PSEG Public Service Electric and Gas Company

80 Park Plaza, Newark, NJ 07101 / 201 430-8217 MAILING ADDRESS / P.O. Box 570, Newark, NJ 07101

Robert L. Mittl General Manager
Nuclear Assurance and Regulation

August 13, 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.

In addition, enclosed for your review and approval (see Attachment 4) are the resolutions to the Draft SER open items, and FSAR question responses listed in Attachment 3. 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 open items, please contact us.

Very truly yours,

R L Mittl

Attachments

B001
1/1

C D. H. Wagner
USNRC Licensing Project Manager

W. H. Bateman
USNRC Senior Resident Inspector

FM05 1/2

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 Hope Creek Generating Station Draft Safety Evaluation Report open item responses and FSAR Question responses.

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
T. J. Martin
Vice President - Engineering
and Construction

Sworn to and subscribed before me, a Notary Public of New Jersey, this 13th day of August 1984.

David K. Burd

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

GJ02/2

DATE: 8/13/84

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	Open	
2a	2.3.3	Accuracies of meteorological measurements	Complete	7/27/84
2b	2.3.3	Accuracies of meteorological measurements	Complete	7/27/84
2c	2.3.3	Accuracies of meteorological measurements	Complete	8/13/84 (Rev. 1)
2d	2.3.3	Accuracies of meteorological measurements	Complete	8/13/84 (Rev. 1)
3a	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/01/84
3b	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Complete	8/01/84 (Rev. 1)
3c	2.3.3	Upgrading of onsite meteorological measurements program (III.A.2)	Open	
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	6/01/84
5b	2.4.5	Wave impact and runup on service water intake structure	Open	
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	6/01/84
6a	2.4.10	Stability of erosion protection structures	Open	
6b	2.4.10	Stability of erosion protection structures	Open	
6c	2.4.10	Stability of erosion protection structures	Complete	8/03/84

M P84 80/12 1-gs

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	Open	
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
23	2.5.4	Clarification of FSAR Tables 2.5.13 and 2.5.14	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	Open	
27	2.5.5	Slope stability	Complete	6/1/84
28a	3.4.1	Flood protection	Complete	7/27/84
28b	3.4.1	Flood protection	Complete	7/27/84
28c	3.4.1	Flood protection	Complete	7/27/84
28d	3.4.1	Flood protection	Complete	7/27/84
28e	3.4.1	Flood protection	Complete	7/27/84
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
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
36	3.6.2	Postulated pipe ruptures	Complete	6/29/84
37	3.6.2	Feedwater isolation check valve operability	Open	
38	3.6.2	Design of pipe rupture restraints	Open	
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	6/1/84
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	6/1/84
46	3.8.5	ACI 349 deviations for foundations	Complete	6/1/84
47	3.8.6	Base mat response spectra	Complete	8/10/84 Rev.1
48	3.8.6	Rocking time histories	Complete	6/1/84
49	3.8.6	Gross concrete section	Complete	6/1/84
50	3.8.6	Vertical floor flexibility response spectra	Complete	6/1/84
51	3.8.6	Comparison of Bechtel independent verification results with the design-basis results	Complete	8/10/84 Rev. 1

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	6/1/84
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	6/1/84
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	6/1/84
60	3.8.6	BSAP element size limitations	Complete	6/1/84
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
64	3.8.6	SSI analysis 12 Hz cutoff frequency	Complete	6/1/84
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	6/1/84
78	3.8.6	Dead load calculations	Complete	6/1/84
79	3.8.6	Post-modification seismic loads for the torus	Complete	6/1/84
80	3.8.6	Torus fluid-structure interactions	Complete	6/1/84
81	3.8.6	Seismic displacement of torus	Complete	6/1/84
82	3.8.6	Review of seismic Category I tank design	Complete	6/1/84
83	3.8.6	Factors of safety for drywell buckling evaluation	Complete	6/1/84
84	3.8.6	Ultimate capacity of containment (m~terials)	Complete	6/1/84
85	3.8.6	Load combination consistency	Complete	6/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
86	3.9.1	Computer code validation	Open	
87	3.9.1	Information on transients	Open	
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
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	6/15/84
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
100b	3.9.6	10CFR50.55a paragraph (g)	Open	
101	3.9.6	PSI and ISI programs for pumps and valves	Open	
102	3.9.6	Leak testing of pressure isolation valves	Complete	6/29/84
103a1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103a7	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103b1	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103b2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103b3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103b4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103b5	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
103b6	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103cl	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103c2	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103c3	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
103c4	3.10	Seismic and dynamic qualification of mechanical and electrical equipment	Open	
104	3.11	Environmental qualification of mechanical and electrical equipment	NRC Action	
105	4.2	Plant-specific mechanical fracturing analysis	Complete	7/18/84
106	4.2	Applicability of seismic andd LOCA loading evaluation	Complete	7/18/84
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	Open	
109b	4.4.7	TMI-2 Item II.F.2	Open	
110a	4.6	Functional design of reactivity control systems	Complete	7/27/84
110b	4.6	Functional design of reactivity control systems	Complete	7/27/84
111a	5.2.4.3	Preservice inspection program (components within reactor pressure boundary)	Complete	6/29/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	7/27/84
112b	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	7/27/84
112c	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	7/27/84
112d	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	7/27/84
112e	5.2.5	Reactor coolant pressure boundary leakage detection	Complete	7/27/84
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	7/18/84
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	Open	
118	5.3.4	Lead factors and neutron fluence for surveillance capsules	Open	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
119	6.2	TMI item II.E.4.1	Complete	6/29/84
120a	6.2	TMI Item II.E.4.2	Open	
120b	6.2	TMI Item II.E.4.2	Open	
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
124a	6.2.1.5.1	RPV shield annulus analysis	Complete	6/1/84
124b	6.2.1.5.1	RPV shield annulus analysis	Complete	6/1/84
124c	6.2.1.5.1	RPV shield annulus analysis	Complete	6/1/84
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)	Open	
126b	6.2.1.6	Redundant position indicators for vacuum breakers (and control room alarms)	Open	
127	6.2.1.6	Operability testing of vacuum breakers	Complete	7/18/84
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	6/29/84
131	6.2.3	Administration of secondary containment openings	Complete	7/18/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
132	6.2.4	Containment isolation review	Complete	6/15/84
133a	6.2.4.1	Containment purge system	Open	
133b	6.2.4.1	Containment purge system	Open	
133c	6.2.4.1	Containment purge system	Open	
134	6.2.6	Containment leakage testing	Complete	6/15/84
135	6.3.3	LPCS and LPCI injection valve interlocks	Open	
136	6.3.5	Plant-specific LOCA (see Section 15.9.13)	Complete	7/18/84
137a	6.4	Control room habitability	Open	
137b	6.4	Control room habitability	Open	
137c	6.4	Control room habitability	Open	
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	7/27/84
140b	9.1.2	Spent fuel pool storage	Complete	7/27/84
140c	9.1.2	Spent fuel pool storage	Complete	7/27/84
140d	9.1.2	Spent fuel pool storage	Complete	7/27/84
141a	9.1.3	Spent fuel cooling and cleanup system	Complete	8/1/84
141b	9.1.3	Spent fuel cooling and cleanup system	Complete	8/1/84
141c	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/1/84

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	8/1/84
141e	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/1/84
141f	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/1/84
141g	9.1.3	Spent fuel pool cooling and cleanup system	Complete	8/1/84
142a	9.1.4	Light load handling system (related to refueling)	Closed (5/30/84-Aux.Sys.Mtg.)	6/29/84
142b	9.1.4	Light load handling system (related to refueling)	Closed (5/30/84-Aux.Sys.Mtg.)	6/29/84
143a	9.1.5	Overhead heavy load handling	Open	
143b	9.1.5	Overhead heavy load handling	Open	
144a	9.2.1	Station service water system	Complete	7/27/84
144b	9.2.1	Station service water system	Complete	7/27/84
144c	9.2.1	Station service water system	Complete	7/27/84
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
147a	9.3.1	Compressed air systems	Complete	8/3/84 (Rev 1)
147b	9.3.1	Compressed air systems	Complete	8/3/84 (Rev 1)

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
147c	9.3.1	Compressed air systems	Complete	8/3/84 (Rev 1)
147d	9.3.1	Compressed air systems	Complete	8/3/84 (Rev 1)
148	9.3.2	Post-accident sampling system (II.B.3)	Open	
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	7/27/84
151b	9.4.1	Control structure ventilation system	Complete	7/27/84
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	8/1/84 (Rev 1)
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	
157	9.5.1.4.e	Cable tray protection	Open	
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	7/18/84
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
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

<u>ATTACHMENT 1 (Cont'd)</u>

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	8/13/84 Rev. 1
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	Open	
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	7/18/84
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	Open	
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

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	6/1/84
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)
198	7.3.2.6	TMI Item II.K.3.18-ADS actuation	Open	
199	7.4.2.1	IE Bulletin 79-27-Loss of non-class IE instrumentation and control power system bus during operation	Complete	8/1/84
200	7.4.2.2	Remote shutdown system	Complete	6/1/84
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	8/1/84
208	7.7.2.2	Multiple control system failures	Complete	8/1/84
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
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
216b	5.3.1	Reactor vessel materials	Complete	7/27/84
217	9.5.1.1	Fire protection organization	Open	
218	9.5.1.1	Fire hazards analysis	Complete	6/1/84
219	9.5.1.2	Fire protection administrative controls	Open	
220	9.5.1.3	Fire brigade and fire brigade training	Open	
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	8/1/84
223	8.2.2.3	Independence of offsite circuits between the switchyard and class IE buses	Complete	8/1/84
224	8.2.2.4	Common failure mode between onsite and offsite power circuits	Complete	8/1/84
225	8.2.3.1	Testability of automatic transfer of power from the normal to preferred power source	Complete	8/1/84
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

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	8/1/84
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	8/1/84
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	8/1/84
238	8.2.2.7	Sequencing of loads on the offsite power system	Complete	8/1/84
239	8.3.1.8	Testing to verify 80% minimum voltage	Open	
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	8/1/84
242	8.3.2.1	Compliance with position 1 of Regulatory Guide 1.128	Complete	8/1/84
243	8.3.3.1.3	Protection or qualification of Class 1E equipment from the effects of fire suppression systems	Complete	8/1/84
244	8.3.3.3.1	Analysis and test to demonstrate adequacy of less than specified separation	Complete	8/1/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
245	8.3.3.3.2	The use of 18 versus 36 inches of separation between raceways	Complete	8/1/84
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	8/1/84
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
251	8.3.3.5.5	Fault current analysis for all representative penetration circuits	Complete	8/1/84
252	8.3.3.5.6	The use of a single breaker to provide penetration protection	Complete	8/1/84
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	8/1/84
254	8.3.3.1.5	Protection of class 1E power supplies from failure of unqualified class 1E loads	Complete	8/1/84
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	8/13/84

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
257	8.3.2.5	Justification for a 0 to 13 second load cycle	Complete	8/1/84
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	8/1/84
260	8.3.3.3.5	Use of a single breaker tripped by a LOCA signal used as an isolation device	Comp'ete	8/1/84
261	8.3.3.3.6	Automatic transfer of loads and interconnection between redundant divisions	Complete	8/1/84
262	11.4.2.d	Solid waste control program	Open	
263	11.4.2.e	Fire protection for solid radwaste storage area	Complete	8/13/84
264	6.2.5	Sources of oxygen	Open	
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	Open	
269	5.2.2	Code cases N-242 and N-242-1	Open	
270	5.2.2	Code case N-252	Open	
TS-1	2.4.14	Closure of watertight doors to safety-related structures	Open	

ATTACHMENT 1 (Cont'd)

OPEN ITEM	DSER SECTION NUMBER	SUBJECT	STATUS	R. L. MITTL TO A. SCHWENCER LETTER DATED
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	
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	

ATTACHMENT 2 DATE: 8/13/84

DRAFT SER SECTIONS AND DATES PROVIDED

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

CT:db

MP 84 95/03 01

DATE: 8/13/84

ATTACHMENT 3

OPEN ITEM	DSER SECTION	SUBJECT
2c	2.3.3	Accuracies of meteorological measurements.
2d	2.3.3	Accuracies of meteorological measurements.
160	9.5.1.5.b	Firewater pump capacity.
176a	14.2	Initial plant test program.
176b	14.2	Initial plant test program.
176d	14.2	Initial plant test program.
176f	14.2	Initial plant test program.
176h	14.2	Initial plant test program.
186	7.2.2.3	Testability of plant protection system power.
226	8.2.2.5	Grid stability.
263	11.4.2.e	Fire protection for solid Radwaste storage area.
265	6.8.1.4	ESF Filter system.
266	6.8.1.4	Field leak tests.
267	6.4.1	Control room toxic chemical detectors.

Attachment 3 (cont'd)

QUESTION NUMBER	FSAR SECTION
430.102	9.5.5
430.108	9.5.5
430.110	9.5.5
430.111	9.5.5
430.135	9.5.7
430.149	9.5.8
430.151	10.2
430.169	10.4.4

RSC:sal
8/13/84

ATTACHMENT 4

Rev 1.

DSER Open Item No. 2c and d (Section 2.3.3)

The meteorological measurements program, during plant operation, will include those parameters currently measured. Meteorological parameters are to be available for display through the radiation monitoring system central radiation processor (CRP), although the method of display has not been specified. Calculations of atmospheric transport and diffusion are also to be available through the CRP, although the models and/or methodology have not been described.

Response

For the information requested above, see the response to DSER Open item 3a and b.

DSER Open Item No. 160 (DSER Section 9.5.1.5.b)

FIRE WATER PUMP CAPACITY

The source of water for the fire protection system is from two 350,000 gal fire water storage tanks. Of the 350,000 gal of storage capacity for each tank, 321,000 gal is dedicated to the fire protection water system, and the remaining amount is available for the fresh water system. Water is pumped by two 650-gpm deep-well water pumps, each of which is capable of filling the fire water portion of either fire water storage tank within 8 hours and 15 minutes. Operating in parallel, both well pumps can fill the fire water portion of one tank in less than 8 hours. The greatest water demand for the fixed fire suppression system has not been specified. The staff will require the applicant to verify that each fire water pump has enough capacity to meet Section C.6.b of BTP CMEB 9.5-1.

RESPONSE

Each fire water pump has enough capacity to meet Section C.6.b of BTP CMEB 9.5-1 as clarified in FSAR Sections 9.5.1.6.19 and 9.5.1.6.21. FSAR Sections 9.5.1.2.3.1 and 9.5.1.2.3.2 have been revised to clarify the fixed fire suppression system demand and the fire water pump capacity.

FIRE PUMP DESIGN FLOW SUMMARY CALCULATION

OBJECTIVE: To show that the Hope Creek Generating Station Fire Protection System is capable of providing:

a. 2228 gpm of water at a pressure of 68 psig to the largest hydraulic designed sprinkler system, 1WS8

b. And at the same time provide a total of 500 gpm at a minimum pressure of 65 psig to the following hose stations, which could be used to fight a fire in the area covered by 1WS8: 1H-H109, 1H-HR106, and 1H-HR105.

METHOD:

1. The hose station pressure was calculated at the interface between the standpipe and the hose station.

2. A flow diagram was drawn which showed the sprinkler interface and all standpipe-hose station interfaces.

3. Node numbers were assigned to the flow diagram.

4. By inspection of the piping isometric drawings, it was determined which hose station and standpipe had the longest equivalent length of pipe. The longest yard piping loop was used.

5. The equivalent lengths of pipe were determined using the criteria of NFPA 13-1978, Table 7-4.2.

6. The pressure at the 1WA8 sprinkler interface was calculated twice: once with no flow to the hose stations and 2228 gpm to 1WS8, and once with 750 gpm to the hose stations and 2228 gpm to 1WS8. This was done to assure that the sprinkler interface pressure did not drop below 68 psig.

7. The pressure was calculated twice at the standpipe-hose station interface: once with 2228 gpm to 1WS8 and 0 gpm to the hose station, and once with 2228 gpm to 1WS8 and 750 gpm to the hose station.

8. The method used for calculating the pressure loss is outlined in NFPA 13-1978 and is based on the Hazen-Williams formula:

$$P = \frac{(4.52)\ Q^{1.85}}{c^{1.85}\ d^{4.87}}$$

where Q = Flowrate in gpm
c = Friction loss coefficient
d = Inside diameter of piping (inches)
P = Pressure loss per foot in psi

9. Pressure vs. flow was plotted for the sprinkler system and for the hose station-standpipe interface on log base 1.85 graph paper. From the plot, the hose station flow rate was determined for a pressure of 65 psig.

<u>RESULTS</u>: The largest sprinkler system is 1WS8 at elevation 102'-0" in the turbine building. With a pressure of 65 psig at the hose station-standpipe interface, and 2228 gpm flowing to 1WS8, the maximum calculated flowrate available for the hose stations is 500 gpm. The calculated pressure at the sprinkler interface is 76 psig. Therefore, the fire pumps are capable of delivering, over the longest route, water for the largest sprinkler system plus a margin of 500 gpm for manual hose streams that can be brought to ~~bare~~ bear on the same fire. ✗

HOSE STATION DESIGN, PER NFPA 14 SUMMARY CALCULATION

OBJECTIVE: Show that the Hope Creek Generating Station Fire Protection System is capable of providing a 100 gpm flowrate to the highest fire hose station in each of the power block buildings (turbine, diesel/control, reactor and service radwaste) at a pressure greater than 65 psig.

METHOD:

1. From the fire protection drawings and the pipe system isometrics, determine the highest hose station in each building with the longest equivalent length.

2. Assume a flowrate of 100 gpm.

3. Determine the pressure at the highest hose station with a flowrate of 100 gpm using the Hazen-Williams formula and the method outlined in NFPA 13-1978.

RESULTS: The results are tabulated below:

BUILDING	ELEVATION	HOSE STATION	PRESSURE 100 GPM
REACTOR	205'-4"	1-CHR201	67 psig
TURBINE	175'-0"	1-CHR104	80 psig
DG/CONTROL	203'-6"	1-VHR401	70 psig
RAD/SERVICE	179'-0"	0-WHR201	80 psig

K52/2-11

DSER OPEN ITEM 160

k. Nuclear Regulatory Commission's Appendix A to BTP APCSB 9.5-1 and 10 CFR 50, including Appendix R.

9.5.1.2.3 Fire Protection Water Supply Systems

9.5.1.2.3.1 Water Source

Fire protection water supply is from two, 350,000-gallon, fire water storage tanks located north of the plant. Each tank feeds the FPS and the fresh water system. Of the 350,000 gallons of storage capacity for each tank, 328,000 gallons is dedicated to the fire protection water system, and the remaining amount is available for the fresh water system. Water is pumped by two deep-well water pumps, each of which is capable of filling the fire water portion of either fire water storage tank within 8 hours.

Insert A →

The fire pump suction piping and valve arrangement allows either fire pump to take water from either or both fire water storage tanks. With the present arrangement and normal valve line-up, a leak in the pump suction piping could cause the loss of water from both tanks. However, low water inventory in the storage tanks is annunciated in the control room. Isolation valves have been provided in the storage tank supply headers and in the fire pump suction headers to prevent loss of reserved fire water from both tanks. This combination of water level instrumentation and isolation valve arrangement provides adequate protection against losing the fire water inventory from one tank and/or both tanks.

9.5.1.2.3.2 Pumps

Two 100%-capacity, UL-listed, horizontal, centrifugal fire pumps are provided in accordance with NFPA 20, each with a rated flow and pressure of 2500 gpm and 125 psig, respectively. One fire pump is electric-motor-driven and the other is diesel-engine-driven. A jockey pump rated at 50 gpm and 125 psig is also provided to maintain the system pressure between 115 and 125 psig and to provide makeup for system leakage. The two fire pumps and the jockey pump are arranged so that each pump can take suction from either tank and pump water into the yard loop system.

Insert B →

The electric-motor-driven fire pump starts automatically at 110 psig. If it fails to start or cannot meet the water flow demand, the diesel-engine-driven fire pump starts automatically

Insert A

The dedicated fire water storage capacity of 328,000 gallons in each tank will provide water to meet the demand of 2228 gpm of the largest sprinkler system plus 500 gpm for manual hose streams for 2-hours

Insert B

Each fire pump is capable of providing, over the longest route of the water supply system, the design demand of 2228 gpm for the largest sprinkler system at the design pressure of 68 psig and 500 gpm for manual hose streams. In addition, each pump is capable of providing a minimum of 65 psig at the highest standpipe outlet with 100 GPM flowing from the outlet in accordence with NFPA 14. See Section 9.5.1.6.19, 9.5.1.6.21 and Table 9.5-18.

DSER OPEN ITEM 176a (Section 14.2)

INITAL PLANT TEST PROGRAM

FSAR FIGURE 14.2-5 , "Test Schedule and Conditions," should be modified to reference the subsection number for the various tests, or the test abstracts should be modified to include the "Test No." as denoted in the figure.

RESPONSE

FSAR Figure 14.2-5 has been revised to reference the subsection number for the various tests as requested above.

DSER OPEN ITEM 176b (Section 14.2)

INITIAL PLANT TEST PROGRAM

The following FSAR Subsection 14.2.12 test abstracts should be modified as stated to provide adequate acceptance criteria:

Test Abstract	Modification
1.5.d.1	A reference should be provided for acceptable closing times.
1.7.d.1 1.15.d.2	A reference should be provided for the design specifications.
1.23.d.4 d.6	Reference should be 6.2.5.2.5 Reference should be 6.2.5.2.3
1.35.d.6	A reference should be provided regarding safe levels of hydrogen buildup
1.41.d.1	A reference should be provided regarding the appropriate accuracy of response
1.47.d.4	A reference should be provided for the prescribed time.
1.52.d.2 1.60.d.3 1.61.d.1 1.65.d.2 1.71.d.2 3.24.d.5	The parameters in these tests should meet or exceed the design values described in their respective references; they should not simply "be comparable" or "compare favorably.
1.68.e.1	A reference should be provided regarding the negative pressure specification.

Additionally, all startup tests should be modified to specify the appropriate level of acceptance criteria (Level 1, 2, or 3) as defined in FSAR Subsection 14.2.12.2.

RESPONSE

FSAR Section 14.2.12.1 was revised in Amendment 6 to provide the information requested above.

In addition, Section 14.2.12.1.7.d.1 and 14.2.12.3.24.d.5 has been revised to reflect the new GE Test Specifications and all the startup tests in Section 14.2.12.3 have been modified to specify the appropriate level of acceptance criteria.

Rev1

HCGS

DSER Open Item 176d (Section 14.2)

INITIAL PLANT TEST PROGRAM

The response does not address the concerns of I&E Information Notice Number 83-17, March 31, 1983. The concern is that if a time delay prevents fuel from being supplied to the diesel generator following a shutdown signal, the air supply may be exhausted before the fuel supply is reinstated. The response to this item should be modified to address these concerns.

RESPONSE

The response to Q640.10 has been revised to provide the information requested above.

QUESTION 640.10 (SECTION 14.2.12)

Modify your FSAR submittal to address the following concerns regarding emergency diesel generator testing:

1. FSAR Subsections 1.8.1.108 and 14.2.13.5 state that Regulatory Guide 1.108 (Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants) is not applicable to Hope Creek. It is the staff's position that this guide is applicable to your facility. Therefore, either delete or provide justification for this statement.

2. FSAR Subsections 1.8.1.108 and 14.2.13.5 take exception to Position C.2.a(5) of Regulatory Guide 1.108. These subsections state that testing of the sequencing controls after the 24 hour test run does not subject the controls to more severe conditions than testing accomplished under other circumstances. Provide technical justification for your position or perform this test in accordance with this guide. Additionally, modify FSAR Subsection 14.2.12.1.30 (KJ-Emergency Diesel Generators) to perform a restart simulating loss of ac directly after the 24-hour run in accordance with your statement in the aforementioned FSAR subsections.

3. Modify FSAR Subsections 14.2.12.1.30 (KJ-Emergency Diesel Generators), 14.2.12.3.30 (Loss of Turbine-Generator and Offsite Power), or other test abstracts as appropriate, to:

   a. Perform the simultaneous, redundant diesel starts specified in Position C.2.b of Regulatory Guide 1.108.

   b. Include prerequisite testing to ensure the satisfactory operability of all check valves in the flow path of cooling water for the diesel generators from the intake to the discharge (see I&E Bulletin No. 83-03: Check Valve Failures in Raw Water Cooling Systems of Diesel Generators).

   c. Provide assurance that any time delays in the diesel generator's restart circuitry will not cause the supply of compressed air used to initially rotate the engine to be consumed in the presence of a safety injection signal (see I&E Information Notice Number 83-17, March 31, 1983).

RESPONSE FSAR Sections 1.8.1.108 and 14.2.13.5 will be revised as requested above

~~NRC Regulatory Guide 1.108 is not applicable to HCGS. This is justified as stated in Implementation Section D of Regulatory~~

~~Guide 1.108 which provides that the guide is to be used in the evaluation of submittals for construction permits.~~

Section 14.2.12.1.30.c.6 has been revised to state that a restart simulating loss of ac power will be performed following the 24-hour run.

Upon restart, a sequencing check will not be performed since the 24-hour run test has no effect on the sequencing circuit. The sequencing circuits are located in the emergency load sequencer panels remote from the diesel generator room. The circuits will not have left their standby state since the 24-hour run is accomplished without a loss-of-power or loss-of-coolant accident condition, and is synchronized to the grid. However, the sequencing will be checked during the ECCS integrated initiation during loss-of-offsite power test described in Section 14.2.12.1.47.

Simultaneous redundant diesel starts are accomplished as described in Section 14.2.12.1.47.c.2.

Section 14.2.12.1.30 has been revised to include prerequisite component testing on all diesel generator cooling water check valves.

The diesel generator control design has a time delay relay which holds the fuel racks closed to allow the unit to come to a complete stop. However, in the event of an emergency start signal due to ECCS requirements during the count down of the time delay relay, this relay is functionally overridden and the fuel racks open to allow the diesel to continue to run or restart through the normal starting air sequence described in Section 9.5.6.

1.8.1.107 Conformance to Regulatory Guide 1.107, Revision 1, February 1977: Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures

Regulatory Guide 1.107 is not applicable to HCGS.

1.8.1.108 Conformance to Regulatory Guide 1.108, Revision 1, August 1977: Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

~~Although Regulatory Guide 1.108 is not applicable to HCGS, per its implementation section,~~ HCGS complies with ~~it,~~ Regulatory Guide 1.108, with the following exception:

Position C.2.a(5) requires that the accident loading sequence to design load requirements be performed directly after the 24-hour run. This does not test the sequencing controls under a more severe condition than if sequentially loaded at an earlier or later period. A restart simulating loss of ac power can be performed directly after the 24-hour run. Sequencing, however, will be performed when the loads can be lined up for operation and all four diesels are available.

1.8.1.109 Conformance to Regulatory Guide 1.109, Revision 1, October 1977: Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I

HCGS complies with Regulatory Guide 1.109.

For further discussion, see Chapter 15.

1.8.1.110 Conformance to Regulatory Guide 1.110, Revision 0, March 1976: Cost-Benefit Analysis for Radwaste Systems For Light-Water-Cooled Nuclear Power Reactors

HCGS complies with Regulatory Guide 1.110.

calibration completed prior to performing the preoperational test.

14.2.13.5 <u>SRP II.e, Regulatory Guide 1.108, Revision 1, August 1977: Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants</u>

~~Although Regulatory Guide 1.108 is not applicable to HCGS, per its implementation section,~~ HCGS complies with ~~it~~ Regulatory Guide 1.108, with the following clarifications:

a. Position C.2.a (5) requires that the accident loading sequence to design load requirements be performed directly after the 24 hour run. This does not test the sequencing controls under a more severe condition than if sequentially loaded at an earlier or later period. A restart simulating loss of ac can be performed directly after the 24-hour run.

Sequencing, however, will be performed when the loads can be lined up for operation and all four diesels are available.

DSER OPEN ITEM 176f (Section 14.2)

INITIAL PLANT TEST PROGRAM

(0640.14 Items 1&2)

Commit to ensuring that a neutron count rate of at least 1/2 count per second registers on the startup channels before startup begins and that the signal-to-noise ratio is greater than two, or modify FSAR Subsection 14.2.13-1 to include an exception to Regulatory Guide 1.68, "Initial Test Programs for Water-cooled Nuclear Power Plants," Appendix A, Paragraph 3.

RESPONSE

FSAR Section 14.2.12.3.6.d has been revised to provide the requested information.

DSER OPEN ITEM 176h (Section 14.2)

INITIAL PLANT TEST PROGRAM

Q 640.20

PREOPERATIONAL TESTS

32. The Reactor Building Ventilation Test (FSAR Subsection 14.2.12.1.68) should state that the RBVS will isolate on a high radiation signal, not on LOCA. Additionally, Subsection "e" of this test abstract should be incorporated into Subsection "d".

37. The Cranes and Hoists Test (FSAR Subsection 14.2.12.1.59.b.2) prerequisite static load tests should be accomplished at 125% of rated load in accordance with NUREG-0612.

40. A test abstract should be provided for the Makeup Demineralizer regardless of whether construction is completed prior to or after initial fuel load.

47. Refer to 640.20, Item 37.

POWER TESTS

4. A test abstract should be provided which describes the conditions under which baseline data for the Loose Parts Monitoring System is obtained.

5. No response has been provided.

8. FSAR Subsection 9.4.5.1.c states that the maximum design temperature for concrete structures within the drywell is 150°F. The acceptance criteria of the Penetration Temperature Test (FSAR Subsection 14.2.12.3.37) should be modified accordingly, or justification should be provided for the 200°F limit.

RESPONSE

The information requested above for preoperational tests 32, 37, 40 and 47 was provided as part of Amendment 6 to the HCGS FSAR.

The response to Question 640.20 has been revised to provide the information requested above for Power Tests 4 and 5.

176h cont'd

The response to Power Test No.8 is as follows:

(a) The maximum design temperature for concrete structures within the drywell are specified in Section 3.8.2. Subsection 9.4.5.1 lists the design bases for drywell air cooling system. Therefore Subsection 9.4.5.1.c has been revised to reference the correct section for concrete design temperatures.

(b) Section 14.2.12.3.34 has been revised to reference Section 3.8.2 instead of specifying the maximum design temperature.

(c) FSAR Section 3.8.2.3.4 states the maximum design temperature of $150^{\circ}F$ for concrete structures in drywell for normal operation. Civil-Structural Design Criteria, Appendix A, Secton 3.5 specifies this and includes, "except for local areas which are allowed to have increased temperatures not to exceed $200^{\circ}F$." Concrete surrounding hot piping penetrations is one of these "local areas" (as defined by ACI-349) and is what is tested in Power Ascension Testing.

QUESTION 640.17 (SECTION 14.2.12)

Modify FSAR Subsection 14.2.12.3.24 (Relief Valves) to describe or reference any confirmatory in-plant tests of safety-relief valves to be performed in compliance with NUREG-0763 "Guidelines for Confirmatory Inplant Tests of Safety-Relief Valve Discharges for BWR Plants."

RESPONSE

A description of the confirmatory in-plant tests ~~to be performed at HCGS will be available by January 1985.~~ is in FSAR Subsection 14.2.12.3.40.

d. Acceptance Criteria

1. All valves, alarms, controls, interlocks, and logic shall function in accordance with the ~~system electrical schematics~~ for core spray.
GE Preoperational test specification

2. For the core spray test mode and core spray injection mode, the pump head/flow requirements, the NPSH requirements, and the system design flow requirements meet the GE preoperational test specification acceptance criteria.

3. All modes of operation and flow paths shall be as specified in the GE preoperational test specifications.

4. The jockey pump can fill and pressurize the core spray system

14.2.12.1.8 BF-Control Rod Drive - Hydraulic

a. Objective

The test objective is to demonstrate that the control rod drive (CRD) system is fully operational, and that all components, including the hydraulic drive mechanism, manual control system, rod position indicator system, and all safety and control devices, function per design.

b. Prerequisites

1. All component tests have been completed and approved.

2. AC and dc power are available.

3. All instrumentation has been calibrated and instrument loop checks completed.

their recommendations. This report must discuss alternatives of action, as well as the concluding recommendation, so that it can be evaluated by all related parties.

Level 3

If level 3 performance is not satisfied, plant operating or startup test plans would not necessarily be altered. The numerical limits stated in this category are associated with expectations of individual component or inner control loop transient performance. Because overall system performance is a mathematical function of its individual components, one component whose performance is slightly worse than specified can be accepted if a system adjustment elsewhere will positively overcome this small deficiency. Large deviations from Level 3 performance are not allowable. Level 3 performance is also not specified in fuel or vessel protective systems. When a Level 3 performance is not satisfied, the subject component or inner loop must be analyzed closely. If all Level 1 and Level 2 criteria are satisfied, then it is not required to repeat the transient test to satisfy Level 3 performance. The occurrence must be documented in the test report. Level 3 performance is to be viewed as highly desirable rather than required to be satisfied. Good engineering judgement is necessary in the application of these rules.

During performance of startup tests, technical specifications override any test in progress if plant conditions dictate.

14.2.12.3 Startup Test Procedures

14.2.12.3.1 Chemical and Radiochemical Monitors and Sample Systems

a. Objectives

The tests provide verification of the sample systems' ability to:

1. Maintain quality control of the plant systems' chemistry and ensure that sampling equipment, procedures, and analytical techniques supply the

data required to demonstrate that fluids meet quality specifications and process requirements

2. Monitor fuel integrity, operation of filters and demineralizers, condenser tube integrity, operation of the offgas system and steam separator-dryer, and tuning of system monitors.

b. Prerequisites

Intrument calibration and preoperational testing of chemical, radiation, and radiochemical monitors have been completed.

c. Test Method

Prior to fuel loading, a complete set of chemical and radiochemical samples are taken to ensure that all sample stations are functioning properly and to determine the initial concentrations. During reactor heatup, subsequent to fuel loading, samples are taken and measurements made at each major power level plateau to determine the chemical and radiochemical quality of reactor water and reactor feedwater, amount of radiolytic gas in the steam, gaseous activities after the air ejectors, decay time in the gaseous radwaste lines, and performance of filters and demineralizers. Baseline data for the main steam process radiation monitoring subsystems and the offgas monitoring subsystems is also taken at each major power level plateau. Adjustments are made, as required, to monitors in the liquid waste management system (LWMS), liquid process lines, and offgas treatment system.

d. Acceptance Criteria

Level 1:

The chemical and radiochemical, and water of quality factors are maintained within the technical specifications and fuel warranty requirements. Gaseous, particulate, and liquid effluents' activities shall conform with Technical Specifications.

14.2.12.3.2 Radiation Measurements

a. Objective

The test objective is to monitor radiation at selected power levels during plant operation to ensure the adequacy of shielding for personnel protection, and to verify compliance with 10 CFR 20.

b. Prerequisites

Prior to fuel loading, a survey of natural background radiation is made at selected locations throughout the plant site.

c. Test Method

During reactor heatup and at selected power levels subsequent to fuel loading, gamma dose rates, and where appropriate, neutron dose rate measurements are made at specific locations around the plant including all potentially high radiation areas.

d. Acceptance Criteria

Level 1:

Plant radiation doses and personnel occupancy times shall be within allowable limits, as defined in 10 CFR 20.

14.2.12.3.3 Fuel Loading

a. Objective

The test objective is to load fuel safely and efficiently to the full core size.

b. Prerequisites

Section 14.2.10 (initial fuel loading) describes the prerequisites for commencing fuel loading.

c. Test Procedure

The fuel loading procedure includes any tests performed during the fuel loading evolution, including subcriticality checks, shutdown margin verifications, and control rod functional checks.

d. Acceptance Criteria

Level 1:

The core shall be fully loaded in accordance with established procedures and the core shall be subcritical by at least 0.38% $\Delta K/K$ with the analytically determined strongest rod withdrawn.

14.2.12.3.4 Full Core Shutdown Margin

a. Objective

The test objective is to demonstrate that the reactor will remain subcritical throughout the first fuel cycle with the most reactive control rod withdrawn.

b. Prerequisites

The core is fully loaded at ambient temperature in the xenon-free condition.

c. Test Method

The shutdown margin is measured by withdrawing selected control rods until criticality is reached. The empirical data is reviewed and compared with design data to determine the test results.

50466

d. Acceptance Criteria

Level 1:

The shutdown margin measurements shall verify that the core remains subcritical with the most reactive control rod withdrawn and all other control rods fully inserted by at least 0.38% ΔK/K. ~~Additionally,~~ criticality should occur within ±1.0% ΔK/K of the predicted critical.

Level 2:

14.2.12.3.5 Control Rod Drive System

a. Objective

The test objective is to obtain the baseline data for the CRD system, and to demonstrate that the system operates over the full range of primary coolant conditions, from ambient to operating.

b. Prerequisites

Preoperational testing of the CRD system has been completed and the system is ready for operation.

c. Test Method

The startup tests performed on the CRD system are an extension of the preoperational tests. Initial post fuel load tests with zero reactor pressure include position indication, normal insert/withdraw stroking, friction testing, and scram testing. Coupling checks are verified using station operating procedures. Following initial heatup to rated reactor pressure, the friction and scram test is accomplished. Following initial heatup, the four slowest CRDs are measured for scram times following planned reactor scram as detailed on Figure 14.2-5. In addition, proper response of the CRD flow control valve will be verified.

d. Acceptance Criteria

The insert and withdrawal times, scram times, and friction test results shall meet the requirements of the GE startup test specification limits. The CRD system flow requirements and flow control valve

Level 1:

The withdrawal speeds and scram times shall meet the requirements of the GE startup test specifications.

Level 2:

The friction test results shall meet the requirements of the GE startup test specifications.

Level 3:

The CRD system flow requirements and flow control value response shall meets the requirements of the GE startup test specifications.

~~response meets the requirements of the GE startup test specification.~~

14.2.12.3.6 Source Range Monitor Performance and Control Rod Sequence

a. Objective

The test objective is to demonstrate that the neutron sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner. ~~The effects of typical rod movements on reactor power are recorded and evaluated.~~

Delete

b. Prerequisites

Fuel loading is complete, neutron sources have been installed, and all control rods have been inserted. The CRD system is operational.

c. Test Method

With the neutron sources installed, source range monitor count rate data is taken and compared to the required signal count and signal count-to-noise count ratio. Source range data is taken during rod withdrawals to the point of criticality. See Attach B. During heatup to rated temperature, critical rod patterns are recorded. Rods will be withdrawn in accordance with a pre-established withdrawal sequence. Movement of rods in a prescribed sequence is monitored by the RWM and RSCS which prevents out of sequence movement. ~~As the withdrawal of each rod group is completed during power ascension, the electrical power, system flow, and APRM response will be recorded.~~

Delete

d. Acceptance Criteria

Attach. A →

~~The neutron signal count-to-noise count ratio and minimum counts of the SRMs shall meet the requirements of the GE startup test specification.~~

See Att. ch

ATTACH. A

Level 1:

There must be a neutron signal count-to-noise count ratio of at least two and a minimum neutron count ~~[illegible]~~ rate of 1/2 counts/second on the required operable SRMs.

ATTACH. B.

Initial criticality will be approached with a period greater than 30 seconds.

90#66

14.2.12.3.7 Rod Sequence Exchange

This Test Has Been Deleted

14.2.12.3.8 Intermediate Range Monitor Performance

a. Objective

The test objective is to determine IRM system response to neutron flux and to optimize the IRM overlap with the SRMs and APRMs.

b. Prerequisites

The reactor is critical and the IRM gains have been set at maximum for conservatism.

c. Test Method

After criticality, and when flux level is sufficient, the IRM response to neutron flux and the IRM/SRM overlap is verified. Following the calibration of the APRM, the IRM gains are adjusted if necessary. If any adjustments are made, the overlap of the SRM and IRM is verified when flux levels are in the appropriate range.

d. Acceptance Criteria

Level 1:

Each IRM channel must be on scale before the SRMs exceed their rod block setpoint. Each APRM must be on scale before the IRMs exceed their rod block setpoint.

Level 2: ~~Also,~~ Each ~~each~~ IRM should be adjusted for half decade overlap with SRMs and one decade overlap with APRMs.

14.2.12.3.9 Local Power Range Monitor Calibration

a. Objective

The test objective is to calibrate the LPRM.

b. Prerequisites

Reactor power and LPRM gains are sufficient to observe detector response. The process computer or other means are available for determining calibration factors.

c. Test Method

Core power is maintained at the specified level for a sufficient time to allow equilibrium conditions to be established. The process computer computes the average heat flux and calibration factor for each LPRM. Each LPRM is calibrated in accordance with the calibration procedure.

d. Acceptance Criteria

Level 2:

Each LPRM reading should be within 10% of its calculated value.

11 of 66

14.2.12.3.10 Average Power Range Monitor Calibration

a. Objective

The test objective is to calibrate the APRM.

b. Prerequisite

The core is in a steady-state condition at the desired power level and core flow rate. Instrumentation used to determine core thermal power has been calibrated.

c. Test Method

A heat balance is taken at selected power levels. Each APRM channel reading is adjusted to agree with the core thermal power as determined from the heat balance. In addition, the APRM channels are calibrated at the frequency required by the Technical Specifications.

d. Acceptance Criteria

Level 1:

1. The APRM channels must be calibrated to read equal to or greater than the actual core thermal power.

2. Technical specification limits on APRM scram and rod block must not be exceeded.

3. In the startup mode, all APRM channels must produce a scram at less than or equal to the thermal power setpoint required by technical specification.

Level 2:

~~4.~~ 1. With the above criteria met, the APRMs are considered accurate if they agree with the heat balance ~~required by the GE startup test specification~~ or the minimum value required based on TPF, MLHGR, and fraction of rated power to within the limits specified in the GE startup test specification.

14.2.12.3.11 NSSS Process Computer

a. Objective

The test objective is to verify the performance of the process computer under plant operating conditions.

b. Prerequisites

Computer calculational programs have been verified using simulated input conditions. The computer room HVAC is operational and plant data is available for computer processing.

c. Test Method

During plant heatup and ascension to rated power following fuel loading, the NSSS and the balance-of-plant system process variables sensed by the computer become available. The validity of these variables is verified and the results of performance calculations of the NSSS and the balance-of-plant (BOP) are checked for accuracy.

d. Acceptance Criteria

Level 2:

1. The process computer performance codes calculating the minimum critical power ratio (MCPR), linear heat generation rate (LHGR), and maximum average planar heat generation rate (MAPLHGR), and an independent method of calculation shall not differ in their results by more than the value specified in the GE startup test specification.

13 of 66

2. The LPRM calibration factors calculated by the independent method and the process computer shall not differ by more than the value specified in the GE startup test specification.

Delete ~~3. The remaining programs shall be considered operational upon successful completion of the static and dynamic testing.~~

14.2.12.3.12 Reactor Core Isolation Cooling System

a. Objective

The test objective is to verify the proper operation of the RCIC over its required operating pressure range.

b. Prerequisite

Fuel loading has been completed and sufficient nuclear heat is available to operate the RCIC pump. Instrumentation has been installed and calibrated.

c. Test Method

The RCIC system is designed to be tested in two ways:

1. By flow injection into a test line leading to the condensate storage tank (CST), and

2. By flow injection directly into the reactor vessel.

The earlier set of CST injection tests consist of manual and automatic mode starts at 150 psig and near rated reactor pressure conditions. The pump discharge pressure during these tests is throttled to be 100 psi above the reactor pressure to simulate the largest expected pipeline pressure drop. This CST testing is done to demonstrate general system operability and for making most controller adjustments.

Reactor vessel injection tests follow to complete the controller adjustments and to demonstrate automatic starting from a cold standby condition. "Cold" is defined as a minimum 72 hours without any kind of RCIC operation. Data will be taken to determine the RCIC high steam flow isolation trip setpoint while injecting at rated flow to the reactor vessel.

After all final controller and system adjustments have been determined, a defined set of demonstration tests must be performed with that one set of adjustments. Two consecutive reactor vessel injections starting from cold conditions in the automatic mode must satisfactorily be performed to demonstrate system reliability. Following these tests, a set of CST injections are done to provide a benchmark for comparison with future surveillance tests.

After the auto start portion of certain of the above tests is completed, and while the system is still operating, small step disturbances in speed and flow command are input (in manual and automatic mode respectively) in order to demonstrate satisfactory stability. This is to be done at both low (above minimum turbine speed) and near rated flow initial conditions to span the RCIC operating range.

A demonstration of extended operation of up to two hours (or until pump and turbine oil temperature is stabilized) of continuous running at rated flow conditions is to be scheduled at a convenient time during the startup test program.

Depressing the manual initiation pushbutton is defined as automatic starting or automatic initiation of the RCIC system.

d. Acceptance Criteria

Level 1:

1. Following automatic initiation, the pump discharge flow must be equal to or greater than rated flow as specified in Section 5.4.6 within the time specified by the GE startup test specification.

15 of 66

2. The RCIC turbine shall not trip or isolate during automatic or manual start tests.

Level 2:

~~3~~.1. The turbine gland seal system is capable of preventing steam leakage to the environment.

~~4~~.2. The delta-pressure setpoints for RCIC steam supply line high flow isolation trip shall be calibrated to the requirements of technical specifications using actual flow conditions.

~~5~~.3. To provide overspeed and isolation trip avoidance margin, the transient start speed peaks must not exceed the requirements of the GE startup test specification.

~~6~~.4. The speed and flow control loops are adjusted to meet the decay ratio specified in the GE startup test specification.

14.2.12.3.13 High Pressure Coolant Injection System

a. Objective

The test objective is to verify the proper operation of the HPCI over its required operating pressure range.

b. Prerequisite

Fuel loading has been completed and sufficient nuclear heat is available to operate the HPCI pump. Instrumentation has been installed and calibrated.

c. Test Method

The HPCI system is designed to be tested in two ways:

1. By flow injection into a test line leading to the condensate storage tank (CST), and

2. By flow injection directly into the reactor vessel.

The earlier set of CST injection tests consist of manual and automatic mode starts at 150 psig and near rated reactor pressure conditions. The pump discharge pressure during these tests is throttled to be 100 psi above the reactor pressure to simulate the largest expected pipeline pressure drop. This CST testing is done to demonstrate general system operability and for making most controller adjustments.

Reactor vessel injection tests follow to complete the controller adjustments and to demonstrate automatic starting from a cold standby condition. "Cold" is defined as a minimum 72 hours without any kind of HPCI operation. Data will be taken to determine the HPCI high steam flow isolation trip setpoint while injecting at rated flow to the reactor vessel. Dpressing the manual initiation pushbutton is defined as automatic starting or automatic initiation of the HPCI system.

After all final controller and system adjustments have been determined, a defined set of demonstration tests must be performed with that one set of adjustments. Two consecutive reactor vessel injections starting from cold conditions in the automatic mode must satisfactorily be performed tc demonstrate system reliability. Following these tests, a set of CST injections are done to provide a benchmark for comparison with future surveillance tests.

After the auto start portion of certain of the above tests is completed, and while the system is still operating, small step disturbances in speed and flow command are input (in manual and automatic modes respectively) in order to demonstrate satisfactory stability. This is to be done at both low (above minimum turbine speed) and near rated flow initial conditions to span the HPCI operating range.

A continuous running test is to be scheduled at a convenient time during the startup test program. This demonstration of extended operation should be for up to 2 hours or until steady turbine and pump conditions are reached or until limits on plant operation are encountered.

d. Acceptance Criteria

Level 1:

1. Following automatic initiation, the pump discharge flow must be equal to or greater than the rated flow, and within the time specified in Section 6.3.2.2.1.

2. The HPCI turbine shall not isolate or trip during automatic or manual start tests.

Level 2:

~~3.~~ 1. The speed and flow control loops are adjusted to meet the decay ratio specified in the GE startup test specification.

~~4.~~ 2. The turbine gland seal system is capable of preventing steam leakage to the atmosphere.

~~5.~~ 3. The delta-pressure setpoints for HPCI steam supply line high flow shall be calibrated to technical specification requirements using actual flow conditions.

~~6.~~ 4. In order to provide overspeed and isolation trip avoidance margin, the transient start speed peaks must not exceed the requirements of the GE startup test specification.

14.2.12.3.14 Selected Process and Water Level Reference Leg Temperatures

a. Objectives

1. To establish low speed limits for the recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel (RPV) bottom head region

2. To ensure that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operation.

3. To measure the reactor water level instrument reference leg temperature and recalibrate the affected indicators if the measured temperature is different than expected.

18/66

b. Prerequisites

The plant is in a hot standby condition. System and test instrumentation have been installed.

c. Test Method

During initial heatup at hot standby conditions, the bottom drain line temperature and applicable reactor parameters are monitored as the recirculation pump speed is slowly lowered to determine the proper setting of the low speed limiter. The parameters above are also monitored during planned recirculation pump trips to determine if temperature stratification occurs in the idle loop(s) and to assure that idle loop-to-bulk coolant temperature differentials are within Technical Specification limits prior to restarting the pump(s). The bottom drain line temperature and applicable parameters are monitored when core flow is 100% of rated flow.

A test is also performed at rated temperature and pressure under steady state conditions to verify that the reference leg temperature of the level instrumentation is the value assumed during initial calibration. Recalibration will be performed if necessary.

d. Acceptance Criteria

Level 1:

1. The reactor recirculation pumps shall not be started unless the loop to loop delta-temperatures and steam dome to bottom drain delta-temperatures are within the technical specification limits.

Level 2:

~~2.~~1. During two pump operation at 100% core flow, the difference between the bottom drain line thermocouple and recirculation loop thermocouple is within the delta-temperature required in the GE startup test specification.

~~3.~~2. The difference between actual reference leg temperature and the value used for calibration is less than the amount specified in the GE startup test specification.

14.2.12.3.15 System Expansion

a. Objective

The test objective is to demonstrate that major components and piping systems throughout the plant are free and unrestrained with regard to thermal expansion.

b. Prerequisites

Fuel loading has been completed and cold plant data has been recorded. Instrumentation required has been installed and calibrated. The system piping to be tested is supported and restrained properly.

c. Test Method

During heatup, observations and recordings of the horizontal and vertical movements of major equipment and piping in the NSSS and auxiliary systems are made in order to ensure that components are free to move as designed. Adjustments are made if necessary to allow freedom of movement. Snubbers, whose testing requirements are governed by technical specifications, will be monitored for thermal movement. The systems to be monitored are listed in Section 3.9.2.

d. Acceptance Criteria

Level 1

1. There shall be no evidence of blocking of the displacement of any system component caused by thermal expansion of the system.

2. Inspected hangers shall not be bottomed out or have the spring fully stretched.

3. The position of the shock suppressors shall be such as to allow adequate movement at operating temperature.

4. The piping displacements at the established transducer locations shall not exceed the limits

specified by the piping designer, which are based on not exceeding ASME Section III Code stress values. These specified displacements will be used as acceptance criteria in the appropriate startup test procedures.

14.2.12.3.16 ~~Core Power Distribution~~ TIP Uncertainty

a. Objective

The test objective is to demonstrate the reproducibility of the TIP system readings.

b. Prerequisites

The core is at steady-state power level with equilibrium xenon, so as to require no rod motion or change in core flow to maintain power level during data acquisition by the TIP system.

c. Test Method

1. Core power distribution data are obtained during the power ascension test program. Axial power distribution data are obtained at each TIP location. At intermediate and higher power levels, several sets of TIP data are obtained to determine the overall TIP uncertainty.

2. TIP data are obtained with the reactor operating with a symmetric rod pattern and at steady-state conditions. The total TIP uncertainty for the test is calculated by averaging the total TIP uncertainty determined from each set of TIP data. The TIP uncertainty is made up of random noise and geometric components.

3. Core power symmetry is also calculated using the TIP data. Any asymmetry, as determined from the analysis, will be accounted for in the calculations for MCPR.

d. Acceptance Criteria

Level 2:

The total TIP uncertainty shall be within the specified limits required in the GE startup test specification.

14.2.12.3.17 Core Performance

a. Objective

The test objective is to evaluate the principal thermal and hydraulic parameters associated with core behavior.

b. Prerequisites

The plant is operating at a steady-state power level.

c. Test Method

With the core operating in a steady-state condition, the core performance evaluation is used to determine the following principal thermal and hydraulic parameters associated with core behavior:

1. Core flow rate

2. Core thermal power level

3. MLHGR

4. MCPR

5. MAPLHGR.

d. Acceptance Criteria

Level 1:

Core flow rate, core thermal power level, MLHGR, MCPR, and MAPLHGR not exceed the limits specified by the plant technical specifications.

14.2.12.3.18 Warranty Test

a. Objective

The test objective is to demonstrate the reliability of the NSSS and to measure the steam production rate and plant heat rate.

b. Prerequisite

The plant has been stabilized at rated conditions. All required instrumentation has been installed and calibrated.

c. Test Method

The plant is operated for 100 hours at rated conditions. During the 100-hour run, the steam production rate and plant heat rate is measured.

d. Acceptance Criteria

Level 1:

The reliability of the NSSS and the ability of the NSSS to develop rated output shall be demonstrated to be within warranty specifications.

14.2.12.3.19 Core Power - Void Mode

a. Objective

The objective of this test is to measure the stability of the core power void dynamic response, and to demonstrate that its behavior is within specified design limits.

b. Prerequisites

The core is maintained in a steady-state condition prior to the starting of this test.

c. Test Method

The core power void loop mode, that results from a combination of the neutron kinetics and core thermal hydraulics dynamics, is least stable near the natural circulation end of the rated 100% power rod line. A fast change in the reactivity balance is obtained by two methods: (1) pressure regulator step change, and (2) by moving a very high worth control rod one or two notches. Both local flux and total core response will be evaluated by monitoring selected LPRMs during the transient.

d. Acceptance Criteria

Level 1:

The transient response of any system-related variables to any test input must not diverge. System related variables are heat flux and reactor pressure.

14.2.12.3.20 Pressure Regulator

a. Objectives

1. To determine optimum pressure regulator setting to control transients induced in the reactor pressure control system.

2. To demonstrate the takeover capability of the backup pressure regulator via simulated failure of the controlling pressure regulator and to set the regulating pressure difference between the two regulators and an appropriate value.

24 of 66

3. To demonstrate smooth pressure control transition between the turbine control valves and bypass valves.

b. Prerequisites

Instrumentation has been checked and calibrated. The plant is at a steady-state power level.

c. Test Method

The pressure setpoint is decreased rapidly and then increased rapidly by about 10 psi. The response of the system is measured in each case. The backup pressure regulator is tested by simulating failure of the operating pressure regulator. The bypass valve is tested by reducing the load limit, which requires the bypass valves to open and control the bypass steam flow. At certain test conditions, the results of the backup regulator test will be included with the core power - void mode test report.

d. Acceptance Criteria

Level 1:

1. The transient response of any pressure control system related variable to any test input must not diverge.

Level 2:

~~2.~~ 1. In the recirculation manual mode the response time from initiation of pressure setpoint change to the turbine inlet pressure peak should be less than that specified in the GE startup test specification.

~~3.~~ 2 Pressure control system deadband should be small enough that steady state limit cycles shall produce steam flow variations no greater than specified in the GE startup test specification.

~~4.~~ 3 For all pressure regulator transients the peak neutron flux/peak vessel pressure should remain below the scram settings by the margins specified in the GE startup test specification.

25 of 66

8.4, The ratio of the maximum to the minimum value of the incremental change in pressure control signal divided by the incremental change in steam flow shall meet the requirements of the GE startup test specification.

Level 3:

8.1 Control or bypass valve motion responds to pressure input with deadband no greater than that required in the GE startup test specification.

~~7. Dynamics of both pressure regulators are similar.~~ DELETE

14.2.12.3.21 Feedwater Control System

a. Objectives

1. To evaluate and adjust feedwater controls

2. To demonstrate capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump at 100% power

3. To calibrate the feedwater speed controller and to verify that the maximum feedwater flow during pump runout does not exceed the flows assumed in Section 15.1.2.

4. To demonstrate response to feedwater temperature loss

5. To demonstrate acceptable reactor water level control.

b. Prerequisite

Instrumentation has been checked and calibrated as appropriate. The plant is operating at steady-state conditions.

c. Test Method

1. Reactor water level setpoint changes of several inches are used to evaluate and adjust the feedwater control system (FCS) settings for all power and feedwater pump modes. The level setpoint change also demonstrates core stability to subcooling changes.

2. From near 100% power, one of the operating feedwater pumps is tripped. The automatic recirculation runback circuit will reduce recirculation pump speed to drop power to within the capacity of the remaining turbine driven feedwater pumps. It is not expected that the reactor will scram on low water level.

3. The condensate/feedwater system will be subjected to a loss of feedwater heating. The initial power level will be approximately 80% prior to the start of the test. It is expected that the feedwater temperature decrease will be less than 100°F.

4. Feedwater pumps and turbine parameters are monitored during the power ascension to demonstrate operability within specifications. This test includes initial calibration of the speed controllers, and verification that maximum feedwater flows do not exceed the flows assumed in the FSAR.

d. Acceptance Criteria

Level 1:

1. The transient response of any level control system related variable must not diverge.

Level 2:

~~2.~~ 1. Level control system oscillatory modes of response, open loop dynamic response, response to step disturbances, and steady state operation shall meet the requirements specified in the GE startup test specification.

27 of 66

put into Level 2

3.7 For feedwater heater loss, the maximum feedwater temperature decrease due to single failure is less than that specified in the GE startup test specification, and the resultant MCPR must be greater than the fuel thermal safety limit specified in the FSAR.

put under Level 2

4.2 On the trip of one feedwater pump, the reactor shall avoid low water level scram by the margin specified by the GE startup test specification.

put under Level 1

5.3 Maximum speed attained shall deliver flows consistent with the requirements specified by the GE startup test specification limits.

14.2.12.3.22 Turbine Valve Surveillance

a. Objective

The test objective is to demonstrate the methods to be used and the maximum power level for routine surveillance testing of the main stop, control, and bypass valves.

b. Prerequisite

The plant has been stabilized at the required power level.

c. Test Method

Individual main stop, control, and bypass valves are manually closed and reset at selected power levels. The response of the reactor is monitored and the maximum power level conditions for the performance of this test are determined. The rate of valve stroking and timing of the closed-open sequence are chosen to minimize the disturbance introduced.

d. Acceptance Criteria

Level 2:

Peak heat flux, vessel pressure, and steam flow shall remain below scram or isolation trip settings by a margin consistent with the GE startup test specification.

14.2.12.3.23 Main Steam Isolation Valves

a. Objectives

1. To functionally check the MSIVs at selected power levels and determine the maximum power level they can be tested at individually

2. To determine isolation valves' closure times.

3. To determine reactor transient behavior during and following simultaneous closure of all MSIVs.

b. Prerequisites

The plant has been stabilized at the required power level.

c. Test Method

1. Individual closure of each MSIV is performed at selected power levels to verify functional performance and to determine closure times. The maximum power level is determined for individual closure with ample margin to scram.

2. A test of the simultaneous full closure of all MSIVs is performed at about 100% power. Operation of the RCIC system and the relief valves is demonstrated. Reactor parameters are monitored to determine transient behavior of the system during the simultaneous full closure test. The reactor will immediately scram due to the actuation of the

MSIV position switches. Recirculation pumps will trip if Level 2 in the RPV is reached. The feedwater control system will prevent the RPV water level from reaching the steam lines.

d. Acceptance Criteria

Level 1:

1. MSIV closure times shall be as specified in the GE startup test specification.

Level 2:

~~2.~~1. Peak neutron flux, vessel pressure, and steam flow shall remain below scram or isolation trip settings by a margin consistent with design requirements when individually testing the MSIVs.

Put under Level 1

~~3.~~2. Following the full closure of all MSIVs, vessel pressure and heat flux level shall be as specified in the GE startup test specification.

Put under Level 2

~~4.~~2. The RCIC system and relief valves shall function in accordance with the GE startup test specification following the MSIV closure from high power.

Put under Level 1

~~5.~~3 The reactor must immediately scram and the feedwater control system must prevent the water from reaching the main steam lines following full closure of MSIVs from high power.

14.2.12.3.24 Relief Valves

a. Objectives

1. To demonstrate proper operation of the main steam relief valves and determine their capacity

2. To demonstrate their leaktightness following operation.

b. Prerequisites

The reactor is on pressure control with adequate bypass or main steam flow.

c. Test Method

A functional test of each safety relief valve (SRV) shall be made as early in the startup program as practical. This is normally the first time the plant reaches 250 psig. The test is then repeated at rated reactor pressure. Bypass valves (BPV) response is monitored during the low pressure test and the electrical output response is monitored during the rated pressure test. The test duration will be about 10 seconds to allow turbine valves and tailpipe sensors to reach a steady state.

The tailpipe sensor responses will be used to detect the opening and subsequent closure of each SRV. The BPV and MWe responses will be analyzed for anomalies indicating a restriction in an SRV tailpipe.

Valve capacity will be based on certification by ASME code stamp and the applicable documentation being available in the onsite records. Note that the nameplate capacity/pressure rating assumes that the flow is sonic. This will be true if the back pressure is not excessive. A major blockage of the line would not necessarily be offset and it should be determined that none exists through the BPV response signatures.

Vendor bench test data of the SRV opening responses will be available onsite for comparison with Section 5.2.2. The acoustic monitoring subsystem will be monitored during the relief valve test program to determine that the setpoints do reflect valve open/valve closed conditions.

SRV opening and reclosure setpoint data will be obtained and evaluated during each high power trip test at which an SRV actuation is anticipated.

31 of 66

d. Acceptance Criteria

Level 1

1. There should be positive indication of steam discharge during the manual actuation of each valve.

Level 2

~~2.~~ 1. Decay ratio for pressure control variables is as specified in the GE startup test specification.

~~3.~~ 2. The temperature measured by thermocouples on the discharge side of the valves should return to the temperature recorded before the valve was open as required in the GE startup test specification. The acoustic monitors shall indicate the valve is closed after valve closure.

~~4.~~ 3. During the 250 psig and the rated pressure functional tests, steam flow through each relief valve as compared to average relief valve flow is as specified in the GE startup test specification.

See Attached ~~5. The vendor bench data for SRV capacity compares favorably with Section 5.2.2 and the accident analysis.~~

14.2.12.3.25 Turbine Trip and Generator Load Rejection

a. Objective

The test objective is to demonstrate the proper response of the reactor and its control systems following trips of the turbine and generator.

b. Prerequisites

Power testing has been completed to the extent necessary for performing this test. The plant is stabilized at the required power level.

4. During the rated pressure test the steam flow through each relief valve, as measured by MWe, shall not be lower than the average valve response by more than that specified in the GE startup test specifications.

c. Test Method

See insert #3 attached

~~The turbine is tripped at three different power levels throughout the power ascension program. For the turbine trip, the main generator breakers remain loaded for a time so there is no rise in turbine generator speed, whereas, in the generator trip, the main generator breakers open and residual turbine steam will cause a momentary rise in the generator speed.~~

At test condition 3, a turbine trip will be initiated manually from the control room. At test condition 6, a generator trip (load rejection) will be initiated by simulating a condition that will cause the generator output breakers to open. During both transients it is expected that the reactor will scram. ~~It is not expected the HPCI or RCIC will initiate.~~ see insert #4 attached Reactor water level, pressure, and heat flux will be monitored. The action of relief valves will be monitored.

A generator trip will be performed at low power such that nuclear boiler system steam generation is just within bypass valve capacity. The purpose of this test is to demonstrate scram avoidance.

During all three transients, main turbine stop, control, and bypass valve positions will be monitored. Prior to the low power generator trip, bypass valve capacity will be measured.

d. Acceptance Criteria

Level 1

1. For turbine and generator trips at power levels greater than 50%, the response times of stop, control, and bypass valves shall be as specified in the GE startup test specification.

2. Feedwater control system settings must prevent flooding the main steam lines.

3. The reactor recirculation pump drive flow coastdown shall be as specified in the GE startup test specification.

INSERT # 3

This test is performed at three different power levels in the power ascension program. For the turbine trip, the main generator remains loaded for a time so there is no rise in turbine generator speed, whereas, in the generator trip, the main generator output breakers open and residual steam will cause a momentary rise in turbine generator speed.

INSERT # 4 (add to the sentence)

and the recirculation pump trip (RPT) breakers will open.

35/66

4. The positive change in vessel dome pressure and heat flux must not exceed the limits specified in the GE startup test specification.

5. The total time delay from start of turbine stop valve motion or turbine control valve motion to complete suppression of electrical arc between the fully open contacts of the RPT circuit breakers shall be less than the limit specified in the GE startup test specification.

Level 2:

6. The measured bypass valve capacity shall be equal to or greater than that required by the GE startup test specification, which compares bypass valve capacity to the accident analysis.

~~7~~. 2. There shall be no MSIV closure during the first three minutes of the transient and operator action shall not be required during that period to avoid the MSIV trip.

~~8~~. 3. For the generator trip within bypass valves capacity, the reactor shall not scram for initial thermal power valves within that bypass valve capacity and below the power level at which trip scram is inhibited.

~~9~~. 4. Low water level recirculation pump trip, HPCI and RCIC shall not be initiated.

~~10~~. 5. Feedwater level control shall avoid loss of feedwater due to high level trip during the event.

~~11~~. 6. The temperature measured by thermocouples on the discharge side of the valves should return to the temperature recorded before the valve was open as required in the GE startup test specification. The acoustic monitors shall indicate the valve is closed after valve closure.

14.2.12.3.26 Shutdown From Outside the Main Control Room

a. Objective

The test objective is to demonstrate that the reactor can be brought from an initial steady-state power level to hot standby and that the plant has the potential for being safely taken to a cold shutdown condition from hot standby from outside the main control room.

b. Prerequisites

The plant is operating at the required power level.

c. Test Method

The test will be performed at a low power level and will consist of demonstrating the capability to scram and initiate controlled cooling from outside the control room. The reactor will be scrammed ~~and isolated~~ from outside the control room after a simulated control room evacuation. Reactor pressure and water level will be controlled using SRVs, RCIC, and RHR from outside the control room during subsequent cooldown. The cooldown will continue until RHR shutdown cooling mode is placed in service from outside the control room. Alternatively, verification of satisfactory operation of RHR shutdown cooling mode from outside the control room may be done at some other, more convenient time during the startup program. In either case, coolant temperature must be lowered at least 50°F while in the shutdown cooling mode. During the shutdown cooling mode demonstration, cooling to the RHR heat exchanger via the safety auxiliaries cooling system and the station service water system will be accomplished from the remote shutdown panel. All other operator actions not directly related to reactor vessel level, temperature, and pressure control will be performed in the main control room. The plant will be maintained in hot standby condition for at least 30 minutes during the performance of this test.

Delete

d. Acceptance Criteria

Level 2:

During a simulated main control room evacuation, the ability to bring the reactor to hot standby and subsequently cool down the plant and control vessel pressure and water level shall be demonstrated using equipment and controls located outside the main control room.

14.2.12.3.27 Recirculation Flow Control

a. Objectives

1. To determine plant response to changes in the recirculation flow

2. To optimize the setting of the master flow controller

3. To demonstrate plant loading capability.

b. Prerequisites

The reactor is operating at steady-state conditions at the required power level.

c. Test Method

With the reactor plant at the 50% load line, the recirculation speed loops are tested using large plus and minus step changes and and the speed controller gains are optimized. After the speed loops have been optimized, the system may be switched to the master manual mode and the automatic load following mode loop shall be optimized.

When the plant is tested along the 100% load line, the recirculation system shall be tested by inserting small plus and minus step changes in the local manual and master manual modes. The automatic load following loop is also tested by means of small load demand changes.

During recirculation flow control testing at the 50% and 100% load lines no scrams due to neutron flux or heat flux changes transients are expected.

d. Acceptance Criteria

Level 1

1. The transient response to any recirculation system related variable to any test input must not diverge.

Level 2

~~2.~~ 1. A scram shall not occur due to recirculation flow maneuvers. Neutron flux and heat flux trip avoidance margins are as specified in the GE startup test specification.

~~3.~~ 2. The decay ratio of any oscillatory controlled variable must be less than that required by the GE startup test specification.

Delete ~~4. Closed and open speed loop adjustments are as specified in the GE startup test specification.~~

~~5.~~ 3. Steady state limit cycles shall not produce turbine steam flow variations greater than the value of steam flow specified in the GE startup test specification.

~~6.~~ 4. In the scoop tube reset function, if the speed demand meter has not been replaced by an error meter, the speed demand meter must agree with the speed meter within the GE startup test specifications.

14.2.12.3.28 Recirculation System

a. Objectives

1. To determine transient responses and steady-state conditions following recirculation pump trips at selected power levels

2. To obtain recirculation system performance data

3. To verify that cavitation in the recirculation system does not occur in the operating region of the power/flow map.

4. To verify the adequacy of the recirculation runback to mitigate a scram upon loss of one feedwater pump.

5. To verify that the feedwater control system can control water level without causing a turbine trip/scram following a single recirculation pump trip.

6. To demonstrate the adequacy of the recirculation pump restart procedure at the highest possible power level.

b. Prerequisites

The reactor is operating at steady-state conditions at required power level.

c. Test Method

Single pump trips are performed at test condition 3 and 6. Dual pump trip is demonstrated at test condition 3. The one-pump trip tests are to demonstrate that water level will not rise enough to threaten a high level trip of the main turbine or the feedwater pumps. The dual pump trip verifies the performance of the RPT circuit and the recirculation pump flow coastdown prior to the high power turbine generator trip tests. Single pump trips are initiated by tripping the MG set generator output breaker. ~~M-G set drive motor breaker.~~ Adequate margins to scrams and capability of the feedwater system to prevent a high level trip will be monitored. The two pump trip will be initiated by simultaneously tripping both recirculation RPT breakers using a test switch. The recirculation pump restart demonstrates the adequacy of the restart operating procedure at the highest possible power level.

delete

At several power and flow conditions, and in conjunction with sihgle pump trip recoveries, recirculation system parameters are recorded.

At test condition 3 and at near rated recirculation flow, a loss of a feedwater pump is simulated. This is done prior to an actual feedwater pump trip to determine the adequacy of recirculation pump runback feature in preventing a scram.

While at test condition 3, it will be demonstrated that the cavitation interlocks which runback the recirculation pumps on decreased feedwater flow are adequate to prevent operation where recirculation pump or jet pump cavitation can occur.

d. Acceptance Criteria

Level 1

1. During recovery from one pump-trip, the reactor shall not scram.

Level 2

2. Neutron flux, heat flux, and reactor water level scram avoidance margins are as specified in the GE startup test specification.

~~3.~~ 2 The two pump drive flow coastdown time following a dual recirculation pump trip is as specified in the GE startup test specification.

~~4.~~ 2. System performance parameters, including core flow, drive flow, jet pump M-ratio, core delta-pressure, recirculation pump efficiency and jet pump nozzle and riser plugging criteria are as specified in the GE startup test specification.

~~5.~~ 3 Runback logic shall have settings adequate to prevent operation in areas of potential cavitation.

~~6.~~ 4 The recirculation pump shall runback upon a trip of the runback circuit as required by the GE startup test specification.

14.2.12.3.29 Recirculation System Flow Calibration

a. Objective

The test objective is to perform a complete calibration of the installed recirculation system flow instrumentation, including specific signals to the plant process computer.

b. Prerequisites

The reactor is operating at steady-state conditions. The initial calibration of the recirculation system flow instrumentation has been completed.

c. Test Method

During the testing program at operating conditions required for rated flow at rated power, the jet pump flow instrumentation is adjusted to provide correct flow indication based on the jet pump flow. The flow-biased APRM/RBM system is adjusted to correctly follow core flow based on drive flow. Additionally, the total core flow and recirculation flow signals to the process computer will be calculated to read these two process variables.

d. Acceptance Criteria

Level 2

1. Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder provides core flow at rated conditions.

2. The APRM/RBM flow bias instrumentation shall be adjusted to function per design at rated conditions, as specified in the GE startup test specification.

3. see attached

~~INSERT # 5~~

The flow control system shall be adjusted to limit maximum core flow to the value specified by the GE startup test specification.

14.2.12.3.30 Loss of Turbine-Generator and Offsite Power

a. Objective

The objective of this test is to demonstrate the response of the reactor and electrical equipment and systems during loss of the main generator and offsite power.

b. Prerequisites

The SDGs are in the auto-start mode, and the plant is operating at power.

c. Test Method

With the power plant synchronized to the grid between 20% and 30% power, the main turbine generator will be tripped followed by manual trips of all offsite power to the 13.8 kV ring bus. This will simulate loss of turbine generator and offsite power.

Reactor water level and the operation of safety systems, including RPS, standby diesels, RCIC, and HPCI, will be monitored.

The loss of offsite power condition will be maintained for at least 30 minutes to demonstrate that necessary equipment, controls, and indication are available following the station blackout to remove decay heat from the core using only emergency power supplies and distribution systems.

d. Acceptance Criteria

Level 1:

1. All safety systems, such as the RPS, SDG, RCIC, and HPCI, function per design without manual assistance. Reactor parameters are maintained within acceptable design limits. Normal reactor cooling systems maintain adequate suppression pool water temperature, adequate drywell cooling, and

prevent actuation of the automatic depressurization system.

Level 2

~~2~~. Proper instrument display to the reactor operator shall be demonstrated, including power monitors, pressure, water level, control rod position, suppression pool temperature, and reactor cooling system status.

~~3~~.2. The temperature measured by thermocouples on the discharge side of the valve should return to the temperature recorded before the valve was open as required in the GE startup test specification. The acoustic monitors shall indicate the valve is closed after valve closure.

14.2.12.3.31 ~~Drywell~~ Piping Vibration Tests

a. Objective

The test objective is to verify that steady state vibration and transient induced pipe motion of systems discussed in Section 3.9.2 are acceptable.

b. Prerequisites

The system piping to be tested is supported and restrained properly. Instrumentation for monitoring vibration has been installed and calibrated, where applicable.

c. Test Method

This test is an extension of the preoperational test program. During steady state operation, designated pipes as delineated in Section 3.9.2 will be monitored for vibration. Dynamic vibration measurements will be made on applicable piping following various plant and system transients as specified in Sections 3.9.2.1.2.3, 3.9.2.1.3, and 3.9.2.2.4.

d. Acceptance Criteria

Level 1

The piping displacements at the established locations shall not exceed the limits specified by the piping designer, which are based on not exceeding ASME Section III Code stress values or ANSI B31.1 values. These acceptable vibration levels will be used as acceptance criteria in the appropriate piping vibration startup test procedures.

14.2.12.3.32 Reactor Water Cleanup System

a. Objective

The test objective is to demonstrate the operation of the RWCU system.

b. Prerequisites

The reactor has been operated at a near rated temperature and pressure long enough to achieve a steady-state condition.

c. Test Method

With the reactor at rated temperature and pressure, process variables are recorded during steady-state operation in three modes of operation of the RWCU system: blowdown, hot standby, and normal. The bottom head drain flow indicator will be calibrated by taking flow from the bottom drain only and using the RWCU system inlet flow indicator as a standard to compare against.

d. Acceptance Criteria

Level 2

1. The data indicating operation in the listed modes shall be acceptable as specified by the GE startup test specification.

2. Recalibrate bottom head flow indicator against RWCU flow indicator if the deviation is greater than GE startup test specifications.

3. Pump vibration as measured on the bearing housing and coupling end shall be less than or equal to GE startup test specifications.

14.2.12.3.33 Residual Heat Removal System

a. Objectives

1. To demonstrate the ability of the RHR system to remove residual and decay heat from the nuclear system, so that refueling and nuclear system servicing can be performed

2. To condense steam while the reactor is isolated from the main condenser, in conjunction with the RCIC system.

b. Prerequisites

Preoperational testing has been completed. The test procedure has been reviewed, approved, and released for testing. Instrumentation has been checked or calibrated as appropriate. The plant is at or near normal operating pressure and temperature.

c. Test Method

Three modes are tested to verify system capability under actual operating conditions. The modes to be tested are suppression pool cooling, shutdown cooling and steam condensing. During the operations, the heat transfer rate is controlled to maintain acceptable cooldown rates. Data are recorded and reviewed to verify the satisfactory operation of the RHR system within design limits.

d. Acceptance Criteria

Level 2:

1. The RHR system performance in the steam condensing mode, suppression pool cooling mode and shutdown cooling mode meets the requirements of the GE startup test specification.

14.2.12.3.34 Drywell and Steam Tunnel Cooling ~~System~~

a. Objective

The test objective is to demonstrate, under actual operating conditions, satisfactory ~~performance of the~~ cooling ~~drywell atmospheric cooling systems~~ of the drywell and steam tunnel, including concrete surrounding hot piping penetrations.

b. Prerequisites

Appropriate preoperational tests have been completed

~~Airflow balancing of the Drywell Cooling system has been completed~~.

Power ascension testing is in progress.

Representative penetrations have been instrumented.

c. Test Method

see attached #1

Drywell atmospheric steam tunnel atmospheric and penetration temperatures are monitored and recorded during plant heatup and power operation up to rated power. ~~Drywell temperatures are demonstrated to be at or below the design limits. Adjustments to air flows and/or cooling water flows are made, if required, to maintain acceptable temperature limits~~.

d. Acceptance Criteria

Level 1:

1. Drywell and steam tunnel atmospheric temperature control shall meet or exceed the limits specified in the plant technical specifications.

see attached #2

#1: In addition, drywell atmospheric, steamtunnel atmospheric, and hot piping penetration concrete temperatures are checked at various power levels, up to rated, with minimum drywell cooling capacity in service. Design temperature limits are verified to be met, and cooling system adjustments are made as required to maintain acceptable temperatures. 480/66

#2:

2. The concrete temperatures surrounding hot piping penetrations during normal operation shall not exceed the allowable local area limit for normal operations, specified in Section 3.8.2.

14.2.12.3.35 ~~Offgas Treatment~~ Gaseous Radwaste System

a. Objective

The test objective is to demonstrate proper operation of the ~~offgas treatment~~ Gaseous Radwaste system over its expected operating range.

b. Prerequisites

Initial calibration of instrumentation has been completed. Power ascension testing is in progress.

c. Test Method

See attached #1

~~During startup and power operations,~~ condenser ~~offgas~~ ~~is processed by the offgas treatment system~~. ~~During power ascension testing at steady-state conditions, system parameters of the offgas treatment system are monitored and recorded for evaluation of system performance.~~ Adjustments will be made, if necessary, to meet acceptable system performance.

~~Gaseous~~ ~~Rad~~waste

d. Acceptance Criteria

Level 2:

~~The radioactive gaseous and particulate effluent from the offgas treatment system shall not exceed limits specified in the technical specifications~~. System performance as verified by data analysis shall meet design requirements specified in Section 11.3.1. d and K.

14.2.12.3.36 Water Level Measurement

This test was included in Section 14.2.12.3.14.

#1/ During power ascension testing at steady-state conditions, gaseous radwaste system operational data for system flow, pressure, temperature, and dewpoint are recorded.

~~#2~~/

14.2.12.3.37 Penetration Temperature Test

This test was included in Section 14.2.12.3.~~21~~ 34.

Delete

a. ~~Objective~~

~~To verify that the drywell penetrations associated with hot piping systems provide adequate protection for the surrounding concrete.~~

b. ~~Prerequisites~~

1. ~~Power ascension testing is in progress.~~

2. ~~Instrumentation is calibrated.~~

c. ~~Test Method~~

~~During heatup and power operations, the concrete temperatures surrounding hot penetrations will be monitored.~~

d. ~~Acceptance Criteria~~

~~The concrete temperatures surrounding hot piping penetrations shall not exceed 200°F.~~

14.2.12.3.38 Safety Auxiliaries Cooling System

a. Objective

The test objective is to demonstrate that the safety auxiliaries cooling system (SACS) performance margin is adequate to support engineered safety features equipment over their full range of design requirements.

b. Prerequisites.

Initial instrument calibrations have been completed. The plant is operating at the required test condition.

c. Test Method

During the performance of the RHR shutdown cooling mode test, the SACS will also be evaluated to determine the heat removal capacity of the system and demonstrate the capability of achieving cold shutdown within the time specified in the design specificiation. ~~During operation of other ESF equipment, the capability of SACS to maintain the required environment will be verified~~.

Delete

d. Acceptance Criteria

Level 1:

~~The SACS cooling capability shall meet or exceed the requirements of Section 9.2.2.~~

14.2.12.3.39 BOP Piping Vibration and Expansion

This test was included in Sections 14.2.12.3.15 and 14.2.12.3.31.

See Attachment 2

Level 2:

The SACS heat exchanger shall meet or exceed the design heat removal capacity listed in Table 9.2-3.

Attachment 1

14.2.12.3.40 CONFIRMATORY INPLANT TEST OF SAFETY-RELIEF VALVE DISCHARGE

a. OBJECTIVE

The objective of this test is to confirm assumptions and methodologies used in the plant unique analysis (PUA) (see a summary report in Appendix 3B) and show that the loads and structural responses documented in the PUAR for SRV discharge related loads are conservative compared to the responses which occur during actual SRV discharges.

b. PREREQUISITES

1. Power level should be sufficient to support steady steam flow, during the test duration, through SRV discharge line with normal plant operating pressure at the SRV.

2. Instrumentation for monitoring loads and structural responses has been installed and calibrated.

c. TEST METHOD

A shakedown test will be conducted to verify the test set-up is functioning properly. The testing will consist of single valve actuations (SVA) and subsequent consecutive valve actuations (CVA) of the same valve. Selection of the SRV discharge line used for testing will be based on NUREG-0763, "Guidelines for Confirmatory Inplant Tests of Safety-Relief Valve Discharges for BWR Plants," recommendations. Data will be collected and analyzed by computer code to verify design analysis.

d. ACCEPTANCE CRITERIA

Level 1

The peak pool boundary pressure during air clearing and steam discharge during the valve actuation is less than the predicted valve specified in the PUAR.

14.2.13 SRP RULE REVIEW

14.2.13.1 SRP 14.2, II, Regulatory Guide 1.68 Revision 2, August 1978: Initial Test Programs for Water-Cooled Nuclear Power Plants

HCGS complies with Regulatory Guide 1.68, with the following exceptions and clarifications:

a. Position C.1 provides the criteria for selection of plant features that are tested during the initial test program. At HCGS, testing is conducted on structures, systems, components, and design features as described in this section based on their safety-related functions.

   The objective of Regulatory Guide 1.68 is to describe the scope and depth of a test program required to ensure that plant structures, systems, and components perform satisfactorily in service. The basis for this Regulatory Guide is Appendix B to 10 CFR 50, which specifically applies only to testing the performance of safety-related functions. Therefore, this Regulatory Guide is applied only to plant structures, systems, and components that have safety-related function, defined as those plant features necessary to ensure the integrity of the RCPB, the capability to shut down the reactor and maintain it in a safely shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in offsite exposures comparable to the guideline exposure of 10 CFR 100.

   Safety-related structures, systems, and components are identified as such in this section and are tested to meet the requirements of Regulatory Guide 1.68. Other systems and components within the plant are not safety-related may or may not be tested in accordance with the Regulatory Guide. Since the plant units that are not safety-related by definition do not compromise the safety-related aspects of the plant, it is not planned to test them to the Regulatory Guide.

b. Position C.7 and Section 1.h of Appendix C of Regulatory Guide 1.68 state that one of the objectives

FSAR Subsection 14.2.12.3.##

TEST NO.	TEST NAME	OPEN VESSEL	HEAT UP	1	2	3	4	5	6	WARRANTY
1	Chemical and Radiochemical	X	X	X		X		X	X	
2	Radiation Measurement	X	X	X		X			X	
3	Fuel Loading	X			•					
4	Full Core Shutdown Margin	X								
5	Control Rod Drive	X	X		X(2)	X(2)			X(2)	
6	SRM Perf & Cont Rod Seq	X	X	X						
8 ~~10~~	IRM Performance		X	X						
9 ~~11~~	LPRM Calibration		X	X		X			X	
10 ~~12~~	APRM Calibration		X	X	X	X		X	X	
11 ~~13~~	Process Computer	X	X	X(3)		X		X		
12 ~~14~~	RCIC		X	X						
13 ~~15~~	HPCI		X			X				
14 ~~16A~~	Selected Process Temp		X			X	X(4)		X	
14 ~~16B~~	Water Level Ref Leg Temp		X			X	X		X	
15 ~~17~~	System Expansion	X	X	X		X			X	
16 ~~18~~	~~Core Power Distribution~~ TIP Uncertainty					X			X	
17 ~~19~~	Core Performance			X	X	X	X	X	X	X
18 ~~20~~	Steam Production									X
19 ~~21~~	Core Pwr-Void Mode Response						X	X		
20 ~~22~~	Pressure Regulator			X	X	X	X	X	X	
21 ~~23A~~	Feed Sys-Setpoint Changes		X	X	X	X	X	X	X	
21 ~~23B~~	Feed Sys-Loss FW Heating								X(5)	
21 ~~23C~~	Feedwater Pump Trip								X(6)	
21 ~~23D~~	Max FW Runout Capability								X(7)	
22 ~~24~~	Turbine Valve Surveillance					X(8)		X(9)	X(10)	
23 ~~25A~~	MSIV Functional Test		X	X(11)	X(12)			X(13)		
23 ~~25B~~	MSIV Full Isolation								X	
24 ~~26~~	Relief Valves		X		X	X(20)			X(20)	
25 ~~27~~	Turbine Trip & Load Rejection				X(15)	X(16)			X(17)	
26 ~~28~~	Shutdown Outside CRC				X					
27 ~~29~~	Recirculation Flow Control				X(14)			X(18)		
28 ~~30A~~	Recirc-One Pump Trip					X			X	
27 ~~30B~~	RPT Trip-Two Pumps					X(19)				
28 ~~30C~~	Recirc System Performance				X	X	X		X	
28 ~~30D~~	Recirc Pump Runback					X				
28 ~~30E~~	Recirc Sys Cavitation					X				
30 ~~31~~	Loss of T-G & Offsite Pwr		~~X~~	X						
31 ~~33~~	Pipe Vibration		X	X	X	X			X	
29 ~~35~~	Recirc Flow Calibration					X			X	
32 ~~70~~	RWCU		X							
33 ~~71~~	RHR & Steam Tunnel			X					X(21)	
34 ~~72~~	Drywell Cooling ~~System and Penetration Temperature~~		X	X	~~X~~	X			X	
35 ~~74~~	Gaseous Radwaste		~~X~~	X	~~X~~	X			X	
38 ~~75~~	SACS Performance			X	X	~~X~~		~~X~~	X	

FSAR 3/7

(1) Test conditions refer to plant conditions on Figure 14.2-4

(2) Perform Test 5, timing of 4 slowest control rods, in conjunction with expected scrams

(3) Dynamic System Test Case to be completed between test conditions 1 and 3

(4) After recirculation pump trips (natural circulation)

(5) Between 80 and 90 percent thermal power, and near 100 percent core flow

(6) ~~Test Nos. 23C and 30D~~ Max FW Runout Capability & Recirc Pump Runback must have already been completed

(7) Reactor power between 80 and 90 percent

(8) Reactor power between 45 and 65 percent

(9) Reactor power between 75 and 90 percent

(10) At maximum power that will not cause scram

(11) Perform between test conditions 1 and 3

(12) Reactor power between 40 and 55 percent

(13) Reactor power between 60 and 85 percent

(14) Between test conditions 2 and 3

(15) Generator load rejection, within bypass valve capacity

(16) Reactor power between 60 and 80 percent at core flow $\geq$ 95 percent - turbine trip

(17) Load reject

(18) Between test conditions 5 and 6

(19) >50% power and $\geq$95 core flow, and performed before ~~test No. 27~~ Turbine Trip & Load Rejection

(20) Check SRV set points during major scram tests

(21) Performed during cooldown from test condition 6

FSAR 3/7

HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

TEST SCHEDULE AND CONDITIONS

FIGURE 14.2-5

Amendment 5, 4/84

55 of 66

QUESTION 640.14 (SECTION 14.2.12)

For compliance with Regulatory Guide 1.68, Appendix A.3, modify FSAR Subsection 14.2.12.3.6 (Source Range Monitor Performance and Control Rod Sequence) to ensure:

1. A neutron count rate of at least 1/2 count per second registers on the startup channels before startup begins.

2. The signal-to-noise ratio is greater than two.

3. Initial criticality will be approached on a startup rate of less than 1 decade/minute.

RESPONSE

~~The acceptance criteria for the minimum neutron count rate is as specified in the GE Startup Test Specification in Section 14.2.12.3.6.d. Additionally, the minimum count rate will meet the requirements of Chapter 16, Technical Specifications.~~

~~The acceptance criteria for the signal count-to-noise ratio is as specified in the GE Startup Test Specification in Section 14.2.12.3.6.d.~~

Section 14.2.12.3.6.c has been revised to indicate a precaution that initial criticality will be approached at a period greater than 30 seconds (equivalent to starting rate less than 0.91 decades per minute).

SECTION ~~14.2.12.3.d~~ 14.2.12.3.6.d HAS BEEN REVISED TO SPECIFY ACCEPTANCE CRITERIA FOR A MINIMUM NEUTRON COUNT RATE OF 1/2 COUNTS PER SECOND AND A SIGNAL-TO-NOISE RATIO GREATER THAN TWO.

drive startup test, described in Section 14.2.12.3.5, during initial heatup and just after fuel load. Also, the reactor protection system is verified to operate following scheduled transient tests such as MSIV isolation and turbine trip.

2. Leak Detection: Although there will be no startup test procedure designated Leak Detection, portions of leak detection governed by Technical Specifications will be functionally checked just prior to fuel load using station surveillance and calibration procedures. Setpoints related to leak detection high steam flow in HPCI and RCIC are verified and set as stated in Sections 14.2.12.3.12 and 14.2.12.3.13. Normal operation of leak detection systems, such as the drywell equipment drain sump pump will be accomplished using station operating procedures.

3. Equipment and Floor Drainage: Although there will be no startup test designated Equipment and Floor Drainage, these systems will be functionally checked using station operating procedures. Any portions of equipment and floor drainage systems governed by Technical Specifications will be functionally checked prior to fuel load using station surveillance and calibration procedures.

4. Loose Parts Monitoring: Although there will be no startup test procedure designated Loose Parts Monitoring, additional data to supplement the preoperational program on loose parts monitoring will ~~be taken as stated in revised Section 14.2.10.~~
→SEE ATTACHED

6. Hotwell Level Control: Although there will be no startup test procedure designated Hotwell Level Control, operation of the hotwell level control system will be verified using station operating procedures and monitoring hotwell level during Phase III startup testing.

7. Leak Detection System - Refer to response for item 2 above.

8. Penetration Coolers: Addressed in Amendment 1, Section 14.2.12.3.~~31~~ 34.

9. ATWS Test: Although there will be no startup test procedure designated ATWS, the ATWS subsystems are thoroughly checked out logically and functionally during the preoperational test program, as described in Sections 14.2.12.1.2.c.6, 14.2.12.1.3.c.3., 14.2.12.1.4.c.4., 14.2.12.1.8.c.9, 14.2.12.1.9.c.7.,

4.cont Baseline Data will be taken at 25, 50, 75, and 100% of system flow for system piping on which the sensors are located. In addition, noise signatures of selected transients (e.g. MSIV closures, recirculation pump trips) that may cause increased noise levels at the sensors will be taken to aid in ~~resolving~~ evaluating short lived noise transients later in plant life.

5. Electrohydraulic Control: addressed in Sections 14.2.12.3.20 and 14.2.12.3.22

QUESTION 640.23 (SECTION 14.2.12)

To help facilitate approval of future changes to the Hope Creek Initial Test Program, list and provide technical justification for any startup tests or protions of startup tests which you believe should be exempted from the license condition requiring prior NRC notification of major test changes to tests described in FSAR Chapter 14. Such a list should include those tests not necessary to verify the proper design, construction, or performance of systems, structures, or components important to safety (fulfill General Design Criteria (GDC) functions and/or are subject to 10 CFR 50 Appendix B Quality Assurance requirements).

RESPONSE

CM ~~Using Figure 14.2-5 as a guide,~~ the following tests are exempted from the license condition requiring prior NRC notification of major test changes:

1. ~~Test No. 20~~ - Steam Production (Section 14.2.12.3.18)

   Justification: The sole purpose of this test is to demonstrate the nuclear steam supply system provides sufficient steam to satisfy all appropriate warranties as defined in the contract between General Electric and PSE&G.

2. ~~Test No. 22~~ - Pressure Regulator (Section 14.2.12.3.20)

   Justification: The purpose of the test is to tune the pressure regulator control system, to demonstrate the backup pressure regulator, and to demonstrate smooth pressure control transition between the bypass valves and the turbine control valves. This system is classified as a power generation system and is not a safety-related system, does not fulfill a general design criteria, and is not subject to 10 CFR 50 Appendix B requirements.

3. ~~Test No. 23A~~ - Feedwater System - Water Level Setpoint Changes (Section 14.2.12.3.21)

   Justification: The purpose of the test is to tune the feedwater control system for all feedwater pump and valve configurations. This system is classified as a power generation system and is not a safety-related system, does not fulfill a general design criteria or is not subject to 10 CFR 50, Appendix B requirements.

4. ~~Test No. 23C~~ - Feedwater Pump Trip (Section 14.2.12.3.21)

Justification: The purpose of this test is to verify that the reactor recirculation runback circuit activated by a feedwater pump trip will act to drop power within the capacity of the remaining feedwater pumps. The acceptance criteria for the test is simply that there is an avoidance to scram due to the runback circuit, thus providing a capacity factor improvement. This is not a safety-related circuit, does not fulfill general design criteria, and is not subject to 10 CFR 50 Appendix B requirements.

5. ~~Test No. 24~~ Turbine Valve Surveillance (Section 14.2.12.3.22)

Justification: The purpose of the test is to demonstrate acceptable procedures and maximum power levels for recommended periodic surveillance testing of the main turbine control, stop, and bypass valves without producing a reactor scram, thus providing a capacity factor improvement. This test does not prove a safety-related system or circuit, does not fulfill general design criteria, and is not subject to 10 CFR 50, Appendix B requirements.

6. ~~Test No. 29~~ - Recirculation Flow Control (Section 14.2.12.3.27)

Justification: The purposes of this test are to adjust and demonstrate flow control capability and to determine that the electrical compensators and controllers are set for desired system performance and stability. This system is considered a power generation system and is not considered a safety system. No portions of this test fulfill a general design criteria, nor is this system subject to 10 CFR 50, Appendix B requirements.

7. ~~Test No. 30D~~ Recirculation Pump Runback (Section 14.2.12.3.28)

Justification: This test is accomplished in conjunction with ~~Test No. 23C~~ Feedwater Pump Trip Test. The justification is the same as that given for ~~Test No. 23C~~ Item 4 above

8. ~~Test No. 30E~~ Recirculation System Cavitation (Section 14.2.12.3.22

Justification: The purpose of this test is to show that the recirculation system flow will be runback to prevent operation in areas of potential cavitation to protect installed plant equipment. The test does not address any nuclear safety-related concern, does not fulfill a general design criteria, and the runback circuit is not subject to 10 CFR 50 Appendix B requirements.

9. ~~Test No. 70~~ Reactor Water Cleanup (RWCU) (Section 14.2.12.3.32)

Justification: The purpose of the test is to demonstrate specific aspects of the mechanical operability of the RWCU system, including NPSH to the RWCU pumps, non-regenerative heat exchanger performance, and bottom head flow indication. The test does not prove any safety-related aspects of the RWCU system, such as system isolation. Additionally, the test does not fulfill general design criteria, nor do functions of the test fall under 10 CFR 50 Appendix B requirements.

RESPONSE

CHV ~~Using Figure 14.2-5 as a guide~~, the following tests are exempted from the license condition requiring prior NRC notification of major test changes:

1. ~~Test No. 20 -~~ Steam Production (Section 14.2.12.3.18)

   Justification: The sole purpose of this test is to demonstrate the nuclear steam supply system provides sufficient steam to satisfy all appropriate warranties as defined in the contract between General Electric and PSE&G.

2. ~~Test No. 22 -~~ Pressure Regulator (Section 14.2.12.3.20)

   Justification: The purpose of the test is to tune the pressure regulator control system, to demonstrate the backup pressure regulator, and to demonstrate smooth pressure control transition between the bypass valves and the turbine control valves. This system is classified as a power generation system and is not a safety-related system, does not fulfill a general design criteria, and is not subject to 10 CFR 50 Appendix B requirements.

3. ~~Test No. 23A -~~ Feedwater System - Water Level Setpoint Changes (Section 14.2.12.3.21)

   Justification: The purpose of the test is to tune the feedwater control system for all feedwater pump and valve configurations. This system is classified as a power generation system and is not a safety-related system, does not fulfill a general design criteria or is not subject to 10 CFR 50, Appendix B requirements.

4. ~~Test No. 23C -~~ Feedwater Pump Trip (Section 14.2.12.3.21)

   Justification: The purpose of this test is to verify that the reactor recirculation runback circuit activated by a feedwater pump trip will act to drop power within the capacity of the remaining feedwater pumps. The acceptance criteria for the test is simply that there is an avoidance to scram due to the runback circuit, thus providing a capacity factor improvement. This is not a safety-related circuit, does not fulfill general design criteria, and is not subject to 10 CFR 50 Appendix B requirements.

5. ~~Test No. 21~~ Turbine Valve Surveillance (Section 14.2.12.3.22)

Justification: The purpose of the test is to demonstrate acceptable procedures and maximum power levels for recommended periodic surveillance testing of the main turbine control, stop, and bypass valves without producing a reactor scram, thus providing a capacity factor improvement. This test does not prove a safety-related system or circuit, does not fulfill general design criteria, and is not subject to 10 CFR 50, Appendix B requirements.

6. ~~Test No. 29~~ Recirculation Flow Control (Section 14.2.12.3.27)

Justification: The purposes of this test are to adjust and demonstrate flow control capability and to determine that the electrical compensators and controllers are set for desired system performance and stability. This system is considered a power generation system and is not considered a safety system. No portions of this test fulfill a general design criteria, nor is this system subject to 10 CFR 50, Appendix B requirements.

7. ~~Test No. 30D~~ Recirculation Pump Runback (Section 14.2.12.3.28)

Justification: This test is accomplished in conjunction with ~~Test No. 23C~~ Feedwater Pump Trip Test. The justification is the same as that given for ~~Test No. 23C~~. Item 4 above.

8. ~~Test No. 30E~~ Recirculation System Cavitation (Section 14.2.12.3.28)

Justification: The purpose of this test is to show that the recirculation system flow will be runback to prevent operation in areas of potential cavitation to protect installed plant equipment. The test does not address any nuclear safety-related concern, does not fulfill a general design criteria and the runback circuit is not subject to 10 CFR 50 Appendix B requirements.

9. ~~Test No. 70~~ Reactor Water Cleanup (RWCU) (Section 14.2.12.3.32)

Justification: The purpose of the test is to demonstrate specific aspects of the mechanical operability of the RWCU system, including NPSH to the RWCU pumps, non-regenerative heat exchanger performance, and bottom head flow indication. The test does not prove any safety-related aspects of the RWCU system, such as system isolation. Additionally, the test does not fulfill general design criteria, nor do containment prepurge cleanup system (CPCS), and the reactor building ventilation system (RBVS). The drywell air cooling system removes heat from the drywell during normal plant operation, plant shutdown, and certain abnormal conditions.

The capability to purge the drywell and torus is provided by the CPCS and the RBVS, as described in Section 9.4.2.

9.4.5.1 Design Bases

The design bases for the drywell air cooling system are as follows:

a. During normal reactor operation, limit the average air temperature inside the drywell to 135°F maximum, with no location over 150°F, and 128°F maximum around the recirculating pump motors.

b. During scram, but without loss of offsite power (LOP), limit the maximum ambient temperature in the area under the reactor vessel to 165°F or lower, for up to 30 minutes.

c. During normal reactor operation, prevent concrete structures within the drywell from exceeding their maximum design temperature [redacted] specified in Section 3.8.2.

d. During normal shutdown operation, limit the air temperature inside the drywell to 104°F maximum and 60°F minimum by use of the RBVS purge mode.

e. In the event of LOP and reactor scram, limit the ambient temperature inside the drywell to 185°F.

f. The single failure of an active or passive component in the system cannot result in a complete failure of the system.

g. The drywell air cooling system is not a safeguard system for a loss-of-coolant accident (LOCA), but can

65 of 66

Each SACS loop is located in a different room. Power is supplied from four independent divisions. Failure of either a motor-operated valve (MOV), standby diesel generator, electrical division, or pump does not prevent the system from removing the full heat load. This arrangement ensures that the full heat removal capacity required is available after a postulated single active failure.

The TACS has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant. In the event of a LOCA, LOP, or a pipe break, TACS is isolated from the SACS.

9.2.2.4 Test and Inspection

see attached

~~The SACS is tested in accordance with the requirements of Chapter 14 during the startup testing.~~

Inservice Inspection and functional testing of the safety-related portions of the system and components will be in accordance with the examination and testing criteria of Articles IWA, IWD, IWP and IWV of Section XI, ASME Code, 1977 Edition and addenda through Summer, 1978.

The specific examination and tests of the system and components will be listed in the Station Inservice Inspection (ISI) and Inservice pump and Valve Test (ISI) Program Administrative Procedures.

9.2.2.5 Instrumentation Applications

The SACS is designed for remote operation from the main control room. In addition, one loop of the SACS and its associated valves can be operated from the remote shutdown panel.

Local and remote indications are provided to monitor process parameters of the system. The following conditions are annunciated in the main control room:

a. High-high/low-low level in the expansion tank

The SACS is tested in both the preoperational test phase and power ascension test phase. ~~For~~ Test ~~&~~ abstracts for these tests are decribed in subsections 14.2.12.1.16 and 14.2.12.3.38.

Rev 1

HCGS

DSER Open Item No. 186 (DSER Section 7.2.2.3)

TESTABILITY OF PLANT PROTECTION SYSTEM POWER

We will require that the applicant demonstrate the capability of the design for on-line testing of each instrumentation channel, logic, actuation device and actuated equipment in the ECCS and BOP ESF systems. All actuated contacts and devices should be considered and those which cannot be tested on-line should be identified and justification provided.

RESPONSE

The response to Question 421.22 has been revised to provide the requested information concerning on-line testability.

QUESTION 421.22 (SECTIONS 7.2, 7.3, 7.4, 7.5, 7.6, & 7.7)

The design of the instrumentation channels, logic and actuation devices of nuclear plant safety systems should include provisions for surveillance testing. Guidance is included in Reg. Guide 1.118 and IEEE Standard 338 for implementing the requirements of IEEE Standard 279, which requires in part that systems be designed to permit periodic testing during reactor operation.

Section 3.1.2.3.2 and 7.2.2.3.2 includes a brief description of the at-power testing capability of the reactor protection system. However, sufficient information has not been provided to determine the acceptability of the at-power testing capabilities provided in the Hope Creek design. Provide a detailed discussion with illustrations from applicable drawings on the at-power testing capability of the reactor trip system, engineered safety features actuation system and auxiliary supporting features, the actuation instrumentation for the reactor core isolation cooling system, and the instrumentation and controls that function to prevent accidents (i.e., high pressure/low pressure interlocks) or terminate transients (i.e., level 8 - turbine trip). This discussion should include the sensors, signal conditioning circuitry, voting logic, actuation devices and actuated components. Include in the discussion those design features that will initiate protection systems automatically, if required during testing, upon receipt of a valid initiation signal.

RESPONSE

As required by IEEE Standard 279, capability for at-power testing has been provided in the design of the HCGS safety systems. Conformance to the guidance specified in Regulatory Guide 1.118 and correspondingly, IEEE Standard 338, is as stated in Section 1.8.1.118.

The analysis portions of the various system descriptions in Chapter 7 for the safety-related systems referenced in the question describe the methods by which the safety system designs satisfy the testability requirements of IEEE Standard 279. The specific sections covering the testability of these systems are listed below:

RPS -	7.2.1.2
ECCS - HPCI	7.3.1.1.1.1(c)
- ADS	7.2.1.1.1.2(c)
- CORE SPRAY	7.3.1.1.1.3(c)
- RHR-LPCI	7.3.1.1.1.4(c)
PCRVICS	7.3.1.1.2(d)
RHR-CSCM	7.3.1.1.3(c)
RHR-SPCM	7.3.1.1.4(c)

DSER OPEN ITEM 186

DSER OPEN ITEM 186

PCIS		7.3.1.1.5(j)
CACS	- Supp. Chamber to Drywell Press. Relief	7.3.1.1.6.1(c)
	- RB to Supp. Chamber Press. Relief Sys.	7.3.1.1.6.2(c)
	- HOAS	7.3.1.1.6.3(c)
	- CHRS	7.3.1.1.6.4(c)
MCRHIS		7.3.1.1.7(j)
MSIVSS		7.3.1.1.8(c)
FRVS		7.3.1.1.9
RBVIS		7.3.1.1.10(h)
EAS	- SSWS	7.3.1.1.11.1(c)
	- SACS	7.3.1.1.11.2(c)
PCIGS		7.3.1.1.1.11.4(c)
CACWS		7.3.1.1.1.11.5(c)
EACS	- RBEAC	7.3.1.1.11.6.1(c)
	- ABDA	7.3.1.1.11.6.2(c)
	- ABCA	7.3.1.1.11.6.3(c)
	- SWIS	7.3.1.1.11.6.4(c)
RCIC		7.4.1.1.3
SLC		7.4.1.2.3
RRCS		7.6.2.7.2(b)
		7.6.2.7.2(n)
		7.6.2.7.4.1

Design drawings in the form of elementary diagrams, P&IDs, logic diagrams, instrument location drawings, and electrical drawings that describe this capability are listed in Tables 1.7-1, 1.7-2, and 1.7-3.

In response to the NRC's request for additional information during the meeting of January 11, 1984, review of the systems identified above, with the exception of the reactor protection system (RPS), reactor core isolation cooling (RCIC) system, standby liquid control (SLC) system, and redundant reactivity control system (RRCS) ~~will be~~ was performed. The review ~~will~~ examined ~~determine~~ the capability for the at-power testing of all circuits and sensors used in these systems. All actuated contacts and devices were ~~will be~~ considered. ~~Any system, subsystem, or component that lacks the capability for at-power testing will be identified and a justification will be provided. The results will be documented in a revision to this response to be submitted by July 1984.~~

INSERT B

The review did not identify any device- or circuit-bypassing methods, other than those specifically permitted by position C6 of Regulatory Guide 1.118, needed for ESF at-power testing. Built-in test jacks, which provide connections for plug-in test switches, built-in test switches, and normal operational equipment, provide this testing capability as shown on the system elementary diagrams. During testing, redundant channels or systems are available to provide the safety function.

INSERT A →

PSE&G plans to conduct that at-power surveillance testing prescribed by the BWR 4 version of the NRC's Standard Technical Specifications.

— INSERT A —

During the review, the at-power testability of an item was established if an affirmative response could be verified for the following three questions:

a. Is the item sufficiently accessible to conduct the test during normal operation?

b. Is the item sufficiently isolatable to permit its safety-related function to be verified or is a safety-related system or subsystem encompassing the item isolatable and testable?

c. Does any bypassing method that must be used to accomplish the test conform to position C6 of Regulatory Guide 1.118?

for the NSSS safety systems

By these criteria two items were judged to be untestable at power, the ADS SRVs, which would cause depressurization if tested, and the steam-tunnel temperature elements, which are inaccessible. The reliability and redundancy of the ADS instrumentation, logic, and actuation devices and the multiplicity of the SRVs adequately justify the lack of ADS at-power testability. Adequate element multiplicity and comparison tests of at-power output signals and electrical characteristics preclude the need for change-of-state testability of the steam-tunnel temperature elements.

DSER OPEN ITEM 186

By these criteria, for the non-NSSS safety systems the following items were judged to be untestable at power:

a. PCIS — the LOCA signals of reactor low level (level 1), drywell high pressure, or manual initiation originating from core spray system relays K18A-D do not satisfy the criteria of question-b above. This affects actuation signals to close 43 containment isolation valves, to trip 16 MCC breakers, and to initiate control room isolation. The affected equipment is identified on Figure 7.3-26 (sheets 2-5) and Figure 7.3-27 (sheets 2 and 3). All other methods for actuation of this equipment can be verified at power;
only this particular actuation signal ~~to each piece of equipment~~ can not be tested.

b. PCIS — the coincidence circuitry for the reactor building area and refueling floor area high-high radiation signals do not satisfy the criteria of question — b above. The individual high-high radiation signals can be verified up to the input buffers of the logic modules but must be tested one at a time since each signal is transmitted (through isolation devices) to all 4 channels of the PCIS simultaneously. See Figure 7.3-26 (sheets 6-9). This only affects the logic circuitry of the PCIS itself and does not inhibit the testing of the actual actuation signals from the PCIS to the individual actuated components.

Rev 1

DSER Open Item No. 226 (DSER Section 8.2.2.5)

GRID STABILITY

In regard to the grid stability analysis presented in Section 8.2.2 of the FSAR, it is the staff concern, due to the close proximity of the Salem and Hope Creek Generating Station, that simultaneous trip of Hope Creek Unit 1, Salem Unit 1 and Salem Unit 2, should be considered.

In response to this concern, the applicant by Amendment 4 to the FSAR stated that the Hope Creek Station will remain stable with the loss of both Salem Units 1 and 2, clarification and basis for this statement will be pursued with the applicant.

RESPONSE

The response to question 430.8 has been revised to provide the requested information.

QUESTION 430.8 (SECTION 8.2)

In regard to the grid stability analysis presented in Section 8.2.2 of the FSAR, it is the staff concern, due to the close proximity of the Hope Creek generating stations, that simultaneous trip of Hope Creek Unit 1, Salem Unit 1, and Salem Unit 2 should be considered. Either provide the results of a grid stability analysis that demonstrate grid stability assuming simultaneous failure of these three units or provide the results of analysis that demonstrates that trip of both Salem Units 1 and 2 will not cause trip of Hope Creek.

RESPONSE

Section 8.2.2 has been revised to provide this response.

In accordance with these "Reliability Principles and Standards for Planning Bulk Electric Supply Systems of the Mid-Atlantic Area Coordination Group" (MAAC), grid stability analyses have been performed as indicated in Section 8.2.2. Additionally, analysis of the most severe multi-phase fault with delayed clearing (stuck 500KV Breaker 60X) on the Hope Creek - Keeney 500KV line at HOpe Creek, shows that Salem No. 1 and 2, and Hope Creek No. 1 Units will lose synchronism and trip. However, the 500KV system remains transiently stable.

DSER Open Item No. 263 (DSER Section 11.4.2.e)

FIRE PROTECTION FOR SOLID RADWASTE STORAGE AREA

Insufficient information has been provided regarding the fire protection features for the solid waste equipment processing the asphalt and also the solid waste product storage area.

RESPONSE

FSAR Section 9.5.1.2.31 provides a description of the fire protection features for the radwaste building. This section has been revised to indicate that the preaction sprinkler system protects the filled radwaste drum storage area.

9.5.1.2.29 New Fuel Area Fire Protection

Portable extinguishers and hose stations are provided in the vicinity of the new fuel area. Automatic smoke detection is also provided by photoelectric-beam-type smoke detectors installed on the reactor building wall just above the polar crane for alarm and annunciation both locally and in the main control room.

A 4-inch curb is provided all around the top edge of the new fuel vault. The new fuel vault is provided with a steel plate cover. Thus, water inadvertently spilled on the refueling floor, which is at floor elevation 201 feet, is not likely to drain into the vault. Furthermore, a 6-inch floor drain is located at the bottom of the vault at floor elevation 181 feet 4 inches to preclude accumulation of water.

9.5.1.2.30 Spent Fuel Pool Area Fire Protection

A hose station and portable extinguishers are provided in the vicinity of the spent fuel pool. Automatic smoke detection is provided by photoelectric-beam-type smoke detectors installed on the reactor building wall just above the polar crane for alarm and annunciation both locally and in the main control room.

9.5.1.2.31 Radwaste Building Fire Protection

Most of the radwaste area is separated from the control area, reactor building, and turbine building by 3-hour fire barriers with Class A fire doors.

The radwaste area ventilation system can be isolated.

All drainage in the radwaste area is directed to the liquid radwaste sumps.

Wet pipe sprinklers are provided for the solid radwaste area. A preaction sprinkler system is provided for the radwaste truck loading area and solid radwaste FILLED drum storage area.

DSER OPEN ITEM 263

HGCS

DSER OPEN ITEM NO. 265 (DSER Section 6.8.1.4)

ESF FILTER TESTING

Regarding ESF filter testing, FSAR Table 6.8-6, page 6, table note b, states charcoal filter leakage testing is acceptable at a penetration of 0.25%. This value is inconsistent with Regulatory Guide 1.52 which requires in-place leakage testing for both HEPA and charcoal filters with air acceptance of less than 0.05% penetration. Please correct this statement or provide justification for departure with Regulatory Guide 1.53.

RESPONSE

FSAR Table 6.8-6, page 6, table note b has been revised to state that the downstream concentration is less than 0.05% penetration.

b. Inplace Testing of Adsorber

1. Refrigerant (R-11 or R-112) is introduced into the upstream side of the adsorber at a concentration of approximately 20 ppm at rated airflow. The downstream concentration is less than ~~0.25%~~ 0.05% of the upstream 20 ppm. No more than four tests are conducted on any given carbon adsorber. No radioactive isotopes are used in the efficiency tests performed on the carbon adsorbers. Each charcoal adsorber is tested for leakage using the test method presented in ANSI N510.

2. The installed carbon adsorber filter bank is visually and dimensionally checked for conformance to the design specifications.

9. FILTER HOUSINGS

In addition to the housing manufacturer's shop tests, a field performance test is conducted for each housing. The housings are designed to withstand pressures ranging from 6 to 23 inches w.g.

10. FILTER INSERVICE TESTS AND INSPECTIONS

a. The air filtering systems are subject to inplace testing before initial startup and after each HEPA filter or adsorber change, with the test interval not to exceed 18 months, in accordance with the recommendations of Regulatory Guide 1.52.

b. Periodic testing of the HEPA filter banks ensures that the filter bank performance is not degraded through normal use, or during standby, to a level below that assumed in the accident analyses. Test methods and sensitivities are the same as or equal to those for initial acceptance of the system components. If the test results indicate that performance of a component has fallen to the level assumed in the accident analyses, the component is replaced.

c. The following filter inservice tests and inspections are performed at regular intervals during plant life to

DSER OPEN ITEM 265

HGCS

DSER OPEN ITEM NO. 266 (DSER Section 6.8.1.4)

FIELD LEAK TESTS

Regarding FSAR Table 6.8-6, Page 7, note 3, change to read, "Field leak tests are conducted after each change of HEPA or charcoal filters in a system."

RESPONSE

FSAR Table 6.8-6, page 7, note 3 has been revised to include Field Leak Testing after charcoal filter change.

JES:az

M P84 126/19 01-az

determine that the filtration systems are functioning correctly:

1. With the fan running, readings on the differential pressure gauges, which are mounted on the filter plenum, are observed and recorded.

2. HEPA filters are replaced when the pressure drop across them reaches 3.0 inches w.g. Where there are two HEPA filter banks in series, the second one is changed at 4 inches w.g.

3. Field leak tests are conducted after each change of HEPA or charcoal filters in a system

4. Field leak tests of HEPA filter banks are conducted with cold-generated dioctylphtholate, and a light-scattering aerosol photometer is used for measuring percentage penetration. An efficiency of less than 99.95% requires corrective action, as stated previously

5. Corrective action after a leak test may consist of increasing the contact pressure on a seal or replacement of a cell or cells. After corrective action is taken, an additional leak test is made

6. Tests of successive canisters of charcoal in the airsteam of the charcoal adsorbers are made every 12 months after the charcoal adsorber bank is installed. Test procedures are the same as those used during initial batch qualification for elemental iodine and methyl iodide attenuating capacity. Tests for hardness, ignition temperature, and radioactivity are not made on these samples.

11. DUCTWORK

a. Leakage tests on all ductwork are conducted during construction

DSER OPEN ITEM NO. 267 (DSER Section 6.4.1)

CONTROL ROOM TOXIC CHEMICAL DETECTORS

Where are the Toxic Chemical detectors and associated instrumentation included in the Control Room Air Supply System?

RESPONSE

No toxic chemical detectors and associated instrumentation is required (and therefore not included) in the Control Room Supply System.

Evaluation of accidents relating to the release of toxic chemicals is addressed in FSAR Section 2.2.3.1.3.

Also, per DSER Section 6.4 page 6-3:

"With respect to toxic gas protection, the staff's evaluation in accordance with SRP Section 6.4, RGs 1.78 and 1.95 indicated that there is no danger to control room personnel from toxic chemicals, including chlorine, stored onsite or offsite, or transported nearby (See Section 2.2.3)."

QUESTION 430.102 (SECTION 9.5.5)

Indicate the measures to preclude long-term corrosion and organic fouling in the diesel engine cooling water system that would degrade system cooling performance, and the compatability of any corrosion inhibitors or antifreeze compounds used with the materials of the system. Indiate if the water chemistry is in conformance with the engine manufacturers ~~recommendations~~ chemistry requirements. (SRP 9.5.5, Parts I & III)

Response

Colt has included recommendations on jacket water ~~treatment~~ chemistry in their instruction book. The following is typical of the shop water treatment: ~~In accordance with the manufacturer's recommendations,~~ the cooling water is softened to a total hardness (as $CaCO_3$) of less than 50 ppm or 3 GR/GAL., and "NALCO 41" corrosion inhibitor is added and maintained in the ratio of 3-3.75 pints per 100 gallons of water (0.5-0.6 fluid ounces per gallon). These measures will preclude long term corrosion and scale. ~~As demineralized water circulating in the 150°F to 180°F range will be utilized, organic fouling will not be a problem to system cooling performance.~~

INSERT A

Section 9.5.5.2 has been revised to show that the demineralized water is treated in accordance with the manufacturer's chemistry ~~recommendations.~~ requirements.

INSERT B

1/5

INSERT A

430.102

¶ Colt can not make specific recommendations for water treatment to meet their specific water chemistry requirements due to complexity of possible water chemistries at the HCGS site. HCGS will analyze the actual site water conditions and use appropriate water treatments, both for initial filling and maintenance as they relate to Colt's general water chemistry requirements

INSERT B

430.102

¶ The SDG cooling water systems will be filled with demineralized water and treated AS NECESSARY ~~with appropriate water treatments~~ to meet Colt Industries recommended water chemistry requirements and to prevent organic fouling of the cooling surfaces. The SDG cooling, jacket water and intercooler systems are closed systems which are filled through the jacket water surge tank. The jacket water system and intercooler systems are cooled by the Safety Auxiliaries Cooling system (SACS) ~~system~~ through a shell and

430.102 (cont)

tube heat exchanger. The SACS water does not directly interface with the jacket water and intercooler. The SACS water system is also filled with demineralized water. The demineralized water system receives water from on-site deep wells. The water from the wells is chlorinated prior to being demineralized. The chlorination process destroys ~~eliminates organic~~ organizms which would cause organic fouling.

System separation, chlorination and water

JUL 19 '84 0268069

(3)

430.102 (cont)

chemistry control will prevent corrosion and organic fouling.

5/5

QUESTION 430.108 (SECTION 9.5.5)

Recent licensee event reports have shown that tube leaks are being experienced in the heat exchangers of diesel engine jacket cooling water systems with resultant engine failure to start on demand. Provide a discussion of the means used to detect tube leakage and the corrective measures that will be taken. Include jacket water leakage into the lube oil system (standby mode), lube oil leakage into the jacket water (operating mode), jacket water leakage into the engine air intake and governor system (operating or standby mode). Provide the permissable inleakage or outleakage in each of the above conditions which can be tolerated without degrading engine performance or causing engine failure. The discussion should also include the effects of jacket water/service water systems leakage. (SRP 9.5.5, Parts II & III)

RESPONSE

~~This question is being reviewed by the diesel engine manufacturer and a response will be provided in March 1984.~~

The heat exchangers are procured to ASME Section III design and quality requirements, and are seismically qualified. ← INSERT 1

Leaks at tubes in heat exchange equipment are very difficult to discern by any means short of removing the heat exchanger from the system and subjecting it to hydrostatic testing. Instruments to determine lube oil in water or water in lube oil are generally not reliable. Monitoring of small the lube oil level or the cooling water level is not reliable in as much cases as there are so many influences other than the heat exchange equipment.

The cooling water systems chemistry will be analyzed in accordance with plant operating procedures.

could be

Generally, lube oil in the water system has no detrimental effect on the engine. However, water in the lube oil of concern.

INSERT 2 The diesel engine lube oil will be monitored and analyzed in accordance with the particular lube oil suppliers recommendations and diesel manufacturers operation and maintenance procedures. A discussion of water contamination of lube oil is included in response to Question 430.12.

The rocker arm lubrication system is separated from the main lubrication system because of the proximity of the rocker system to sources of water (cylinder heads, rocker assemblies, etc). Addition of water to that system, due to leakage, would be detected by the high rocker arm tank level alarm. 1/5

cont

430.108

INSERT 1

The heat exchangers in these systems are hydrostatically tested, in accordance with the Code, prior to installation and startup.

The cooling water for the tube and shell side of the jacket water cooler and the intercooler heat exchanger, and the tube side of the lube oil heat exchanger is demineralized water treated with corrosion inhibitors. Treated demineralized water is also used to cool the governor oil. The tube material for

430.108 cont

Insert 1 cont

lube oil, jacketwater and intercooler heat exchangers is corrosion resistant 90/10 copper nickel ~~nickle~~.

These design provisions give reasonable assurance that the heat exchangers will last the 40 year design life without leakage. The diesel manufacturer has confirmed that their past operating experience with similar designs has not shown leakage to be a problem

Insert 2

~~However~~ The diesel engine manufacturer does not have prescribed acceptable leak rates or limits since these parameters are ~~is~~ peculiar to the type of lube oil being used in the units.

430.108 cont

The intercooler (combustion air cooler) cools the combustion air after compression. During the cooling process moisture in the combustion air is condensed. The condensate collects at the outlet of the cooler, after passing through stationary baffle plates which remove moisture, and is drained through an open 3/4 inch line which is vented. If a leak in the intercooler occurs the excessive moisture would be detected by the presence of higher than normal spray from the drain line. The diesel engine manufacturer has indicated that during engine operation there is little or no moisture dripping from the

430.108 (cont) (14)

drain. However, during operation in high humidity (95-100%) and high air temperature there would be a spray from the drain.

ii The governor control oil is sensitive to contamination by sludge, dirt, air and water. The governor oil will be checked according to plant operating procedures. If the sample is found to have water contamination, the governor oil will be drained and the cooler checked for leaks. If a leak is found, the cooler will be replaced.

5/5

QUESTION 430.110 (SECTION 9.5.5)

Figure 9.5.8 22 of the FSAR shows a three-way thermostatic valve, labelled "5", connecting the jacket water system and the intercooler water system. The FSAR states that both cooling water systems are self contained and closed loop systems. Describe the purpose of this valve, its size, and its mode of operation. (SRP 9.5.5, Part III)

RESPONSE

The three-way thermostatic valve is a 1-inch valve. It's function is to temper the injector cooling water (i.e., that portion of the intercooler water used to cool the fuel injection nozzles) by mixing the hotter water from the jacket water system with the cooler intercooler water. ~~The mixed water is returned to the jacket water expansion tank. Returning the water to the jacket water and intercooler water systems is accomplished via the respective pump surge lines. This valve does not prevent the jacket water system and the intercooler water system from operating independently. See response to Question 430.113 for additional information.~~

INSERT

1/3

INSERT

430.110

¶ The injector cooling water thermostatic control valve is located in the two systems such that if heating of the injector cooling water is required, a small flow of water is admitted from the jacket water system. When cooling of the injector cooling water is required, water is admitted from the intercooler water system. The injector nozzle cooling water return is by way of the expansion tank which is shared by both the jacket water and intercooler systems.

430.110 cont

A ~~The~~ failure of the thermostatic valve at either position would be of little consequence. The nozzle cooling water could not get colder than the intercooler water nor hotter than the jacket cooling water. The nominal spread in these temperatures is not sufficient to cause a problem in the injection system. This valve does not prevent the jacket water system and the intercooler water system from operating independently. See response to Question 430.113 for additional information.

QUESTION 430.111 (SECTION 8.3 & 9.5.5)

The diesel generators are required to start automatically on loss of all offsite power and in the event of a LOCA. The diesel generator sets should be capable of operation at less than full load for extended periods without degradation of performance or reliability. Should a LOCA occur with availability of offsite power, the diesel generator, running in an unloaded (standby) condition for an extended period of time, should not result in degradation of engine performance or reliability. In Section 9.5.5.1 of the FSAR you state that the diesel generator should "remain operational after 8 hours of no-load operation, provided that the SDG runs up to a minumum of 25% of full load for 1 hour immediately after such no load operation." Verify the following: #9

a. Verify that the statement conforms to the manufacturer's recommended no-load operation for this diesel or justify non-conformance.

b. Verify that the conditions for no-load operation will be included in the plant operating procedures. (SRP 8.3.1, Parts II and III and SRP 7.5.5, Part III)

RESPONSE

a. In conformance with the manufacturer's la~~s~~test recommendation, Section 9.5.5.1.e. has been revised to state that the diesel generators should remain operational after 12 ~~8~~ hours of no-load operation, provided that the SDG runs up to a minimum of 50% of full load for 1 hour immediately after such no load operation. This exceeds the recommendation by Colt Industries for the PC2 type of engine. Reference Letter to Mr. Clemerson (NRC) from Mr. V.T. Stonehocker (Colt Industries), dated September 11, 1975, para. 2.a.

b. The conditions for diesel generator no-load operation will be included in OP-SO.KJ-001(Q), Emergency Diesel Generator Operation. Available January 1985.

1/2

9.5.5 STANDBY DIESEL GENERATOR COOLING WATER SYSTEM

The standby diesel generator (SDG) cooling water system provides cooling water to the SDGs and is safety-related.

9.5.5.1 Design Bases

The design bases of the SDG cooling water system are as follows:

a. Cool the engine cylinder jackets, turbocharger, combustion air, generator outboard bearings, speed governor oil, and the lubricating oil sufficiently to permit continuous operation of the SDG at full load

b. Maintain the jacket coolant in a warmed condition while the diesel engine is in normal standby status to promote reliable starting

c. Ensure that the single failure of any active component will not affect the operation of more than one SDG

d. Remain functional during and after a safe shutdown earthquake (SSE)

e. Remain operational after 12 hours of no-load operation, provided that the SDG runs up to a minimum of 50% of full load for 1 hour immediately after such no-load operation

f. Permit testing and inspection of active system components during plant operation

g. Withstand wind, tornadoes, floods, and missiles.

The SDG cooling water system is designed to Seismic Category I requirements and complies with IEEE Standard 387. The quality group classification and corresponding codes and standards that apply to the design of the system are discussed in Section 3.2.

2/2

RESPONSE

Insert A

Insert B

~~a.~~ ~~The 250 gallon lube oil make-up tank is provided with inspection ports, one upper and one lower. If algae growth is detected in the lube oil make up tanks a lube oil addative can be added to eliminate the algae and to prevent further growth.~~

~~Inspections of the lube oil makeup tanks will be performed during each refueling outage.~~

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 manufactures recommendations. The interior of the tank is not coated because the lube oil is non-corrosive. ~~and the tank is expected to be maintained in the full condition.~~ delete

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. 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. Should there be any carry over into the transfer line, it would be trapped in the strainer and/or filter before entering the engine sump.

A normally closed drain valve is provided at the low point of the tank, reference Figure 9.5-27. The drain valve will be opened in accordance with plant operating procedures deleterious to remove any sediment, water or other material that may accumulate in the bottom of the tank.

~~The following concerns will be addressed by July, 1984:~~

~~a. Description of corrosion protection~~

~~b. Effects of sedimentation~~

~~c. Algae detection and control in the lube oil make up tank.~~

delete

~~this item is in 430.135-3~~

Insert A

Deleterious material is prevented from entering the diesel engine lube oil make-up tank by:

1. Procuring high quality, high purity lube oil with ~~pr~~ lubricating properties ~~as required~~ in accordance with the manufacturer's recommendations.
2. Insuring that ~~additions~~ 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 vacinity 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.

Insert B

a. Algae formation may occur due to condensate accumulation in the make-up lube oil tank. Prior to diesel engine operability testing the lube oil make-up tank drain will ~~p~~ be ~~opede~~ opened to remove any water, sediment, algae or other deleterious material. If lube oil purity is degraded any of the following ~~actions~~ 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.

QUESTION 430.149 (SECTION 9.5.8)

Figures 1.2-35 through 1.2-39 show the routing of the diesel engine exhaust system from the diesel generator room to the roof of the auxiliary building. The figures show that the exhaust mufflers for all the diesel generators are located in a common corridor (Elevation 102'-0") and that the exhaust stacks pass through the following areas:

1. Remote D/G control and vital switchgear areas (elevation 130'-0")
2. Vital battery control rooms (elevation 137'-0")
3. Switchgear HVAC Area (elevation 163'-0")
4. Diesel and control rooms HVAC area (elevation 178'-0")

The exhaust system is considered a high energy system by virtue of temperature. A exhaust system pipe break in any one of these areas and a single active failure in one of the other diesels or just pipe break in the exhaust system in the muffler corridor, switchgear HVAC area, or diesel and control room HVAC area could result in an inability to shut down the plant.

The figures referenced above do not clearly show or decribe the diesel engine exhaust stack enclosures. Describe the stack enclosure in each of the areas noted above and show that an exhaust stack break in any one of these areas will not result in the inability to shut down the plant or result in failure or unavailability of all diesel generators. (SRP 9.5.8, Parts II and III)

RESPONSE

As discussed in response to Question 430.82 the SDG combustion air exhaust system is not classified as high energy system. Therefore a high energy pipe break ~~in~~ is not considered.

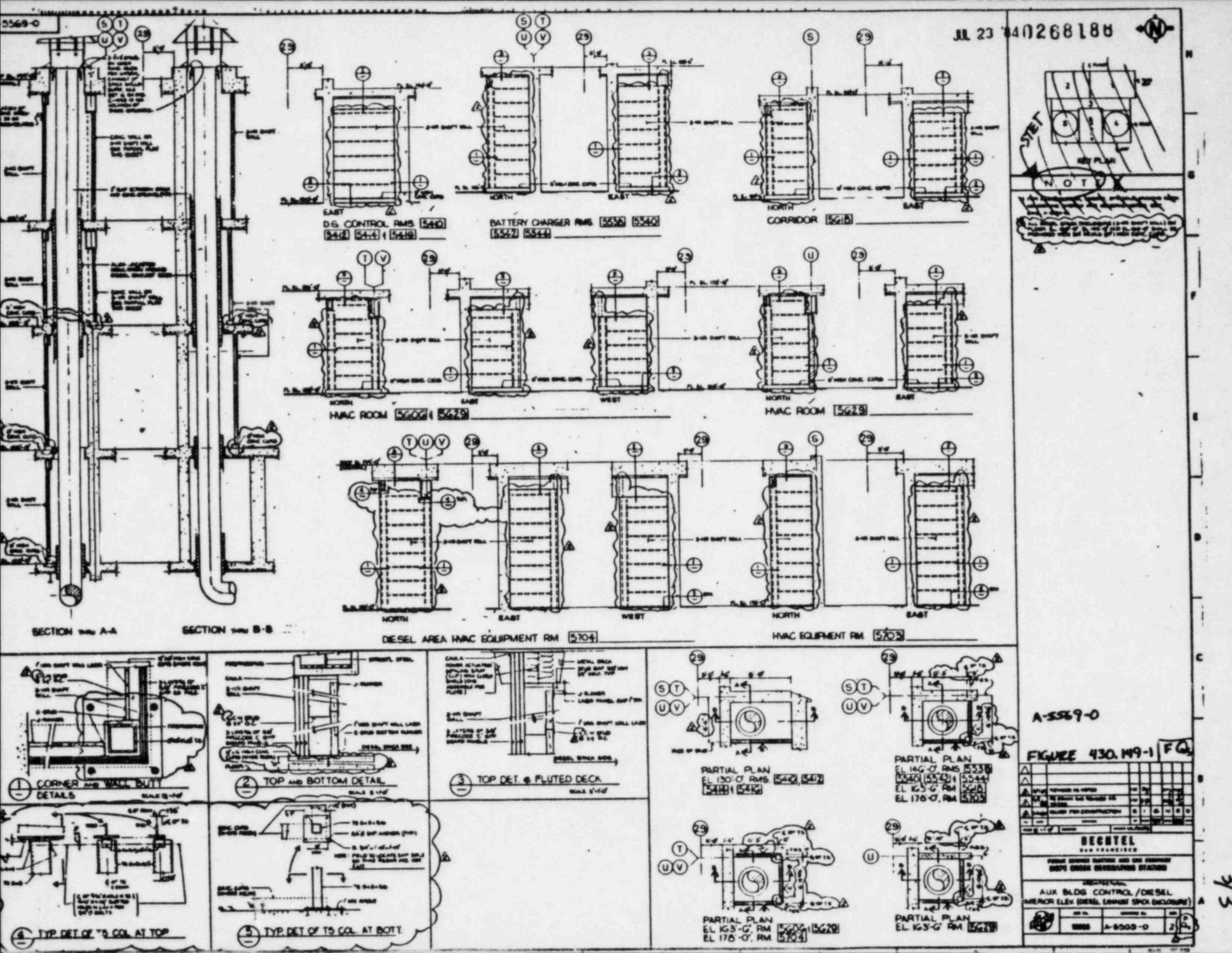
The exhaust stack which passes through the areas mentioned in the above question is designed to Seismic Category I requirements, as discussed in Section 3.7. ~~It is also provided with liner/partition panels~~ ← INSERT as shown on Figures 1.2-35 through 1.2-39, and
430.149-1 to minimize heat rejection and noise in the areas through which it passes.

— 1/3

430.149

Insert

The standby diesel generator exhaust stack is provided with aluminium jacketed insulation, around the stack, and three hour fire barrier exhaust shaft walls ...



JUL 23 '84 0268188
5569-0
SECTION thru A-A
SECTION thru B-B
D.G. CONTROL RMS. 5410 5412 5414 & 5416
BATTERY CHARGER RMS. 5536 5540 5542 5544
CORRIDOR 5618
HVAC ROOM 5606 & 5629
HVAC ROOM 5629
DIESEL AREA HVAC EQUIPMENT RM 5704
HVAC EQUIPMENT RM 5703
1 CORNER and WALL BUTT DETAILS
2 TOP and BOTTOM DETAIL
3 TOP DET. @ FLUTED DECK
4 TYP DET OF TS COL AT TOP
5 TYP DET OF TS COL AT BOTT.
PARTIAL PLAN EL 130'-0" RMS. 5410, 5412 5414 5416
PARTIAL PLAN EL 146'-0" RMS. 5538 5540 5542 & 5544 EL 163'-6" RM 5618 EL 178'-0" RM 5703
PARTIAL PLAN EL 163'-6" RM 5606 & 5629 EL 178'-0" RM 5704
PARTIAL PLAN EL 163'-6" RM 5629
KEY PLAN
NOTE
A-5569-0
FIGURE 430.149-1
BECHTEL
SAN FRANCISCO
AUX BLDG CONTROL/DIESEL INTERIOR ELEV. (DIESEL EXHAUST SPACE ENCLOSURE)
A-5569-0
3/3

QUESTION 430.151 (SECTION 10.2)

Expand your discussion of the turbine speed control and overspeed protection system. Provide additional explanation of the turbine and generator electrical load following capability for the turbine speed control system with the aid of the system schematics (including turbine control and extraction steam valves to the heaters). Tabulate the individual speed control protection devices (normal, emergency and backup), the design speed (or range of speed) at which each device begins operation to performs its protective function (in terms of percent of normal turbine operating speed). In order to evaluate the adequacy of the control and overspeed protection system provide schematics and include identifying numbers to valves and mechanisms (mechanical and electrical) on the schematics. Describe in detail, with references to the identifying numbers, the sequence of events in a turbine trip including response times, and show that the turbine stabilizes. Provide the results of a failure mode and effects analyses for the overspeed protection systems. Show that a single steam valve failure cannot disable the turbine overspeed trip from functioning. (SRP 10.2, Parts II & III)

~~RESPONSE~~

~~Sections 10.2.2.5 and 10.2.2.6 have been revised to include the requested information except for a failure mode and effects analysis for the overspeed protection systems. Such an analysis is not necessary because turbine missiles generated by a failure of the overspeed protection systems would have a low probability of affecting any safety-related systems; turbine missile analysis is discussed in Section 3.5.1.3. See the response to Question 430.152.~~

—1/6

RESPONSE

Sections 10.2.2.5 and 10.2.2.6 have been revised to include the requested information.

An analytical failure mode and effect analysis has not been prepared for the turbine overspeed protection system.

The diversity of devices shown on Table 10.2-1, along with the addition of Table 10.2-~~1A~~2,

illustrates that a minimum of two independent lines of defense is employed for protection against overspeed and that no single failure of any device or steam valve can disable the turbine overspeed trip from functioning.

In addition, turbine missiles generated by a failure of the overspeed protection systems would have a low probability of affecting any safety-related systems; turbine missile analysis is discussed in Section 3.5.1.3. See the response to Question 430.152.

Rapid closure of the control valves or stop valve closure initiates an input signal to the reactor protection system (RPS) to initiate reactor shutdown.

10.2.2.6 Overspeed Protection

Insert Ⓐ →

To protect the turbine-generator against overspeed, when the turbine speed begins increasing, the EHC system will rapidly throttle the control valves and the intercept valves. If the speed continues to rise, the main stop valves and the intermediate stop valves will be closed by one of the following trip devices:

a. A mechanical overspeed trip that is initiated if the turbine speed reaches approximately 10% above rated speed

b. Electrical overspeed trip that serves as a backup to the mechanical trip and is initiated at approximately 12% above rated speed.

The mechanical overspeed trip device (Figure 10.2-9) is an unbalanced ring mounted on the turbine shaft and held concentric by a spring. When the turbine speed reaches the trip speed, the centrifugal force acting on the ring overcomes the tension of the spring, and the ring snaps to an eccentric position. The ring then strikes the trip finger, which actuates the mechanical trip valve. This three-way valve feeds hydraulic fluid at 1600 psi to the lockout valve. When tripped, this valve blocks the hydraulic fluid supply system and releases the emergency trip system pressure, which causes the main stop valves, control valves, and combined intermediate valves to close. Failure of the hydraulic portion of this trip results in the closure of main stop valves, control valves, and combined intermediate valves. Failure of the normal turbine speed control system will not prevent the turbine overspeed control system from shutting down the turbine.

The electrical overspeed trip receives its signal from a 112% speed trip relay (VCS 840, Figure 10.2-10) operated by the signal from a magnetic pickup, through a magacycler and a voltage comparator (Figure 10.2-11).

The signal from the speed relay energizes the master trip relay XKT 1000 (Figure 10.2-11) which then energizes the mechanical

3/6

trip solenoid (MTS) and de-energizes the master trip solenoid valves MTSV-A and MTSV-B which removes the emergency trip system pressure causing the turbine valves to close. Loss of either signal or hydraulic function of this trip results in a main stop valve closure.

Insert B →

When the mechanical overspeed trip is being tested, using the overspeed governor lockout device, the electrical overspeed trip protects the turbine against overspeed.

An additional feature of the protective system that will minimize the likelihood of an overspeed condition is the power/load unbalance circuitry (Figure 10.2-12). Generator load is sensed by means of three current transformers and is compared with the turbine power input which is sensed by the turbine intermediate pressure sensor. Control valve action will occur only when the power load unbalance is approximately 40 percent or greater while the generator current (load) is lost at a rate equivalent to going from rated to zero in approximately 35 msec. or less.

There are four steam lines at the high pressure stage. Each line is provide with one stop valve in series with one control valve. Steam from the high pressure stage flows to the moisture separators and then to the three low pressure stages. Each of the six low pressure lines has a combined intercept valve that consists of a stop valve in series with a control valve, in one housing. All of the above valves close within 0.2 seconds on turbine trip. Assuming a single failure within the above system of 20 valves in case of a turbine overspeed trip signal, the turbine will be successfully tripped.

The diversity of devices shown on Table 10.2-1 ensures that stable operation following a turbine trip proceeds from the requirement that both the stop valves and the combined intercept valves close in a turbine trip, thereby preventing steam from the main steam line from entering the turbine and preventing the expansion of steam already in the high pressure stage and in the moisture separator. An additional provision is made to automatically isolate the major steam extraction lines from the turbine by power-assisted check valves. Closure times of the check valves will be in accordance with the turbine manufacturer's recommendations.

Any postulated accident, including the effects of high or moderate energy pipe failures, that results in a loss of hydraulic pressure or loss of the electrical signal to the

4/6

Insert (A)

¶ Although the turbine-generator overspeed protection system is not safety related and consequently not subject to all of the separation and redundancies required in systems which are safety related, it is part of a high energy system central to the overall protection of the plant.

Insert (B)

¶ It is highly improbable that a single disruption will cause a malfunction in both the mechanical overspeed trip and the electrical overspeed trip. This is due to the physical and functional independence of the mechanical overspeed trip, which actuates via the hydraulic fluid supply system, and the electrical overspeed trip, which actuates via the signal from the speed trip relay.

TABLE 10.2-~~1A~~2
TURBINE OVERSPEED PROTECTION

For protection against over-speed, a minimum of two independent lines of defense are employed. The following redundancies are used:

1. Main Stop Valves - back-up: Control Valves
2. Intercept Valves - combine both stop & control functio.
3. Speed Control - Overspeed Trip & Back-up Overspeed Trip Provided
4. Trip Solenoid Valves - Redundant deenergizing 24 volt master trip solenoid energizing 125 volt mechanical trip solenoid
5. Mechanical Trip - Back-up: Electrical trip
6. Fast Acting solenoid valves - Back-up: Hydraulic Fluid Trip System

In addition, these features are used:

"FAIL SAFE" mode of operation of all valves: If hydraulic pressure is lost, all turbine valves will close.

Power/Load Unbalance to reduce overspeed on loss of high loads.
Spring closed extraction check valves with air assist.

Speed Control Unit with two redundant circuits.

QUESTION 430.169 (SECTION 10.4.4)

Provide the results of a failure mode and effects analysis to determine the effect of malfunction of the turbine bypass system including controls on the operation of the reactor and main turbine generator unit. (SRP 10.4.4, Parts II & III).

RESPONSE

As discussed in the response to Question 430.166, the failure mode of the bypass valves is closure of the valves. The effects of this malfunction on the operation of the reactor is summarized in Table 15.0-1 and discussed in Sections 15.2.2 and 15.2.3. The effect of this malfunction on the turbine generator is discussed in the response to Question 430.166.

The effects of a malfunctioning of the Turbine bypass valve due to a faulty control signal to the fully open position is also bounded by Chapter 15 analyses. The following consequences would occur due to this malfunction.

a. The bypass valves would move to full open position causing reactor pressure to decrease ~~vessel depressurization~~; the consequent increase in coolant voids would cause the vessel water level to increase.

b. The pressure regulation system, sensing the pressure reduction, would cause movement of the turbine control valves to reduce turbine steam flow so as to maintain the pressure.

c. Then, there are two possible scenarios:

1. If the water level swell were large enough to cause a high water level (L8) turbine trip, then the remainder of the event would be similar to - and the consequences would not be worse than - the transient caused by "Pressure Regulator Failure - Open," as described in ~~FSAR~~ Section 15.1.3.

2. If the pressure regulation system can gain control soon enough to prevent the L8 turbine trip, then the turbine control valves would settle to a position corresponding to about 75% NBR steam flow through turbine control valves and 25% NBR steam flow through turbine bypass valves, with no appreciable effect on the reactor. If the turbine bypass misoperation cannot be readily corrected, the reactor operator would take appropriate action, which could include reactor shutdown.

1/1