

ATTACHMENT

TECHNICAL SPECIFICATION BASES UPDATES

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TECHNICAL SPECIFICATIONS BASES
LIST OF EFFECTIVE PAGES

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B 2.0-2	0	B 3.1-18	0	B 3.2-14	0	B 3.3-41	0
B 2.0-3	0	B 3.1-19	1	B 3.2-15	0	B 3.3-42	0
B 2.0-4	0	B 3.1-20	0	B 3.2-16	0	B 3.3-43	0
B 2.0-5	0	B 3.1-21	0	B 3.2-17	0	B 3.3-44	0
B 2.0-6	0	B 3.1-22	0	B 3.2-18	0	B 3.3-45	0
B 2.0-7	0	B 3.1-23	0	B 3.3-1	0	B 3.3-46	0
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B 2.0-9	0	B 3.1-25	0	B 3.3-3	0	B 3.3-48	0
B 3.0-1	0	B 3.1-26	0	B 3.3-4	0	B 3.3-49	1
B 3.0-2	0	B 3.1-27	0	B 3.3-5	0	B 3.3-50	0
B 3.0-3	0	B 3.1-28	0	B 3.3-6	0	B 3.3-51	1
B 3.0-4	0	B 3.1-29	0	B 3.3-7	0	B 3.3-52	1
B 3.0-5	0	B 3.1-30	0	B 3.3-8	0	B 3.3-53	0
B 3.0-6	0	B 3.1-31	0	B 3.3-9	0	B 3.3-54	1
B 3.0-7	0	B 3.1-32	0	B 3.3-10	1	B 3.3-55	1
B 3.0-8	0	B 3.1-33	0	B 3.3-11	1	B 3.3-56	0
B 3.0-9	0	B 3.1-34	0	B 3.3-12	0	B 3.3-57	0
B 3.0-10	0	B 3.1-35	0	B 3.3-13	0	B 3.3-58	0
B 3.0-11	0	B 3.1-36	0	B 3.3-14	0	B 3.3-59	1
B 3.0-12	2-1	B 3.1-37	0	B 3.3-15	0	B 3.3-60	0
B 3.0-13	2-1	B 3.1-38	0	B 3.3-16	0	B 3.3-61	0
B 3.0-14	0	B 3.1-39	0	B 3.3-17	1	B 3.3-62	0
B 3.0-15	0	B 3.1-40	0	B 3.3-18	1	B 3.3-63	0
B 3.1-1	0	B 3.1-41	0	B 3.3-19	1	B 3.3-64	0
B 3.1-2	0	B 3.1-42	1	B 3.3-20	1	B 3.3-65	0
B 3.1-3	0	B 3.1-43	1	B 3.3-21	1	B 3.3-66	0
B 3.1-4	0	B 3.1-44	1	B 3.3-22	1	B 3.3-67	1
B 3.1-5	0	B 3.1-45	0	B 3.3-23	1	B 3.3-68	1
B 3.1-6	0	B 3.1-46	0	B 3.3-24	1	B 3.3-69	1
B 3.1-7	0	B 3.1-47	0	B 3.3-25	1	B 3.3-70	0
B 3.1-8	1	B 3.1-48	0	B 3.3-26	1	B 3.3-71	0
B 3.1-9	0	B 3.1-49	0	B 3.3-27	1	B 3.3-72	1
B 3.1-10	0	B 3.2-1	0	B 3.3-28	1	B 3.3-73	1
B 3.1-11	0	B 3.2-2	0	B 3.3-29	1	B 3.3-74	2-1
B 3.1-12	0	B 3.2-3	0	B 3.3-30	1	B 3.3-75	2-1
B 3.1-13	0	B 3.2-4	0	B 3.3-31	2-2	B 3.3-76	0
B 3.1-14	0	B 3.2-5	0	B 3.3-31a	2-2	B 3.3-77	0
B 3.1-15	0	B 3.2-6	0	B 3.3-32	0	B 3.3-78	0
B 3.1-16	0	B 3.2-7	0	B 3.3-33	0	B 3.3-79	0
		B 3.2-8	0	B 3.3-34	0		
		B 3.2-9	0	B 3.3-35	0		
		B 3.2-10	0	B 3.3-36	0		
		B 3.2-11	0	B 3.3-37	0		
		B 3.2-12	0	B 3.3-38	0		
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TECHNICAL SPECIFICATIONS BASES
LIST OF EFFECTIVE PAGES

PAGE NUMBER	REV	PAGE NUMBER	REV	PAGE NUMBER	REV	PAGE NUMBER	REV
B 3.3-80	0	B 3.3-120	0	B 3.3-160	0	B 3.3-200	0
B 3.3-81	0	B 3.3-121	0	B 3.3-161	0	B 3.3-201	0
B 3.3-82	0	B 3.3-122	0	B 3.3-162	0	B 3.3-202	0
B 3.3-83	0	B 3.3-123	0	B 3.3-163	0	B 3.3-203	0
B 3.3-84	0	B 3.3-124	0	B 3.3-164	0	B 3.3-204	0
B 3.3-85	0	B 3.3-125	0	B 3.3-165	0	B 3.3-205	0
B 3.3-86	0	B 3.3-126	0	B 3.3-166	0	B 3.3-206	0
B 3.3-87	0	B 3.3-127	0	B 3.3-167	0	B 3.3-207	0
B 3.3-88	0	B 3.3-128	0	B 3.3-168	0	B 3.3-208	0
B 3.3-89	0	B 3.3-129	0	B 3.3-169	0	B 3.3-209	1
B 3.3-90	0	B 3.3-130	0	B 3.3-170	0	B 3.3-210	1
B 3.3-91	0	B 3.3-131	0	B 3.3-171	0	B 3.3-211	1
B 3.3-92	0	B 3.3-132	0	B 3.3-172	0	B 3.3-212	1
B 3.3-93	0	B 3.3-133	0	B 3.3-173	0	B 3.3-213	0
B 3.3-94	0	B 3.3-134	0	B 3.3-174	1	B 3.3-214	0
B 3.3-95	0	B 3.3-135	0	B 3.3-175	0	B 3.3-215	0
B 3.3-96	0	B 3.3-136	0	B 3.3-176	0	B 3.3-216	0
B 3.3-97	0	B 3.3-137	0	B 3.3-177	0	B 3.3-217	0
B 3.3-98	0	B 3.3-138	0	B 3.3-178	0	B 3.3-218	0
B 3.3-99	0	B 3.3-139	0	B 3.3-179	0	B 3.3-219	0
B 3.3-100	0	B 3.3-140	0	B 3.3-180	0	B 3.3-220	0
B 3.3-101	0	B 3.3-141	0	B 3.3-181	0	B 3.3-221	1
B 3.3-102	0	B 3.3-142	0	B 3.3-182	0	B 3.3-222	0
B 3.3-103	0	B 3.3-143	0	B 3.3-183	1	B 3.4-1	0
B 3.3-104	0	B 3.3-144	0	B 3.3-184	0	B 3.4-2	0
B 3.3-105	0	B 3.3-145	0	B 3.3-185	0	B 3.4-3	0
B 3.3-106	0	B 3.3-146	0	B 3.3-186	0	B 3.4-4	0
B 3.3-107	0	B 3.3-147	0	B 3.3-187	0	B 3.4-5	1
B 3.3-108	0	B 3.3-148	0	B 3.3-188	0	B 3.4-6	1
B 3.3-109	0	B 3.3-149	0	B 3.3-189	0	B 3.4-7	0
B 3.3-110	0	B 3.3-150	0	B 3.3-190	0	B 3.4-8	0
B 3.3-111	0	B 3.3-151	0	B 3.3-191	0	B 3.4-9	0
B 3.3-112	0	B 3.3-152	0	B 3.3-192	0	B 3.4-10	0
B 3.3-113	0	B 3.3-153	0	B 3.3-193	0	B 3.4-11	0
B 3.3-114	0	B 3.3-154	0	B 3.3-194	0	B 3.4-12	0
B 3.3-115	0	B 3.3-155	0	B 3.3-195	0	B 3.4-13	0
B 3.3-116	0	B 3.3-156	0	B 3.3-196	0	B 3.4-14	0
B 3.3-117	0	B 3.3-157	0	B 3.3-197	0	B 3.4-15	0
B 3.3-118	0	B 3.3-158	0	B 3.3-198	0	B 3.4-16	0
B 3.3-119	0	B 3.3-159	0	B 3.3-199	0	B 3.4-17	1

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LIST OF EFFECTIVE PAGES

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B 3.4-19	0	B 3.4-59	0	B 3.6-11	2-3	B 3.6-51	2-1
B 3.4-20	1	B 3.4-60	0	B 3.6-12	2-3	B 3.6-52	1
B 3.4-21	0	B 3.4-61	0	B 3.6-13	2-3	B 3.6-53	0
B 3.4-22	0	B 3.4-62	0	B 3.6-14	2-3	B 3.6-54	0
B 3.4-23	0	B 3.4-63	0	B 3.6-15	0	B 3.6-55	0
B 3.4-24	0	B 3.5-1	0	B 3.6-16	0	B 3.6-56	0
B 3.4-25	0	B 3.5-2	0	B 3.6-17	0	B 3.6-57	0
B 3.4-26	0	B 3.5-3	0	B 3.6-18	0	B 3.6-58	0
B 3.4-27	0	B 3.5-4	0	B 3.6-19	0	B 3.6-59	0
B 3.4-28	0	B 3.5-5	0	B 3.6-20	0	B 3.6-60	0
B 3.4-29	0	B 3.5-6	0	B 3.6-21	0	B 3.6-61	0
B 3.4-30	0	B 3.5-7	0	B 3.6-22	0	B 3.6-62	0
B 3.4-31	0	B 3.5-8	0	B 3.6-23	0	B 3.6-63	0
B 3.4-32	0	B 3.5-9	0	B 3.6-24	0	B 3.6-64	0
B 3.4-33	0	B 3.5-10	0	B 3.6-25	1	B 3.6-65	0
B 3.4-34	0	B 3.5-11	1	B 3.6-26	1	B 3.6-66	0
B 3.4-35	0	B 3.5-12	0	B 3.6-27	2-1	B 3.6-67	0
B 3.4-36	0	B 3.5-13	0	B 3.6-28	2-1	B 3.6-68	0
B 3.4-37	0	B 3.5-14	0	B 3.6-29	2-1	B 3.6-69	0
B 3.4-38	0	B 3.5-15	0	B 3.6-30	0	B 3.6-70	1
B 3.4-39	0	B 3.5-16	0	B 3.6-31	0	B 3.6-71	0
B 3.4-40	0	B 3.5-17	0	B 3.6-32	0	B 3.6-72	0
B 3.4-41	0	B 3.5-18	0	B 3.6-33	0	B 3.6-73	0
B 3.4-42	0	B 3.5-19	0	B 3.6-34	0	B 3.6-74	0
B 3.4-43	0	B 3.5-20	0	B 3.6-35	0	B 3.6-75	0
B 3.4-44	0	B 3.5-21	0	B 3.6-36	0	B 3.6-76	0
B 3.4-45	0	B 3.5-22	0	B 3.6-37	1	B 3.6-77	0
B 3.4-46	0	B 3.5-23	0	B 3.6-38	0	B 3.6-78	0
B 3.4-47	0	B 3.5-24	0	B 3.6-39	0	B 3.6-79	0
B 3.4-48	0	B 3.5-25	0	B 3.6-40	0	B 3.6-80	0
B 3.4-49	0	B 3.6-1	0	B 3.6-41	0	B 3.6-81	1
B 3.4-50	0	B 3.6-2	2-1	B 3.6-42	0	B 3.6-82	0
B 3.4-51	0	B 3.6-3	2-1	B 3.6-43	0	B 3.6-83	1
B 3.4-52	0	B 3.6-4	2-1	B 3.6-44	1	B 3.6-84	0
B 3.4-53	0	B 3.6-5	0	B 3.6-45	0	B 3.6-85	1
B 3.4-54	0	B 3.6-6	2-3	B 3.6-46	0	B 3.6-86	1
B 3.4-55	0	B 3.6-7	2-3	B 3.6-47	1	B 3.6-87	0
B 3.4-56	0	B 3.6-8	2-3	B 3.6-48	0	B 3.6-88	0
B 3.4-57	0	B 3.6-9	2-3	B 3.6-49	0	B 3.6-89	0

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B 3.6-91	0	B 3.6-131	2-4	B 3.7-30	0	B 3.8-31	0
B 3.6-92	0	B 3.6-132	2-4	B 3.7-31	0	B 3.8-32	0
B 3.6-93	0	B 3.6-133	2-4	B 3.8-1	0	B 3.8-33	0
B 3.6-94	0	B 3.6-134	0	B 3.8-2	0	B 3.8-34	0
B 3.6-95	0	B 3.6-135	0	B 3.8-3	0	B 3.8-35	0
B 3.6-96	0	B 3.6-136	0	B 3.8-4	0	B 3.8-36	0
B 3.6-97	1	B 3.6-137	0	B 3.8-5	0	B 3.8-37	0
B 3.6-98	0	B 3.6-138	0	B 3.8-6	0	B 3.8-38	0
B 3.6-99	0	B 3.6-139	0	B 3.8-7	0	B 3.8-39	0
B 3.6-100	0	B 3.6-140	0	B 3.8-8	0	B 3.8-40	0
B 3.6-101	0	B 3.6-141	0	B 3.8-9	0	B 3.8-41	0
B 3.6-102	0	B 3.7-1	0	B 3.8-10	0	B 3.8-42	0
B 3.6-103	0	B 3.7-2	0	B 3.8-11	0	B 3.8-43	0
B 3.6-104	0	B 3.7-3	0	B 3.8-12	0	B 3.8-44	0
B 3.6-105	0	B 3.7-4	1	B 3.8-13	0	B 3.8-45	0
B 3.6-106	0	B 3.7-5	1	B 3.8-14	0	B 3.8-46	0
B 3.6-107	0	B 3.7-6	0	B 3.8-15	0	B 3.8-47	0
B 3.6-108	0	B 3.7-7	1	B 3.8-16	0	B 3.8-48	0
B 3.6-109	0	B 3.7-8	1	B 3.8-17	0	B 3.8-49	0
B 3.6-110	0	B 3.7-9	0	B 3.8-18	1	B 3.8-50	0
B 3.6-111	0	B 3.7-10	0	B 3.8-19	0	B 3.8-51	0
B 3.6-112	0	B 3.7-11	0	B 3.8-20	0	B 3.8-52	0
B 3.6-113	0	B 3.7-12	0	B 3.8-21	0	B 3.8-53	0
B 3.6-114	0	B 3.7-13	0	B 3.8-22	0	B 3.8-54	1
B 3.6-115	0	B 3.7-14	1	B 3.8-23	0	B 3.8-55	0
B 3.6-116	0	B 3.7-15	0	B 3.8-24	0	B 3.8-56	2-5
B 3.6-117	0	B 3.7-16	0	B 3.8-25	0	B 3.8-57	0
B 3.6-118	0	B 3.7-17	0	B 3.8-26	0	B 3.8-58	0
B 3.6-119	0	B 3.7-18	0	B 3.8-27	0	B 3.8-59	0
B 3.6-120	2-4	B 3.7-19	0	B 3.8-28	0	B 3.8-60	0
B 3.6-121	2-4	B 3.7-20	0	B 3.8-29	0	B 3.8-61	0
B 3.6-122	2-4	B 3.7-21	0			B 3.8-62	0
B 3.6-123	2-4	B 3.7-22	0			B 3.8-63	0
B 3.6-124	2-4	B 3.7-23	0			B 3.8-64	0
B 3.6-125	2-4	B 3.7-24	1			B 3.8-65	0
B 3.6-126	2-4	B 3.7-25	0			B 3.8-66	1
B 3.6-127	2-4	B 3.7-26	0			B 3.8-67	0
B 3.6-128	2-4	B 3.7-27	0			B 3.8-68	0
B 3.6-129	0	B 3.7-28	0			B 3.8-69	1

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PAGE NUMBER	REV	PAGE NUMBER		PAGE NUMBER	REV	PAGE NUMBER	REV
B 3 8-70	0	B 3 9-18	0	B 3.10-25	0		
B 3 8-71	0	B 3 9-19	0	B 3.10-26	0		
B 3 8-72	0	B 3 9-20	0	B 3.10-27	0		
B 3 8-73	0	B 3 9-21	0	B 3.10-28	0		
B 3 8-74	0	B 3 9-22	0	B 3.10-29	0		
B 3 8-75	0	B 3 9-23	0	B 3.10-30	0		
B 3 8-76	0	B 3 9-24	0	B 3.10-31	0		
B 3 8-77	0	B 3 9-25	0	B 3.10-32	0		
B 3 8-78	0	B 3 9-26	0	B 3.10-33	0		
B 3 8-79	1	B 3 9-27	0	B 3.10-34	0		
B 3 8-80	0	B 3 9-28	0	B 3.10-35	0		
B 3 8-81	0	B 3 9-29	0	B 3.10-36	0		
B 3 8-82	0	B 3 9-30	0	B 3.10-37	0		
B 3 8-83	0	B 3 9-31	0	B 3.10-38	0		
B 3 8-84	0	B 3 9-32	0				
B 3 8-85	0	B 3.10-1	0				
B 3 8-86	0	B 3.10-2	0				
B 3 8-87	0	B 3.10-3	0				
B 3 8-88	1	B 3.10-4	0				
B 3 8-89	0	B 3.10-5	0				
B 3 8-90	0	B 3.10-6	0				
B 3 8-91	0	B 3.10-7	0				
B 3 8-92	0	B 3.10-8	0				
B 3 9-1	0	B 3.10-9	0				
B 3 9-2	0	B 3.10-10	0				
B 3 9-3	0	B 3.10-11	0				
B 3 9-4	0	B 3.10-12	0				
B 3 9-5	0	B 3.10-13	0				
B 3 9-6	0	B 3.10-14	0				
B 3 9-7	0	B 3.10-15	0				
B 3 9-8	0	B 3.10-16	0				
B 3 9-9	0	B 3.10-17	0				
B 3 9-10	0	B 3.10-18	0				
B 3 9-11	0	B 3.10-19	0				
B 3 9-12	0	B 3.10-20	0				
B 3 9-13	0	B 3.10-21	0				
B 3 9-14	0	B 3.10-22	0				
B 3 9-15	0	B 3.10-23	0				
B 3 9-16	0	B 3.10-24	0				
B 3 9-17	0						

BASES

SR 3.0.2
(continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by the TS, and the SR include a Note in the Frequency stating, "SR 3.0.2 is not applicable." An example of an exception when the test interval is not specified in the regulations is the Note in the Primary Containment Leakage Rate Testing Program, "SR 3.0.2 is not applicable." This exception is provided because the program already includes extension of test intervals."

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is less, applies from the point in time that it is discovered that the Surveillance has not been

(continued)

BASES

SR 3.0.3
(continued)

performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

SR 3.0.3 also provides a time limit for completion of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

(continued)

BASES

BACKGROUND
(continued)

is critical at RTP, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel.

The predicted core reactivity, as represented by control rod density (the number of control rod notches inserted as a fraction of the total number of control rod notches; all rods fully inserted is equivalent to 100% rod density), is calculated by a 3D core simulator code as a function of cycle exposure. This calculation is performed for projected operating states and conditions throughout the cycle. The core reactivity is determined from control rod densities for actual plant conditions and is then compared to the predicted value for the cycle exposure.

APPLICABLE
SAFETY ANALYSES

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod drop accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted rod density for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict rod density may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the measured rod density from the predicted rod density that develop during fuel depletion may be an indication that the assumptions of the DBA and transient analyses are no longer valid, or that an unexpected change in core conditions has occurred.

Reactivity anomalies satisfy Criterion 2 of the NRC Policy Statement.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.3.2 and SR 3.1.3.3 (continued)

determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

SR 3.1.3.4

Verifying the scram time for each control rod to notch position 13 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.5

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity, since only an uncoupled CRD can reach the overtravel position. In addition, during this Surveillance any indicated response of the nuclear instrumentation while withdrawing the control rod is observed as a backup to the withdrawn overtravel position indication. The verification is required to be performed anytime a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This includes control rods inserted one notch and then returned to the "full out" position during the performance of SR 3.1.3.2. This

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.7.3 and SR 3.1.7.5 (continued)

The 31 day Frequency of these Surveillances is appropriate because of the relatively slow variation of boron concentration between surveillances.

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure proper operation will occur if required. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.1.7.6 verifies each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual, power operated, and automatic valves in the SLC System flow path ensures that the proper flow paths will exist for system operation. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve controls. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct positions. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensure correct valve positions.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.1.7.7

Demonstrating each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1220 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve, and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8

This Surveillance ensures that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 36 months, at alternating 18 month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. In order to pump this water, the test valve 1C41*F031 is open. A system initiation signal (which normally signals the 1C41*F001 storage tank suction valve) is generated with the test valve open and verification is made that the storage tank suction valve remains closed. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.1.7.8 (continued)

components usually pass the Surveillance test when performed at the 18 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.1.7.9

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the sodium pentaborate solution to determine the actual B-10 enrichment must be performed once within 24 hours after boron is added to the solution in order to ensure that the B-10 enrichment is adequate. Enrichment testing is only required when boron addition is made since enrichment change cannot occur by any other process.

REFERENCES

1. 10 CFR 50.62.
 2. USAR, Section 9.3.5.3.
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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

2.c. Average Power Range Monitor Fixed Neutron Flux—High
(continued)

safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 7) takes credit for the Average Power Range Monitor Fixed Neutron Flux—High Function to terminate the CRDA.

The AFRM System is divided into two groups of channels with four APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Six channels of Average Power Range Monitor Fixed Neutron Flux—High with three channels in each trip system arranged in a one-out-of-three logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux—High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux—High Function is assumed in the CRDA analysis that is applicable in MODE 2, the Average Power Range Monitor Neutron Flux—High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux—High Function is not required in MODE 2.

2.d. Average Power Range Monitor—Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than Operate, an APRM module is unplugged, or the APRM has too few LPRM inputs (<11) as indicated by low voltage, an inoperable trip signal will be

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

2.d. Average Power Range Monitor—Inop (continued)

received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

Six channels of Average Power Range Monitor—Inop with three channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure—High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure—High Function initiates a scram for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 2, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—High signal, not the Reactor Vessel Steam Dome Pressure—High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

9. Turbine Stop Valve Closure
(continued)

Turbine Stop Valve Closure signals are initiated by limit switches at each stop valve. Two independent limit switches are associated with each stop valve. One of the two limit switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve Closure channels, each consisting of one limit switch. The logic for the Turbine Stop Valve Closure Function is such that three or more TSVs must be closed to produce a scram.

This Function must be enabled at THERMAL POWER \geq 40% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER \geq 40% RTP. Alternately, the bypass channel can be placed in the conservative condition (non-bypass). If placed in the non-bypass condition, this Surveillance Requirement is met and the channel is considered OPERABLE.

The Turbine Stop Valve Closure Allowable Value is selected to be low enough to detect imminent TSV closure thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is \geq 40% RTP. This Function is not required when THERMAL POWER is $<$ 40% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

10. Turbine Control Valve Fast Closure, Trip Oil
Pressure—Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

10. Turbine Control Valve Fast Closure, Trip Oil
Pressure—Low (continued)

transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure transmitter associated with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER \geq 40% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER \geq 40% RTP. Alternately, the bypass channel can be placed in the conservative condition (non-bypass). If placed in the non-bypass condition, this Surveillance Requirement is met and the channel is considered OPERABLE. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Stop Valve Closure Function.

The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is \geq 40% RTP. This Function is not required when THERMAL POWER is $<$ 40% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

11. Reactor Mode Switch—Shutdown Position

The Reactor Mode Switch—Shutdown Position Function provides signals, via the manual scram logic channels, that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with four channels, each of which inputs into one of the RPS logic channels.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

Four channels of Reactor Mode Switch—Shutdown Position Function, with two channels in each trip system, are available and required to be OPERABLE. The Reactor Mode—Switch Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

12. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, to each of the four RPS logic channels that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the four RPS logic channels. In order to cause a scram it is necessary that at least one channel in each trip system be actuated.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

12. Manual Scram (continued)

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic, are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate, inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 9) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases.) If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic for any Function would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 9 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference 9, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels, if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, it is permissible to place the other trip system or its inoperable channels in trip.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram or RPT), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 6 (Main Steam Isolation Valve—Closure), this would require both trip systems to have each channel associated with the MSIVs in three MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip). For Function 9 (Turbine Stop Valve Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

(continued)

BASES

ACTIONS
(continued)

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C, and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, G.1, and H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, prompt action must be taken to place the plant in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

I.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the RPS reliability analysis (Ref. 9) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift on one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate $\geq 100\%$ of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when $< 25\%$ RTP is provided that requires the SR to be met only at $\geq 25\%$ RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when $< 25\%$ RTP. At low power levels, a high degree of accuracy is unnecessary because of the large inherent margin to thermal limits (MCPR and APLHGR). At $\geq 25\%$ RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function uses the recirculation loop drive flows to vary the trip setpoint. This SR ensures that the APRM Function accurately reflects the required setpoint as a function of flow. A variable calibrated flow signal is applied to each APRM flow biased simulated thermal power channel, and the trip setpoint is verified to be acceptable by application of a variable power signal to the channel.

The Frequency of 7 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average availability over the Frequency interval and is based on reliability analysis (Ref. 9).

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 9. (The Manual Scram Function's CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions' Frequencies.)

SR 3.3.1.1.6 and SR 3.3.1.1.7

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status. The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a region without adequate neutron flux indication. This is

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (initiate a rod block) if adequate overlap is not maintained.

Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above 2/40 on Range 1 before SRMs have reached the upscale rod block.

As noted, SR 3.3.1.1.7 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channel(s) that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

For Functions 9 and 10 the CHANNEL FUNCTIONAL TEST shall include the turbine first stage pressure instruments.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.10

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

For Functions 9 and 10 all applicable trip unit setpoints must be calibrated including the turbine first stage pressure instrument trip unit setpoints.

The Frequency of 92 days for SR 3.3.1.1.10 is based on the reliability analysis of Reference 9.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.17

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

For Functions 9 and 10 the CHANNEL CALIBRATION shall include the turbine first stage pressure instruments.

Note 1 states that neutron detectors and flow reference transmitters are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). Calibration of the flow reference transmitters is performed on an 18 month Frequency (SR 3.3.1.1.17). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. The Frequency of SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.17 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.14

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The filter time constant is specified in the COLR and must be verified to ensure that the channel is accurately reflecting the desired parameter.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.14 (continued)

The Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq 40\%$ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER $\geq 40\%$ RTP to ensure that the calibration remains valid.

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at $\geq 40\%$ RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.1.1.16 (continued)

can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.18

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 10.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. In addition, for Functions 3, 4, and 5, the associated sensors are not required to be response time tested. For these functions, response time testing for the remaining channel components is required. This allowance is supported by Reference 11.

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. Therefore, staggered testing results in response time verification of these devices every 18 months. This Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

REFERENCES

1. USAR, Figure 7.2-1.
2. USAR, Section 5.2.2.
3. USAR, Section 6.3.3.

(continued)

BASES

REFERENCES
(continued)

4. USAR, Chapter 15.
 5. USAR, Section 15.4.1.
 6. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
 7. USAR, Section 15.4.9.
 8. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980, as attached to NRC Generic Letter dated December 9, 1980.
 9. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
 10. RBS Technical Requirements Manual.
 11. NEDO-32291-A, "System Analysis for Elimination of Selected Response Time Testing Requirements," January 1994.
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B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events. The instruments that monitor these variables are designated as Type A, Category I, and non-Type A, Category I in accordance with Regulatory Guide 1.97 (Ref. 1).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A, variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (EOP). These variables are restricted to preplanned actions for the primary success path of Design Basis Accidents (DBAs) (e.g., loss of coolant accident (LOCA)); and
- Take the specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for safety systems to accomplish their safety function.

The PAM instrumentation LCO also ensures OPERABILITY of Category I, non-Type A, variables. This ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;

(continued)

BASES

LCO
(continued)

Listed below is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1, in the accompanying LCO.

1. Reactor Steam Dome Pressure

Reactor steam dome pressure is a Category I variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig monitor pressure. Wide range recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

2. 3. Reactor Vessel Water Level

Reactor vessel water level is a Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. The wide range and fuel zone water level channels provide the PAM Reactor Vessel Water Level Function. The wide range water level channels measure from two inches above the top of active fuel to 218 inches above the top of active fuel. The fuel zone water level channels overlap with the wide range channels and measure down to the bottom of the active fuel. Wide range water level is measured by two independent differential pressure transmitters. Fuel zone water level is measured by three independent differential pressure transmitters. The output from the wide range channels are recorded on two independent pen recorders. One of the fuel zone channels is output to a pen recorder, the other two channels are output to meters. These recorders and meters are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

The wide range water level instruments are uncompensated for variation in reactor water density and are calibrated to be most accurate at operational pressure and temperature.

4. Suppression Pool Water Level

Suppression pool water level is a Category I variable

(continued)

BASES

LCO

4. Suppression Pool Water Level (continued)

provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. The wide range suppression pool water level measurement provides the operator with sufficient information to assess the status of the RCPB and to assess the status of the water supply to the ECCS. The wide range water level indicators monitor the suppression pool level from 5 ft above the bottom of the pool to 23 ft 9 inches above the bottom of the pool. Two wide range suppression pool water level signals are transmitted from separate differential pressure transmitters and are continuously recorded on two recorders in the control room. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5. Suppression Pool Sector Water Temperature

Suppression pool sector water temperature is a Category I variable provided to detect a condition that could potentially lead to containment breach, and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature instrumentation allows operators to detect trends in suppression pool water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool.

Fourteen temperature sensors are provided for normal monitoring of suppression pool sector water temperature. Four of the fourteen are located below the post LOCA ECCS drawdown water level of the suppression pool and are used for post accident monitoring. The output of both normal pool temperature monitoring sensors and the PAM sensors are recorded in the main control room. One sector is monitored by division I PAM sensors 1CMS*RTD40A (az 32° 0') and 1CMS*RTD40C (az 325° 36'). The other sector is monitored by division II PAM sensors 1CMS*RTD40B (az 218° 0') and 1CMS*RTD40D (az 144° 30').

These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

(continued)

BASES

LCO
(continued)

9. Primary Containment Area Radiation (High Range)

Primary containment area radiation (high range) is a Category I variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Primary containment area radiation (high range) PAM instrumentation consists of two high range containment area radiation signals transmitted from separate radiation elements and continuously recorded and displayed on two control room recorders. The recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

10, 11. Drywell and Containment Hydrogen Analyzer

Drywell and containment hydrogen analyzers are Category I instruments provided to detect high hydrogen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions.

The drywell and containment hydrogen analyzers PAM instrumentation consists of containment and drywell hydrogen concentration signals transmitted from two separate hydrogen analyzers and recorded on two two-pen recorders in the control room. One pen records the hydrogen concentration and one pen records the sample point on each of the two independent recorders. Measurement capability is provided over the range of 0 to 10 percent hydrogen concentration using a sample drawing system.

12. Penetration Flow Path, Automatic Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the status of the containment penetration flow path. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each automatic PCIV in a containment penetration flow path, i.e.,

(continued)

BASES

LCO

12. Penetration Flow Path, Automatic Primary Containment Isolation Valve (PCIV) Position (continued)

two total channels of PCIV position indication for a penetration flow path with two automatic valves. For containment penetrations with only one automatic PCIV having control room indication, Note (c) requires a single channel of valve position indication to be OPERABLE. This is sufficient to verify redundantly the isolation status of each isolable penetration via indicated status of the automatic valve and, as applicable, prior knowledge of passive valve or system boundary status. If a penetration is isolated by at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration is not required to be OPERABLE.

The PCIV position PAM instrumentation consists of individual position indication (open - closed) in the control room for each automatic containment isolation valve as described in USAR Section 7.5 (Reference 3). Automatic PCIVs are listed in Technical Requirements Manual, Table TR 3.6.1.3-1 (Reference 4).

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the Actions even though the Actions may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to diagnose an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.3.1.1 (continued)

The Frequency of 31 days is based upon plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given function in any 31 day interval is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

SR 3.3.3.1.2 and SR 3.3.3.1.3

For all Functions except the containment and drywell hydrogen analyzers, a CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The Frequency is based on operating experience and consistency with the typical industry refueling cycles.

For the containment and drywell hydrogen analyzers, the CHANNEL CALIBRATION is performed every 92 days. This Frequency is based on operating experience.

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2, December 1980.
 2. NRC Safety Evaluation Report, "Conformance to Regulatory Guide 1.97, Revision 2, River Bend Station, Unit 1," dated June 30, 1986.
 3. USAR Section 7.5.
 4. Technical Requirements Manual
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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

its actual trip setpoint is not within its required Allowable Value. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., TSV electrohydraulic control (EHC) pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analysis, LCO, and Applicability discussions are listed below on a Function by Function basis.

Turbine Stop Valve Closure

Closure of the TSVs and a main turbine trip result in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an EOC-RPT is initiated on TSV Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring the MCPR SL is not exceeded during the worst case transient.

Closure of the TSVs is determined by limit switches on each stop valve. There are two limit switches associated with each stop valve, and the signal from each limit switch is assigned to a separate trip system. Thus, each trip system

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

Turbine Stop Valve Closure (continued)

receives an input from four Turbine Stop Valve Closure channels, each consisting of one limit switch. The logic for the TSV Closure Function is such that This Function must be enabled at THERMAL POWER \geq 40% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER \geq 40% RTP. Four channels of TSV Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV Closure Allowable Value is selected high enough to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is \geq 40% RTP with any recirculating pump in fast speed. Below 40% RTP or with the recirculation in slow speed, the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor (APRM) Fixed Neutron Flux—High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

TCV Fast Closure, Trip Oil Pressure—Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure—Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the EHC fluid pressure at each control valve. There is one pressure transmitter associated with each control valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure—Low Function is such that two or more TCVs must be closed (pressure transmitter trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER \geq 40% RTP. This is normally accomplished automatically by pressure

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY

TCV Fast Closure, Trip Oil Pressure—Low
(continued)

transmitters sensing turbine first stage pressure; therefore to consider this function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER \geq 40% RTP. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

This protection is required consistent with the analysis, whenever the THERMAL POWER is \geq 40% RTP with any recirculating pump in fast speed. Below 40% RTP or with recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure—High and the APRM Fixed Neutron Flux—High Functions of the RPS are adequate to maintain the necessary safety margins. The turbine first stage pressure/reactor power relationship for the setpoint of the automatic enable is identical to that described for TSV closure.

ACTIONS

A Note has been provided to modify the ACTIONS related to EOC-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable EOC-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable EOC-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Action B.1 Bases),

(continued)

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SURVEILLANCE
REQUIREMENTS

SR 3.3.4.1.1 (continued)

The CHANNEL FUNCTIONAL TEST shall include the turbine first stage pressure instruments.

The Frequency of 92 days is based on reliability analysis (Ref. 5).

SR 3.3.4.1.2

The calibration of the turbine first stage pressure transmitter trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.1.5. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on assumptions of the reliability analysis (Ref. 5) and on the methodology included in the determination of the trip setpoint.

SR 3.3.4.1.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The CHANNEL CALIBRATION shall include the turbine first stage pressure instruments.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.4.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 18 month Frequency.

SR 3.3.4.1.5

This SR ensures that an EOC-RPT initiated from the TSV Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is $\geq 40\%$ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER $\geq 40\%$ RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at $\geq 40\%$ RTP either due to open main turbine bypass valves or other reasons), the affected TSV Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

The Frequency of 18 months has shown that channel bypass failures between successive tests are rare.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.3.4.1.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 6.

A Note to the Surveillance states that breaker interruption time may be assumed from the most recent performance of SR 3.3.4.1.7. This is allowed since the time to open the contacts after energization of the trip coil and the arc suppression time are short and do not appreciably change, due to the design of the breaker opening device and the fact that the breaker is not routinely cycled.

EOC-RPT SYSTEM RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Each test shall include at least the logic of one type of channel input (Turbine Stop Valve Closure or Turbine Control Valve Fast Closure, Trip Oil Pressure - Low) such that both types of channel inputs are tested at least once per 36 months. Response times cannot be determined at power because operation of final actuated devices is required. Therefore, this Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components that cause serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.4.1.7

This SR ensures that the RPT breaker interruption time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. Breaker Interruption time is defined as Breaker Response time plus Arc Suppression time. Breaker Response is the time from application of voltage to the trip coil until the arcing contacts separate. Arc Suppression is the time from arcing contact separation until the complete suppression of the electrical arc across the open contacts. Breaker Response shall be verified by testing to be within the manufacturer's design response time. Testing of the breaker response time verifies the design interruption time to be \leq five cycles (83.3 ms). Breaker arc suppression shall be validated by visual observation of puffer performance and insulation testing of the breaker arc chutes. The 60 month Frequency of

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.3.4.1.7 (continued)

the testing is based on the difficulty of performing the test and the reliability of the circuit breakers.

REFERENCES

1. USAR, Section 7.6.1.1.
 2. USAR, Section 5.2.2.
 3. USAR, Sections 15.1.1, 15.1.2, and 15.1.3.
 4. USAR, Sections 15.2.2, 15.2.3 and 15.2.5.
 5. GENE-770-06-1, "Bases for Changes To Surveillance Test Intervals And Allowed Out-Of-Service Times For Selected Instrumentation Technical Specifications," February 1991.
 6. RBS Technical Requirements Manual.
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BASES

APPLICABLE
SAFETY ANALYSES,
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2. Drywell Pressure—High
(continued)

steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

3 and 4. Fuel Building Ventilation Exhaust Radiation—High

High secondary containment exhaust radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the fuel building due to a fuel handling accident. When Exhaust Radiation—High is detected, secondary containment isolation and actuation of the associated ventilation system are initiated to limit the release of fission products as assumed in the USAR safety analyses (Ref. 1).

The Exhaust Radiation—High signals are initiated from radiation detectors that are located on the ventilation exhaust duct coming from the fuel building ventilation. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

The Exhaust Radiation—High Function is required to be OPERABLE during movement of irradiated fuel assemblies in the fuel building because the capability of detecting radiation releases due to fuel failures (due to fuel uncover or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments, as defined by 10 CFR 50.49) are accounted for. These uncertainties are described in the setpoint methodology.

In MODES 1, 2, and 3, a DBA could cause pressurization and increased temperatures within the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining primary containment unit coolers OPERABLE is not required in MODE 4 or 5.

The specific Applicable Safety Analyses and LCO discussions are listed below on a Function by Function basis.

1. Drywell Pressure—High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The Containment Unit Cooler System mitigates the consequences of steam leaking from the drywell directly into containment airspace, bypassing the suppression pool.

Four Drywell Pressure—High transmitters (two per trip system) are available and are required to be OPERABLE and capable of automatically initiating the Containment Unit Cooler System. This ensures that no single instrument failure can preclude the containment cooling function. The

(continued)

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for the Division 1, 2, and 3 buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage.

The LOP instrumentation is comprised of two undervoltage protection levels for Divisions 1, 2, and 3, which represent different voltage levels that cause various bus transfers and disconnects. Each Division 1 and 2 Function is monitored by three undervoltage relays for each emergency bus whose outputs are arranged in a two-out-of-three logic configuration (Ref. 1). The Division 3 undervoltage protection levels are each monitored by two undervoltage relays which sense voltage at the incoming side of the normal supply breaker whose outputs are arranged in a two-out-of-two logic configuration (Ref. 1). The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for the Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

the DGs provide plant protection in the event of any of the analyzed accidents in References 2, 3, and 4 in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of the NRC Policy Statement.

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoint does not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation

(continued)

BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

4.16 kV Emergency Bus Undervoltage

1.a, 1.b, 2.a, 2.b. 4.16 kV Emergency Bus Undervoltage
(Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

Three channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Four channels input to each of the three DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and LCO 3.8.2, "AC Sources—Shutdown," for Applicability Bases for the DGs.

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BASES

APPLICABLE
SAFETY ANALYSES,
LCO, and
APPLICABILITY
(continued)

1.c, 1.d, 1.e, 2.c, 2.d, 2.e. 4.16 kV Emergency Bus
Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that while offsite power may not be completely lost to the respective emergency bus, power may be insufficient for starting large motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Three channels of Division I and II - 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated emergency bus and two channels of Division III - 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Functions per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency (including time delay) channel to ensure that the entire channel will perform the intended function.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The 184 day Frequency and the Note in the Surveillance are based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

ACTIONS

A.1 (continued)

Alternatively, if the single loop requirements of the LCO are applied to operating limits and RPS setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

The 2 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

B.1

Should a LOCA occur with THERMAL POWER > 70% RTP, during single loop operation the core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to reduce THERMAL POWER to \leq 70% RTP.

The 1 hour Completion Time is based on the low probability of an accident occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing changes in THERMAL POWER to be quickly detected.

C.1, D.1, and E.1

Due to thermal hydraulic stability concerns, operation of the plant is divided into three regions based on THERMAL POWER and core flows. Region III is a power/flow ratio with core flow < 39% of the rated core flow. Region II is a power/flow ratio with core flow \geq 39% and < 45% of the rated core flow. Deliberate entry into Region III is not permitted, and if it occurs, immediate action is required to exit the region within 4 hours by reducing THERMAL POWER through control rod insertion or by increasing recirculation loop flow by opening the flow control valve. Operation in Region II is also more susceptible to instability than normal operating parameters. However, operation in this region is allowed with the exception that if evidence of

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BASES

ACTIONS

B.1, C.1, and D.1 (continued)

instability occurs (i.e., APRM or LPRM neutron flux level is three times the established baseline) then action is required to exit this region within 2 hours. The allowed Completion Times are reasonable, based on operating experience, to restore plant parameters to normal in an orderly manner and without challenging plant systems.

A determination of APRM and LPRM neutron flux noise levels every 8 hours provides frequent periodic information relative to established baseline noise levels (see Condition D) that indicate stable steady state operation. A determination of these noise levels within 30 minutes after an increase of $\geq 5\%$ RTP provides a more frequent indication of the stability of operation following any significant potential for change of the thermal hydraulic properties of the system. These Frequencies provide early detection of neutron flux oscillations due to core thermal hydraulic instabilities. Action must be initiated to restore the plant to a more stable power/flow ratio if such indications of limit cycle neutron flux oscillations are detected.

F.1, F.2, and F.3

With no recirculation loops in operation, the unit is required to be brought to a MODE in which the LCO does not apply. Action must be initiated to reduce THERMAL POWER to be within the limits defined in the COLR to assure thermal hydraulic stability concerns are addressed. The plant is then required to be placed in MODE 2 in 6 hours and MODE 3 in 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Times are reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (S/RVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool.

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic piston or cylinder and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Five of the S/RVs providing the relief function also provide the low-low set relief function specified in LCO 3.6.1.6, "Low-Low Set (LLS) Valves." Seven of the S/RVs that provide the relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS—Operating." The instrumentation associated with the relief valve function and low-low set relief function is discussed in the Bases for LCO 3.3.6.4, "Relief and Low-Low Set (LLS) Instrumentation," and instrumentation for the ADS function is discussed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation."

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BASES

SURVEILLANCE
REQUIREMENTS

SR 3.4.4.1 (continued)

lift settings must be performed during shutdown, since this is a bench test, and in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

The Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings.

SR 3.4.4.2

The required relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.4.4.3

A manual actuation of each required S/RV is performed to verify that the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitor). Adequate reactor

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.5.1.4 (continued)

The pump flow rates are verified with a pump differential pressure that is sufficient to overcome the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing. The Frequency for this Surveillance is in accordance with the Inservice Testing Program requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves in the flow path to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

BACKGROUND
(continued)

2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

APPLICABLE
SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.26% by weight of the containment and drywell air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 7.6 psig (Ref. 4).

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Primary containment OPERABILITY is maintained by limiting overall leakage to $\leq 1.0 L_a$. During the first startup following testing in accordance with the Primary Containment Leakage Rate Testing Program (Ref. 5), the leakage rate acceptance criteria are $\leq 0.60 L_a$ for the Type B and Type C tests and $\leq 0.75 L_a$ for Type A tests. Compliance with this LCO will ensure a primary containment configuration,

(continued)

BASES

LCO
(continued) including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2.

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment leakage limits are not required to be met in MODES 4 and 5 to prevent leakage of radioactive material from primary containment (refer to LCO 3.6.1.10, "Primary Containment-Shutdown").

ACTIONS A.1

In the event that primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.1.1 (continued)

test requirements of the Primary Containment Leakage Rate Testing Program (Ref. 5). Failure to meet air lock leakage testing (SR 3.6.1.2.1 and SR 3.6.1.2.4) resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.5), secondary containment bypass leakage (SR 3.6.1.3.9), main steam positive leakage control system (SR 3.6.1.3.10), hydrostatically tested valve leakage (SR 3.6.1.3.11), or annulus bypass leakage (SR 3.6.1.3.12) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. The Primary Containment overall leakage rate acceptance criteria is $\leq 1.0 L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60 L_a$ on a Maximum Pathway Leakage Rate (MXPLR) for the Type B and Type C tests and $\leq 0.75 L_a$ for Type A tests. The MXPLR for combined Type B and C leakage is the measured leakage through the worst of the two isolation valves, unless a penetration is isolated by use of one closed and deactivated automatic valve, closed manual valve, or blind flange. In this case, the MXPLR of the isolated penetration is assumed to be the measured leakage through the isolation device. At $\leq 1.0 L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Testing Program.

REFERENCES

1. USAR, Section 6.2.
 2. USAR, Section 15.6.5.
 3. 10 CFR 50, Appendix J, Option B.
 4. USAR, Section 6.2.6.
 5. Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.
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BASES

BACKGROUND
(continued)

DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

APPLICABLE
SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.26% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of 7.6 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment.

During plant operations in other than MODES 1, 2, and 3, the primary containment contains the fission products from a fuel handling accident (FHA), involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 11 days) inside the primary containment (Ref. 4), to limit doses at the site boundary to within limits. The primary containment air lock OPERABILITY assures a leak tight fission product barrier during activities with the unit shutdown.

Primary containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA, an FHA involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 11 days) or other unanticipated reactivity or water level excursion. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such events.

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BASES

LCO
(continued)

The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from primary containment.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining OPERABLE primary containment air locks in MODE 4 or 5 to ensure a control volume is only required during situations for which significant releases of radioactive material can be postulated; such as during operations with a potential for draining the reactor vessel (OPDRVs) or during fuel movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, primary containment air locks are only required during fuel handling in the primary containment involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 11 days).

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door,

(continued)

ACTIONS

even if it means the primary containment boundary is

BASES

(continued) temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed.

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock.

This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by a third Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment-Operating," to be taken in this event.

The leakage limits of LCO 3.6.1.1 are only applicable in MODES 1, 2, and 3, therefore, the provisions of Note 3 apply only during MODES 1, 2, and 3.

A.1, A.2, and A.3

With one primary containment air lock door inoperable in one or more primary containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

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BASES

ACTIONS

A.1, A.2, and A.3

Required Action A.3 ensures that the affected air lock with an inoperable door has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls.

Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Times from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both have an inoperable door. This 7 day restriction begins when the second airlock is discovered inoperable.

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and assuring the OPERABLE door is relocked after

(continued)

BASES

ACTIONS

A.1, A.2, and A.3

completion of the containment entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or both primary containment air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in one air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits. Required Action C.2 requires that one door in the affected primary containment air locks must be verified closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time while operating in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1, E.2, and E.3

If the inoperable primary containment airlock cannot be restored to OPERABLE status within the associated Completion Time during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies in the primary containment, action is required to immediately suspend activities that represent a potential for releasing radioactive material,

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program (Ref. 5). This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria (i.e., $\leq 13,500$ cc/hr for the combination of all annulus bypass leakage paths that are required to be meeting leak tightness) ensures that the combined leakage rate of annulus bypass leakage paths is less than the specified leakage rate. This provides assurance in MODES 1, 2, and 3 that the assumptions in the radiological evaluations are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (e.g., leakage through the air lock door with the highest leakage) unless the penetration is isolated by use of (for this Specification) one closed and locked air lock door. The leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation devices (e.g., air lock door). If both air lock doors are closed, the actual leakage rate is the lesser leakage rate of the two barriers (doors). This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J, Option B, maximum pathway leakage limits used to evaluate Type A, B and C limits are to be quantified in accordance with Appendix J, Option B).

During the operational conditions of moving irradiated fuel assemblies in the primary containment, CORE ALTERATIONS, or OPDRVS, the only annulus bypass path leakage required to be met is through the two primary containment airlocks; therefore the entire 13,500 cc/hr limit can be applied to

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.2.1 (continued)

the air locks. In these operational conditions the reactor coolant system is not pressurized and specific primary containment leakage limits are not imposed. However, due to the size of the air lock penetration, leakage limits are imposed to assure an OPERABLE barrier. In these conditions the leakage limits are not related to radiological evaluations, but only reflect engineering judgment of an acceptable barrier. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1 during operation in MODES 1, 2, and 3. This ensures that air lock leakage is properly accounted for in determining the overall primary containment leakage rate. Since the overall primary containment leakage rate is only applicable in MODE 1, 2, and 3 operation, the Note 2 requirement is imposed only during these MODES.

SR 3.6.1.2.2

The seal air flask pressure is verified to be at ≥ 90 psig every 7 days to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable through operating experience and is considered adequate in view of the other indications available to operations personnel that the seal air flask pressure is low.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.2.3

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure (Ref. 3), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the nature of this interlock, and given that the interlock mechanism is only challenged when the primary containment airlock door is opened, this test is only required to be performed upon entering or exiting a primary containment air lock, but is not required more frequently than once per 184 days. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls.

SR 3.6.1.2.4

A seal pneumatic system test to ensure that pressure does not decay at a rate equivalent to > 1.28 psig for a period of 24 hours from an initial pressure of 90 psig is an effective leakage rate test to verify system performance.

The 18 month Frequency is based on the fact that operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 3.8.
 2. 10 CFR 50, Appendix J, Option B.
 3. USAR, Table 6.2-1.
 4. USAR, 15.7.4.
 5. Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.
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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.3.5

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 4), is required to ensure OPERABILITY. The acceptance criterion for the purge supply valves is a combined leakage rate of $\leq 13,500$ cc/hr for all required annulus bypass leakage paths when pressurized to $\geq P_a$, 7.6 psig. The acceptance criterion for each purge exhaust valve is $\leq 0.01 L_a$ when pressurized to $\geq P_a$, 7.6 psig. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining this penetration leak tight (due to the direct path between primary containment and the environment), a Frequency of 184 days was established. Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

The SR is modified by a Note stating that the primary containment purge valves are only required to meet leakage rate testing requirements in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, purge valve leakage must be minimized to ensure offsite radiological release is within limits. At other times pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.

SR 3.6.1.3.6

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges. The Frequency of this SR is in accordance with the Inservice Testing Program.

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BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.6 overlaps this SR to provide complete testing of the safety function. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8

The use of MS-PLCS as a positive leakage barrier results in in-leakage and gradual pressure buildup within the containment. The total allowable MSIV in-leakage rate does not have radiological consequences. This surveillance ensures that the total allowable air in-leakage rate from the MSIVs and valves served by the PVLCS is limited such that containment pressurization does not exceed 50 percent of the design value in a 30 day period due to these sources.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.9

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate when pressurized to $\geq P_a$, 7.6 psig. This provides assurance that the assumptions in the radiological

(continued)

BASES

SURVEILLANCE
REQUIREMENTSSR 3.6.1.3.9 (continued)

evaluations of Reference 4 are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J, Option B maximum pathway leakage limits are to be quantified in accordance with Appendix J, Option B). The Frequency is required by the Primary Containment Leakage Rate Testing Program (Ref. 5).

A note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2 and 3. In the other conditions the Reactor Coolant System is not pressurized and primary containment leakage limits are not required.

SR 3.6.1.3.10

The analyses in References 2 and 3 are based on leakage out of the primary containment that is less than the specified leakage rate. Leakage through the valves sealed in each division of MS-PLCS must be ≤ 150 scfh per division when tested at $\geq P_a$, 7.6 psig. The leakage rate must be verified to be in accordance with the leakage test requirements of Reference 4, as modified by approved exemptions.

A note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2 and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. The Frequency is required by the Primary Containment Leakage Rate Testing Program (Ref. 5).

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines at $\geq 1.1 P_a$, 8.36 psig provides assurance that the calculation assumptions of References 2 and 3 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 1.0 gpm times the total number of hydrostatically tested PCIVs when tested at $1.1 P_a$. The combined leakage rates must be demonstrated at the frequency of the leakage test requirements of the Primary Containment Leakage Rate Testing Program (Ref. 5).

A note is added to this SR which states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.

SR 3.6.1.3.12

This SR ensures that the combined leakage rate of annulus bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 4 are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. This method of quantifying maximum pathway leakage is only to be used for this SR (i.e., Appendix J, Option B maximum pathway leakage limits are to be quantified in accordance with Appendix J, Option B). The Frequency is required by the Primary Containment Leakage Rate Testing Program (Ref. 5).

(continued)

BASES (continued)

REFERENCES

1. USAR, Chapter 15.
 2. USAR, Section 6.2.
 3. USAR, Table 6.2-40.
 4. 10 CFR 50, Appendix J, Option B.
 5. Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.
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BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.6.1

A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitor). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Adequate pressure at which this test is to be performed is consistent with the pressure recommended by the valve manufacturer. Also, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. The 18 month Frequency was developed based on the S/RV tests required by the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 3). The Frequency of 18 months on a STAGGERED TEST BASIS ensures that each solenoid for each S/RV is alternately tested. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Since steam pressure is required in order to perform the Surveillance, however, and steam may not be available during a unit outage, the Surveillance may be performed during the shutdown prior to or the startup following a unit outage. Unit startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified by Reference 3 prior to valve installation. After adequate reactor steam pressure and flow are reached, 12 hours are allowed to prepare for and perform the test.

SR 3.6.1.6.2

The LLS designed S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function.

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BASES (continued)

LCO Two PVLCS subsystems must be OPERABLE such that in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A PVLCS subsystem is OPERABLE when all necessary components are available to supply each required dual seat isolation valve with sufficient air pressure to preclude containment leakage when the containment atmosphere is at the maximum peak containment pressure, P_a .

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the PVLCS is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

With one PVLCS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE PVLCS subsystem is adequate to perform the leakage control function. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA, the amount of time available after the event for operator action to prevent exceeding this limit, the low probability of failure of the OPERABLE PVLCS subsystem, and the availability of the PCIVs.

B.1

With two PVLCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA, the availability of operator action, and the availability of the PCIVs.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.9 Main Steam-Positive Leakage Control System (MS-PLCS)

BASES

BACKGROUND	<p>The MS-PLCS supplements the isolation function of the MSIVs by processing the fission products that could leak through the closed MSIVs after a Design Basis Accident (DBA) loss of coolant accident (LOCA).</p> <p>The MS-PLCS consists of two independent subsystems: an inboard subsystem, which is connected between the inboard and outboard MSIVs; and an outboard subsystem, which is connected between the double disk of main steamline shutoff valves and the valve stem packing glands of the outboard MSIVs at a positive air pressure with respect to reactor vessel pressure following system actuation. The MS-PLCS is supplied with compressed air by two separate and redundant compressed air supply subsystems that are integral components of the PVLCS. Each subsystem receives power from a separate division of the emergency power supply.</p> <p>The MS-PLCS is manually initiated approximately 20 minutes following a DBA LOCA (Ref. 1), and is designed to control and minimize leakage through the MSIVs for up to 30 days.</p>
APPLICABLE SAFETY ANALYSES	<p>The MS-PLCS mitigates the consequences of a DBA LOCA by ensuring that fission products that may leak from the closed MSIVs are ultimately filtered by the SGT System. The analyses in Reference 2 provide the evaluation of offsite dose consequences. The operation of the MS-PLCS prevents a release of untreated leakage for this type of event.</p> <p>The MS-PLCS satisfies Criterion 3 of the NRC Policy Statement.</p>
LCO	<p>One MS-PLCS subsystem can provide the required processing of the MSIV leakage. To ensure that this capability is available, assuming worst case single failure, two MS-PLCS subsystems must be OPERABLE.</p>
APPLICABILITY	<p>In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment. Therefore, MS-PLCS OPERABILITY is required during these MODES. In MODES 4</p>

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.10 Primary Containment-Shutdown

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier for accidents during shutdown conditions:

- a. All penetrations required to be closed during accident conditions are closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, or the equivalent, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";
- b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks"; and
- c. All equipment hatches are closed.

This Specification ensures that the performance of the primary containment, in the event of a fuel handling accident (FHA), inadvertent criticality, or reactor vessel draindown, provides an acceptable leakage barrier to contain fission products, thereby minimizing offsite doses.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it contain the fission products from a FHA inside the

(continued)

BASES

APPLICABLE
SAFETY ANALYSES
(continued)

primary containment (Ref.2), to limit doses at the site boundary to within limits. The primary containment performs no active function in response to this event; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage rates assumed in safety analyses.

The FHA inside the primary containment is assumed to occur only after ≥ 80 hours since the reactor was last critical. The fission product release is, in turn, based on an assumed leakage rate from vent and drain valves with a combined flow rate of 70.2 cfm (based on an assumed 0.367 inch water gauge differential pressure). This assumed pressure reflects the fact that the FHA does not produce elevated containment pressures as is the case for the DBA LOCA. However, as an added conservatism, the analysis assumes a non-mechanistic additional leakage of 0.26% of the containment volume per day.

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Primary containment OPERABILITY is maintained by providing a contained volume to limit fission product escape following a FHA or other unanticipated reactivity or water level excursion. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Since no credit is assumed for automatic isolation valve closure, and any leakage which would occur prior to valve closure is similarly not accounted for, all penetrations which could communicate gaseous fission products to the environment must remain closed.

However, a limited number of primary containment penetration vent and drain valves may remain opened, and the primary containment considered OPERABLE provided the calculated leakage flow rate through the open vent and drain valves is less ≤ 70.2 cfm.

Leakage rates specified for the primary containment and air locks, addressed in LCO 3.6.1.1 and LCO 3.6.1.2 are not directly applicable during the shutdown conditions addressed in this LCO.

(continued)

BASES (continued)

APPLICABILITY

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining an OPERABLE primary containment in MODE 4 or 5 to ensure a control volume, is only required during situations for which significant releases of radioactive material can be postulated; such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the primary containment.

Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1.

ACTIONS

A.1, A.2, and A.3

In the event that primary containment is inoperable, action is required to immediately suspend activities that represent a potential for releasing radioactive material, thus placing the unit in a Condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Action must continue until OPDRVs are suspended.

SURVEILLANCE
REQUIREMENTS

SR 3.6.1.10.1

This SR verifies that each primary containment penetration that could communicate gaseous fission products to the environment during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive gases outside of the primary containment boundary is within design limits. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, or equivalent. This SR does not require any testing or valve manipulation.

(continued)

BASES

ACTIONS
(continued)

C.1

If any Required Action and required Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR requires verification that the minimum heater sheath temperature increases to $\geq 1215^{\circ}\text{F}$ in ≤ 5 hours and that it is maintained > 1150 and $< 1450^{\circ}\text{F}$ for ≥ 4 hours to check the capability of the recombiner to properly function.

Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.2

This SR ensures that there are no physical problems (i.e., loose wiring or structural connections, deposits of foreign material, etc.) that could affect primary containment hydrogen recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failures involve loss of power, blockage of the internal flow path, missile impact, etc. A visual inspection is sufficient to determine abnormal conditions that could cause such failures.

Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

ACTIONS
(continued)

B.1 and B.2

With two primary containment/drywell hydrogen mixing subsystems inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by one division of the hydrogen igniters. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two primary containment/drywell hydrogen mixing subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two primary containment/drywell hydrogen mixing subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.3.3.1

Operating each primary containment/drywell hydrogen mixing subsystem from the control room for ≥ 15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan failure, or excessive vibration can be detected for corrective action. The 92 day Frequency is consistent with Inservice Testing Program Frequencies,

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment—Operating

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System, Fuel Building Ventilation System, and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment consists of the shield building, auxiliary building, and fuel building, and completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump/motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Dampers (SCIDs)," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," LCO 3.6.4.4, "Shield Building Annulus Mixing System," and LCO 3.6.4.5, "Fuel Building."

The isolation devices for the penetrations in the secondary containment boundary are a part of the secondary containment barrier. To maintain this barrier:

- a. All Auxiliary Building penetrations, Fuel Building penetrations and Shield Building annulus penetrations required to be closed during accident conditions are either:

(continued)

BASES

LCO
(continued)

auxiliary building, or fuel building, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during movement of irradiated fuel assemblies in the fuel building. The fuel building OPERABILITY during irradiated fuel handling is addressed in LCO 3.6.4.7, "Fuel Building Ventilation Systems—Fuel Handling."

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If the secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the shield building annulus, auxiliary building, and fuel building boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches are closed/installed and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. In this application the term "sealed" has no connotation of leak tightness, rather inadvertent opening is prevented. Maintaining secondary containment OPERABILITY requires verifying each door in the access opening is closed, except when the access opening is being used for entry and exit. The 31 day Frequency for these SRs has been shown to be adequate based on operating experience, and is considered adequate in view of the other controls on secondary containment access openings.

SR 3.6.4.1.4 and SR 3.6.4.1.6

The SGT System exhausts the shield building annulus and auxiliary building atmosphere to the environment through

(continued)

BASES

BACKGROUND (continued)

If the SGT System filter trains are not treating the annulus atmosphere or the exhaust air of the shielded compartments in the auxiliary building, the containment and drywell purge can be manually diverted through both SGT System filter trains. By utilizing both SGTs filter trains, a maximum of 25,000 cfm of containment/drywell purge air can be processed by the filter trains.

The SGT System is designed to maintain a negative pressure of at least 0.50 in W.G. in the annulus during post-LOCA operation. With the annulus at a negative pressure, any potential leakage is directed inward (away from the shield building). Therefore, if a primary containment DBA occurs, airborne radioactivity which exfiltrates the steel primary containment is collected and passed through a filter train of the SGT System before being released.

The SGT System is also designed to maintain a negative pressure of at least 0.25 in W.G. in the Auxiliary Building.

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream. The prefilter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter is provided to collect any carbon fines exhausted from the charcoal adsorber (Ref. 2).

APPLICABLE SAFETY ANALYSES

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident (Ref. 3). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.

The SGT System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two operable subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS
(continued)

SR 3.6.5.1.3

The analyses in Reference 1 are based on a maximum drywell bypass leakage. This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable A/\sqrt{k} design value of 1.0 ft². As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be $\leq 10\%$ of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design A/\sqrt{k} . At the design A/\sqrt{k} the containment temperature and pressurization response are bounded by the assumptions of the safety analysis. This surveillance is performed at least once every 10 years on a performance based frequency. The frequency is consistent with the difficulty of performing the test, risk of high radiation exposure, and the remote possibility that sufficient component failures will occur such that the drywell bypass leakage limit will be exceeded. If during the performance of this required Surveillance the drywell bypass leakage rate is greater than the drywell bypass leakage limit, the Surveillance Frequency is increased to every 48 months. If during the performance of the subsequent consecutive Surveillance the drywell bypass leakage rate is less than or equal to the drywell bypass leakage limit, the 10 year Frequency may be resumed. If during the performance of two consecutive Surveillances the drywell bypass leakage is greater than the drywell bypass leakage limit, the Surveillance Frequency is increased to at least once every 24 months. The 24 month Frequency is maintained until during the performance of two consecutive Surveillances the drywell bypass leakage rate is less than or equal to the drywell bypass leakage limit, at which time the 10 year Frequency may be resumed. For two Surveillances to be considered consecutive, the Surveillances must be performed at least 12 months apart. Since the frequency is performance based, the Frequency was concluded to be acceptable from a reliability standpoint

SR 3.6.5.1.4

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.1.4 (continued)

performing its intended function. This SR ensures that drywell structural integrity is maintained. The Frequency was chosen so that the interior and exterior surfaces of the drywell can be inspected in conjunction with the inspections of the primary containment required by 10 CFR 50, Appendix J (Ref. 2). Due to the passive nature of the drywell structure, the specified Frequency is sufficient to identify component degradation that may affect drywell structural integrity.

SR 3.6.5.1.5

This SR requires a test be performed to verify seal leakage of the drywell air lock doors at 3.0 psid. An administrative seal leakage rate limit has been established in plant procedures to ensure the integrity of the seals. The Surveillance is only required to be performed once within 72 hours after each closing. The Frequency of 72 hours is based on operating experience.

SR 3.6.1.6

This SR requires a test to be performed to verify air lock leakage of the drywell air lock at pressures ≥ 3 psid. Prior to the performance of this test, the air lock is pressurized to ≥ 19.2 psid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for violating the drywell boundary. Operating experience has shown these components usually pass the Surveillance and requires the SR to be performed once each refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Chapter 6 and Chapter 15.
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.2 Drywell Air Lock

BASES

BACKGROUND

The drywell air lock forms part of the drywell boundary and provides a means for personnel access during MODES 2 and 3 during low power phase of unit startup. For this purpose, one double door drywell air lock has been provided, which maintains drywell isolation during personnel entry and exit from the drywell. Under the normal unit operation, the drywell air lock is kept sealed. The air pressure in the seals is maintained > 60 psig by the seal air flask and pneumatic system, which is maintained at a pressure ≥ 75 psig.

The drywell air lock is designed to the same standards as the drywell boundary. Thus, the drywell air lock must withstand the pressure and temperature transients associated with the rupture of any primary system line inside the drywell and also the rapid reversal in pressure when the steam in the drywell is condensed by the Emergency Core Cooling System flow following loss of coolant accident flooding of the reactor pressure vessel (RPV). It is also designed to withstand the high temperature associated with the break of a small steam line in the drywell that does not result in rapid depressurization of the RPV.

The air lock is nominally a right circular cylinder, 10 ft in diameter, with doors at each end that are interlocked to prevent simultaneous opening. During periods when the drywell is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent drywell entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA).

The air lock is provided with limit switches on both doors that provide control room indication of door position.

The drywell air lock forms part of the drywell pressure boundary. Not maintaining air lock OPERABILITY may result in degradation of the pressure suppression capability, which is assumed to be functional in the unit safety analyses.

(continued)

BASES

APPLICABLE
SAFETY ANALYSES

Analytical methods and assumptions involving the drywell are presented in Reference 2. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Since the drywell air lock is part of the drywell pressure boundary, its design and maintenance are essential to support drywell OPERABILITY, which assures that the safety analyses are met.

The drywell air lock satisfies Criterion 3 of the NRC Policy Statement.

LCO

The drywell air lock forms part of the drywell pressure boundary. The air lock safety function assures that steam resulting from a DBA is directed to the suppression pool. Thus, the air lock's structural integrity is essential to the successful mitigation of such an event.

The air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of the drywell does not exist when the drywell is required to be OPERABLE. Air lock leakage is excluded from this Specification. The air lock leakage rate is part of the drywell leakage rate and is controlled as part of OPERABILITY of the drywell in LCO 3.6.5.1, "Drywell."

Closure of a single door in the air lock is necessary to support drywell OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the drywell air lock is not required to be OPERABLE in MODES 4 and 5.

ACTIONS The ACTIONS are modified by Note 1 which that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is inoperable, however, then there is a short time during which the drywell boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the drywell boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the drywell during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

A.1, A.2, and A.3

With one drywell air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1). This ensures that a leak tight drywell barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

Required Action A.3 verifies that the air lock has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable drywell boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls that ensure

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

that the OPERABLE air lock door remains closed.

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. The exception of the Note does not affect tracking the Completion Times from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. Drywell entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions as well as other activities on equipment inside the drywell that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the drywell was entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and assuring the OPERABLE door is relocked after completion of the drywell entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the drywell during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With the drywell air lock interlock mechanism inoperable, the Required Actions and associated Completion Times consistent with Condition A are applicable.

The Required Actions are modified by two Notes. Note 1 ensures only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. Note 2 allows entry and exit into the

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

drywell under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time.

C.1 and C.2

With the air lock inoperable for reasons other than those described in Condition A or B, required Action C.1 requires that one door in the drywell air lock must be verified to be closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.5.1, which requires that the drywell be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status, considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable drywell air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.2.1

DELETED

SR 3.6.5.2.2

Every 7 days the drywell air lock seal air flask pressure is verified to be ≥ 75 psig to ensure that the seal system

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.2.2 (continued)

remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The 7 day Frequency has been shown to be acceptable, based on operating experience, and is considered adequate in view of the other indications to the plant operations personnel that the seal air flask pressure is low.

SR 3.6.5.2.3

The air lock door interlock is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the air lock are designed to withstand the maximum expected post accident drywell pressure, closure of either door will support drywell OPERABILITY. Thus, the door interlock feature supports drywell OPERABILITY while the air lock is being used for personnel transit in and out of the drywell. Periodic testing and preventive maintenance of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the nature of this interlock, and given that the interlock mechanism is only challenged when a drywell air lock door is opened, this test is only required to be performed once every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the reduced reactivity conditions that apply during a plant outage and the potential for violating the drywell boundary. Operating experience has shown these components usually pass the Surveillance, and the Frequency is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The Surveillance is modified by a Note requiring the Surveillance to be performed only upon entry into the drywell.

SR 3.6.5.2.4

DELETED

SR 3.6.5.2.5

This SR ensures that the drywell air lock seal pneumatic

(continued)

BASES (continued)

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.2.5 (continued)

system pressure does not decay at an unacceptable rate. The air lock seal will support drywell OPERABILITY down to a pneumatic pressure of 75 psig. Since the air lock seal air flask pressure is verified in SR 3.6.5.2.2 to be ≥ 75 psig, a decay rate ≤ 0.67 psig over 24 hours is acceptable. The 24 hour interval is based on engineering judgment, considering that there is no postulated DBA where the drywell is still pressurized 24 hours after the event. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage when the air lock OPERABILITY is not required. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix J.
 2. USAR, Chapters 6 and 15.
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BASES

BACKGROUND
(continued)

The drywell purge isolation valves fail closed on loss of instrument air or power. The drywell purge isolation valves are fast closing valves (approximately 4 seconds).

APPLICABLE
SAFETY ANALYSES

This LCO is intended to ensure that releases from the core do not bypass the suppression pool so that the pressure suppression capability of the drywell is maintained. Therefore, as part of the drywell boundary, drywell isolation valve OPERABILITY minimizes drywell bypass leakage. Therefore, the safety analysis of any event requiring isolation of the drywell is applicable to this LCO.

The limiting DBA resulting in a release of steam, water, or radioactive material within the drywell is a LOCA. In the analysis for this accident, it is assumed that drywell isolation valves either are closed or function to close within the required isolation time following event initiation.

The drywell isolation valves and drywell purge isolation valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

The drywell isolation valve safety function is to form a part of the drywell boundary.

The power operated drywell isolation valves are required to have isolation times within limits. Power operated automatic drywell isolation valves are also required to actuate on an automatic isolation signal. Additionally, drywell purge valves are required to be closed.

Drywell isolation valve leakage is excluded from this Specification. The drywell isolation valve leakage rates are part of the drywell leakage rate and are controlled as part of OPERABILITY of the drywell in LCO 3.6.5.1, "Drywell."

The normally closed isolation valves or blind flanges are considered OPERABLE when, as applicable, manual valves are closed or opened in accordance with applicable administrative controls, automatic valves are de-activated and secured in their closed position, check valves with flow through the valve secured, or blind flanges are in place. The valves covered by this LCO are included (with their

(continued)

BASES (continued)

LCO (continued)	associated stroke time, if applicable, for automatic valves) in Reference 2.
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APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the drywell isolation valves are not required to be OPERABLE in MODES 4 and 5.
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ACTIONS	<p>The ACTIONS are modified by four Notes. The first Note allows penetration flow paths, except for the 24 inch purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated when a need for drywell isolation is indicated.</p>
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The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable drywell isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable drywell isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The third Note requires the OPERABILITY of affected systems to be evaluated when a drywell isolation valve is inoperable. This ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable drywell isolation valve.

A.1 and A.2

With one or more penetration flow paths with one drywell isolation valve inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. In this condition, the remaining OPERABLE drywell isolation valve is adequate to perform the isolation function. However, the overall reliability is reduced because a single failure in the OPERABLE drywell isolation valve could result in a loss of drywell isolation. The 8 hour Completion Time is acceptable due to the low probability of the inoperable valve resulting in excessive drywell leakage and the low probability of the limiting event for drywell leakage occurring during this short time frame. In addition, the Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting drywell OPERABILITY during MODES 1, 2, and 3.

For affected penetration flow paths that have been isolated in accordance with Required Action A.1, the affected penetrations must be verified to be isolated on a periodic basis. This is necessary to ensure that drywell penetrations that are required to be isolated following an accident, and are no longer capable of being automatically isolated, will be isolated should an event occur. This Required Action does not require any testing or device manipulation; rather, it involves verification that those devices outside drywell and capable of potentially being mispositioned are in the correct position. Since these devices are inside primary containment, the time period specified as "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls that will ensure that misalignment is an unlikely possibility. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)."

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

(continued)

BASES

ACTIONS
(continued)

B.1

With one or more penetration flow paths with two drywell isolation valves inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. The 4 hour Completion Time is acceptable due to the low probability of the inoperable valves resulting in excessive drywell leakage and the low probability of the limiting event for drywell leakage occurring during this short time frame. The Completion Time is reasonable, considering the time required to isolate the penetration, and the probability of a DBA, which requires the drywell isolation valves to close, occurring during this short time is very low.

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE
REQUIREMENTS

SR 3.6.5.3.1

Each 24 inch drywell purge isolation valve is required to be verified sealed closed at 31 day intervals. This Surveillance is required since the drywell purge isolation valves are not qualified to close under accident conditions. This SR is designed to ensure that a gross breach of drywell is not caused by an inadvertent or spurious drywell purge isolation valve opening. Detailed analysis of these 24 inch drywell purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to support drywell OPERABILITY. Therefore, these valves are required to be in sealed closed position during MODES 1, 2, and 3. These 24 inch drywell purge valves that are sealed closed must have motive power to the valve operator removed. This

(continued)

BASES (continued)

APPLICABILITY In MODES 1, 2, and 3, the SSW System and UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the SSW System and UHS and required to be OPERABLE in these MODES.

 In MODES 4 and 5, the OPERABILITY requirements of the SSW System and UHS are determined by the systems they support.

ACTIONS

A.1

If one UHS cooling tower fan cell in one division is inoperable, it must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE fan cells are adequate to perform the heat removal function. The 30 day Completion Time is reasonable, based on the low probability of an accident occurring during the 30 days that one cooling tower fan cell is inoperable, the number of available fan cells, and the time required to complete the Required Action.

B.1

If one UHS cooling tower fan cell in each division is inoperable, at least one cooling tower fan cell in either division must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE fan cells are adequate to perform the heat removal function. The 7 day Completion Time is reasonable, based on the low probability of an accident occurring during the 7 days that one cooling tower fan cell in each division is inoperable, the number of available fan cells in each division, and the time required to complete the Required Action.

C.1

If both UHS cooling tower fan cells in one division are inoperable (this is equivalent to the loss of function of one SSW subsystem), at least one cooling tower fan cell must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE fan cells are adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE fan cell division could result in loss of

(continued)

BASES

ACTIONS

C.1 (continued)

function. The 72 hour Completion Time for restoring the SSW subsystem to OPERABLE status was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

D.1

If the UHS basin is inoperable (i.e., the UHS water volume or temperature is not within the limit), action must be taken to restore the inoperable UHS to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable considering the time required to restore the required UHS parameter, the margin contained in the available heat removal capacity, and the low probability of a DBA occurring during this period.

E.1

If one SSW pump in one SSW subsystem is inoperable, it must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE SSW pumps are adequate to perform the heat removal function. The 30 day Completion Time is reasonable, based on the low probability of an accident occurring during the 30 days that one SSW pump is inoperable, the number of available SSW pumps, and the time required to complete the Required Action.

F.1

If one SSW pump in both SSW subsystems is inoperable, at least one SSW pump in either subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE SSW pumps are adequate to perform the heat removal function. The 7 day Completion Time is reasonable, based on the low probability of an accident occurring during the 7 days that one SSW pump in each subsystem is inoperable, the number of available SSW pumps in each subsystem, and the time required to complete the Required Action.

(continued)

BASES

SURVEILLANCE
REQUIREMENTS

SR 3.7.1.1 (continued)

inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

Verification of the UHS arithmetical average water temperature ensures that the heat removal capability of the SSW System is within the assumptions of the DBA analysis. The average shall include at least 4 OPERABLE sensors of which at least half shall be located above elevation 94'-0". The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.3

Operating each cooling tower fan cell for ≥ 15 minutes ensures that all fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration can be detected for corrective action. The 31 day Frequency is based on operating experience, the known reliability of the fan units, the redundancy available, and the low probability of significant degradation of the cooling tower fans occurring between Surveillances.

SR 3.7.1.4

Verifying the correct alignment for each required manual, power operated, and automatic valve in each SSW subsystem flow path provides assurance that the proper flow paths will exist for SSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position within the required time. This SR does not require any testing or valve manipulation; rather, it involves verification that

(continued)

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SR 3.7.1.4 (continued)

those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

Isolation of the SSW subsystem to components or systems does not necessarily affect the OPERABILITY of the SSW System. As such, when all SSW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the SSW subsystem needs to be evaluated to determine if it is still OPERABLE.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.1.5

This SR verifies that the automatic isolation valves of the SSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the SSW pump and cooling tower fans in each subsystem. Any series of sequential or overlapping steps which demonstrate the required function may be used to satisfy this requirement.

Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.
3. USAR, Table 9.2-15.
4. USAR, Section 6.2.1.

(continued)

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ACTIONS
(continued)

E.1, E.2, and E.3

During movement of irradiated fuel assemblies in the primary or secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two CRFA subsystems inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the primary and secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

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SR 3.7.2.1

This SR verifies that a subsystem in a standby mode starts on demand from the control room and continues to operate with flow through the HEPA filters and charcoal adsorbers. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each subsystem once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated for ≥ 10 continuous hours with the heaters energized to demonstrate the function of the system. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two subsystem redundancy available.

(continued)

BASES (continued)

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SR 3.7.4.1

This SR requires an isotopic analysis of an offgas sample if the measured release rate of radioactivity increases significantly (by $\geq 50\%$ after correcting for expected increases due to changes in THERMAL POWER), within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The noble gases to be sampled are Xe-133, Xe-133m, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88.

SR 3.7.4.2

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-133m, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. USAR, Section 15.7.1.
 2. NUREG-0800.
 3. 10 CFR 100.
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SR 3.8.1.7 (continued)

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

- 1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and
- 2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.8

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for DG 1A is the 917.5 kW low pressure core spray pump; for DG 1B, the 462.2 kW residual heat removal (RHR) pump; and for DG 1C the 1995 kW HPCS pump. The Standby Service Water (SSW) pump values are not used as the largest load since the SSW supplies cooling to the associated DG. If this load were to trip, it would result in the loss of the DG. As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip

(continued)

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ACTIONS

C.1 and C.2 (continued)

conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

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SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. 8).

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. Only those terminals and connectors which have visible corrosion must be measured for connection resistance.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

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SURVEILLANCE
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SR 3.8.4.6 (continued)

the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied. Momentary transients that are not attributable to charger performance do not invalidate this test.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the once per 60 months performance of SR 3.8.4.8 in lieu of SR 3.8.4.7. This substitution is acceptable because SR 3.8.4.8 represents a more severe test of battery capacity than SR 3.8.4.7. The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance. Examples of unplanned events may include:

- 1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

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(continued)

SR 3.8.6.3

This Surveillance verification that the average temperature of representative (at least one out of six connected) cells is $\geq 60^{\circ}\text{F}$ is consistent with a recommendation of IEEE-450 (Ref. 3), which states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer's recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose corrected electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer's recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra 1/4 inch allowance above the high water level indication for operating margin to account for temperature and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided

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Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote c to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 31 days following a battery recharge. Within 31 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 31 days.

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15.
3. IEEE Standard 450, 1987.

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availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant (Ref. 4). This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

- a. An assumed loss of all offsite or onsite AC electrical power; and
- b. A worst case single failure.

The AC, DC, and AC vital bus electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required AC, DC, and AC vital bus power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The required AC, DC, and AC vital bus electrical power primary distribution subsystems are required to be OPERABLE.

Maintaining the required AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the AC distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

(continued)

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	NOMINAL VOLTAGE	DIVISION I*	DIVISION II*	DIVISION III*
AC Electric Power Distribution System	4160 V	1ENS*SWG1A**	1ENS*SWG1B**	1E22*S004**
	480 V LDCs	1EJS*LDC1A** 1EJS*LDC2A**	1EJS*LDC1B** 1EJS*LDC2B**	---
	480 V MCCs	1EHS*MCC2A 2C, 2E, 2G, 2J, 2L, 8A, 14A, 15A, 16A	1EHS*MCC2B 2D, 2F, 2H, 2K, 8B, 14B, 15B, 16B	1E22*S002**
	120 V Dist. Panels	1SCV*PNL2A1 2A2, 2C1, 2E1, 2G1, 2J1, 2L1, 8A1, 14A1, 15A1, 16A1	1SCV*PNL2B1 2B2, 2D1, 2F1, 2H1, 2K1, 8B1, 14B1, 15B1, 16B1	1E22*S002 PNL
AC Vital Bus Electric Power Distribution System	120 VAC	1VBS*PNL01A**	1VBS*PNL01B**	---
DC Electric Power Distribution System	125 V	1ENB*SWG01A**	1ENB*SWG01B**	---
	Dist. Panels	1ENB*PNL02A 03A, 04A 1ENB*MCC1	1ENB*PNL02B 03B	1E22*S001 PNL**

* Each division of the AC and DC electrical power distribution systems is a subsystem.

** Voltage verification required.