LIMITING CONDITIONS FOR OPERATION

SURVEILLANCE REQUIREMENTS

4.7.A. Primary Containment

4.7.A.2.g (Cont'd)

The total path leakage from all penetrations and isolation valves shall not exceed 60 percent of L_a per 24 hours. Leakage from containment isolation valves that terminate below suppression pool water level may be excluded from the total leakage provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig. Leakage from containment isolation valves that are in closed-loop, seismic class I lines that will be water sealed during a DBA will be measured but will be excluded when computing the total leakage.

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
1	Main steamline isolation valves (FCV-1-14, -26, -37, & -51; 1-15 -27,- 38, & -52)	4	4	3 < T < 5	0	GC	7
1	Main steamline drain isolation valves (FCV-1-55 & 1-56)	1	1	15	0	GC	1
1 *	Reactor Water sample line isolation valves (FCV-43-13,-14)	1	1	5	C	SC	1
2	RHRS shutdown cooling supply isolation valves (FCV-74-48 & -47)	1	1	40	C	SC	1
2	RHRS - LPCI to reactor (FCV-74-53, -67)		2	30	C	SC	3
2	Reactor vessel head spray isolation valves (FCV-74-77, -78)	1	1	30	C	SC	3
2	RHRS flush and drain vent to suppression chamber (FCV-74-102, -103, -119, & -120)		4	20	C	SC	1
2	Suppression Chamber Drain (FCV 75-57, -58)		2	15	0**	GC	2
2	Drywell equipment drain discharge isolation valves (FCV-77-15A, & -15B)		2	15	0	GC	1
2	Drywell floor drain discharge isolation valves (FCV-77-2A & -2B)		2	15	0	GC	1

*These valves isolate only on reactor vessel low low water level (378") and main steam line high radiation of Group 1 isolations.

**These valves are normally open when the pressure suppression head tank is aligned to serve the RHR and CS discharge piping and closed when the condensate head tank is used to serve the RHR and CS discharge piping. (See Specification 3.5.H)

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
3	Reactor water cleanup system supply isolation valves (FCV-69-1, & -2)	1	1	30	0	GC	1
3	Reactor water cleanup system return isolation valves (FCV-69-12)		1	60	0	GC	1
4	HPCI Warm-up FCV 73-81		1	10	C	SC	1
4	HPCIS steamline isolation valves (FCV-73-2 & -3)	1	1	20	0	GC	1
5	RCICS steamline isolation valves (FCV-71-2 & -3)	1	1	15	0	GC	1
6	Drywell nitrogen make-up inlet isolation valves (FCV-76-18)		1	5	C	SC	1
6	Suppression chamber nitrogen make-up inlet isolation valves (FCV-76-19)		1	5	C	SC	1
6	Drywell Main Exhaust isolation valves (FCV-64-29 and -30)		2	2.5	C	SC	1
6	Suppression chamber main exhaust isolation valves (FCV-64-32 and -33)		2	2.5	C	SC	1
6	Drywell/Suppression Chamber purge inlet (FCV-64-17)		1	2.5	C	SC	1
6	Drywell purge inlet (FCV-64-18)		1	2.5	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves		Maximum Operating Time (Sec.)	Normal Position	Action on Initiating Signal	Notes
		Inboard	Outboard				
6	Torus Hydrogen Sample Line Valves Analyzer A (FSV-76-55, -56)		2	NA	O/C	GC/SC	6, 1
6	Torus Oxygen Sample Line Valves Analyzer A (FSV-76-53, -54)		2	NA	O/C	GC/SC	6, 1
6	Drywell Hydrogen Sample Line Valves Analyzer A (FSV-76-49, -50)		2	NA	O/C	GC/SC	6, 1
6	Drywell Oxygen Sample Line Valves Analyzer A (FSV-76-51, -52)		2	NA	O/C	GC/SC	6, 1
6	Sample Return Valves - Analyzer A (FSV-76-57, -58)		2	NA	O	GC	1
6	Torus Hydrogen Sample Line Valves Analyzer B (FSV-76-65, -66)		2	NA	O/C	GC/SC	6, 1
6	Torus Oxygen Sample Line Valves-Analyzer B (FSV-76-63, -64)		2	NA	O/C	GC/SC	6, 1
6	Drywell Hydrogen Sample Line Valves-Analyzer B (FSV-76-59, -60)		2	NA	O/C	GC/SC	6, 1
6	Drywell Oxygen Sample Line Valves-Analyzer B (FSV-76-61, -62)		2	NA	O/C	GC/SC	6, 1
6	Sample Return Valves-Analyzer B (FSV-76-67, -68)		2	NA	O	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
6	Suppression Chamber purge inlet (FCV-64-19)		1	2.5	C	SC	1
6	Drywell/Suppression Chamber nitrogen make-up inlet (FCV-76-17)		1	5	C	SC	1
6	Drywell Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-31)		1	5	0	GC	1
6	Suppression Chamber Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-34)		1	5	0	GC	1
6	Drywell/Suppression Chamber Nitrogen Purge Inlet (FCV-76-24)		1	5	C	SC	1
6	System Suction Isolation Valves to Air Compressors "A" and "B" (FCV-32-62, -63)		2	15	0	GC	1
8	TIP Guide Tubes (5) (FCV-94-501, 502, 503, 504, 505)		1 per guide tube	NA	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
	Standby liquid control system check valves (CV 63-526 & -525)	1	1	NA	C	Process	1
	Feedwater check valves (CV-3-558, -572, -554 & -568)	2	2	NA	0	Process	1
	Control rod hydraulic return check valve (CV-85-576)		1	NA	0	Process	1
	RHRS – LPCI to reactor check valves (CV-74-54 & -68)	2		NA	C	Process	3
	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-19)		1	NA	C	SC	1
	Core Spray Discharge to Reactor Check Valves (FCV-75-26, -54)	2		NA	C	Process	3
6	Drywell P air compressor suction valve (FCV-64-139)		1	10	C	SC	1
6	Drywell P air compressor discharge valve (FCV-64-140)		1	10	C	SC	1
6	Drywell CAM suction valves (FCV-90-254A and -254B)		2	10	0	GC	1
6	Drywell CAM discharge valves (FCV-90-257A and -257B)		2	10	0	GC	1
6	Drywell CAM suction valve (FCV-90-255)		1	10	0	GC	1
6	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-20)		1	10	C	SC	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Core Spray Discharge to reactor isolation valves (75-25,75-53)		2	N/A	C	N/A	3
N/A	PSC return line check valves (12-738,12-741)		2	N/A	C	N/A	2
N/A	Suppression chamber sample RHR pumps A&C isolation valves (43-28A,43-28B)		2	N/A	C	N/A.	2
N/A	Suppression chamber sample RHR pumps B&D isolation valves (43-29A,43-29B)		2	N/A	C	N/A	2
N/A	PSC head tank tie-in to RHR check valves (74-803, 74-804, 74-792, 74-802)		4	N/A	0	Process	3
N/A	PSC head tank tie-in to CS check valves (75-606, 75-609, 75-607, 75-610)		4	N/A	0	Process	3
N/A	TIP nitrogen purge check valve (76-653)		1	N/A	C	Process	1
N/A	Drywell Control Air Inlet Header Check Valve (32-2516,32-2521)	1	1	N/A	0	Process	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	HPCI turbine exhaust drain check valves (73-24,73-609)		2	N/A	C	Process	2
N/A	RCIC turbine exhaust check (71-14,71-580)		2	N/A	C	Process	1
N/A	RCIC vacuum pump discharge check valves (71-32,71-592)		2	N/A	C	Process	2
N/A	RHR suppression chamber spray isolation valves (74-58, 74-72, 74-57, 74-71)		4	N/A	C	NA	3
N/A	RHR drywell spray isolation valves (74-61, 74-75, 74-60, 74-74)		4	N/A	C	Process	3
N/A	RHR shutdown cooling supply bypass check valves (74-661/662)	2		N/A	C	Process	1,5
N/A	Suppression chamber drain isolation valve (74-722)		1	N/A	C	NA	2,4
N/A	CAD admission check valves to DW (84-600,84-602)		2	N/A	C	Process	1
N/A	CAD admission check valves to suppression chamber (84-601,84-603)		2	N/A	C	Process	1
N/A	CAD admission isolation valves to DW (84-8A,84-8D)		2	N/A	C	NA	1
N/A	CAD admission isolation valves to Suppression Chamber (84-8B,84-8C)		2	N/A	C	NA	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Reactor Building closed cooling water drywell supply check valve (70-506)		1	N/A	O	Process	1
N/A	RCICS pump suction isolation valves (71-17,71-18)		2	N/A	C	SC	2
N/A	RCICS pump minimum flow bypass isolation valve (71-34)		1	N/A	C	SC	2
N/A	RCICS pump discharge check valve valves (71-40)		1	N/A	C	Process	1
N/A	RCICS pump minimum flow bypass check valve (71-547)		1	N/A	C	Process	2
4	HPCI pump suction isolation valves (73-26,73-27)		2	80 sec.	C	SC	2
N/A	HPCI pump minimum flow bypass isolation valve (73-30)		1	N/A	C	SC	2
N/A	HPCI pump discharge check valve (73-45)		1	N/A	C	Process	1
N/A	HPCI pump minimum flow bypass check valve (73-559)		1	N/A	C	Process	2
N/A	HPCI turbine exhaust check valves (73-23,73-603)		2	N/A	C	Process	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Demineralized water supply check valve (2-1192)			N/A	C	N/A	1
N/A	Demineralized water supply isolation valve (2-1383)			N/A	C	N/A	1,4
N/A	Service air supply isolation valves (33-1070)		1	N/A	C	N/A	1
N/A	Service air supply check valve (33-785)	1		N/A	C	N/A	1,4
N/A	Drywell control air inlet header check valves (32-2163,32-336)	1	1	N/A	0	Process	1
N/A	Suppression chamber vacuum relief (64-20,64-21)		2	N/A	0	N/A	1
N/A	Suppression chamber vacuum relief check valves (64-800, 64-801)		2	N/A	C	Process	1
N/A	Recirculation pump A seal injection check valves (68-508,68-550)	1	1	N/A	0	Process	1
N/A	Recirculation pump B seal injection check valves (68-523,68-555)	1	1	N/A	0	Process	1
N/A	Reactor water cleanup system discharge check valve (69-579)		1	N/A	0	Process	1
N/A	Reactor Building closed cooling water drywell return isolation valve (70-47)		1	N/A	0	GC	1

NOTES FOR TABLE 3.7.A

Key: 0 = Open
C = Closed
SC = Stays Closed
GC = Goes Closed

Note: Isolation groupings are as follows:

Group 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor Vessel Low Water Level (378")
2. Main Steamline High Radiation
3. Main Steamline High Flow
4. Main Steamline Space High Temperature
5. Main Steamline Low Pressure

Group 2: The valves in Group 2 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure

Group 3: The valves in Group 3 are actuated by any of the following conditions:

1. Reactor Low Water Level (538")
2. Reactor Water Cleanup System Space High Temperature
3. Reactor Water Cleanup System High Drain Temperature

Group 4: The valves in Group 4 are actuated by any of the following conditions:

1. HPCI Steamline Space High Temperature
2. HPCI Steamline High Flow
3. HPCI Steamline Low Pressure

Group 5: The valves in Group 5 are actuated by any of the following condition:

1. RCIC Steamline Space High Temperature
2. RCIC Steamline High Flow
3. RCIC Steamline Low Pressure

Group 6: The valves in Group 6 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure
3. Reactor Building Ventilation High Radiation

Group 7: (Deleted)

Group 8: The valves in Group 8 are automatically actuated by only the following conditions:

1. High Drywell Pressure

2. Reactor Vessel Low Water Level (538")

Note 1: Primary containment isolation valve(s) requiring LLRT at not less than 49.6 psig.

Note 2: Primary containment isolation valves(s) which may be LLRT with water and not included in the 60-percent L_a tabulation, provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54. 6 psig.

Note 3: Primary containment isolation valves that are in closed loop, seismic Class 1 lines that will be water sealed during a DBA. These valves will be tested but not included in the 60-percent L_a tabulation.

Note 4: Primary containment isolation valves that are manually operated.

Note 5: Primary containment valves 74-661/662 are considered as a single containment boundary and LLRT as such.

Note 6: Analyzers are such that one is sampling drywell hydrogen and oxygen (valves from drywell open, valves from torus close), while the other is sampling torus hydrogen (valves from torus open, valves from drywell close).

Note 7: Primary containment isolation valves requiring LLRT at not less than 25-psig.

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, ensure that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

During initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required, there will be no pressure on the system thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect to minimize the probability of an accident occurring.

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 49.6 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the requirements of Appendix J of 10 CFR Part 50 (type A, B, and C tests).

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat release during primary system blowdown from 1,035 psig. Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss of coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 62 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water levels given in the specification, containment pressure during the design basis accident is approximately 49 psig, which is below the maximum of 62 psig. The maximum water level indications of -1 inch corresponds to a downcomer submergence of three feet seven inches and a water volume of 127,800 cubic feet with or 128,700 cubic feet without the drywell-suppression chamber differential pressure control. The minimum water level indication of -6.25 inches with differential pressure control and -7.25 inches without differential pressure control corresponds to a downcomer submergence of approximately three feet and water volume of approximately 123,000 cubic feet.

Maintaining the water level between these levels will ensure that the torus water volume and downcomer submergence are within the aforementioned limits during normal plant operation. Alarms, adjusted for instrument error, will notify the operator when the limits of the torus water level are approached.

The maximum permissible bulk pool temperature is limited by the potential for stable and complete condensation of steam discharged from safety relief valves and adequate core spray pump net positive suction head. At reactor vessel pressures above approximately 555 psig, the bulk pool temperature shall not exceed 180°F. At pressures below approximately 240 psig, the bulk temperature may be as much as 184°F. At intermediate pressures, linear interpolation of the bulk temperature is permitted.

They also represent the bounding upper limits that are used in suppression pool temperature response analyses for safety relief valve discharge and loss-of-coolant accident (LOCA) cases. The actions required by Specification 3.7.c., -d. -e. and -f., assure the reactor can be depressurized in a timely manner to avoid exceeding the maximum bulk suppression pool water limits. Furthermore, the 184°F limit provides that adequate RHR and core spray pump NPSH will be available without dependency on containment overpressure.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for core standby cooling systems operability. Under full power operation conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a peak long term water temperature which is sufficient for complete condensation.

Limiting suppression pool temperature to 105°F during RCIC, HPCI, or relief valve operation when decay heat and stored energy is removed from the primary system by discharging reactor steam directly to the suppression chamber ensures adequate margin for controlled blowdown anytime during RCIC operation and ensures margin for complete condensation of steam from the design basis LOCA.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a relief valve inadvertently opens or sticks open. This action would include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling heat exchangers, (3) initiate reactor shutdown, and (4) if other relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

If a LOCA were to occur when the reactor water temperature is below approximately 330°F, the containment pressure will not exceed the 62 psig code permissible pressures even if no condensation were to occur. The maximum allowable pool temperature, whenever the reactor is above 212°F, shall be governed by this specification. Thus, specifying water volume-temperature requirements applicable for reactor-water temperature above 212°F provides additional margin above that available at 330°F.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed ("Torus Support System and Attached Piping Analysis for the Browns Ferry Nuclear Plant Units 1, 2, and 3," dated September 9, 1976 and supplemented October 12, 1976) which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure of 1.1 psid and a suppression chamber water level corresponding to a downcomer submergence range of 3.06 feet to 3.58 feet will assure the integrity of the suppression chamber when subjected to post-loss-of-coolant suppression pool hydrodynamic forces.

Inerting

The relativity small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (a percent or so) reaction of the zirconium and steam during a LOCA could lead to the liberation of hydrogen combined with an air atmosphere to result in a flammable concentration in the containment. If a sufficient amount of hydrogen is generated and oxygen is available in stoichiometric quantities the subsequent ignition of the hydrogen in rapid recombination rate could lead to failure of the containment to maintain a low leakage integrity. The <4 percent hydrogen concentration minimizes the possibility of hydrogen combustion following a LOCA.

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the LOCA upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration.

To ensure that the hydrogen concentration is maintained less than 4 percent following an accident, liquid nitrogen is maintained on-site for containment atmosphere dilution. About 2,260 gallons would be sufficient as a seven-day supply, and replenishment facilities can deliver liquid nitrogen to the site within one day; therefore, a requirement of 2,500 gallons is conservative. Following a LOCA the Containment Air Monitoring (CAM) System continuously monitors the hydrogen concentration of the containment volume. Two independent systems (a system consists of one hydrogen sensing circuit) are installed in the drywell and the torus. Each sensor and associated circuit is periodically checked by a calibration gas to verify operation. Failure of one system does not reduce the ability to monitor system atmosphere as a second independent and redundant system will still be operable.

In terms of separability, redundancy for a failure of the torus system is based upon at least one operable drywell system. The drywell hydrogen concentration can be used to limit the torus hydrogen concentration during post-LOCA conditions. Post-LOCA calculations show that the CAD system initiated within two hours at a flow rate of 100 scfm will limit the peak drywell and wetwell hydrogen concentration to 3.6-percent (at 4 hours) and 3.8-percent (at 32 hours), respectively. This is based upon purge initiation after 20 hours at a flow rate of 100 scfm to maintain containment pressure below 30 psig. Thus, peak torus hydrogen concentration can be controlled below 4.0 percent using either the direct torus hydrogen monitoring system or the drywell hydrogen monitoring system with appropriate conservatism ($\leq$ 3.8-percent), as a guide for CAD/Purge operations.

Vacuum Relief

The purpose of the vacuum relief valves is to equalize the pressure between the drywell and suppression chamber and reactor building so that the structural integrity of the containment is maintained. The vacuum relief system from the pressure suppression chamber to reactor building consists of two 100-percent vacuum relief breakers (two parallel sets of two valves in series). Operation of either system will maintain the pressure differential less than 2 psig; the external design pressure. One reactor building vacuum breaker may be out of service for repairs for a period of seven days. If repairs cannot be completed within seven days, the reactor coolant system is brought to a condition where vacuum relief is no longer required.

When a drywell-suppression chamber vacuum breaker valve is exercised through an opening-closing cycle the position indicating lights in the control room are designed to function as specified below:

Initial and Final Condition	Check - On Green - On Red - Off	(Fully Closed)
Opening Cycle	Check - Off Green - Off Red - On	(Cracked Open) (> 80° Open) (> 3° Open)
Closing Cycle	Check - On Green - On Red - Off	(Fully Closed) (< 80° Open) (< 3° Open)

The valve position indicating lights consist of one check light on the check light panel which confirms full closure, one green light next to the hand switch which confirms 80° of full opening and one red light next to the hand switch which confirms "near closure" (within 3° of full closure). Each light is on a separate switch. If the check light circuit is operable when the valve is exercised by its air operator there exists a confirmation that the valve will fully close. If the red light circuit is operable, there exists a confirmation that the valve will at least "nearly close" (within 3° of full closure). The green light circuit confirms the valve will fully open. If none of the lights change indication during the cycle, the air operator must

be inoperable or the valve disc is stuck. For this case, a check light on and red light off confirms the disc is in a nearly closed position even if one of the indications is in error. Although the valve may be inoperable for full closure, it does not constitute a safety threat.

If the red light circuit alone is inoperable, the valve shall still be considered fully operable. If the green and red or the green light circuit alone is inoperable the valve shall be considered inoperable for opening. If the check and green or check light circuit alone is inoperable, the valve shall be considered inoperable for full closure. If the red and check light circuits are inoperable the valve shall be considered inoperable and open greater than 3°. For a light circuit to be considered operable the light must go on and off in proper sequence during the opening-closing cycle. If none of the lights change indication during the cycle, the valve shall be considered inoperable and open unless the check light stays on and the red light stays off in which case the valve shall be considered inoperable for opening.

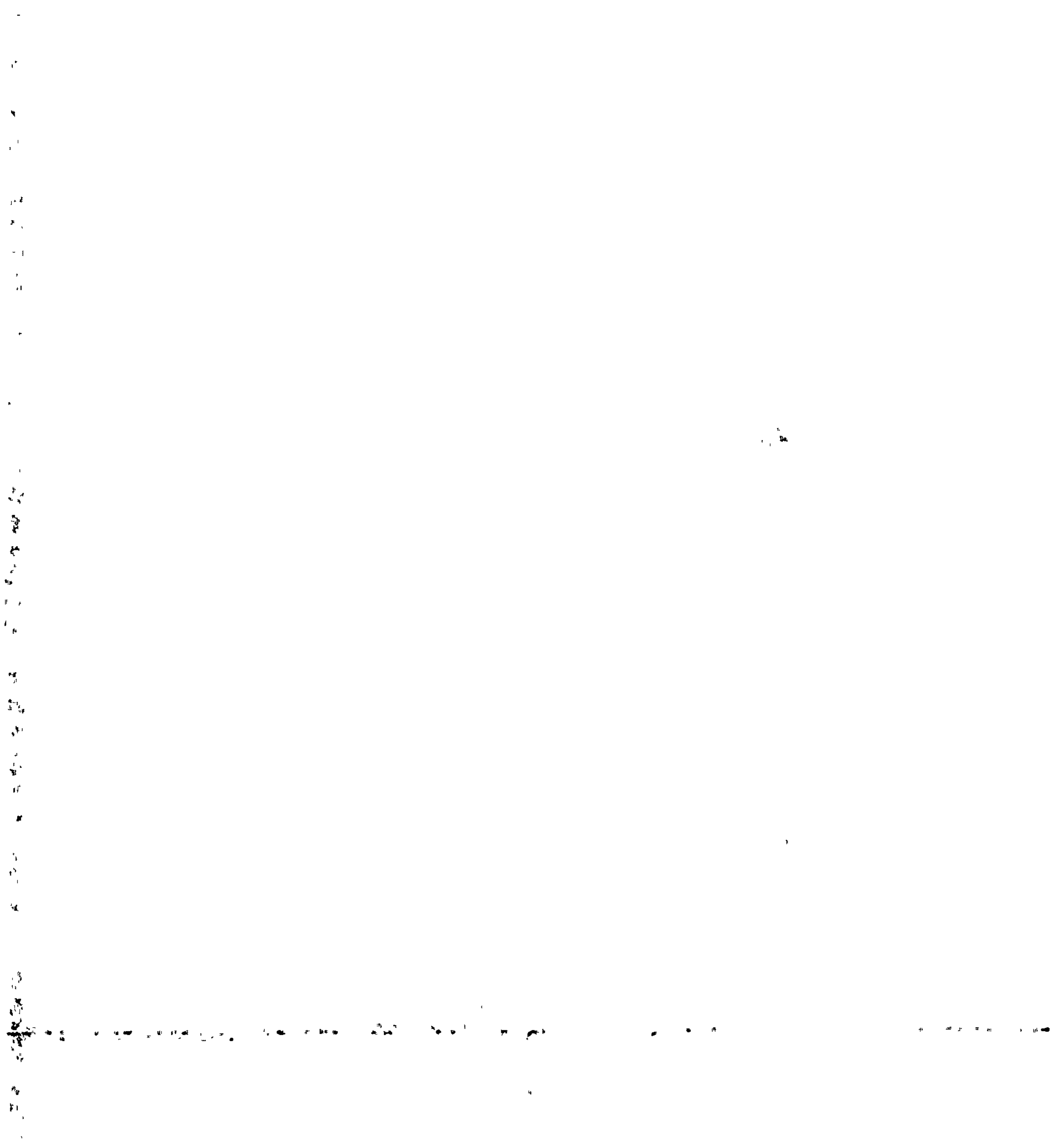
The 12 drywell vacuum breaker valves which connect the suppression chamber and drywell are sized on the basis of the Bodega pressure suppression system tests. Ten operable to open vacuum breaker valves (18-inch) selected on this test basis and confirmed by the green lights are adequate to limit the pressure differential between the suppression chamber and drywell during postaccident drywell cooling operations to a value which is within suppression system design values.

The containment design has been examined to determine that a leakage equivalent to one drywell vacuum breaker opened to no more than a nominal 3° as confirmed by the red light is acceptable.

On this basis an indefinite allowable repair time for an inoperable red light circuit on any valve or an inoperable check and green or check light circuit alone or a malfunction of the operator or disc (if nearly closed) on one valve, or an inoperable green and red or green light circuit alone on two valves is justified.

During each operating cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chamber. The drywell pressure will be increased by at least one psi with respect to the suppression chamber pressure and held constant. The two psig setpoint will not be exceeded. The subsequent suppression chamber pressure transient (if any) will be monitored with a sensitive pressure gauge. If the drywell pressure cannot be increased by one psi over the suppression chamber pressure it would be because a significant leakage path exists; in this event the leakage source will be identified and eliminated before power operation is resumed.

With a differential pressure of greater than one psig, the rate of change of the suppression chamber pressure must not exceed 0.25 inches of water per minute as measured over a 10-minute period, which corresponds to about 0.09 lb/sec of containment air. In the event the rate of change exceeds this value then the source of leakage will be identified and eliminated before power operation is resumed.



The water in the suppression chamber is used for cooling in the event of an accident; i.e., it is not used for normal operation; therefore, a daily check of the temperature and volume is adequate to assure that adequate heat removal capability is present.

The interior surfaces of the drywell and suppression chamber are coated as necessary to provide corrosion protection and to provide a more easily decontaminable surface. The surveillance inspection of the internal surfaces each operating cycle assures timely detection of corrosion. Dropping the torus water level to one foot below the normal operating level enables an inspection of the suppression chamber where problems would first begin to show.

The primary containment preoperational test pressures are based upon the calculated primary containment pressure response in the event of a LOCA. The peak drywell pressure would be about 49 psig which would rapidly reduce to less than 30 psig within 20 seconds following the pipe break. Following the pipe break, the suppression chamber pressure rises to 27 psig within 25 seconds, equalizes with drywell pressure, and decays with the drywell pressure decay.

The design pressure of the drywell and suppression chamber is 56 psig. The design leak rate is 0.5-percent per day at the pressure of 56 psig. As pointed out above, the pressure response of the drywell and suppression chamber following an accident would be the same after about 25 seconds. Based on the calculated containment pressure response discussed above, the primary containment preoperational test pressures were chosen. Also based on the primary containment pressure response and the fact that the drywell and suppression chamber function as a unit, the primary containment will be tested as a unit rather than the individual components separately.

The calculated radiological doses given in Section 14.9 of the FSAR were based on an assumed leakage rate of 0.635-percent at the maximum calculated pressure of 49.6 psig. The doses calculated by the NRC using this bases are 0.14 rem, whole body passing cloud gamma dose, and 15.0 rem, thyroid dose, which are respectively only 5×10^{-3} and 10^{-1} times the 10 CFR 100 reference doses. Increasing the assumed leakage rate at 49.6 psig to 2.0 percent as indicated in the specifications would increase these doses approximately a factor of three, still leaving a margin between the calculated dose and the 10 CFR 100 reference values.

Establishing the test limit of 2.0-percent/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly from the containment design value to take advantage of the design leak-tightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate by 0.75 thereby providing a 25-percent margin to allow for leakage deterioration which may occur during the period between leak rate tests.

The primary containment leak rate test frequency is based on maintaining adequate assurance that the leak rate remains within the specification. The leak rate test frequency is based on the NRC guide for developing leak rate testing and surveillance of reactor containment vessels. Allowing the test intervals to be extended up to 10 months permits some flexibility needed to have the tests coincide with scheduled or unscheduled shutdown periods.

The penetration and air purge piping leakage test frequency, along with the containment leak rate tests, is adequate to allow detection of leakage trends. Whenever a bolted double-gasketed penetration is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. It is expected that the majority of the leakage from valves, penetrations and seals would be into the reactor building. However, it is possible that leakage into other parts of the facility could occur. Such leakage paths that may affect significantly the consequences of accidents are to be minimized.

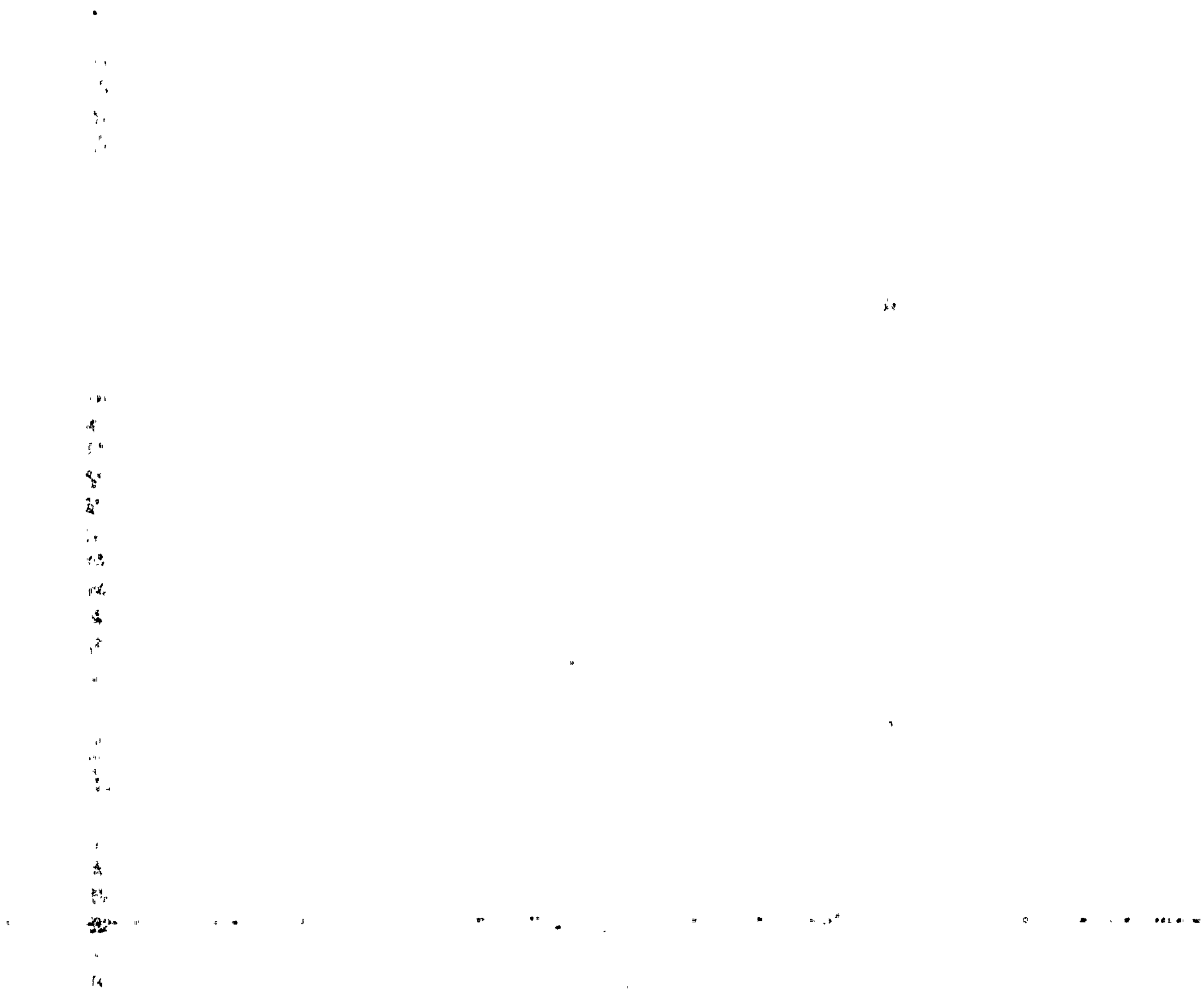
The primary containment is normally slightly pressurized during period of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, determining the oxygen concentration twice a week serves as an added assurance that the oxygen concentration will not exceed 4 percent.

3.7.B/3.7.C <u>Standby Gas Treatment System and Secondary Containment</u>

The secondary containment is designed to minimize any ground level release of radioactive materials which might result from a serious accident. The reactor building provides secondary containment during reactor operation, when the drywell is sealed and in service; the reactor building provides primary containment when the reactor is shutdown and the drywell is open, as during refueling. Because the secondary containment is an integral part of the complete containment system, secondary containment is required at all times that primary containment is required as well as during refueling.

The standby gas treatment system is designed to filter and exhaust the reactor building atmosphere to the stack during secondary containment isolation conditions. All three standby gas treatment system fans are designed to automatically start upon containment isolation and to maintain the reactor building pressure to the design negative pressure so that all leakage should be in-leakage.

High efficiency particulate air (HEPA) filters are installed before and after the charcoal absorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine absorbers. The charcoal absorbers are installed to reduce the potential release of radioiodine to the environment. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal absorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal absorbers are as specified, the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed. Operation of the fans significantly



different from the design flow will change the removal efficiency of the HEPA filters and charcoal absorbers.

Only two of the three standby gas treatment systems are needed to clean up the reactor building atmosphere upon containment isolation. If one system is found to be inoperable, there is no immediate threat to the containment system performance and reactor operation or refueling operation may continue while repairs are being made. If more than one train is inoperable, the plant is brought to a condition where the standby gas treatment system is not required.

4.7.B/4.7.C <u>Standby Gas Treatment System and Secondary Containment</u>

Initiating reactor building isolation and operation of the standby gas treatment system to maintain at least a 1/4 inch of water vacuum within the secondary containment provides an adequate test of the operation of the reactor building isolation valves, leak tightness of the reactor building and performance of the standby gas treatment system. Functionally testing the initiating sensors and associated trip logic demonstrates the capability for automatic actuation. Performing these tests prior to refueling will demonstrate secondary containment capability prior to the time the primary containment is opened for refueling. Periodic testing gives sufficient confidence of reactor building integrity and standby gas treatment system performance capability.

The test frequencies are adequate to detect equipment deterioration prior to significant defects, but the tests are not frequent enough to load the filters, thus reducing their reserve capacity too quickly. That the testing frequency is adequate to detect deterioration was demonstrated by the tests which showed no loss of filter efficiency after two years of operation in <u>the rugged</u> shipboard environment on the US Savannah (<u>ORNL 3726</u>). Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Heater capability, pressure drop and air distribution should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon refrigerant shall be performed in accordance with USAEC Report DP-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures <u>should</u> allow for the removal of <u>one adsorber tray</u>, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

All elements of the heater should be demonstrated to be functional and operable during the test of heater capacity. Operation of each filter train for a minimum of 10 hours each month will prevent moisture buildup in the filters and adsorber system. [illegible]

[illegible]
With doors closed and fan in operation, DOP aerosol shall be sprayed externally along the full linear periphery of each respective door to check the gasket seal. Any detection of DOP in the fan exhaust shall be considered an unacceptable test result and the gaskets repaired and test repeated.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign material, the same tests and sample analysis shall be performed as required for operational use. The determination of significant shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability and operability of filter cooling is necessary to assure system performance capability. If one standby gas treatment system is inoperable, the other systems must be tested daily. This substantiates the availability of the operable systems and thus reactor operation and refueling operation can continue for a limited period of time.

3.7.D/4.7.D <u>Primary Containment Isolation Valves</u>

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a LOCA.

<u>Group 1</u> - Process lines are isolated by reactor vessel low water level (378") in order to allow for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems. The valves in Group 1, except the reactor water sample line valves, are also closed when process instrumentation detects excessive main steam line flow, high radiation, low pressure, or main steam space high temperature. The reactor water sample line valves isolate only on reactor low water level at 378" or main steam line high radiation.

<u>Group 2</u> - Isolation valves are closed by reactor vessel low water level (538") or high drywell pressure. The Group 2 isolation signal also "isolates" the reactor building and starts the standby gas treatment system. It is not desirable to actuate the Group 2 isolation signal by a transient or spurious signal.

<u>Group 3</u> - Process lines are normally in use, and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from nonsafety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high drain temperature. Also, since the vessel could potentially be drained through the cleanup system, a low-level isolation is provided.

Groups 4 and 5 - Process lines are designed to remain operable and mitigate the consequences of an accident which results in the isolation of other process lines. The signals which initiate isolation of Groups 4 and 5 process lines are therefore indicative of a condition which would render them inoperable.

Group 6 - Lines are connected to the primary containment but not directly to the reactor vessel. These valves are isolated on reactor low water level (538"), high drywell pressure, or reactor building ventilation high radiation which would indicate a possible accident and necessitate primary containment isolation.

Group 7 - (Deleted)

Group 8 - Line (traveling in-core probe) is isolated on high drywell pressure or reactor low water level (538"). This is to assure that this line does not provide a leakage path when containment pressure or reactor water level indicates a possible accident condition.

The maximum closure time for the automatic isolation valves of the primary containment and reactor vessel isolation control system have been selected in consideration of the design intent to prevent core uncovering following pipe breaks outside the primary containment and the need to contain released fission products following pipe breaks inside the primary containment.

In satisfying this design intent, an additional margin has been included in specifying maximum closure times. This margin permits identification of degraded valve performance prior to exceeding the design closure times.

In order to assure that the doses that may result from a steam line break do not exceed the 10 CFR 100 guidelines, it is necessary that no fuel rod perforation resulting from the accident occur prior to closure of the main steam line isolation valves. Analyses indicate that fuel rod cladding perforations would be avoided for main steam valve closure times, including instrument delay, as long as 10.5 seconds.

These valves are highly reliable, have low service requirements and most are normally closed. The initiating sensors and associated trip logic are also checked to demonstrate the capability for automatic isolation. The test interval of once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate. More frequent testing for valve operability results in a greater assurance that the valve will be operable when needed.

The main steam line isolation valves are functionally tested on a more frequent interval to establish a high degree of reliability.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25-inch restricting orifice inside the primary containment and an excess flow check valve outside the primary containment.

3.7.E/4.7.E Control Room Emergency Ventilation

The control room emergency ventilation system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room emergency ventilation system is designed to automatically start upon control room isolation and to maintain the control room pressure to the design positive pressure so that all leakage should be out leakage.

High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radioiodine to the control room. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal adsorbers are as specified, the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR Part 50. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, there is no immediate threat to the control room and reactor operation or refueling operation may continue for a limited period of time while repairs are being made. If the system cannot be repaired within seven days, the reactor is shutdown and brought to Cold Shutdown within 24 hours or refueling operations are terminated.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

Operation of the system for 10 hours every month will demonstrate operability of the filters and adsorber system and remove excessive moisture built up on the adsorber.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability is necessary to assure system performance capability.

3.7.F/4.7.F <u>Primary Containment Purge System</u>

The primary containment purge system is designed to provide air to purge and ventilate the primary containment system. The exhaust from the primary containment is first processed by a filter train assembly and then channeled through the reactor building roof exhaust system. During power operation, the primary containment purge and ventilation system is isolated from the primary containment by two isolation valves in series.

HEPA (high efficiency particulate air) filters are installed before the charcoal adsorbers followed by a centrifugal fan. The in-place test results should indicate a leak tightness of the system housing of not less than 99-percent and a HEPA efficiency of at least 99-percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 85-percent. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, the Standby Gas Treatment System may be used to purge the containment.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than 8.5 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

If significant painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

LIMITING CONDITIONS FOR OPERATION

SURVEILLANCE REQUIREMENTS

4.7.A. Primary Containment

4.7.A.2.g (Cont'd)

The total path leakage from all penetrations and isolation valves shall not exceed 60 percent of L_a per 24 hours. Leakage from containment isolation valves that terminate below suppression pool water level may be excluded from the total leakage provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig. Leakage from containment isolation valves that are in closed-loop, seismic class I lines that will be water sealed during a DBA will be measured but will be excluded when computing the total leakage.

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
1	Main steamline isolation valves (FCV-1-14, 26, 37, & 51; 1-15, 27, 38, & 52)	4	4	$3 < T < 5$	0	GC	7
1	Main steamline drain isolation valves (FCV-1-55 & 1-56)	1	1	15	0	GC	1
1*	Reactor Water sample line isolation valves (FCV-43-13,-14)	1	1	5	C	SC	1
2	RHRS shutdown cooling supply isolation valves (FCV-74-48 & 47)	1	1	40	C	SC	1
2	RHRS - LPCI to reactor (FCV-74-53 & 67)		2	30	C	SC	3
2	Suppression Chamber Drain (FCV-75-57, 58)		2	15	0**	GC	2
2	Drywell equipment drain discharge isolation valves (FCV-77-15A & 15B)		2	15	0	GC	1
2	Drywell floor drain discharge isolation valves (FCV-77-2A & 2B)		2	15	0	GC	1

*These valves isolate only on reactor vessel low low water level (378") and main steam line high radiation of Group 1 isolations.

**These valves are normally open when the pressure suppression head tank is aligned to serve the RHR and CS discharge piping and closed when the condensate head tank is used to serve the RHR and CS discharge piping. (See Specification 3.5.H)

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
3	Reactor water cleanup system supply isolation valves FCV-69-1, & 2	1	1	30	0	GC	1
4	HPCI warm-up FCV 73-81		1	10	C	SC	1
4	HPCIS steamline isolation valves FCV-73-2 & 3	1	1	20	0	GC	1
5	RCICS steamline isolation valves FCV-71-2 & 3	1	1	15	0	GC	1
6	Drywell nitrogen make-up inlet isolation valves (FCV-76-18)		1	5	C	SC	1
6	Suppression chamber nitrogen make-up inlet isolation valves (FCV-76-19)		1	5	C	SC	1
6	Drywell Main Exhaust isolation valves (FCV-64-29 and 30)		2	2.5	C	SC	1
6	Suppression chamber main exhaust isolation valves (FCV-64-32 and 33)		2	2.5	C	SC	1
6	Drywell/Suppression Chamber purge inlet (FCV-64-17)		1	2.5	C	SC	1
6	Drywell purge inlet (FCV-64-18)		1	2.5	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (Sec.)	Normal Position	Action on Initiating Signal	Notes
6	Torus Hydrogen Sample Line Valves Analyzer A (FSV-76-55, 56)		2	NA	O/C	GC/SC	6, 1
6	Drywell Hydrogen Sample Line Valves Analyzer A (FSV-76-49, 50)		2	NA	O/C	GC/SC	6, 1
6	Sample Return Valves - Analyzer A (FSV-76-57, 58)		2	NA	0	GC	1
6	Torus Hydrogen Sample Line Valves Analyzer B (FSV-76-65, 66)		2	NA	O/C	GC/SC	6, 1
6	Drywell Hydrogen Sample Line Valves-Analyzer B (FSV-76-59, 60)		2	NA	O/C	GC/SC	6, 1
6	Sample Return Valves-Analyzer B (FSV-76-67, 68)		2	NA	0	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
6	Suppression Chamber purge inlet (FCV-64-19)		1	2.5	C	SC	1
6	Drywell/Suppression Chamber nitrogen make-up inlet (FCV-76-17)		1	5	C	SC	1
6	Drywell Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-31)		1	5	0	GC	1
6	Suppression Chamber Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-34)		1	5	0	GC	1
6	System Suction Isolation Valves to Air Compressors "A" and "B" (FCV-32-62, 63)		2	15	0	GC	1
8	TIP Guide Tubes (5) (FCV-94-501,502,503,504,505)	1 per guide tube		NA	C	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
	Standby liquid control system check valves (CV 63-526 & 525)	1	1	NA	C	Process	1
	Feedwater check valves (CV-3-558, 572, 554 & 568)	2	2	NA	0	Process	1
	Control rod hydraulic return check valves (CV-85-576)		1	NA	0	Process	1
	RHRS – LPCI to reactor check valves (CV-74-54 & 68)	2		NA	C	Process	3
	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-19)		1	NA	C	SC	1
6	Drywell/Suppression Chamber Nitrogen Purge Inlet (FCV-76-24)		1	5	C	SC	1
	Core Spray Discharge to Reactor Check Valves FCV-75-26, 54	2		NA	C	Process	3
6	Drywell P air compressor suction valve (FCV-64-139)		1	10	C	SC	1
6	Drywell P air compressor discharge valve (FCV-64-140)		1	10	C	SC	1
6	Drywell CAM suction valves (FCV-90-254A and 254B)		2	10	0	GC	1
6	Drywell CAM discharge valves (FCV-90-257A and 257B)		2	10	0	GC	1
6	Drywell CAM suction valve (FCV-90-255)		1	10	0	GC	1
6	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-20)		1	10	C	SC	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Core Spray Discharge to reactor isolation valves (75-25,75-53)	2	2	N/A	C	SC	3
N/A	PSC return line check valves (12-738,12-741)		2	N/A	C	N/A	2
N/A	Suppression chamber sample RHR pumps A&C isolation valves (43-28A,43-28B)		2	N/A	C	SC	2
N/A	Suppression chamber sample RHR pumps B&D isolation valves (43-29A,43-29B)		2	N/A	C	SC	2
N/A	PSC head tank tie-in to RHR check valves (74-803, 74-804, 74-792, 74-802)		4	N/A	O	Process	3
N/A	PSC head tank tie-in to CS check valves (75-606, 75-609, 75-607, 75-610)		4	N/A	O	Process	3
N/A	TIP nitrogen purge check valve (76-653)		1	N/A	C	Process	1
N/A	CAD Crosstie to DW Control Air Check Valve (84-617)		1	N/A	C	Process	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	HPCI turbine exhaust drain check valves (73-24,73-609)		2	N/A	C	Process	2
N/A	RCIC turbine exhaust check (71-14,71-580)		2	N/A	C	Process	1
N/A	RCIC vacuum pump discharge check valves (71-32,71-592)		2	N/A	C	Process	2
N/A	RHR suppression chamber spray isolation valves (74-58, 74-72; 74-57, 74-71)		4	N/A	C	SC	3
N/A	RHR drywell spray isolation valves (74-61, 74-75; 74-60, 74-74)		4	N/A	C	Process	3
N/A	RHR shutdown cooling supply bypass check valves (74-661/662)	2		N/A	C	Process	1,5
N/A	Suppression chamber drain isolation valve (74-722)		1	N/A	C	SC	2,4
N/A	CAD admission check valves to DW (84-600,84-602)		2	N/A	C	Process	1
N/A	CAD admission check valves to suppression chamber (84-601,84-603)		2	N/A	C	Process	1
N/A	CAD admission isolation valves to DW (84-8A,84-8D)		2	N/A	C	SC	1
N/A	CAD admission isolation valves to Suppression Chamber (84-8B,84-8C)		2	N/A	C	SC	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Reactor Building closed cooling water drywell supply check valve (70-506)		1	N/A	O	Process	1
N/A	RCICS pump suction isolation valves (71-17,71-18)		2	N/A	C	SC	2
N/A	RCICS pump minimum flow bypass isolation valve (71-34)		1	N/A	C	SC	2
N/A	RCICS pump discharge check valve valves (71-40)		1	N/A	C	Process	1
N/A	RCICS pump minimum flow bypass check valve (71-547)		1	N/A	C	Process	2
N/A	HPCI pump suction isolation valves (73-26,73-27)		2	80 sec.	C	SC	2
N/A	HPCI pump minimum flow bypass isolation valve (73-30)		1	N/A	C	SC	2
N/A	HPCI pump discharge check valve (73-45)		1	N/A	C	Process	1
N/A	HPCI pump minimum flow bypass check valve (73-559)		1	N/A	C	Process	2
N/A	HPCI turbine exhaust check valves (73-23,73-603)		2	N/A	C	Process	1

NOTES FOR TABLE 3.7.A

Key: 0 = Open
C = Closed
SC = Stays Closed
GC = Goes Closed

Note: Isolation groupings are as follows:

Group 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor Vessel Low Water Level (378")
2. Main Steamline High Radiation
3. Main Steamline High Flow
4. Main Steamline Space High Temperature
5. Main Steamline Low Pressure

Group 2: The valves in Group 2 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure

Group 3: The valves in Group 3 are actuated by any of the following conditions:

1. Reactor Low Water Level (538")
2. Reactor Water Cleanup System Space High Temperature
3. Reactor Water Cleanup System High Drain Temperature

Group 4: The valves in Group 4 are actuated by any of the following conditions:

1. HPCI Steamline Space High Temperature
2. HPCI Steamline High Flow
3. HPCI Steamline Low Pressure

Group 5: The valves in Group 5 are actuated by any of the following condition:

1. RCIC Steamline Space High Temperature
2. RCIC Steamline High Flow
3. RCIC Steamline Low Pressure

Group 6: The valves in Group 6 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure
3. Reactor Building Ventilation High Radiation

Group 7: (Deleted)

Group 8: The valves in Group 8 are automatically actuated by only the following conditions:

1. High Drywell Pressure
2. Reactor Vessel Low Water Level (538")

Note 1: Primary containment isolation valve(s) requiring LLRT at not less than 49.6 psig.

Note 2: Primary containment isolation valves(s) which may be LLRT with water and not included in the 60-percent L_a tabulation, provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54. 6 psig.

Note 3: Primary containment isolation valves that are in closed loop, seismic Class 1 lines that will be water sealed during a DBA. These valves will be tested but not included in the 60-percent L_a tabulation.

Note 4: Primary containment isolation valves that are manually operated.

Note 5: Primary containment valves 74-661/662 are considered as a single containment boundary and LLRT as such.

Note 6: Analyzers are such that one is sampling drywell hydrogen and oxygen (valves from drywell open, valves from torus close), while the other is sampling torus hydrogen (valves from torus open, valves from drywell close).

Note 7: Primary containment isolation valves requiring LLRT at not less than 25-psig.

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, ensure that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

During initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required, there will be no pressure on the system thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect to minimize the probability of an accident occurring.

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 49.6 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the requirements of Appendix J of 10 CFR Part 50 (type A, B, and C tests).

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat release during primary system blowdown from 1,035 psig. Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss of coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 62 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water levels given in the specification, containment pressure during the design basis accident is approximately 49 psig, which is below the maximum of 62 psig. The maximum water level indications of -1 inch corresponds to a downcomer submergence of three feet seven inches and a water volume of 127,800 cubic feet with or 128,700 cubic feet without the drywell-suppression chamber differential pressure control. The minimum water level indication of -6.25 inches with differential pressure control and -7.25 inches without differential pressure control corresponds to a downcomer submergence of approximately three feet and a water volume of approximately 123,000 cubic feet.

Maintaining the water level between these levels will ensure that the torus water volume and downcomer submergence are within the aforementioned limits during normal plant operation. Alarms, adjusted for instrument error, will notify the operator when the limits of the torus water level are approached.

The maximum permissible bulk pool temperature is limited by the potential for stable and complete condensation of steam discharged from safety relief valves and adequate core spray pump net positive suction head. At reactor vessel pressures above approximately 555 psig, the bulk pool temperature shall not exceed 180°F. At pressures below approximately 240 psig, the bulk temperature may be as much as 184°F. At intermediate pressures, linear interpolation of the bulk temperature is permitted.

They also represent the bounding upper limits that are used in suppression pool temperature response analyses for safety relief valve discharge and loss-of-coolant accident (LOCA) cases. The actions required by Specifications 3.7.C. - 3.7.F. assure the reactor can be depressurized in a timely manner to avoid exceeding the maximum bulk suppression pool water limits. Furthermore, the 184°F limit provides that adequate RHR and core spray pump NPSH will be available without dependency on containment overpressure.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for core standby cooling systems operability. Under full power operation conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a peak long term water temperature which is sufficient for complete condensation.

Limiting suppression pool temperature to 105°F during RCIC, HPCI, or relief valve operation when decay heat and stored energy is removed from the primary system by discharging reactor steam directly to the suppression chamber ensures adequate margin for controlled blowdown anytime during RCIC operation and ensures margin for complete condensation of steam from the design basis LOCA.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a relief valve inadvertently opens or sticks open. This action would include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling heat exchangers, (3) initiate reactor shutdown, and (4) if other relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

If a LOCA were to occur when the reactor water temperature is below approximately 330°F, the containment pressure will not exceed the 62 psig code permissible pressures even if no condensation were to occur. The maximum allowable pool temperature, whenever the reactor is above 212°F, shall be governed by this specification. Thus, specifying water volume-temperature requirements applicable for reactor-water temperature above 212°F provides additional margin above that available at 330°F.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed ("Torus Support System and Attached Piping Analysis for the Browns Ferry Nuclear Plant Units 1, 2, and 3," dated September 9, 1976 and supplemented October 12, 1976) which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure of 1.1 psid and a suppression chamber water level corresponding to a downcomer submergence range of 3.06 feet to 3.58 feet will assure the integrity of the suppression chamber when subjected to post-loss-of-coolant suppression pool hydrodynamic forces.

Inerting

The relativity small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (a-percent or so) reaction of the zirconium and steam during a LOCA could lead to the liberation of hydrogen combined with an air atmosphere to result in a flammable concentration in the containment. If a sufficient amount of hydrogen is generated and oxygen is available in stoichiometric quantities the subsequent ignition of the hydrogen in rapid recombination rate could lead to failure of the containment to maintain a low leakage integrity. The <4 percent hydrogen concentration minimizes the possibility of hydrogen combustion following a LOCA.

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the LOCA upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration.

To ensure that the hydrogen concentration is maintained less than 4 percent following an accident, liquid nitrogen is maintained on-site for containment atmosphere dilution. About 2,260 gallons would be sufficient as a seven-day supply, and replenishment facilities can deliver liquid nitrogen to the site within one day; therefore, a requirement of 2,500 gallons is conservative. Following a LOCA the Containment Air Monitoring (CAM) System continuously monitors the hydrogen concentration of the containment volume. Two independent systems (a system consists of one hydrogen sensing circuit) are installed in the drywell and the torus. Each sensor and associated circuit is periodically checked by a calibration gas to verify operation. Failure of one system does not reduce the ability to monitor system atmosphere as a second independent and redundant system will still be operable.

In terms of separability, redundancy for a failure of the torus system is based upon at least one operable drywell system. The drywell hydrogen concentration can be used to limit the torus hydrogen concentration during post-LOCA conditions. Post-LOCA calculations show that the CAD system initiated within two hours at a flow rate of 100 scfm will limit the peak drywell and wetwell hydrogen concentration to 3.6-percent (at 4 hours) and 3.8-percent (at 32 hours), respectively. This is based upon purge initiation after 20 hours at a flow rate of 100 scfm to maintain containment pressure below 30 psig. Thus, peak torus hydrogen concentration can be controlled below 4.0 percent using either the direct torus hydrogen monitoring system or the drywell hydrogen monitoring system with appropriate conservatism ($\leq$ 3.8-percent), as a guide for CAD/Purge operations.

Vacuum Relief

The purpose of the vacuum relief valves is to equalize the pressure between the drywell and suppression chamber and reactor building so that the structural integrity of the containment is maintained. The vacuum relief system from the pressure suppression chamber to reactor building consists of two 100-percent vacuum relief breakers (two parallel sets of two valves in series). Operation of either system will maintain the pressure differential less than 2 psig; the external design pressure. One reactor building vacuum breaker may be out of service for repairs for a period of seven days. If repairs cannot be completed within seven days, the reactor coolant system is brought to a condition where vacuum relief is no longer required.

When a drywell-suppression chamber vacuum breaker valve is exercised through an opening-closing cycle the position indicating lights in the control room are designed to function as specified below:

Initial and Final Condition	Check - On	(Fully Closed)
	Green - On	
	Red - Off	
Opening Cycle	Check - Off	(Cracked Open)
	Green - Off	(> 80° Open)
	Red - On	(> 3° Open)
Closing Cycle	Check - On	(Fully Closed)
	Green - On	(< 80° Open)
	Red - Off	(< 3° Open)

The valve position indicating lights consist of one check light on the check light panel which confirms full closure, one green light next to the hand switch which confirms 80° of full opening and one red light next to the hand switch which confirms "near closure" (within 3° of full closure). Each light is on a separate switch. If the check light circuit is operable when the valve is exercised by its air operator there exists a confirmation that the valve will fully close. If the red light circuit is operable, there exists a confirmation that the valve will at least "nearly close" (within 3° of full closure). The green light circuit confirms the valve will fully open. If none of the lights change indication during the cycle, the air operator must

be inoperable or the valve disc is stuck. For this case, a check light on and red light off confirms the disc is in a nearly closed position even if one of the indications is in error. Although the valve may be inoperable for full closure, it does not constitute a safety threat.

If the red light circuit alone is inoperable, the valve shall still be considered fully operable. If the green and red or the green light circuit alone is inoperable the valve shall be considered inoperable for opening. If the check and green or check light circuit alone is inoperable, the valve shall be considered inoperable for full closure. If the red and check light circuits are inoperable the valve shall be considered inoperable and open greater than 3°. For a light circuit to be considered operable the light must go on and off in proper sequence during the opening-closing cycle. If none of the lights change indication during the cycle, the valve shall be considered inoperable and open unless the check light stays on and the red light stays off in which case the valve shall be considered inoperable for opening.

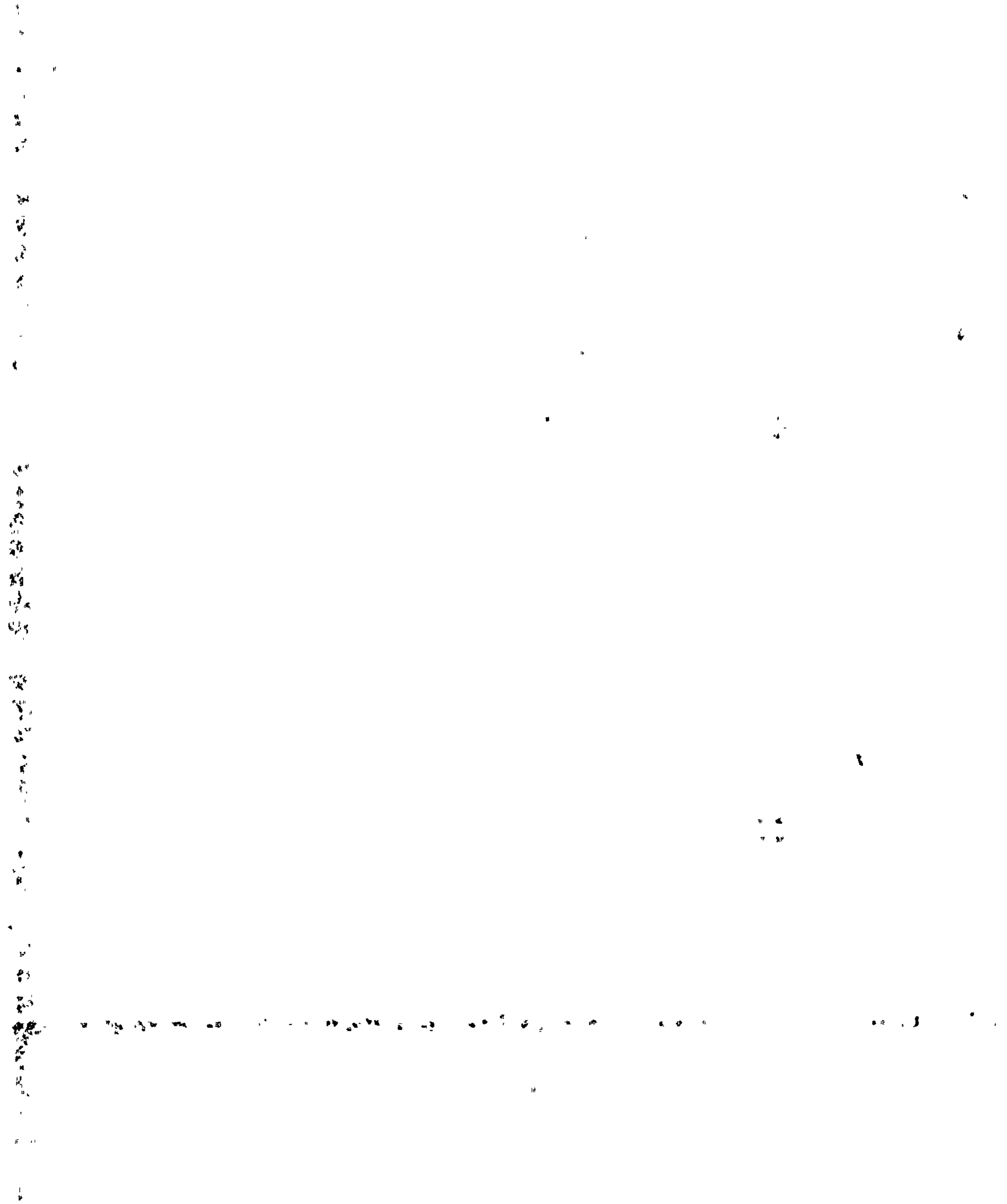
The 12 drywell vacuum breaker valves which connect the suppression chamber and drywell are sized on the basis of the Bodega pressure suppression system tests. Ten operable to open vacuum breaker valves (18-inch) selected on this test basis and confirmed by the green lights are adequate to limit the pressure differential between the suppression chamber and drywell during postaccident drywell cooling operations to a value which is within suppression system design values.

The containment design has been examined to determine that a leakage equivalent to one drywell vacuum breaker opened to no more than a nominal 3° as confirmed by the red light is acceptable.

On this basis an indefinite allowable repair time for an inoperable red light circuit on any valve or an inoperable check and green or check light circuit alone or a malfunction of the operator or disc (if nearly closed) on one valve, or an inoperable green and red or green light circuit alone on two valves is justified.

During each operating cycle, a leak rate test shall be performed to verify that significant leakage flow paths do not exist between the drywell and suppression chamber. The drywell pressure will be increased by at least one psi with respect to the suppression chamber pressure and held constant. The two psig setpoint will not be exceeded. The subsequent suppression chamber pressure transient (if any) will be monitored with a sensitive pressure gauge. If the drywell pressure cannot be increased by one psi over the suppression chamber pressure it would be because a significant leakage path exists; in this event the leakage source will be identified and eliminated before power operation is resumed.

With a differential pressure of greater than one psig, the rate of change of the suppression chamber pressure must not exceed 0.25 inches of water per minute as measured over a 10-minute period, which corresponds to about 0.09 lb/sec of containment air. In the event the rate of change exceeds this value then the source of leakage will be identified and eliminated before power operation is resumed.



The water in the suppression chamber is used for cooling in the event of an accident; i.e., it is not used for normal operation; therefore, a daily check of the temperature and volume is adequate to assure that adequate heat removal capability is present.

The interior surfaces of the drywell and suppression chamber are coated as necessary to provide corrosion protection and to provide a more easily decontaminable surface. The surveillance inspection of the internal surfaces each operating cycle assures timely detection of corrosion. Dropping the torus water level to one foot below the normal operating level enables an inspection of the suppression chamber where problems would first begin to show.

The primary containment preoperational test pressures are based upon the calculated primary containment pressure response in the event of a LOCA. The peak drywell pressure would be about 49 psig which would rapidly reduce to less than 30 psig within 20 seconds following the pipe break. Following the pipe break, the suppression chamber pressure rises to 27 psig within 25 seconds, equalizes with drywell pressure, and decays with the drywell pressure decay.

The design pressure of the drywell and suppression chamber is 56 psig. The design leak rate is 0.5-percent per day at the pressure of 56 psig. As pointed out above, the pressure response of the drywell and suppression chamber following an accident would be the same after about 25 seconds. Based on the calculated containment pressure response discussed above, the primary containment preoperational test pressures were chosen. Also based on the primary containment pressure response and the fact that the drywell and suppression chamber function as a unit, the primary containment will be tested as a unit rather than the individual components separately.

The calculated radiological doses given in Section 14.9 of the FSAR were based on an assumed leakage rate of 0.635-percent at the maximum calculated pressure of 49.6 psig. The doses calculated by the NRC using this bases are 0.14 rem, whole body passing cloud gamma dose, and 15.0 rem, thyroid dose, which are respectively only 5×10^{-3} and 10^{-1} times the 10 CFR 100 reference doses. Increasing the assumed leakage rate at 49.6 psig to 2.0 percent as indicated in the specifications would increase these doses approximately a factor of three, still leaving a margin between the calculated dose and the 10 CFR 100 reference values.

Establishing the test limit of 2.0-percent/day provides an adequate margin of safety to assure the health and safety of the general public. It is further considered that the allowable leak rate should not deviate significantly from the containment design value to take advantage of the design leak-tightness capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate by 0.75 thereby providing a 25-percent margin to allow for leakage deterioration which may occur during the period between leak rate tests.

The primary containment leak rate test frequency is based on maintaining adequate assurance that the leak rate remains within the specification. The leak rate test frequency is based on the NRC guide for developing leak rate testing and surveillance of reactor containment vessels. Allowing the test intervals to be extended up to 10 months permits some flexibility needed to have the tests coincide with scheduled or unscheduled shutdown periods.

The penetration and air purge piping leakage test frequency, along with the containment leak rate tests, is adequate to allow detection of leakage trends. Whenever a bolted double-gasketed penetration is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. It is expected that the majority of the leakage from valves, penetrations and seals would be into the reactor building. However, it is possible that leakage into other parts of the facility could occur. Such leakage paths that may affect significantly the consequences of accidents are to be minimized.

The primary containment is normally slightly pressurized during period of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase oxygen concentration. Once the containment is filled with nitrogen to the required concentration, determining the oxygen concentration twice a week serves as an added assurance that the oxygen concentration will not exceed 4 percent.

3.7.B/3.7.C Standby Gas Treatment System and Secondary Containment

The secondary containment is designed to minimize any ground level release of radioactive materials which might result from a serious accident. The reactor building provides secondary containment during reactor operation, when the drywell is sealed and in service; the reactor building provides primary containment when the reactor is shutdown and the drywell is open, as during refueling. Because the secondary containment is an integral part of the complete containment system, secondary containment is required at all times that primary containment is required as well as during refueling.

The standby gas treatment system is designed to filter and exhaust the reactor building atmosphere to the stack during secondary containment isolation conditions. All three standby gas treatment system fans are designed to automatically start upon containment isolation and to maintain the reactor building pressure to the design negative pressure so that all leakage should be in-leakage.

High efficiency particulate air (HEPA) filters are installed before and after the charcoal absorbers to minimize potential release of particulates to the environment and to prevent clogging of the iodine absorbers. The charcoal absorbers are installed to reduce the potential release of radioiodine to the environment. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal absorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal absorbers are as specified, the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed. Operation of the fans significantly

different from the design flow will change the removal efficiency of the HEPA filters and charcoal absorbers at rate remains [illegible]

[illegible] requirement is based on the [illegible]

Only two of the three standby gas treatment systems are needed to clean up the reactor building atmosphere upon containment isolation. If one system is found to be inoperable, there is no immediate threat to the containment system performance and reactor operation or refueling operation may continue while repairs are being made. If more than one train is inoperable, the plant is brought to a condition where the standby gas treatment system is not required.

4.7.B/4.7.C Standby Gas Treatment System and Secondary Containment

Initiating reactor building isolation and operation of the standby gas treatment system to maintain at least a 1/4 inch of water vacuum within the secondary containment provides an adequate test of the operation of the reactor building isolation valves, leak tightness of the reactor building and performance of the standby gas treatment system. Functionally testing the initiating sensors and associated trip logic demonstrates the capability for automatic actuation. Performing these tests prior to refueling will demonstrate secondary containment capability prior to the time the primary containment is opened for refueling. Periodic testing gives sufficient confidence of reactor building integrity and standby gas treatment system performance capability.

The test frequencies are adequate to detect equipment deterioration prior to significant defects, but the tests are not frequent enough to load the filters, thus reducing their reserve capacity too quickly. That the testing frequency is adequate to detect deterioration was demonstrated by the tests which showed no loss of filter efficiency after two years of operation in the rugged shipboard environment on the US Savannah (ORNL 3726). Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Heater capability, pressure drop and air distribution should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon refrigerant shall be performed in accordance with USAEC Report DP-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

All elements of the heater should be demonstrated to be functional and operable during the test of heater capacity. Operation of each filter train for a minimum of 10 hours each month will prevent moisture buildup in the filters and adsorber system. [illegible] atmosphere upon [illegible]

With doors closed and fan in operation, DOP aerosol shall be sprayed externally along the full linear periphery of each respective door to check the gasket seal. Any detection of DOP in the fan exhaust shall be considered an unacceptable test result and the gaskets repaired and test repeated.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign material, the same tests and sample analysis shall be performed as required for operational use. The determination of significant shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability and operability of filter cooling is necessary to assure system performance capability. If one standby gas treatment system is inoperable, the other systems must be tested daily. This substantiates the availability of the operable systems and thus reactor operation and refueling operation can continue for a limited period of time.

3.7.D/4.7.D Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a LOCA.

Group 1 - Process lines are isolated by reactor vessel low water level (378") in order to allow for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems. The valves in Group 1, except the reactor water sample line valves, are also closed when process instrumentation detects excessive main steam line flow, high radiation, low pressure, or main steam space high temperature. The reactor water sample line valves isolate only on reactor low water level at 378" or main steam line high radiation.

Group 2 - Isolation valves are closed by reactor vessel low water level (538") or high drywell pressure. The Group 2 isolation signal also "isolates" the reactor building and starts the standby gas treatment system. It is not desirable to actuate the Group 2 isolation signal by a transient or spurious signal.

Group 3 - Process lines are normally in use, and it is therefore not desirable to cause spurious isolation due to high drywell pressure resulting from nonsafety related causes. To protect the reactor from a possible pipe break in the system, isolation is provided by high temperature in the cleanup system area or high drain temperature. Also, since the vessel could potentially be drained through the cleanup system, a low-level isolation is provided.

Groups 4 and 5 - Process lines are designed to remain operable and mitigate the consequences of an accident which results in the isolation of other process lines. The signals which initiate isolation of Groups 4 and 5 process lines are therefore indicative of a condition which would render them inoperable.

Group 6 - Lines are connected to the primary containment but not directly to the reactor vessel. These valves are isolated on reactor low water level (538"), high drywell pressure, or reactor building ventilation high radiation which would indicate a possible accident and necessitate primary containment isolation.

Group 7 - (Deleted)

Group 8 - Line (traveling in-core probe) is isolated on high drywell pressure or reactor low water level (538"). This is to assure that this line does not provide a leakage path when containment pressure or reactor water level indicates a possible accident condition.

The maximum closure time for the automatic isolation valves of the primary containment and reactor vessel isolation control system have been selected in consideration of the design intent to prevent core uncovering following pipe breaks outside the primary containment and the need to contain released fission products following pipe breaks inside the primary containment.

In satisfying this design intent, an additional margin has been included in specifying maximum closure times. This margin permits identification of degraded valve performance prior to exceeding the design closure times.

In order to assure that the doses that may result from a steam line break do not exceed the 10 CFR 100 guidelines, it is necessary that no fuel rod perforation resulting from the accident occur prior to closure of the main steam line isolation valves. Analyses indicate that fuel rod cladding perforations would be avoided for main steam valve closure times, including instrument delay, as long as 10.5 seconds.

These valves are highly reliable, have low service requirements and most are normally closed. The initiating sensors and associated trip logic are also checked to demonstrate the capability for automatic isolation. The test interval of once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate. More frequent testing for valve operability results in a greater assurance that the valve will be operable when needed.

The main steam line isolation valves are functionally tested on a more frequent interval to establish a high degree of reliability.

The primary containment is penetrated by several small diameter instrument lines connected to the reactor coolant system. Each instrument line contains a 0.25-inch restricting orifice inside the primary containment and an excess flow check valve outside the primary containment.

3.7.E/4.7.E Control Room Emergency Ventilation

The control room emergency ventilation system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room emergency ventilation system is designed to automatically start upon control room isolation and to maintain the control room pressure to the design positive pressure so that all leakage should be out leakage.

High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radioiodine to the control room. The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 90 percent for expected accident conditions. If the efficiencies of the HEPA filters and charcoal adsorbers are as specified, the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR Part 50. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, there is no immediate threat to the control room and reactor operation or refueling operation may continue for a limited period of time while repairs are being made. If the system cannot be repaired within seven days, the reactor is shutdown and brought to Cold Shutdown within 24 hours or refueling operations are terminated.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than six inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

Operation of the system for 10 hours every month will demonstrate operability of the filters and adsorber system and remove excessive moisture built up on the adsorber.

If significant painting, fire or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

Demonstration of the automatic initiation capability is necessary to assure system performance capability.

3.7.F/4.7.F Primary Containment Purge System

The primary containment purge system is designed to provide air to purge and ventilate the primary containment system. The exhaust from the primary containment is first processed by a filter train assembly and then channeled through the reactor building roof exhaust system. During power operation, the primary containment purge and ventilation system is isolated from the primary containment by two isolation valves in series.

HEPA (high efficiency particulate air) filters are installed before the charcoal adsorbers followed by a centrifugal fan. The in-place test results should indicate a leak tightness of the system housing of not less than 99-percent and a HEPA efficiency of at least 99-percent removal of DOP particulates. The laboratory carbon sample test results should indicate a radioactive methyl iodide removal efficiency of at least 85-percent. Operation of the fans significantly different from the design flow will change the removal efficiency of the HEPA filters and charcoal adsorbers.

If the system is found to be inoperable, the Standby Gas Treatment System may be used to purge the containment.

Pressure drop across the combined HEPA filters and charcoal adsorbers of less than 8.5 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated. Tests of the charcoal adsorbers with halogenated hydrocarbon shall be performed in accordance with USAEC Report-1082. Iodine removal efficiency tests shall follow ASTM D3803. The charcoal adsorber efficiency test procedures should allow for the removal of one adsorber tray, emptying of one bed from the tray, mixing the adsorbent thoroughly and obtaining at least two samples. Each sample should be at least two inches in diameter and a length equal to the thickness of the bed. If test results are unacceptable, all adsorbent in the system shall be replaced with an adsorbent qualified according to Table 1 of Regulatory Guide 1.52. The replacement tray for the adsorber tray removed for the test should meet the same adsorbent quality. Tests of the HEPA filters with DOP aerosol shall be performed in accordance to ANSI N510-1975. Any HEPA filters found defective shall be replaced with filters qualified pursuant to Regulatory Position C.3.d of Regulatory Guide 1.52.

If significant painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemicals or foreign materials, the same tests and sample analysis shall be performed as required for operational use. The determination of significance shall be made by the operator on duty at the time of the incident. Knowledgeable staff members should be consulted prior to making this determination.

LIMITING CONDITIONS FOR OPERATION

SURVEILLANCE REQUIREMENTS

4.7.A. Primary Containment

4.7.A.2.g (Cont'd).

The total path leakage from all penetrations and isolation valves shall not exceed 60 percent of L_a per 24 hours. Leakage from containment isolation valves that terminate below suppression pool water level may be excluded from the total leakage provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig. Leakage from containment isolation valves that are in closed-loop, seismic class I lines that will be water sealed during a DBA will be measured but will be excluded when computing the total leakage.

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
1	Main steamline isolation valves (FCV-1-14, -26, -37, & -51; 1-15 -27,- 38, & -52)	4	4	3 < T < 5	0	GC	7
1	Main steamline drain isolation valves (FCV-1-55 & 1-56)	1	1	15	0	GC	1
1 *	Reactor Water sample line isolation valves (FCV-43-13,-14)	1	1	5	C	SC	1
2	RHRS shutdown cooling supply isolation valves (FCV-74-48 & -47)	1	1	40	C	SC	1
2	RHRS - LPCI to reactor (FCV-74-53, -67)		2	30	C	SC	3
2	RHRS flush and drain vent to suppression chamber (FCV-74-102, -103, -119, & -120)		4	20	C	SC	1
2	Suppression Chamber Drain (FCV 75-57, -58)		2	15	0**	GC	2
2	Drywell equipment drain discharge isolation valves (FCV-77-15A, & -15B)		2	15	0	GC	1
2	Drywell floor drain discharge isolation valves (FCV-77-2A & -2B)		2	15	0	GC	1

*These valves isolate only on reactor vessel low low water level (378") and main steam line high radiation of Group 1 isolations.

**These valves are normally open when the pressure suppression head tank is aligned to serve the RHR and CS discharge piping and closed when the condensate head tank is used to serve the RHR and CS discharge piping. (See Specification 3.5.H)

TABLE 3.7.A (Cont'd)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
3	Reactor water cleanup system supply isolation valves (FCV-69-1, & -2)	1	1	30	0	GC	1
4	HPCI warm-up FCV-73-81		1	10	C	SC	1
4	HPCIS steamline isolation valves (FCV-73-2 & -3)	1	1	20	0	GC	1
5	RCICS steamline isolation valves (FCV-71-2 & -3)	1	1	15	0	GC	1
6	Drywell nitrogen make-up inlet isolation valves (FCV-76-18)		1	5	C	SC	1
6	Suppression chamber nitrogen make-up inlet isolation valves (FCV-76-19)		1	5	C	SC	1
6	Drywell Main Exhaust isolation valves (FCV-64-29 and -30)		2	2.5	C	SC	1
6	Suppression chamber main exhaust isolation valves (FCV-64-32 and -33)		2	2.5	C	SC	1
6	Drywell/Suppression Chamber purge inlet (FCV-64-17)		1	2.5	C	SC	1
6	Drywell purge inlet (FCV-64-18)		1	2.5	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (Sec.)	Normal Position	Action on Initiating Signal	Notes
6	Suppression Chamber purge inlet (FCV-64-19)		1	2.5	C	SC	1
6	Drywell/Suppression Chamber nitrogen make-up inlet (FCV-76-17)		1	5	C	SC	1
6	Drywell Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-31)		1	5	0	GC	1
6	Suppression Chamber Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-34)		1	5	0	GC	1
6	System Suction Isolation Valves to Air Compressors "A" and "B" (FCV-32-62, -63)		2	15	0	GC	1
6	Drywell/Suppression Chamber Nitrogen Purge Inlet (FCV-76-24)		1	5	C	SC	1
6	Torus Hydrogen Sample Line Valves Analyzer A (FSV-76-55, -56)		2	NA	O/C	GC	6, 1
6	Torus Oxygen Sample Line Valves Analyzer A (FSV-76-53, -54)		2	NA	O/C	SC	6, 1
6	Drywell Hydrogen Sample Line Valves Analyzer A (FSV-76-49, -50)		2	NA	O/C	SC	6, 1
6	Drywell Oxygen Sample Line Valves Analyzer A (FSV-76-51, -52)		2	NA	O/C	SC	6, 1
6	Sample Return Valves - Analyzer A (FSV-76-57, -58)		2	NA	0	GC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
6	Torus Hydrogen Sample Line Valves Analyzer B (FSV-76-65, -66)		2	NA	O/C	GC	6, 1
6	Torus Oxygen Sample Line Valves-Analyzer B (FSV-76-63, -64)		2	NA	O/C	GC	6, 1
6	Drywell Hydrogen Sample Line Valves-Analyzer B (FSV-76-59, -60)		2	NA	O/C	GC	6, 1
6	Drywell Oxygen Sample Line Valves-Analyzer B (FSV-76-61, -62)		2	NA	O/C	GC	6, 1
6	Sample Return Valves-Analyzer B (FSV-76-67, -68)		2	NA	O	GC	1
8	TIP Guide Tubes (5) (FCV-94-501, 502, 503, 504, 505)		1 per guide tube	NA	C	SC	1

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
	Standby Liquid Control System Check Valves (CV 63-526 & -525)	1	1	NA	C	Process	1
	Feedwater Check Valves (CV-3-558, -572, -554 & -568)	2	2	NA	0	Process	1
	Control Rod Hydraulic Return Check Valves (CV-85-576)		1	NA	0	Process	1
	RHRS – LPCI to Reactor Check Valves (CV-74-54 & -68)	2		NA	C	Process	3
	Core Spray Discharge to Reactor Check Valves (FCV-75-26, -54)	2		NA	C	Process	3
6	Drywell W P Air Compressor Suction Valve (FCV-64-139)		1	10	C	SC	1
6	Drywell W P Air Compressor Discharge Valve (FCV-64-140)		1	10	C	SC	1
6	Drywell CAM Discharge Valves (FCV-90-257A and -257B)		2	10	0	GC	1
6	Drywell CAM Suction Valves (FCV-90-254A and -254B)		2	10	0	GC	1
6	Drywell CAM Suction Valve (FCV-90-255)		1	10	0	GC	1
	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-19)		1	NA	C	SC	1
6	CAD System Torus/Drywell Exhaust to Standby Gas Treatment (FCV-84-20)		1	10	C	SC	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Core Spray Discharge to reactor isolation valves (75-25,75-53)		2	N/A	C	SC	3
N/A	PSC return line check valves (12-738,12-741)		2	N/A	C	N/A	2
N/A	Suppression chamber sample RHR pumps A&C isolation valves (43-28A,43-28B)		2	N/A	C	SC	2
N/A	Suppression chamber sample RHR pumps B&D isolation valves (43-29A,43-29B)		2	N/A	C	SC	2
N/A	PSC head tank tie-in to RHR check valves (74-803, 74-804, 74-792, 74-802)		4	N/A	O	Process	3
N/A	PSC head tank tie-in to CS check valves (75-606, 75-609, 75-607, 75-610)		4	N/A	O	Process	3
N/A	TIP nitrogen purge check valve (76-653)		1	N/A	C	Process	1
N/A	Discharge Check Valve Cleanup System (69-624)		1	N/A	C	Process	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	HPCI turbine exhaust drain check valves (73-24,73-609)		2	N/A	C	Process	2
N/A	RCIC turbine exhaust check (71-14,71-580)		2	N/A	C	Process	1
N/A	RCIC vacuum pump discharge check valves (71-32,71-592)		2	N/A	C	Process	2
N/A	RHR suppression chamber spray isolation valves (74-58, 74-72, 74-57, 74-71)		4	N/A	C	SC	3
N/A	RHR drywell spray isolation valves (74-61, 74-75, 74-60, 74-74)		4	N/A	C	Process	3
N/A	RHR shutdown cooling supply bypass check valves (74-661/662)	2		N/A	C	Process	1,5
N/A	Suppression chamber drain isolation valve (74-722)		1	N/A	C	SC	2,4
N/A	CAD admission check valves to DW (84-600,84-602)		2	N/A	C	Process	1
N/A	CAD admission check valves to suppression chamber (84-601,84-603)		2	N/A	C	Process	1
N/A	CAD admission isolation valves to DW (84-8A,84-8D)		2	N/A	C	SC	1
N/A	CAD admission isolation valves to Suppression Chamber (84-8B,84-8C)		2	N/A	C	SC	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Reactor building closed cooling water drywell supply check valve (70-506)		1	N/A	O	Process	1
N/A	RCICS pump suction isolation valves (71-17,71-18)		2	N/A	C	SC	2
N/A	RCICS pump minimum flow bypass isolation valve (71-34)		1	N/A	C	SC	2
N/A	RCICS pump discharge check valve valves (71-40)		1	N/A	C	Process	1
N/A	RCICS pump minimum flow bypass check valve (71-547)		1	N/A	C	Process	2
4	HPCI pump suction isolation valves (73-26,73-27)		2	N/A	C	SC	2
N/A	HPCI pump minimum flow bypass isolation valve (73-30)	1		N/A	C	SC	2
N/A	HPCI pump discharge check valve (73-45)		1	N/A	C	Process	1
N/A	HPCI pump minimum flow bypass check valve (73-559)		1	N/A	C	Process	2
N/A	HPCI turbine exhaust check valves (73-23,73-603)		2	N/A	C	Process	1

TABLE 3.7.A
PRIMARY CONTAINMENT ISOLATION VALVES

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal	Notes
N/A	Demineralized water supply Check valve (2-1192)		1	N/A	C	N/A	1
N/A	Demineralized water supply Inspection valve (2-1383)		1	N/A	C	N/A	1,4
N/A	Service air supply isolation valves (33-1070)		1	N/A	C	N/A	1
N/A	Service air supply check valve (33-785)		1	N/A	C	N/A	1,4
N/A	Drywell control air inlet header check valves (32-2163,32-336)	1	1	N/A	0	Process	1
N/A	Suppression chamber vacuum relief (64-20,64-21)		2	N/A	0	N/A	1
N/A	Suppression chamber vacuum relief check valves (64-800,64-801)		2	N/A	C	Process	1
N/A	Recirculation pump A seal injection check valves (68-508,68-550)	1	1	N/A	0	Process	1
N/A	Recirculation pump B seal injection check valves (68-523,68-555)	1	1	N/A	0	Process	1
N/A	Reactor water cleanup system discharge check valve (69-579)		1	N/A	0	Process	1

NOTES FOR TABLE 3.7.A

Key: 0 = Open
C = Closed
SC = Stays Closed
GC = Goes Closed

Note: Isolation groupings are as follows:

Group 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor Vessel Low Water Level (378")
2. Main Steamline High Radiation
3. Main Steamline High Flow
4. Main Steamline Space High Temperature
5. Main Steamline Low Pressure

Group 2: The valves in Group 2 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure

Group 3: The valves in Group 3 are actuated by any of the following conditions:

1. Reactor Low Water Level (538")
2. Reactor Water Cleanup System Space High Temperature
3. Reactor Water Cleanup System High Drain Temperature

Group 4: The valves in Group 4 are actuated by any of the following conditions:

1. HPCI Steamline Space High Temperature
2. HPCI Steamline High Flow
3. HPCI Steamline Low Pressure

Group 5: The valves in Group 5 are actuated by any of the following condition:

1. RCIC Steamline Space High Temperature
2. RCIC Steamline High Flow
3. RCIC Steamline Low Pressure

Group 6: The valves in Group 6 are actuated by any of the following conditions:

1. Reactor Vessel Low Water Level (538")
2. High Drywell Pressure
3. Reactor Building Ventilation High Radiation

Group 7: (Deleted)

Group 8: The valves in Group 8 are automatically actuated by only the following conditions:

1. High Drywell Pressure
2. Reactor Vessel Low Water Level (538")

Note 1: Primary containment isolation valve(s) requiring LLRT at not less than 49.6 psig.

Note 2: Primary containment isolation valve(s) which may be LLRT with water and not included in the 60-percent L_a tabulation, provided a sufficient fluid inventory is available to ensure the sealing function for at least 30 days at a pressure of 54.6 psig.

Note 3: Primary containment isolation valves that are in closed loop, seismic Class 1 lines that will be water sealed during a DBA. These valves will be tested but not included in the 60-percent L_a tabulation.

Note 4: Primary containment isolation valves that are manually operated.

Note 5: Primary containment isolation valves 74-661/662 are considered as a single containment boundary and LLRT as such.

Note 6: Analyzers are such that one is sampling drywell hydrogen and oxygen (valves from drywell open, valves from torus close), while the other is sampling torus hydrogen and oxygen (valves from torus open, valves from drywell close).

Note 7: Primary containment isolation valves requiring LLRT at not less than 25-psig.

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, ensure that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

During initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required, there will be no pressure on the system thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect to minimize the probability of an accident occurring.

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 49.6 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates are consistent with the requirements of Appendix J of 10 CFR Part 50 (type A, B, and C tests).

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat release during primary system blowdown from 1,035 psig. Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss of coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 62 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water levels given in the specification, containment pressure during the design basis accident is approximately 49 psig, which is below the maximum of 62 psig. The maximum water level indications of -1 inch corresponds to a downcomer submergence of three feet seven inches and a water volume of 127,800 cubic feet with or 128,700 cubic feet without the drywell-suppression chamber differential pressure control. The minimum water level indication of -6.25 inches with differential pressure control and -7.25 inches without differential pressure control corresponds to a downcomer submergence of approximately three feet and a water volume of approximately 123,000 cubic feet.

ENCLOSURE 2

DESCRIPTION AND JUSTIFICATION
BROWNS FERRY NUCLEAR PLANT (BFN)

Description of Change

The BFN Units 1, 2, and 3 Technical Specifications Table 3.7.A, "Primary Containment Isolation Valves," is being updated and corrected to reflect changes due to plant modifications and the BFN Appendix J program. The table is being expanded to include all primary containment isolation valves.

Specific details of the change are as follows:

Note: Changes apply to all units unless specified otherwise.

A. Delete from technical specification table 3.7.A the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) steamline drain valves (FCV-71-6A, 6B, and FCV-73-6A, 6B), the RCIC condensate pump drain valves (FCV-71-7A, 7B), and the HPCI hotwell pump discharge isolation valves (FCV-73-17A, 17B). Delete the Group 7 description from bases section 3.7.

B. Separate FCV-84-19 and FCV-84-20 (CAD System Torus/Drywell Exhaust to Standby Gas Treatment) into two entries in table 3.7.A. FCV-84-20 is a group 6 valve. FCV-84-19 will no longer be a group 6 valve and will have no maximum operating time.

C. Combine the existing 10 CFR 50, Appendix J valve testing tables (tables 3.7.D, E, and F) into table 3.7.A and make necessary changes to reflect the current BFN Appendix J program. Pertinent notes are also added to designate the applicability of the valves in the revised table 3.7.A to local leak rate testing.

D. Delete testable penetration tables 3.7.B, C, and H.

E. Delete control rod hydraulic return check valve (85-573).

F. For unit 2 only - Delete the residual heat removal (RHR) flush and drain vent to suppression chamber valves FCV-74-102, 103, 119, and 120.

G. For unit 2 only - Delete the torus and drywell oxygen sample line valves to analyzers A and B, FCV-76-51, 52, 53, 54, 61, 62, 63, and 64.

H. For unit 2 only - Add the containment atmosphere dilution (CAD) crosstie to drywell control air check valve 84-617.

I. Delete HPCI/RCIC pump discharge isolation valves (FCV-73-44 and 71-39).

J. Add HPCI pump suction isolation valves (73-26, 73-27) to the group 4 isolation valves.

K. Make the following administrative changes to the technical specifications:

1. Add valve numbers to reactor water sample line isolation valves, FCV-43-13 and 14.

2. Change the reactor vessel water level isolation setpoint from 470 inches to 378 inches on the single asterisk note on technical specification page 3.7/4.7-25 for units 1 and 2 and page 3.7/4.7-24 for unit 3.

3. Revise descriptions of FCV-76-17, 18, and 19 and FCV-64-18 to more accurately identify their functions.

4. Add valve numbers to traversing incore probe (TIP) guide tubes, FCV-94-501, 502, 503, 504, and 505.

5. Change valve description (for FCV-73-81) to HPCI warmup. Change normal position to closed.

6. Move "Note 1" on technical specification page 3.7/4.7-27 for units 1 and 2 and page 3.7/4.7-26 for unit 3 to the notes for table 3.7.A and renumber as note "Note 6." Change the normal position of the valves applicable to this note to "o/c" denoting open/closed, and the action on initiating signal to "GC/SC" denoting go closed/stay closed.

7. Editorial change to SR 4.7.A.2.g.

8. Correct errors in table 3.7.A.

9. Renumber remaining pages of section 3.7/4.7 to be consistent.

<u>Reason for Change</u>

The changes are made to update table 3.7.A for recent modifications and to combine the 10 CFR 50 Appendix J valve testing requirements into one table.

<u>Justification for Changes</u>

A. These valves described as "Group 7" isolation valves are system isolation valves, perform no containment isolation function, and receive no primary containment isolation signal (PCIS). The valves are located outboard of the primary containment isolation valves. The valves only isolate when the respective system turbine steam supply valve is not fully closed. Deleting these valves from table 3.7.A will eliminate possible confusion as to the function and operability requirement of the valves.

Justification for Change (Cont'd)

B. FCV 84-19 does not isolate on a Group 6 containment isolation signal. The valve is normally closed and requires a senior reactor operator to unlock the hand switch before the valve can be opened.

A separate entry is proposed for FCV-84-20 with a Group 6 designator with no change to the existing technical specification requirements for this valve.

C. Combining tables 3.7.D, E, and F into table 3.7.A and properly noting testing applicability will eliminate the confusion that exists when comparing table 3.7.A to tables 3.7.D, E, and F.

Changes to the BFN Appendix J testing program have resulted in some valves being added to the program and other valves which have been redefined as being subject to the local leakage criteria of 0.60 La. The changes to the BFN Appendix J program are conservative changes that reflect current Appendix J testing requirements.

Notes 1-5 and 7 are proposed to delineate specific local leak-rate testing applicability.

D. BFN Technical Specification 4.7.A.2 requires that the provisions of the 10 CFR 50, Appendix J, be satisfied for BFN Units 1, 2, and 3. Furthermore, 10 CFR 50.54(o) requires that all water cooled power reactors meet the containment leakage test requirements set forth in Appendix J. Appendix J of 10 CFR 50 defines the primary containment penetrations for which Type B leak rate tests are required to be performed.

Lists of primary penetrations for which Type B tests must be performed are maintained for BFN Units 1, 2, and 3 in the Appendix J program (BFN Site Director Standard Practice 17.1). Since the information being deleted from BFN technical specification is contained in the Appendix J program, and since a test report listing the penetrations tested is required to be submitted for NRC review after each integrated leak rate test, no reductions in testing requirements or NRC review will result due to this change. Standard Technical Specification NUREG-1202 (Hope Creek) does not contain lists of primary containment penetrations for leak-rate test requirements.

E. This valve was physically removed from each unit per the recommendations of General Electric Service Information Letter 200-R2. The valve was inadvertently left in table 3.7.A. This change will bring the technical specification table 3.7.A up to date.

F. These valves (unit 2 only) are no longer isolation valves. The valves are still installed and are used for RHR drain and vent but are no longer connected to the primary containment. As they are no longer primary containment isolation valves, they have been deleted from the table.

<u>Justification for Change</u> (Cont'd)

G. These valves have been deleted per an ECN (unit 2 only).

H. This valve has been added per a recent ECN (unit 2 only) and provides Appendix R long-term drywell control air capability.

I. The HPCI/RCIC pump discharge isolation valves (FCV-71-39 and FCV-73-44) do not perform a containment isolation function. These valves automatically open on an accident signal to allow the systems to perform their safety function. The flowpaths for these systems contain two check valves in series which serve as automatic isolation valves under the BFN design basis described in FSAR section 5.2.3.5. These check valves are now included in table 3.7.A as containment isolation valves (they had previously been listed on table 3.7.D).

J. The HPCI pump suction isolation valves have the same automatic isolation logic as the other Group 4 isolation valves.

K. This item contains administrative changes to the technical specifications to revise valve descriptions, add unique valve identifiers to the tables, and other minor changes to the tables for consistency throughout. These changes are administrative in nature and make the table more usable.

ENCLOSURE 3

DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATION
BROWNS FERRY NUCLEAR PLANT (BFN)

Description of Amendment Request

The proposed amendment would change the technical specification of BFN Units 1, 2, and 3 to accomplish the following:

1. Combine the existing 10 CFR 50, Appendix J valve testing tables (tables 3.7.D, E, and F) into the primary containment isolation valve table (table 3.7.A) and delete the testable penetration tables (tables 3.7.B, C, and H).

2. Add to table 3.7.A valves which have been added to the Appendix J testing program and those which have been redefined as subject to the local leak rate test criteria of 0.60 La. Delete from table 3.7.A two valves that are not containment isolation valves.

3. Correct table 3.7.A to reflect plant configuration.

4. Add clarity to sections of technical specification 3.7/4.7.

Basis for Proposed No Significant Hazards Consideration Determination

NRC has provided standards for determining whether a significant hazards consideration exists as stated in 10 CFR 50.92(c). A proposed amendment to an operating license involves no significant hazards considerations if operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated, (2) create the possibility of a new or different kind of accident from an accident previously evaluated, or (3) involve a significant reduction in a margin of safety.

A discussion of these standards as they relate to this amendment follows.

1. The proposed amendment will not involve an increase in the probability or consequences of an accident previously evaluated. There is no change in the BFN commitment to comply with the provisions of Appendix J to 10 CFR 50, and by incorporating the valve testing tables into table 3.7.A. confusion regarding the requirements of primary containment isolation valves will be reduced.

2. The proposed amendment will not create the possibility of a new or different kind of accident from any accident previously analyzed since it does not eliminate or modify any requirement or commitment to comply with the provisions of 10 CFR 50, Appendix J, or BFN Technical Specification 3/4.7.A.

Basis for Proposed No Significant Hazards Consideration Determination

3. The margins of safety will not be reduced since the requirements of and the BFN commitment to comply with the provisions of 10 CFR 50, Appendix J, and BFN technical specification 3/4.7.A remain unchanged.

Determination of Basis for Proposed No Significant Hazards (Cont'd)

Since the application for amendment involves a proposed change that is encompassed by the criteria for which no significant hazards consideration exists, TVA has made a proposed determination that the application involves no significant hazards consideration.