PAPER AND PAPERBOARD	108,395	73,291	30,607	-----	4,148	14	-----	34	301
2691 PULP AND PAPER PRODUCTS, NEC	4,690	440	4,169	-----	66	-----	-----	5	-----
2711 PRINTED MATTER	3,063	1,088	1,963	2	10	-----	-----	-----	-----
2810 SODIUM HYDROXIDE	174,698	-----	-----	-----	-----	141,410	-----	33,288	-----
2811 CRUDE TAR, OIL, GAS PRODUCTS	33,878	-----	57	-----	-----	14,997	16,151	1,685	-----

Figure 3.1. A Page from the "Waterborne Commerce of the United States, 1980."

TABLE 3.1

CALCULATION OF TRAFFIC PASSING ARTIFICIAL ISLAND DURING 1980 IN MILLIONS OF SHORT TONS

CATEGORY OF TRAFFIC \ HAZARDOUS COMMODITIES	Crude Petroleum	Liquid Sulfur	Benzene and Toluene	Sulfuric Acid	Basic Chemicals & Products	Gasoline	Jet Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Lubricating Oils & Greases	Naptha	Asphalt, Tars and Pitches	TOTAL
Foreign Imports	42.9	-	-	-	0.2	0.2	-	-	-	2,1	0.2	-	0,2	45,8
Foreign Exports	-	-	-	-	0.1	-	-	-	-	-	0.2	-	-	0.3
Foreign Through Upbound	0.3	-	-	-	-	-	-	-	-	0.7	-	-	-	1.0
Subtotal Foreign Traffic Upbound	43.2	-	-	-	0.2	0.2	-	-	-	2.8	0.2	-	0.2	46.8
Subtotal Foreign Traffic Downbound	-	-	-	-	0.1	-	-	-	-	-	0.2	-	-	0.3
Subtotal All Foreign Traffic	43.2	-	-	-	0.3	0.2	-	-	-	2.8	0.4	-	0.2	47.1
Domestic Coastwise Receipts	2.5	0.2	0.1	0.1	0.3	0.8	-	0.1	1.5	4.4	0.4	.3	-	10.7
Domestic Coastwise Shipments	0.2	-	-	-	0.1	3.7	0.2	-	2.0	2.3	0.3	.1	-	8.9
(Less One-Half Westbound Canal Traffic)	-	-	-	-	-	(0.1)*	-	-	-	(0.1)*	-	-	(0.1)*	.3
Domestic Coastwise Through Upbound	0.3	-	-	-	-	0.3	0.1	-	0.2	1.1	0.2	.1	0.2	2.5
Domestic Coastwise Through Downbound	-	-	-	-	-	1.6	0.1	0.1	0.9	0.4	-	-	0.4	3.5
Subtotal Domestic Coastwise Upbound	2.8	0.2	0.1	0.1	0.3	1.1	0.1	0.1	1.7	5.5	0.6	0.4	0.2	13.2
Subtotal Domestic Coastwise Downbound	0.2	-	-	-	0.1	5.2	0.3	0.1	2.9	2.6	0.3	0.1	0.3	12.1
Subtotal All Domestic Coastwise Traffic	3.0	0.2	0.1	0.1	0.4	6.3	0.4	0.2	4.6	8.1	0.9	0.5	0.5	25.3
10% Internal Inbound Downbound	-	-	-	-	-	-	-	-	0.1	0.1	-	-	-	0.2
Internal Outbound Upbound All Crude & 10% Other Traffic	0.6	-	-	-	-	0.1	-	-	0.1	0.1	-	-	-	0.9
Internal Upbound All Crude & 10% Other Traffic	7.4	-	-	-	-	-	-	-	0.1	0.2	-	-	-	7.7
10% Internal Downbound	-	-	-	-	-	-	-	-	-	0.2	-	-	-	0.2
Subtotal Internal Upbound Traffic	8.0	-	-	-	-	0.1	-	-	0.2	0.3	-	-	-	8.6
Subtotal Internal Downbound Traffic	-	-	-	-	-	-	-	-	0.1	0.3	-	-	-	0.4
Subtotal All Internal Traffic	8.0	-	-	-	-	0.1	-	-	0.3	0.6	-	-	-	9.0
TOTAL ALL UPBOUND TRAFFIC	54.0	0.2	0.1	0.1	0.5	1.4	0.1	0.1	1.9	8.6	0.8	0.4	0.4	68.6
TOTAL ALL DOWNBOUND TRAFFIC	0.2	-	-	-	0.2	5.2	0.3	0.1	3.0	2.9	0.5	0.1	0.3	12.8
TOTAL ALL TRAFFIC	54.2	0.2	0.1	0.1	0.7	6.6	0.4	0.2	4.9	11.5	1.3	0.5	0.7	81.4

*Deducted from Coastwise Shipments and Domestic Coastwise Through Downbound to Arrive at Downbound Traffic.

SOURCE: Ref. 7

TABLE 3.2

LPG Shipping through the Delaware River

1980	No. of Ships	Total Tonnage
Butane	9	95,569
Butadiene	12	34,295
Propane	2	45,675
		175,629

1981	No. of Ships	Total Tonnage
Butane	8	78,140
Butadiene	6	37,110
Propane	3	50,631
		165,881

Source: Poten and Partners, Inc. data provided by PSEG. (See Appendix B).

A summary of the hazardous material traffic past Artificial Island is provided in Table 3.3. The average lot size data for most commodities in the table were obtained from the earlier ADL report. Some of the numbers in the table were cross-checked with other sources, and in case of discrepancies the numbers which would overestimate the risk were selected. For example, the U.S. Coast Guard reported the number of LPG ships in the past three years to be:

1980 - 14

1981 - 15

1982 - 4 (as of 11/18/82)

These numbers were slightly smaller than those provided by Poten & Partners. So the Poten & Partners data are used in this report. Similarly, the number of ships classified as carrying oil in the Philadelphia Maritime Exchange Register for 1980 is at least 2058; a large number of entries did not have any commodity identified. This number is lower than 3030 ships carrying oil (crude oil and fuel oil) as per Table 3.3.

The total number of vessels carrying hazardous material past the Artificial Island in 1980 is estimated to be 4089 which is about the same as that estimated for 1972 in the previous ADL report. [Ref. 1]

Looking at the near future, there are no dockets/proposals for construction of an LNG terminal on the Delaware River, according to the Department of Energy, Federal Agency Regulatory Commission. The traffic in general has been reducing in the river; the number of pilot assignments, according to the Pilots Association for the Delaware River and Bay (Capt. Robert W. Baily), has reduced by 15% since mid 1979. However, in the future there may be a substantial increase in the coal traffic. For example, the Conrail facility may be upgraded from 3 million tons per year to 15 million tons per year. According to Capt. Bailey, this coal may be loaded in 40' draft ships in Philadelphia and topped off to a 55' draft by barges accompanying this ship outside the river. Although coal is not a hazardous substance, the increased

TABLE 3.3

Hazardous Material Traffic Past Artificial Island-1980

	Number of Vessels	Average[1] Lot Size (thousands of tons)	Annual[2] Tonnage (millions)
TANKERS			
Foreign Crude Oil	880	49	43.2
Domestic Crude Oil	120	25	3.0
Fuel Oil	650	25	16.4
Gasoline	260	25	6.6
Butane	9[3]	11	0.1[3]
Propane	2[3]	23	0.046
TANK BARGES			
Crude Lighters	1,380	5.8	8.0
Jet Fuel	285	1.4	0.4
Sulfuric Acid	125	0.8	0.1
OTHER			
Ammonia	16[4]	7[5]	0.11
Naptha	230	18	0.5
Benzene & Toulene	10	10	0.1
Liquid Sulfur	20	10	0.2
Basic Chemicals	70	10	0.7
Kerosene	20	10	0.2
Lubricating Oils & Greases	130	10	1.3
Asphalt, Tars & Pitches	70	10	0.7
Butadiene	12[3]	3	0.034[3]

[1] ADL 1974 report. [Ref. 1]

[2] Corps of Engineers, "Waterborne Commerce of the U.S., 1980," Delaware River, Trenton, N.J., to the Sea (adjusted, as shown in Table 3.1).

[3] Poten & Partners (See Appendix B).

[4] Philadelphia Maritime Exchange - 1980 records.

[5] Captain of the Port, U.S. Coast Guard.

traffic of large coal carrying ships and barges will need to be monitored because it can adversely affect the probability of collision.

A survey of the chemical facilities along the Delaware River was conducted by PSEG, as shown in Appendix C. The results of the survey, summarized in Table 3.4, show that only one facility, the Sun Gas Terminals and Storage (PA), Inc., of Wayne, Pennsylvania, anticipates any increase in the traffic of LPG. The amount of increase was, however, not specified.

3.1.2 Accident Data for the Delaware River

The accident data for FY79 and FY80 were obtained by analyzing the 1982 version of the U.S. Coast Guard Marine Casualty Computer tape. The accident files for each incident thus identified were examined by PSEG to remove those incidents which are not applicable because they involved small vessels which are not representative of large ships under consideration [Ref. 4]. Table 3.5 shows the serial numbers of all applicable collisions in the Delaware River in the following seven categories:

1. Meeting situation
2. A crossing situation
3. An overtaking situation
4. An anchored or moored condition
5. Fog
6. Docking or undocking operations
7. Not otherwise classified.

We identified, at the same time, all collisions with fixed objects for use in determining the probability of collision with fixed objects in vicinity of the HCGS, as discussed in the next subsection. The serial numbers of these type of collisions are also provided in Table 3.5.

The number of collisions with vessels thus obtained was added to the number for FY69 through FY78, obtained from the PSEG report [Ref. 3] on monitoring of LNG and LPG shipping and construction activities in the Delaware River, November 1980, to give the total number of collisions with vessels over the years 1969-1980:

TABLE 3.4

Results of a Survey of Chemical Facilities

Capability to receive	Texaco	Sun (Marcus Hook)	Sun (Wayne,PA)	BP*	Getty	Mobil	Cities Services
• Propane	No	Yes	Yes	No	No	No	No
• Butadiene	No	No	No	No	No	No	No
• Butane	No	Yes	Yes	No	No	No	No
• Vinyl Chloride	No	No	No	No	No	No	No
• LNG	No	No	No	No	No	No	No
Ships in 1982	No	One LPG 50M DWT	No	No	No	No	No
Plans	None	None	Increase	None	None	None	None

* Both Marcus Hook, PA and Paulsboror, NJ.

Source: PSEG Survey.

TABLE 3.5

Serial Numbers of Accidents of Interest in FY79-FY80

Collision with Another Vessel

FY79	FY80
91724	02782
92484	03404
92579	03842
94593	05160
94671*	

Collision with Fixed Object

FY79	FY80
91788	02412
92596*	02418**
93174**	02709
94601**	03630
94606**	03827
	04975
	05148
	05150

*Collision in fog

**Involved moored ship

Source: U.S. Coast Guard Marine Casualty Computer Tape, 1982.

Number of collisions in FY79-FY80	9	
Number of collisions in FY69-FY78	21	(including accidents involving moored ships)
Total number of collisions	30	

The shipping activity in the river was quantified in terms of number of one-way trips. For years 79-80, the total number of one-way trips of tankers, dry cargo and passenger ships of greater than 18 ft. draft was 14,498, according to the Waterborne Commerce. Since 94,665 cumulative trips were made in years 69-78, (the PSEG Report, Nov. 1980), the total number of one-way trips in the period covered (1969-80) was 109,163. The cumulative collision rate, assuming that the river is about 100 miles long, can then be calculated as:

$$\text{Collision rate per ship-mile} = \frac{30}{109{,}163 \times 100}$$

$$= 2.7 \times 10^{-6}$$

This number is used in calculating the probabilities of various ship related accidents in Section 2. The collision rate for a ship carrying LPG will be slightly smaller than this (i.e. 2.3×10^{-6}), because one of the collision incidents included in Table 3.5 occurred in fog, and four incidents in earlier years involved moored ships, both of which are unlikely events for an LPG vessel because of U.S. Coast Guard regulations [Ref. 8].

3.1.3 Rammable Objects in the Vicinity

In order to update the probability of a ship of over 18 feet draft colliding with a rammable object in the vicinity of the Hope Creek Power plant, we performed the following tasks:

- The number of rammable objects in 18 feet or greater depth within the 24 mile zone of interest (12 miles upstream and 12 miles downstream of the plant site) were counted from NOAA Navigational Charts of 1980 [Ref. 9].
- The 24 mile zone of interest, from the Delaware Memorial Bridge South of Wilmington, Delaware to the Ship John Light in the Delaware Bay, was meticulously surveyed by flying over the river in a helicopter.

We found that there are only two rammable objects in the vicinity of the Hope Creek Plant; Tower 97, which is about 9 miles up-river of the Hope Creek Plant and a partially submerged shipwreck about 4.5 miles up-river of the plant.

The NOAA charts show that there are at least 100 rammable objects elsewhere on the Delaware River (including piers and docks) which large ships can strike. The above objects represent just two of them. The probability of a ship striking either of these fixed objects was obtained in the following manner:

- The information on collisions with fixed objects for years 1979 and 1980 was obtained from the U.S. Coast Guard accident casualty data, as shown in Table 3.5.
- The number of one-way trips was obtained from "Waterborne Commerce" as shown below:

TABLE 3.6

Delaware River One-Way Traffic in Tankers, Dry Cargo, and Passenger Ships of Greater than 18 ft Draft

(Source: "Waterborne Commerce")

Year:	1969	1970	1971	1972	1973	1974
One-way trips	9744	10151	9258	9553	9858	9086

Year:	1975	1976	1977	1978	1979	1980
One-way trips	8671	9559	9300	9485	7789	6709

$$\text{Average One-Way Trips} = \frac{109{,}163}{12} = 9100$$

At each one-way trip representing a distance of about 100 miles, the average annual exposure of traffic of large ships on the Delaware River will be 9.1×10^5. As can be seen from the PSEG report of November 1980 [Ref. 3], this figure is almost 4% lower than that two years ago. This reflects a significant drop in traffic in the past two years.

The rate of a ship ramming an object in the vicinity of the power plant can be obtained by:

$$\text{Rate of collision per fixed object per passage} = \frac{\text{No. of collisions with fixed objects in a given period in Delaware River}}{\text{(Number of one-way trips in that period X total number of fixed objects in the river)}}$$

For 1979 - 1980, this number is found to be:

$$\text{Rate of collision} = \frac{13}{14{,}498 \times 100} = 9.0 \times 10^{-6}$$

Using the data provided in PSEG reports [Refs. 3 and 4], the cumulative rate over 1969 - 1980 period is found to be:

$$\text{Rate of collision} = \frac{37}{109{,}163 \times 100} = 3.4 \times 10^{-6}$$

The rate of collision per passage in a catchment area can then be obtained by multiplying the above rate by the number of fixed objects in the catchment distance. The corresponding rates of collision for a ship carrying LPG are lower (i.e. 5.5×10^{-6} and 2.6×10^{-6} respectively) because the collision incidents used in calculating the above numbers include those which involved moored vessels or those which occurred in fog. Due to U.S. Coast Guard regulations, both of these are unlikely events for a ship carrying LPG [Ref. 8].

3.2 Updated Regulations

3.2.1 LFG (Liquified Flammable Gas) Shipment

An updated version of the U.S. Coast Guard Publication titled "Procedures for the Movement of Liquified Flammable Gas (LFG)" was procured from the Captain of the Port of Philadelphia. This publication [Ref. 8] describes the following topics related to LFG shipment:

- General Requirements;
- Vessel Documents;
- Transit Restrictions;
- Anchorage;
- Vessel Transfer Operations;
- Facility Operations; and
- Emergencies.

As we mentioned in one of our earlier reports [Ref. 2], liquefied gas carriers operate in U.S. Coastal Waters under very strict supervision of the U.S. Coast Guard. In the section of river adjacent to the Hope Creek Generating Facility, the tanker will be moving in the channel at all times under Coast Guard escort. In particular, in this section of the river, the liquid gas carrier:

- will not be moored
- will overtake or be overtaken by other ships only in certain areas and only after notifying U.S. Coast Guard
- will not meet other ships at bends
- will meet oncoming ships only if the ground speed of either vessel does not exceed 10 knots
- will not itself exceed the speed of the U.S. Coast Guard escort vessel
- will only transit if visibility is two miles or greater
- will only transit with tug escort
- will be in continuous communications on two radio channels
- will be U.S. Coast Guard supervised
- will be required to ensure that the vessel and its machinery, all cargo handling equipment, and gas detection equipment are in proper operating condition. If no such message is sent, the ship will be boarded by the Coast Guard for inspection of vessel's seaworthiness.

These regulations differ a little from those provided in the previous report:

- Southbound vessels are allowed to overtake in Liston Range north of buoy "N34" which is in vicinity of the Hope Creek Plant
- Instead of a restriction on the relative speed with respect to an oncoming ship, the new regulation restricts the speed of both ships
- The new regulation restricts the speed of the LFG ship to that of the U.S. Coast Guard escort vessel instead of 12 knots as was reported earlier

These changes are not expected to change the method employed in calculating the probability of an LPG tanker having an accident and that of a flammable vapor cloud affecting the HCGS.

3.2.2 Explosive Anchorage

The nautical chart for the Delaware River in the vicinity of the Hope Creek Plant provided by NOAA, (Chart No. 12311, 1980), shows an explosive anchorage, called Explosives Anchorage 2, next to Artificial Island. According to the U.S. Coast Guard, this anchorage has not been used in recent years. Also, as shown in Appendix D, a request has been filed in the Federal Register of September 27, 1982, to prohibit ships carrying explosives to anchor at Anchorage 2. Thus, this potential source of risk will be eliminated.

3.3 Updated Accident Consequences

3.3.1 Intake Blockage

The analysis on blocking of the intake structure provided in the 1974 ADL report [Ref. 1, Chapter 6 and Appendix 6] was updated to reflect:

- a reduction of service pumps from 8 to 4
- a design low-low water elevation of 76.0 ft.
- additional information on the performance characteristics of the water pumps

- revised criteria regarding water flow rates for safe plant operations

The results are expressed in terms of the minimum allowable unobstructed cross sectional area for flow (A_1) and, its equivalent, the maximum tolerable fractional blockage (MTFB) of the unobstructed cross sectional flow area at the access to two bays (360 ft^2) under normal operating conditions for safe, reliable pump operation at the flow rate conditions established. The table below summarizes these results:

Criteria	$A_1 (ft^2)$	MTFB
2 operating pumps @ 16,500 gpm/pump = 33,000 gpm	14.3	0.960
4 operating pumps @ 16,500 gpm/pump = 66,000 gpm	28.5	0.921

The main difference between the current calculated results and those made previously derive from the fact that the net positive suction head (NPSH) requirement of the pump (21 ft at rated flow rate) does not provide the ultimate limit to safe, reliable operation. Rather the appropriate criterion is a water level at the pump inlet sufficient to keep the plane of the bellmouth submerged. A minimum depth of submergence of 1.75 ft has been assumed in the above results. The revised analyses and calculations in support of the results presented is provided in Reference 10.

In the above analysis, two cases have been considered; only two pumps operating and all four pumps operating. Under normal circumstances, the HCGS can operate and reach cold shut-down with only two pumps operating because the cooling tower can provide additional cooling. Thus, a potential risk will be posed only if a barge or a ship blocks more than 96% of the intake area. In an extraordinary situation in which the plant is experiencing an emergency which prevent the cooling tower from operating, at the same time as when blocking occurs, a hot shut-down will be necessary, and all four pumps will be required to operate. In that case, the maximum allowable blocking will be 92.1% of the intake area. However, such coincidences are considered unlikely.

As mentioned in the 1974 report [Ref. 1], the degree of blockage of the intake area would require a vessel, the draft of which is equal to or shallower than the water level at the intake structure, to penetrate up to the intake structure without grounding on the dredged side slopes, turn parallel with the intake opening, and in the case of those vessels with drafts shallower than the water depth, sink immediately in front of and close up against the intake opening. This would be impossible because:

- A conventionally-shaped ship has sufficient curvature at the bow and stern not to block so much of the intake area
- A barge usually has flat rectangular sides, but it has to be shorter than 125 ft to be able to maneuver into an appropriate position, and longer than 90 ft to block three of the four intake bays. To our knowledge, no barge operating in the Delaware River meets these size restrictions. [Ref. 1]

In the previous report [Ref. 1], we had mentioned two design features of the intake structure which would essentially preclude the possibility of blockage under any conceivable situation. These design features are the fish escape area and the marine dock bumper. According to PSEG [Ref. 11], the current design incorporates the fish escape area and dolphins (made of wood) located about 2 ft from the inlet. Thus, the argument against the blockage of inlet presented in the earlier report is still valid.

3.3.2 Ramming of the Intake Structure

In order to update the analysis performed in the earlier ADL report to estimate the effects of a ramming ship on the intake structure, we studied the most recent river bathymetry and NOAA charts [Refs. 12 and 9 respectively] in vicinity of the structure and calculated the closest distance a ship could come before grounding. The method followed was essentially the same as the outlined in Appendix 4 of the earlier report [Ref. 1].

Tables 3.7 and 3.8 summarize the results of the analysis performed for mean low water condition. The tables show that, irrespective of the mechanism considered in estimating the grounding distance, a ship with a displacement of 2,000 tons or more would get grounded at least 400 ft.

TABLE 3-7

Transit Length in Grounding by Vertical Translation

Ship Displacement (Tons)	Estimated Speed (Knots)	Draft (Ft.)	Transit Length in Grounding-d (Ft.)	Distance From Intake (Ft.)	d/L
2,000	10	12	445	450	1.85
5,000	9	16	361	900	1.13
10,000	8	20	285	1,300	0.71
20,000	7	25	436	3,500	0.87
40,000	6	32	320	5,200	0.50
80,000	5	40	222	6,800	0.28

L = ship length.

TABLE 3.8

Transit Length in Grounding by Displacement of Bottom Material

Ship Displacement (Tons)	Estimated Speed (Knots)	Draft (Ft.)	Transit Length in Grounding-d (Ft.)	Distance From Intake (Ft.)	d/L
2,000	10	12	362	540	1.50
5,000	9	16	398	900	1.24
10,000	8	20	410	1,200	1.02
20,000	7	25	559	3,440	1.18
40,000	6	32	563	4,950	0.88
80,000	5	40	562	6,440	0.70

L = Ship length.

from the intake structure. These vessels would be able to reach the structure at higher water levels, but, as argued in the earlier report [Ref. 1, Subsection 6.3], even large vessels may not be able to damage the structure to an extent that would cause blockage. In collisions of two bodies with very different relative strengths, the weaker body absorbs most of the energy. Consequently, the vessel will get damaged much more severely than the intake structure. And, since the extent of blockage required to harm the functioning of the plant is so large (96% as calculated in the earlier subsection), that the resulting rubble and debris from structural failure and deformation of vessel components will not be able to preclude safe operation of the plant.

3.3.3 Vapor Dispersion

The original downwind hazard zone estimates made for evaluating potential risks to the HCGS from an LPG carrier accident in the Delaware River are now considered conservative. As summarized in Appendix A, more recent advances, both from more realistic heavy gas dispersion modeling and experimental observations, indicate that, for larger spills, gravity spreading will produce a wider vapor cloud which will disperse in shorter downwind distance. At the present time, data are not available on a large enough scale to distinguish between the several different models currently being used for hazard zone prediction. However, all acceptable models suggest that maximum down wind hazard zones from "worst case" large spill of liquified gas on water will be in the range of 2-11 miles. Therefore, the catchment distance of 22 miles (2 x 11) used in estimating the possibility of a flammable vapor cloud reaching the HCGS site is quite conservative.

3.4 Storage and Transport of Chemicals On Site

The major hazards that may result from accidental spills of chemicals stored and transported on site are as follows:

- Explosion and flammability hazards resulting from release of hydrogen and propane;
- Thermal radiation hazard resulting from fuel oil spills; and

- Toxic vapor dispersion hazard due to spills of sulfuric acid and sodium hypochlorite.

In the following sections, we have given a brief discussion of hazard assessment models used to determine the consequences of accidental release of chemicals stored and transported on site.

3.4.1 Explosion Hazard

An explosion is the sudden release of pressure without regard to the source. The resultant pressure discontinuity or shock wave moves away from the source at a rate determined in part by the pressure differential and in part by the properties of the material through which it propagates. The pressure differential across the shock and the wind generated by the blast produces an unbalanced force when the wave passes a target. The biological and structural damage from an explosion can be estimated by computing the instantaneous overpressure created by explosion.

In the event of a highly unlikely blast which is modeled as an equivalent low yield detonation, one can express the energy released as a TNT equivalent charge, and thus utilize the extensive overpressure data available for TNT explosions. This is accomplished first by comparing the energy released by unit mass of a vapor cloud with that of unit mass of TNT, while taking into consideration that only 2% to 10% of the cloud will detonate (because of the narrow detonability limit of most gases in air). Secondly, we utilize the overpressure data compiled from measurements on TNT explosions, given as a function of an appropriately scaled distance. The distance at which a specified overpressure is produced is computed using the following equation:

$$D = D_S W^{1/3} \tag{3.1}$$

where D_S = scale distance for specified overpressure

W = TNT equivalent charge

Utilizing this method, we can obtain good estimates of the overpressure experienced in the far field. The far field region is of greater interest to us because a small pressure rise may be sufficient to cause failures of buildings and structures. The overpressures obtained using this procedure in the near field would be overestimated.

Hydrogen is stored in twelve bottles of 56 cubic foot capacity under a pressure of about 2000 psig. These bottles are installed horizontally in three separate manifolded banks located outside the turbine building. Accidental releases of hydrogen pose both explosion and flammability hazards. The hazard distances for our explosion of hydrogen contained in a single bottle are indicated in Table 3.9. Also indicated in Table 3.9 is the type of structural damage experienced by a specified overpressure. It is seen that an overpressure of about 3 psi (sufficient to cause structural damage to concrete structures) can be generated at distances of about 43 ft from the source. Overpressure of 0.5 psi can be experienced at distances of about 168 ft from the source.

Propane is stored in a 47 gallon capacity container outside the auxiliary boiler building. It is estimated that the maximum quantity of propane stored is about 200 lbs. The explosion hazard distances for an instantaneous release of 200 lbs of propane are also indicated in Table 3.9. An overpressure of about 3 psi can be experienced at distances of up to 60 feet. Since the auxiliary boiler building is in the immediate vicinity of the propane tank, severe structural damage to the building walls can be expected.

3.4.2 Thermal Radiation Hazards

There are two sources of thermal radiation hazard. Upon immediate ignition, hydrogen can burn in the form of a rising fireball and radiate thermal energy to the surrounding objects. A spill of fuel oil, upon ignition, can result in a large pool fire. In order to determine thermal radiation hazards, the size, shape and thermal radiation characteristics of the resulting fires must be determined. Further, a criterion must be established to determine the damage resulting from thermal radiation.

The thermal radiation from a fire may cause burns on bare skin if the intensity of radiation is sufficiently large and if the exposure is

TABLE 3.9

EXPLOSION HAZARD DISTANCES

Overpressure (psi)	Structural Damage	Distance from the center of explosion (ft)	
		Hydrogen	Propane
15	Severe structural damage (Nearly 90%)	18	23
5	Shattering of non-reinforced concrete walls, 8 to 12 inches thick	29	43
3	Concrete cinder block failure	43	59
1	Failure of wood siding panels	92	126
0.5	Shattering of glass windows	168	235

of sufficient duration. Burns caused by the heat from fires are commonly classified as first, second, and third-degree burns. The first-degree burns involve only the outer layer of the skin and are characterized by abnormal redness. Second-degree burns penetrate more deeply into the skin and produce blisters. Third-degree burns are the most severe, and penetrate down to the subcutaneous fat, causing permanent tissue damage.

In general, damage to skin exposed to thermal radiation depends on the intensity and duration of exposure to the radiation. The data of Buettner [Ref. 13] obtained by having volunteers expose their forearms to varying degrees of thermal radiation indicate that threshold pain is felt by human beings when the average temperature of 0.1 mm depth of skin increases to 45°C. Buettner's data for severe pain can be correlated with reasonable accuracy by:

$$T_P = (35/I)^{4/3} \qquad (3.2)$$

where T_P = time for feeling severe pain in seconds
I = intensity of thermal radiation, kW/m^2

Mehta, Wong, and Williams [Ref. 14] concluded that the severity of the burn depends on the energy absorbed after the skin surface has reached a temperature of 55°C. Mehta et al also indicated that irreversible damage occurs to the skin protein collagen when 80 kJ/m^2 of energy is absorbed after the skin surface temperature reaches 55°C. Buettner's data for severe pain and for Mehta et al's data for severe burns are indicated in Table 3.10 for various intensities of steady state thermal radiation. In obtaining the results of Table 3.10, no allowance was made for protection of the skin by clothing, nor for the skin being cooled by convection due to wind or motion and perspiration. For times of exposures greater than about 100 seconds, the natural cooling will be significant, and, therefore, the time for burns will be longer than those indicated in Table 3.10.

The United States Federal Safety Standards for Liquefied Natural Gas Facilities (49 CFR, Part 193, 1980) suggest an acceptable level for human direct exposure to thermal flux of 1600 Btu/hr ft^2 (5.0 kW/m^2).

TABLE 3.10

TIMES FOR SECOND-DEGREE BURN INJURY

Intensity of Radiation kW/m^2	Btu/hr ft^2	Time for Severe Pain[1] Seconds	Time For Severe Burn[2] Seconds
1	300	115	663
2	600	45	187
3	1,000	27	92
4	1,300	18	57
5*	1,600	13	40
6	1,900	11	30
8	2,500	7	20
10**	3,200	5	14
12	3,800	4	11

[1] See Buettner [Ref. 13]

[2] See Mehta [Ref. 14]

* Criteria chosen for injury

** Criteria chosen for fatality

At this level, exposure time on bare skin before unbearable pain is about 13 seconds and second-degree burns may occur in about 40 seconds.

The level at which "fatality" is likely to occur is difficult to define. At a flux level of 3200 Btu/hr ft^2 (10 kW/m^2), second-degree burns occur after about a 10-15 second exposure of bare skin. In our hazard assessment, we are using 3200 Btu/hr ft^2 level as the criterion for "fatality".

The effect of radiant heat on human skin has been adequately documented for the case of exposure to a steady state flux in the previous section. In a steady state thermal radiation, the duration of exposure is the only relevant parameter. For rapidly changing thermal flux (such as the radiation from a rising fireball), the duration of exposure is only a few seconds and the definition of a hazardous exposure zone requires a detailed examination of the temperature response of the human skin.

The effect of a thermal dose on human skin is to bring about a thermal denaturation of skin proteins in the epidermis, or outer layer and to destroy the cell structure and collagen protein in the underlying dermis layer. The severity of the burn depends on the extent of destruction of the tissues. A "Critical Energy Model" was developed to correlate the results of experimental data on pig skin, and it has been verified on human tissue.

The critical energy model assumes that the severity of the burn depends upon the amount of energy that is absorbed by the skin after the surface temperature reaches 55°C. If the amount of excess energy is 40 kJ/m^2, pain or mild second-degree burns will be experienced. For an additional exposure of 80 kJ/m^2 or more, a blister or severe second-degree burn will become evident. Finally, for an exposure of greater than 160 kJ/m^2, severe third-degree burns will result in permanent injury. By computing the time history of the incident thermal radiation and coupling it with the temperature response of the human skin, the extent of the damage may be determined.

An unconfined volume of an initially pressurized flammable gas (such as hydrogen or propane), if ignited, can burn as an unsteady turbulent diffusion flame in which buoyancy is induced by the burning process. In case of hydrogen, the existing buoyancy is enhanced by the burning process. The ambient air is entrained at the edges of the burning cloud and thus increase the size of the cloud. The cloud also rises en masse because of buoyancy induced forces. This type of burning of unconfined vapor clouds is called a "fireball". The duration of the fireball is typically of the order of seconds because of rapid mixing with surrounding air. However, during this short duration, the objects and personnel in the vicinity of the fireball are subjected to intense thermal radiation. We have used the unsteady thermal radiation criterion to determine the thermal radiation hazards posed by accidental release of hydrogen stored under pressure.

Our calculations indicate that the maximum diameter of the fireball resulting from the failure of a single hydrogen bottle is about 33 ft. The fireball reaches a height of about 55 ft and the duration of combustion is about 11 seconds. The thermal radiation hazards for serious burn injury extends to about 25 ft from the location of the release. Personnel in the immediate vicinity of the fireball are likely to be fatally injured.

The maximum diameter and the maximum height of a propane fireball are 92 feet and 153 feet respectively. The duration of burning is about 10 seconds. The thermal radiation hazards for serious burn injury extends to about 40 feet from the location of release. Personnel in the immediate vicinity of the fireball are likely to be fatally injured.

The fuel oil tank is located in a dike. Any inadvertant spill of fuel oil will be confined by the dike. An ignition is likely to result in a pool fire of dimensions equal to those of the dike. The thermal radiation hazards can be determined using a solid flame radiation model. Our calculations indicate that the thermal radiation hazards for serious burn injuries are limited to about 30 ft from the dike edge. The zone for fatal burn injuries is limited to the immediate vicinity of the fire.

3.4.3 Vapor Dispersion Analysis

In the absence of immediate ignition, the released hydrogen will disperse in the atmosphere. The extent of dispersion will depend upon the atmospheric stability, wind speed and the source release rate. In case of hydrogen, buoyancy will give rise to a significant plume rise and thus will affect dispersion. At lower wind speeds, the plum rise will be higher.

The plume rise is given by [Ref. 15].

$$Z(X) = 1.6\ F_p^{\,1/3}\ U_w^{\,-1}\ X^{\,2/3} \qquad (3.3)$$

where F_p = initial buoyancy flux

= $Vg\Delta/\pi t$

V = initial volume of gas

t = duration of release

g = acceleration due to gravity

Δ = $1 - \rho_v/\rho_a$ = density defect

U_w = wind speed

X = downwind distance

If we assume that the hydrogen contained in a single bottle is released instantaneously (say in 1 second) and the wind speed is 4.5 mph, equation (3.3) will predict that the puff of hydrogen will rise to the following heights:

downwind distance	150 ft	height	160 ft
downwind distance	300 ft	height	260 ft
downwind distance	500 ft	height	380 ft

The dispersion of the instantaneously released puff is given by

$$C_c = \frac{2Q_T}{(2\pi)^{3/2}\ \sigma_x\sigma_y\sigma_z}\ e^{-1/2\left[\frac{Z(x)}{\sigma_z}\right]^2} \qquad (3.4)$$

where C_c = maximum ground level concentration

Q_T = released mass of hydrogen

$\sigma_x, \sigma_y, \sigma_z$, = dispersion coefficients in axial, lateral and vertical directions

Our calculations indicate that the maximum ground level concentrations are well below the lower flammability limits (4% by volume for hydrogen) for both near neutral and stable atmospheric weather conditions.

Propane is stored under a pressure of about 8 atmospheres. Sudden release of pressure (tank rupture) will result in a flash vaporization. Nearly 37% of the 200 lbs propane stored in the tank will vaporize instantaneously. The vigorous boiling process will also result in the entrainment of the remaining liquid fraction into the vapor cloud. The initial density of the vapor cloud is much greater than that of ambient air and therefore the dispersion is dominated by the gravitational effects.

The lower flammability limit for propane is 2.1% by volume. Since gravitational effects dominate the dilution process, the dispersion of the vapor cloud will take place at ground level. Our calculations indicate that a concentration of lower flammability limit is reached at a downwind distance of 220 feet. The maximum radius of the vapor cloud is about 100 feet and occurs at a downwind distance of 120 feet.

Sulfuric acid and sodium hypochlorite are nonflammable. Therefore, spills of these chemicals will result in an evaporating pool and represent a toxic vapor dispersion hazard. A 5000 gallon spill of these chemicals will result in a pool of approximately 200 ft in diameter. The dispersion of emanating vapors is governed by the prevailing wind speed and atmospheric stability conditions.

The vapor pressure of sulfuric acid is about 0.001 mm of mercury. Therefore, a 200 ft diameter pool of sulfuric acid will result in a source strength of about 1.5 lb/hr at a wind speed of 11 mph and less than 1 lb/hr at a wind speed of 4.5 mph. The immediately dangerous to life and health (IDLH) level for exposure to sulfuric acid fumes is 2 mg/m^3. The dispersion distances extend to about 15 ft from the pool under neutral weather conditions and to about 50 ft under stable weather conditions.

The vapor pressure of sodium hypochlorite is lower than that of sulfuric acid. Further, sodium hypochlorite vapors do not present short-term inhalation hazards. However, contact with liquid sodium hypochlorite can cause severe irritation to skin and eyes. Therefore, the exposure hazard to the spill is limited to the pool size.

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APPENDIX A

DOWNWIND TRAVEL OF VAPORS FROM LARGE SPILLS OF LNG AND LPG ON WATER; CURRENT STATUS OF PREDICTIVE MODELS

1. Background

In 1974, an evaluation was made concerning the potential risks to the PSE&G nuclear power plant from proposed large scale shipping operations of LNG and LPG on the Delaware River. The assessment looked at a series of "worst case" scenarios. These included consideration of a spill of 25,000 m^3 of LNG, instantaneously, onto water. This scenario is based on catastrophic failure of one tank of a 125,000 m^3 LNG carrier - the largest such ship anticipated. The resultant flammable vapor cloud was assumed to travel downwind, toward the power station. Stable atmospheric conditions and low wind speeds (the worst condition for dispersion by atmospheric turbulence) were also assumed. If the vapor were still in the flammable range when the power station was reached, a potential hazard was assumed present.

The original distance estimate was based on a "point source" model and, for the worst case described, a maximum travel distance of 22 miles was predicted. The "point source" model was selected since it was known to be "conservative"; that is, to overpredict downwind travel hazard distances.

Since the original estimates were made, considerable effort has been expended by a number of researchers to develop more realistic models and a number of LNG spill and dispersion experiments have been conducted in spill sizes up to about 40 m^3 of LNG. This report summarizes the impact of this more recent work on the original estimate.

2. Review of Improved Models

2.1 Point Source Model[1]

The original classical point source model assumed that the total quantity of LNG spilled vaporized instantly and emanated from a point in the center of the spill. The vapor cloud thus formed then was carried downwind in the x-direction at wind speed, u, and the concentrations in the cloud varied in space (relative to the origin) and time (from the instant of spill) as

$$C(x,y,z,t) = \frac{Q}{(2\pi)^{3/2}\,\sigma_x\,\sigma_y\,\sigma_z} \exp\left\{-\tfrac{1}{2}\left[\frac{(x-ut)^2}{\sigma_x^2} + \frac{y^2}{\sigma_y^2} + \frac{z^2}{\sigma_z^2}\right]\right\}$$

where C = concentration

x,y,z = spatial coordinates

u = wind speed

t = time

Q = total LNG vapor volume generated by spill source

$\sigma_x, \sigma_y, \sigma_z$ = dispersion coefficients based on past experimental observations of dispersion of pollutants.

Since the pollutants are in low concentration, the dispersing material is treated as being of the same density as air.

In this model, the maximum concentration at any downwind distance, x, is

$$C_{Max}(x) = \left[\frac{Q}{(2\pi)^{3/2}\,\sigma_x\sigma_y\sigma_z}\right]$$

At x = 0, σ_x also equals zero and the calculated concentration is infinite. This is physically impossible, but for long distances downwind the model becomes plausible although downwind distances are overestimated to some extent.

2.2 CHRIS Model

The CHRIS model (Chemical Hazard Response Information System) was developed for the U.S. Coast Guard as part of a general hazard assessment program[2]. To make the model more realistic than the point source model, the LNG was assumed to spread and boil as it was spilled. The boiling rate of LNG on water is known fairly well from experiments, and the spreading rate can be modelled using well established theory. For a 25,000 m^3 instantaneous spill, the maximum pool size estimated just before evaporation is complete is about 1250 feet in radius. (Variation in pool radius estimates by all the major researchers [3,4,5] is from 1239 to 1420 feet for this size spill.)

The CHRIS model then employs a vertical point source model which assumes a vertical point source located five pool diameters upwind. The same point source equation, discussed previously, is applied to the vertical source. In the CHRIS model, the concentrations at the spill point are finite and the source has an initial width approximating the maximum liquid pool diameter. The CHRIS model predicts downwind travel distances, under comparable unfavorable weather conditions, of 16.3 miles.

2.3 Analytic Heavy Gas Models

Since cold LNG vapor is heavier than air, the cloud generated from a boiling LNG pool will tend to layer and spread laterally. As the vapors mix with air due to entrainment of air by the spreading motion or by atmospheric turbulent mixing, the relative negative buoyancy difference decreases and gravity spreading effects become negligible. As the cloud approaches neutral buoyancy, mixing by atmospheric turbulence will dominate, and the usual analyses for dispersion of neutrally buoyant pollutants will become applicable.

As an improvement on the simple Gaussian dispersion models, a number of analysts have proposed models where gravitational spreading is included. The Germeles-Drake model[6] assumes initial gravity spreading of a flat cylindrical vapor cloud initially of 100% vapor concentration and of the same diameter as the maximum boiling pool. When spreading velocities become low relative to wind speed, the analysis switches to a conventional atmospheric dispersion model.

A number of models of this type have been proposed. The major such models are those of van Ulden[7], Eidsvik[8], Colenbrander[9] and te Reile[10]. All these models result in vapor cloud contours which are wider near the source (for large spills where gravitational spreading is important; e.g., 25,000 m^3 spills), but result in shorter downwind dispersion distances. For example, the Germeles-Drake model predicts a downwind travel distance of 11.5 miles for a 25,000 m^3 spill of LNG under unfavorable weather conditions.

2.4 "K"-Theory Models

The overall problem of heavy gas dispersion can also be analyzed by starting with the basic differential equations for continuity, momentum and energy. With the incorporation of boundary conditions and some reasonable approximations, these equations can be solved numerically. The first such model was SIGMET[11]. This model predicted relatively short downwind hazard zones for 25,000 m^3 LNG spills. At low wind speeds (4.5 mph), a downwind hazard distance of about 1.1 miles was estimated. However, this model had the characteristic that longer downwind travel distances resulted at higher wind speeds. For example, at a wind speed of 15 mph, the downwind travel is about 2.2 miles.

Since the original SIGMET model was developed, improvements in the model have been made. Current models which are all improvements on the original SIGMET model are SIGMET-N (Science Applications, Inc., LaJolla, California), DISCO and ZEPHYR (Energy Resources Co., LaJolla, California) and MARIAH (Deygon-Ra, Inc., LaJolla, California). All these models give results similar to those of the original SIGMET.

3. An Independent Assessment of Dispersion Models

Havens[12] has conducted a detailed assessment and comparison of the K-theory and several approximate dense gas models. Havens also chaired a recent workshop on heavy gas dispersion which was co-sponsored by the Gas Research Institute and the Massachusetts Institute of Technology[13]. The panel at the workshop included Dr.

Ermak (Lawrence Livermore Laboratory), Dr. Fay (M.I.T.), Dr. Drake (A.D. Little, Inc.) and Dr. McQuaid (U.K. Health and Safety Executive). The audience included a wide spectrum of scientists from government, academia and industry - both U.S. and international. Discussions covered dispersion modelling as well as past and planned experiments for model verification. Recent experiments at China Lake, California and at Maplin Sands, U.K. show important gravity spreading effects. Additional tests to study gravitational spreading are being planned by the U.K. Health and Safety Executive for 1983.

The conclusions of both the original Haven's assessment and of the recent workshop are that, for spills as large as 25,000 m^3 of LNG, gravity spreading effects are of major importance. Consideration of these effects results in a wider dispersing cloud which will be diluted to below the flammable limit in a distance less than for a neutrally buoyant vapor cloud of the same quantity of released material.

While the different models indicate a range of potential hazard zones for poor dispersion conditions, the estimates of the most recent improved models are considerably less than those predicted by point source models and by simplified gravity spread models such as the Germeles-Drake model.

4. Conclusion

The original downwind hazard zone estimates made for evaluating potential risks to the Public Service Electric and Gas Company nuclear power plant due to potential liquefied gas carrier accidents on the Delaware River are now considered to be considerable overestimates of distance. More recent advances, both from more realistic heavy gas dispersion modelling and experimental observations indicate that, for large spills, gravity spreading will produce a wider vapor cloud which will disperse in a shorter downwind distance. At the present time, data are not available on a large enough scale to distinguish between the several different models currently being used for hazard zone prediction. However, all those models, which are accepted in the scientific community, suggest that maximum downwind hazard zones from a "worst case" 25,000 m^3 LNG spill on water will be in the range of 2-11 miles. Therefore, the original hazard studies are expected to be quite conservative; that is, to overpredict the extent of potential hazard.

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APPENDIX B

LIQUEFIED GAS SHIPMENT ON THE DELAWARE RIVER

IN THE YEARS 1980, 1981

POTEN & PARTNERS, INC.

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED
MAR 1 1982
REFER TO FILE
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FILE POT, LNG

February 24, 1982

Mr. Robert P. Douglas
Licensing Manager
Public Service Electric and Gas Company
80 Park Place
Newark, New Jersey 07101

Dear Mr. Douglas,

In accordance with your purchase order of July 2, 1981, please find attached a summary of gas ships transiting the Delaware River during 1981. As was the case in our 1979 and 1980 summaries, the name of the importer of record in many cases was not reported. However, it was our understanding that this is of little significance to you.

The data as reported are believed to be substantially complete. They are based upon official data, corrected where necessary from private correspondence with importers. In some cases, reported volumes are estimated. We cannot guarantee, of course, that no unrecorded ship transits occurred, but believe that in such case the number would be quite small. If you have any questions about the attached report, please do not hesitate to contact us.

A summary detailing the 1982 Delaware River transit of gas vessels will be forwarded you the first week of March 1983. Thank you for the opportunity to participate in these studies.

Sincerely,

POTEN & PARTNERS, INC.

Christine J. Gorzanski

Christine J. Gorzanski

CJG/pr
Att.

711 THIRD AVENUE • NEW YORK, N.Y. 10017 • TELEPHONE: (212) 557-0410
TLX: 222464/420811 • TWX: 710-5813475 • CABLE ADDRESS: POTENTANK

Liquefied Gas Cargos Transiting the Delaware River - 1981

Discharge Date	Quantity (M Tons)	Product	Vessel	Origin	Importer
January					
February					
8	11,350	Propane	Hoegh Sword	Kuwait	Elf/Sun
8	7,650	Propane	Hoegh Sword	Saudi Arabia	MSK/Sun
24	3,200	Butadiene	Garbeta	Netherlands	Exxon
24	5,700	Butadiene	Garbeta	Netherlands	Exxon
24	1,900	Butadiene	Garbeta	United Kingdom	Exxon
24	3,400	Butadiene	Garbeta	France	Exxon
March					
11	6,125	Butane	Katrisa	Venezuela	Gulf Oil
April					
18	10,410	Butane	Mundogas Pacific	Venezuela	Warren
May					
June					
10	3,970	Butadiene	Pascal	United Kingdom	
20	6,777	Butane	Clerk Maxwell	Venezuela	Warren
25	3,019	Butadiene	Nestefox	Terneuzen	

Liquefied Gas Cargos Transiting the Delaware River - 1981 (continued)

Discharge Date	Quantity (M Tons)	Product	Vessel	Origin	Importer
July					
19	20,000	Propane	Monge	Saudi Arabia	Sun
25	4,039	Butadiene	Pascal	Netherlands	Paulsboro
25	1,645	Butadiene	Pascal	Netherlands	
25	1,244	Butadiene	Pascal	Netherlands	Paulsboro
25	1,256	Butadiene	Pascal	Netherlands	
25	1,244	Butadiene	Pascal	Netherlands	
ugust					
iptember					
9	8,245	Butane	Devonshire	Saudi Arabia	Mitsui
15	5,483	Butane	Devonshire	Saudi Arabia	Mitsui
tober					
25	11,631	Propane	Mundogas Pacific	Saudi Arabia	Mitsui
November					
25	13,000	Butane	Mundogas Pacific	Venezuela	Warren
D cember					
10	4,500	Butadiene	Sine Maersk	Netherlands	
12	1,993	Butadiene	Linge Gas	Netherlands	
20	15,000	Butane	Hoegh Skean	Saudi Arabia	Warren
27	13,100	Butane	Luigi Lagrange	Saudi Arabia	Warren

LIQUEFIED GAS CARGO [illegible] DELAWARE RIVER 1980

DISCHARGE DATE	QUANTITY (METRIC TONS)	PRODUCT	VESSEL	ORIGIN	IMPORTER
1/ 8/80	3,167	Butane	Clerk Maxwell	Venezuela	Gulf
1/ 8/80	3,616	Butane	Clerk Maxwell	Venezuela	Gulf
1/20/80	1,857	Butadiene	Pascal	United Kingdom	Exxon
1/21/80	2,319	Butadiene	Pascal	United Kingdom	ICI
1/23/80	7,308	Butane	Lincolnshire	Venezuela	Warren
1/23/80	10,837	Butane	Lincolnshire	Venezuela	Warren
1/14/80	35,605	Propane	Hoegh Sword	Saudi Arabia	Sun
2/ 1/80	8,000	Butane	Gay Lussac	Venezuela	Warren
2/18/80	3,546	Butane	Lucian	Venezuela	Warren
2/18/80	4,489	Butane	Lucian	Venezuela	Warren
2/18/80	6,515	Butane	Lucian	United Kingdom	Warren
3/12/80	2,000	Butadiene	Benghazi	United Kingdom	
3/17/80	2,911	Butadiene	Havfrost	United Kingdom	Exxon
3/16/80	8,692	Butane	Celsius	Venezuela	
4/20/80	605	Butadiene	Bow Elm	United Kingdom	BP Chem.
4/24/80	1,608	Butadiene	Permian Gas	United Kingdom	
4/24/80	2,500	Butadiene	Permian Gas	Netherlands	
4/10/80	3,992	Butadiene	Bow Elm	United Kingdom	BP Chem.
5/ 8/80	12,831	Butane	Discaria	Libya	Warren
5/15/80	2,271	Butadiene	Sunny Duke	United Kingdom	
6/ 9/80	2,263	Butadiene	Sunny Duke	United Kingdom	
8/12/80	847	Butadiene	Nestefox	United Kingdom	
8/12/80	1,041	Butadiene	Nestefox	Netherlands	
8/19/80	3,912	Butadiene	Eirik Raude	Netherlands	MSK
8/28/80	3,172	Butadiene	Benghazi	France	Mitsui
9/12/80	7,057	Butane	Sine Maersk	Venezuela	Warren
9/10/80	2,997	Butadiene	Sofie Maersk	Netherlands	ICI
10/ /80	10,181	Butane	Faraday	Venezuela	Gulf
12/ 6/80	9,330	Butane	Hektor	Venezuela	Lagoven
12/20/80	10,160	Propane	Faraday	Venezuela	

APPENDIX C

CORRESPONDENCE WITH THE INDUSTRIAL FACILITIES ON THE SHORES OF THE DELAWARE RIVER

September 13, 1982

Gentlemen:

The purpose of this letter is to again request your assistance in obtaining certain information needed by Public Service Electric and Gas Company to analyze the shipment of certain types of cargo on the Delaware River. You have previously provided this type of information in your letter to us dated .

Amendment No. 5 to the Hope Creek Construction Permit requires Public Service Electric and Gas Company to monitor LNG and LPG traffic development and construction activity along the Delaware River. These factors might affect the calculated probability of a flammable vapor cloud, due to a LNG or LPG spill, passing over Hope Creek Generating Station. To accomplish this task, PSE&G is trying to develop information relating to facilities on the Delaware River that are capable of receiving shipments of propane, butadiene, butane, vinyl chloride, or liquified natural gas. Hence, we are requesting that you respond to the following questions.

1. Is your facility now capable of receiving ships carrying any of the chemicals mentioned above?

2. How many ships carrying each of the above chemicals have you received in the past year? What was the size of these ships?

3. Do you anticipate any change in the rate at which you receive these chemicals in the future? Is this change the result of a change in total fuel storage capacity or a redistribution of the type of fuel stored?

4. Is there someone, other than yourself, who could be contacted in the future to discuss changes in shipping rates at your facility?

Any information you choose to furnish would be greatly appreciated and would be considered confidential. The information will be used only in summaries of the total number of ships passing by the nuclear facility, and the receiving terminal will not be identified. We would appreciate your acknowledgement of this request and if you would like to discuss this before responding, please do not hesitate to call us.

Very truly yours,

R. P. Douglas
Manager - Licensing and Analysis
Licensing and Environment

FAM:li

M P82 126/07 1/2.1

TEXACO

PETROLEUM PRODUCTS

TEXACO
U.S.A.
A DIVISION OF TEXACO INC.
P.O. BOX 98
WESTVILLE, NJ 08093
609-845-8000

September 21, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. ~~P.~~ DOUGLAS
NOTED
SEP 23 1982
REFER TO FILE (EAM)
DUE
COPIES EAM
FILE

Mr. R. P. Douglas
Manager - Licensing & Analysis
P. S. E. & G.
P. O. Box 570
Newark, NJ 07101

Dear Mr. Douglas:

In response to your inquiry of September 13, 1982, our refining facility located in Westville, NJ does not have and has not had the capability to receive shipments of propane, butadiene, butane, vinyl chloride or liquified natural gas from vessels on the Delaware River. Additionally, at present, we do not have any plans to construct unloading facilities for the above commodities.

Very truly yours,

R J Fischbach
R. J. FISCHBACH
PLANT MANAGER

CTW-KDP

Sun Gas Terminals
and Storage (PA), Inc.
Suite 1204
988 Old Eagle School Road
Wayne PA 19087-4095
215 293 9705

September 20, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD
SEP 23 1982
REFER TO FILE (FAM)
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Mr. R. P. Douglas
Public Service Electric & Gas Company
P. O. Box 570
Newark, NJ 07101

Dear Mr. Douglas:

We are in receipt of your letter dated September 13, 1982, wherein you ask for assistance in obtaining information concerning the shipment of certain types of cargoes on the Delaware River. In your letter you asked specific questions, and the answers to these questions now follow:

1. Our facility is capable of receiving vessels carrying cryogenic propane, cryogenic butane, and split cargoes of both.

2. We did not receive any vessels during 1982.

3. We anticipate an increase in the amount of traffic through our terminal by vessel. This change is a result of new customers we have obtained and the source of their product is not from Delaware Valley.

4. I am the person you should contact both now and in the future to discuss any possible or potential changes in shipping rates at our facility.

Very truly yours,

Ron

Ronald G. Raver
Vice President

/cdc

BP Oil Inc.

P.O. BOX 428, MARCUS HOOK, PENNSYLVANIA 19061

TELEX 83-4720 TELEPHONE (215) 494-3600

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD

SEP 27 1982

REFER TO FILE (FAM)

DUE

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FILE X

September 23, 1982

PSE & G
80 Park Plaza
Newark, N.J. 07101

ATTENTION: R. P. Douglas

Dear Sir:

There have been no changes at the BP Oil Inc. Marcus Hook Refinery Dock Facility since the previous report in my letter dated May 28, 1980.

However, listed below are the responses requested to your questions:

1.) Our facility is not capable of receiving ships carrying Propane, Butadiene, Butane, Vinyl Chloride, or Liquified Natural Gas.

2.) None.

3.) Not applicable.

4.) Capt. James Burroughs, Port Captain of this facility, could be contacted in the future to discuss changes in shipping at our facility.

Also, please note that BP Oil Inc. is the proper identification of our company at this facility.

Very truly yours,

BP OIL INC.

R. S. Yurko

R. S. Yurko
Operations Superintendent

RSY:tz

Getty

Getty Refining and Marketing Company | Delaware City, Delaware 19706 • Telephone (302) 834-6200

R. K. Arzinger, Vice President Manufacturing, Eastern Region

September 20, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD
SEP 28 1982
REFER TO File
[EAM]
DUE
COPIES EAM
FILE X

Mr. R. P. Douglas
Licensing Manager
Licensing and Environment Department
Public Service Electric and Gas Company
80 Park Place
Newark, NJ 07101

Dear Mr. Douglas:

In reply to the questions in your letter of September 13, 1982, the following answers are given:

1. We are not capable of receiving ships carrying shipments of propane, butadiene, butane, vinyl chloride, or liquified natural gas at the Delaware City Refinery of the Getty Refining and Marketing Company.

2. No ships were received carrying the above chemicals in the past year.

3. We anticipate no change in the next year.

4. All inquiries of this nature should be directed through my office.

Sincerely,

R. K. Arzinger

R. K. Arzinger

RKA/sjl

Mobil Oil Corporation

PAULSBORO REFINERY
PAULSBORO, NEW JERSEY 08066

Technical Department
September 24, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD
OCT 5 1982
REFER TO FILE (FAM)
DUE
COPIES FAM
FILE

Mr. R. P. Douglas
Public Service Electric and Gas Company
80 Park Plaza
Newark, New Jersey 07101

0.03 PSE&G HOPE CREEK
NUCLEAR FACILITY

Dear Mr. Douglas:

In response to your September 13, 1982 inquiry, please be advised that the Mobil Paulsboro Refinery does not presently have the capability to receive over-the-water shipments of propane, butadiene, butane, vinyl cloride or liquified natural gas. During the last year, we have not received shipments of any of the above products over our dock.

We do not anticipate any change in this situation in the near future. If we can be of any further assistance, please let us know.

Very truly yours,

Arthur B. Hiser
RAB

Arthur B. Hiser
Refinery Manager

DTJohnston:ajg

PSE&G Public Service Electric and Gas Company

80 Park Plaza, Newark, NJ 07101 / 201 430-7000 MAILING ADDRESS / P.O. Box 570, Newark, NJ 07101

September 13, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD
OCT 6 1982
REFER TO FILE (EAM)
DUE
COPIES EAM
FILE

Cities Services Company
Box 300
Tulsa, Oklahoma 74102

Attn: J. P. Miller

Gentlemen:

The purpose of this letter is to again request your assistance in obtaining certain information needed by Public Service Electric and Gas Company to analyze the shipment of certain types of cargo on the Delaware River. You have previously provided this type of information in your letter to us dated June 2, 1980.

Amendment No. 5 to the Hope Creek Construction Permit requires Public Service Electric and Gas Company to monitor LNG and LPG traffic development and construction activity along the Delaware River. These factors might affect the calculated probability of a flammable vapor cloud, due to a LNG or LPG spill, passing over Hope Creek Generating Station. To accomplish this task, PSE&G is trying to develop information relating to facilities on the Delaware River that are capable of receiving shipments of propane, butadiene, butane, vinyl cloride, or liquified natural gas. Hence, we are requesting that you respond to the following questions.

1. Is your facility now capable of receiving ships carrying any of the chemicals mentioned above? NO

2. How many ships carrying each of the above chemicals have you received in the past year? What was the size of these ships? NONE

3. Do you anticipate any change in the rate at which you receive these chemicals in the future? Is this change the result of a change in total fuel storage capacity or a redistribution of the type of fuel stored? N/A

4. Is there someone, other than yourself, who could be contacted in the future to discuss changes in shipping rates at your facility? TERMINAL MANAGER
P.O. BOX 171
PENNSAUKEN, N.J. 08110

The Energy People

Any information you choose to furnish would be greatly appreciated and would be considered confidential. The information will be used only in summaries of the total number of ships passing by the nuclear facility, and the receiving terminal will not be identified. We would appreciate your acknowledgement of this request and if you would like to discuss this before responding, please do not hesitate to call us.

Very truly yours,

RP Douglas

R. P. Douglas
Manager - Licensing and Analysis
Licensing and Environment

FAM:mw

AA02 1/2

BP Oil Inc.

P.O. BOX 71, PAULSBORO, NEW JERSEY 08066

TELEPHONE: (609) 423-4000 • TWX: (609) 423-2936

PETROLEUM AND CHEMICAL STORAGE

October 4, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED RPD
OCT 18 1982
REFER TO FILE (FAM)
DUE
COPIES FAM
FILE

Public Service Electric & Gas Company
P.O. Box 570
Newark, N.J. 07101

Attention: Mr. R. P. Douglas, Manager

Dear Mr. Douglas:

This is in response to your letter dated September 13, 1982 requesting information to analyze the shipment of certain types of cargo on the Delaware River.

Our facility does not handle any of the chemicals or cargoes mentioned in your letter.

Sincerely

D F Sundberg

D. F. SUNDBERG

TERMINAL SUPERINTENDENT

DFS/jc

Sun Refining and
Marketing Company
P O Box 426
Marcus Hook PA 19061
215 447 1000

October 22, 1982

MANAGER
LICENSING AND ANALYSIS
LICENSING AND ENVIRONMENT
R. P. DOUGLAS
NOTED
OCT 27 1982
REFER TO FILE (FAM to [illegible])
DUE
COPIES FAM
FILE

Mr. R. P. Douglas
Manager-Licensing & Analysis
Licensing & Environment
Public Service Electric & Gas Co.
P. O. Box 570
Newark, NJ 07101

Dear Mr. Douglas:

Ref: RPD:CP, 9/13/82

Our response to the questions asked in your letter pertaining to LNG and LPG activities at our facility on the Delaware River are:

1. Yes - Propane and Butane only.

2. One LPG vessel - 50M DWT.

3. At present time, no.

4. No.

Sincerely,

C. E. Phillips /fh

C. E. PHILLIPS, Supt.
Transfer & Shipping

CEP/fh

APPENDIX D

THE PETITION TO PROHIBIT SHIPS CARRYING EXPLOSIVES TO ANCHOR AT ANCHORAGE 2 specify that appropriate costs and expenses including attorneys' fees may be awarded to the permittee from any person but only if the Council finds that "the person knew or *should have known* that no violation or imminent hazard occurred or existed to support the enforcement action". The stipulation that the person may be assessed costs and expenses if he/she "should have known" that no violation or imminent hazard occurred places a greater burden on a person than the Federal requirements. 43 CFR 4.1294(d) specifies that a person may be assessed costs and expenses only if it is demonstrated that the person acted in bad faith for the purpose of harassing or embarrassing the permittee. Under Wyoming's rule a person acting in good faith who initiated an administrative proceeding to review an enforcement action could be assessed costs and expenses upon a finding that no violation or imminent hazard had occurred. The Secretary finds that to be consistent with the Federal requirements, Wyoming's program must provide that a person may be assessed reasonable costs or expenses only if he/she initiated a proceeding in bad faith.

Because the material submitted by Wyoming does not fully satisfy condition "c" and because OSM has not yet acted on the petition discussed above which may have a bearing on the State's satisfaction of this condition, the Secretary has decided to extend the deadline for Wyoming to meet condition "c" until May 20, 1983. This extension will allow OSM time to act on the petition and allow Wyoming time to submit additional modifications to correct the deficiencies outlined above.

Public Comment

The public comment period on the State's request for an extension to meet condition "c" ended June 25, 1982, and the comment period on the amendments submitted by the State on May 26, 1982, ended August 13, 1982. No comments were received.

A public hearing scheduled for August 11, 1982, on the proposed program modifications was cancelled as no one expressed an interest in presenting testimony.

Additional Determinations

1. *Compliance with the National Environmental Policy Act.* The Secretary has determined that, pursuant to Section 702(d) of SMCRA, 30 U.S.C. 1292(d), no environmental impact statement need be prepared on this rulemaking.

2. *Compliance with the Regulatory Flexibility Act.* The Secretary hereby determines that this proposed rule will not have a signficant economic impact on small entities within the meaning of the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*

3. *Compliance with Executive Order No. 12291.* On August 28, 1981, the Office of Management and Budget (OMB) granted the Office of Surface Mining exemption from Sections 3, 4, 6, and 8 of Executive Order 12291 for all actions taken to approve or conditionally approve State regulatory programs, actions or amendments. Therefore, a Regulatory Impact Analysis and regulatory review by OMB are not needed for this condition removal and extension.

4. *Concurrence of the Environmental Protection Agency.* On August 23, 1982, the Environmental Protection Agency transmitted its written concurrence on the Secretary's approval of the amendatory provisions addressed in this notice.

List of Subjects in 30 CFR Part 950

Coal mining, Intergovernmental relations, Surface mining, Underground mining.

Dated: September 20, 1982.

Daniel N. Miller, Jr.,

Assistant Secretary for Energy and Minerals.

PART 950—WYOMING

Accordingly, Part 950 of Title 30 is amended as set forth herein.

1. 30 CFR 950.10 is amended by revising it to read as follows:

§ 950.10 State program approval.

The Wyoming permanent program, as submitted on August 15, 1970, as amended October 23, 1979, May 30, 1980, and August 5, 1980, was approved effective November 26, 1980. The amendments to the program submitted March 26, 1981 and April 8, 1981, were approved effective February 18, 1982. The amendment to the program submitted May 26, 1982, pertaining to the definition of "toxic materials" is approved effective September 27, 1982. Copies of the approved program, as amended, are available at:

Wyoming Department of Environmental Quality, Land Quality Division, Hathaway Building, Cheyenne, Wyoming 82002.

Office of Surface Mining, Room 5315, 1100 "L" Street, N.W., Washington, D.C. 20240, Telephone: (202) 345-7896.

2. 30 CFR 950.11 is amended by removing the material and reserving paragraph (b), and revising paragraph (c) to read as follows:

§ 950.11 Terms and conditions of State program approval.

* * * * *

(b) [Reserved]

(c) On or before May 20, 1983, Wyoming must establish requirements which are consistent with the Federal attorneys' fees and intervention regulation in 43 CFR Part 4.

* * * * *

[FR Doc. 82-26506 Filed 9-24-82; 8:45 am]

BILLING CODE 4310-05-M

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 110

[CGD3-80-3A]

Anchorage Grounds, Delaware Bay and River

AGENCY: Coast Guard, DOT.

ACTION: Interim rule with request for comments.

SUMMARY: The Coast Guard is delegating the authority over operation of the Delaware Bay and River Anchorages from Commander, Third Coast Guard District to the Captain of the Port, Philadelphia; eliminating provisions redundant with authority provided in 33 CFR Part 160; redesignating Anchorage 2 as a general anchorage and permitting the handling of explosives in all general anchorages except Anchorage 2 by permit from the Captain of the Port; and eliminating the requirement for vessels handling explosives and other dangerous cargo to display a red light at night. The present requirements are cumbersome and inefficient and place unnecessary burdens on the users of the anchorages. This change will provide for more efficient management of the vessels in the anchorages without reducing the level of safety.

DATES: Interim rule effective October 27, 1982, comments must be received on or before November 12, 1982.

ADDRESSES: Comments may be mailed to Captain Daniel B. Charter Jr., Captain of the Port, Philadelphia, U.S. Coast Guard Base, Gloucester City, New Jersey, 08030.

FOR FURTHER INFORMATION CONTACT: Captain Daniel B. Charter Jr., Captain of the Port, Philadelphia, U.S. Coast Guard Base, Gloucester City, New Jersey 08030 (Tel: 609-456-1370 or 215-923-4320) between 7:00 AM and 4:30 PM Monday through Friday, except holidays.

SUPPLEMENTARY INFORMATION: On June 23, 1980, the Coast Guard published a notice of proposed rulemaking, Docket CGD3-80-3A (45 FR 41981). Interested persons were requested to submit comments and two comments were received. No public hearing was held.

Drafting Information: The principal person involved in drafting this rule is Captain Daniel B. Charter Jr., Project Officer, Captain of the Port, Philadelphia.

Discussion of Comments: One of the two comments was from a port affairs spokesman for twenty-one Delaware Valley civic and trade associations. These twenty-one associations represent the vast majority of the public that will be affected by the rule change and their views were considered based on this representation.

Both of the comments agreed with the proposal to transfer authority over the operations of the Delaware River and Bay anchorages from Commander, Third Coast Guard District to the Captain of the Port, Philadelphia. Both also agreed with elimination of the requirement to display the red light at anchor and considered the change a safety enhancement by eliminating the possibility for confusing the red light with a navigation light. No comments were received on the proposal to eliminate the requirements redundant with authority contained in 33 CFR Part 160.

Both comments objected to the redesignation of Anchorage 1 as an explosive anchorage and Anchorage 2 as a general anchorage. They indicated that Anchorage 2 was not an acceptable general anchorage since it could not accommodate deep draft vessels (the primary users of Anchorage 1). Further, they indicated that Anchorage 1 is crucial to and an integral part of the Delaware River navigation system.

The commenter representing the twenty-one civic and trade associations indicated loading or discharging of explosives is a rare circumstance and that the COTP could make the decision with respect to anchorage assignment at the time of application. He also indicated their belief that the provisions of the Ports and Waterways Safety Act provided the necessary authority for the COTP to follow this practice.

The records at the COTP Office in Philadelphia were reviewed and it was found that there were *no* requests for explosive handling by vessels at anchor in the past three years.

The purpose of the amendment as expressed in the NPRM was to reduce the potential hazards caused by the proximity of a nuclear electric generating plant to the explosive anchorage (Anchorage 2). The Coast Guard agrees with the comment that anchorage assignments can be considered at the time an application for explosive handling is received and therefore Anchorage 1 will remain as a general anchorage and Anchorage 2 will be redesignated as a general anchorage. The handling of explosives will be permitted in all general anchorages except Anchorage 2, on a case-by-case basis with a permit from the Captain of the Port as the situation warrants.

One commenter also objected to the proposal to reduce the size of Anchorage 1. The purpose of the reduction in size was to more accurately reflect the area of usable depth. Since the pilots are well aware of the water depths in the area and these are clearly plotted on the charts, it appears there is no practical benefit in reducing the size of the anchorage. Usage will continue to be limited to areas suitable to the draft of the vessels involved: therefore, the present description of the size of Anchorage 1 is retained at this time. However, it is the intent of the Coast Guard to explore better descriptions of the anchorage boundaries in a future rulemaking action.

There were no comments on the proposal to extend to all the general anchorages of the Delaware River the COTP authorization to grant permits for anchoring for periods in excess of 48 hours now limited to Anchorages 15 and 16. This change clarifies the intent of the permit process.

Finally, the citations for Dangerous Cargo regulations have been amended in paragraph 110.157(c). This editorial change reflects the shift of the Dangerous Cargo regulations excluding military explosives from Title 46 Code of Federal Regulations to Title 49 Code of Federal Regulations. Additionally, the term "other dangerous cargo" is being deleted from the regulations for vessels carrying and handling explosives (regulations for explosives anchorage) since the permit required from the Captain of the Port only pertains to explosives.

Summary of Final Evaluation: This amendment has been evaluated under Executive Order 12291 and the Coast Guard has determined that this is not a major rule. This amendment has also been evaluated under the Department of Transportation Order 2100.5, "Policies and Procedures for Simplification, Analysis and Review of Regulations" dated May 22, 1980 and has been determined to be non-significant. This amendment is primarily editorial, updating the regulations to reflect management practices in existence for five years, or merely a redelegation of authority. The impact is considered so minimal that a regulatory evaluation is not required.

Likewise it is hereby certified that this amendment will not have any significant economic impact on a substantial number of small entities, as described in the Regulatory Flexibility Act (Pub. L. 96-354; 5 U.S.C. 601, et seq.). This certification is made in accordance with Section 605 of Title 5 of the United States Code.

List of Subjects in 33 CFR Part 110

Anchorage grounds.

PART 110—ANCHORAGE REGULATIONS

In consideration of the foregoing, Part 110 of Title 33, Code of Federal Regulations is amended as follows:

1. In § 110.157, paragraph (a)(3) is revised to read as follows:

§ 110.157 Delaware Bay and River.

(a) * * *

(3) Anchorage 2 northwest of Artificial Island. On the east side of the channel along Reedy Island Range, bounded as follows: Beginning at a point bearing 105° from the northernmost point of Reedy Island, 167 yards easterly of the east edge of the channel along Reedy Island Range: thence 105°, 800 yards; thence 195°, 4,500 yards; thence 285°, 800 yards, to a point (approximately latitude 39°28'58", longitude 75°33'37") opposite the intersection of Reedy Island and Baker Ranges; and thence 15°, 4,500 yards, to the point of beginning.

§ 110.157 [Amended]

2. Section 110.157 is amended by removing the words "District Commander" and inserting, in their place, the words "Captain of the Port" in the following places: 33 CFR 110.157(a)(16), (a)(17), (b)(1), (b)(3), (b)(7).

3. In § 110.157, paragraph (b)(2) is revised to read as follows:

§ 110.157 Delaware Bay and River.

* * * * *

(b) * * *

(2) No vessel shall occupy any prescribed anchorage for a longer period than 48 hours without a permit from the Captain of the Port. Vessels expecting to be at anchor for more than 48 hours shall obtain a permit from the Captain of the Port for that purpose. No vessel in such condition that it is likely to sink or otherwise become a menace or obstruction to navigation or anchorage of other vessels shall occupy an anchorage except in an emergency, and