

WM. H. ZIMMER POWER STATIONINSTRUCTIONS FOR UPDATING YOUR FSAR

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instruments will be provided for generator MW output and main bus voltage. Kilowatt-hour meters will be provided for main generator outputs and for auxiliary power system loads.

Instrumentation also will be provided for monitoring generator and transformer temperatures. Other types of monitoring instrumentation will be provided as required to ensure proper operation of equipment.

Control of transmission line circuit breakers and associated instrumentation will be by supervisory control from a system load dispatcher office located remote from the plant.

1.2.2.7.3 Nuclear System Process Control and Instrumentation

1.2.2.7.3.1 Reactor Manual Control System

The reactor manual control system provides the means by which control rods are positioned from the control room for power control. The system operates valves in each hydraulic control unit to change control rod position. Only one control rod can be manipulated at a time. The reactor manual control system includes the logic that restricts control rod movement (rod block) under certain conditions as a backup to procedural controls.

1.2.2.7.3.2 Recirculation Flow Control System

The recirculation flow control system controls the variable-position flow control discharge valve. Adjusting this valve changes the coolant flow rate through the core and thereby changes the core power level. The system can be set to have reactor power automatically follow the turbine power output.

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1.2.2.7.3.3 Neutron Monitoring System

The neutron monitoring system is a system of incore neutron detectors and out-of-core electronic monitoring equipment. The system provides indication of neutron flux, which can be correlated to thermal power level for the entire range of flux conditions that can exist in the core. The source range monitors (SRM's) and the intermediate range monitors (IRM's) provide flux level indications during reactor startup and low-power operation. The local power range monitors (LPRM's) and average power range monitors (APRM's) allow assessment of local and overall flux conditions during power range operation. Rod block monitors (RBM's) are provided to prevent rod withdrawal to the point required to produce the limiting level of local reactor power at the existing reactor coolant flow rate. The traversing incore probe (TIP) system provides a means to calibrate the individual LPRM sensors.

1.2.2.7.3.4 Refueling Interlocks

A system of interlocks that restricts movement of refueling equipment and control rods when the reactor is in the refueling and startup modes

TABLE 1.3-9 (Cont'd)

<u>ITEM</u>	<u>CHANGE</u>	<u>REASON FOR CHANGE</u>	<u>FSAR PORTION IN WHICH CHANGE IS DISCUSSED</u>
Standby liquid control (SLC) system	Interlocks on the SLC system were revised.	To prevent inadvertent boron injection during system testing	Figure 7.4-3
SLC system	The explosive valve rating was changed to Class A.	NRC criteria on containment isolation	Table 3.2-1
SLC system	The REECO flow switch will be eliminated; system flow will be monitored by a changing level in storage tanks.	Elimination of field problems associated with REECO switch	No reference
SLC system	The piping was changed from carbon to stainless steel.	The piping system was simplified.	Figure 4.2-23
SLC system	System level initiation of ADS and ECCS at system level signals was added.	Comply with IEEE 279-1971 requirements	Figure 7.3-4b
Automatic depressurization system (ADS)	The interlocks on the automatic depressurization system were revised.	To meet IEEE 279-1971 requirements	7.3.1.1.1.2

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TABLE 2.5-28

SETTLEMENT RECORD

STRUCTURE	SETTLEMENT POINT	APPROXIMATE DATE ESTABLISHED	CALCULATED SETTLEMENT (in.)	DATUM (ft MSL)	OCTOBER 1975 ELEVATION (ft MSL)	SETTLEMENT (in.)	JANUARY 1976 ELEVATION (ft MSL)	SETTLEMENT (in.)	APRIL 1976 ELEVATION (ft MSL)	SETTLEMENT (in.)
Reactor Building	1	9-73	$1\frac{1}{2} \pm \frac{1}{4}$	521.048	520.992	.67	520.968	.96	520.965	1.00
	14	9-73		506.262	504.978	.96	504.976	.98	504.976	.98
Auxiliary Building	13	5-73	$1\frac{1}{4} \pm \frac{1}{4}$	506.601	500.950	.96	500.950	.96	500.944	1.03
Turbine Building	3	9-73	$1 \pm \frac{1}{4}$	521.010	520.954	.67	520.933	.92	--	--
	8	9-73		521.010	520.959	.61	520.948	.74	520.937	.88
	12	6-73		506.108	500.944	.71	500.943	.92	500.943	.92
Heater Bay	9	10-73	$1\frac{1}{4} \pm \frac{1}{4}$	521.038	520.954	1.01	--	--	--	--
Circulatory Water Pump Structure	15	5-74		520.577	521.347	1.50	521.348	1.49	521.349	1.48
	16	5-74		520.567	521.428	1.67	521.433	1.61	--	--
	17	5-74		520.276	521.287	1.75	521.279	1.85	--	--
	18	5-74		520.478	521.225	1.80	521.222	1.84	521.209	1.99
Diesel Generator	2	8-74	$2\frac{1}{2} \pm \frac{1}{4}$	521.010	520.962	.58	520.943	.80	--	--
Radwaste Building	10	9-74	$1\frac{1}{2} \pm \frac{1}{4}$	521.606	504.945	1.19	504.940	1.25	504.922	1.46
	11	8-74		521.404	500.932	1.24	500.933	1.22	500.916	1.43
Machine and Service Building	4	3-75		519.575	519.521	.65	519.515	.72	519.496	.96
Storage Building	5	3-75		520.525	520.465	.72	520.461	.77	520.444	.97
	6	3-75		520.288	520.219	.83	520.223	.78	520.213	.90
	7	3-75		520.523	520.464	.71	520.463	.72	520.447	.91

- Settlement points 10, 11, 15, 16, 17 and 18 were reset prior to the July 1976 readings; settlement point 14 was reset prior to the April 1, 1977, reading. Settlement points 12, 13, and 14 reset prior to the October 4, 1978 reading.
- Settlements indicated in this table are total settlements observed since the beginning of the monitoring program.

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TABLE 2.5-28 (Cont'd)

STRUCTURE	JULY 1976		OCTOBER 1976		JANUARY 1977		APRIL 1977		AUGUST 1977	
	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)
Reactor Building	520.954	1.13	520.950	1.18	520.947	1.21	520.957	1.09	520.949	1.19
	504.953	1.26	504.957	1.21	504.947	1.33	504.118	.77	504.120	.74
Auxiliary Building	500.935	1.14	500.939	1.09	500.893	1.64	500.918	1.34	500.917	1.36
Turbine Building	520.939	.85	520.933	.92	520.938	.86	520.942	.82	520.937	.88
	520.942	.82	520.934	.91	520.922	1.06	520.941	.83	520.921	1.07
	500.936	1.01	500.940	.96	500.900	1.44	500.926	1.13	500.926	1.23
Heater Bay	--	--	--	--	--	--	--	--	520.932	1.27
Circulatory Water Pump Structure	520.500	.68	520.489	.82	520.510	.56	520.488	.83	520.484	.88
	520.501	.79	520.484	1.00	520.447	1.44	520.499	.82	520.473	1.13
	520.103	2.08	520.089	2.24	520.106	2.02	520.094	2.18	520.080	2.35
	520.303	2.10	520.292	2.23	520.304	2.09	520.294	2.21	520.272	2.47
	520.939	.85	--	--	--	--	520.943	.80	520.936	.89
Radwaste Building	521.504	1.22	521.493	1.36	521.491	1.38	521.519	1.04	521.490	1.39
	521.297	1.28	521.294	1.32	521.282	1.46	521.300	1.25	521.258	1.75
Machine and Service Building	519.494	.97	519.488	1.04	519.490	1.02	519.492	1.00	519.482	1.12
Storage Building	520.445	.96	520.439	1.03	520.438	1.04	520.443	.98	520.428	1.16
	520.213	.90	520.207	.97	520.210	.94	520.212	.91	520.198	1.08
	520.452	.85	520.449	.89	520.439	1.01	520.452	.85	520.437	1.03
		93			93			93		

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TABLE 2.5-28 (Cont'd)

STRUCTURE	OCTOBER 1977		JULY 1978		OCTOBER 1978		DECEMBER 1978		FEBRUARY/MARCH 1979		93
	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	
Reactor Building	521.048	1.13	520.931	1.40	520.937	1.33	520.932	1.39	520.931	1.40	93
	504.124	.70	504.154	0.34	506.227	0.42	506.214	0.58	520.219	0.52	
Auxiliary Building	500.913	1.40	500.945	1.02	506.519	0.98	506.504	1.16	506.509	1.10	
Turbine Building	520.931	.95	520.940	0.84	520.943	0.80	520.930	0.96	520.940	0.84	
	520.926	1.01	520.927	1.00	520.954	0.67	520.933	0.92	520.940	0.84	
	500.922	1.18	500.940	0.96	506.051	0.68	506.034	0.89	506.042	0.79	
Hester Bay	520.930	1.30	520.933	1.26	520.963	0.90	520.948	1.08	520.952	1.03	59
Circulatory Water Pump Structure	520.465	1.10	520.488	0.83	520.495	0.74	520.472	1.02	520.489	0.82	
	520.462	1.26	520.475	1.10	520.482	1.02	520.461	1.27	520.475	1.09	
	520.063	2.56	520.074	2.42	520.091	2.22	520.077	2.39	520.083	2.32	
	520.260	2.62	520.273	2.46	520.290	2.26	520.275	2.44	520.312	1.99	
Diesel Generator	520.929	.97	520.933	0.88	520.939	0.85	520.927	1.00	520.935	0.90	
Radwaste Building	521.476	1.96	521.486	1.44	521.503	1.24	521.490	1.39	521.494	1.34	
	521.265	1.67	521.264	1.68	521.299	1.26	521.285	1.43	521.288	1.39	
Machine and Service Building	519.482	1.12	519.474	1.21	519.487	1.06	519.479	1.15	519.480	1.14	
Storage Building	520.430	1.14	520.425	1.20	520.448	0.92	520.435	1.08	520.441	1.01	
	520.199	1.07	520.190	1.18	520.217	0.85	520.203	1.02	520.210	0.94	
	520.436	1.04	520.433	1.08	520.465	0.70	520.446	0.92	520.450	0.88	
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TABLE 2.5-28 (Cont'd)

STRUCTURE	APRIL 1979		JULY 1979		OCTOBER 1979		JANUARY 1980		APRIL 1980		93
	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	
Reactor Building	--	--	---	---	inaccessible	at present	520.934	1.37	520.943	1.26	67
	506.228	0.41	506.226	0.43	506.222	0.48	506.224	0.46	506.232	0.36	
Auxiliary Building	506.517	1.01	506.515	1.03	506.512	1.07	506.514	1.04	506.524	0.92	
Turbine Building	520.943	0.80	520.946	0.77	520.949	0.73	520.941	0.83	520.950	0.72	
	520.947	0.76	520.947	0.76	520.951	0.71	520.950	0.72	520.953	0.68	
	506.049	0.71	506.050	0.70	506.053	0.66	506.047	0.73	506.059	0.58	
Heater Bay	520.962	0.91	520.955	1.00	520.959	0.95	520.960	0.94	520.963	0.90	
Circulatory Water Pump Structure	520.495	0.74	520.498	0.71	520.493	0.77	520.497	0.72	520.479	0.94	
	520.481	1.03	520.478	1.07	Electrical Box over Point		inaccessible	at present	---	---	
	520.092	2.21	520.088	2.26	520.085	2.29	520.089	2.24	520.096	2.16	
	520.285	2.32	520.288	2.28	520.284	2.33	520.288	2.34	520.294	2.21	
Diesel Generator	520.942	0.82	520.933	0.87	520.945	0.78	520.933	0.92	520.944	0.79	
Radwaste Building	521.498	1.30	521.501	1.26	521.502	1.25	521.497	1.31	521.501	1.26	
	521.294	1.32	521.283	1.33	521.298	1.27	521.289	1.38	521.299	1.28	
Machine and Service Building	519.488	1.04	519.434	1.09	519.489	1.03	519.496	1.19	519.487	1.06	
Storage Building	520.442	1.00	520.446	0.95	520.450	0.90	520.436	1.07	520.451	0.89	
	520.216	0.86	520.216	0.86	520.216	0.86	520.208	0.96	520.218	0.84	
	520.458	0.78	520.459	0.77	520.461	0.74	520.457	0.79	520.459	0.77	

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TABLE 2.5-28 (Cont'd)

STRUCTURE	JULY 1980		OCTOBER 1980		JANUARY 1981		APRIL 1981		JULY 1981	
	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)
Reactor Building	520.944	1.25	520.941	1.28	520.939	1.31	520.947	1.21	520.930	1.42
	506.245	0.20	506.234	0.34	506.219	0.52	506.232	0.36	506.221	0.49
Auxiliary Building	506.535	0.79	506.525	0.91	506.516	1.02	506.524	0.92	506.510	1.09
Turbine Building	520.949	0.73	520.944	0.79	520.945	0.78	520.947	0.76	520.938	0.86
	520.952	0.70	520.950	0.72	520.939	0.85	520.957	0.64	520.946	0.77
	506.069	0.47	506.057	0.61	506.032	0.67	506.058	0.60	506.044	0.77
Heater Bay	520.958	0.96	520.958	0.96	520.950	1.06	520.967	0.85	520.953	1.02
Circulatory Water Pump Structure	520.509	0.58	520.491	0.79	520.494	0.76	520.485	0.86	520.488	0.83
	---	---	---	---	---	---	---	---	---	---
	520.098	2.14	520.080	2.35	520.087	2.27	520.076	2.40	520.074	2.42
	520.297	2.17	520.284	2.33	520.293	2.22	520.278	2.40	520.279	2.39
Diesel Generator	520.943	0.80	520.938	0.86	520.940	0.84	520.942	0.82	520.931	0.95
Radwaste Building	521.497	1.31	521.499	1.28	521.489	1.40	521.502	1.25	521.493	1.36
	521.306	1.18	521.305	1.19	521.306	1.18	521.291	1.36	521.290	1.37
Machine and Service Building	519.484	1.09	519.483	1.10	519.485	1.08	519.490	1.02	519.475	1.20
Storage Building	520.443	0.08	520.441	1.01	520.446	0.95	---	---	---	---
	520.212	0.91	520.209	0.95	---	---	---	---	---	---
	520.437	0.79	520.456	0.80	520.452	0.85	520.464	0.71	520.451	0.86
Service Building Addition (Established April 11, 1981)							520.401	0.00	520.382	0.23

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TABLE 2.5-28 (Cont'd)

STRUCTURE	OCTOBER 1981		JANUARY 1982		APRIL 1982		JULY 1982		OCTOBER 1982	
	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)	ELEVATION (ft MSL)	SETTLEMENT (in.)
Reactor Building	520.939	1.31	520.936	1.34	520.947	1.21	520.926	1.46	520.936	1.34
	506.227	0.42	506.224	0.46	506.232	0.36	506.218	0.53	506.224	0.46
Auxiliary Building	506.514	1.04	506.515	1.03	506.524	0.92	506.509	1.10	506.517	1.01
Turbine Building	520.941	0.83	520.934	0.91	520.947	0.76	520.938	0.86	520.942	0.82
	520.950	0.72	520.942	0.82	520.957	0.64	520.953	0.68	520.955	0.66
	506.046	0.74	506.057	0.61	506.058	0.60	506.041	0.80	506.049	0.71
Heater Bay	520.960	0.94	520.961	0.92	520.967	0.85	520.957	0.97	520.959	0.95
Circulatory Water Pump Structure	520.487	0.84	520.492	0.78	520.485	0.86	520.484	0.88	520.488	0.83
	520.487	2.39	520.087	2.27	520.076	2.40	520.070	2.47	520.074	2.42
	520.487	2.40	520.293	2.22	520.278	2.40	520.275	2.44	520.275	2.44
Diesel Generator	520.935	0.88	520.935	0.90	520.942	0.82	520.929	0.97	520.938	0.86
Radwaste Building	521.496	1.28	521.499	1.28	521.502	1.25	521.500	1.27	521.500	1.27
	521.296	1.31	521.295	1.31	521.291	1.36	521.287	1.40	521.292	1.34
Machine and Service Building	519.480	1.14	519.481	1.13	519.490	1.02	519.477	1.18	519.476	1.19
Storage Building	--	--	--	--	--	--	--	--	--	--
	520.460	0.76	520.455	0.82	520.464	0.71	520.456	0.80	520.455	0.82
Service Building Addition*	520.392	0.11	520.388	0.16	520.401	0.00	520.384	0.20	520.381	0.24

* New location and initial elevation April 1981
0-8 feet South of 2 and 1 foot 6 inches West of UA.

TABLE 2.5-29
COMPARISON OF ESTIMATED WITH
MEASURED TOTAL SETTLEMENTS

STRUCTURE	FOUNDATION ELEVATION	TOTAL SETTLEMENT (in.)				
		ESTIMATED (TABLE 2.5-22)	MAXIMUM MEASURED. OCT. 1982			
Reactor Building	468 ft 10 in.	1.50 ± 0.25	1.34			
Auxiliary Building	465 ft 9 in.	1.25 ± 0.25	1.00		41	
	488 ft 6 in.	2.00 ± 0.25			59	92
					67	
Diesel Generator Building	500 ft	2.50 ± 0.25	0.86	2	71	
					73	
					77	
Turbine Building	465 ft 9 in.	1.00 ± 0.25	0.82		79	93
Heater Bay	465 ft 9 in.	1.25 ± 0.25	0.95		81	
					84	92
Radwaste Building	489 ft	1.50 ± 0.50	1.34			93

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water systems is discussed in the evaluation of Criterion 46. It is concluded that the requirements of Criterion 37 are met.

For further discussion, see the following chapters, sections, or subsections:

- a. Overpressurization, Subsection 5.2.2;
- b. ECCS Inspection and Testing, in Section 6.3;
- c. ECCS - Instrumentation and Control, in Section 7.3;
- d. Standby A-C Power System, in Chapter 8.0; and
- e. Technical Specifications, in Chapter 16.0.

3.1.2.4.9 Criterion 38 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptable low levels.

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Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

3.1.2.4.9.1 Evaluation Against Criterion 38

The primary containment heat removal function is accomplished by the containment cooling mode of the residual heat removal system (RHR). In the event of a loss-of-coolant accident within the drywell, the pressure suppression system rapidly condenses the steam to prevent overpressure of the containment. With the RHR in the suppression pool cooling subsystem of the containment cooling mode, water is pumped from the suppression pool through the RHR heat exchangers and back to the pool. In the containment spray subsystem of the containment cooling mode, water is pumped through the RHR heat exchangers and back through spray headers in the drywell and in the suppression chamber. Cooling systems remove heat from the reactor core, the drywell, and from the water in the suppression pool during accident conditions, and thus provide continuous cooling of the drywell.

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The emergency core cooling system is actuated to provide core cooling in the event of a loss-of-coolant accident. Low water level in the reactor vessel or high pressure in the drywell will initiate the emergency core cooling system to prevent excessive fuel temperature. Sufficient water is provided in the suppression pool to accommodate the initial energy which can be released from the postulated pipe failure.

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fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

3.1.2.4.12.1 Evaluation Against Criterion 41

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As described in other sections of this FSAR (Section 9.4), ventilation and refrigeration systems are provided in the drywell and reactor building areas to maintain suitable temperature conditions and to provide thorough mixing of the atmospheres during normal operation.

The standby gas treatment system (SGTS) is utilized during abnormal conditions to maintain the reactor building at a negative pressure and to filter the exhaust air of potential fission products. Re-circulation fans and duct works are provided to mix the reactor building air to provide a dilute sample to the SGTS equipment trains for filtering and release to the atmosphere.

A containment inerting system is provided. This system maintains the containment oxygen content to less than 4% during normal operation as detailed in the technical specifications.

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The drywell and suppression chamber purge system is provided to reduce containment pressure, in case of overpressurization during operation, and to deinert and clean up the containment prior to entry of personnel following an operating period.

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The containment inerting system maintains the oxygen content of the containment <4% during reactor operation.

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A manually controlled combustible gas control system is provided to control the concentration of combustible gas in the primary containment following a LOCA. The system has redundant active components and power supplies that conform to the requirements of Regulatory Guide 1.7 (draft Regulatory Guide dated September 1976). During normal plant operation, the containment atmosphere is continuously monitored for combustible gas concentration. Following a LOCA, grab samples of the containment atmosphere will be manually taken by means of the post-accident sampling analysis system.

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The above described systems meet the requirements of Criterion 41. For further discussion, see the following chapters, sections, or subsections:

TABLE 3.2-1

STRUCTURES, EQUIPMENT, AND COMPONENT CLASSIFICATIONS

PRINCIPAL COMPONENT(1)*	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
I. Reactor System						
1. Reactor vessel	PC	I	A	I	11/69	
2. Reactor vessel support skirt	PC	I	NA	I	11/71	
3. Reactor vessel appurtenances, pressure retaining portions	PC	I	A	I		
4. CRD housing supports	PC	I	NA	I	2/71	(15)*
5. Reactor internal structures, engineered safety features	PC	I	NA	I		
6. Core support structures	PC	I	NA	I	9/71	(15) (23)
7. Other internal structures (e.g., dryers, separators, and shroud head assembly)	PC	NA	NA	II		
8. Control rods	PC	I	NA	I		(15)
9. Control rod drives	PC	I	NA	I	8/71	
10. Power range detector hardware	PC	I	B	I		
11. Fuel assemblies	PC	I	NA	I		(15)
12. Reactor vessel stabilizer	PC	I	NA	I	6/72	(15)
13. Reactor vessel insulation	PC	NA	NA	II		
14. In-core Housing Penetrations	PC	I	A	I		(22)
II. Nuclear Boiler System						
1. Vessels, instrumentation condensing chambers	PC	I	A/B	I		
2. Vessels, air accumulators	PC	I	C	I		(16)
3. Piping, relief valve discharge	PC	I	C	II		(23)
4. Piping, main steam within outermost isolation valve	PC	I	A	I	2/72	
5. Pipe suspension, main steam	PC	I	A	I	5/73	
6. Piping, restraints, main steam	PC	I	NA	I		
7. Piping, feedwater, within outermost isolation valve	PC, RB, T	I	A	I		
8. Other primary coolant pressure boundary piping within isolation valves	PC	I	A	I		
9. Piping, instrumentation beyond outermost isolation valves	RB	NA	D	II		(10)
10. Safety/relief valves	PC	I	A	I	1/71	
11. Valves, main steam isolation valves	PC, RB	I	A	I	12/70	(9)
12. Valves, feedwater isolation valves and within	PC, RB	I	A	I		
13. Valves, other, isolation valves and within primary containment	PC, RB	I	A	I		
14. Valves, safety related instrument air that operate ADS and MSIV valves	RB	I	NA	I		(16) (10)
15. Electrical modules with safety function	PC, EB, A	I	NA	I		(15)
16. Cable, with safety function	PC	I	NA	I		(25)
17. Quencher and quencher support	PC	I	C	I		
18. Downcomers and braces	PC	I	C	I		
19. Feedwater Spargers	PC	I	NA	II		(23)

*The key to information referenced numerically in the table headings and in the "Comments" columns of this table appears on pp. 3.2-15 ff.

TABLE 3.2-1 (cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE	COMMENTS
III. <u>Recirculation System</u>						
1. Piping	PC	I	A	I	2/71	
2. Pipe suspension, recirculation line	PC	I	A	I	5/73	
3. Pipe restraints, recirculation line	PC	I	NA	I	6/71	
4. Pumps	PC	I	A	I	5/71	
5. Valves	PC	I	A	I	3/71	
6. Motor, pump	PC	Special	NA	II	6/71	(19) (15)
7. Electrical modules with safety function	PC	I	NA	I		(15)
8. Cable with safety function	PC	NA	NA	I		
IV. <u>CRD Hydraulic System</u>						
1. Valves, isolation, water return line	PC, RB	I	A	I		
2. Valves, scram discharge volume lines	RB	I	B	I		
3. Valves insert and withdraw lines	RB	I	B	I		(6)
4. Valves, other	RB	NA	D	II		
5. Piping, water return line within isolation valves	PC, RB	I	A	I		
6. Piping, scram discharge volume lines	RB	I	B	I		
7. Piping, insert and withdraw lines	PC, RB	I	B	I		
8. Piping, other	RB	NA	D	II		
9. CRD pumps, filter	RB	NA	D	II	11/71	(15)
10. CRD strained	RB	NA	D	II	6/71	(15)
11. Hydraulic control unit and shutoff valves	RB	I	E	I	6/71	(13) (15)
12. Motor	RB	NA	NA	II		
13. Cable, with safety function		NA	NA	I		
14. Electrical modules with safety function	EB, A	NA	NA	I		

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TABLE 3.2-1 (Cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
V. <u>Standby Liquid Control System</u>						
1. Standby liquid control storage tank	RB	I	B	I	2/74	
2. Pumps	RB	I	B	I	6/71	
3. Pump motor	RB	I	NA	I	6/71	
4. Valves, explosive	RB	I	A	I		
5. Valves, isolation and within primary containment	RB	I	A	I		
6. Valves, beyond isolation valves	RB	I	B	I		
7. Piping, within isolation valves	PC, RB	I	A	I		
8. Piping, beyond isolation valves	RB	I	B	I		
9. Electrical modules with safety function	RB, A	I	NA	I		(15)
10. Cable, with safety function	--	NA	NA	I		
11. Valves and piping, other	RB	NA	D	NA		
VI. <u>Neutron Monitoring System</u>						
1. Piping, TIP	PC, RB	I	B	I		
2. Valves, isolation, TIP subsystem	RB	I	B	I		
3. Electrical modules, IRM and APRM	RB, PC	I	NA	I		(15)
4. Cable, IRM and APRM	--	NA	NA	I		(25)
VII. <u>Reactor Protection System</u>						
1. Electrical modules	PC, RB, A	I	NA	I		(15)
2. Cables	--	NA	NA	I		
VIII. <u>Process Radiation Monitors</u>						
1. Electrical modules, steamline and reactor building ventilation, and fuel pool vent plenum monitors	RE	I	NA	II		(15)
2. Cable, main steamline and reactor building ventilation, and fuel pool vent plenum monitors	--	NA	NA	I		(25)
3. Electrical modules for RHR, off-gas post- and pretreatment, radwaste effluent, closed cooling water, service water effluent, service water discharge systems	A, T, RB, RW	NA	NA	II		(15)
4. Radioactivity Monitors		NA	NA	II		(15) (23)
5. Radioactivity sampling		NA	NA	II		(15) (23)

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TABLE 3.2-1 (Cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
IX. Residual Heat Removal System RHR						
1. Heat exchangers, primary side	RB	I	B	I	5/71	
2. Heat exchangers, secondary side	RB	I	C	I	5/71	
3. Piping, connected to RCPB within outermost isolation valves	PC, RB	I	A	I		
4. Piping, beyond outermost isolation valves	RB	I	B	I		
5. Pumps	RB	I	B	I	8/70	
6. Pump motors	RB	I	NA	I	11/70	(15)
7. Valves, isolation, LPCI and shutdown lines	PC, RB	I	A	I		
8. Valves, isolation, other	PC, RB	I	B	I		
9. Valves, beyond isolation valves	RB	I	B	I		
10. Electrical modules with safety function	RB, A	I	NA	I		(15)
11. Cable, with safety function	--	NA	NA	I		
12. Containment spray	PC, RB	I	B	I		
X. Low Pressure Core Spray System LPCS						
1. Piping, within outermost isolation valves	PC, RB	I	A	I		
2. Piping, beyond outermost isolation valves	RB	I	B	I		
3. Pumps	RB	I	B	I	8/70	
4. Pump motors	RB	I	NA	I	11/70	(15)
5. Valves, isolation and within	PC, RE	I	A	I		
6. Valves, beyond outermost isolation valves	RB	I	B	I		
7. Electrical modules with safety function	RB, A	I	NA	I		(15)
8. Cable, with safety function	--	NA	NA	I		
XI. High Pressure Core Spray System HPCS						
1. Piping, within outermost isolation valves	PC, RB	I	A	I		
2. Piping, beyond outermost isolation valves	RB	I	B	I		
3. Piping, return test line to condensate storage tank beyond Reactor Building	O, T	NA	D	II		
4. Pump discharge line	RB	I	B	I		
5. Pump	RB	I	B	I	1/71	
6. Valves, within outermost isolation valve	PC, RB	I	A	I	1/72	
7. Valves, return test line to condensate storage	RB	I	B	I		
8. Valves, other	RB	I	B	I		
9. HPCS diesel	A	I	NA	I		
10. Electrical modules with safety function	RB, A	I	NA	I		(15)
11. Cable, with safety function	--	NA	NA	I		(25)
12. Motor	RB	I	NA	I		(15)

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TABLE 3.2-1 (Cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
XII. <u>Reactor Core Isolation Cooling System RCIC</u>						
1. Piping, within outermost isolation valves	PC, RB	I	A	I		
2. Piping, beyond outermost isolation valves	RB	I	B	I		
3. Piping, return test line to condensate storage tank beyond Reactor Building	O	NA	D	II		
4. Vacuum pump discharge line from vacuum pump to containment isolation valves	RB	NA	D	II		
5. Pumps	RB	I	B	I	10/70	
6. Valves, isolation and within	PC, RB	I	A	I		
7. Valves, return test line to condensate storage	RB	I	B	I		
8. Valves, other	RB	I	B	I		
9. Turbine	RB	I	E		10/70	(11) (17) (15) (23) 73
10. Electrical modules with safety function	RB, A	I	NA	I		(15) 93
11. Cable, with safety function	--	NA	NA	I		(25)
XIII. <u>Fuel Service Equipment</u>						
1. Fuel preparation machine	RB	I	NA	I		(15)
2. General purpose grapple	RB	NA	NA	I		(15)(26) 93
XIV. <u>Reactor Vessel Service Equipment</u>						
1. Steamline plugs	RB	NA	NA	NA		(15)
2. Dryer and separator sling	RB	NA	NA	I	4/73	(15)(26) 93
3. Head strongback	RB	NA	NA	I		(15)(26)
XV. <u>In-Vessel Service Equipment</u>						
1. Control rod grapple	RB	NA	NA	I		(15)(26) 93
XVI. <u>Refueling Equipment</u>						
1. Refueling platform	RB	I	NA	I	10/73	(23) 73
2. Refueling bellows, reactor cavity	PC	I	NA	II		(23)
3. New fuel inspection stand	RB	NA	NA	II		(15)

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TABLE 3.2-1 (Cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
XVII. <u>Storage Equipment</u>						
1. Fuel storage racks	RB	I	NA	I		(15)
2. Defective fuel storage container	RB	NA	NA	I		(15)(27)
3. Spent fuel pool, dryer/sep. pool, Rx well	RB	I	NA	I		
4. Spent Fuel pool liner	RB	I	NA	I		
XVIII. <u>Radwaste System</u>						
1. Tanks, atmospheric	RW,T	NA	D	II		
2. Heat exchange.s	RW,T	NA	D	II		
3. Piping, containment isolation	PC,RB	I	B	I		
4. Valves, containment isolation	PC,RB	I	B	I		
5. Piping, other	RB,T,RW	NA	D	II		
6. Pumps	RB,RW,T,A	NA	D	II		
7. Valves, flow control and filter system	RW,T	NA	D	II		
8. , other	RB,RW,T,A	NA	D	II		
XIX. <u>Reactor Water Cleanup System</u>						
1. Vessels: filter/demineralizer	RB	NA	C	II	6/71	
2. Heat exchangers	RB	NA	C	II	4/70	(14)
3. Piping, within outermost isolation valves	RB,PC	I	A	I		
4. Piping, beyond outermost isolation valves	RB	NA	C	II		
5. Pumps/motors	RB	NA	C	II	6/71	(14)
6. Valves, isolation valves and within	RB	I	A	I		
7. Valves, beyond outermost isolation valves	RB	NA	C	II	6/71	
XX. <u>Fuel Pool Cooling and Cleanup System</u>						
1. Demineralizer vessel	RB	NA	C	II		
2. Filters	RB	NA	C	II		
3. Pumps, purification	RB	NA	C	II		
4. Piping, excluding item 7	RB	NA	C	II		
5. Valves	RB	NA	C	II		
6. Heat exchanger	RB	NA	C	II		
7. Fuel pool cooling piping	RB	I	C	II		
8. Cooling pumps and heat exchanger supports	RB	I	C	II		

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TABLE 3.2-1 (Cont'd)

	PRINCIPAL COMPONENT(1)	LOCATION (3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY (4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS	
XXXVII.	<u>Miscellaneous Ventilation Systems</u>							
	1. Battery room H & V	A	I	NA	I			
	2. Service water structure	P	I	NA	I			
	3. Relay and emergency switchgear H & V	A	I	NA	I			
	4. Control room air conditioning	A	I	NA	I			
	5. Emergency diesel generator ventilation system	A	I	NA	I			
XXXVIII.	<u>Area Radiation Monitoring System</u>							
	1. All components (fixed and portable)	RW,T,A,RB	NA	NA	II		(23)	73
XXXIX.	<u>Leak Detection System</u>							
	1. Temperature element	RB, T	I	NA	I		(15)	
	2. Temperature switch	RB, T	I	NA	I		(15)	
	3. Differential temperature switch	RB, T	I	NA	I		(15)	
	4. Differential flow switch	RB	I	NA	I		(15)	
	5. Pressure switch	RB	I	NA	I		(15)	
	6. Differential pressure switch	RB	I	NA	I		(15)	
	7. Differential flow summer	RB	I	NA	I		(15)	
	8. Reactor building floor drain sumps	RB	NA	NA	II			
	9. Reactor building floor drain pumps and piping	RB	NA	NA	II			
	10. Power Supply	RB	I	NA	I		(15)	
	11. Square Root Converter	RB	I	NA	I		(15)	
	12. Flow transmitter	PC,RB	I	NA	I		(15)	
	13. Timers	RB	I	NA	I		(15)	
	14. Differential flow indicator	RB	NA	NA	II		(15)	
	15. Instrument Lines	RB,PC	I	I	I		(15)	
XL.	<u>Fire Protection System</u>							
	1. Water spray deluge systems	-	NA	NA	II			
	2. Sprinklers, carbon dioxide systems	-	NA	NA	II			
	3. Portable and wheeled extinguishers	-	NA	NA	II			
	4. Halon system	-	NA	NA	II			
XLI.	<u>Civil Structures</u>							
	1. Reactor building	RB	I	NA	I			
	2. Service water pump structure	P	I	NA	II		(23)	

TABLE 3.2-1 (Cont'd)

PRINCIPAL COMPONENT(1)	LOCATION(3)	SEISMIC(5) CATEGORY	QUALITY(4a) GROUP CLASSIFICATION	QUALITY(4b) ASSURANCE REQUIREMENT	PURCHASE DATE(2)	COMMENTS
3. Radwaste building	RW	NA	NA	II		(23)
4. Auxiliary building	A	I	NA	II		(23)
5. Turbine building	T	NA	NA	II		
6. Service water pipe supports & encasements	O	I	NA	II		(23)
7. Radiation shielding:	RB	I	NA	II		
a. Primary containment	PC	I	NA	I		
b. Reactor building	RB	I	NA	II		(23)
c. Auxiliary building	A	I	NA	II		(23)
d. Internal masonry walls	RE,A	I	NA	II		(23)
e. Sacrificial shield wall	PC	I	NA	I		
f. Turbine and Radwaste Building	T,RW	NA	NA	II		(23)
XLII. <u>Containment Related Items</u>						
1. Drywell equipment hatch	PC	I	NA	I		
2. Personnel lock	PC	I	NA	I		
3. Suppression pool hatch	PC	I	NA	I		
4. PC penetrations	PC, RB	I	NA	I		
5. Vacuum relief valves	PC	I	C	I		
6. CRD removal hatch	PC	I	NA	I		
XLIII. <u>Other Radiological Equipment</u>						
1. Radiation contamination measurement equipment	-	NA	NA	II		(23)
2. Personnel monitoring internal and external	-	NA	NA	II		(23)
3. Decontamination equipment	-	NA	NA	II		(23)
4. Respiratory protection equipment	-	NA	NA	II		(23)
XLIV. <u>MSIV Leakage Control System</u>						
1. Piping, within RCPB isolation valve	PC, RB	I	A	I		
2. Piping, other upstream of second isolation valve	PC, RB	I	A	I		
3. Piping, downstream system from steamline	RB	NA	D	II		(23)
4. Piping, other downstream system lines	RB	NA	D	II		(23)
5. Valves, within RCPB	RB	I	A	I		
6. Valves, other	RB	NA	D	II		(23)
7. Heater	RB	NA	D	II		(23)
8. Blowers	RB	NA	D	II		(23)
XLV. <u>Instrument and Control Equipment</u>						
1. Safety-related instrument and control systems	-	-	-	-		(24)

TABLE 3.2-1 (Cont'd)

The design and construction specifications for the HCU do invoke such codes and standards as can be reasonably applied to individual parts in developing required quality levels, but these codes and standards are supplemented with additional requirements for these parts and for the remaining parts and details. For example, 1) all welds are LP inspected, 2) all socket welds are inspected for gaps between pipe and socket bottom, 3) all welding is performed by qualified welders, 4) all work is done per written procedures. Quality Group D is generally applicable because the codes and standards invoked by that group contain clauses which permit the use of manufacturer's standards and proven design techniques which are not explicitly defined within the codes of Quality Groups A, B, or C. This is supplemented by the QC techniques described above.

(14) Reactor Water Cleanup

A high leaktight integrity isolation valve will be provided in the reactor water cleanup discharge line connecting to the feedwater header outside of the containment. This valve will be remote manually operated from the control room using signals which indicate loss of flow of cleanup water.

The reactor water cleanup discharge line from the feedwater header to and including the high leaktight valve and the suction line from the reactor to and including the outermost isolation valve will be classified Group A. The remainder of the cleanup system will be Group C.

(15) No principal industrial code is applicable.

- (16) Pneumatic systems associated with actuation of safety-related valves to accomplish safety functions (e.g., main steam isolation valves, main steam safety/relief valves) are classified Quality Group C. This classification is intended to apply to components such as the air piping, fittings, and accumulator tanks (Refer to Figure 3.2-1). This classification does not apply to components of the system such as air control valves, air check valves, and cylinder (or diaphragm) air actuators with Quality Group Classification NA. These components are classified as "special equipment" and are selected based on engineering reviews, operating experience and testing as being the most suitable for the application. Such equipment is required to be qualified to demonstrate operability during normal and emergency ambient conditions. Components normally furnished with the process valve (e.g., air control valves, air actuators) are performance tested with the valve as part of its acceptance test procedure. Group C classification has not been applied to these components due to the nonavailability of the equipment with "N" symbol stamp and due to the inappropriate restrictions (e.g., materials, minimum allowable wall thickness) imposed by the code on the equipment in the relatively low pressure, low-temperature air service. The special equipment designation for the above described components is based on considerations

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TABLE 3.2-1 (Cont'd)

consistent with those of Comment 15 above.

- (17) RCIC turbine steam exhaust line is Quality Group B except that hydrostatic testing of this portion of the line is not required.
- (18) Fuel pool (cooling) supply (RHR intertie) is Quality Group B and Seismic Category I; the rest of system is Seismic NA.
- (19) Special (engineered design-quality) requirements (motors, pumps, tanks, and equipment).

The recirculation pump motor has a design capability of 4.2 g's and 3.6 g's in the horizontal and vertical directions, respectively. Maximum calculated accelerations to which the motor is subjected are 1.53 g's horizontal and 1.12 g's vertical. This equipment is capable of withstanding inertial forces equal to the weight multiplied by the seismic coefficient specified in Subsection 3.9.2 as applied to each member and to the system as a whole.

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The QA/QC requirements are as required by either:

- 1) ASME B&PVC Section III, Appendix XI or equivalent; equipment ordered prior to January 1, 1970 apply QC plan "in effect" based on purchase order requirements.
- 2) A QA plan/program at least equivalent to that required by QAR 2 as specified in Chapter 17.0.

(20) Deleted

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- (21) The main steamline from the outermost main steamline containment isolation valve, up to and including the main stop and control valve assembly, and all branch line 2½" (IPS inches) diameter and

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TABLE 3.2-1 (Cont'd)

- (25) The trays and supports for safety-related cables meet Seismic Category I and 10 CFR 50, Appendix B requirements, except in the turbine building. All Class 1E and affiliated circuits, including RPS circuits located in a non-Seismic Category I structure (i.e., Turbine Building), are contained within Class 1E, Seismic Category I raceways although they are supported from a non-Seismic Category I structure.
- (26) This item is classified as Seismic Category NA (exempt from seismic evaluation) because it is suspended from a cable which dampens out the transmission of floor response spectra.
- (27) This item is classified Seismic Category NA (exempt from seismic evaluation) because it is isolated from seismic excitation.

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TABLE 3.2-2

CODE GROUP DESIGNATION - INDUSTRY CODES AND STANDARDS FOR MECHANICAL COMPONENTS

QUALITY GROUP CLASSIFICATION	ASME B&PV CODE CLASSES/DIV. 1968 ED./1971 ED.	COMPONENTS ORDERED PRIOR TO JAN. 1, 1970***	COMPONENTS ORDERED ON OR AFTER JAN. 1, 1970 TO JULY 1, 1971	COMPONENTS ORDERED ON OR AFTER JULY 1, 1971 AND PRIOR TO JULY 1, 1974
A	A 1	ASME III, 1968 through Summer 1970 Addenda, A ANSI B31.1.0 TEMA C (1968) See Note (a)	ASME III, A ANSI B31.7 I NP & VC I TEMA C (1968) See Note (a) and (f)	ASME III, 1971, including mandatory Addenda, 1 NA & NB Subsections B31.7 (1969) I** TEMA C (1968) See Note (c)
B	B*,C 2,MC*	ASME III, 1968 through Summer 1970 Addenda, B*,C ANSI B31.1.0 TEMA C (1968) See Notes (a) and (e)	ASME III, B*,C ANSI B31.7, 1969 II NP & VC, II TEMA C (1968), R TANKS API 620/650 See Notes (a), (e) and (f)	ASME III, 1971, including mandatory Addenda, 2 & MC* NA & NC Subsections NA & NE Subsections TEMA C (1968) TANKS **** See Notes (c) and (e)
C	I 3	ASME VIII, Div. 1 ANSI B31.1.0 TEMA C (1968) See Notes (b) and (e)	ASME VIII, Div. 1 ANSI B31.7, III NP & VC III TEMA C (1968), R TANKS API 620/650 See Notes (b), (e) and (f)	ASME III, 3 1971, including mandatory Addenda NA & ND Subsections TEMA C (1968) TANKS **** See Notes (c) and (e)
D	I I	ASME VIII, Div. 1 ANSI B31.1.0 TEMA C (1968) See Notes (b) and (e)	ASME VIII, Div. 1 ANSI B31.1.0 TEMA C (1968) TANKS API 620/650 See Notes (b), (e) and (f)	ASME VIII, Div. 1 1971 ANSI B31.1.0 1967 through Addenda d, 1972 TEMA C (1968) TANKS API 620/650 See Notes (d) and (e)
E	SPECIAL ENGINEERED EQUIPMENT WITH CODES AND STANDARDS AS SPECIFIED IN NOTES AND COMMENTS IN TABLE 3.2-1			

* Metal containment vessel only.

** Section II - 71 Ed. requires design of pipe supporting elements to be in accordance with the requirement of ANSI 31.7-6a, Divisions 1-720 and 1-721.

*** No piping procured prior to Jan. 1, 1970.

**** See Comment 12 of Table 3.2-1.

The seismic qualification in the laboratory generally followed the same procedures, which consisted of the following:

- a. The equipment was mounted on the shake table in such a manner as to represent its installed condition.
- b. Sine sweep tests were performed covering all practicable frequency ranges with constant or variable acceleration levels to determine the resonance frequencies of the equipment. This procedure enables the determination of the predominant mode periods by monitoring the output response.
- c. With the predominant period thus obtained, it was used for the determination of the necessary acceleration levels which were obtained from the applicable floor response spectra. | 68
- d. With acceleration levels and predominant frequencies obtained, the full level or endurance tests were performed to establish the adequacy of equipment. This is accomplished by one of the following methods: | 68

1. Sine Dwell Test | 68

This test utilizes a sine wave function with one of the natural frequencies of the equipment and the corresponding acceleration levels as input vibrations. The test duration is generally 30 seconds, during which time the behavior of the equipment is observed and recorded.

2. Sine Beat Test | 68 | 93

A sine beat function, with number of beats and cycles per beat corresponding to the natural frequency of the equipment and with predetermined acceleration level, is used as input motion to test and record the behavior of the equipment tested.

3. Random Motion Test

This test is performed by applying a random excitation (in the form of white noise) to the equipment. The excitation is controlled to provide a test response spectra (TRS) which envelopes the required response spectra (RRS). This approach simulates the actual conditions the equipment would experience in an actual earthquake. | 68

3.9.2.2.2.4 Hydraulic Control Unit (HCU)

The HCU's were originally designed and qualified for seismic loading. The HCU's were modified and requalified for the postulated seismic, SRV, LOCA, and normal operating loads. The modifications consisted of:

- a. adding structural steel to support the HCU pipe frame,
- b. replacing the internal support brackets with stronger brackets, and
- c. providing additional support to the HCU interfacing piping.

The requalification was accomplished by finite element response spectrum analysis.

3.9.2.2.2.5 Fuel Channels

GE BWR fuel channel design bases, analytical methods and evaluation results including seismic considerations, are contained in References 3 and 4.

3.9.2.2.2.6 Recirculation Pump and Motor Assembly

Calculations were made which show that the recirculation pump and motor assembly design can withstand 4.2 g's horizontal and 3.6 g's vertical. The flooded assembly was analyzed as a free body supported by constant support hangers from the brackets on the motor mounting member with hydraulic snubbers attached to brackets located on the pump case and the top of the motor frame.

Primary stresses due to horizontal and vertical forces were considered to act simultaneously and are conservatively added directly. The horizontal and vertical seismic forces were applied at mass centers and equilibrium reactions determined for motor and pump brackets.

3.9.2.2.2.7 ECCS Pump and Motor Assembly

This section discusses the ECCS pump and motor assemblies. The qualification of these pump and motor assemblies as a unit while operating under seismic and dynamic conditions was provided by a detailed finite element analysis of the coupled system. An acceleration response spectrum and model superposition method of analysis was utilized to determine the response of the system in the three orthogonal directions. The effects of normal operating loads, seismic and hydrodynamic loads, and nozzle loads were considered in the analysis. The loads were combined in accordance with Sargent & Lundy document A51.70, "Design Criteria for Design Load Combinations." The results of the analysis indicate that both pump and motor are capable of sustaining the above loading without overstressing the pump components.

TABLE 3.9-25 (Cont'd)

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<u>SYSTEM</u>	<u>COMPONENT IDENTIFICATION AS SHOWN ON APPLICABLE P&ID</u>	<u>NAME</u>	<u>CLASSIFICATION: ASME CODE CLASS</u>	
RCIC	1E51C001	RCIC pump	2	93
	1E51C003	CSCS water leg pump	2	
	1E51F010	Gate valve	2	
	1E51F012	Gate valve	2	
	1E51F022	Globe valve	2	
	1E51F031	Gate valve	2	
	1E51F045	Globe valve	2	
	1E51F068	Gate valve	2	
Main Steam	1B21F576	Gate Valve	2	93
Extraction steam	1ES059	Gate valve	2	
Fuel pool cooling and cleanup	1FC029	Gate valve	2	
	1FC034	Gate valve	2	
	1FC035	Gate valve	2	
Instrument nitrogen supply	1IN012	Globe valve	2	
	1IN013	Globe valve	2	
Equipment drain to radwaste	1RE048	Globe valve	2	22
	1RE049	Globe valve	2	
Floor drain to radwaste	1RF001	Globe valve	2	
	1RF002	Globe valve	2	
Pumphouse ventilation	1VH001	Butterfly valve	3	
	1VH002	Butterfly valve	3	
	1VH003	Butterfly valve	3	
	1VH004	Butterfly valve	3	
Primary contain- ment HVAC	1VQ001	Butterfly valve	2	
	1VQ002	Butterfly valve	2	
	1VQ003	Butterfly valve	2	
	1VQ004	Butterfly valve	2	
Reactor building closed cooling water	1WR01P	RBCC water pump	3	
	1WR054	Gate valve	2	
	1WR055	Gate valve	2	

3.10.1.2.2 Reactor Protection, Engineered Safety Features, and
Emergency Power Circuits

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- a. The reactor protection system and the engineered safety feature circuits (Chapter 7.0) will maintain functional operability during and following any preaccident or post-accident earthquake accelerations, at the equipment location, of a magnitude up to and including 1.5g in the horizontal direction and 0.5g in the vertical direction and a frequency of 0.25 to 33 hertz.

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The design of building and electrical equipment support structure is such as to hold the safe shutdown earthquake accelerations at the equipment locations of a magnitude outlined in Section 3.7.

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- b. The equipment associated with the Emergency Power System is identified in Subsection 3.10.1.1.2 and the qualification is described in Subsection 3.10.2.2.

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3.10.1.2.3 Cable Tray, Wireway, Conduit, and Cable Bus Support Criteria

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The following criteria are used in the design of cable tray, wireway, conduit, and cable bus supports:

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- a. Regardless of cable tray or bus duct function, all supports are designed to meet the Seismic Category I requirements in Seismic Category I structures by dynamic analysis using the appropriate seismic response spectra.
- b. The most probable maximum values are obtained by taking the square root of the sum of the squares of the stresses and reactions of all significant modes.
- c. Cable tray loading of 40 psf is used throughout and includes cables, tray and tray appurtenances such as covers, splice plates, bolts, and side rail extensions. Any tray sections exceeding this limit must undergo a specific analysis of the support system adequacy.
- d. Cable bus loading that is used is as follows:

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3-conductor bus

cable -----	10.8
bus -----	7.0
	<u>17.8 psf</u>

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6-conductor bus

cable -----	21.6
bus -----	8.0
	<u>29.6 psf</u>

12-conductor bus

cable -----	43.2
bus -----	12.0
	<u>55.2 psf</u>

power level. These data support the qualitative observations that fission product release rates are functions of power density and that progressive deterioration is a function of time. However, available failure data are insufficient to quantify the detailed correlation between these variables.

4.2.1.3.2.1 Fuel Densification

4.2.1.3.2.1.1 Fuel Densification Models

The GE Fuel densification models are described in References 21, 22 and 23. References 22 and 23 contain a description of the most recent densification models, as modified and approved by the NRC. Possible effects due to fuel densification are: (a) power spikes due to axial gap formation; (b) increase in LHGR because of pellet length shortening; (c) creep collapse of the cladding due to axial gap formation; and (d) changes in stored energy due to decreased pellet/cladding thermal conductance resulting from increased radial gap size.

4.2.1.3.2.1.2 Densification Analysis

The amount of densification employed in the following models was determined through the use of models defined in Reference 22.

4.2.1.3.2.1.2.1 Power Spiking Analysis for 8x8 Fuel Lattice

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The following equation employed to calculate maximum gap size is as described in Reference 22:

$$\frac{\Delta L}{L} = \frac{\Delta \rho}{2} + 0.0025 \quad (4.2-2)$$

where:

- ΔL = maximum axial gap length,
- L = fuel column length,
- $\Delta \rho$ = the average change in density as measured by thermal simulation for 24 hours at 1700° C,
- 2 = anisotropic factor applied to densification, and
- 0.0025 = allowance for irradiation-induced cladding growth and axial strain caused by fuel/cladding mechanical interaction.

The result for power spiking penalty at the top of the core is 2.2%. The power spiking penalty as a function of elevation from the bottom of the core can be conservatively expressed by:

$$\left(\frac{\Delta P}{P}\right)_x = \left(\frac{\Delta P}{P}\right)_L \frac{x}{L} \quad (4.2-3)$$

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the extent of deformation and buckling instability, if any. Of particular interest are: 1) the responses of the guide tubes and the metal channels around the fuel bundles, and 2) the potential leakage around the jet pump joints.

The guide tube is evaluated for buckling instability caused by externally applied pressure. Two primary modes of failure have been analyzed and are described in Subsection 4.2.3.1.3. For a guide tube with minimum wall thickness and maximum allowed ovality, the pressure which causes yield stress is 93 psi compared to the design pressure of 37.5 psi. The design pressure is in all cases greater than any pressure differential the guide tube will experience including accident conditions. The stress the guide tube would experience is given in Subsection 3.9.2. It is concluded that the guide tube will not fail under the assumed conditions.

The fuel channel load resulting from an internally applied pressure is evaluated, utilizing a fixed-beam analytical model under a uniform load. Tests to verify the applicability of the analytical model indicate that the model is conservative. A roller, at the top of the control rod, guides the blade as it is inserted. If the gap between channels is less than the diameter of the roller, the roller deflects the channel walls as it makes its way into the core. The friction force is a small percentage of the total force available to the control rod drives for overcoming such friction, and it is concluded that the main steamline break accident does not impede the insertability of the control rod.

Jet pump joints have been analyzed to evaluate the potential leakage from within the floodable inner volume of the reactor vessel during the recirculation line break and subsequent LPCI reflooding. Because the jet pump diffuser is welded to the shroud support, the only

For automatic actuation of the ADS safety/relief valves, an external pneumatic piston is provided to open the valve against the spring force at any steam pressure down to 0 psig. This pneumatic operator is so arranged that if it malfunctions it will not prevent the valve disc from lifting if steam inlet pressure reaches spring set pressure. The control system for the actuator for depressurization operation is described in Subsection 7.3.1.1.1. For overpressure relief operation, a pressure switch adjustable between 200 and 1200 psig, is provided for each valve. When the pressure setpoint is reached, the external pneumatic piston is actuated to open the safety/relief valve. The delay time (maximum elapsed time between receiving the overpressure signal at the valve actuator and actual valve motion) and the response time (maximum valve stroke time) are each equal to or less than 0.2 second (delay time plus stroke time = total valve opening time). |68 | 93

Each safety/relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The safety/relief valve discharge piping is designed to limit valve outlet pressure to 40% of maximum valve inlet pressure with the valve wide open. Water in the line more than a few feet above suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, a vacuum relief valve is provided on each safety/relief valve discharge line to prevent drawing an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. The safety/relief valves are located on the main steamline piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steamlines are more accessible during a shutdown for valve maintenance.

Each of the safety/relief valves provided for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators assure that the valves can be held open following failure of the air supply to the accumulators. They are sized to be capable of opening the valves and holding them open against the maximum drywell pressure of 45 psig and contain sufficient air for an additional activation at 70% of maximum drywell pressure.

The nuclear pressure relief system automatically depressurizes the nuclear system sufficiently to permit the LPCI and LPCS systems to operate as a backup for the high-pressure core spray system. Automatic depressurization occurs when some of the safety/relief valves are opened automatically. The signal for the safety/relief valves to open and to remain open is based on simultaneous signals from (1) drywell high pressure, (2) reactor vessel low water level, and (3) output pressure from at least one LPCI or one core spray pump. Further descriptions of the operation of the automatic depressurization feature are found in Section 6.3 and in Subsection 7.3.1.1.1.

The nuclear system can be depressurized manually if the main condenser is not available as a heat sink after reactor shutdown. The safety/relief valves are operated by remote-manual controls from the main control room.

The safety function of the safety/relief valves is a backup to the relief function. The safety/relief valves are spring-loaded and are designed, constructed, and coded in accordance with ASME codes.

5.2.2.2.4 Safety Evaluation

The ASME Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from overpressure. The code allows a peak allowable pressure of 110% of vessel design pressure (upset condition). The code specifications for safety valves require that: (1) the lowest safety valve be set at or below vessel design pressure and (2) the highest safety valve be set so that total accumulated pressure does not exceed 110% of the design pressure. The safety/relief valves are set to open (safety function) at pressure settings indicated in Table 5.2-6. This satisfies the ASME Code specifications for safety valves, because all valves open at less than 1250 psig (nuclear system design pressure).

There are two major transients, the closure of all main steamline isolation valves and a turbine trip with a coincident closure of the turbine steam bypass system valves that provide the most severe abnormal operational transients resulting in a nuclear system pressure rise.

The transient produced by the closure of all main steamline isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The required safety valve capacity is determined by analyzing the pressure rise from such a transient. The plant is assumed to be operating at the turbine-generator design conditions at a maximum vessel dome pressure of 1020 psig. The analysis hypothetically assumes the failure of the direct isolation valve position scram. The reactor is shutdown by the backup, indirect, high neutron flux scram. The analysis indicates that the design valve capacity is capable of maintaining adequate margin (at least 50 psi at the bottom of the vessel) below the peak ASME code allowable pressure in the nuclear system (1375 psig). Figure 5.2-2 shows a curve produced by this analysis. The sequence of events assumed in this analysis was investigated to meet code requirements and to evaluate the pressure relief system exclusively (see Attachment 5A for more information).

Under the general requirements for protection against overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, 1968 through summer 1970 Addenda, credit can be allowed for a scram from the reactor protection system. In addition, credit is also taken for the protective circuits which are indirectly derived when determining the required safety/relief valve capacity. The backup reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving dual purpose safety/relief valves. Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety/relief valve capacity of nuclear vessels under the provisions of

- c. set pressure test, and
- d. seat leakage test.

The valves are installed as received from the factory. The GE equipment specification requires certification from the valve manufacturer that design and performance requirements have been met. This includes capacity and blowdown requirements. The setpoints are adjusted, verified, and indicated on the valves by the vendor. Specified manual and automatic actuation relief mode of each safety/relief valve is verified during the preoperational test program.

It is not feasible to test the safety/relief valve setpoints while the valves are in place. The valves are mounted on 6-inch diameter, 1500-pound primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. One-half of the complement of valves will be tested to check set pressure at every refueling outage. The external surface and seating of all safety/relief valves are 100% visually inspected when the valves are removed for maintenance or bench checks.

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5.2.2.3 Report on Overpressure Protection

An overpressure protection report will be provided as Attachment 5A to this chapter. The report will supply sufficient information and documentation to show compliance with all the requirements of Article 9 of the ASME Code, Section III, 1968, including 1970 addenda. Included is the design basis for the sizing of the safety/relief valves, the overpressure protection analysis, and the analysis of the safety valve - reactor protection system availability. The manufacturer of the safety/relief valves guarantees to meet the flow requirements as specified in Table 5.2-6 (Part A).

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5.2.3 General Material Considerations

5.2.3.1 Material Specifications

Table 5.2-7 lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components.

5.2.3.2 Compatibility with Reactor Coolant

The materials of construction exposed to the reactor coolant consist of the following:

- a. solution annealed austenitic stainless steels (both wrought and cast) Types 304, 304L, 316 and 316L;
- b. nickel base alloys - Inconel 600 and Inconel X750;

TABLE 5.2-3

REACTOR COOLANT PRESSURE BOUNDARY LOADING COMBINATIONSA. REACTOR PRESSURE VESSEL

<u>PLANT CONDITIONS</u>	<u>LOADING COMBINATIONS</u>
Normal	W + (P+J) for Events* 1.7, 10 and 11
Upset	W + (P+J) for Events* 9A-9C W + (P+J) + OBE (Event* 8) at Rated Operating Conditions
Emergency	W + (P+J) for Events* 12-15 W + (P+J) OBE for Events* 9A-9C**
Faulted	W + (P+J) + Event* 16 and 17 W + (P+J) SSE for Event* 16

Where W is the weight, superimposed, handling, vibration and reaction loads applied to the component during the event indicated, SSE is the maximum seismic load caused by the Safe Shutdown Earthquake. (P+J) are the combined pressure and jet loads during the events indicated.

B. LOADING AND STRESS CRITERIA FOR THE FOLLOWING RCPB COMPONENTS ARE SPECIFIED IN THE LISTED TABLES.

<u>COMPONENT</u>	<u>TABLE</u>
1. Recirculation Loop Piping	Table 3.9-7
2. Main Steamline Piping	Table 3.9-6
3. Safety/Relief Valves	Table 3.9-9
4. Main Steam Isolation Valves	Tables 3.9-10 and 3.9-11
5. Recirculation Loop Pumps and Valves	Tables 3.9-12 and 3.9-13

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* For definition of event(s), refer to Table 5.2-2.

** The peak pressure is within 110% of design pressure for these emergency plant conditions and the resultant stresses fall within condition limits for upset. No special analysis is required.

5.4.2.3 Description

5.4.2.3.1 Reactor Vessel

The reactor vessel (Figure 5.4-1) is a vertical, cylindrical pressure vessel of welded construction. The vessel is designed, fabricated, tested, inspected, and stamped in accordance with the ASME Code Section III, Class 1 including the addenda in effect at the date of order placement, November 1969. Design of the reactor vessel and its support system meets Seismic Category I equipment requirements. The materials used in the reactor pressure vessel are shown in Table 5.2-7.

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The cylindrical shell and bottom head of the reactor vessel are fabricated of low alloy steel, the interior of which is clad with stainless steel weld overlay. Nozzle and nozzle weld zones are unclad except for those mating to stainless steel piping system.

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Inplace annealing of the reactor vessel is unnecessary because shifts in transition temperature caused by irradiation during the 40-year life can be accommodated by raising the minimum pressurization temperature. Radiation embrittlement is not a problem outside of the vessel beltline region because the irradiation in those areas is less than 1×10^{18} nvt with neutron energies in excess of 1 MeV.

Quality control methods used during the fabrication and assembly of the reactor vessel and appurtenances ensure that design specifications are met.

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The vessel top head is secured to the reactor vessel by studs and nuts. These nuts are tightened with a stud tensioner. The vessel flanges are sealed with two concentric metal seal rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including heating to operating pressure and temperature at a maximum rate of 100° F/hr in any 1-hour period. To detect seal failure, a vent tap is located between the two seal rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal.

5.4.2.3.2 Shroud Support

The shroud support is a circular plate welded to the vessel wall. This support is designed to carry the weight of the shroud, shroud head, peripheral fuel elements, neutron sources, core plate, top guide, the steam separators, the jet pump diffusers, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME code stress limits.

valve for proper operation, position and torque switch setting, position transmitter function (where applicable) and speed requirements. Valves have additionally been tested to demonstrate adequate stem thrust (or torque) capability to open (or close) the valve within the specified time at specified differential pressure. Tests verified no mechanical damage to valve components during full stroking of the valve. Suppliers were required to furnish assurance of acceptability of the equipment for the intended service based on any combination of:

- a. test stand data,
- b. prior field performance,
- c. prototype testing, and
- d. engineering analysis.

Preoperational and operational testing performed on the installed valves consists of total circuit checkout and performance tests to verify speed requirements at specified differential pressure.

5.5.13 Safety and Relief Valves

5.5.13.1 Safety Design Bases

Overpressure protection has been provided at isolatable portions of systems in accordance with the rules set forth in the Nuclear Pump and Valve Code as of order date January 1971 for the GE-furnished valves for the NSSS and ASME Section III, 1971, for all other safety-related systems. See Table 3.2-1 for detailed information.

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5.5.13.2 Description

Pressure relief valves have been designed and constructed in accordance with the same code class as that of the piping and valves in the system.

Table 3.9-9 lists the applicable code classes for the main steam relief valves and system design pressures and temperatures. The design criteria, design loading, and design procedure are as described in Subsection 3.9.2.

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5.5.13.3 Safety Evaluation

The use of pressure-relieving devices ensures that overpressure will not exceed 10% above the design pressure of the system, as allowed by code. The number of relieving devices on a system or portion of a system were determined on an individual component basis to meet the above design criteria.

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5.5.13.4 Inspection and Testing

No provisions are made for in-line testing of pressure relief valves. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer and further examination would necessitate removal of the component.

with leakage characteristics consistent with leakage requirements of the entire building. The reactor building is designed to limit the in-leakage to 100% of the reactor building free volume per day at -0.25 inch H₂O gauge, while operating the standby gas treatment system. The building structure above the refueling floor is also designed to contain a negative interior pressure -0.25 inch H₂O gauge. Entrance to the reactor building is through an interlocking double door airlock. Rail car personnel access openings in the reactor building at elevation 521 feet provided with double doors to assure that building access will not interfere with maintaining integrity of the secondary containment. | 1 | 93

Ventilation for the reactor building will be provided by means of a once-through ventilation system. (See Figure 9.4-5). Outdoor air is evaporatively cooled to reduce the supply air dry bulb temperature to increase the sensible cooling capacity of this air. This air is then filtered and preheated as required to satisfy the plant operating requirements. | 93 | 93

The equipment is arranged as follows: outside air inlet, filter, heating coil, evaporative cooler, and supply fans. Three 50% vane axial fans are provided, two of which normally operate and one which serves as a standby.

Supply air is distributed to the reactor building by means of a duct system to provide equipment cooling in various areas as required. Air is routed from clean areas to areas with progressively greater contamination potential. Pressure differential control dampers are used as required to maintain negative pressures in potentially contaminated cubicles. Exhaust air from the RWCU cubicles is normally exhausted by the reactor building exhaust fans. Upon detection of contamination in the exhaust air, the normal exhaust path can be isolated by a locally mounted handswitch and the exhaust air routed to the primary containment purge system. | 75 | 75

All supply air delivered to the refueling floor level is exhausted from the periphery of the spent fuel and equipment storage pools and the reactor well. This air is routed directly to the main system exhaust duct. Three vane axial exhaust fans are provided, two of which normally operate and one of which serves as a standby. The discharge from the exhaust fans is routed to the plant vent where the air is discharged to the atmosphere. All exhaust air is monitored for radiation.

With the exception of supply duct downstream of the secondary containment isolation valves on supply duct and exhaust duct upstream of the secondary containment isolation valves on exhaust duct, this system is not required to operate during accident conditions and is automatically shut down whenever the standby gas treatment system starts. The equipment for this system is not powered from essential buses. To maintain the integrity of the secondary containment, two isolation valves are provided in the supply air duct between the supply fan discharge and the penetration through the secondary containment wall. The reactor building ventilation supply fans are located on floor elevation 567 feet 5 inches in the auxiliary building. Two isolation valves are provided in series in the exhaust duct between the | 91 | 68

3. The flow in the drywell-to-suppression chamber vents is compressible except for the liquid phase.
4. No heat loss from the gases inside the primary containment is assumed. This adds extra conservatism to the analysis; that is, the analysis will tend to predict higher containment pressures than would actually result.

Figures 6.2-9 and 6.2-10 show the blowdown flowrates from the primary system to the containment. Table 6.2-2 shows the primary system energy distribution at time of break.

The calculated containment pressure and temperature responses to this LOCA are shown in Figures 6.2-11 and 6.2-12. The calculated peak drywell pressure is 40.4 psig, which is 10.2% below the design pressure of 45 psig for this design. After the discharge of primary coolant from the RPV into the drywell, the temperature of the suppression chamber water approaches 125° F and the suppression chamber pressure stabilizes at approximately 36 psig. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the noncondensable gases in the drywell initially are forced into the suppression chamber. However, the noncondensables will redistribute between the drywell and suppression chamber via the vacuum breaker system as the drywell pressure is decreased by steam condensation.

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The LPCI and/or LPCS system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting metal-water reaction to less than 0.1%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water transports the core decay heat out of the RPV, through the broken recirculation line, in the form of hot water that flows into the suppression chamber via the drywell to suppression chamber vent pipes. Steam flow is negligible. This flow, in addition to heat losses to the drywell walls, offers considerable cooling to the drywell atmosphere and causes a depressurization of the containment as the steam in the drywell is condensed.

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The LPCI/RHR pumps that are used to flood the core are also used as the containment spray pumps. Prior to activation of the containment cooling mode (arbitrarily assumed at 600 seconds after the accident) all of the LPCI pump flow will be used only to flood the core. After 600 seconds, the LPCI pump flow can be diverted from the RPV to the containment spray. This is a manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment design pressure. In either case (LPCI/RHR pumps flow to the RPV or to the containment spray), the RHR heat exchangers must be activated within some reasonable time after the accident, e.g., one hour, to limit the peak temperature of the suppression chamber below the allowable limit.

- a. Following the LOCA, the hydrogen concentration in the containment atmosphere (drywell and suppression pool areas) will begin to increase due to metal-water reaction generated hydrogen. The hydrogen concentration is observed via the hydrogen monitoring instrumentation, and if the concentration approaches the control limit (4% by volume) in Regulatory Guide 1.7 (Draft 2), the recombiner will be activated remote manually from the main control room, thereby reducing and maintaining the volumetric oxygen concentration to well below 5%.
- b. The oxygen concentration in the containment (drywell and suppression pool areas) may continue to increase due to radiolysis, eventually approaching the control limit (5% by volume). The recombiner system will be manually activated before the control limit is reached. Operation of the recombiner reduces and maintains the overall oxygen concentration below the control limit at all times. Containment sprays and natural turbulence resulting from diffusion and convection caused by the elevated temperature will ensure that no local pocket with greater than 5% oxygen can occur.

6.2.5.2.2 Hydrogen and Oxygen Monitoring

As mentioned previously, the concentration of oxygen will be the limiting parameter. The hydrogen and oxygen concentration will be monitored following the postulated LOCA, and displayed in the control room. An alarm indicates when the H_2 or O_2 concentration approaches undesirable levels. The alarm setpoint will be determined after the design characteristics of the sensing instrumentation are finalized. The monitoring instrumentation is described in Subsection 7.6.1.

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6.2.5.2.3 Flammability Control (Recombiner) System

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The concentration of combustible gases in the primary containment (drywell and suppression pool areas), following a loss-of-coolant accident, is controlled by the flammability control (recombiner) system. The recombiner system is located outside the primary containment.

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The system processes the primary containment atmosphere at a maximum rate of 100 scfm using a blower to supply containment gases to a condenser which controls dew point, then passes through a thermal recombiner where oxygen in the gas stream is thermally recombined with hydrogen. The gas stream is then cooled and the resulting water and remaining gases are returned to the primary containment. Suction is taken from the drywell area and the discharge is returned to the suppression pool area above water level. The flammability control (recombiner) system equipment is skid mounted into an integral package. All pressure-containing equipment including piping between components is considered an extension of the containment and is classified Quality Group B (see Table 3.2-1). The skid and the equipment mounted on it meet Seismic Category I requirements. The flammability control (recombiner) system is designed to accommodate conditions present in the containment (temperature and pressure) following the occurrence of a loss-of-coolant accident. The flammability control (recombiner) system shall be used in conjunction with monitoring the atmosphere of the containment for hydrogen and oxygen concentrations. The monitoring system is automatically initiated following a loss-of-coolant accident. Readout is available in the control room.

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The initiation of warmup of the flammability control (recombiner) system is from remote-manual controls following the loss-of-coolant accident. The system is placed into operation manually from the control room. Once placed into operation, the system continues to operate without maintenance or adjustment until manually shutdown when an adequate margin in hydrogen or oxygen concentration is reached. The operation of the system can be tested from the control room. The test is conducted by electrical means which produces a simple "operable" or "nonoperable" indication. Following a plant shutdown, local adjustment or servicing of the flammability control (recombiner) system is not required when the plant is placed back into operation.

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The operation of the flammability control system is serviced by electrical power and cooling water systems placed into operation concurrent with the loss-of-coolant accident.

Cooling water for operation of the system is taken from the essential part of the reactor building closed cooling water system. This cooling water is used for the following purposes:

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- a) condensing steam in the gases from the primary containment and reducing the temperature of these gases, and

- f. Flow of reactor building closed cooling water (RBCCW) may range from 20 gpm to 33 gpm at a maximum temperature and pressure of 105°F and 120 psig, respectively.
- g. Service water is not required. Interface connections shall be capped off.
- h. The FCS is provided with redundant Class 1E power sources (Division A and Division B).
- i. The FCS is provided with check valves in each of the RBCCW inlet lines upstream of the hand block valves to prevent backflow of RBCC water in case of power failure to either set of motor-operated gate block valves.

6.2.5.2.3.2 General (Replaces Paragraph 6.2.5.1.1 of Reference 3)

The FCS is an engineered safety feature and meets the requirements of Regulatory Guide 1.7 (draft Regulatory Guide dated September 1976). The FCS is designated as a "Safety Class 2" system and designed in accordance with the following:

- a. Quality Group B,
- b. Quality Assurance per 10 CFR 50 Appendix B, and
- c. Seismic Category I.

The system is designed to begin recombination at 3.5 hours after a loss-of-coolant-accident (LOCA); this includes 0.5 hours for operator decision to activate the system and 3.0 hours for recombiner warmup to operating temperature.

The hydrogen design basis for the system is satisfied by varying the containment draw of noncondensibles from 0 scfm to 100 scfm maximum. Containment pressure after a LOCA is adequate to maintain 100 scfm.

6.2.5.2.3.3 System Design

6.2.5.2.3.3.1 Principle of Operation (Replaces Paragraph 6.2.5.2.4.1 of Reference 3)

The flammability control system (FCS) is designed to:

- a. pump the process gas from the primary containment to the thermal recombiner,
- b. thermally recombine hydrogen and oxygen to water vapor in the thermal recombiner by means of a controlled flameless reaction,
- c. cool and condense the water vapor in the recombiner exhaust gas,
- d. return the recombiner exhaust gas and condensate to the pressure suppression chamber, and
- e. satisfy the hydrogen design basis for the system by varying the containment draw of noncondensibles from 0 scfm to 100 scfm maximum. Containment pressure after a LOCA is adequate to maintain 100 scfm.

6.2.5.2.3.3.2 Process Stream Flow Path (Replaces Paragraph 6.2.5.2.4.5.1.1 of Reference 3)

Post-LOCA containment gas enters the FCU through one of two parallel, redundant flow paths, each path containing two motor-operated gate block valves (F002A/B, 14A/B) and one flow control valve (15A/B) which controls containment draw up to a maximum of 100 scfm of noncombustibles on a dry basis. Entrance gas flow rate control information is obtained from ΔP flow orifice, FE-19; located in the process stream piping downstream of the second aftercooler, 33. The gas is then directed to centrifugal gas blower (6A or B) which increases the stream flow pressure by a minimum of 4 psi. This pressure rise is necessary to overcome system piping and component friction losses. The gas passes from the blower to the condenser (5) where the gas is cooled to condense the stream present in the gas during Time Zone 2 of the design-basis conditions for inerted containments. During Time Zone 5 the gas stream quality is very low, yielding a negligible condensation rate.

The condensate flows through a 1-inch Schedule 100 drainline and connects to the process return line prior to discharging into the pressure suppression chamber. Condensate return is regulated by restricting orifice, RO-20. This orifice also restricts process gas bypass to negligible rate during Time Zone 5.

The process gas then flows to the thermal recombiner (3) where it is heated to reaction temperature (1320° F) and reacted to form water vapor.

The superheated recombiner exhaust vapor/gas mixture is then directed to two heat exchangers. The first exchanger (32) is a gas cooler which cools the gas from its exhaust temperature of $\sim 1400^{\circ}\text{F}$ to 360°F . The second exchanger (33) is a partial condenser which further cools the process gas to 150°F and condenses the water vapor. The cool gas/water stream is then split between a recycle stream and a pressure suppression pool return stream.

6.2.5.2.3.3.3 Utility Stream Flow Paths (Replaces Paragraph 6.2.5.2.4.5.1.2 of Reference 3)

The source of cooling water for the various heat exchangers on the FCU module is the plant reactor building closed cooling water (RBCCW) system. This system is supplied with emergency electrical power and will be operable after a LOCA. The low-temperature (105°F) RBCCW is admitted to the recombiner SCR heat exchanger through one of two redundant, parallel flow paths (A or B), each containing a set of two motor-operated block valves (8A, 9A, or 8B, 9B). RBCCW water flow rate is limited to 30 gpm by a preset globe in the discharge line from the FCU. The valve will be preset during system preop tests. The water then flows through the condenser and aftercoolers. Table 6.2.3 of Reference 3 is also applicable to the function of the RBCCW water. Outlet RBCCW water from aftercooler 33 is returned to the RBCCW system through two sets of redundant motor-operated block valves (22A/B, 1WR110A/B). Flow rate of RBCCW water is indicated by a ΔP flow orifice, FE-11, located in the RBCCW inlet piping to the precooler. The service water lines are nonfunctioning and interface connections are capped off.

6.2.5.2.3.3.4 Operational Control of Thermal Recombiner to Preclude Process Gas Bypass

As described previously in General Electric Standard Product Report, Flammability Control System (Thermal Recombiner), NEDE-21071-P, May 1976, the FCS was designed to be activated manually within one-half hour after a LOCA.

Assuming a LOCA has occurred, manual startup/operation of the FCS consists of seven individual sequential steps as follows:

- a. Establish cooling water flow through heat exchangers and SCR cabinets during plant operation by opening normally closed valves 8A and 9A or 8B and 9B and outlet valves 22A or 22B and the AE supplied valves downstream of valve F022A or F022B.
- b. Using meter on local panel, set the outlet throttle to allow cooling flows between 20 gpm and 33 gpm.
- c. Open normally closed gas outlet valves 21A(B) and F004A(B), otherwise interlock prevents turn on of power to thermal recombiner.

- d. Turn on recombiner.
- e. Turn on blower.
- f. Open normally closed gas inlet valves F002A(B) and 14A(B).
- g. Regulate exhaust gas flow controller R605A(B) to open and mod-normally closed gas inlet flow control valve 15A(B).

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Now, to establish a gas leak path from the containment through the PCS to the suppression pool, the operator must unwittingly perform at least two of the above steps out of sequence. Multiple operator errors are not considered as a design-basis criterion. If the operator performs only one step out of sequence or fails to perform any one step, a leak path cannot be established. The following scenarios are presented as proof that such a leak path cannot be established or is outside the scope of design due to multiple mode failure.

Scenario 1

Operator Action: Performs Step 1, but performs all other steps out of sequence.

Consequence: None. Since cooling water flow has been established, condenser will be capable of condensing steam and water vapor in the flowing gas.

Scenario 2

Operator Action: Fails to perform step 1, performs Step 3 instead.

Consequence: None. Gas inlet valves and gas flow control valves are still closed.

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Scenario 3

Operator Action: Fails to perform Step 1, performs Steps 6, 3, 4 in immediate succession.

Consequence: None. Gas bypass not established as flow control valves are still closed. Immediately on performing Step 3 a low-flow alarm sounds indicating low or no cooling water flow. Operator must acknowledge alarm and establish cooling water flow.

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Scenario 4

Operator Action: Fails to perform Step 1, performs Steps 6, 3, 7, 4 in immediate succession and cooling water low-flow alarm malfunctions.

Consequence: Gas bypass flow is established. However, this is a five-mode failure and not considered as a design basis.

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Scenario 5

Operator Action: Fails to perform Step 1, performs Steps 3, 6, 7
in rapid succession.

Consequence: Gas bypass is established. However, this is a three-
mode failure and is not considered a design basis.

Scenario 6

Operator Action: Performs startup sequence in correct order and system
is operating, but power fails.

Consequence: None. Gas flow control valve closes by spring action
on power failure preventing gas bypass. On indica-
tion of power failure operator secures controls
of failed system and manually switches to redundant
system, observing the identical startup sequence.

As can be seen by the above and other scenarios, to establish a gas
bypass will necessitate a two-mode or greater failure which is not required
for design reliability. Thus, additional interlocks(s) are not necessary.

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- d. a 2-minute evolution time at a constant reaction rate is assumed, with the resulting hydrogen uniformly distributed in the containment compartments enclosing the primary coolant system.

Figure Q042.7, Sheets 1 through 4, shows drywell hydrogen concentration as a function of time based on the assumptions listed on each figure.

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6.2.5.3.1.2 Long-Term Hydrogen Generation

The generation of hydrogen and oxygen due to radiolysis begins immediately after the LOCA. The conservative assumptions of Regulatory Guide 1.7 (Draft 2) are used to determine hydrogen and oxygen generation rates.

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6.2.5.3.2 Analysis

The loss-of-coolant accident is described in Section 6.3. As previously noted, the occurrence of a 1% metal-water reaction cannot be related to any credible physical process during a LOCA. Therefore, the following assumptions were made with respect to the sequence of events occurring after a LOCA:

- a. As mentioned above, it is assumed that metal-water reaction begins immediately after the LOCA and proceeds at a rate consistent with the assumptions listed in Subsection 6.2.5.3.1.1 until 1% of the cladding has reacted.
- b. Radiolysis begins immediately and proceeds at a rate consistent with the assumptions stated in Subsection 6.2.5.3.1.2.

Based on these assumptions, it is calculated that the hydrogen concentration in the drywell may eventually reach 4% volume approximately 16 hours after the LOCA due to radiolytic hydrogen generation and the oxygen concentration will reach 5% in approximately 5 hours.

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Before this occurs, the recombiner system shall be activated. This system is designed to keep the hydrogen concentration below 4% volume, or oxygen below 5%, at all times until radiolytic generation has ceased.

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The realistic analysis indicated that the ECCS would operate to limit the amount of metal-water reaction, and therefore the amount of metal-water reaction generated hydrogen, to undetectable amounts.

in accordance with Seismic Category I criteria (see Chapter 3.0). The available NPSH will be calculated in accordance with the NRC Regulatory Guide 1.1 (Revision 0).

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6.3.2.2.5 ECCS Discharge Line Fill System

One design requirement of any core cooling system is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick start system characteristic is provided by quick opening valves, quick start pumps, and standby a-c power source. The lag between the signal pump start and the initiation of flow into the RPV can be minimized by always keeping the core cooling pump discharge lines full. If these lines were empty when the systems were called for, the large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. The ECCS discharge line fill system maintains the pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the suppression pool, check or stop-check valves are provided near the pumps to prevent back flow from emptying the lines into the suppression pool. Past experience has shown that these valves will leak slightly, producing a small back flow that will eventually empty the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept filled, a water leg pump is provided for each ECCS system. The power supply to these pumps is classified as essential when the main ECCS pumps are deactivated. Indication is provided in the control room as to whether these pumps are operating, and alarms indicate low discharge line pressure.

6.3.2.2.6 ECCS Pumps NPSH

The ECCS pump specifications are such that the NPSH requirements for HPCS, LPCS and LPCI are met with the containment at atmospheric pressure and the suppression pool at saturation temperature. These bases are in full conformance with paragraph C of NRC Regulatory Guide 1.1 (Revision 0).

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6.3.2.3 Applicable Codes and Classification

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All piping systems and components (pumps, valves, etc.) for the ECCS comply with the applicable codes, addenda, code cases and errata in effect at the time the equipment was procured. The applicable classifications and requirements are defined in Tables 3.2-1 and 3.2-2.

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The piping and components of the ECCS subsystems within the containment and out to and including the pressure retaining injection valve are Quality Group A. All other piping and components are Quality Group B. Subsections NA, NB, and NC of the code apply to the ECCS.

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The equipment and piping of the ECCS, in order to meet specified seismic capabilities, are designed to the requirements of Seismic

in the RHR system are discussed in Section 6.2.

6.3.2.9 ECCS Flow Diagrams

A schematic diagram, the flow rates and the pressures of the various ECCS subsystems can be obtained from the following process diagrams; Figure 6.3-2, High-Pressure Core Spray System; Tables I and II; Figure 6.3-5, Low-Pressure Core Spray System; Tables I and II and Figures 6.3-8, Residual Heat Removal System. (The RHR process diagrams show the low-pressure coolant injection system.) These parameters are presented for several modes of operation, including loss-of-coolant accident and test conditions.

6.3.2.10 Relief Valves and Vents

The ECCS subsystems contain relief valves to protect the components and piping from inadvertent overpressure conditions.

The HPCS system has one relief valve on the discharge side of the pump downstream of the check valve to relieve thermally expanded fluid.

Relief setting: 1300 psig Capacity: >10 gpm-10% Accumulation | 1 | 93

HPCS suction side relief valve:

Relief setting: 100 psig Capacity: >10 gpm-10% Accumulation

The LPCS system pump discharge relief valve:

Relief setting: 500 psig Capacity: 100 gpm-10% Accumulation | 1

LPCS suction side relief valve:

Relief setting: 100 psig Capacity: >10 gpm-10% Accumulation

The LPCI system pump discharge relief valve (one for each of three pumps):

Relief setting: 500 psig. Capacity: >10 gpm-10% Accumulation | 1

6.3.2.11 System Reliability

The ECCS reliability has been achieved through an evolutionary process. Initially a proposed system configuration was submitted for evaluation. A reliability model of the proposed system was constructed and an estimate of the system success probability was made. Reliability models were then constructed for alternate ECCS configurations and a comparative trade-off study yielded the most reliable system configuration. Upon completion of the final design, a formal reliability analysis was performed to:

is sized to filter radioactive particulates and iodine for at least 30 days' operation after the accident, based on inlet concentrations described in the previous paragraph.

The temperature and pressure inside the control room are ensured at $73^{\circ}\text{F} \pm 1^{\circ}\text{F}$ temperature and 0.125 inch H_2O positive pressure (Note: The control room is maintained at a positive pressure because the turbine building ventilation system maintains areas adjacent to the control room at -0.125 to -0.25 in. water gauge. Even if control room air intakes are isolated, the control room pressure will gradually drop to a level slightly above the turbine building pressure. This is acceptable to Regulatory Guides 1.95 (Revision 0) and 1.78 since pressurizing air would air would contain ammonia or chlorine which would produce higher room concentrations than if only infiltration was the transport mechanism.) With respect to surroundings during and after all the postulated conditions, as discussed below.

- a. The control room and other areas served by the control room HVAC system are completely isolated from the high-energy pipelines to preclude any effect of steam pipe rupture of the control room temperature and pressure.
- b. To further ensure that the control room atmosphere is not affected by the surrounding conditions, the control room is isolated on annunciation of any abnormal station operating condition, on the main control board. Strict administrative procedures are laid out for ingress and egress to the control room following isolation.
- c. The control room temperature and pressure cannot rise due to loss of control room HVAC system component failure, because two, 100%-capacity, redundant HVAC systems are available for the control room, as discussed in Subsections 3.11.4 and 9.4.1.
- d. The control room operator doses for LOCA, assuming 99% iodine removal efficiency and $10 \text{ ft}^3/\text{min}$ unfiltered infiltration rate are given in Subsection 15.1.39.

The ionization detection subsystem is used to provide early warning of the presence of combustion products in the control room, auxiliary electric equipment room, computer room, or cable spreading room. On annunciation of any ionization products inside the control room, 50% of the mixture of outside air and recirculated air for the control room HVAC

TABLE 7.1-3

CODES AND STANDARDS APPLICABILITY MATRIX

	RPS	CRVCS	ECCS	NMS	REFUEL INTLK	CRD/RMCS	VESSEL INST	FLOW CONTROL	FEEDWATER I&C	TURB GEN I&C	PROCESS RAD	AREA RAD	HEALTH PHYSICS	COMPUTER	ESSENTIAL SER WATER	ESSENTIAL RX BLDG	CLSD CLG WATER	CONT ATM MS	RCIC I&C	STBY LIQUID I&C	RADWASTE I&C	RECIR WATER	CLEANUP I&C	STANDBY PWR I&C	LEAK DET I&C	RHR SHUTDOWN I&C	FFC&C I&C	COMBUSTIBLE GAS	RECOMBINER I&C	MSIV-LCS
IEEE-279-1971	X	X	X	APRM, IRM(1)	/	/			3	X				2	X	X			X			X	X					X	X	
IEEE-308-1971			X												X	X							X							
IEEE-323-1971	X	X		APRM, IRM						X					X	X			X	X			X	X				X	X	
IEEE-338-1971	X	X	X	APRM, IRM						X					X	X	X	X					X	X				X		
IEEE-344-1971	X	X	X	APRM, IRM						X					X	X	X	X	X				X	X				X	X	
IEEE-379-1972	X	X	X	APRM, IRM						X					X	X							X	X				X		
IEEE-384-1974																												X		
IEEE-387-1972			X																				X							
R.G. 1.6 (Rev. 0)			X												X	X							X							
R.G. 1.9 (Rev. 0)																							X							
R.G. 1.21										X			X								X									
R.G. 1.22 (Rev. 0)	X	X	X	APRM, IRM						X					X	X	X	X					X	X				X		
R.G. 1.29 (Rev. 0)	X	X	X	APRM, IRM						X					X	X	X	X					X	X				X		
R.G. 1.32 (Rev. 0)			X												X	X							X							
R.G. 1.45 (Rev. 0)																									X					
R.G. 1.47 (Rev. 0)	4	4	4	APRM, IRM						4													4	4				4		
R.G. 1.53 (Rev. 0)	X	X	X	APRM, IRM						X					X	X							X	X				X		
R.G. 1.56 (Rev. 0)																					X									
R.G. 1.62 (Rev. 0)	X	X	X												X	X												X		
R.G. 1.66																														
R.G. 1.75 (Rev. 1)																														
R.G. 1.96 (Rev. 0)																														
GDC 13	X	X	X	APRM, IRM						X					X	X	X	X					X	X				X		
GDC 17			X																				X							
GDC 18			X																				X							
GDC 19	X	X	X	APRM, IRM									X		X	X							X	X				X		
GDC 20	X	X	X	APRM, IRM						X								X	X				X	X				X		
GDC 21	X	X	X	APRM, IRM						X								X	X				X	X				X		
GDC 22	X	X	X	APRM, IRM						X								X	X					X				X		
GDC 23	X	X	X	APRM, IRM						X								X						X				X		
GDC 24	X	X	X	APRM, IRM, RBM	X	X			X															X				X		
GDC 26					X															X										
GDC 29	X	X	X	APRM, IRM						X								X						X				X		
GDC 30													X											X						
GDC 34		X													X			X						X	X					
GDC 35			X																					X						
GDC 37			X																X											
GDC 41																														
GDC 43																														
GDC 54																								X						
GDC 61													X													X	X			
GDC 63											X	X																		
GDC 64										X		X																		

- (1) INTERLOCK FUNCTIONS FOR ROD WITHDRAWAL BLOCK (RBM) ARE REQUIRED TO MEET SPECIFIC AEC REQUIREMENTS, RATHER THAN IEEE-279.
- (2) PROCESS COMPUTER CONTAINS ROD WORTH MINIMIZER PROGRAM, WHICH IS A PORTION OF THE ROD WITHDRAWAL BLOCK INTERLOCK FUNCTION.
- (3) THE PRESSURE REGULATOR AND TURBINE CONTROL SYSTEM IS A NON-SAFEGUARD PROCESS CONTROL SYSTEM. HOWEVER, RPS TRIP SIGNALS DERIVED FROM: (a) STOP VALVE CLOSURE LIMIT SWITCHES; (b) CONTROL VALVE FAST CLOSURE OIL PRESSURE SWITCHES; and (c) FIRST-STAGE (FLOW) PRESSURE SWITCHES ARE ENGINEERED TO ALL APPLICABLE IEEE AND SAFETY CRITERIA AND DESCRIBED UNDER RPS DESCRIPTION.
- (4) CONFORMANCE TO R.G. 1.47 PER APPLICANT/AE INTERPRETATION DUE TO PROMULGATION OF R.G. 1.47 AFTER ISSUANCE OF CONSTRUCTION PERMIT FOR ZPS-1.

valve. Since these isolation dampers operate as spring-to-close, air supply is not required to assure isolation. On a loss of control power, or control air, the dampers will close.

All controls for interrupting any part of the system operation are located in the main control room. Local control panels are located in equipment rooms that are locked to prevent unauthorized operation. Isolation valves in the standby gas treatment system fail safe if motive power, such as air or electric power, is lost.

All controls and instrumentation essential to the startup and operation of the standby gas treatment system are designed to meet IEEE 279-1971 criteria. The instrumentation is independently connected to logic trains that initiate independent and separate signals for system operation that prevent connecting redundant instrumentation trains to a common point.

Each standby gas treatment equipment train is instrumented with local pressure drop indicators measuring differentials across filter banks. Temperature indicators mounted on the filter equipment and in the local control panels are provided as shown in Figures 6.2-35 and 7.3-36. A flow control valve on the inlet to each equipment train limits the air-flow rate through the train to design value to permit high filtration efficiencies. This valve is responsive to a flow transmitter and controller sensing the airflow through a monitor upstream of the valve.

Pressure differentials and temperatures are displayed as required by Regulatory Guide 1.52 (Revision 0).

Adsorber bed deluge valves are controlled from hand switches in the main control room where an alarm is visibly and audibly annunciated if high temperatures are detected in any adsorber bed.

High temperature cutout switches deenergize the single-stage electric heater and cause alarms in the main control room if a heater element overheats.

The effluent of the SBGTS is monitored by the SBT vent radiation monitoring system, capable of continuous noble gas readout in the main control room and capable of providing iodine and particulate samples for laboratory analysis.

7.3.1.1.8.2 Design Bases Information

The station conditions which cause standby gas treatment system initiation are listed in the previous subsection. Drywell pressure, reactor water level, and radiation levels in exhaust air from the reactor building are the variables monitored to provide protective action. The number, location, and setpoints of these sensors are discussed in Section 7.2 and in Subsection 6.2.3.

Capability for Test and Calibration (IEEE 279-1971 Paragraph 4.10)

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The auto depressurization system is not tested in its entirety during actual plant operation but provisions are incorporated so that operability of all elements of the system can be verified at periodic intervals. The operability of individual valves may be verified by means of the individual control switches on the main control room panels. Testing of control circuitry is accomplished at the control relay cabinets by means of test jacks, switches, and indicator lights while exercising sensors one at a time. The test method is generally as follows:

<u>Action</u>	<u>Observation</u>
1. Exercise a sensor	a. Sensor relay pickup b. Alarm is given
2. Start an LPCS or RHR (LPCI mode) pump	a. Off-normal alarm b. Low-pressure cooling system available relay pickup
3. Exercise logic channel by means of plug-in test switch	a. Logic channel relay pickup b. Continuity lights on each valve circuit are energized
4. Reset logic channel	a. Annunciators clear
5. Repeat above steps for other sensors, other low-pressure core cooling pumps, other logic channels	Same as for associated steps above

Channel Bypass or Removal from Operation (IEEE 279-1971 Paragraph 4.11)

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Calibration of each sensor will introduce a single instrument channel trip. This does not cause a protective action without the coincident trip of the other channel in that division or a separate trip from the other division. Removal of an instrument channel from service during calibration will be brief and will not significantly increase the probability of failure to operate. There are no channel bypasses in the auto-depressurization system. Removal of a sensor from operation during calibration does not prevent the redundant trip circuit from functioning if accident conditions occur. The manual reset buttons can interrupt the auto depressurization for a limited time. However, releasing either one of the two reset buttons will allow automatic timing and action to resume.

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Operating Bypasses (IEEE 279-1971 Paragraph 4.12)

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The ADS system has no provision for operating bypasses.

system is manually initiated after the above steps have been taken. The instrumentation and control system is completely redundant and in no event can the failure of a component in one system loop prevent the operation of the other system loop.

7.3.2.5.2 Specific Regulatory Requirements Conformance

7.3.2.5.2.1 Regulatory Guides Conformance

Regulatory Guide 1.22 (Revision 0)

All valves, blowers, heaters, controls, and instrumentation may be tested from the control room actuation device to the actuated device during normal plant operation without any disruption to the normal plant operation.

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Regulatory Guide 1.62 (Revision 0)

All system initiation is manual for each recombiner control system. Sequence interlocks are provided in each system to require opening of valves in proper sequence for starting the recombiner system.

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Regulatory Guide 1.47 (Revision 0)

Each motor-operated valve, blower, and recombiner heater in each of the redundant control systems annunciates an alarm in the respective control room panel for an inoperable condition such as loss of power or over-load trip. Control room indicating lights provide information on the status of valve position (open or closed), blower operation, or heater operation. System flow status is indicated on the respective control room panel for each control system and is annunciated for a low flow condition. Cooling water loss or low flow to the condenser is annunciated in the respective control room panel.

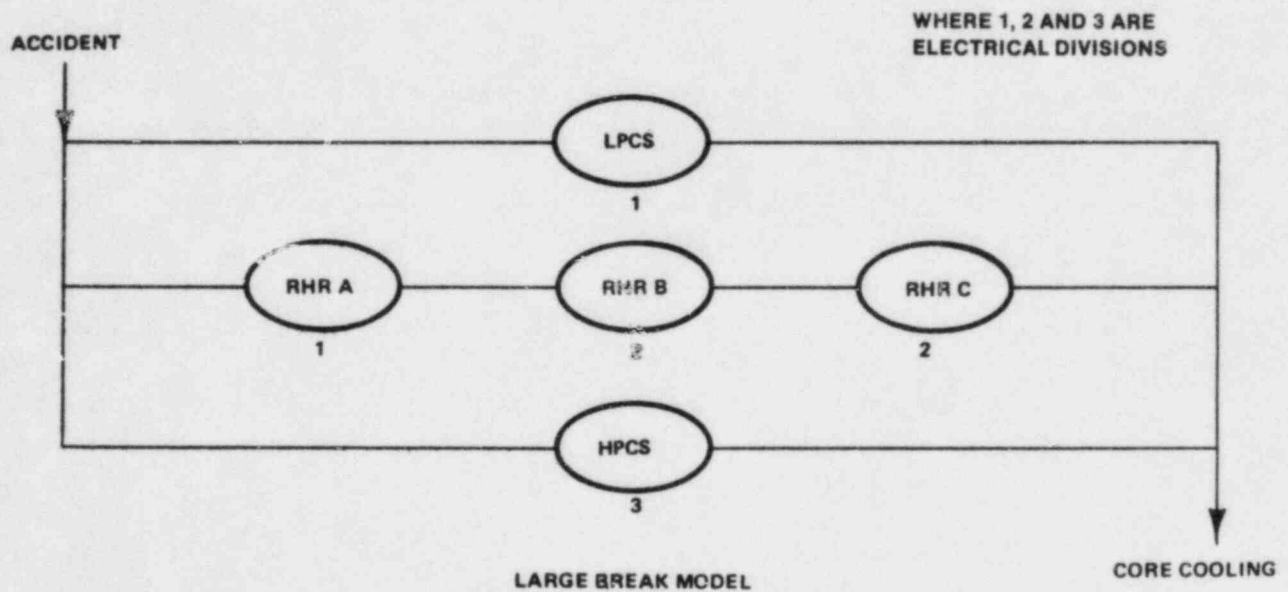
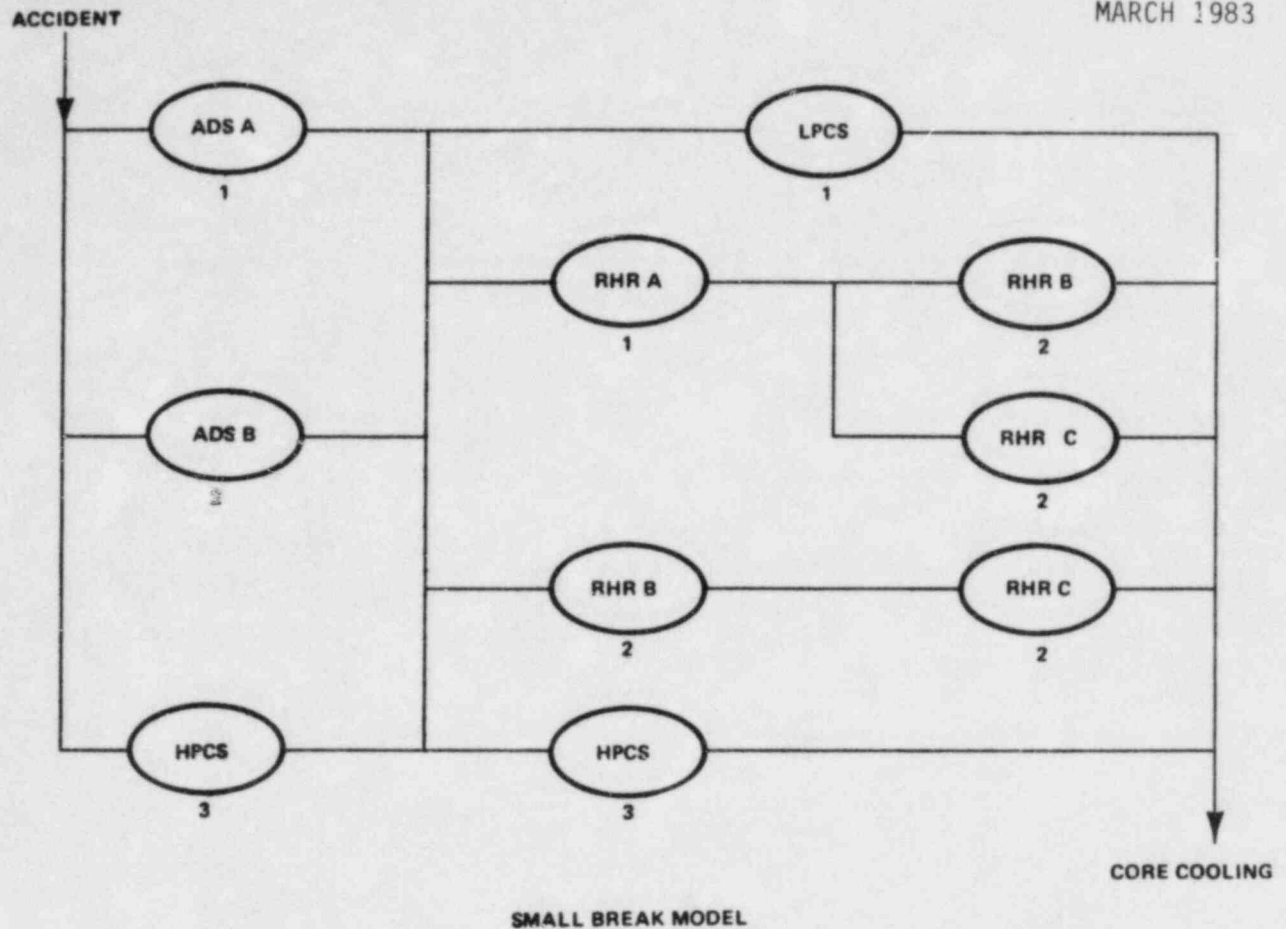
Regulatory Guide 1.53 (Revision 0)

Each control and instrumentation system is separate and therefore redundant. No single failure in one control system will interfere or prevent operation of the redundant control system.

Regulatory Guide 1.75 (Revision 1)

Each system instrument and control system is completely separate and independent for the redundant systems. The instrument and control system is totally Class 1E. The skid-mounted instrumentation, controls, enclosures, panels, and electrical equipment are separate and conform to the requirements of this regulatory guide for separation. Separate and independent conduits are routed from each device to each respective system enclosure. The system conduit groupings comply with the requirements of this regulatory guide. Each system has a separate and independent control room panel.

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WM. H. ZIMMER NUCLEAR POWER STATION, UNIT 1
FINAL SAFETY ANALYSIS REPORT

FIGURE 7.3-1

ECCS-MECHANICAL AND INSTRUMENTATION
NETWORK MODELS

MARCH 1983

fully address the concerns. We are pursuing this issue and will report on the resolution of this issue in a supplement to this report.

RESPONSE

On ZPS-1, only the Class 1E buses are required to achieve a cold shutdown condition. These buses and the equipment required to achieve cold shutdown were identified in the initial response to Bulletin 79-27. In addition, the indications and alarms provided in the control room for these buses were identified.

In response to the NRC request for additional information, the emergency procedures for loss of power to these buses were reviewed to ensure they are adequate to allow the operator to achieve cold shutdown.

- a. Loss of the d-c buses is covered in Emergency Operating Procedure (EOP) 28, Loss of D-C Power. There is no specific EOP for loss of individual a-c buses. Loss of Auxiliary Power (A-C) is covered in EOP 21. Loss of individual a-c buses is handled by the appropriate Annunciator Procedure for those loads to which power is lost. Indications are powered from independent power supplies with operators relying on redundant indications when some indicators lose power.
- b. Review of the existing procedures shows them to be adequate in ensuring the capability to achieve cold shutdown. All EOP's were revised in February 1981 to be compatible with the Emergency Procedure Guidelines (EPG) and Emergency Guideline Contingencies (EGC). These Zimmer specific EPG's and EGC's were issued in February 1981 based on the generic set of EPG's and EGC's developed by the GE BWR Owners' Group. These are designed to provide an appropriate response to mitigate core damage for any set of analyzed or nonanalyzed occurrences.

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Results of this review indicate that no single loss of any bus can prevent achieving a cold shutdown condition and that the procedures are adequate to safely shutdown the reactor.

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However, in order to resolve further concerns on this issue, the applicant will reevaluate the effect of a loss of power to individual buses. The following procedure will be utilized:

- a. Identify the Class 1E and non-Class 1E buses supplying power to safety and non-safety-related instrumentation and control systems which could effect the ability to achieve a cold shutdown.
- b. Identify the instrument and control system loads connected to the bus.
- c. Assume a loss of power to the bus.

Ceiling-mounted detectors are uniformly distributed spatially to provide full detection coverage of each room. The ionization detection system is not considered safety related but is qualified for seismic integrity.

The duct-mounted ionization detectors are located in each main return air duct connected to the main control boards. All detectors have adjustable sensitivity settings. These devices will be field adjusted and tested after installation. Setpoints will be established in the field by challenging each detector with normally expected background concentrations of products of combustion and then adjusting sensitivity to a slightly lower level to limit spurious alarms.

Ionization detection is annunciated on the ionization detector panel portion of the fire-protection status panel on the main control board.

Chlorine is detected in the two outside air intakes by four detectors, two located in each outside air intake. The power supplies for the detectors are divisionally separated such that primary intake detectors are powered from Division 1 and alternate intake detectors are powered from Division 2. This design satisfies the redundancy requirements of Regulatory Guide 1.95 (Revision 0). On detection of chlorine gas (at approximately 5 ppm) in an outside air intake, the affected intake mode is isolated and the system placed in recirculation mode.

Ammonia is detected in the two minimum outside air intakes by four detectors, two located in each intake. The power supplies for the detectors are divisionally separated such that primary intake detectors are powered from Division 1 and alternate intake detectors are powered from Division 2. This design satisfies the redundancy requirements of Regulatory Guide 1.95 (Revision 0).

The ducts connected to the primary and alternate outside air intakes are sized to provide a delay time which exceeds the response time of the detectors plus the closure time of the isolation dampers. Thus upon detection of ammonia gas (>25 ppm) in an intake, the outside intake is isolated and system placed in recirculation mode before the ammonia reaches the isolation dampers. In addition, breathing apparatus and bottled air supply is provided near the operators.

of the associated diesel-generator unit, the other two divisions of the Class 1E power system will provide adequate power to safely shut down the station or to mitigate the consequences of any of the postulated accidents.

The diesel-generator cooling water system tanks, heat exchangers and off-skid interconnecting piping are of quality group and seismic category as listed in Table 3.2-1.

9.5.5.4 Testing and Inspection

To ensure the availability of the diesel-generator cooling water system, scheduled inspection and testing of the equipment will be performed as part of the overall engine performance checks. Instrumentation will be provided to monitor cooling water temperatures, pressure, and head tank level.

The cooling water in the engine water jacket closed loop system will be analyzed at regular intervals and will be treated as necessary to maintain the desired quality.

9.5.6 Diesel-Generator Starting Air System

9.5.6.1 Design Bases

Each of the three diesel-generator units has two independent, automatic, pneumatic starting systems. The starting system has the capability to start the diesel so that rated voltage and frequency is achieved within 10 seconds, and the unit is ready to accept load.

9.5.6.2 System Description

The starting air system is Seismic Category I. Equipment and piping, from and including, the receiver tanks through the check valve at the compressor are designed to ASME Section III (1971 through Winter 1972 Addendum) Safety Class 3 requirements. Each of the two starting systems for each diesel-generator unit has two air receiver tanks (accumulators) equipped with shutoff valves. This permits a tank to be removed from service without loss of starting air. The air starting system is capable of providing five diesel-generator starts as previously described in Subsection 9.5.6.1 from the combined four air receivers. For each diesel-generator set, one air compressor is driven by a 460-V, 3-phase, 60-Hz motor and the other compressor by a 125-Vdc motor. The air receivers are rated at 275 psig and cranking continues to less than 150 psig. The a-c compressor operates between 220 psig and 250 psig. The d-c compressor operates between 210 psig and 250 psig. Figures 9.5-2 and 9.5-3a show the starting air system.

55 | 75
92 | 93
3 | 55 | 56
75

9.5.6.3 Safety Evaluation

The starting air system offers two independent systems per diesel-generator unit, and thus, even with a single failure within the starting system, cranking of all three of the diesels can be accomplished.

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REGULATORY GUIDE 1.95 (REV.0)PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS
AGAINST AN ACCIDENTAL CHLORINE RELEASE

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Applicant's Position:

Compliance with Regulatory Guide 1.95 (Revision 0) is as described in FSAR Subsections 6.4.1.1 and 9.4.1.2.

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POSITION 011.0 (3.0)

"In reviewing your July 26, 1983 response to the requirements of NUREG-0803, the staff developed several requests for additional information needed to complete its review. Please amend your response to provide the following information.

- (1) Identify all systems and equipment (with equipment I.D. numbers) that would be used to detect a break and/or leak in the SDV system and state that this equipment is, or provide a commitment that it will be qualified for service in the Zimmer SDV break environment.
- (2) Provide the SDV break environmental profile (temperature and humidity as a function of time) for any zones which experience more severe environments than previously calculated in the environmental qualification program.
- (3) Identify all systems and components (with equipment I.D. numbers) needed for the prompt depressurization function and all emergency systems and equipment, i.e., systems and equipment needed for mitigation of an SDV pipe break, safe shutdown of the plant and long-term core cooling. State that this equipment is, or provide a commitment that it will be, qualified for service in the Zimmer SDV break environment. 93
- (4) Identify any emergency systems and equipment that could be sprayed with water, directly or indirectly, from dripping or splattering of overflow leakage down open stairwells or equipment hatches following a break in the SDV systems, and state that this equipment is, or provide a commitment that it will be, qualified for operation with water impingement.
- (5) If any equipment needed (a) to detect a break and/or leak in the SDV system, (b) for mitigation of an SDV system pipe break, (c) for safe shutdown of the plant, and (d) for long-term core cooling is not qualified for service in an environment that could exist following a break in the SDV system, provide justification for interim operation pending qualification of the equipment or replacement with qualified equipment.
- (6) Provide an analysis of the ZNPS reactor building environment following an SDV failure to show that the environmental conditions of an SDV break are enveloped by the environmental conditions of a LOCA or HELB in all zones."

RESPONSE

- (1) 1. Reactor Building Area Radiation Monitor Alarm (AL302);
2. Reactor Building Floor Drain Sump Level Alarm (N202, N203);
3. CRD High Temperature Alarm (AH301);
4. CRD Drift Alarm (AH303);
5. Reactor Building Ventilation High Radiation Alarm (AB103);
6. Reactor Building Ventilation Isolation Alarm (T203, T303, P303, T406, Q105).

As stated in our July 26, 1982 response to NUREG-0803,

"Any one of these signals by itself would provide insufficient information on SDV status, but the combination of signals for such an event quickly identifies a significant leak outside of primary containment."

Please note that all these signals are "latched" alarms in the control room and are independent of the SDIV break environment. They are not required to continue to function for this event. Therefore, they will not be qualified beyond any ongoing EQ effort.

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- (2) A temperature and humidity profile vs. time is being calculated for the postulated SDIV break. These profiles are expected by July 30, 1983 and will be forwarded to the NRC after our review.
- (3) The equipment necessary to fulfill the prompt depressurization function consists of the manual portion of the Automatic Depressurization System (ADS). The ADS consists of safety-related equipment and major components are located inside primary containment. Thus, it is appropriately qualified for seismic and hydrodynamic events and major components would not be exposed to an environment resulting from an SDV rupture or leak in the reactor building.

The equipment components necessary for safe shutdown and long-term cooling for the SDV break are the same as those necessary for a LOCA and HELB. The environmental conditions of an SDV break are enveloped by the environmental conditions of a LOCA or HELB. Zimmer is in the process of qualifying the necessary equipment to meet these conditions.

As discussed in the preceding paragraphs, the equipment necessary to mitigate, provide long-term core cooling, safe shutdown, and rapid depressurization are the same for an SDV break as for a LOCA/HELB. Therefore, the equipment I.D. numbers are provided in our July 16, 1982 Environmental Qualification submittal.

- (4) At Zimmer there is only one stairwell with a direct flow path from the HCU-SDV area to an emergency core cooling equipment room, the HPCS corner room. With the most likely leakage paths being through the floor grating to the basement inner annulus or through floor drains to the inner annulus sump, spraying of the HPCS equipment is very unlikely. Even if this extremely remote occurrence is accepted and the even more unlikely failure of the HPCS system, the reactor has been depressurized by the operator to limit SDV leakage. Therefore, any of the protected low pressure ECCS systems can handle long-term cooling. Physical location of equipment needed for mitigation is such that wetdown from leakage through equipment hatches is not considered possible. To reach the emergency core cooling and long-term cooling pumps the water will have to drop through three consecutive hatches. The resistance to such flow will be high. Floor drains would minimize water leakage through an equipment hatch. Further, if the water finally reached a motor through an equipment hatch it would be cooler than 212° F. Nevertheless, all the motors are qualified for wetdown by 212° F water from the top; i.e., flow around the hatch covers.
- (5) See the responses to questions 1, 3, and 4.
- (6) See the response to question 2.
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POSITION 410.67 (3.0)

"In Section 3.6.2 of the FSAR you provided a list of systems which required pipe whip restraints. Provide justification for the omission of applicable portions of the control rod drive system from this list."

RESPONSE

The control rod drive (CRD) system is made up of the 1-inch and 3/4-inch insert and withdrawal lines, which because of their size (1 inch or less) are not considered for pipe rupture. The 8-inch and 10-inch scram discharge volume line after the hydraulic control units are assumed high energy for less than 2% of the operating time of the plant and are, therefore, also not considered for pipe rupture. The line from the control rod drive water pumps to the RPV also is assumed to be high energy less than 2% of the time except for the portion between check valve 1C11F383 and RPV nozzle N10. This portion is high energy and it will be determined if pipe whip restraints are needed or not.

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POSITION 410.63 (4.0)

"You have revised P&ID Figure 4.2-24 (Standby Liquid Control System) in FSAR revision 89. However, there are no indications on the drawing or in the narrative with regard to the changes made; provide information describing the change(s) and the reason for the change(s)."

RESPONSE

Revised P&ID M-57-1, Revision S (Figure 4.2-24) was inadvertently incorporated in FSAR Revision 89 without the revision note included in the drawing. The revision note should read as follows:

Added lines 1SA700A3/4 and 1SA700B $\frac{1}{2}$, added valve 1SA800 and 1PISA700; deleted valve 1SA119 on line 1SA19E1. Per DDC M-5703, Revision B and ECR-717, Revision 1. For file record release per MT-10086.

The reason for this change is that the valve, 1SA119, was used for reducing service air pressure to 20 psig before introducing the air into the Standby Liquid Control Storage Tank (1C41A001) via a sparger. It was concluded after an engineering review that the same could be accomplished by manually throttling the service air with valve 1SA117 which is also in line 1SA19E1. This will eliminate the cost and maintenance for valve 1SA119.

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POSITION 410.64 (4.0)

"A drain line and header line have been deleted on sheet 3 of P&ID figure 4.2-18 (Control Rod Drive Hydraulic System) in revision 86 to the FSAR. Explain the reason for this deletion."

RESPONSE

P&ID M-56-3, Revision AH (Figure 4.2-18, Sheet 3) submitted in FSAR Revision 89 resulted from ECR 736, Revision 1 per DDC M-5686. Extensive modifications and additions to and on the CRD HCU's required the deletion of the header due to interferences. The header, while convenient, was not required. The same function can be carried out with a hose.

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POSITION 222.1a (8.3)

"During the course of the staff's review of the Zimmer FSAR, revisions 76 through 90, it was noted that the discussion in Section 8.3.1.11.2.4 regarding embedded conduit in concrete walls and floors lacked sufficient detail. Provide information on the type of circuits (i.e., control, power, signal, 480V ac, 125V dc, etc.) routed through these conduits. Also indicate what design consideration was given to heat dissipation between adjacent conduits during normal and faulted conditions."

RESPONSE

The types of cables installed in embedded conduits at the Zimmer Nuclear Power Station, Unit 1, include 4 kV power feeds to core cooling pumps, 480-V motor-operated valve feeds, 120-Vac and 125-Vdc control conduits and instrument signal cables.

Conduits embedded in structural concrete require separation dictated by structural requirements. This separation is greater than 3 inches and includes embedded conduits in sleeves through walls, in turbine foundations, structural floors, and structural beams.

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Conduits embedded in finish floors do not have a structural requirement, as there is no reinforcing steel and no large aggregate in the concrete mix. The minimum separation requirement for redundant conduits of "do not touch," as stated in the FSAR (Subsection 8.3.1.11.2.4), is only to allow the conduit to be completely surrounded by the concrete mass. Conduits embedded within a finish floor are installed, essentially, on the rough floor (1 level) with the 8-inch or 10-inch finish concrete poured over them. The effect of heat generated by a faulted power cable within one of the conduits is of such low energy level that it cannot adversely affect cables in adjacent conduits.

In addition, surveyors' drawings of conduit embedded in finish floors were reviewed. The results of the review indicate that the majority of embedded conduits containing redundant safety functions are separated by at least 1 inch. The few conduits that are within 1 inch of each other contain low energy instrumentation or control circuits. Heat dissipation in these conduits during normal and faulted conditions cannot adversely affect cables in adjacent conduits.

POSITION 410.65 (9.0)

"In Section 9.2.1 of the FSAR you discuss the functions of the safety-related station service water system; Section 9.2.1.5 is entitled "Instrument Application." You state, in Section 9.2.1.5 (in the paragraph modified in revision 68 and 77) that "Instrumentation is provided to sense the flow through each service water pump...and maintain the flows through each pump above the minimum requirements to prevent long-term pump damage." Show that failure of this system will not prevent the service water system from functioning properly in the event of an accident or transient requiring its use."

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RESPONSE

The information requested in this NRC Position is provided in FSAR Appendix J, Section J.7.

POSITION 410.66 (9.0)

"You have revised P&ID figure 9.3-1, Sheet 1 (Revision 86) to add line 1IN 39 B1. Discuss the purpose of line 1IN 39B1."

RESPONSE

P&ID M-40-1, Revision P (Figure 9.3-1) was revised to add line 1IN39B1 per DDC M-3890 for the following reason:

Line number 1IN39B1 was added to reflect field changes which provide a 1-inch line between the 3-inch tank nozzle connection and the safety valve.

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POSITION 041.61 (15.0)

- "a. In a previous discussion, you stated that the operator would be directed to event trees to determine a further course of action when following emergency procedure OP.EOP.18 (Piping Break Outside Primary Containment). One of these would have the operator follow emergency guideline contingency procedure OP.EGC.02 (Rapid RPV Depressurization). Confirm this statement.
- "b. In a previous submittal, you stated that you would follow the recommendations of the BWR Owners Group (BWROG) on procedures dealing with a break in the scram discharge volume (SDV) system. Verify that the foregoing procedures (OP.EOP.18 and OP.EGC.02) do follow the BWROG recommendations or provide justification for not having followed those recommendations.
- "c. The discussion relating to improvement of procedures in the event of an SDV break in Section 2.2.6 of your July 1982 submittal does not specifically address those indications which are recommended in emergency procedure OP.EOP.18 for operator guidance in determining whether an SDV break has occurred; later sections of that same submittal (Sections 3.3.2 through 3.3.8) contain a variety of indications which could be used by the operator in determining whether a break has occurred in the SDV system. Discuss which indications are to be used and how they are to be used by the operator as guidance in OP.EOP.18 in determining the existence of an SDV break and in deciding whether to use OP.EGC.02. Show which indications to be used by the operator in accordance with the provisions of OP.EOP.18 to detect an SDV break are safety-grade including environmental qualification and power supply."

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RESPONSE

- a. The above statement is true.
- b. Revision 1 of the BWROG recommendations were incorporated into our procedures and approved by the NRC. The current revisions of the BWROG recommendations are under review by both the NRC and our operations staff. These recommendations will be incorporated after the review process is complete.
- c. When concurrent alarms (as discussed in our previous submittal) are received, an operator is sent out to investigate. This action will rapidly lead to the conclusion of an SDIV break. As the operators are well aware, for a nonresetable scram, the SDIV is a nonisolatable extension to the RPV and will be directed by OP.EOP.18 to rapid depressurization per OP.EGC.02.

POSITION 041.62 (15.0)

"In response to questions we asked informally regarding the SDV system, we understood you to have stated the following:

- a. That you have reviewed all surveillance, maintenance, inspection and modification procedures which have the potential for defeating SDV integrity and that you have concluded that you have found no procedures which would cause a loss of SDV integrity when SDV integrity should be available.
- b. That all procedures affecting SDV integrity have to pass through a review chain usually consisting of a supervisor, superintendant of the area affected by the procedures, e.g., maintenance; then had to pass a quality assurance review and then had to be reviewed by the Safety Review Board and by the Independent Safety Review Group.
- c. That the SDV headers in the ZNPS did not contain any pressure or temperature monitors (which could be used as aids in determining the existence of an SDV break).
- d. That in the event of the worst SDV break, operator action to depressurize after 30 minutes would not allow any core damage.
- e. That the possibility of damage to the HPCS in the event of an SDV break is very low because of preferential drainage through floor gratings and drains in lieu of flowing down the one stairwell and spraying the HPCS equipment (also discussed in Section 2.2.2 of Reference 2)."

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RESPONSE

The above statements are correct with the above items a and b modified as follows:

- a. That you will review all surveillance, maintenance, inspection, and modification procedures which have the potential for defeating SDV integrity.
- b. That all procedures affecting SDV integrity have to pass through a review chain usually consisting of a supervisor, superintendant of the area affected by the procedures, then had to be reviewed by the Station Review Board.