WATTS BAR NUCLEAR PLANT

DRAFT TECHNICAL SPECIFICATIONS

ENCLOSURE 1

ITEM E1.1

<u>Definition of E-Average Disintegration Energy</u> (Pages 1-2 and 3/4 4-29)

This definition is questionable. In earlier versions and in Table 4.4-4 footnotes of this version, iodine activity is excluded and there is an exclusion statement based on half-lives of less than 10 minutes. Also a clarification has been requested from the NRC concerning H-3, SR-89, and 90. (Beta emitters)

CONTAINMENT INTEGRITY

1.7 CONTAINMENT INTEGRITY shall exist when:

a. All penetrations required to be closed during accident conditions are either:

   1) Capable of being closed by an OPERABLE containment automatic isolation valve system, or

   2) Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except as provided in Table 3.6-2 of Specification 3.6.3.

b. All equipment hatches are closed and sealed,

c. Each air lock is in compliance with the requirements of Specification 3.6.1.3,

d. The containment leakage rates are within the limits of Specification 3.6.1.2, and

e. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

CONTROLLED LEAKAGE

1.8 CONTROLLED LEAKAGE shall be that seal water flow supplied to the reactor coolant pump seals.

CORE ALTERATION

1.9 CORE ALTERATION shall be the movement or manipulation of any component within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATION shall not preclude completion of movement of a component to a safe conservative position.

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microCurie/gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites" (or Table E-7 of NRC Regulatory Guide 1.109, Rev. 1, October 1977).

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the sample) of the sum of the average beta and gamma energies per disintegration (MeV/d) for the radionuclides in the sample.

TABLE 4.4-4

REACTOR COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Gamma Specific Activity Determination**	At least once per 72 hours	1, 2, 3, 4
2. ~~Isotopic Analysis for~~ DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination***	1 per 6 months*	1
4. DOSE EQUIVALENT ~~Isotopic Analysis for Iodine Including~~ I-131, ~~I-133, and I-135~~ Concentration and Gross Gamma Specific Activity	a) Once per 4 hours, whenever the specific activity exceeds 1 μCi/gram DOSE EQUIVALENT I-131 or 100/$\bar{E}$ μCi/gram, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1-hour period.	1, 2, 3

#Until the specific activity of the Reactor Coolant System is restored within its limits.

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

**A gross gamma radioactivity analysis shall consist of quantitative measurement of the total specific activity of the reactor coolant except for radionuclides with half lives less than 10 minutes and all radioiodines. The total gamma specific activity shall be the sum of the degassed ~~beta~~ gamma activity and the total of all identified gaseous activities in the sample within 2 hours after the sample is taken and extrapolated back to when the sample was taken.

***A radiochemical analysis for $\bar{E}$ shall consist of the quantitative measurement of the specific activity for each radionuclide, except for radionuclides with half lives less than 10 minutes and all radioiodines, which is identified in the reactor coolant. The specific activities for these individual radionuclides shall be used in the determination of $\bar{E}$ for the reactor coolant sample.

ITEM E1.2

Definition of Dewatering (Pages 1-2, 1-4, and 3/4 11-17)

We request that NRC incorporate the definition of DEWATERING into Section 1 of the tech specs. The new definition of SOLIDIFICATION no longer covers dewatering. Attached are the changes required to the specs. This matter was discussed with Jack Nehamias of REB branch of NRC on March 29, 1983.

CONTAINMENT INTEGRITY

1.7 CONTAINMENT INTEGRITY shall exist when:

a. All penetrations required to be closed during accident conditions are either:

   1) Capable of being closed by an OPERABLE containment automatic isolation valve system, or

   2) Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except as provided in Table 3.6-2 of Specification 3.6.3.

b. All equipment hatches are closed and sealed,

c. Each air lock is in compliance with the requirements of Specification 3.6.1.3,

d. The containment leakage rates are within the limits of Specification 3.6.1.2, and

e. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

CONTROLLED LEAKAGE

1.8 CONTROLLED LEAKAGE shall be that seal water flow supplied to the reactor coolant pump seals.

CORE ALTERATION

1.9 CORE ALTERATION shall be the movement or manipulation of any component within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATION shall not preclude completion of movement of a component to a safe conservative position.

ADD DEWATERING → (see attached)

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microCurie/gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites" (or Table E-7 of NRC Regulatory Guide 1.109, Rev. 1, October 1977).

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the sample) of the sum of the average beta and gamma energies per disintegration (MeV/d) for the radionuclides in the sample.

DEWATERING

Dewatering shall be the removal of unbound liquid from bead resins, powdered resins, and/or filter sludges to form a waste product as specified in the PROCESS CONTROL PROGRAM (PCP).

OPERABLE - OPERABILITY

1.18 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s), and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL MODE - MODE

1.19 An OPERATIONAL MODE (i.e., MODE) shall correspond to any one inclusive combination of core reactivity condition, power level, and average reactor coolant temperature specified in Table 1.2.

PHYSICS TESTS

1.20 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the core and related instrumentation: (1) described in Chapter 14.0 of the FSAR, or (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.21 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a nonisolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.

PROCESS CONTROL PROGRAM

1.22 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the SOLIDIFICATION of wet radioactive wastes results in a waste form with properties that meet the requirements of 10 CFR Part 61 and of low level radioactive waste disposal sites. The PCP shall identify process parameters influencing SOLIDIFICATION such as pH, oil content, H_2O content, solids content, ratio of solidification agent to waste and/or necessary additives for each type of anticipated waste, and the acceptable boundary conditions for the process parameters shall be identified for each waste type, based on laboratory scale and full scale testing or experience. The PCP shall also include an identification of conditions that must be satisfied, based on full scale testing, to assure that ~~dewatering~~ of bead resins, powdered resins, and filter sludges will result in volumes of free water, at the time of disposal, within the limits of 10 CFR Part 61 and of low level radioactive waste disposal sites.

DEWATERING

RADIOACTIVE EFFLUENTS

3/4.11.3 SOLID RADIOACTIVE WASTE

LIMITING CONDITION FOR OPERATION

3.11.3 Radioactive wastes shall be solidified or dewatered in accordance with the PROCESS CONTROL PROGRAM to meet shipping and transportation requirements during transit, and disposal site requirements when received at the disposal site.

APPLICABILITY: At all times.

ACTION:

a. With SOLIDIFICATION or ~~dewatering~~ DEWATERING not meeting disposal site and shipping and transportation requirements, suspend shipment of the inadequately processed wastes and correct the PROCESS CONTROL PROGRAM, and procedures and/or the Solid Waste System as necessary to prevent recurrence.

b. With SOLIDIFICATION or ~~dewatering~~ DEWATERING not performed in accordance with the PROCESS CONTROL PROGRAM: (1) test the improperly processed waste in each container to ensure that it meets burial ground and shipping requirements, and (2) take appropriate administrative action to prevent recurrence.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.3 SOLIDIFICATION of at least one representative test specimen from at least every tenth batch of each type of wet radioactive waste (e.g., filter sludges, spent resins, evaporator bottoms, boric acid solutions, and sodium sulfate solutions) shall be verified in accordance with the PROCESS CONTROL PROGRAM:

a. If any test specimen fails to verify SOLIDIFICATION, the SOLIDIFICATION of the batch under test shall be suspended until such time as additional test specimens can be obtained, alternative SOLIDIFICATION parameters can be deteremined in accordance with the PROCESS CONTROL PROGRAM, and a subsequent test verifies SOLIDIFICATION. SOLIDIFICATION of the batch may then be resumed using the alternative SOLIDIFICATION parameters determined by the PROCESS CONTROL PROGRAM;

b. If the initial test specimen from a batch of waste fails to verify SOLIDIFICATION, the PROCESS CONTROL PROGRAM shall provide for the collection and testing of representative test specimens from each consecutive batch of the same type of wet waste until at least three

ITEM E1.3

Three RC Loop Operation (Pages 2-1, 2-2, 2-3, B 2-1, 3/4 1-1, 3/4 1-19, 3/4 1-21, 3/4 1-22, 3/4 1-23, 3/4 2-8, 3/4 2-10, 3/4 2-16, 3/4 3-2, 3/4 3-6, 3/4 7-1, 3/4 7-2, B 3/4 7-1, and B 3/4 7-2)

TVA does not intend to operate with only 3 RC loops at Watts Bar and thus, has not requested NRC approval for 3 loop operation. Therefore the references in the technical specifications to 3 loop operation are unnecessary. In order to keep extraneous material to a minimum, all references to 3 loop operation should be deleted from the specs.

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and the highest operating loop coolant temperature (T_{avg}) shall not exceed the limits shown in Figure~~s~~ 2.1-1 ~~and 2.1-2 for four loop and three loop operation, respectively~~.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of the highest operating loop average temperature and THERMAL POWER has exceeded the appropriate pressurizer pressure line, be in HOT STANDBY within 1 hour, and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2735 psig.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour, and comply with the requirements of Specification 6.7.1.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2735 psig, reduce the Reactor Coolant System pressure to within its limit within 5 minutes, and comply with the requirements of Specification 6.7.1.

REACTOR CORE SAFETY LIMIT - ~~FOUR LOOPS IN OPERATION~~

Figure 2.1-2 left blank pending NRC approval of three-loop operation.

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB through the W-3 correlation. The W-3 DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, and is indicative of the margin to DNB.

The minimum value of the DNBR during steady-state operation, normal operational transients, and anticipated transients is limited to 1.30. This value corresponds to a 95% probability at a 95% confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The curve~~s~~ of Figure~~s~~ 2.1-1 ~~and Figure 2.1-2~~ show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than 1.30, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

Th~~ese~~ is curve~~s~~ ~~are~~ is based on an enthalpy hot channel factor, $F^N_{\Delta H}$, of 1.55 and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} = 1.55\ [1 + 0.2\ (1-P)]$$

Where P is the fraction of RATED THERMAL POWER.

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion assuming the axial power imbalance is within the limits of the f_1 (delta I) function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature Delta T trips will reduce the Setpoints to provide protection consistent with core Safety Limits.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - T_{avg} >200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to 1.6% delta k/k ~~for four loop operation~~.

APPLICABILITY: MODES 1, 2*, 3, and 4.

ACTION:

With the SHUTDOWN MARGIN less than 1.6% delta k/k, immediately initiate and continue boration at greater than or equal to 10 gpm of a solution containing greater than or equal to 20,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.6% delta k/k:

a. Within ~~one~~ 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s);

b. When in MODE 1 or MODE 2 with K_{eff} greater than or equal to 1.0 at least once per 12 hours by verifying that control bank withdrawal is within the limits of Specification 3.1.3.6;

c. When in MODE 2 with K_{eff} less than 1.0, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.6;

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of Specification 4.1.1.1.1e below, with the control banks at the maximum insertion limit of Specification 3.1.3.6; and

*See Special Test Exception 3.10.1.

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and control) rod drop time from the fully withdrawn position shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 551°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With the drop time of any full-length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

~~b. With the rod drop times within limits but determined with three reactor coolant pumps operating, operation may proceed provided THERMAL POWER is restricted to:~~

~~1. Less than or equal to (*)% of RATED THERMAL POWER when the reactor coolant stop valves in the nonoperating loop are open, or~~

~~2. Less than or equal to (*)% of RATED THERMAL POWER when the reactor coolant stop valves in the nonoperating loop are closed.~~

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of full-length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the Control Rod Drive System which could affect the drop time of those specific rods, and

c. At least once per 18 months.

~~*These values left blank pending NRC approval of three loop operation.~~

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control banks shall be limited in physical insertion as shown in Figure~~s~~ 3.1-1 ~~and 3.1-2.~~

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification 4.1.3.1.2:

a. Restore the control banks to within the limits within 2 hours, or

b. Reduce THERMAL POWER within 2 hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the above figures, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each control bank shall be determined to be within the insertion limits at least once per 12 hours except during time intervals when the rod insertion limit monitor is inoperable, then verify the individual rod positions at least once per 4 hours.

*See Special Test Exceptions 3.10.2 and 3.10.3.
#With K_{eff} greater than or equal to 1.0.

FIGURE 3.1-1

ROD BANK INSERTION LIMITS VERSUS THERMAL POWER

~~FOUR LOOP OPERATION~~

Figure 3.1-2 left blank pending NRC approval of three-loop operation

3/4.2.3 RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

LIMITING CONDITION FOR OPERATION

3.2.3 The combination of indicated Reactor Coolant System (RCS) total flow rate and R_1, R_2 shall be maintained within the region of allowable operation shown on Figure 3.2-3 ~~for four loop operation~~.

Where:

a. $R_1 = \dfrac{F^N_{\Delta H}}{1.49\ [1.0 + 0.2\ (1.0 - P)]}$,

b. $R_2 = \dfrac{R_1}{[1\text{-}RBP(BU)]}$,

c. $P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$,

d. $F^N_{\Delta H}$ = Measured values of $F^N_{\Delta H}$ obtained by using the movable incore detectors to obtain a power distribution map. The measured values of $F^N_{\Delta H}$ shall be used to calculate R since Figure 3.2-3 includes measurement uncertainties of 3.5% for flow and 4% for incore measurement of $F^N_{\Delta H}$, and

e. RBP (BU) = Rod Bow Penalty as a function of region average burnup as shown in Figure 3.2-4, where a region is defined as those assemblies with the same loading date (reloads) or enrichment (first core).

APPLICABILITY: MODE 1.

ACTION:

With the combination of RCS total flow rate and R_1, R_2 outside the region of acceptable operation shown on Figure 3.2-3:

a. Within 2 hours either:

1. Restore the combination of RCS total flow rate and R_1, R_2 to within the above limits, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER and reduce the Power Range Neutron Flux - High Trip Setpoint to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

FIGURE 3.2-3
RCS TOTAL FLOW RATE VERSUS R_1 AND R_2
~~FOUR LOOPS IN OPERATION~~

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS: Four Loops in Operation	LIMITS: ~~Three Loops in Operation~~
Reactor Coolant System T_{avg}	$\leq$ 593°F	~~(**)~~
Pressurizer Pressure	$\geq$ 2220 psia*	~~(**)~~

*Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% of RATED THERMAL POWER.

~~**These values left blank pending NRC approval of three loop operation.~~

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2 2	1 1	2 2	1, 2 3*, 4*, 5*	1 10
2. Power Range, Neutron Flux - High Setpoint	4	2	3	1, 2	$2^{\#}$
Low Setpoint	4	2	3	$1^{\#\#\#}$, 2	$2^{\#}$
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	$2^{\#}$
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	$2^{\#}$
5. Intermediate Range, Neutron Flux	2	1	2	$1^{\#\#\#}$, 2	3
6. Source Range, Neutron Flux					
a. Startup	2	1	2	$2^{\#\#}$	4
b. Shutdown	2	1	2	3*, 4*, 5*	10
c. Shutdown	2	0	1	3, 4, and 5	5
7. Overtemperature ΔT					
a. Four Loop Operation	4	2	3	1, 3	$6^{\#}$
~~b. Three Loop Operation~~	~~(**)~~	~~(**)~~	~~(**)~~	~~(**)~~	~~(**)~~
8. Overpower ΔT					
a. Four Loop Operation	4	2	3	1, 2	$6^{\#}$
~~b. Three Loop Operation~~	~~(**)~~	~~(**)~~	~~(**)~~	~~(**)~~	~~(**)~~
9. Pressurizer Pressure-Low	4	2	3	1	$6^{\#}$
10. Pressurizer Pressure--High	4	2	3	1, 2	$6^{\#}$
11. Pressurizer Water Level--High	3	2	2	1	$7^{\#}$

TABLE 3.3-1 (Continued)

TABLE NOTATION

*With the Reactor Trip System breakers in the closed position, the Control Rod Drive System capable of rod withdrawal.

~~**Values left blank pending NRC approval of three loop operation.~~

#The provisions of Specification 3.0.4 are not applicable.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 1 hour;

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 2 hours for surveillance testing of other channels per Specification 4.3.1.1; and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line Code safety valves associated with each steam generator shall be OPERABLE with lift settings as specified in Table 3.7-3.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With four reactor coolant loops and associated steam generators in operation and with one or more main steam line Code safety valves inoperable, operation in MODES 1, 2, and 3 may proceed provided, that within 4 hours, either the inoperable valve is restored to OPERABLE status or the Power Range Neutron Flux High Trip Setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

~~b. With three reactor coolant loops and associated steam generators in operation and with one or more main steam line Code safety valves associated with an operating loop inoperable, operation in MODES 1, 2, and 3 may proceed provided, that within 4 hours, either the inoperable valves is restored to OPERABLE status or the Power Range Neutron Flux High Trip Setpoint is reduced per Table 3.7-2; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.~~

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 No additional requirements other than those required by Specification 4.0.5.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING FOUR LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	87
2	65
3	43

TABLE 3.7-2

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING THREE LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR*	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	(**)
2	(**)
3	(**)

* ~~At least two safety valves shall be OPERABLE on the non-operating steam generator.~~

** ~~These values left blank pending NRC approval of three loop operation.~~

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary Coolant System pressure will be limited to within 110% (1303 psig) of its design pressure of 1185 psig during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is 1.59×10^7 lbs/hr which at 1284 psig is 105% of the total secondary steam flow of 15.14×10^6 lbs/hr at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-2.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor trip settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

For four loop operation:

$$SP = \frac{(X) - (Y)(V)}{X} \times (109)$$

~~For three loop operation:~~

$$\cancel{SP = \frac{(X) - (Y)(U)}{X} \times (*)}$$

Where:

SP = Reduced Reactor Trip Setpoint in percent of RATED THERMAL POWER,

V = Maximum number of inoperable safety valves per steam line,

U = Maximum number of inoperable safety valves per operating steam line, SAFETY VALVES (Continued)

109 = Power Range Neutron Flux-High Trip Setpoint for four loop operation,

~~* = Maximum percent of RATED THERMAL POWER permissible by P-8 Setpoint for three loop operation. (This value left blank pending NRC approval of three loop operation.),~~

X = Total relieving capacity of all safety valves per steam line in lbs/hour of 3.98 x 10^6 lbs/hr at 1284 psig, and

Y = Maximum relieving capacity of any one safety valve in lbs/hour of 795,000 lb/hr at 1284 psig.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of offsite power.

The steam-driven auxiliary feedwater pump is capable of delivering 940 gpm (total feedwater flow) and each of the electric-driven auxiliary feedwater pumps are capable of delivering 470 gpm (total feedwater flow) to the entrance of the steam generators at steam generator pressures equivalent to that required to relieve 11% of nominal flow from the steam generator's safety valves. A total feedwater flow of 470 gpm is sufficient to ensure that adequate feed-water flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F where the RHR System may be placed into operation.

3/4.7.1.3 CONDENSATE STORAGE TANK

The OPERABILITY of the condensate storage tank with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 2 hours with steam discharge to the atmosphere concurrent with total loss of offsite power. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.7.1.4 SPECIFIC ACTIVITY

The limitations on Secondary Coolant System specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 dose guideline values in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm reactor to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the accident analyses.

ITEM E1.4

Power Range Negative Rate Trip T.S. page B2-4 (Reference WB FSAR, page 15.2-14a)

The bases for this trip has been modified to more accurately reflect the circumstances under which Watts Bar rod drop event analysis was performed. From this analysis it is concluded that the DNBR will remain conservative (above 1.30) for all dropped single RCCA. The analysis takes no credit for a reactor trip for a dropped single RCCA.

Power Range, Neutron Flux, High Rates

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of a rupture of a control rod drive housing. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from mid-power.

The Power Range Negative Rate trip provides protection for control rod drop accidents. At high power a ~~single or~~ multiple rod drop accident could cause local flux peaking which could cause an unconservative local DNBR to exist. The Power Range Negative Rate trip will prevent this from occurring by tripping the reactor. No credit is taken for operation of the Power Range Negative Rate trip for ~~those~~ single control rod drop accidents (since ~~for which~~ DNBR's will remain ~~be~~ greater than 1.30)

Intermediate and Source Range, Neutron Flux

The Intermediate and Source Range, Neutron Flux trips provide core protection during reactor startup ~~STARTUP~~ to mitigate the consequences of an uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition. These trips provide redundant protection to the Low Setpoint trip of the Power Range, Neutron Flux channels. The Source Range channels will initiate a Reactor trip at about 10^5 counts per second unless manually blocked when P-6 becomes active. The Intermediate Range channels will initiate a Reactor trip at a current level equivalent to approximately 25% of RATED THERMAL POWER unless manually blocked when P-10 becomes active.

It is shown that in all cases of dropped single RCCA, the DNBR remains greater than 1.30 at power and, consequently, a dropped single RCCA does not cause core damage.

For all cases of dropped banks, the reactor is tripped by the power range negative neutron flux rate trip and consequently dropped banks do not cause core damage.

For all cases of any bank inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn, the DNBR remains greater than 1.30.

ITEM E1.5

Table 2.2-1 and Bases (Pages 2-7 and B2-6)

The setpoint for P-8 should be increaseed to 48% with an allowable value of 49% to agree with the Watts Bar Safety Analysis and Westinghouse P.L.S.

References

WBNP FSAR 15.3.4
W P.L.S. B.I.4.c

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
20. Reactor Trip System Interlocks		
A. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
B. Low Power Reactor Trips Block, P-7		
a. P-10 Input	10% of RATED THERMAL POWER	≥ 9%, ≤ 11% of RATED THERMAL POWER
b. P-13 Input	≤ 10% RTP Turbine Impulse Pressure Equivalent	≤ 11% RTP Turbine Impulse Pressure Equivalent
C. Power Range Neutron Flux, P-8	≤ ~~35%~~ 48% of RATED THERMAL POWER	≤ ~~36%~~ 49% of RATED THERMAL POWER
D. Low Setpoint Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	≥ 9%, ≤ 11% of RATED THERMAL POWER
E. Turbine Impulse Chamber Pressure, P-13	≤ 10% RTP Turbine Impulse Pressure Equivalent	≤ 11% RTP Turbine Impulse Pressure Equivalent
F. Power Range Neutron Flux, P-9	≤ 50% of RATED THERMAL POWER	≤ 51% of RATED THERMAL POWER
21. Reactor Trip Breakers	Not Applicable	Not Applicable
22. Automatic Trip Logic	Not Applicable	Not Applicable

Pressurizer Pressure

In each of the pressure channels, there are two independent bistables, each with its own trip setting to provide for a High and Low Pressure trip thus limiting the pressure range in which reactor operation is permitted. The Low Setpoint trip protects against low pressure which could lead to DNB by tripping the reactor in the event of a loss of reactor coolant pressure.

On decreasing power the Low Setpoint trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with turbine impulse chamber pressure at approximately 10% of full power equivalent); and on increasing power, automatically reinstated by P-7.

The High Setpoint trip functions in conjunction with the pressurizer relief and safety valves to protect the Reactor Coolant System against system overpressure.

Pressurizer Water Level

The Pressurizer High Water Level trip is provided to prevent water relief through the pressurizer safety valves. On decreasing power the Pressurizer High Water Level trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine impulse chamber pressure at approximately 10% of full equivalent); and on increasing power, automatically reinstated by P-7.

Loss of Flow

The Loss of Flow trips provide core protection to prevent DNB by mitigating the consequences of a loss of flow resulting from the loss of one or more reactor coolant pumps.

On increasing power above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine impulse chamber pressure at approximately 10% of full power equivalent), an automatic Reactor trip will occur if the flow in more than one loop drops below 90% of nominal full loop flow. Above P-8 (a power level of approximately ~~35%~~ 48% of RATED THERMAL POWER) an automatic Reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. Conversely on decreasing power between P-8 and the P-7 an automatic Reactor trip will occur on loss of flow in more than one loop and below P-7 the trip function is automatically blocked.

<u>Table 2.2-1</u> (Page 2-5)

Design Flow is the flow rate given in R_1, less the uncertainties

$$F + 3.5\%F = R_1$$

$$1.035F = R_1$$

$$F = R_1/1.035$$

$$F = 403{,}600/1.035$$

$$4 = 389{,}951 \text{ gpm}$$

$$\text{Loop Flow} = \frac{F}{4}$$

$$L.F = 97{,}488 \text{ gpm}$$

$$\text{FSAR Flow} = 97{,}500 \text{ gpm}$$

The design flow for Table 2.2-1 is therefore 97,500 gpm

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Range, Neutron Flux	Low Setpoint - $\leq$ 25% of RATED THERMAL POWER High Setpoint - $\leq$ 109% of RATED THERMAL POWER	Low Setpoint - $\leq$ 26% of RATED THERMAL POWER High Setpoint - $\leq$ 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	$\leq$ 5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds	$\leq$ 5.5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	$\leq$ 5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds	$\leq$ 5.5% of RATED THERMAL POWER with a time constant $\geq$ 2 seconds
5. Intermediate Range, Neutron Flux	$\leq$ 25% of RATED THERMAL POWER	$\leq$ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	$\leq 10^5$ counts per second	$\leq 1.5 \times 10^5$ counts per second
7. Overtemperature ΔT	See Note 1	See Note 3
8. Overpower ΔT	See Note 2	See Note 3
9. Pressurizer Pressure--Low	$\geq$ 1950 psig	$\geq$ 1930 psig
10. Pressurizer Pressure--High	$\leq$ 2385 psig	$\leq$ 2395 psig
11. Pressurizer Water Level--High	$\leq$ 92% of instrument span	$\leq$ 93% of instrument span
12. Loss of Flow-Single Loop (Above P-8)	$\geq$ 90% of design flow per loop*	$\geq$ 89% of design flow per loop*
13. Loss of Flow-Two Loops (Above P-7 and Below B-8)	$\geq$ 90% of design flow per loop*	$\geq$ 89% of design flow per loop*

*Design flow is ~~94,400~~ 97,500 gpm per loop.

ITEM E1.7

<u>Surveillance Requirements 4.1.2.4.1 and 4.5.2(f)</u> (Page 3/4 1-10 and 3/4 5-7)

ASME Section XI requires that the test be run under repeatable conditions. It no longer requires that a test must be run in recirculation mode. Watts Bar feels that the pump test that is run during Modes 1-4 should be run at normal operating conditions rather than realigning the system to do the test in recirculation mode. This would eliminate the potential for error in realignment of the system and placing it back in service.

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4#.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4.1 At least two charging pumps shall be demonstrated OPERABLE by verifying, ~~on recirculation flow~~, a differential pressure across each pump of greater than or equal to ~~2400~~ psid is developed when tested pursuant to Specification 4.0.5.
To be provided later

4.1.2.4.2 All charging pumps, except the above required OPERABLE pump, shall be demonstrated inoperable at least once per 31 days whenever the temperature of one or more of the RCS cold legs is less than or equal to 310°F by verifying that the motor circuit breakers are secured in the open position.

A maximum of one centrifugal charging pump shall be OPERABLE whenever the temperature of one or more of the RCS cold legs is less than or equal to 310°F.

SURVEILLANCE REQUIREMENTS (Continued)

e. At least once per 18 months, during shutdown, by:

1) Verifying that each automatic valve in the flow path actuates to its correct position on Safety Injection actuation and Automatic Switchover to Containment Sump test signals, and

2) Verifying that each of the following pumps start automatically upon receipt of a Safety Injection actuation test signal:

a) Centrifugal charging pump,

b) Safety injection pump, and

c) RHR pump.

f. By verifying that each of the following pumps develops the indicated discharge pressure ~~on recirculation flow~~ when tested pursuant to Specification 4.0.5:

1) Centrifugal charging pump ≥ ~~2400~~ To be provided later psig,

2) Safety Injection pump ≥ 1407 psig, and (recirc flow)

3) RHR pump ≥ 165 psig. (recirc flow)

g. By verifying the correct position of the following ECCS throttle valves:

1) Within 4 hours following completion of each valve movement or maintenance on the valve when the ECCS subsystems are required to be OPERABLE, and

2) At least once per 18 months.

CC Discharge Valve Number	SI Cold Leg Throttle Valves Valve Number	SI Hot Leg Throttle Valves Valve Number
63-582	63-550	63-542
63-583	63-552	63-544
63-584	63-554	63-546
63-585	63-556	63-548

ITEM E1.8

Figure 3.1-2 (Page 3/4 1-22)

The figure for rod bank insertion limits versus thermal power was provided in TVA's 12/4/81 submittal.

ITEM E1.9

Surveillance Requirement 4.2.1.4 (Page 3/4 2-2)

The end of cycle predicted axial offset at full power may or may not be zero. The linear interpolation should be performed between the last measured valve and the predicted end of cycle value.

LIMITING CONDITION FOR OPERATION

ACTION (Continued)

c. THERMAL POWER shall not be increased above 50% of RATED THERMAL POWER unless the indicated AFD has not been outside of the ±5% target band for more than 1 hour penalty deviation cumulative during the previous 24 hours. Power increases above 50% of RATED THERMAL POWER do not require being within the target band provided the accumulative penalty deviation is not violated.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AXIAL FLUX DIFFERENCE shall be determined to be within its limits during POWER OPERATION above 15% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1) At least once per 7 days when the AFD Monitor Alarm is OPERABLE, and

2) At least once per hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status.

b. Monitoring and logging the indicated AXIAL FLUX DIFFERENCE for each OPERABLE excore channel at least once per hour for the first 24 hours and at least once per 30 minutes thereafter, when the AXIAL FLUX DIFFERENCE Monitor Alarm is inoperable. The logged values of the indicated AXIAL FLUX DIFFERENCE shall be assumed to exist during the interval preceding each logging.

4.2.1.2 The indicated AFD shall be considered outside of its ±5% target band when 2 or more OPERABLE excore channels are indicating the AFD to be outside the target band. Penalty deviation outside of the ±5% target band shall be accumulated on a time basis of:

a. One minute penalty deviation for each 1 minute of POWER OPERATION outside of the target band at THERMAL POWER levels equal to or above 50% of RATED THERMAL POWER, and

b. One-half minute penalty deviation for each 1 minute of POWER OPERATION outside of the target band at THERMAL POWER levels between 15% and 50% of RATED THERMAL POWER.

4.2.1.3 The target flux difference of each OPERABLE excore channel shall be determined by measurement at least once per 92 Effective Full Power Days. The provisions of Specification 4.0.4 are not applicable.

4.2.1.4 The target flux difference shall be updated at least once per 31 Effective Full Power Days by either determining the target flux difference pursuant to Specification 4.2.1.3 above or by linear interpolation between the most recently measured value and ~~[illegible]~~ the predicted value at the end of the cycle life. The provisions of Specification 4.0.4 are not applicable.

ITEM E1.10

Figure 3.2-1 (Page 3/4 2-3)

The figure for axial flux difference limits as a function of rated thermal power was provided by TVA's 12/4/81 submittal.

ITEM E1.11

Figure 3.2-4 (Page 3/4 2-11)

The figure for rod blow penalty as a function of burnup was provided by TVA's 12/4/81 submittal.

ITEM E1.12

Table Notation (Pages 3/4 3-4, -6, and -8)

A turbine trip will not actuate a reactor trip below the P-9 setpoint. The turbine trip instrumentation is needed only above the P-9 setpoint. Action statement 1 should apply to turbine stop valve closure instead of action statement 11. There are no provisions designed in Watts Bar Nuclear Plant to allow a turbine stop valve closure signal to be placed in the tripped position.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
A. Low Fluid Oil Pressure	3	2	2	1####	7#
B. Turbine Stop Valve Closure	4	4	~~1~~ 4	1####	1 ~~11~~#
19. Safety Injection Input from ESF	2	1	2	1, 2	9
~~20. General Warning Alarm~~	~~2~~	~~2~~	~~2~~	~~1, 2~~	~~10~~
21. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Low Setpoint Power Range Neutron Flux, P-10	4	2	3	1, 2	8
e. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8
f. Power Range Neutron Flux, P-9	4	2	3	1	8

TABLE 3.3-1 (Continued)

TABLE NOTATION

*With the Reactor Trip System breakers in the closed position, the Control Rod Drive System capable of rod withdrawal.

~~**Values left blank pending NRC approval of three loop operation.~~

#The provisions of Specification 3.0.4 are not applicable.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

Above the P-9 (Power Range Neutron Flux Interlock) Setpoint

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 1 hour;

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 2 hours for surveillance testing of other channels per Specification 4.3.1.1; and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2. This action statement is not applicable if the QUADRANT POWER TILT RATIO is still monitored and alarmed by the excore detectors.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 10 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor trip breakers within the next hour.

~~ACTION 11 - With the number of OPERABLE channels less than the Total Number of Channels, operation may be continued provided the inoperable channels are placed in the tripped condition within 1 hour.~~

~~and with THERMAL POWER above the P-9 setpoint~~

ITEM E1.13

<u>RPS Instrumentation Testing</u> (Pages 3/4 3-6, -7, -8, -11, -12, -13, -14, and B3/4 3-1)

The changes made to the RPS instrumentation section are consistent with WCAP 10271 and the technical specification optimization program of the Westinghouse Owners Group.

Page 3/4 3-6, Action 2.c--Action 2.c is written to include failures of the excore detectors. However, the requirement to reduce power or monitor QPTR more often is excessive when the high flux and rate trip channels are inoperable because of rack equipment failures. The proposed change eliminates these requirements when the equipment failures are limited to those areas identified on the attached figure (figure 11.5-2).

TABLE 3.3-1 (Continued)

TABLE NOTATION

*With the Reactor Trip System breakers in the closed position, the Control Rod Drive System capable of rod withdrawal.

** ~~Values left blank pending NRC approval of three loop operation.~~

#The provisions of Specification 3.0.4 are not applicable.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

Above the P-9 (Power Range Neutron Flux Interlocks) Setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within ~~1~~ 6 hour;

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to ~~2~~ 4 hours for surveillance testing of other channels per Specification 4.3.1.1; and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2. This action Statement is not applicable if the QUADRENT POWER TILT RATIO is still monitored and alarmed by the excore detectors.

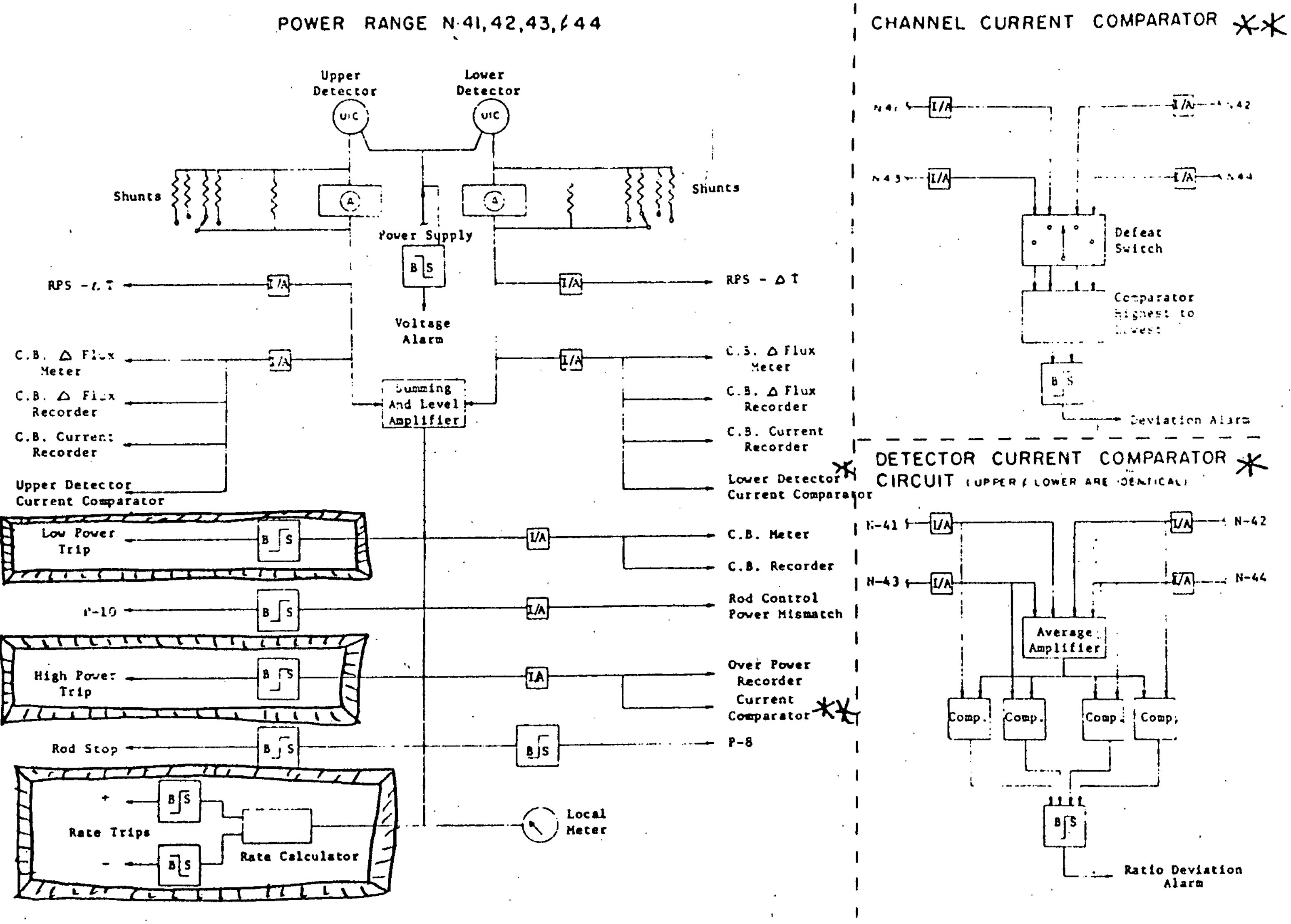

Figure 11.5-2

POWER RANGE CHANNEL BLOCK DIAGRAM

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint; and

b. Above the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint but below 10% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10% of RATED THERMAL POWER.

ACTION 4 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement suspend all operations involving positive reactivity changes.

ACTION 5 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within ~~1~~ 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to ~~2~~ 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

ACTION 7 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed ~~until performance of the next required OPERATIONAL TEST~~ provided:

a. the inoperable channel is placed in the tripped condition within 6 hours.

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

b. an additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1 provided the inoperable channel is in the tripped condition.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 4 ~~8~~ hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 10 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor trip breakers within the next hour.

ACTION 11 - With the number of OPERABLE channels less than the Total Number of Channels, operation may be continued provided the inoperable channels are placed in the tripped condition within ~~1~~ 6 hours.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux High Setpoint	S (9)	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	~~M~~ Q	N.A.	N.A.	1, 2
Low Setpoint	S (9)	R(4)	~~M~~ Q	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	~~M~~ Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	~~M~~ Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S (9)	R(4, 5)	Q ~~S/U(1), M~~	N.A.	N.A.	1###, 2
6. Source Range, Neutron Flux	S (9)	R(4, 5)	Q (9) ~~S/U(1), M(9)~~	N.A.	N.A.	2##, 3, 4, 5
7. Overtemperature ΔT	S	R	~~M~~ Q	N.A.	N.A.	1, 2
8. Overpower ΔT	S	R	~~M~~ Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure--Low	S	R	~~M~~ Q	N.A.	N.A.	1
10. Pressurizer Pressure--High	S	R	~~M~~ Q	N.A.	N.A.	1, 2
11. Pressurizer Water Level--High	S	R	~~M~~ Q	N.A.	N.A.	1
12. Loss Of Flow - Single Loop	S	R	~~M~~ Q	N.A.	N.A.	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Loss Of Flow - Two Loops	S	R	~~M~~ Q	N.A.	N.A.	1
14. Steam Generator Water Level-- Low-Low	S	R	~~M~~ Q	N.A.	N.A.	1, 2
15. Steam Generator Water Level - Low Coincident with Steam/ Feedwater Flow Mismatch	S	R	~~M~~ Q	N.A.	N.A.	1, 2
16. Undervoltage - Reactor Coolant Pumps	N.A.	R	N.A.	~~M~~ Q	N.A.	1
17. Underfrequency - Reactor Coolant Pumps	N.A.	R	N.A.	~~M~~ Q	N.A.	1
18. Turbine Trip						
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	S/U(1, 10)	N.A.	1
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	S/U(1, 10)	N.A.	1
19. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R	N.A.	1, 2
20. General Warning Alarm	N.A.	N.A.	N.A.	R.	N.A.	1, 2
21. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	~~M~~ Q	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R(4)	Q ~~M~~ (8)	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R(4)	Q ~~M~~ (8)	N.A.	N.A.	1

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
d. Low Setpoint Power Range Neutron Flux, P-10	N.A.	R (4)	Q ~~M~~ (8)	N.A.	N.A.	1, 2
e. Turbine Impulse Chamber Pressure, P-13	N.A.	R	Q ~~M~~ (8)	N.A.	N.A.	1
f. Power Range Neutron Flux, P-9	N.A.	R (4)	Q ~~M~~ (8)	N.A.	N.A.	1
22. Reactor Trip Breaker	N.A.	N.A.	N.A.	SA ~~M~~ (7,11)	N.A.	1, 2, 3*, 4*, 5*
23. Automatic Trip Logic	N.A.	N.A.	N.A.	N.A.	SA ~~M~~ (7)	1, 2, 3*, 4*, 5*

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With the Reactor Trip System breakers closed and the Control Rod Drive System capable of rod withdrawal.

- Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

- Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

(1) - If not performed in previous ~~7~~ 92 days.

(2) - Comparison of calorimetric to excore power indication above 15% of RATED THERMAL POWER. Adjust excore channel gains consistent with calorimetric power if absolute difference is greater than 2%. The provisions of Specification 4.0.4 are not applicable to entry into MODE 2 or 1.

(3) - Single point comparison of incore to excore axial flux difference above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(4) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) - Detector plateau curves shall be obtained, evaluated and compared to manufacturer's data. For the Intermediate Range and Power Range Neutron Flux channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) - Incore - Excore Calibration, above 75% of RATED THERMAL POWER. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) - Each train shall be tested at least every ~~62~~ 184 days on a STAGGERED TEST BASIS.

(8) - With power greater than or equal to the Interlock Setpoint the required OPERATIONAL TEST shall consist of verifying that the interlock is in the required state by observing the permissive annunciator window.

(9) - Monthly surveillance in MODES 3*, 4* and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window.

(10) - Setpoint verification is not required.

(11) - At least once per 18 months and following maintenance or adjustment of the Reactor trip breakers, the TRIP ACTUATING DEVICE OPERATIONAL TEST shall include independent verification of the Undervoltage and Shunt trips.

based on maintaining ~~an~~ an appropriate level of reliability of the RPS and ESF instrumentation.

3/4.3.1 and 3/4.3.2 REACTOR TRIP AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip System and Engineered Safety Features Actuation System instrumentation and interlocks ensure that: (1) the associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint, (2) the specified coincidence logic ~~is maintained, (3)~~ and sufficient redundancy is maintained to permit a channel to be out-of-service for testing or maintenance~~,~~ and (3) ~~(4)~~ sufficient system functional capability is available from diverse parameters.

consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability.

The measurement of response time at the specified frequencies provides assurance that the Reactor trip and the Engineered Safety Features actuation associated with each channel is completed within the time limit assumed in the accident analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those Engineered Safety Features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss-of-coolant accident: (1) Safety Injection pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) Phase A containment isolation, (6) Turbine trip, (7) auxiliary feedwater pumps start, (8) containment air return fans start, (9) essential raw cooling water pumps start and automatic valves position, (10) Control Room Isolation And Ventilation Systems start, and (11) component cooling water pumps start.

New ¶ Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP 10271, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection System" and supplements to that report. Surveillance intervals and out of service times were determined

Previously Identified

Table 3.3-3, -4, -5 (Pages 3/4 3-21 and 3/4 3-35)

Change the setpoints for Auxiliary Feedwater Suction Pressure Low per attached. The pumps do not start on low suction pressure. The suction supply switches over from the Condensate Storage Tank to ERCW at this low setpoint.

References: Watts Bar Drawing 47B601-3

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
6. Auxiliary Feedwater (continued)					
c. Stm. Gen. Water Level-Low-Low					
1) Start Motor-Driven Pumps	3/stm. gen.	2/stm. gen. in any operating stm gen.	2/stm. gen. in each operating stm. gen.	1, 2, 3	15*
2) Start Turbine-Driven Pump	3/stm. gen.	2/stm. gen. in any 2 operating stm. gen.	2/stm. gen in each operating stm. gen	1, 2, 3	15*
d. Safety Injection Start Motor-Driven Pumps and Turbine-Driven Pump	See Item 1 above for all Safety Injection initiating functions and requirements				
e. Station Blackout Start Motor-Driven Pumps and Turbine-Driven Pump	2/shutdown board	1/shutdown board	2/shutdown board	1, 2, 3	18*
f. Trip of Main Feedwater Pumps Start Motor-Driven Pumps and Turbine-Driven Pump	1/pump	1/pump	1/pump	1, 2	18*
g. Auxiliary Feedwater Suction Pressure - Low ~~Start Motor-Driven Pumps and Turbine-Driven Pump~~	3/pump	2/pump	2/pump	1, 2, 3	18*

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. Auxiliary Feedwater (continued)		
e. Station Blackout Start Motor-Driven Pumps Start Turbine-Driven Pump	0.0 volts with a 5.0 second time delay	0.0 volts with a 5.0 ± 1.0 second time delay
f. Trip of Main Feedwater Pumps - Start Motor-Driven Pumps and Turbine-Driven Pump	N.A.	N.A.
g. Auxiliary Feedwater Suction Pressure-Low Suction Transfer to ERCW		
1) ~~Start~~ Motor Driven Pump	≥ ~~2.0~~ 1.7 psig	≥ ~~1.0~~ 1.7 ± .5 psig
2) ~~Start~~ Turbine Driven Pump	≥ ~~6.5~~ 11.1 psig	≥ ~~5.5~~ 11.1 ± .5 psig
7. Automatic Switchover To Containment Sump		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. RWST Level - Low Coincident With	≥ 130" from tank base	≥ 126" from tank base
Containment Sump Level - High	≤ 30" above elev. 703'	≤ 30.0 ± 2.5" above elev. 703'
And		
Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints/ Allowable Values	

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
13. Loss of Power/Degraded Voltage	
6.9 kV Shutdown Board	$\leq 10^{(9)}$
14. ~~Auxiliary~~ Feedwater Suction Pressure-Low	
Auxiliary Feedwater Pumps	--

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T3.3-4 Item 9a (Page 3/4 3-31)

The setpoint for P-11 should be changed to agree with Westinghouse P.L.S. document.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. 6.9 kV Shutdown Board		
a. Loss of Power		
1) Start Diesel Generator	0.0 volts with a 1.5 second time delay	0.0 volts with a 1.5 ± 0.5 second time delay
2) Load Shedding	0.0 volts with a 5 second time delay	0.0 volts with 5 ± 1 second time delay
b. Degraded Voltage		
1) Voltage Sensor	6560 volts	6560 volts ± 33 volts
2) Diesel Generator Start and Load Shedding Timer	10 seconds	10 seconds ± .1 seconds
3) Safety Injection Degraded Voltage Logic Enable Timer	300 seconds	300 seconds ± 1.5 seconds
9. Engineered Safety Feature Actuation System Interlocks		
a. Pressurizer Pressure, P-11	$\leq$ ~~1955~~ 1970 psig	$\leq$ ~~1965~~ 1980 psig
b. Low-Low T_{avg}, P-12, increasing	$\leq$ 550°F	$\geq$ ~~551~~ 552 °F ~~and $\leq$ 555°F~~
decreasing	$\leq$ 550°F	$\geq$ 548°F
c. Reactor Trip, P-4	N.A.	N.A.

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Diesel Generator Response Time (Pages 3/4 3-32, -33, -34, and 3/4 3-35)
T.S. Table 3.3-5

The functions for which D.G. starting times are applicable (i.e., safety injection, etc.) have 2 response times listed: one with and one without D.G. start included (see notes 1, 2, 4, and 5 for this table). Additionally, S.R. 4.8.1.1.2.a.5 covers response time testing of the diesel generators. It is redundant and unnecessary to include D.G. start as a separate function under each initiating signal.

Component Cooling Water Response Times
T.S. Table 3.3-5 (Reference WBN ECN 3519)

An 8 second delay has been added to the component cooling pumps when supplied by the perferred source (offsite). Thus the response time for CCW has been increased to 43.0 seconds.

Originating Signal

The table has been modified to better show where each signal originates. This was discussed with Fred Anderson of NRC on 3/29/83.

TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Containment Isolation	
Phase "A" Isolation	N.A.
Phase "B" Isolation	N.A.
Ventilation Isolation	N.A.
d. Steam Line Isolation	N.A.
e. Feedwater Isolation	N.A.
f. Auxiliary Feedwater	N.A.
g. Essential Raw Cooling Water	N.A.
h. Control Room Isolation	N.A.
i. Containment Air Return Fan	N.A.
j. Component Cooling Water	N.A.
k. Start Diesel Generators	N.A.
l. Reactor Trip	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
b. Reactor Trip ~~(from Safety Injection)~~ *	≤ 2
c. Feedwater Isolation*	$\leq 8^{(3)}$
d. Containment Isolation-Phase "A"(6)*	$\leq 18^{(2)}/28^{(1)}$
e. Containment Ventilation Isolation*	N.A.
f. Auxiliary Feedwater Pumps*	≤ 60
g. Essential Raw Cooling Water*	$\leq 65^{(2)}/75^{(1)}$
h. Control Room Isolation*	N.A.
i. Component Cooling Water*	$\leq \cancel{35}\ 43^{(2)}/45^{(1)}$
~~j. Start Diesel Generators~~	

* Signal comes from SI

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
b. Reactor Trip ~~(from SI)~~ *	≤ 2
c. Feedwater Isolation *	$\leq 8^{(3)}$
d. Containment Isolation-Phase "A"(6) *	$\leq (18)^{(2)}/28^{(1)}$
e. Containment Ventilation Isolation *	N.A.
f. Auxiliary Feedwater Pumps *	≤ 60
g. Essential Raw Cooling Water *	$\leq 65^{(2)}/75^{(1)}$
h. Control Room Isolation *	N.A.
i. Component Cooling Water *	$\leq$ ~~35~~ 43$^{(2)}/45^{(1)}$
~~j. Start Diesel Generators~~	~~$\leq$~~
4. Differential Pressure Between Steam Lines-High	
a. Safety Injection (ECCS)	$\leq 22^{(4)}/12^{(5)}$
b. Reactor Trip ~~(from SI)~~ *	≤ 2
c. Feedwater Isolation *	$\leq 8.0^{(3)}$
d. Containment Isolation-Phase "A"(6) *	$\leq 18^{(2)}/28^{(1)}$
e. Containment Ventilation Isolation *	N.A.
f. Auxiliary Feedwater Pumps *	≤ 60
g. Essential Raw Cooling Water *	$\leq 67^{(2)}/77^{(1)}$
h. Control Room Isolation *	N.A.
i. Component Cooling Water *	$\leq$ ~~35~~ 43$^{(2)}/45^{(1)}$
~~j. Start Diesel Generators~~	~~$\leq$~~
5. Steam Flow in Two Steam Lines - High Coincident with T_{avg}--Low-Low	
a. Safety Injection (ECCS)	$\leq 24^{(4)}/14^{(5)}$
b. Reactor Trip ~~(from SI)~~ *	≤ 4
c. Feedwater Isolation *	$\leq 10^{(3)}$
d. Containment Isolation-Phase "A"(6) *	$\leq 20^{(2)}/30^{(1)}$
e. Containment Ventilation Isolation *	N.A.
f. Auxiliary Feedwater Pumps *	≤ 60
g. Essential Raw Cooling Water *	$\leq 67^{(2)}/77^{(1)}$
h. Steam Line Isolation	$\leq 9^{(3)}$
i. Control Room Isolation *	N.A.
j. Component Cooling Water *	$\leq$ ~~35~~ 43$^{(2)}/45^{(1)}$
~~k. Start Diesel Generators~~	~~$\leq$~~

* signal comes from SI

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Flow in Two Steam Lines-High Coincident with Steam Line Pressure-Low	
a. Safety Injection (ECCS)	$\leq 12^{(5)}/22^{(4)}$
b. Reactor Trip (~~from SI~~)*	≤ 2
c. Feedwater Isolation*	$\leq 8^{(3)}$
d. Containment Isolation-Phase "A"$^{(6)}$*	$\leq 18^{(2)}/28^{(1)}$
e. Containment Ventilation Isolation*	N.A.
f. Auxiliary Feedwater Pumps*	≤ 60
g. Essential Raw Cooling Water*	$\leq 65^{(2)}/75^{(1)}$
h. Steam Line Isolation	≤ 7
i. Control Room Isolation*	N.A.
j. Component Cooling Water*	$\leq$ ~~35~~ $43^{(2)}/45^{(1)}$
~~k. Start Diesel Generators~~	
7. Containment Pressure--High-High	
a. Containment Spray	$\leq 58^{(2)}$
b. Containment Isolation-Phase "B"	$\leq 65^{(1)}/75^{(2)}$
c. Steam Line Isolation	≤ 7
8. Steam Generator Water Level--High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	$\leq 11^{(3)}$
9. Steam Generator Water Level - Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps	$\leq 60^{(7)}$
b. Turbine-driven Auxiliary Feedwater Pumps	$\leq 60^{(8)}$
10. RWST Level-Low Coincident with Containment Sump Level-High and Safety Injection	
Automatic Switchover to Containment Sump	≤ 250
11. Station Blackout	
Auxiliary Feedwater Pumps	≤ 60
12. Trip of Main Feedwater Pumps	
Auxiliary Feedwater Pumps	≤ 60

*Signal comes from SI

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
13. Loss of Power/Degraded Voltage	
6.9 kV Shutdown Board	$\leq 10^{(9)}$
~~14. Auxiliary Feedwater Suction Pressure-Low~~	
~~Auxiliary Feedwater Pumps~~	~~--~~

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Table 3.3-5 notes (Page 3/4 3-36)

Note 10 - The last sentence 'See attached worksheet' should be deleted. That phrase was included in TVA's September 15, 1982 submittal to guide the NRC reviewers to a worksheet we had prepared. The sentence was not meant to be included in the spec.

TABLE 3.3-5 (Continued)

TABLE NOTATION

(1) Diesel generator starting and sequence loading delays included.

(2) Diesel generator starting and sequence loading delay not included. Offsite power available.

(3) Air operated valves.

(4) Diesel generator starting and sequence loading delay included. RHR & SI pumps not included.

(5) Diesel generator starting and sequence loading delays not included. SI and RHR pumps not included.

(6) The following valves are exceptions to the response time shown in the table and will have the following response times for the initiating signals and functions:

FCV-70-143	FCV-26-240, -243	FCV-61-96, -97, -110, -122, -191, -192, -193, -194
2.d $62^{(2)}/72^{(1)}$	2.d $22^{(2)}/32^{(1)}$	2.d 32
3.d $62^{(2)}/72^{(1)}$	3.d $22^{(2)}/32^{(1)}$	3.d 32
4.d $62^{(2)}/72^{(1)}$	4.d $22^{(2)}/32^{(1)}$	4.d 32
5.d $64^{(2)}/74^{(1)}$	5.d $24^{(2)}/34^{(1)}$	5.d 34
6.d $62^{(2)}/72^{(1)}$	6.d $22^{(2)}/32^{(1)}$	6.d 32

(7) On 2/3 any Steam Generator.

(8) On 2/3 in 2/4 Steam Generators.

(9) The response time is measured from the time the 6.9 kV shutdown boards voltage exceeds the Setpoint until the time full voltage is returned for the loss of voltage sensors; or from the time the degraded voltage timers generate a signal to start the diesels or shed loads until the time full voltage is returned for the degraded voltage sensors. ~~See attached worksheet~~.

ITEM E1.18

Table 3.3-6 (Pages 3/4 3-44, 3/4 3-45, 3/4 3-46, and 3/4 3-47)

Items 2.a and 2.b should use action statement 28. These monitors do not initiate Main Control Room isolation. The Main Control Room isolation function would still be OPERABLE per item 4 and technical specification 3.7.7. Item 2.c should be deleted. Page 12 of the Special Nuclear Material License contains the exemption and justification. Action statement 28 has been revised to reflect the fact that the monitors in question are G-M tubes. The NRC version of the action statement is written for gas monitors. The two are not the same.

TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS

FUNCTIONAL UNIT	CHANNELS TO TRIP/ALARM	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	ACTION
1. Containment Purge Isolation					
a. Manual Initiaion	1	2	1, 2, 3, 4,	N.A.	26
b. Containment Atmosphere Radioactivity-High	1	~~2~~ 1	1. 2, 3, 4	$\leq$ 2X Background	26
c. Containment Purge Exhaust Radioactivity-High	1	~~2~~ 1	1, 2, 3, 4	#	26
2. Fuel Storage Pool Area-Ventilation Isolation					
a. Manual Initiation	1	2	All	N.A.	~~27~~ 28
b. Spent Fuel Pool Radioactivity-High	1	2	**	~~$\leq$ 2X Background~~	~~27~~ 28
~~*c. Criticality Radiation Level~~	~~1~~	~~2~~	~~**~~	$\leq$ 15 mR/hr	~~28~~
3. Containment Atmosphere					
a. Gaseous Radioactivity-RCS Leakage Detection	N.A.	1	1, 2, 3, 4	N.A.	29
b. Particulate Radioactivity RCS Leakage Detection	N.A.	1	1, 2, 3, 4	N.A.	29
4. Control Room Ventilation Isolation					
a. Manual Initiation	1	2	All	N.A.	27

TABLE 3.3-6 (Continued)

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS

FUNCTIONAL UNIT	CHANNELS TO TRIP/ALARM	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	ACTION
4. Control Room Ventilation Isolation (Continued)					
~~b. Containment Atmosphere Radioactivity-High~~	~~1~~	~~2~~	~~All~~	~~≤ 2X Background~~	~~27~~
~~c. Containment Purge Exhaust Radioactivity-High~~	~~1~~	~~2~~	~~All~~	~~#~~	~~27~~
d. Control Room Air Intake Radioactivity-High	1	2	All	≤ 2X Background	27

TABLE NOTATION

* - With fuel in the fuel storage areas.
** - With irradiated fuel in the fuel storage areas.
\# - Must satisfy Specification 3.3.3.10 requirements.

Action 26 - With less than the Minimum Channels OPERABLE requirement, operation may continue provided the containment purge valves are maintained closed.

Action 27 - With the number of operable channels one less than the Minimum Channels OPERABLE requirement, within 1 hour isolate the Control Room Ventilation System or initiate operation of the Control Room Ventilation System in the recirculation mode.

Action 28 - With less than the Minimum Channels OPERABLE requirement, ~~operation may continue for up to 30 days provided an appropriate portable continuous monitor with the same Alarm Setpoint is provided in the fuel pool area. Restore the inoperable monitors to OPERABLE status within 30 days or suspend all operations involving fuel movement in the fuel storage pool area.~~ perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours

Action 29 - Must satisfy the ACTION requirement for Specification 3.4.6.1.

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES REQUIRING SURVEILLANCE
1. Containment Purge Isolation				
a. Manual Initiation	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Containment Atmosphere Radioactivity-High	S	R	M	1, 2, 3, 4
c. Containment Purge Exhaust Radioactivity-High	S	R	M	1, 2, 3, 4
2. Fuel Storage Pool Area-Ventilation Isolation				
a. Manual Initiation	N.A.	N.A.	N.A.	All
b. Spent Fuel Pool Radioactivity-High	S	R	M	** *
~~c. Criticality-High Radiation Level~~	~~S~~	~~R~~	~~M~~	*
3. Containment Atmosphere				
a. Gaseous Radioactivity-RCS Leakage Detection	S	R	M	1, 2, 3, 4
b. Particulate Radioactivity - RCS Leakage Detection	S	R	M	1, 2, 3, 4

TABLE 4.3-3 (Continued)

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES REQUIRING SURVEILLANCE
4. Control Room Ventilation Isolation				
a. Manual Initiation	N.A.	N.A.	N.A.	All
~~b. Containment Atmosphere Radioactivity-High~~	~~S~~	~~R~~	~~M~~	~~All~~
c. ~~Containment Purge Exhaust Radioactivity-High~~	~~S~~	~~R~~	~~M~~	~~All~~
d. Control Room Air Intake Radioactivity-High	S	R	M	All

TABLE NOTATION

* - With fuel in the fuel storage areas.

** - With irradiated fuel in the fuel storage areas.

<u>T3.3-10 Items 21 & 23</u> (Pages 3/4 3-60 and 3/4 3-62)

Watts Bar does not have a high range Noble Gas Monitor in the Auxiliary Building Vent because the vent isolates on a Phase A isolation or a High Radiation signal. In addition the ABGTS exhausts into the Shield Building Vent.

Watts Bar also does not have any radiation monitors in the Steam Generator Safety valve stacks.

TABLE 3.3-10 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
19. Plant Liquid Discharge Monitor (RE-90-211)	1	1
20. Shield Building Vent-High Range Noble Gas Monitor	1	1
~~21. Auxiliary Building Vent-High Range Noble Gas Monitor~~	~~1~~	~~1~~
22. Condenser Vacuum Exhaust Vent-High Range Noble Gas Monitor	1	1
~~23. Steam Line Relief Noble Gas Monitor~~	~~1~~	~~1~~

TABLE 4.3-7 (Continued)

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

90-

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
19. Plant Liquid Discharge Monitor (RE-211)	M	R
20. Shield Building Vent-High Range Noble Gas Monitor	M	R
~~21. Auxiliary Building Vent High Range Noble Gas Monitor~~	~~M~~	~~R~~
22. Condenser Vacuum Exhaust Vent-High Range Noble Gas Monitor	M	R
~~23. Steam Line Relief Noble Gas Monitor~~	~~M~~	~~R~~

3.3.3.8 (Pages 3/4 3-64 and B 3/4 3-4)

Watts Bar does not have an Early Warning only fire detector system, the system actuates when a single or pair of detectors sense a fire. Therefore, all reference to Function A detectors should be removed and the actions changed per the attached. LCO 3.3.3.8c has been added to eliminate many unnecessary LERs.

This change will eliminate many unnecessary LER's.

C. In lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the actions taken, the cause of the inoperability and the plans and schedule for restoring the instrument(s) to OPERABLE status.

INSTRUMENTATION

FIRE DETECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.8 As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.3-11 shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the fire detection instrument is required to be OPERABLE.

ACTION:

a. With one less than the minimum number of instruments ~~any, but not more than one-half the total in any fire zone, Function A fire detection instrument~~ shown in Table 3.3-11 inoperable, restore the ~~inoperable~~ instrument(s) to OPERABLE status within 14 days and ~~or~~ within the next 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour, unless the instrument(s) is located inside the containment, then inspect that containment zone at least once per 8 hours (or monitor the containment air temperature at least once per hour at the location listed in Specification 4.6.1.6).

~~b. With more than one-half of the Function A fire Detection instruments in any fire zone shown in Table 3.3-11 inoperable, or with any two or more adjacent fire detection instrument shown in Table 3.3-11 inoperable, within 1 hour establish a fire watch patrol to inspect the zone(s) with the inoperable instrument(s) at least once per hour, unless the instrument(s) is located inside the containment, then inspect that containment zone at least once per 8 hours (or monitor the containment air temperature at least once per hour at the locations listed in Specification 4.6.1.6).~~

b ~~c~~. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.8.1 Each of the above required fire detection instruments which are accessible during plant operation shall be demonstrated OPERABLE at least once per 6 months by performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST. Fire detectors which are not accessible during plant operation shall be demonstrated OPERABLE by the performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST during each COLD SHUTDOWN exceeding 24 hours unless performed in the previous 6 months.

4.3.3.8.2 The NFPA Standard 72D supervised circuits supervision associated with the detector alarms of each of the above required fire detection instruments shall be demonstrated OPERABLE at least once per 6 months.

4.3.3.8.3 The nonsupervised circuits, between the local panel and actuated equipment ~~associated with detector alarms, between the instrument and the control room~~ shall be demonstrated OPERABLE at least once per ~~31 days~~ 6 months.

3/4.3.3.7 CHLORINE DETECTION SYSTEMS

The OPERABILITY of the Chlorine Detection System ensures that sufficient capability is available to promptly detect and initiate protective ACTION in the event of an accidental chlorine release. This capability is required to protect control room personnel and is consistent with the recommendations of Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release," Revision 1, January 1977.

3/4.3.3.8 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the fire detection instrumentation ensures that ~~both adequate warning capability is available for prompt detection of fires and that~~ Fire Suppression Systems, that are actuated by fire detectors, will discharge extinguishing agents in a timely manner. Prompt detection and suppression of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program.

~~Fire detectors that are used to actuate Fire Suppression Systems represent a more critically important component of a plant's fire protection program than detectors that are installed solely for early fire warning and~~

In the event that a portion of the fire detection instrumentation is inoperable, the establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

~~by fire detectors, represents a significant degradation of fire protection for any area. As a result, the establishment of a fire watch patrol must be initiated at an earlier stage than would be warranted for the loss of detectors that provide only early fire warning. The establishment of frequent fire patrols in the affected areas is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.~~

3/4.3.3.9 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The radioactive liquid effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The Alarm/Trip Setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50. The purpose of tank level indicating devices is to assure the detection and control of leaks that if not controlled could potentially result in the transport of radioactive materials to UNRESTRICTED AREAS.

ITEM E1.21

Table 3.3-12 Item 2a (Page 3/4 3-76)

Add RE-90-140 and RE-90-141 to table 3.3-12, Item 2.a, Essential Raw Cooling Water Effluent Line since they are redundant monitors to RE-90-133 and RE-90-134, respectively.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release		
a. Waste Disposal System Liquid Effluent Line (RE-122) 90	1	31
b. Steam Generator Blowdown Effluent Line (RE-~~124~~) 90-120	1	32
c. Condensate Demineralizer Regenerant Effluent Line (RE-225) 90	1	31
d. Plant Liquid Discharge Line (RE-211) 90	1	33
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Essential Raw Cooling Water Effluent Line (RE-133 & ~~134~~) 90 140	1	33
90 RE-90-134 + 141		
b. Turbine Building Sump Effluent Line (RE-212)	1	33
3. Flow Rate Measurement Devices		
a. Waste Disposal System Liquid Radwaste Effluent Line	1	34
b. Condensate Demineralizer Regenerant Effluent Line	1	34
c. Steam Generator Blowdown Effluent Line	1	34
d. Diffuser Discharge Effluent Line	1	34
4. Tank Level Indicating Devices		
a. Condensate Storage Tank	1	35
b. Steam Generator Layup Tank*	1	35

*Required when connected to the Secondary Coolant System

ITEM E1.22

Tables 3.3-12 and 3.3-13 (Pages 3/4 3-77 and 3/4 3-83)

Changes made to be consistent with NUREG-0472, Rev. 2.

TABLE 3.3-12 (Continued)

TABLE NOTATION

ACTION 31 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases may continue ~~for up to 14 days~~ provided that prior to initiating a release:

a. At least two independent samples are analyzed in accordance with Specification 4.11.1.1.1, and

b. At least two technically qualified members of the Facility Staff independently verify the release rate calculations and discharge line valving;

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 32 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue ~~for up to 30 days~~ provided grab samples are analyzed for gross radioactivity beta or gamma at a limit of detection of at least 10^{-7} microCuries/ml; or the gamma isotopic analysis is performed with LLD's as given in Table 4.11-1:

a. At least once per ~~8~~ 12 hours when the specific activity of the secondary coolant is greater than 0.01 microCuries/gram DOSE EQUIVALENT I-131, and

b. At least once per 24 hours when the specific activity of the secondary coolant is less than or equal to 0.01 microCuries/gram DOSE EQUIVALENT I-131.

ACTION 33 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue ~~for up to 30 days~~ provided that, at least once per ~~8~~ 12 hours, grab samples are collected and analyzed for gross radioactivity beta or gamma at a limit of detection of at least 10^{-7} microCuries/ml; or the gamma isotopic analysis is performed with LLD's as given in Table 4.11-1.

ACTION 34 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue ~~for up to 30 days~~ provided the flow rate is estimated at least once per 4 hours during actual releases. Pump curves may be used to estimate flow.

ACTION 35 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, liquid additions to this tank may continue ~~for up to 30 days~~ provided the tank liquid level is estimated during all liquid additions to the tank.

TABLE 3.3-13 (Continued)

TABLE NOTATION

* At all times.

** During WASTE GAS HOLDUP SYSTEM operation.

*** During operation of the Containment Purge System Auxiliary Building Gas Treatment System or waste gas decay tank disposal.

ACTION 37 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, the contents of the tank(s) may be released to the environment ~~for up to 14 days~~ provided that prior to initiating the release:

a. At least two independent samples of the tank's contents are analyzed per Table 4.11-2, and

b. At least two technically qualified members of the Facility Staff independently verify the release rate calculations and discharge valve lineup.

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 38 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue ~~for up to 30 days~~ provided the flow rate is estimated at least once per 4 hours.

ACTION 39 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue ~~for up to 30 days~~ provided grab samples are taken at least once per ~~8~~ 12 hours and these samples are analyzed for noble gas gross radioactivity or an isotopic analysis is performed with LLD's as given in Table 4.11-2 within 24 hours.

ACTION 40 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of this waste gas disposal system may continue for up to ~~7~~ 14 days provided grab samples are collected at least once per 24 hours and analyzed within the following 4 hours to meet the requirements of Specification 3.11.2.5. ~~With the hydrogen and oxygen monitors inoperable, be in at least HOT STANDBY within 6 hours.~~

ACTION 41 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via the affected pathway may continue ~~for up to 30 days~~ provided that within 4 hours after the channel has been declared inoperable samples are continuously collected with auxiliary sampling equipment as required in Table 4.11-2.

ITEM E1.23

Table 3.3-12 and 3.3-13 (Pages 3/4 3-76, 3/4 3-81, and 3/4 3-82)

Please add the system numbers to the radiation monitors listed and correct monitor number on the Steam Generator Blowdown Effluent line.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release		
a. Waste Disposal System Liquid Effluent Line (RE-122) -90	1	31
b. Steam Generator Blowdown Effluent Line (RE-~~124~~) -90-120	1	32
c. Condensate Demineralizer Regenerant Effluent Line (RE-225) -90	1	31
d. Plant Liquid Discharge Line (RE-211) -90	1	33
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Essential Raw Cooling Water Effluent Line (RE-133 & 134) -90	1	33
b. " " " " " -90 (RE90-140 & 141)		
c ~~b~~. Turbine Building Sump Effluent Line (RE-212)	1	33
3. Flow Rate Measurement Devices		
a. Waste Disposal System Liquid Radwaste Effluent Line	1	34
b. Condensate Demineralizer Regenerant Effluent Line	1	34
c. Steam Generator Blowdown Effluent Line	1	34
d. Diffuser Discharge Effluent Line	1	34
4. Tank Level Indicating Devices		
a. Condensate Storage Tank	1	35
b. Steam Generator Layup Tank*	1	35

*Required when connected to the Secondary Coolant System

TABLE 3.3-13

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. WASTE GAS HOLDUP SYSTEM (RE-90-118)			
a. Noble Gas Activity Monitor ~~(RE-118)~~	1	*	37
b. Effluent System Flow Rate Measuring Device	1	*	38
2. WASTE GAS HOLDUP SYSTEM Explosive Gas Monitoring System			
a. Hydrogen ~~and Oxygen~~ Monitor~~s~~	1 ~~each~~	**	40
b. Oxygen Monitor	1	**	40
3. Condenser Vacuum Exhaust System (RE 90-119)			
a. Noble Gas Activity Monitor ~~(RE-119)~~	1	*	39
b. Effluent System Flow Rate Measuring Device	1	*	38
c. Monitor Flow Rate Measuring Device	1	*	38
4. Shield Building Exhaust System (RE-90-100)			
a. Noble Gas Activity Monitor ~~(RE-100)~~	1	***	39
b. Iodine Sampler	1	***	41
c. Particulate Sampler	1	***	41
d. Effluent System Flow Rate Measuring Device	1	***	38
e. Sampler Flow Rate Measuring Device	1	***	38
f. Monitor Flow Rate Measuring Device	1	***	38

TABLE 3.3-13 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
5. Auxiliary Building Ventilation System And Fuel Handling Area Ventilation System RE-90-101			
a. Noble Gas Activity Monitor ~~(RE-101)~~	1	*	39
b. Iodine Sampler	1	*	41
c. Particulate Sampler	1	*	41
d. Effluent System Flow Rate Measuring Device	1	*	38
e. Sampler Flow Rate Measuring Device	1	*	38
f. Monitor Flow Rate Measuring Device	1	*	38
6. Service Building Ventilation System RE-90-132			
a. Noble Gas Activity Monitor ~~(RE-132)~~	1	*	39
b. Effluent System Flow Rate Measuring Device	1	*	38
c. Monitor Flow Rate Measuring Device	1	*	38

ITEM E1.24

Tables 4.4-1 and 4.4-2 (Pages 3/4 4-17 and 3/4 4-18)

The tables concerning steam generators were provided by TVA's 12/4/81 submittal.

ITEM E1.25

4.4.6.2.1 (Page 3/4 4-21)

Monitoring the containment atmosphere gaseous or particulate radioactivity monitor at least once per 12 hours to demonstrate RCS unidentified leakage is less than 1 gpm.

The monitor readings will not be a reliable quantitative measurement of RCS unidentified leakage. At best they can indicate a change in leak rate. The pocket sump inventory will be a much better measurement of RCS unidentified leakage. The requirement should be changed to indicate that the monitor will be used as a continuous monitor to indicate sudden changes in RCS leak rate.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous or particulate radioactivity monitor for relative changes at least once per 12 hours;

b. Monitoring the containment pocket sump inventory and discharge at least once per 12 hours;

c. Measurement of the CONTROLLED LEAKAGE to the reactor coolant pump seals when the Reactor Coolant System pressure is 2235 ± 20 psig at least once per 31 days with the modulating valve fully open. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4;

d. Performance of a Reactor Coolant System water inventory balance at least once per 72 hours during steady-state operation or within 1 hour of receiving an intersystem leakage alarm; and

e. Monitoring the Reactor Head Flange Leakoff System at least once per 24 hours.

4.4.6.2.2 Each Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1 shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once per 18 months;

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 72 hours or more and if leakage testing has not been performed in the previous 9 months;

c. Prior to returning the valve to service following maintenance, repair or replacement work on the valve; and

d. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve.

The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4.

ITEM E1.26

Figure 3.4-1 (Page 3/4 4-28)

The figure for reactor coolant activity was provided by TVA's 12/4/81 submittal.

<u>Table 4.4-4</u> (Page 3/4 4-29)

The changes made to the table are for clarification and they are in conjunction with the change to the footnote.

1. See footnote changes

2. Deleted because it is required to do a dose equivalent I-131

3. The analysis is being compared to dose equivalent I-131 limits of 1.0 μCi/g. (There are no limits for I-131, I-133, and I-135 only for D.E.I-131) and to 100/E gross specific activity.

The changes made to the ** footnote were made because if we do a gamma scan we would not pick up H-3, Sr 89-90 nuclides if we do a gross beta-gamma count we would not identify the individual activities; therefore, we would not be able to eliminate the iodine activities nor could we decay correct back to sample time.

If the changes are made, we could degas the sample and perform a gamma scan on both the gas and liquid. We would know that H-3, Sr 89-90 would not be required and we could eliminate the iodine activity from the total specific activity. This would allow us to perform the iodine isotopic analysis at the same time. We would also be able to do automatic (computer programmed) decay corrections to sample time and compare the results to the acceptance criteria.

The *** footnote does not agree with the E definition in the definition section.

TABLE 4.4-4

REACTOR COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Gamma Specific Activity Determination**	At least once per 72 hours	1, 2, 3, 4
2. ~~Isotopic Analysis for~~ DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination***	1 per 6 months*	1
4. DOSE EQUIVALENT ~~Isotopic Analysis for Iodine Including~~ I-131, ~~I-133, and I-135~~ Concentration and Gross Gamma Specific Activity	a) Once per 4 hours, whenever the specific activity exceeds 1 μCi/gram DOSE EQUIVALENT I-131 or 100/$\bar{E}$ μCi/gram, and	1#, 2#, 3#, 4#, 5#
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15% of the RATED THERMAL POWER within a 1-hour period.	1, 2, 3

#Until the specific activity of the Reactor Coolant System is restored within its limits.

*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

**A gross gamma radioactivity analysis shall consist of quantitative measurement of the total specific activity of the reactor coolant except for radionuclides with half lives less than 10 minutes and all radioiodines. The total gamma specific activity shall be the sum of the degassed ~~beta~~ gamma activity and the total of all identified gaseous activities in the sample within 2 hours after the sample is taken and extrapolated back to when the sample was taken.

***A radiochemical analysis for $\bar{E}$ shall consist of the quantitative measurement of the specific activity for each radionuclide, except for radionuclides with half lives less than 10 minutes and all radioiodines, which is identified in the reactor coolant. The specific activities for these individual radionuclides shall be used in the determination of $\bar{E}$ for the reactor coolant sample.

ITEM E1.28

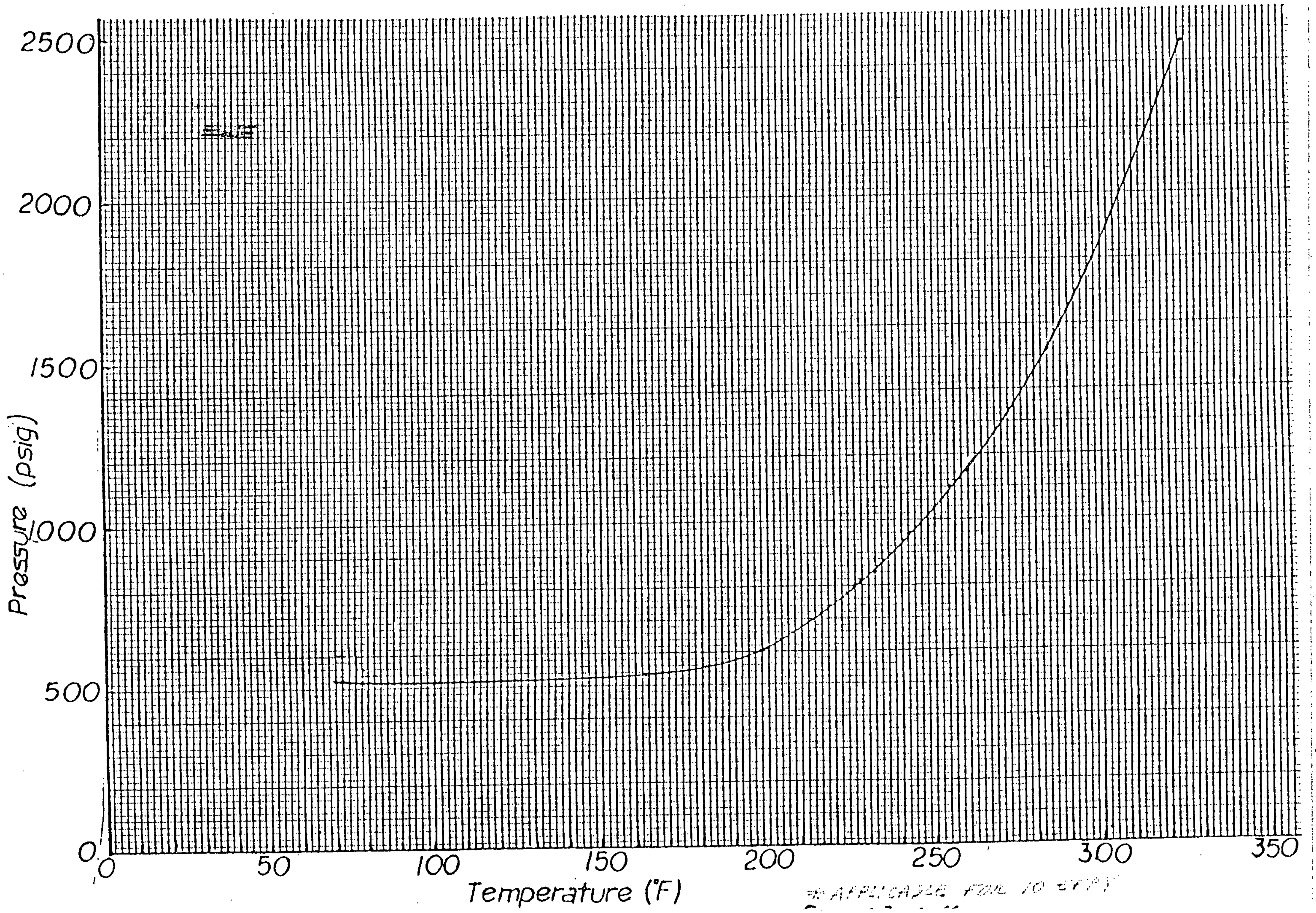
<u>Figure 3.4-3</u> (Page 3/4 4-32)

The figure for heatup-cooldown was provided by TVA's 12/4/81 submittal.

ITEM E1.29

<u>LTOP Setpoint Curve</u> (Pages 3/4 4-36 and 3/4 4-37)
T.S. figure 3.4-4

In response to NRC concerns raised in IE Information Notice 82-45, a note should be added to figure 3.4-4 which indicates the EFRYs those setpoints are valid for (also SR 4.4.9.3.3 is being added). This is similar to notes already on the RCS heatup and cooldown curves.



*APPLICABLE FOR 10 EFPY

4.4.9.3.1 Each PORV shall be demonstrated OPERABLE by:

a. Performance of a ANALOG CHANNEL OPERATIONAL TEST on the PORV actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the PORV is required OPERABLE and at least once per 31 days thereafter when the PORV is required OPERABLE;

b. Performance of a CHANNEL CALIBRATION on the PORV actuation channel at least once per 18 months; and

c. Verifying the PORV isolation valve is open at least once per 72 hours when the PORV is being used for overpressure protection.

4.4.9.3.2 The RCS vent(s) shall be verified to be open at least once per 12 hours* when the vent(s) is being used for overpressure protection.

4.4.9.3.3 The reactor vessel irradiation surveillance specimens shall be removed and examined, to determine changes in material properties, as required by 10 CFR 50 appendix H in accordance with the schedule in Table 4.4-5. The results of these examinations shall be used to update Figure 3.4-4

*Except when the vent pathway is provided with a valve which is locked, sealed, or otherwise secured in the open position, then verify these valves open at least once per 31 days.

ITEM E1.30

Technical Specification 3.4.9.2 (Page 3/4 4-34)

Based on the Westinghouse Electric Corporation letter, WAT-D-5354 dated March 2, 1983, the maximum differential temperature between the spray water and the pressurizer is 625°F, not 320°F as currently stated in specification 3.4.9.2. The maximum temperature difference that will be experienced during normal and accident conditions is about 605°F. Since we can never exceed the maximum temperature difference of 625°F LCO 3.4.9.2, part c and the second part of S.R. 4.4.9.2 are no longer necessary and should be deleted. The cyclic limits on inadvertent auxiliary spray at temperatures above 320°F are covered under specification 5.7.1.

REACTOR COOLANT SYSTEM

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.9.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100°F in any 1-hour period,

b. A maximum cooldown of 200°F in any 1-hour period, and

~~c. A maximum spray water temperature differential of 320°F.~~

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown. ~~The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during auxiliary spray operation.~~

3/8/83 - JAR DLH/TU
cc: *H. J. Green, 1750 CST2-C
MEDS, W5B63 C-K
R. M. Pierce, 104 [illegible] TA-SENT MAR
J. C. Standifer, 204 GB-K
G. Wadewitz, Watts Bar Nuclear CONST (3)

*Reference [illegible] memo to M. N. Sprouse dated October 28, 1982 (DES 821029 [illegible]

320-35

Westinghouse Electric Corporation
Water Reactor Divisions
Nuclear Operations Division
Box 355
Pittsburgh Pennsylvania 15230

MAR 03 1983

NEB '830309 272

JAR: CBW	DRAFT REPLY	COM. COPY	INFO COPY	DUE DATE
CC:				
EEB, W5C126C-K	✓			4/5
CEB, W5C[illegible]C-K				
MEB, W7C126C-K				
QTC 249A HBB-K				
DWW				
TGC		|		3/31
LWL				
JCS				
R		|		3/31

DAVE HILL
X-7281

March 2, 1983

TVA Contract No. 71C62-54114-1
NOT-D-5354
NS-PL-11322
S.O. [illegible]

Ref: N-4771 of 12-7-82

Mr. J. A. Raulston
Chief Nuclear Engineer
TENNESSEE VALLEY AUTHORITY
400 West Summit Hill Drive, W10 C126
Knoxville, TN 37902

* Please coordinate with NUC PR.

Dear Mr. Raulston:

TENNESSEE VALLEY AUTHORITY
WATTS BAR NUCLEAR PLANT
UNIT NUMBERS 1 and 2

Differential Temperature Limit for Pressure Spray Initiation (320-35) N3M-2-X

The above referenced letter identified TVA's safety and operational concerns regarding the proposed differential temperature limit for pressurizer spray and requested Westinghouse to address these concerns specifically.

It is the recommendation of Westinghouse that the L.C.O. (Limiting Condition for Operation) referring to a maximum differential temperature (ΔT) for auxiliary sprays initiation (specification 3.4.9.2.c) be modified as on the attached page. The bases for these recommendations are as follow:

1. 320°F is not a limiting design value, ΔT's up to 625°F have been analyzed.
2. Limits on the ΔT present at the time of spray initiation exist as cyclic limits and in the case of auxiliary spray initiation is addressed in Table 5.7-1 "Component Cyclic or Transient Limits".

During normal operation, the ΔT between spray water and [illegible] number of cycles with a 125 ΔT to spray initiation under these conditions should not be a major concern. Spray initiation with ΔT's higher than 125°F should be in accordance with the system's design document; that is, counted as one cycle of some specific category of design cycles depending on the ΔT present at the time of spray initiation. As long as the design cyclic limit is not exceeded, a specific engineering evaluation is not required.

MASTER FILE

MEDS, W-5B63 C-K

ADVANCE COPY OF THIS LETTER SENT TO SWP.

N3M-2-X

A precautionary note in the PLS indicates that spray flow should not normally be initiated if the ΔT is greater than 100°F. This is based on engineering judgement to assure that thermal stresses are minimized to the affected components. The operator should adhere to this precaution when possible (i.e. normal operation) but the precaution is not intended to be limiting on plant operations such as heatup, cooldown, or RCP starting. Thermal transients such as heatup and cooldown are addressed in Westinghouse letter WAT-D-3505.

In summary, Watts Bar is not more restricted than other Westinghouse plants. The utility is encouraged to use good engineering judgement in plant operation to avoid unnecessary or severe transients where possible and to minimize thermal shock to plant components. This ensures that expected plant lifetime is not shortened.

If you have any further questions on this subject, please do not hesitate to contact us.

Very truly yours,

WESTINGHOUSE ELECTRIC CORPORATION

J. L. Tain / Lee

J. L. Tain, Manager
Tennessee Valley Authority
Projects

/rcc
attachment

J. A. Raulston, 3L 3A

cc: J. Larkin, 1L
S. A. Moser, 1L
B. Wade, 1L
L. M. Mills, 1L 1A

LIMITING CONDITION FOR OPERATION

3.4.9.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100 °F in any 1-hour period,

b. A maximum cooldown of 200 °F in any 1-hour period, and

c. A maximum spray water temperature differential of 625°F

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psig within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown. The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during auxiliary spray operation.

UPET Vol 4

Model D Series Pressurizer Spray Analysis

each case.

TABLE 3-3

THERMAL TRANSIENT SUMMARY

OPERATING CONDITION	NO. OF OCCURENCES	DURATION OR RATE	PRESSURE RANGE(psi)	TEMP. RANGE(°F)	SPRAY NOZZLE ΔT	DURATION OF SPRAY(SEC)	FLOW RATE(GPM)
Normal Conditions:							
Heat Up at 100°F/hr	200	See Fig.*	15-2250	70-653	-320 (1200 Cycles)	60	900
Cooldown to 400 psia	"	"	2250-400	653-445	-320 (1200 cycles)	"	"
Cooldown from 400 psia	"	"	400-15	445-70	-330 (1000 cycles) -415 (200 cycles)	"	200
Unit loading at 5%/minute	18300	"	2250 ± 50	653 ± 3	-125	"	900
Unit unloading at 5%/minute	18300	"	2250 ± 50	653 ± 3	"	"	"
Step load increase of 10% (and 20%)	2000	"	See Fig.	653 ± 2	"	150	"
Step load decrease of 10% (and 20%)	"	"	"	653 ± 4	"	30	"
Large step load decrease with steam dump	200	"	"	653^{+6}_{-10}	-135	60	"
Steady state fluctuations							
Initial	1.5×10^5	120	2250 ± 25	653 ± 3	0	0	0
Random	3×10^6	360	2250 ± 6	653 ± 0.4	"	"	"
Feedwater cycling at hot shutdown	2000	See Fig.	See Fig.	653^{+1}_{-5}	"	"	"
Normal loop shutdown	80	"	"	653 ± 4	-135	60	900
Normal loop startup	70	"	"	653^{+3}_{-0}	"	150	"
Boron concentration equilization	26400	3600	2250^{+25}_{-0}	653^{+2}_{-0}	-125	3600	"

TABLE 3-3 (CONT.)

THERMAL TRANSIENT SUMMARY

OPERATING CONDITION	NO. OF OCCURENCES	DURATION OR RATE	PRESSURE RANGE (psi)	TEMP. RANGE (°F)	SPRAY NOZZLE ΔT	DURATION OF SPRAY (SEC)	FLOW RATE (GPM)
Upset Condition							
Loss of Load	80	See Fig.	See Fig.	653^{+20}_{-34}	-150	45	900
Loss of Power	40	"	"	653^{+13}_{-27}	0	0	0
Partial loss of flow	80	"	"	653^{+4}_{-28}	-125	10	900
Reactor trip from full power - no cooldown	230	"	"	653-633	0	0	0
Reactor trip from full power-Cooldown without SI	160	"	"	653-606	0	0	0
Reactor trip from full power-Cooldown with SI	10	"	"	653-596	"	"	"
Inadvertent RCS depressurization-General Case	20	"	"	653-453	"	"	"
Inadvertent RCS depressurization-Inadvertent Auxiliary Spray	10	5 Min.	NA	NA	~~[illegible]~~	300	200
Inadverent startup of inactive loop	10	See Fig.	See Fig.	653^{+7}_{-18}	-175	60	900
Control rod drop	80	"	"	653^{+0}_{-30}	0	0	0
Inadvertent SI actuation	80	"	"	653^{+6}_{-17}	-135	1800	900

WESTINGHOUSE PROPRIETARY CLASS 2

TABLE 3-3 (CONT.)

THERMAL TRANSIENT SUMMARY

Cont[illegible] drop	80	"	[illegible]	$653^{+[illegible]}_{-30}$	0	0	0
Inadvertent SI actuation	80	"	"	653^{+6}_{-17}	-135	1800	900

TABLE 3-3 (CONT.)

THERMAL TRANSIENT SUMMARY

OPERATING CONDITION	NO. OF OCCURRENCES	DURATION OR RATE	PRESSURE RANGE(psi)	TEMP. RANGE(°F)	SPRAY NOZZLE ΔT	DURATION OF SPRAY(SEC)	FLOW RATE(GPM)
Emergency Conditions							
Small LOCA	5	See Fig.	See Fig.	653^{+0}_{-100}	0	0	0
Small steam line break	5	"	"**	653^{+6}_{-30}	-350	1800	900
Complete loss of flow	5	"	"	653^{+4}_{-27}	-127	10	"
Faulted Conditions							
Reactor Coolant Pipe Break	1	"	"	653-293	-450	180	"
Large steam line break	1	"	"	653^{+20}_{-120}	"	"	"
Feedwater line break	1	"	"	653^{+22}_{-2}	-130	600	"
Reactor coolant pump locked rotor	1	"	"	653^{+21}_{-19}	"	10	"
Control rod ejection	1	"	"	653^{+29}_{-28}	-160	5	"
Test Conditions							
Turbine roll test	20	1000 sec	"	653-605	0	0	0
Primary side hydrostatic test	10	–	3122	120-250	–	–	–
Primary side leak test	200		2250	120-250	–	–	–
Secondary side leak test	200	–	630	120-250	–	–	–

* Refers to figures in Reference 5.

** A later interim revision (#1) of the E-Spec (Reference 2) gave a maximum pressure of 2350 occurring during the Small Steam Break transient. This change will have no appreciable effect on the results of this report.

WESTINGHOUSE PROPRIETARY CLASS 2

ITEM E1.32

Surveillance Requirements 4.5.2.h.1 and 4.5.2.h.2 (Page 3/4 5-8)

The safety injection pumps should be tested in item 1 and the centrifugal charging pump in item 2 since the safety injection pump flow rate is larger than the centrifugal charging pump (or the values should be corrected).

SURVEILLANCE REQUIREMENTS (Continued)

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1) For centrifugal charging pump lines, with a single pump running:

a) The sum of the injection line flow rates, excluding the highest flow rate, is greater than or equal to 462 gpm, and

b) The total pump flow rate is less than or equal to 660 gpm.

2) For Safety Injection pump lines, with a single pump running:

a) The sum of the injection line flow rates, excluding the highest flow rate, is greater than or equal to 346 gpm, and

b) The total pump flow rate is less than or equal to 555 gpm.

3) For RHR pump lines, with a single pump running, the sum of the injection line flow rates is greater than or equal to 3976 gpm.

ITEM E1.33

Technical Specification 3.6.1.9 (Page 3/4 6-15)

The draft Watts Bar specification should be replaced with the attached specification. The attached Sequoyah containment purge system study is applicable to Watts Bar.

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.9 One pair (one purge supply line and one purge exhaust line) of containment purge system lines may be open; the containment purge supply and exhaust isolation valves in all other containment purge lines shall be closed. Operation with purge supply or exhaust isolation valves open for either purging or venting shall be limited to less than or equal to **2000** hours per 365 days. The 365 day cumulative time period will begin every January 1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With a purge supply or exhaust isolation valve open in excess of the above cumulative limit, or with more than one pair of containment purge system lines open, close the isolation valve(s) in the purge line(s) within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.9.1 The position of the containment purge supply and exhaust isolation valves shall be determined at least once per 31 days.

4.6.1.9.2 The cumulative time that the purge supply and exhaust isolation valves are open over a 365 day period shall be determined at least once per 7 days.

4.6.1.9.3 Each Containment Purge isolation valve shall be demonstrated OPERABLE within 24 hours after each closing of the valve, except when the valve is being used for multiple cyclings, then at least once per 72 hours, by verifying that when the measure leakage rate of these valves is added to the leakage rates determined pursuant to Specification 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is $\leq 0.60\ L_a$.

SEQUOYAH NUCLEAR PLANT (SQN)
CONTAINMENT PURGE STUDY

Introduction

The operation of the containment purge and venting systems at SQN units 1 and 2 is limited by plant technical specifications to 1,000 hours per year per unit during modes 1, 2, 3, and 4 using one pair (one purge supply line and one purge exhaust line) of containment purge system lines. The following is a discussion of the surveillance program conducted to ensure the operability of the purge system as well as a discussion of the time required for purging and venting to date and the reasons for purging and venting.

Surveillance Program

The Sequoyah purge system utilizes two pairs of 14,000 cfm supply and exhaust fans along with smaller, approximately 800 cfm, supply and exhaust fans for the incore instrument room. All air discharged by this system is filtered before release through a set of filter banks comprised of prefilters, high efficiency particulate filters, and charcoal filters. These filter banks are tested every 12 months in accordance with ANSI N510-1975 and verified to remove greater than or equal to 99 percent of particulate and halogenated hydrocarbon test gas.

Each of the ten purge system line penetrations through the containment vessel has inboard and outboard isolation valves that are periodically tested for leakage and closure time. The surveillance program requires the isolation valve(s) to be leak tested following each cycling of the valve(s) or every 90 days. The valves are tested for closure time following any maintenance on the valves or every 90 days. The performance of the Sequoyah purge isolation valves has to date been excellent with average closure times well below the required four seconds and leak rates well below the limits specified in the plant technical specifications. In addition, testing of the bypass, override, and reset circuits of all systems receiving engineered safety feature (ESF) signals, including the containment purge system, has been completed at Sequoyah. These tests verified that safety feature actuation signals cannot be inadvertently blocked, overridden, or bypassed, and also verified that safety-related equipment would not return to its nonsafety mode upon reset of the ESF signal.

Containment Venting Requirements

Sequoyah technical specifications require that primary containment internal pressure be maintained between -0.1 and 0.3 psig relative to the annulus pressure and that primary containment internal pressure be determined to be within these limits at least once per 12 hours. The need to vent primary containment to maintain the limits given above results from the slow increase in containment pressure due to the control air bleedoff from the many air-operated valves inside containment and the changes in annulus pressure due to changes in environmental temperature and barometric pressure throughout the day.

Table 1 provides a listing of the venting time required for Sequoyah unit 1 for the 31-day period from March 17, 1982, through April 16, 1982. As indicated in this table, Sequoyah unit 1 is required to vent to release containment pressure an average of 1.69 hours/day in order to meet technical specification limits. Based on this data, Sequoyah unit 1 will require 617 hours of vent time each year.

Containment Purging Requirements

Containment purging is required to reduce the activity levels inside containment and thereby reduce dose to personnel required to enter containment during operation. Ice condenser containments, such as those found at Sequoyah, require significantly more containment entries than other types of containments. This is due to both additional surveillance required by technical specifications and additional inspection and maintenance of the ice condenser systems.

For example, a routine walk-through inspection of the ice condenser is performed three times daily (once per shift). This walk-through inspection requires entry into containment and entry into the ice condenser itself. Since the ice condenser is a closed system with only inleakage from the containment as a source of air, a buildup of airborne activity in the ice condenser is extremely difficult to reduce even though the purge system may reduce the levels in containment relatively fast. It is therefore necessary to keep activity levels in the containment as low as possible to prevent any excessive buildup in the ice condenser. Use of air packs during ice condenser inspections is prohibited due to the increased probability of injury to personnel as a result of the face plate fogging. It should also be noted that use of an air pack impairs an individual's ability to reach the location of certain pieces of equipment as well as his ability to remain in containment for an extended period of time. Table 2 provides a general breakdown of the 1,313 containment entries made in modes 1, 2, 3, and 4 from March 5, 1982, through April 22, 1982.

Table 3 provides a listing of the purging time required for Sequoyah unit 1 for a 32-day period from March 17, 1982, through April 17, 1982, in order to keep containment activity levels below that which would prevent inspection and maintenance. Based on the data in this table, Sequoyah unit 1 is required to purge an average of 3.69 hours per day to comply with our (TVA) ALARA approach toward occupational exposure; therefore, Sequoyah unit 1 (using a single pair of lines) will require 1,347 hours per year to meet its purge requirements.

Summary

TVA has self-imposed limits on occupational exposure which are below those set forth in Federal standards. We have in the past and will continue to follow the ALARA approach toward occupational exposure both in the design and operation of our nuclear plants. In order to achieve our goal of low occupational exposure, Sequoyah will require, as indicated in the above discussion, approximately 1,964 hours total purge time per year (1,347 purging, 617 venting) or 5.34 hours per day. The present technical specification limit of 1,000 hours will limit the time Sequoyah can operate in modes 1, 2, 3, and 4 to approximately six months per year.

It is our belief that, given our strict and comprehensive surveillance program and the performance of our system to date, extending the purge and vent capability at Sequoyah will not significantly increase the probability of an offsite release in excess of 10 CFR 100 guidelines.

BSS:JLR
12/21/82
Attachments
A1355.R1

TABLE 1

VENTING TIME
MARCH 17, 1982 THROUGH APRIL 17, 1982

Date	Time Venting Initiated	Hours Open
3/18	1133	0.75
	1750	0.83
3/19	0227	0.30
	0535	0.50
	1100	0.67
	1825	0.50
3/20	0305	1.00
3/21	0200	1.25
	1745	1.00
3/22	0900	1.00
	1608	0.97
3/23	0504	1.00
	1415	0.83
3/24	0055	0.70
	0925	0.50
3/25	0910	0.50
	1210	0.50
3/26	0158	0.75
	0923	0.33
	1910	0.67
3/28	0612	0.50
	1240	0.67
	2210	0.50
3/29	0645	0.75
	1615	0.75
3/30	0040	1.00
	0859	0.97
3/31	0000	0.75
	1042	0.83
	2350	0.50
4/1	0920	0.73
	1507	1.00

TABLE 1 (cont'd)

Date	Time Venting Initiated	Hours Open
4/2	1223	1.00
	2255	1.00
4/3	0727	1.68
4/4	0025	0.75
	1057	0.83
	1742	1.00
4/5	0622	0.75
	1233	1.02
	1810	0.50
4/6	1223	0.78
	1555	0.42
	1850	0.67
4/7	0250	0.50
	0810	0.33
4/8	0906	1.13
	1815	1.00
4/9	0205	0.75
	1212	0.77
	2205	0.58
4/10	0634	0.68
	1414	0.90
4/11	1251	0.47
	1733	1.00
4/12	0310	0.50
	1110	0.50
	1422	0.50
	1900	0.50
4/13	0400	0.50
	1300	0.50
4/14	0845	0.50
	1325	0.50
	2030	0.50
4/15	0120	0.50
	1000	0.50
	1400	1.00

TABLE 1 (cont'd)

Date	Time Venting Initiated	Hours Open
4/16	0030	0.50
	0835	0.50
	1458	1.00
4/17	0130	0.42
	0912	0.50
	1710	1.00
	TOTAL	52.43
	AVERAGE	1.69 hrs/day

BSS:JLR
12/21/82
A1355.R1

TABLE 2

CONTAINMENT ENTRIES MODES 1 THROUGH 4
MARCH 5, 1982 THROUGH APRIL 22, 1982

Number of Entries	Reason
379	Maintenance
314	Health Physics Inspection
196	Surveillance Requirements
155	Quality Assurance
144	[~~Office of Power Stores~~] operations
78	Instrument Maintenance
17	Janitors
4	Security
26	Others

BSS:JLR
12/21/82
A1355.R1

TABLE 3

PURGING TIME
MARCH 17, 1982 THROUGH APRIL 17, 1982

Date	Time Initiated	Hours Open	Compartment
3/17	1003	4.33	
	1705	11.67	
3/20	1105	2.12	
	1338	2.52	
	1800	2.17	
	2015	1.17	
3/24	1130	5.00	
	1755	4.00	
3/27	0210	7.33	
	0952	6.18	
3/30	1100	6.50	
	1730	4.00	
4/2	0010	4.33	
	1335	5.00	
4/6	0005	4.67	
	0716	3.23	
	1434	0.67	
	1650	0.17	
4/7	1050	2.92	
	1610	7.50	
4/8	0005	4.66	
4/10	1900	5.00	
4/11	0000	1.08	
	0105	5.33	
	0658	3.13	
4/13	1345	4.00	
	1900	6.00	
4/14	0300	2.50	
4/17	2300	1.00	
	TOTAL	118.18	
	AVERAGE	3.69 hours/day	

BSS:JLR
12/21/82
A1355.R1

Surveillance Requirement 4.6.5.6.a (Page 3/4 6-34)

Containment Air Return fans closed damper motor currents test results from the Preop test are

Fan 1A-A	Phase A	72	amps
	B	80	amps
	C	76	amps
Fan 1B-B	Phase A	72.8	amps
	B	74	amps
	C	68	amps

with an average current of 74 amps. Two standard deviations is 20 amps therefore, the setpoint for the fans should be 74 $\pm$ 20 amps.

Also measured in the Preop test were the damper opening torques.

Fan 1A-A damper	140 in-lbs
Fan 1B-B	120 in-lbs

therefore, the damper opening torque should be 150 in-lbs.

CONTAINMENT SYSTEMS

CONTAINMENT AIR RETURN FAN SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.5.6 Two independent containment air return fan systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one containment air return fan system inoperable, restore the inoperable system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.6 Each containment air return fan shall be demonstrated OPERABLE:

a. At least once per 92 days on a STAGGERED TEST BASIS by:

1. Verifying that the fan motor current is ~~28 ± 7.5~~ 74 ± 20 amps with the backdraft dampers closed, and

2. Verifying that with the fan off, the air return fan damper opens when a torque of less than or equal to ~~68.1~~ 150 inch-pounds is applied to the counterweight.

b. At least once per 18 months by verifying that the air return fan starts on Containment Pressure High-High test signal after a 10 ± 1 minute delay and operates for at least 15 minutes.

WATTS BAR NUCLEAR PLANT
PREOPERATIONAL TEST INSTRUCTION
CHANGE NUMBER CN-#17

Test Instruction Number TVA-6 (R1) Unit 1

Test Title Containment Air Return Fans

PAGE	STEP	DESCRIPTION OF CHANGE	REASON FOR CHANGE
15	5.1.6a	Insert a paragraph to read: "Using a clamp-on ammeter measure the current through each phase at 480V SD BD 1A1-A, 10C, and record the data on this sheet. Phase A current 72 amps Phase B current 80 amps Phase C current 76 amps USTVA #125921 w/ WBPAL-1 DEK 5/11/82 DEK 5-11-82	This change collects blocked damper motor currents and damper opening torques as baseline data for the WBNP Technical Specifications

Initiated By Dale Kaulitz Date 3/25/82

SAFETY RELATED CHANGES	NONSAFETY RELATED CHANGES
Recommended ______ Test Program Coordinator	Concurrence R E Bradley 4-26-82 Power Plant Operations Section /Date
Reviewed and Approved by EN DES ______ /Date	Reviewed W. K. Jones 3/25/82 Test Program Coordinator /Date
Reviewed by PORC ______ /Date	[illegible] 4/28/82 Power Plant Superintendent /Date
Approved for Use ______ Power Plant Supertendent	APPROVED FOR USE

CHANGE SHEET

PAGE	STEP	DESCRIPTION OF CHANGE	REASON FOR CHANGE
19	5.2.5a	Insert a paragraph to read: "Using a clamp-on ammeter measure the current through each phase at 480 V SD BD 1B2-B, 9C, and record the data on this sheet. Phase A current 72.8 amps Phase B current 74 amps Phase C current 68 amps DEK 3/31/82	USTVA # 425921 w/ WBPAC-1 DEK 3-31-82
37	5.5.45	Insert a paragraph to read: "Using a 2 3/16 in socket with an indicating torque wrench, measure the torque required to open the (inlet) backdraft damper for CAR Fan 1A-A and record the value on this sheet. Torque 140 in lbs DEK 2/9/83	WBNP TR-T112 cal 1-14-83 due 7-14-83

APPROVED FOR USE

CHANGE SHEET

PAGE	STEP	DESCRIPTION OF CHANGE	REASON FOR CHANGE
47	5.6.65	Insert a paragraph to read: "Using a 2 3/16 in. socket with an indicating torque wrench, measure the torque required to open the (inlet) backdraft damper for CAR Fan 1B-B and record the value on this sheet. Torque 120 in lb. DCK 2/9/83	WBNP TR-T112 Cal. 1-14-83 due 7-14-83

ITEM E1.35

Surveillance Requirement 4.7.1.2 (Page 3/4 7-5)

There are no auto valves in the flow path from the condensate storage tank. The SR has been revised appropriately.

SURVEILLANCE REQUIREMENTS (Continued)

3) Verifying that each automatic valve in the flow path ~~from the condensate water storage tank~~ is OPERABLE whenever the Auxiliary Feedwater System is placed in automatic control or when above 10% RATED THERMAL POWER.

b. At least once per 18 months by:

1) Verifying that each automatic valve in the flow path actuates to its correct position upon receipt of a Safety Injection test signal and a Low Auxiliary Feedwater Pump Suction Pressure test signal, and

2) Verifying that each auxiliary feedwater pump starts as designed automatically upon receipt of each Auxiliary Feedwater Actuation test signal.

ITEM E1.36

Table 4.7-1 (Page 3/4 7-8)

Under item 2 the 'below 10%' should be changed to 'less than or equal to 10%.' This termonology is more correct.

TABLE 4.7-1

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY
SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY
1. Gross Specific Activity Determination	At least once per 72 hours.
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	a) Once per 31 days, whenever the gross specific activity determination indicates concentrations greater than 10% of the allowable limit for radioiodines.
	b) Once per 6 months, whenever the gross specific activity determination indicates concentrations less than or equal to ~~below~~ 10% of the allowable limit for radioiodines.

ITEM E1.37

4.7.8.a (Pages 3/4 7-19, B 3/4 7-4, B 3/4 6-3, and B 3/4 9-3)

The surveillance requirement 4.7.8.a requires the ABGTS heaters to be on during the 10-hour system operation check. This is not consistent with surveillance requirement 4.9.12.1 which requires the heaters to be operating. This means that the heaters can cycle on and off to maintain a set temperature. The bases should also be changed to be consistent.

PLANT SYSTEMS

3/4.7.8 AUXILIARY BUILDING GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8 Two independent Auxiliary Building Gas Treatment (ABGT) Systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one ABGT System inoperable, restore the inoperable system to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours, and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.8 Each ABGT System shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS, by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the system operates for at least 10 hours with the heaters ~~on~~; operating

b. At least once per 18 months, or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the system, by:

1) Verifying that the cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% and uses the test procedure guidance of Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 9000 cfm ± 10%;

2) Verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%; and

ULTIMATE HEAT SINK (Continued)

The limitations on maximum temperature are based on providing a 30-day cooling water supply to safety-related equipment without exceeding their design basis temperature and is consistent with the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," March 1974.

3/4.7.6 FLOOD PROTECTION PLAN

The requirements for flood protection ensures that facility protective actions will be taken and operation will be terminated in the event of flood conditions. The elevations of plant features which could be affected by the submergence during floods vary from 714.5 ft mean sea level (MSL) (access to electrical conduits) to 760.5 ft MSL (emergency exits to diesel generator building). Plant grade is elevation 728 ft MSL. A Stage 1 flood warning is issued when the water at the intake pumping station is predicted to exceed 714.5 feet MSL USGS datum during October 1 through April 15, or 726.5 feet MSL USGS datum during April 16 through September 30. A Stage II flood warning is issued when the water at the intake pumping station is predicted to exceed 727 feet MSL USGS datum. A maximum allowed water level of 727 feet MSL USGS datum provides sufficient margin to ensure waves due to high winds cannot disrupt the flood mode preparation. A Stage I or Stage II flood warning requires the implementation of procedures which include plant shutdown. Further, in the event of a loss of communications simultaneous with a critical combination flood, headwaters, and/or seismically induced dam failure the plant will be shutdown and flood protection measures implemented.

3/4.7.7 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

The OPERABILITY of the Control Room Emergency Ventilation System ensures that: (1) the ambient air temperature does not exceed the allowable temperature for continuous-duty rating for the equipment and instrumentation cooled by this system, and (2) the control room will remain habitable for operations personnel during and following all credible accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criterion 19 of Appendix A, 10 CFR Part 50.

3/4.7.8 AUXILIARY BUILDING GAS TREATMENT SYSTEM

operating

The OPERABILITY of the Auxiliary Building Gas Treatment System ensures that radioactive materials leaking from the ECCS equipment within the pump room following a LOCA are filtered prior to reaching the environment. Operation of the system with the heaters ~~on~~ for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The operation of this system and the resultant effect on offsite dosage calculations was assumed in the accident analyses.

SHIELD BUILDING STRUCTURAL INTEGRITY (Continued)

for the life of the facility. Structural integrity is required to provide: (1) protection for the steel vessel from external missiles, (2) radiation shielding in the event of a LOCA, and (3) an annulus surrounding the steel vessel that can be maintained at a negative pressure during accident conditions. A visual inspection is sufficient to demonstrate this capability.

3/4.6.1.9 EMERGENCY GAS TREATMENT SYSTEM

The OPERABILITY of the EGTS ensures that during LOCA conditions, containment vessel leakage into the annulus will be filtered through the HEPA filters and charcoal adsorber trains prior to discharge to the atmosphere. Operation of the system with the heaters ~~ON~~ operating for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. This requirement is necessary to meet the assumptions used in the accident analyses and limit the SITE BOUNDARY radiation doses to within the dose guideline values of 10 CFR Part 100 during LOCA conditions.

3/4.6.1.10 CONTAINMENT VENTILATION SYSTEM

The 24-inch containment purge supply and exhaust isolation valves are required to be sealed closed during plant operations since these valves have not been demonstrated capable of closing during a LOCA or steam line break accident. Maintaining these valves sealed closed during plant operation ensures that excessive quantities of radioactive material will not be released via the Containment Purge System. To provide assurance that the 24-inch containment valves cannot be inadvertently opened, the valves are sealed closed in accordance with Standard Review Plan 6.2.4 which includes mechanical devices to seal or lock the valve closed, or prevents power from being supplied to valve operator.

The use of the containment purge lines is restricted to the 12-inch purge supply and exhaust isolation valves since, unlike the 24-inch valves, the 12-inch valves will close during a LOCA or steam line break accident. Therefore, the SITE BOUNDARY dose guideline values of 10 CFR Part 100 would not be exceeded in the event of an accident during containment purging operation.

Leakage integrity tests with a maximum allowable leakage rate for containment purge supply and exhaust supply valves will provide early indication of resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop. The 0.60 L_a leakage limit of Specification 3.6.1.2b. shall not be exceeded when the leakage rates determined by the leakage integrity tests of the valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS - CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the Containment Spray System ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

3/4.9.10 and 3/4.9.11 WATER LEVEL - REACTOR VESSEL and STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.12 AUXILIARY BUILDING GAS TREATMENT SYSTEM

The limitations on the Auxiliary Building Gas Treatment System ensure that all radioactive material released from an irradiated fuel assembly will be filtered through the HEPA filters and charcoal adsorber prior to discharge to the atmosphere. Operation of the system with the heaters ~~ON~~ operating for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system and the resulting iodine removal capacity are consistent with the assumptions of the accident analyses.

3/4.9.13 REACTOR BUILDING PURGE VENTILATION SYSTEM

The limitations on the Reactor Building Purge-Ventilation System ensure that all radioactive material released from an irradiated fuel assembly inside containment will be filtered through the HEPA filters and charcoal adsorbers prior to discharge to the atmosphere. The OPERABILITY of this system and the resulting iodine removal capacity are consistent with the assumption of the accident analyses.

ITEM E1.38

Technical Specification 3/4.7.9 (Pages 3/4 7-21, 3/4 7-22, 3/4 7-23, 3/4 7-24, 3/4 7-25, 3/4 7-26, 3/4 7-27, B 3/4 7-5, and B 3/4 7-6)

1. The term 'seismic category I and IL' was consistently inserted throughout the specification to replace the term 'safety-related.' This terminology is more descriptive and is consistent with definitions given in the Final Safety Analysis Report (FSAR) and terminology used in TVA internal procedures. (See page 3.2-1 of the FSAR.)

2. The tabulations of snubbers, Tables 3.7-4a and 3.7-4b, are deleted in the attached specification because they have no bearing on the intent of the specification or the safe operation of the plant. Each snubber will be listed individually by location number in Surveillance Instruction (SI) 4.7.9. As a result of this change, the pages of the specification containing the tabulations (3/4 7-25 and 3/4 7-26) are marked 'This page deleted.' Exclusion of the tabulations of snubbers from the TS is consistent with the snubber TS that was accepted by NRC for Browns Ferry Nuclear Plant.

3. The adjective 'included' has been added to describe snubbers in the action statement and other locations in the specification. The reason for that addition is to clarify the distinction between snubbers installed on seismic category I and IL portions of systems that are within the scope of the specification and other snubbers that are excluded from the scope of the specification.

4. Provision was added for exemptions to the surveillance program when a justifiable basis for the exemption can be established. That provision is allowed in the snubber TS approved by NRC for Sequoyah and Browns Ferry. The provision is also discussed in the fifth paragraph of the bases of the NRC proposed specification.

5. The term 'examination' has been inserted throughout the specification to replace 'inspection.' This change is based in part on the following portions of definitions given in Article IWA-2110 of Section XI of the ASME Code.

   Examination--Denotes the performance of all visual observation and nondestructive testing, . . .

   Inspection--Denotes verifying the performance of examinations and tests . . .

   In this specification, examination refers to the actual performance of visual observations.

   Provision for grouping of snubbers based on design, environment, or other features that may be expected to affect the operability of the snubbers within the group was inserted in lieu of typing of snubbers based only on manufacturer. As a result of this change, the term 'group' has been inserted in place of 'type' throughout the specification. Grouping of snubber based on factors which may be expected to affect operability within the group permits increased surveillance of snubbers susceptible to certain modes of failure resulting from differences in design and operating environment. The change also allows reduced surveillance snubbers not susceptible or less susceptible to these failure modes. For example, PSC-1/4 and -1/2 snubbers use small diameter guide rods and are subject to a mode of failure caused by twisting of the opposite ends about the axis of the snubber. None of the larger PSC snubbers is subject to this failure mode. Therefore, whenever this mode of failure is identified, the TS need only require additional surveillance on those snubbers subject to that mode of failure. This position in principle was incorporated into IE Bulletin 81-01 in that different inspection criterion and inspection schedules were specified based on manufacturer (i.e., design) of the mechanical snubbers within the scope of that bulletin. Also, the snubber TS at both Browns Ferry and Sequoyah allow grouping of snubbers in this manner.

Snubbers of only two manufacturers are used at Watts Bar. Each unit contains 20 Paul-Munroe 1,000 kip hydraulic snubbers which restrain the steam generators. All remaining snubbers (approximately 1,000 per unit) are manufactured by the Pacific Scientific Corporation (PSC). Typing of snubbers as proposed in the NRC specification would result in only two categories composed of 20 Paul-Munroe snubbers and approximately 1,000 PSC snubbers. Grouping snubbers in this manner is undesirable for the reasons given above.

6. 'Refueling Outage Inspection' was changed to 'Supplementary Visual Examinations.' A requirement was also added that snubbers that are accessible during reactor operation be examined as soon as practical after a potentially damaging event and not delayed until the subsequent refueling outage as allowed by the NRC specification.

7. The requirement to functionally test all snubbers to verify their operability from a possible inoperable status has been modified to specify 'if applicable.' Loose attachment bolts or missing clevis pins should not, for this reason only, require functional testing of the snubbers. This change is consistent with the snubber TS accepted by NRC for Browns Ferry and Sequoyah.

8. The requirement that all hydraulic snubbers connected to an inoperable common hydraulic fluid reservoir be declared inoperable was modified. Some common reservoirs have long hose or piping runs which may contain more than enough fluid to permit all of the connected snubbers to perform their required function even when the reservoir is empty. As a result of that consideration, provision was allowed not to declare a snubber inoperable when fluid can be established to be present at the individual snubber inlet sufficient for operation of the snubber. This change is consistent with the snubber TS approved by NRC for Sequoyah.

9. The specification proposed by NRC allowed two sampling plans for the determination of functional test lots. The first plan was changed to allow each subsequent test lot (selected for each snubber in the original or preceeding lot that failed to meet the acceptance criteria) to be composed of 5 percent of the snubbers remaining in the group. The requirement in the specification proposed by NRC was that each subsequent test lot be composed of 10 percent of the snubbers remaining

in the group. This change is only slightly less conservative than the relationship for selection of functional test lots defined by the equation $N = 10\% \, n \, (1 + C/2)$.

Where N = Number of snubbers to be tested
n = Total number of snubbers in group
C = The number of snubbers in the original or preceeding lot that fail to meet the acceptance critieria

This change is consistent with the sampling plan given for functional tests in the snubber TS at Sequoyah.

10. The functional test acceptance criteria for drag force was changed to allow forces not great enough to overstress the attached piping or component during thermal movement or to indicate impending failure of the snubber. The requirement in the specification proposed by NRC was that drag force must be 'within the specified range in both directions of travel.' This change is because the range of acceptable drag forces is directly related to the design of the snubber and its application in the system. Generally, a maximum drag force of 2 percent of the capacity of the snubber is allowed; however, in some cases greater forces can be shown not to damage the attached pipe or component or to indicate impending failure of a certain snubber. The change is consistent with the snubber TS approved by NRC for Browns Ferry.

11. Provision was added to extend the service life of snubbers based on an evaluation of the records of functional tests, maintenance history, and environmental conditions to which the snubbers have been exposed. This provision is discussed in NRC's version of the bases and is allowed in the snubber TS at both Browns Ferry and Sequoyah.

PLANT SYSTEMS

3/4.7.9 SNUBBERS

LIMITING CONDITION FOR OPERATION

(1) 3.7.9 All seismic category I and II snubbers ~~listed in Tables 3.7-4a and 3.7-4b~~ shall be OPERABLE.
(2) These snubbers are listed in Surveillance Instruction (SI) 4.7.9.

APPLICABILITY: MODES 1, 2, 3, and 4. MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES.

ACTION:

(3) With one or more included snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.9g on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.9 Each included snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program. ~~and requirements of Specification 4.0.5.~~ Exemptions to any portion of the surveillance program for any snubber is shown in the listings in SI 4.7.9.

(4)

See next pg (5)

a. ~~Inspection Types~~

~~As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.~~

b. Visual ~~Inspections~~ Examination Schedule

The first inservice visual ~~inspection~~ examination ~~of each type of~~ ~~snubber~~ shall be performed after 4 months but within 10 months of commencing POWER OPERATION and shall include all included snubbers listed in ~~Tables 3.7-4a and 3.7-4b~~ SI-4.7.9. If less than two snubbers of each ~~type~~ group are found inoperable during the first inservice visual ~~inspection~~ examination, the second inservice visual ~~inspection~~ examination shall be performed 12 months ± 25% from the date of the first ~~inspection~~ examination. Otherwise, subsequent visual ~~inspections~~ examinations shall be performed in accordance with the following schedule:

No. Inoperable Snubbers of each ~~type~~ group per ~~Inspection~~ Examination Period	Subsequent Visual ~~Inspection~~ Examination Period*#
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

*The ~~inspection~~ examination interval for each ~~type~~ group of snubbers shall not be lengthened more than one step at a time unless a generic problem has been identified and corrected; in that event the ~~inspection~~ examination interval may be lengthened one step the first time and two steps thereafter if no inoperable snubbers of that ~~type~~ group are found.

#The provisions of Specification 4.0.2 are not applicable.

(c) a. Examination Groups

The snubbers may be categorized into two major groups based on whether the snubbers are accessible or inaccessible during reactor operation. These major groups may be further subdivided into groups based on design, environment, and other features which may be expected to affect the OPERABILITY of the snubbers within the group. Each group may be inspected independently in accordance with 4.7.9.b through 4.7.9.h. The groups may be reconstituted based on the results of a failure analysis required by 4.7.9.g.

SURVEILLANCE REQUIREMENTS (Continued)

(6) c. Supplementary Visual Examinations ~~Refueling Outage Inspections~~

Not later than the subsequent refueling outage ~~At least once per 18 months~~, an inspection shall be performed of all the included snubbers ~~listed in Tables 3.7-4a and 3.7-4b~~ attached to sections of safety systems piping that have experienced unexpected, potentially damaging transients as determined from a review of operational data and a visual examination ~~inspection~~ of the systems.* In addition to satisfying the visual examination ~~inspection~~ acceptance criteria, freedom of motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

* Snubbers on systems accessible during reactor operation shall be examined as soon as practical after a potentially damaging event has been identified.

d. Visual Examination ~~Inspection~~ Acceptance Criteria

Visual examinations ~~inspections~~ shall verify that: (1) there are no visible indications of damage or impaired OPERABILITY, and (2) attachments to the foundation or supporting structure are secure. Snubbers which appear inoperable as a result of visual examinations ~~inspections~~ may be determined OPERABLE for the purpose of establishing the next visual examination ~~inspection~~ interval, provided that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of group ~~type~~ that may be generically susceptible,
(7) and (2) the affected snubber is functionally tested, if applicable, in the as found condition and determined OPERABLE per Specification 4.7.9f. When a fluid port of a hydraulic snubber is found to be uncovered the snubber shall be declared inoperable and shall not be determined OPERABLE via functional testing unless the test is started with the piston in the as-found setting, and extending the piston rod in the tension-mode direction. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable
(8) snubbers, unless fluid is established to be present at the individual snubber inlet sufficient for operation of the snubber.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of either:
(9) (1) at least 10% of the total of each group of included snubbers ~~plant~~ shall be functionally tested either in place or in a bench test. For each snubber of a group ~~type~~ that does not meet the functional test acceptance criteria of Specification 4.7.9f., an additional 5 ~~10%~~ of that group ~~type~~ of snubber shall be functionally tested until no more failures are found or until all snubbers of that group ~~type~~ have been functionally tested, or (2) a representative sample of each group of snubbers ~~snubber~~ shall be functionally tested in accordance with Figure 4.7-1. "C" is the total number of snubbers of a group ~~type~~ found not meeting the acceptance requirements of Specification 4.7.9.f. The cumulative number of snubbers of a group ~~type~~ tested is denoted by "N." At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 4.7-1. If at any time the point plotted falls in the "Reject" region all snubbers of that group ~~type~~ shall be functionally tested. If at any time the point plotted falls in the "Accept" region testing of that group ~~type~~

e. Functional Tests (Continued)

of snubber may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that ~~type~~ group shall be tested until the point falls in the "Accept" region or the "Reject" region, or all the snubbers of that ~~type~~ group have been tested.

The representative sample selected for functional testing shall include the various configurations, operating environments, and the range of size and capacity of snubbers of each ~~type~~ group. The representative sample shall be weighted to include more snubbers from severe service areas such as near heavy equipment. Snubbers placed in the same location as snubbers which failed the previous functional test shall be included in the next test lot if the failure analysis shows that failure was due to location.

f. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1) Activation (restraining action) is achieved within the specified range in both tension and compression, except that inertia dependent, acceleration limiting mechanical snubbers, may be tested to verify only that activation takes place in both directions of travel;

2) Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range;

3) Where required, the force required to initiate or maintain motion of the snubber is ~~within the specified range in both direction of travel;~~ not great enough to overstress the attached piping or component during thermal movement or to indicate impending failure of the snubber;

(10)

4) For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement; and

5) Fasteners for attachment of the snubber to the component and to the snubber anchorage are secure.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of ~~type~~ group which may be subject to the same failure mode.

g. Functional Test Failure Analysis (Continued)

For the snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers ~~of the same type~~ subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Specification 4.7.9e. for snubbers not meeting the functional test acceptance criteria.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers which have repairs which might affect the functional test result shall be tested to meet the functional test criteria before installation in the unit. These snubbers shall have met the acceptance criteria subsequent to their most recent service, and the functional test must have been performed within 12 months before being installed in the unit.

i. Snubber Seal Replacement Program

The seal service life of hydraulic snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for the various seals, seal materials, and applications shall be determined and established based on engineering information and the seals shall be replaced so that the maximum expected service life will not be exceeded during a period when the snubber is required to be OPERABLE. The seal replacements shall be documented and the documentation shall be retained in accordance with Specification 6.10.2.

(11) R= The service life of snubbers may be extended based on an evaluation of the records of functional tests, maintence history, and environmental conditions to which the snubbers have been exposed.

(See item 4) j. Exemption from Visual Inspection or Functional Tests

Permanent or other exemptions from visual inspections and/or functional testing for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and if applicable snubber life destructive testing was performed to qualify snubber operability for the applicable design conditions at either the completion of fabrication or at a subsequent date. Snubbers so exempted shall continue to be listed in SI 4.7.9 with footnotes indicating the extent of the exemptions.

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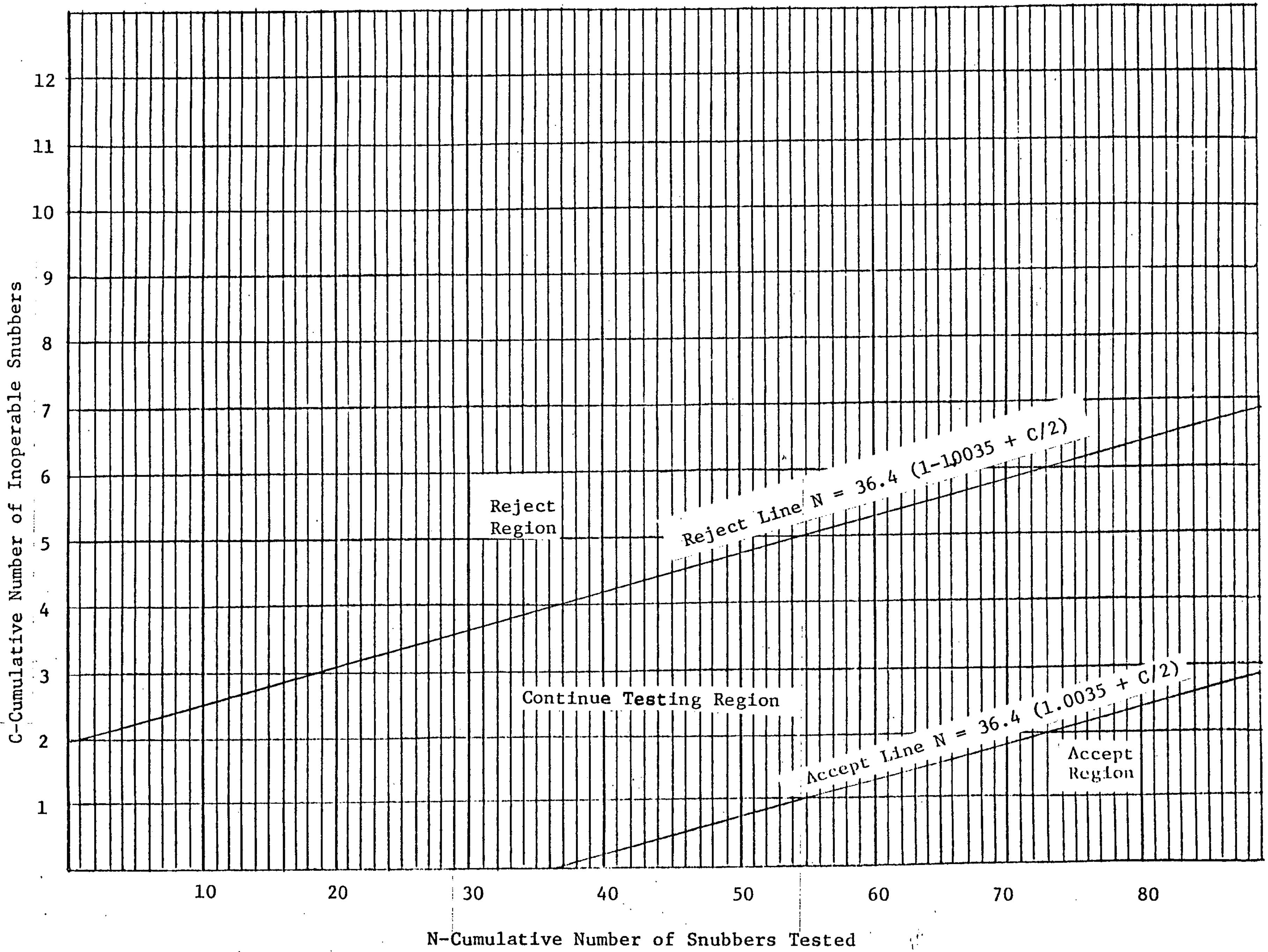


Figure 4.7-1 Sampling Plan for Snubber Functional Tests

3/4.7.9 SNUBBERS

All snubbers are required to be OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other Safety-Related Systems is maintained during and following a seismic or other event initiating dynamic loads. These systems are defined in the FSAR as Seismic Category I and II. Snubbers excluded from this inspection program are those installed on Nonsafety-Related Systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any Safety-Related System. The adjective "included" is used to distinguish between snubbers installed on Seismic Category I and II portions of systems and other snubbers that are excluded from the surveillance program.

Snubbers are ~~classified and~~ grouped by design ~~and manufacturer (but not by size. For example, mechanical snubbers utilizing the same design features of the 2 kip, 10 kip and 100 kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this specification would be of a different type, as would hydraulic snubbers from either manufacturer~~ environment or other features that may be expected to affect the operability of the snubbers within the group. Grouping snubbers in this manner allows increased surveillance of snubbers more susceptible to identical modes of failure.

The visual ~~inspection~~ examination frequency is based upon maintaining a constant level of snubber protection to systems. Therefore, the required ~~inspection~~ examination interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an ~~inspection~~ examination. ~~Inspections~~ Examinations performed before that interval has elapsed may be used as a new reference point to determine the next ~~inspection~~ examination. However, the results of such early ~~inspections~~ examinations performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required ~~inspection~~ examination interval. Any ~~inspection~~ examination whose results require a shorter ~~inspection~~ examination interval will override the previous schedule.

To provide assurance of snubber functional reliability, one of two sampling and acceptance criteria methods are used:

a. Functionally test 10% of a ~~type~~ group of snubber with an additional ~~10%~~ 5% tested for each functional testing failure, or

b. Functionally test a sample size and determine sample acceptance or rejection using Figure 4.7-1.

Figure 4.7-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in "Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubber for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall continue to be listed in ~~Tables 3.7-4a and 3.7-4b~~ the surveillance instruction with footnotes indicating the extent of the exemptions.

SNUBBERS (Continued)

The service life of a snubber is established via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc. . .). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

3/4.7.10 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from Byproduct, Source, and Special Nuclear Material sources will not exceed allowable intake values.

Sealed sources are classified into three groups according to their use, with Surveillance Requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4.7.11 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the Fire Suppression Systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located. The Fire Suppression System consists of the water system, spray, and/or sprinklers, CO_2, and fire hose stations. The collective capability of the Fire Suppression Systems is adequate to minimize potential damage to safety-related equipment and is a major element in the facility fire protection program.

In the event that portions of the Fire Suppression Systems are inoperable, alternate backup fire-fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire-fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

ITEM E1.39

3.7.11.3 (Page 3/4 7-34)

L.C.O. 3.7.11.3.d states the Fuel Oil Pump Rooms CO_2 system shall be operable. This means the Diesel Generator Fuel Oil Pump Rooms. Therefore, the Fuel Oil Pump Rooms should be changed to Diesel Generator Fuel Oil Pump Rooms.

Reason: There is another Fuel Oil Pump Room in the Turbine Building which is used for the Auxiliary Boiler. This room is also protected by a CO_2 but the equipment is not safety related.

ITEM E1.40

Cable Spreading Room CO_2 System (Page 3/4 7-34)

The low pressure CO_2 system has been deleted from the cable spreading room at Watts Bar. The attached spec 3.7.11.3 has been appropriately modified.

PLANT SYSTEMS

CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.11.3 The following Low Pressure CO_2 Systems shall be OPERABLE:

a. Auxiliary instrument room,

b. Diesel generator rooms,

c. Computer room,

d. Diesel Generator Fuel oil pump rooms, and

~~e. Cable spreading room, and~~

~~f.~~ e Diesel generator electrical board rooms.

APPLICABILITY: Whenever equipment protected by the CO_2 Systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required CO_2 Systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11.3.1 Each of the above required CO_2 Systems shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power operated, or automatic) in the flow path is in its correct position.

4.7.11.3.2 Each of the above required Low Pressure CO_2 Systems shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying the CO_2 storage tank level to be greater than 50% and pressure to be greater than 210 psig, and

b. At least once per 18 months by verifying:

1) The system including associated ventilation system fire dampers and fire door release mechanisms actuate manually and automatically, upon receipt of a simulated actuation signal, and

2) Flow from each nozzle during a "Puff Test."

ITEM E1.41

Table 3.7-5 (Page 3/4 7-37)

Please add the attached fire protection hose station to reflect the current as-built condition.

TABLE 3.7-5 (Continued)

LOCATION	ELEVATION	HOSE RACK #
Auxiliary Building		
A9V	676	0-26-691
A8T	676	0-26-663
A3S	692	1-26-668
A7W	692	0-26-680
A8X	692	0-26-681
A8T	692	0-26-662
A3T	713	1-26-667
A8W	713	0-26-690
A8T	713	0-26-661
A8X	729	0-26-658
A8X	729	0-26-659
A5X	729	1-26-686
A11Y ← A11X	730 ← 729	0-26-854 ← 2-26-686
A3T	737	1-26-666
A8X	737	0-26-677
A8T	737	0-26-660
A11Y	750	0-26-855
A3T	757	1-26-665
A4U	757	1-26-670
A5X	757	0-26-682
A10T	757	0-26-684
A5X	763	1-26-693
A3T	772	1-26-664
A5X	775	1-26-694
A4U	782	1-26-669
A5X	786	1-26-695
A5W	757	1-26-671
A5W	757	1-26-672
Control Building		
Stairwell C-1	692	0-26-1194
Stairwell C-1	708	0-26-1193
Stairwell C-1	729	0-26-1192
Stairwell C-1	755	0-26-1191
Stairwell C-2	692	0-26-1189
Stairwell C-2	708	0-26-1188
Stairwell C-2	729	0-26-1187
Stairwell C-2	755	0-26-1186
Intake Pumping Station (ERCW)		
	716	0-26-595
	716	0-26-596
	727	0-26-594
	727	0-26-597
		0-26-1710
		0-26-1711

ITEM E1.42

4.7.12.2a (Page 3/4 7-39)

Watts Bar does not have a fire door supervision system. This was not a requirement of the fall '81 Standard Tech Specs. Watts Bar intends to inspect all fire doors once per 24 hours.

SURVEILLANCE REQUIREMENTS (Continued)

4.7.12.2 Each of the above required fire doors shall be verified OPERABLE by inspecting the automatic hold-open, release and closing mechanism and latches at least once per 6 months, and by verifying:

a. ~~The OPERABILITY of the fire door supervision system for each electrically supervised fire door by performing a TRIP ACTUATING DEVICE OPERATIONAL TEST at least once per 31 days~~,

b. That each locked closed fire door is closed at least once per 7 days,

c. That doors with automatic hold-open and release mechanisms are free of obstructions at least once per 24 hours and performing a functional test at least once per 18 months, and

d. That each unlocked fire door without electrical supervision is closed at least once per 24 hours.

ITEM E1.43

3.8.1.1.b.5 & b.6 (Pages 3/4 8-1, 3/4 8-3, and 3/4 8-9)

Watts Bar has an FSAR Commitment to maintain a minimum of 935 gallons of lube oil onsite and available for use. This amount is not required for the 7-day required operation of the diesels. Enough oil is maintained in the sump to meet this requirement. Therefore this commitment should not be made part of the tech specs. There is no automatic transfer system for lube oil from storage to the oil sump in the Diesel Generator Unit.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Four separate and independent diesel generators, each with:

1) Two separate engine-mounted fuel tanks containing a minimum volume of ~~550~~ 250 gallons of fuel in each tank,

2) A separate 7 day fuel storage tank containing a minimum volume of ~~68,000~~ 62,000 gallons of fuel,

3) A separate fuel transfer pump,

4) A separate 125-volt DC distribution panel, 125-volt D.C. battery bank and associated charger,

~~5) Lubricating oil storage containing a minimum total volume of ___ gallons of oil, and~~

~~6) Capability to transfer lubricating oil from storage to the diesel generator unit.~~

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With either an offsite circuit or diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Specifications 4.8.1.1.1a. and 4.8.1.1.2a.4) within 1 hour and at least once per 8 hours thereafter; restore at least two offsite circuits and four diesel generators to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one offsite circuit and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Specifications 4.8.1.1.1a. and 4.8.1.1.2a.4) within 1 hour and at least once per 8 hours thereafter; restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore at least two offsite circuits and four diesel generators to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one diesel generator inoperable in addition to ACTION a. or b. above, verify that:

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying the fuel level in the 7-day fuel storage tank,

3) Verifying the fuel transfer pump starts and transfers fuel from the 7-day storage ~~system~~ tank to the engine-mounted tank,

~~4) Verifying the lubricating oil inventory in storage,~~

4 ~~5~~) Verifying the diesel starts from ambient condition and accelerates to at least 900 rpm in less than or equal to 10 seconds. The generator voltage and frequency shall be 6900 $\pm$ 690 volts and 60 $\pm$ 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual, or

b) Simulated loss-of-offsite power by itself, or

c) Simulated loss-of-offsite power in conjunction with an ESF actuation test signal, or

d) An ESF actuation test signal by itself.

5 ~~6~~) Verifying the generator is synchronized, loaded to greater than or equal to 4400 kW in less than or equal to 60 seconds for automatic starts and at the maximum practical rate for manual starts, and operates with a load greater than or equal to 4400 kW for at least 60 minutes, and

6 ~~7~~) Verifying the diesel generator is aligned to provide standby power to the associated shutdown boards.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by removing accumulated water from the engine-mounted fuel tanks;

c. At least once per 92 days and from new fuel prior to addition to the storage tanks, by obtaining a sample of fuel oil in accordance with ASTM-D270~~-1975~~, and by verifying that the sample meets the following minimum requirements and is tested within the specified time limits:

1) As soon as sample is taken (or prior to adding new fuel to the storage tank) verify in accordance with the tests specified in ASTM-D975~~-77~~ that the sample has:

a) A water and sediment content of less than or equal to 0.05 volume percent,

b) A kinematic viscosity @ 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, and

ELECTRICAL POWER SYSTEMS

A.C. SOURCES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and

b. Diesel Generator Sets 1A-A and 2A-A or 1B-B and 2B-B each with:

1) Engine-mounted fuel tanks containing a minimum volume of ~~550~~ 250 gallons of fuel per tank,

2) A 7 day fuel storage tank containing a minimum volume of ~~68,000~~ 62,000 gallons of fuel,

3) A fuel transfer pump,

4) A separate 125-volt DC distribution panel, 125-volt DC battery bank, and associated charger,

~~5) Lubricating oil storage containing a minimum total volume of ______ gallons of oil, and~~

~~6) Capability to transfer lubricating oil from storage to the direct generator unit.~~

APPLICABILITY: MODES 5 and 6.

ACTION:

With less than the above minimum required A.C. electrical power sources OPERABLE, immediately suspend all operations involving CORE ALTERATIONS, positive reactivity changes, movement of irradiated fuel, or crane operation with loads over the fuel storage pool, and within 8 hours, depressurize and vent the Reactor Coolant System through at least a 3 square inch vent. In addition, when in MODE 5 with the Reactor coolant loops not filled, or in MODE 6 with the water level less than 23 feet above the reactor vessel flange, immediately initiate corrective ACTION to restore the required sources to OPERABLE status as soon as possible.

SURVEILLANCE REQUIREMENTS

4.8.1.2 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Specifications of 4.8.1.1.1, 4.8.1.1.2 (except for Specification 4.8.1.1.2a.6), 4.8.1.1.3, and 4.8.1.1.4.

ally tested in accordance with TVA Preoperational Test TVA-14B. The system will be periodically tested to verify its ability to function as part of the diesel generator unit to satisfy the Technical Specification 3/4.8 surveillance requirement 4.8.1.1.2. Under normal standby conditions, the Diesel Gen- 24
erator Starting System is maintained and inspected at intervals as prescribed in the <u>Watts Bar Instruction and Maintenance Manual</u> for the diesel generator units. 10.15

9.5.7 <u>Diesel Engine Lubrication System</u>

The Diesel Engine Lubrication System for each diesel engine shown in Figure 9.5-26, is a combination of three subsystems: the main lubricating subsystem, the piston cooling subsystem, and the scavenging oil subsystem.

lubrication. The main lubricating subsystem supplies oil under pressure to the various moving parts of the diesel engine. The piston cooling subsystem supplies oil for piston cooling and lubrication of the piston pin bearing surfaces. The scavenging oil subsystem supplies the other systems with cooled and filtered oil. Oil is drawn from the engine sump by the scavenging pump through a strainer in the strainer housing located on the front site of the engine. From the strainer the oil is pumped through oil filters and a cooler. The filters are of the all-metal, self-cleaning type with automatic bypass, located on the accessory racks of the engines. The oil is cooled in the lubricating oil cooler (as shown in Figure 9.5-27) by the closed circuit cooling water system in order to maintain proper oil temperature during engine operation.

The required quality of oil is maintained by scheduled maintenance of strainers, separators, and filters and by oil changes in accordance with the engine manufacturer's recommendation.

A crankcase pressure detector assembly is provided to cause the engine to shut down in case the normal negative crankcase 28
pressure changes to a positive pressure. This is accomplished by relieving the oil pressure to the engine governor. The pressure detector shutdown device is operative only during diesel generator testing; see FSAR Paragraph 8.3.1.1 under the heading, "Standby Diesel Generator Operation."

An overspeed mechanism is provided to shut down the engine by stopping the injection of fuel into the cylinders should the engine speed become excessive. 40.46

When the diesel generator units are not operating but are in the standby condition, the auxiliary oil system is used to circulate the oil through the engine cooler where it is warmed by the 42
cooling water. The cooling water is maintained at $115^{\circ}F$ - $125^{\circ}F$ by the immersion heater. (Refer to Section 9.5.5, Diesel Generator Cooling Water System.) An alarm is provided to sound in the Main Control Room and locally in the diesel generator building if the lubricating oil temperature should fall below 42
$115^{\circ}F$. Thus, the engines are kept in constant readiness for an immediate start.

The lubricating oil and piston cooling oil pumps are of the positive displacement helical gear type, mounted externally on the front of the engine for accessibility. They are gear driven from the diesel engine. The circulating oil and scavenging oil pumps are separate, gear driven pumps. All lubricating oil pumps are mounted on the diesel engines.

Each of the engines in the tandem generator sets is provided with its own lubricating oil system, which is an integral part of each of the four diesel generator units (see Figure 9.5-27) housed within the Diesel Generator Building. The Building is designed to Seismic Category I requirements, and is designed to withstand the effects of tornados, credible missiles, hurricanes, floods, rain, snow, or ice as defined in Chapter 3, Sections 3.3, 3.4, and 3.5.

The diesel lubricating oil instrumentation alarms are activated to signal on any of the following conditions:

1. Low standby lubricating oil pressure

2. Low engine lubricating oil pressure

3. Low crankcase engine oil level

4. Low engine oil pressure at idle

5. High crankcase pressure

Local engine oil pressure and temperature gauges are provided. The diesel lubricating oil instrumentation alarms visually and audibly in both the Diesel Generator Building and Main Control Room. Each diesel generator is arranged so as to be able to supply power to its own auxiliaries such that a single failure will not result in loss of more than one diesel generator unit.

Each engine crankcase sump contains 400 gallons of lubricating oil, ample for at least seven days of diesel generator unit full load operation without requiring replenishment. The established oil consumption rate is 0.83 gallons per hour. An additional standby oil reserve of approximately 935 gallons is stored within the Diesel Generator Building to replenish the engines for longer periods of operation and to "top off" the engines after their periodic test operations as specified in the Technical Specifications. The diesel generator lubricating oil system components are inspected and serviced as specified in the "Scheduled Maintenance Program for the Watts Bar Diesel Generator Units." The inspection and service of the lubricating oil
systems includes visual checking for, and the correction of, oil 28
leakage. This program sets overall standards and testing
instructions to quality all lubricating oil for use in the diesel 40.4
generator engines.

9.5.8 Diesel Generator Combustion Air Intake and Exhaust System

9.5.8.1 Design Bases

The tandem diesel engine associated with each of the four diesel generator units are equipped with an independent Combustion Air Intake and Exhaust Subsystem. The four subsystems for the plant are housed in physically separated rooms within the Diesel
Generator Building. The Building is designed to Seismic Category 35
I requirements, and is designed to withstand

4.8.1.1.2.d.2 (Page 3/4 8-4)

Change 4.8.1.1.2.d.2 to read 'frequency does not exceed 66.75 Hz'

66.75 Hz is the frequency equivalent to 75 percent of the difference between the D.G. nominal speed (900 RPM) and the overspeed trip setpoint of 1035 RPM. The setpoint for frequency is less than or equal to 75 percent of the difference between nominal speed and overspeed trip setpoint or 15 percent above nominal whichever is less. This is given in STS dated 9/30/81.

2) Verifying the generator capability to reject a load of greater than or equal to 600 kW while maintaining voltage at 6900 ± 690 volts ~~and~~ and the frequency ~~at 60 ± 1.2 Hz~~ does not exceed 66.75 Hz;

3) Verifying the generator capability to reject a load of 4400 kW without tripping. The generator voltage shall not exceed 7866 volts during and following the load rejection;

4) Simulating a loss-of-offsite power by itself, and:

   a) Verifying deenergization of the shutdown boards and load shedding from the shutdown boards, and

   b) Verifying the diesel starts on the auto-start signal, energizes the shutdown boards with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 6900 ± 690 volts and 60 ± 1.2 Hz during this test.

5) Verifying that on an ESF actuation test signal, without loss of offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 6900 ± 690 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady-state generator voltage and frequency shall be maintained within these limits during this test;

6) Verifying that on a simulated loss of the diesel generator, with offsite power not available, the loads are shed from the shutdown boards and that subsequent loading of the diesel generator is in accordance with design requirements;

7) Simulating a loss-of-offsite power in conjunction with an ESF actuation test signal, and

   a) Verifying deenergization of the shutdown boards and load shedding from the shutdown boards;

ITEM E1.45

Surveillance Requirement (Pages 3/4 8-3 and 3/4 8-3a)

Remove all revision dates. Watts Bar tests fuel oil to the referenced ASTM testing requirements, but a later revision to those codes are presently being used. Because these codes are continually being updated and revised, the elimination of the revision would reduce the need for future updated of the T/S.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying the fuel level in the 7-day fuel storage tank,

3) Verifying the fuel transfer pump starts and transfers fuel from the storage system to the engine-mounted tank,

4) Verifying the lubricating oil inventory in storage,

5) Verifying the diesel starts from ambient condition and accelerates to at least 900 rpm in less than or equal to 10 seconds. The generator voltage and frequency shall be 6900 $\pm$ 690 volts and 60 $\pm$ 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

   a) Manual, or

   b) Simulated loss-of-offsite power by itself, or

   c) Simulated loss-of-offsite power in conjunction with an ESF actuation test signal, or

   d) An ESF actuation test signal by itself.

6) Verifying the generator is synchronized, loaded to greater than or equal to 4400 kW in less than or equal to 60 seconds, and operates with a load greater than or equal to 4400 kW for at least 60 minutes, and

7) Verifying the diesel generator is aligned to provide standby power to the associated shutdown boards.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by removing accumulated water from the engine-mounted fuel tanks;

c. At least once per 92 days and from new fuel prior to addition to the storage tanks, by obtaining a sample of fuel oil in accordance with ASTM-D270-~~1975~~, and by verifying that the sample meets the following minimum requirements and is tested within the specified time limits:

1) As soon as sample is taken (or prior to adding new fuel to the storage tank) verify in accordance with the tests specified in ASTM-D975-~~77~~ that the sample has:

   a) A water and sediment content of less than or equal to 0.05 volume percent,

   b) A kinematic viscosity @ 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, and

SURVEILLANCE REQUIREMENTS (Continued)

c) A specific gravity as specified by the manufacturers @ 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity @ 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

2) Within ~~1 week~~ 7 days after obtaining the sample, verify an impurity level of less than 2 mg of insolubles per 100 ml when tested in accordance with ASTM-D2274-~~7~~0; and

3) Within ~~2 weeks~~ 14 days of obtaining the sample verify that the other properties specified in Table 1 of ASTM-D975-~~77~~ and Regulatory Guide 1.137 Position 2.a are met when tested in accordance with ASTM-D975-~~77~~.

d. At least once per 18 months, during shutdown, by:

1) Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service;

Surveillance Requirement 4.8.1.1.2.d.11 (Page 3/4 8-5)

A review of NRC Regulatory Guide 1.108 'Periodic Testing of Diesel Generator Units . . .' section C, 'Regulatory Position,' does not reveal a requirement in paragraph 2, 'Testing,' for performing the tesing described by the SR. The regulatory guide does state the following under C.1.(3):

(3) Periodic testing of diesel generator units should not impair the capability of the unit to supply emergency power within the required time. Where necessary, diesel generator unit design should include an emergency override of the test mode to permit response to bona fide signals.

The Watts Bar design does not impair the ability of the diesel-generator to supply emergency power as specified in reference memorandum number 2 but the diesel trip is associated with an overcurrent relay looking at D/G load rather than the SI signal indicated in the present SR. Once the overcurrent relay operates, the 6.9 kV Board is placed in a blackout configuration and the emergency operation of the diesel-generator is the same as for any other blackout situation or test. Since the diesel-generator response to a blackout signal and/or SI signal is to be tested by other surveillance requirements, there is no reason to require a test of the diesel response from the test mode.

SURVEILLANCE REQUIREMENTS (Continued)

b) Verifying the diesel starts on the auto-start signal, energizes the shutdown boards with permanently connected loads within 10 seconds, energizes the auto-connected emergency (accident) loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the shutdown boards shall be maintained at 6900 ± 690 volts and 60 ± 1.2 Hz during this test; and

c) Verifying that all automatic diesel generator trips, except engine overspeed and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with a Safety Injection actuation signal.

8) Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 5225 kW and during the remaining 22 hours of this test, the diesel generator shall be loaded to greater than or equal to 4400 kW. The generator voltage and frequency shall be 6900 ± 690 volts and 60 ± 1.2 Hz ~~within 10 seconds after the start signal; the steady-state generator voltage~~ and ~~frequency~~ shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, perform Specification 4.8.1.1.2d.7)b);

9) Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 4750 kW;

10) Verifying the diesel generator's capability to:

a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

b) Transfer its loads to the offsite power source, and

c) Be restored to its standby status.

~~11) Verifying that with the diesel generator operating in a test mode, connected to its bus, a simulated Safety Injection signal overrides the test mode by: (1) returning the diesel generator to standby operation, and (2) automatically energizing the emergency loads with offsite power;~~

ITEM E1.47

3.8.3.1 and 3.8.3.2 (Pages 3/4 8-15 and 3/4 8-16)

The word 'division' should be replaced with 'train' in all occurences to be consistant with other uses in Tech Specs and TVA's terminology.

LIMITING CONDITION FOR OPERATION

ACTION:

a. With one of the required ~~divisions~~ train of A.C. train emergency busses not fully energized, re-energize the ~~division~~ within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one A.C. vital bus either not energized from its associated inverter, or with the inverter not connected to its associated D.C. bus: (1) re-energize the A.C. Vital Bus within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; and (2) re-energize the A.C. vital bus from its associated inverter connected to its associated D.C. bus within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With one D.C. Bus not energized from its associated battery bank, re-energize the D.C. bus from its associated battery bank within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.3.1 The specified busses shall be determined energized in the required manner at least once per 7 days by verifying correct breaker alignment and indicated voltage on the busses.

ELECTRICAL POWER SYSTEMS

ONSITE POWER DISTRIBUTION

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.3.2 As a minimum, the following electrical busses shall be energized in the specified manner:

a. One ~~division~~ train of A.C. emergency busses consisting of two 6900-volt and four 480-volt A.C. emergency bus;

b. Two 120-volt A.C. vital busses, either Channels 1-I and 1-III, or 1-IIand 1-IV energized from their associated inverters connected to their respective D.C. channels; and

c. Two 125-volt D.C. busses, either Channels I and III, or II and IV energized from its associated battery bank.

APPLICABILITY: MODES 5 and 6.

ACTION:

With any of the above required electrical busses not energized in the required manner, immediately suspend all operations involving CORE ALTERATIONS, positive reactivity changes, or movement of irradiated fuel, initiate corrective ACTION to energize the required electrical busses in the specified manner as soon as possible, and within 8 hours depressurize and vent the RCS through at least a 3 square inch vent.

SURVEILLANCE REQUIREMENTS

4.8.3.2 The specified busses shall be determined energized in the required manner at least once per 7 days by verifying correct breaker alignment and indicated voltage on the busses.

ITEM E1.48

Table 3.8-1 (Page 3/4 8-20)

Attached is the list of containment penetration conductor overcurrent protective devices. We suggest using a format similar to that used on Sequoyah tech specs.

TABLE 3.8-1

CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

DEVICE NUMBER AND LOCATION	TRIP SETPOINT (Amperes)	RESPONSE TIME (sec/cycles)	SYSTEM POWERED
1. 6900 VAC			Reactor Coolant pump
(Primary breaker)			1
(Back-up breaker)			2
			3
			4
2. 480 VAC from MOAD Centers			
List all; primary breakers			
Back-up breakers			
" "			
3. 480 VAC from MCC			
List all; primary breakers			
Back-up breakers			
" "			
4. 125V DC Lighting			
List all; primary breakers			
Back-up breakers			
" "			
5. 440 VAC CRDM Power			
Primary breakers			
Back-up breakers			
" "			

SEE Attached list

6.9KV BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Trip Setpoint (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
52-202-2/1A	6000A	0.02	52-2112	6000	0.02	6.9KV RCP BD 1A	REAC COOLANT PUMP 1
52-202-2/1B			52-2114			6.9KV RCP BD 1B	REAC COOLANT PUMP 2
52-202-2/1C			52-2122			6.9KV RCP BD 1C	REAC COOLANT PUMP 3
52-202-3/1D			52-2124			6.9KV RCP BD 1D	REAC COOLANT PUMP 4

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device ~~Trip Setpoint~~ RATING (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-212-7B/A1	125	.133	FU-212-A17/13	1/0 (+)		SHUTDOWN BD 1A1-A	CRD MECH CLR FAN 1A-A/1
52-212-7D/A1	125	.133	FU-212-A17/33	1/0 (+)		"	CRD MECH CLR FAN 1A-A/2
52-212-7C/A1	70	.133	FU-212-A17/23	#2 (+)		"	REAC LWR COMPT CLR FAN 1A-A
52-212-10C/A1	150	.133	FU-212-A110/23	4/0 (+)		"	CNTMT AIR RTN FAN 1A-A
52-212-7A/A2	125	.133	FU-212-A27/3	1/0 (+)		SHUTDOWN BD 1A2-A	CRD MECH CLR C-A SUPPLY
52-212-7D/A2	70	.133	FU-212-A27/33	#2 (+)		"	REAC LWR COMPT CLR FAN C-A
52-212-8A/A2	125	.133	FU-212-A28/3	1/0 (+)		"	CRD MECH CLR FAN 1C-A/2
52-212-7C/B1	125	.133	FU-212-B17/23	1/0 (+)		SHUTDOWN BD 1B1-B	CRD MECH CLR FAN 1B-B/1
52-212-7D/B1	70	.133	FU-212-B17/33	#2 (+)		"	REAC LWR COMPT CLR FAN 1B-B
52-212-10D/B1	125	.133	FU-212-B110/23	1/0 (+)		"	CRD MECH CLR FAN 1B-B/2

(+)- CONDUCTOR SIZES ARE GIVEN WHERE CABLE PROTECTORS ARE INSTEAD OF FUSES.

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Breaker	Trip Setpoint (amperes)	Response Time (seconds)	Number	~~Trip Setpoint~~ [illegible] (amperes)	Response Time (seconds)		
52-212-3B/B2	200	.133	FU-212-B23/12	350MCM (+)		SHUTDOWN BD 1B2-B	REAC BLDG POLAR CRANE
52-212-7B/B2	125	.133	FU-212-B27/13	1/0 (+)		"	CRD MECH CLR FAN 1D-B/1
52-212-7D/B2	70	.133	FU-212-B27/33	#2 (+)		"	REAC LWR CONT CLR FAN 1D-B/
52-212-9C/B2	150	.133	FU-212-B29/22	4/0 (+)		"	CNTMNT AIR RT FAN 1B-B
52-212-10C/B2	125	.133	FU-212-B210/23	1/0 (+)		"	CRD MECH CLR FAN 1D-B/2

RR

WBN 1

480 V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-213 -7D/A1	60	.012	FU-213 -A17/32	60		REAC MOV BD 1A1-A	SIS ACC TK 3 FLOW ISLN VLV
52-213 -8D/A1	60	.012	FU-213 -A18/32	60		"	SIS ACC TK 1 FLOW ISLN VLV
52-213 -5B/A1	20	.012	FU-213 -A110/32	30		"	RHR SYS ISLN VLV
52-213 -6D/A1	22	.012	FU-213 -A16/32	30		"	RCS FLOW CONT VLV
52-213 -16A/A1	58	.012	FU-213 -A116/2	80		"	INCORE INSTR RM CLR FAN 1A
52-213 -16B/A1	58	.012	FU-213 -A116/12	30		"	REAC CNTMT PIT SMP EJCTR PMP
52-213 -17E/A1	100	.012	FU-213 -A117/42	2 (+)		"	POWER OUTLETS
52-213 -6D/A2	22	.012	FU-213 -A26/32	30		REAC MOV BD 1A2-A	RHR SYS ISLN BYPASS VLV
52-213 -7D/A2	12	.012	FU-213 -A27/32	30		"	LWR CNTMT 1A CLR DISCH ISLN VLV
52-213 -8D/A2	12	.012	FU-213 -A28/32	80		"	LWR CNTMT 1C CLRS
52-213 -9D/A2	7	.012	FU-213 -A29/32	30		"	UPR CNTMT VT CLR 1A DISCH IS

+ SEE NOTE Pg 2

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-213 -6D/B2	20	.012	FU-213 -B212/32	30		REAC MOV BD 1B2-B	RCP THRM BAR RTN CNTMT ISLN
52-213 -7D/B2	12	.012	FU-213 -B27/32	30		"	LWR CNTMT 1B CLRS DISCH ISLN
52-213 -8D/B2	12	.012	FU-213 -B28/32	30		"	LWR CNTMT 1D CLRS DISCH ISLN
52-213 -9D/B2	7	.012	FU-213 -B29/32	30		"	UPR CNTMT VT CLR 1B DISCH ISLN
52-213 -10D/B2	7	.012	FU-213 -B210/31	30		"	UPR CNTMT VT CLR 1D DISCH ISLN
52-213 -13D/B2	10	.012	FU-213 -B213/32	30		"	RCP OIL CLR RTN CNTMT ISLN

WBN1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device ~~Trip Setpoint~~ Rating (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-232-2A/1A	58	.012	FU-232-A2/2	30		RCTR VENT BD 1A-A	CNTMT FL & SCPT DR SMP PMP 1A
52-232-3A/1A	20	.012	FU-232-A3/2	30		"	INCORE FLUX DET DRIVE UNIT 1D
52-232-3B/1A	20	.012	FU-232-A3/12	30		"	" 1E
52-232-3C/1A	20	.012	FU-232-A3/22	30		"	" 1F
52-232-7B/1A	58	.012	FU-232-A7/12	30		"	RCP 1 MTR HTR
52-232-7D/1A	170	.012	FU-232-A7/32	30		"	RCP 1 OIL LIFT PMP
52-232-8B/1A	58	.012	FU-232-A8/12	30		"	RCP 3 MTR HTR
52-232-8D/1A	170	.012	FU-232-A8/32	30		"	RCP 3 OIL LIFT PMP
52-232-9B/1A	105	.012	FU-232-A9/12	30		"	REC UPR COMPT CLR FAN 1A
52-232-10B/1A	105	.012	FU-232-A10/12	30		"	REC UPR CMPNT CLR FAN 1C
52-232-10F/1A	20	.012	FU-232-A10/52	30		"	STUD TENSION HOIST

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-232 -11D/1A	170	.012	FU-232 -A11/32	60		REAC VENT BD 1A-A	REAC COOL. DRAIN TK PMP 1A
52-232 -11F/1A	20	.012	FU-232 -A11/52	30		"	REAC LWR COMPT U HTR
52-232 -12F/1A	20	.012	FU-232 -A12/52	30		"	CNTMT INSTR RM U HTR 1A
52-232 -13A/1A	40	.012	FU-232 -A13/2	40		"	REAC BLDG MANI CRN 1
52-232 -13D/1A	160	.012	FU-232 -A13/31	4/0 (+)		"	IC AHU(S)
52-232 -14B/1A	36	.012	FU-232 -A14/12	30		"	IC END WALL DOOR 1A
52-232 -14D/1A	140	.012	FU-232 -A14/32	4/0 (+)		"	IC AHU(S)
52-232 -15A/1A	70	.012	FU-232 -A15/2	70		"	REAC UPR COMPT HTR 1A
52-232 -16A/1A	70	.012	FU-232 -A16/2	70		"	REAC UPR COMPT HTR 1C
52-232 -2D/1A	125	.0115	FU-232 -A2/32	#1 (+)		"	H2 ELECT. RECOMBINER 1A
52-232 -2D/1B	125	.0115	FU-232 -B2/32	#1 (+)		"	H2 ELECT. RECOMBINER 1B

+ SEE NOTE Pg 2

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Trip Setpoint (amperes)	Response Time (seconds)	Number	RATING Setpoint (amperes)	Response Time (seconds)		
52-232-2A/1B	56	.012	FU-232-B2/2	30		REAC VENT BD 1B-B	CNTMT FL & EQPT DRAIN SMP PMP
52-232-3A/1B	20	.012	FU-232-B3/2	30		"	INCORE FLUX DET DRIVE UNIT 1A
52-232-3B/1B	20	.012	FU-232-B3/12	30		"	" 1B
52-232-3C/1B	20	.012	FU-232-B3/22	30		"	" 1C
52-232-7B/1B	58	.012	FU-232-B7/12	30		"	RCP 2 MTR HTR
52-232-7D/1B	170	.012	FU-232-B7/32	30		"	RCP 2 OIL LIFT PUMP
52-232-8B/1B	58	.012	FU-232-B8/12	30		"	RCP 4 MTR HTR
52-232-8D/1B	170	.012	FU-232-B8/32	30		"	RCP 4 OIL LIFT PUMP
52-232-9B/1B	105	.012	FU-232-B9/12	30		"	REAC UPR COMPT CLR FAN 1
52-232-10B/1B	105	.012	FU-232-B10/12	30		"	REAC UPR COMPT CLR FAN
52-232-10F/1B	20	.012	FU-232-B10/52	30		"	REAC BLDG JIB CRN

WBN 1

480V BOARDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-232-11D/1B	330	.012	FU-232-B11/32	60		REAC VENT BD 1B-B	REAC COOL DR TK PMP 1B
52-232-11F/1B	20	.012	FU-232-B11/52	30		"	REAC LWR COMPT 4 HTR 1B
52-232-12F/1B	20	.012	FU-232-B12/52	30		"	CNTMT INST RM 4 HTR 1B
52-232-13B/1B	36	.012	FU-232-B13/11	30		"	IC END WALL DR 1B
52-232-13D/1B	175	.0115	FU-232-B13/32	4/0 (+)		"	IC AHUs
52-232-13F/1B	50	.012	FU-232-B13/52	50		"	IC BRIDGE CRN
52-232-14B/1B	7	.012	FU-232-B14/12	30		"	RCC CHANGE HOIST
52-232-14D/1B	150	.012	FU-232-B14/31	4/0 (+)		"	IC AHUs
52-232-14E/1B	40	.012	FU-232-B14/52	50		"	EQPT HATCH HOIST
52-232-15A/1B	70	.012	FU-232-B15/2	70		"	REAC UPR COMPT HTR 1B
52-232-16A/1B	70	.012	FU-232-B16/2	70		"	REAC UPR COMPT HTR 1D

+ SEE NOTE pg 2

WBN 1

480V AC CAB

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device: Number	Primary Device: Trip Setpoint (amperes)	Primary Device: Response Time (seconds)	Backup Device: Number	Backup Device: ~~Trip Setpoint~~ RATING (amperes)	Backup Device: Response Time (seconds)	Location of Devices	System Powered
CB-68 -341F/D1	100	.02	FU-211 -A21/4	*	.01*	DIST CAB CONT GP 1D	PRESSURIZER HTRS GP 1D. ELEMENTS 47,49,51
CB-68 -341F/D2	100	.02	FU-211 -A21/5	*	.01*	"	" ELEM. 52,54,56
CB-68 -341F/D3	100	.02	FU-211 -A21/6	*	.01*	"	" ELEM. 57,59,61
CB-68 -341F/D4	100	.02	FU-211 -A21/7	*	.01*	"	" ELEM. 66,64,62
CB-68 -341F/D5	100	.02	FU-211 -A21/8	*	.01*	"	" ELEM. 67,69,71
CB-68 -341F/D6	100	.02	FU-211 -A21/9	*	.01*	"	" ELEM. 72,74,76
CB-68 -341A/A1-A	100	.02	FU-211 -A20/4	*	.01*	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A. ELEM. 22,24,26
CB-68 -341A/A2-A	100	.02	FU-211 -A20/5	*	.01*	"	" ELEM. 28,30,32
CB-68 -341A/A3-A	100	.02	FU-211 -A20/6	*	.01*	"	" ELEM. 34,36,38
CB-68 -341A/A4-A	100	.02	FU-211 -A20/7	*	.01*	"	" ELEM. 42,40,44
CB-68 -341A/A5-A	100	.02	FU-211 -A20/8	*	.01*	"	ELEM. 5,3,7

* BASED ON XJL 225 FUSE CURVE 300 AMP BREAKER RATING @ 5500% RATED CURRENT, THE PRIMARY & BACKUP DEVICE IS A [illegible]

WBN 1

480V AC CAB.

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Trip Setpoint (amperes)	Response Time (seconds)	Number	~~Trip Setpoint~~ (amperes)	Response Time (seconds)		
CB-68 -341A/A6-A	100	.02	FU-211 -A20/9	*	.01*	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A ELEM. 11, 9, 13
CB-68 -341A/A7-A	100	.02	FU-211 -A20/10	*	.01*	"	" ELEM. 17, 15, 19
CB-68 -341D/B1-B	100	.02	FU-211 -B20/4	*	.01*	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEM. 23, 25, 27
CB-68 -341D/B2-B	100	.02	FU-211 -B20/5	*	.01*	"	" ELEM. 29, 31, 33
CB-68 -341D/B3-4	100	.02	FU-211 -B20/6	*	.01*	"	" ELEM. 35, 37, 39
CB-68 -341D/B4-B	100	.02	FU-211 -B20/7	*	.01*	"	" ELEM. 43, 41, 45
CB-68 -341D/B5-B	100	.02	FU-211 -B20/8	*	.01*	"	" ELEM. 4, 2, 6
CB-68 -341D/B6-B	100	.02	FU-211 -B20/9	*	.01*	"	" ELEM. 10, 8, 12
CB-68 -341D/B7-B	100	.02	FU-211 -B20/10	*	.01*	"	" ELEM. 16, 14, 18
CB-68 -341H/C1	100	.02	FU-211 -B21/4	*	.01*	DIST CAB CONT GP 1C	PRESSURIZER HTRS GP 1C ELEM. 1, 21, 48
CB-68 -341H/C2	100	.02	FU-211 -B21/5	*	.01*	"	ELEM. 50, 53, 55

* SEE NOTE Pg 11.

WBN 1

480V AC DAB.

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
CB-68 -341H/C3	100	.02	FU-211 -B21/6	*	.01*	DIST CAB CONT GP 1C	PRESSURIZER HTRS GP 1C ELEM. 58, 60, 63
CB-68 -341H/C4	100	.02	FU-211 -B21/7	*	.01*	"	" ELEM. 65, 68, 70
CB-68 -341H/C5	100	.02	FU-211 -B21/8	*	.01*	"	" ELEM. 73, 75, 77
CB-68 -341H/C6	100	.02	FU-211 -B21/9	*	.01*	"	" ELEM 20, 46, 78

* SEE NOTE Pg. 11.

WBN 1

MISC V DC
CONTROL PWR

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Rating (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
FU-212-A17/1N	10		BKR-202-BD I/PNL 2	30	.02	480V SHUT DN BD 1A1-A	CRD MECH CLR FAN 1A-A/1
FU-212-A17/31	10		"	30	.02	"	CRD MECH CLR FAN 1A-A/2
FU-212-A17/21N	10		"	30	.02	"	REAC LWR COMPT CLR FAN 1A-A
FU-212-A110/21	10		"	30	.02	"	CNTMT AIR RTN FAN 1A-A
FU-212-A27/1N	10		BKR-203-BD I/PNL 2	30	.02	480V SHUT DN BD 1A2-A	CRD MECH CLR FAN 1C-A/1
FU-212-A27/31	10		"	30	.02	"	REAC LWR COMPT CLR FAN 1C-A
FU-212-A28/1	10		"	30	.02	"	CRD MECH CLR FAN 1C-A/2
FU-212-B17/21N	10		BKR-202-BD II/PNL 2	30	.02	480V SHUT DN BD 1B1-B	CRD MECH CLR FAN 1B-B/1
FU-212-B17/31	10		"	30	.02	"	REAC LWR COMP CLR FAN 1B-B
FU-212-B110/21	10		"	30	.02	"	CRD MECH CLR FAN 1B-B/2
FU-212-A110/22	10		BKR-202-BD II/PN 2	30	.02	480 SHDN BD 1A1-A	CNTMT AIR RTN FAN 1A-A

WBN 1

1E1S 125V DC
CONTROL PWR

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-212 -B23/11	10		BKR 206 -BD III/PNL 2	30	.02	480V SHUTDN BD 182-B	REAC BLDG POLAR CRANE
FU-212 -B27/11N	10		BKR 203 -BD III/PNL 2	30	.02	"	CRD MECH CLR FAN 1D-B/1
FU-212 -B27/31N	10		"	30	.02	"	REAC LWR COMP CLR FAN 1D-B
FU-212 -B29/2	10		"	30	.02	"	CNTMT AIR RTN FAN 1B-B
FU-212 -B210/21	10		"	30	.02	"	CRD MECH CLR FAN 1D-B/2
FU-212 -B29/22	10		"	30	.02	"	CNTMT AIR RTN FAN 1B-B

WBN1

125V DC (VT-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-236 -1/A1	10		52-236 -310/T	30	.018	125V VT-BATT BD I PNL 4	CHGRG FLOW TO RCS COOL LP 4
FU-236 -1/A3	10		"	30	.018	"	RC LP 3 LTDN FLOW VLV 69
FU-236 -1/A6	10		"	30	.018	"	REGEN HT EXCH LET DN TSIN VLV
FU-236 -1/A7	10		"	30	.018	"	"
FU-236 -1/A8	10		"	30	.018	"	"
FU-236 -1/A9	10		"	30	.018	"	RC LP 3 LTDN FLOW VLV 70
FU-236 -1/A11	10		"	30	.018	"	TRESS PWR RLF VLV 68-340A
FU-236 -1/A17	10		"	30	.018	"	REGEN HT EXCH LETDN TSIN VLV
FU-236 -1/A21	10		"	30	.018	"	LWR CNTMT VT CLR A SPRY VLV
FU-236 -1/A22	10		"	30	.018	"	CRD VT CLR A SPRY VLV
FU-236 -1/A23	10		"	30	.018	"	LWR CNTMT VT CLR C SPRY VLV

WBN 1

125VDC (VI-AUR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Rating (amperes)	Response Time (seconds)	Backup Device Number	Trip Setpoint (amperes)	Response Time (seconds)	Location of Devices	System Powered
FU-236 -1/A24	10		52-236 -310/I	30	.018	125V VI-BATT BD I Pnl 4	CRD VT CLRC SPRY VLV
FU-236 -1/A31	10		"	30	.018	"	SIS CK VLV ISLN HDR Flow ISLN VLV
FU-236 -1/A40	10		"	30	.018	"	RCD MOT CLR A SPRY VLV
FU-236 -1/A41	10		"	30	.018	"	RCP MOT CLR C SPRY VLV
FU-236 -1/A42	10		"	30	.018	"	CRD CLG UNIT 1A-A SUCT DMPR
FU-236 -1/A43	10		"	30	.018	"	CRD CLG UNIT 1A-A RM DIUR DMPR
FU-236 -1/A44	10		"	30	.018	"	CRD CLG UNIT 1C-A SUCT DMPR
FU-236 -1/A45	10		"	30	.018	"	CRD CLG UNIT 1C-A RM DIVR DMPR
FU-236 -1/B5	10		52-236 -311/I	30	.018	"	CHGRG Flow To RCS SPRAY
FU-236 -1/B17	10		"	30	.018	"	TEST LINE ISLN VLV FCV-87-7
FU-236 -1/B18	10		"	30	.018	"	"

WBN 1

125VDC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	~~Rating~~ (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
FU-236-1/B29	10		52-236-311/I	30	.018	125V VI-BATT BD I PNL 4	UPR COMPT PURG ISLN VLV
FU-236-1/B30	10		"	30	.018	"	LWR COMPT PURGE ISLN VLV
FU-236-1/B32	10		"	30	.018	"	INSTR RM PURGE ISLN VLV
FU-236-1/B36	10		"	30	.018	"	LWR COMPT PURG VLV
FU-236-1/C3	10		52-236-312/I	30	.018	"	INSTR RM COOL UNIT A VLV
FU-236-1/C4	10		"	30	.018	"	"
FU-236-1/C22	10		"	30	.018	"	ST GEN BLDN ISLN VLV LP 1
FU-236-1/C38	10		"	30	.018	"	" 3
FU-236-1/C46	10		"	30	.018	"	LWR COMPT PUR ISLN VLV
FU-236-1/C48	10		"	30	.018	"	CNTMT ANNS DEG PRESS ISLN V
FU-236-1/C49	10		"	30	.018	"	LOCA H2 CNTM ISLN VLV

WBN 1

125VDC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Setpoint (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
FU-236-1/C50	10		52-236-312/I	30	.018	125V VI-BATT BD I PNL 4	LOCA H2 CNTR ISLN VLV
FU-236-1/D2	10		52-236-217/I	30	.018	"	RCP 3 SEAL RTN FLOW CONT. VLV
FU-236-1/D17	10		"	30	.018	"	RCP 1 SEAL RTN FLOW CONT. VL
FU-236-1/D22	10		"	30	.018	"	GLYCOL SPLY FROM EXP TK FSV-61-11
FU-236-1/D33	10		"	30	.018	"	RCP 1 STD PIPE MAKEUP WTR VL
FU-236-1/D41	10		"	30	.018	"	GLYCOL SPLY FROM EXP TK FSV-61-11
FU-236-1/E34	10		52-236-218/I	30	.018	"	RCP 3 STD PIPE MAKEUP WTR VL
FU-236-1/E36	10		"	30	.018	"	RCS LP 3 HOT FEED TEST LINE V
FU-236-2/A3	10		52-236-310/II	30	.018	125V VI-BATT BD II PNL 4	CHGRG FLOW RCS COOL LP 1
FU-236-2/A4	10		"	30	.018	"	PRESS. RLF TK ISLN VLV
FU-236-2/A5	10		"	30	.018	"	"

WBN 1

125V DC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Rating (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
FU-236-2/A8	10		52-236-310/VI	30	.018	125V VI-BATT BD II PNL 4	EXCESS LETDN DIVR FLOW CONT. VLV
FU-236-2/A9	10		"	30	.018	"	LWR CNTMT VT CLR B SPLY VLV
FU-236-2/A10	10		"	30	.018	"	CRD VT CLR B SPLY VLV
FU-236-2/A11	10		"	30	.018	"	LWR CNTMT VT CLR D SPLY VLV
FU-236-2/A12	10		"	30	.018	"	CRD VT CLR D SPLY VLV
FU-236-2/A13	10		"	30	.018	"	CRD CLG UNIT 1D-B SUCT DMPR
FU-236-2/A14	10		"	30	.018	"	CRD CLG UNIT 1D-B RMDIVR DMPR
FU-236-2/A15	10		"	30	.018	"	CRD CLG UNIT 1B-B SUCT DMPR
FU-236-2/A16	10		"	30	.018	"	CRD CLG UNIT 1B-B RM DIVR DMPR
FU-236-2/A17	10		"	30	.018	"	GLYCOL SPLY ISLN VLV 61-193
FU-236-2/A18	10		"	30	.018	"	" 61-194

WBN 1

125VDC (VI-DIUR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
F4-236-2/A20	10		52-236-310/II	30	.018	125V VI-BATT BD II PNL 4	PRESS. GAS ISLN VLV
F4-236-2/A21	10		"	30	.018	"	PRESS LIQ. ISLN VLV
F4-236-2/A22	10		"	30	.018	"	RCS HOT LEG LP 1 or 3 ISLN VLV
F4-236-2/A23	10		"	30	.018	"	ACC TKS ISLN VLV
F4-236-2/A24	10		"	30	.018	"	RC DR TK TO GAS ANAL ISLN
F4-236-2/A41	10		"	30	.018	"	RCP MOT CLR [illegible] SPLY VLV
F4-236-2/A42	10		"	30	.018	"	RCP MOT CLR [illegible] SPLY VLV
F4-236-2/A43	10		"	30	.018	"	RB SUMP PMP DISCH ISLN VL[illegible]
F4-236-2/A44	10		"	30	.018	"	RC DR TK TO PMPS DISCH. ISLN V[illegible]
F4-236-2/A45	10		"	30	.018	"	RC DR TK TO V DISCH ISLN VLV
F4-236-2/B26	10		52-236-311/II	30	.018	"	UPR COMPT PURGE ISLN VLV

WBN 1

125VDC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-236-2/B27	10		52-236-311/II	30	.018	125V VI-BATT BD II PNL 4	CNTMT BLDG LWR COMPT AIR MON ISLN VLV-90-108
FU-236-2/B28	10		"	30	.018	"	" 90-110
FU-236-2/B32	10		"	30	.018	"	LWR COMPT PURGE ISLN VLV
FU-236-2/B33	10		"	30	.018	"	CNTMT BLDG UPR COMPT AIR MON ISLN VLV-90-114
FU-236-2/B34	10		"	30	.018	"	INSTR RM PURGE ISLN VLV
FU-236-2/B36	10		"	30	.018	"	CNTMT BLDG UPR COMPT AIR MON ISLN VLV 90-116
FU-236-2/C5	10		52-236-312/II	30	.018	"	INSTR RM COOL UNIT B VLV
FU-236-2/C6	10		"	30	.018	"	"
FU-236-2/C7	10		"	30	.018	"	CNTMT ANNS DIFF PRESS ISLN VLV
FU-236-2/C10	10		"	30	.018	"	LOCAL H2 CNTMT ISLN VLV
FU-236-2/C11	10		"	30	.018	"	LCA H2 CNTMT ISLN VLV

WBN 1

125 VDC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-236 -2/C17	10		52-236 -3/2/II	30	.018	125V VI-BATT BD II PNL 4	STM GEN BLDN ISLN VLV LP 2
FU-236 -2/C21	10		"	30	.018	"	DNSTR EXCESS LTDN HX TO HOT SMPLG RM ISLN VLV
FU-236 -2/C24	10		"	30	.018	"	FLOOR CLG GLYCOL INLET ISLN VLV
FU-236 -2/C26	10		"	30	.018	"	FLOOR CLG GLYCOL INLET ISLN VLV
FU-236 -2/C34	10		"	30	.018	"	CNTMT BLDG LWR COMPT AIR MON ISLN
FU-236 -2/C35	10		"	30	.018	"	CNTMT BLDG UPR COMPT AIR MON ISL VLV-90-115
FU-236 -2/C41	10		"	30	.018	"	STM GEN BLDN ISLN VLV 1
FU-236 -2/C42	10		"	30	.018	"	" 2
FU-236 -2/C43	10		"	30	.018	"	" 3
FU-236 -2/C44	10		"	30	.018	"	" 4
FU-236 -2/C47	10		"	30	.018	"	STM GEN BLDN ISLN VLV LP 3

125V DC (VI-Pwr)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-236-2/D5	10		52-236-217/II	30	.018	125V VI-BATT BD II Pn 4	EXCESS LETDN ISLN VLV-62-55
FU-236-2/D6	10		"	30	.018	"	PRESS RLF TK PR WTR SPLY VLV
FU-236-2/D7	10		"	30	.018	"	SIS ACC FILL LINE ISLN VLV
FU-236-2/D8	10		"	30	.018	"	SIS ACC TK 4 H2 Makeup VLV
FU-236-2/D9	10		"	30	.018	"	SIS ACC TK 4 FLOW ISLN VLV
FU-236-2/D10	10		"	30	.018	"	SIS ACC TK FILL VLV
FU-236-2/D12	10		"	30	.018	"	SIS ACC TK 2 H2 Makeup VLV
FU-236-2/D14	10		"	30	.018	"	SIS ACC TK 2 FLOW ISLN VLV
FU-236-2/D18	10		"	30	.018	"	RCP 2 SEAL RTN FLOW CONT VLV
FU-236-2/D21	10		"	30	.018	"	EXCESS LETDN ISLN VLV
FU-236-2/D22	10		"	30	.018	"	PRESS LIQ ISLN VLV

WBN 1

125VDC (VT-PWR2)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Rating (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
F4-236-2/D24	10		52-236-217/II	30	.018	125V VT-BATT BD II PNL 4	RCS HOT LEG LP 3 ISLN VLV
F4-236-2/D27	10		"	30	.018	"	SIS ACC TK 4 OUT CK VLV ISLN
F4-236-2/D29	10		"	30	.018	"	SIS ACC TK 2 CK VLV ISLN VL
F4-236-2/D31	10		"	30	.018	"	SIS CK VLV LEAK TEST ISLN VLV
F4-236-2/D33	10		"	30	.018	"	SIS TEST LINE CK VLV TEST VLV
F4-236-2/D34	10		"	30	.018	"	RCP 2 STD PIPE makeup WTR VLV
F4-236-2/D35	10		"	30	.018	"	RCP 4 STD PIPE makeup WTR VL
F4-236-2/D44	10		"	30	.018	"	PRESS GAS ISLN VLV
F4-236-2/D43	10		"	30	.018	"	RCS HOT LEG LP 1 ISLN VLV
F4-236-2/D45	10		"	30	.018	"	ACC TK NO. 3 ISLN VLV
F4-236-2/E13	10		52-236-218/II	30	.018	"	SIS ACC TK 2 FILL VLV

WBN 1

125V DC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device			Backup Device			Location of Devices	System Powered
Number	Rating (amperes)	Response Time (seconds)	Number	Trip Setpoint (amperes)	Response Time (seconds)		
FU-236-2/E26	10		52-236-218/IT	30	.018	125V VI-BATT BD II PN 14	SIS ACC TK 4 CK VLV ISLN VLV
FU-236-2/E30	10		"	30	.018	"	SIS ACC TK 2 CK VLV ISLN VLV
FU-236-2/E32	10		"	30	.018	"	RCS LP 2 HOT LEG FEED TEST LN
FU-236-2/E37	10		"	30	.018	"	NO. 3 SMPL VLV
FU-236-2/E38	10		"	30	.018	"	STM GEN #4 DRUM SMPL VLV
FU-236-2/E43	10		"	30	.018	"	SIS CK VLV LEAK TEST ISLN VLV
FU-236-2/E44	10		"	30	.018	"	REAC VESSEL SEAL LEAK off VLV
FU-236-2/E45	10		"	30	.018	"	STM GEN NO. 1 BLDN SMPL VLV
FU-236-2/E46	10		"	30	.018	"	NO. 2 BLDN SMPL VLV
FU-236-2/E47	10		"	30	.018	"	NO. 3 BLDN SMPL VLV
FU-236-2/E48	10		"	30	.018	"	STM GEN #4 BLDN SMPL VLV

WBN 1

125VDC (VI-PWR)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Setting (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-236-2/E49	10		52-236-218/IL	30	.018	125V VI-BATT BD II PNL 2	STM GEN NO. 1 SMPL VLV
FU-236-2/E50	10		"	30	.018	"	NO. 2 SMPL VLV
FU-97-R55/M18	10		52-236-218/IL	30	.018	"	SIS ACC TK & Flow ISLN VLV FCV-63-67
"	10		"	30	.018	"	" FCV-63-98
FU-77-L2/LF2	3		52-236-214/IIL	30	.018	(PRI) LOCA PNL L-2 (BKUP) 125V VI-BATT BD III PNL 2	RC DR TK TO SUMP TK VLV

WBN 1

120VAC BDS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setpoint (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
52-220-1/2B2	175	.01	FU-228-1/2B2	200		AUX BLDG LTG BD I	LTG CAB LC-180
52-228-1/2C2	175	.01	FU-228-1/2C2	200		"	LTG CAB LC-181
52-94-M18/2	25	.025	52-237-4/M7	40	.016	U. CONTROL BD M18 (PRI) BD M7 (Bkup)	TRVLG INCORE PROBE SYS WDRW LS (6m)
"	25	.025	"	40	.016	"	TRVLG INCORE PROBE SYS SFTY LS (6m)
"	25	.025	"	40	.016	"	TRVLG INCORE PROBE SYS 10 PATH MOT CONT (6m)
FU-94-M18/Bkp-1	10		52-94-1/M18	35	.03	U. CONTROL BD M18	TRVLG INCORE PROBE DEHUMIDIFIER [illegible]
"	10		"	35	.03	"	" F[illegible]
"	10		"	35	.03	"	" C[illegible]
"	10		52-94-3/M18	35	.03	"	" E[illegible]
"	10		"	35	.03	"	" H[illegible]
"	10		"	35	.03	"	" G[illegible]

WBN 1

120 V AC BPS

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

Primary Device Number	Primary Device Trip Setting (amperes)	Primary Device Response Time (seconds)	Backup Device Number	Backup Device Trip Setpoint (amperes)	Backup Device Response Time (seconds)	Location of Devices	System Powered
FU-278-M4/10	2		52-235-33/II	15	.02	UNIT CONTROL BD M-4 (PRI)	RCS LOOP 1 PRES SPRAY CONT VLV POSN INDR
FU-278-M4/12	2		52-235-42/I	15	.02	"	RCS LOOP 2 PRES SPRAY CONT VLV POSN INDR
FU-40-2222/F3	6		52-237-24/B	15	.02	UNIT CONTROL BD M-7	REAC BLDG FLOOD ALARM LS-40-17-1
FU-275-R76/L9	10		52-235-12/1-III	15	.02	AUX RELAY RK 1-R-76	UPR COMPT VT UNIT A FLOW ALM
FU-275-R76/L15	10		52-235-5/1-IV	15	.02	"	UPR COMPT VT UNIT B FLOW ALM
FU-275-R76/L7	10		52-235-12/1-III	15	.02	"	UPR COMPT VT UNIT C FLOW ALM
FU-275-R76/L17	10		52-235-5/1-IV	15	.02	"	UPR COMPT VT UNIT D FLOW ALM
FU-99-R59/M19	10		52-235-6/1-III	15	.02	NSSS AUX RLY PNL 1-R-58	ICE CONDENSER RELAY
FU-275-R75/K1	10		52-235-4/I-III	15	.02	SEP AUX RLY PNL 1-R-75	CRD MECH CLR UNIT 1B-B AUX SEP RLY
FU-275-R75/L21	10		52-235-8/I-IV	15	.02	"	CRD MECH CLR UNIT 1A-A AUX SEP RLY
52-237-2/1	30		FU-242-BD/F2	40	.02	RAD MON & SMPLG PW DISTR PNL 1	AIR PART MON SYS

WBN 1

ITEM E1.49

3.9.8.2 (Page 3/4 9-9)

Watts Bar intends to follow the standard Westinghouse initial fuel loading criteria. This criteria suggests a reduced water level requirement. Therefore during initial fuel loading, we would need to keep both RHR pumps OPERABLE at all times. If one train of RHR was to become inoperable, we would have to flood the cavity to 23 feet. This problem can be corrected by adding to the original footnote as shown and by an additional footnote to the Applicability statement allowing for the reduced water level.

REFUELING OPERATIONS

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent residual heat removal (RHR) loops shall be OPERABLE, and at least one RHR loop shall be in operation.*

APPLICABILITY: MODE 6 when the water level above the top of the reactor vessel flange is less than 23 feet.#

ACTION:

a. With less than the required RHR loops OPERABLE, immediately initiate corrective ACTION to return the required RHR loops to OPERABLE status, or to establish greater than or equal to 23 feet of water above the reactor vessel flange, as soon as possible.

b. With no RHR loop in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective ACTION to return the required RHR loop to operation. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

SURVEILLANCE REQUIREMENTS

4.9.8.2 At least one RHR loop shall be verified in operation and circulating reactor coolant at a flow rate of greater than or equal to 2800 gpm at least once per 12 hours.

only one independent RHR loop shall be required OPERABLE and in operation

*Prior to initial criticality, the RHR loop may be removed from operation for up to 1 hour per 8-hour period during the performance of CORE ALTERATIONS in the vicinity of the reactor vessel hot legs.

#Prior to initial criticality the water level may be reduced to the top of the hot leg nozzles.

ITEM E1.50

3.9.12 (Page 3/4 9-13)

The applicability of specification 3.9.12 should be changed to match the actions that are taken. The actions only apply to times when fuel is being moved in the storage pool. The way it stands now is that once spent fuel is placed in the pool both trains of ABGTS Filters would have to OPERABLE.

If one train of filters were operable, the action statement would apply only if fuel was in movement. The same things apply for both trains inoperable also.

3/4.9.12 AUXILIARY BUILDING GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 Two independent Auxiliary Building Gas Treatment Systems shall be OPERABLE.

APPLICABILITY: Whenever irradiated fuel is being moved in the storage pool.

ACTION:

a. With one Auxiliary Building Gas Treatment System inoperable, fuel movement within the storage pool or crane operation with loads over the storage pool may proceed provided the OPERABLE Auxiliary Building Gas Treatment System is capable of being powered from an OPERABLE emergency power source and is in operation and discharging through at least one train of HEPA filters and charcoal adsorbers.

b. With no Auxiliary Building Gas Treatment System OPERABLE, suspend all operations involving movement of fuel within the storage pool or crane operation with loads over the storage pool until at least one Auxiliary Building Gas Treatment System is restored to OPERABLE status.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.12 The above required Auxiliary Building Gas Treatment Systems shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS, by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the system operates for at least 10 hours with the heaters operating;

b. At least once per 18 months, or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the system, by:

ITEM E1.51

3.10.5 (Page 3/4 10-5)

*Should be modified to delete the word 'initial.' The word 'initial' could mistakenly be interpreted to indicate that this exception is only applicable prior to initial criticality.

3/4.10.5 POSITION INDICATION SYSTEM - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.10.5 The limitations of Specification 3.1.3.3 may be suspended during the performance of individual full-length (shutdown and control) rod drop time measurements provided;

a. Only one shutdown or control bank is withdrawn from the fully inserted position at a time, and

b. The rod position indicator is OPERABLE during the withdrawal of the rods.*

APPLICABILITY: MODES 3, 4, and 5 during performance of rod drop time measurements.

ACTION:

With the Position Indication System inoperable or with more than one bank of rods withdrawn, immediately open the Reactor trip breakers.

SURVEILLANCE REQUIREMENTS

4.10.5 The above required Rod Position Indication Systems shall be determined to be OPERABLE within 24 hours prior to the start of and at least once per 24 hours thereafter during rod drop time measurements by verifying the demand Position Indication System and the Rod Position Indication Systems agree:

a. Within 12 steps when the rods are stationary, and

b. Within 24 steps during rod motion.

*This requirement is not applicable during the ~~initial~~ calibration of the Rod Position Indication System provided: (1) K_{eff} is maintained less than or equal to 0.95, and (2) only one shutdown or control rod bank is withdrawn from the fully inserted position at one time.

ITEM E1.52

Table 4.11-1 (Pages 3/4 11-2a, 3/4 11-2b, and 3/4 11-4)

The number of Non-Reclaimable Waste Tanks was corrected to one to resolve a discrepancy with our earlier submittal.

Footnote 2 has been revised because earlier NRC reviews pointed out a source of confusion between 'Field Composites' (continuous samples) and 'Lab Composites' (manually combined sample composites). The new footnote is correct for the Lab Composites planned for Watts Bar.

An additional footnote 6 was added to the continuous releases. This was done after review of Sequoyah's operational experience. These two release points are continuously monitored for radioactivity. Also, a primary-to-secondary leakage surveillance instruction is performed on a 72-hour frequency. The radiation monitors are under a strict surveillance test for operability. If there is no primary-to-secondary leakage and the monitors are set to a sensitive conservative limit, there is no significant chance of any harmful radioactive releases from these release points. A tremendous savings in man-power could be realized by this simple change.

TABLE 4.11-1

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

LIQUID RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DETECTION (LLD)(1) (μCi/ml)[a]
1. Batch Releases(3) a. Radwaste System Tanks 1) Waste Condensate (3)	P Each Batch Grab Sample	P Each Batch	Principal Gamma Emitters	$5x10^{-7}$(5)
			I-131	$1x10^{-6}$
2) Cask Decontamination(1) 3) Chemical Drain (1) 4) Monitor (1) 5) Distillate(2) 6) Laundry and Hot Shower(2)	P One Batch/M Grab Sample	M	Dissolved and Entrained Gases (Gamma emitters)	$1x10^{-5}$
b. Condensate Demineralizer System Tanks	P Each Batch Grab Sample	M Lab Composite(2)	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
1) Waste Neutralizer ~~(1)~~ 2) Non-Reclaimable Waste ~~(2)~~ 1 3) High Crud(a)	P Each Batch	Q Lab Composite(2)	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$

TABLE 4.11-1 (Continued)

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

LIQUID RELEASE TYPE	SAMPLING FREQUENCY	MINIMUM ANALYSIS FREQUENCY	TYPE OF ACTIVITY ANALYSIS	LOWER LIMIT OF DECTECTION (LLD) (1) (μCi/ml)[a]
2. Continuous Releases(4) a. Steam(6) Generator Blowdown	D Grab Sample ~~W~~	W Lab Composite ~~W~~	Principal Gamma Emitters	$5x10^{-7}$(5)
			I-131	$1x10^{-6}$
b. Turbine(6) Bldg. Sump	M Grab Sample	M	Dissolved and Entrained Gases (Gamma Emitters)	$1x10^{-5}$
	D Grab Sample	M Lab Composite(2)	H-3	$1x10^{-5}$
			Gross Alpha	$1x10^{-7}$
	D Grab Sample	Q Lab Composite(2)	Sr-89, Sr-90	$5x10^{-8}$
			Fe-55	$1x10^{-6}$

TABLE 4.11-1 (Continued)

TABLE NOTATION

(2) ~~Prior to analyses, all samples taken for the composite shall be proportioned according to the rate of flow in the effluent stream, and thoroughly mixed in order for the composite sample to be representative of the effluent release.~~

(3) A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated, and then thoroughly mixed, by a method described in the ODCM, to assure representative sampling.

(4) A continuous release is the discharge of liquid wastes of a nondiscrete volume; e.g., from a volume of a system that has an input flow during the continuous release.

(5) The principal gamma emitters for which the LLD specification applies exclusively are the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.7.

6 Not applicable during periods of no primary to secondary leakage, provided the discharge radiation monitor setpoint is $\leq 1 \times 10^{-6}$ uCi/ml above background

2. A lab composite sample is one prepared by combining representative samples from each release into one well-mixed, homogeneous sample. The volume of sample added to the composite, from each release shall be proportional to the release volume

ITEM E1.53

Table 4.11-2 (Pages 3/4 11-9 and 3/4 11-11)

Principal gamma emitters was changed to Nobel Gases, for the gas samples, to avoid confusion with the particulate samples.

On the particulate sample 'I-131 and others' was removed from the table, since it is already covered in footnote 7.

Containment purge and venting was separated due to the difference in duration of these release types. Venting is a very short time and frequent and must be sampled daily rather than prior to release. Footnote 10 was added to explain the differences.

Footnote 11 was added (per telecon with J. Bagle, NRC staff) to eliminate redundant sampling of the shield building vent.

The sampling frequency of Containment Purge is 'prior to each release' and the analysis frequency is 'prior to release.'

TABLE 4.[illegible]-2

RADIOACTIVE GASEOUS WASTE MONITORING SAMPLING AND ANALYSIS PROGRAM

Gaseous Release Type	Sampling Frequency	Minimum Analysis Frequency	Type of Activity Analysis	Lower Limit of Detection (LLD) (μCi/ml)[a]
1. Waste Gas Holdup Tank	P Each Tank Grab Sample	P Each Tank	Noble Gases ~~Principal Gamma Emitters~~(7)	1×10^{-4}
2a. Containment Purge	P[9] Grab Each Release	D[9] Each Release	Noble Gases	1×10^{-4}
			H-3	1×10^{-6}
b. Containment Vent	D[10] Grab Sample	D[10]	Noble Gases	1×10^{-4}
			H-3	1×10^{-6}
3. a. Auxiliary Building Exhaust (5) b. Shield Building Exhaust(2)(3)(8)	M[11] Grab Sample	M	~~Principal Gamma Emitters~~(7) Noble Gases	1×10^{-4}
			H-3	1×10^{-6}
	Continuous Sampler (6)	W(4) Charocal Sample	I-131 ~~Dose Equivalent~~	1×10^{-12}
	Continuous (6) Sampler	W(~~4~~) 4 Particulate Sampler	~~Principal Gamma Emitters~~ STET (7) ~~(I-131, Others)~~	1×10^{-11}
	Continuous (6) Sampler	M Composite Particulate	Gross Alpha	1×10^{-11}
	Continuous (6) Sampler	Q Composite Particulate	Sr-89, Sr-90	1×10^{-11}
4. a. Condenser Vacuum Exhaust(8) b. Service Building	M Grab Sampler	M	~~Principal Gamma Emitters~~(7) Noble Gases	1×10^{-4}
			H-3	1×10^{-6}
5. Noble Gases all release types as listed in Items 1, 2, 3, and 4 above	Continuous (6) Monitors	Noble Gas Monitor	Noble Gases Gross Beta or Gamma	1×10^{-6}

TABLE 4.11-2 (Continued)

TABLE NOTATION

(2) Sampling and analyses shall also be performed following shutdown from 15% RATED THERMAL POWER, startup to 15% RATED THERMAL POWER or a THERMAL POWER change exceeding 15% of RATED THERMAL POWER within a 1-hour period.

(3) Tritium grab samples shall be taken at least once per 24 hours when the refueling canal is flooded.

(4) Samples shall be changed at least once per 7 days and analyses shall be completed within 48 hours after changing, or after removal from sampler. Sampling shall also be performed at least once per 24 hours for at least 7 days following each shutdown, STARTUP of THERMAL POWER change exceeding 15% of RATED THERMAL POWER within a 1-hour period and analyses shall be completed within 48 hours of changing. When samples collected for 24 hours are analyzed, the corresponding LLDs may be increased by a factor of 10. This requirement does not apply if: (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the reactor coolant has not increased more than a factor of 3, and (2) the noble gas monitor shows that effluent activity has not increased more than a factor of 3.

(5) Tritium grab samples shall be taken at least once per 7 days from the ventilation exhaust from the spent fuel pool area, whenever spent fuel is in the spent fuel pool.

(6) The ratio of the sample flow rate to the sampled stream flow rate shall be known for the time period covered by each dose or dose rate calculation made in accordance with Specifications 3.11.2.1, 3.11.2.2 and 3.11.2.3.

(7) The principal gamma emitters for which the LLD specification applies, includes the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 in noble gas releases, and Mn-54, Fe-59, I-131, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144 in iodine and particulate releases. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.7.

(8) During releases via this Exhaust System.

(9) In MODES 1, 2, 3 and 4, the upper and lower compartments of the containment shall be sampled prior to ~~VENTING or~~ PURGING. Prior to ~~entering~~ breaking containment integrity in MODE 5 or 6 the upper and lower compartments of the containment shall be sampled. The incore instrument room purge sample shall be obtained at the shield building exhaust between 5 and 10 minutes following initiation of the incore instrument room purge.

(10) Prior to venting, in modes 1, 2, 3 and 4 the upper and lower compartments of the containment shall be sampled daily when venting is to occur on that day.

(11) The monthly Noble Gas and H-3 sample and analysis does not apply to the Shield Building Vent.

ITEM E1.54

Surveillance Requirement 4.11.4.2 (Page 3/4 11-19)

SR 4.11.4.2 states that cumulative dose from direct radiation shall be determined in accordance with the ODCM. However, because this is not a routine calculation (it is performed only if we exceed twice the limits of 3.11.1.2, 3.11.2.2, or 3.11.2.3), the methodology is not included in the ODCM. In the event we ever do exceed the limits of LCO 3.11.4, the special report submitted to NRC under specification 6.9.2 will include a discussion of the methodology used in calculating the cummulative dose contributions from direct radiation.

RADIOACTIVE EFFLUENTS

3/4.11.4 TOTAL DOSE

LIMITING CONDITION FOR OPERATION

3.11.4 The annual (calendar year) dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources shall be limited to less than or equal to 25 mrems to the whole body or any other organ except the thyroid, which shall be limited to less than or equal to 75 mrem.

APPLICABILITY: At all times.

ACTION:

a. With the calculated doses from the release of radioactive materials in liquid or gaseous effluents exceeding twice the limits of S pecifications 3.11.1.2a, 3.11.1.2b, 3.11.2.2a, 3.11.2.2b, 3.11.2.3a, or 3.11.2.3b, calculations should be made including direct radiation contributions from the reactor units and from outside storage tanks to determine whether the above limits of Specification 3.11.4 have been exceeded. If such is the case, in lieu of a Licensee Event Report, prepare and submit to the Commission within 30 days, pursuant to SPECIFICATION 6.9.2, a Special Report that defines the corrective action to be taken to reduce subsequent releases to prevent recurrence of exceeding the above limits and includes the schedule for achieving conformance with the above limits. This Special Report, as defined in 10 CFR Part 20.405c, shall include an analysis that estimates the radiation exposure (dose) to a MEMBER OF THE PUBLIC from uranium fuel cycle sources, including all effluent pathways and direct radiation, for the calendar year that includes the release(s) covered by this report. It shall also describe levels of radiation and concentrations of radioactive material involved, and the cause of the exposure levels or concentrations. If the estimated dose(s) exceeds the above limits, and if the release condition resulting in violation of 40 CFR Part 190 has not already been corrected, the Special Report shall include a request for a variance in accordance with the provisions of 40 CFR Part 190. Submittal of the report is considered a timely request, and a variance is granted until staff action on the request is complete.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.4.1 Cumulative dose contributions from liquid and gaseous effluents shall be determined in accordance with Specifications 4.11.1.2, 4.11.2.2, and 4.11.2.3, and in accordance with the methodology and parameters in the ODCM.

4.11.4.2 Cumulative dose contributions from direct radiation from the units and from radwaste storage tanks shall be determined, ~~in accordance with the methodology and parameters in the ODCM.~~ This requirement is applicable only under conditions set forth in Specification 3.11.4a.

ITEM E1.55

Radiological Effluent Technical Specifications (Pages 3/4 12-1, -2, -4, -5, -6, -7, -8, -11, -12, -13, -14, B 3/4 12-1 and B 3/4 12-2)

Attached is the revised environmental radiological monitoring portion of the Watts Bar Nuclear Plant Radiological Effluent Technical Specifications, incorporating the comments received from the Nuclear Regulatory Commission (NRC).

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.1 The Radiological Environmental Monitoring Program shall be conducted as specified in Table 3.12-1.

APPLICABILITY: At all times.

ACTION:

a. With the Radiological Environmental Monitoring Program not being conducted as specified in Table 3.12-1, in lieu of a Licensee Event Report, prepare and submit to the Commission, in the Annual Radiological Environmental Operating Report required by Specification 6.9.1.~~11~~, a description of the reasons for not conducting the program 6 as required and the plan for preventing a recurrence.

b. With the level of radioactivity as the result of plant effluents in an environmental sampling medium at a specified location exceeding the reporting levels of Table 3.12-2 when averaged over any calendar quarter, in lieu of a Licensee Event Report, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that identifies the cause(s) for exceeding the limit(s) and defines the corrective ACTIONS to be taken to reduce radioactive effluents so that the potential annual dose* to A MEMBER OF THE PUBLIC is less than the calendar year limits of Specification 3.11.1.2, 3.11.2.2, and 3.11.2.3. When more than one of the radionuclides in Table 3.12-2 are detected in the sampling medium, this report shall be submitted if:

$$\frac{\text{concentration (1)}}{\text{reporting level (1)}} + \frac{\text{concentration (2)}}{\text{reporting level (2)}} + \ldots \geq 1.0$$

When radionuclides other than those in Table 3.12-2 are detected and are the result of plant effluents, this report shall be submitted if the potential annual dose* to A MEMBER OF THE PUBLIC is equal to or greater than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2 and 3.11.2.3. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event, the condition shall be reported and described in the Annual Radiological Environmental Operating Report.

c. With milk or fresh leafy vegetable samples unavailable from one or more of the sample locations required by Table 3.12-1, identify locations for obtaining replacement samples and add them to the Radiological Environmental Monitoring Program within 30 days. The specific

*The methodology and parameters used to estimate the potential annual dose to a MEMBER OF THE PUBLIC shall be indicated in this report.

RADIOLOGICAL ENVIRONMENTAL MONITORING

LIMITING CONDITION FOR OPERATION (Continued)

locations from which samples were unavailable may then be deleted from the monitoring program. In lieu of a Licensee Event Report and pursuant to Specification 6.9.1.~~12~~7, identify the cause of the unavailability of samples and identify the new location(s) for obtaining replacement samples in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table for the ODCM reflecting the new location(s).

d. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.12.1 The radiological environmental monitoring samples shall be collected pursuant to Table 3.12-1 from the specific locations given in the table and figure(s) in the ODCM, and shall be analyzed pursuant to the requirements of Tables 3.12-1 and the detection capabilities required by Table 4.12-1.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS(1)	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
2. Airborne			
Radioiodine and Particulates	Samples from five locations (A1-A5): 2 ~~Three samples (A1-A3)~~ from close to the ~~THREE~~ SITE BOUNDARY locations ~~in different sectors~~, of the highest calculated annual average groundlevel D/Q; *Some* *At least 2* *TWO* ~~One sample (A4)~~ *(A3-A4)* from the vicinity of ~~a community~~ having the highest calculated annual average ground-level D/Q; and *communities* *At least 2 samples* One sample (A5) from a control location, as for example 15-30 km distant and in the least prevalent wind direction.(3)	Continuous sampler operation with sample collection weekly, or more frequently if required by dust loading.	Radioiodine Canister: I-131 analysis weekly. Particulate Sampler: Gross beta radioactivity analysis following filter change;(4) and gamma isotopic analysis(5) of composite (by location) quarterly.
3. Waterborne			
a. Surface(6)	One sample upstream (Wa1) One sample downstream (Wa2)	Composite sample over 1-month period(7).	Gamma isotopic analysis(5) monthly. Composite for tritium analysis quarterly.
b. Ground(8)	~~Samples from one or two sources (Wb1, Wb2) only if likely to be affected(8)~~	~~Quarterly.~~	~~Gamma isotopic(5) and tritium analysis quarterly.~~
c. Drinking	One sample ~~of each of one to three~~ (Wc1) ~~- Wc3)~~ of the nearest water supplies that could be affected by ~~its~~ *plant* discharge. 11 One sample from a control location (Wc4)! 12 *2*	Composite sample over ~~2-week~~ period(7) ~~when I-131 analysis is performed, monthly composite otherwise.~~ *of ≤ 31 days*	~~I-131 analysis on each composite when the dose calculated from the consumption of the water is greater than 1 mrem per year.(6)~~ Composite for gross beta and gamma isotopic analyses(5) monthly. Composite for tritium analysis quarterly.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[1]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
d. Sediment from shoreline	One sample from downstream area with existing or potential recreational value (Wd1).	Semiannually.	Gamma isotopic analysis[5] semiannually.
4. Ingestion			
a. Milk	Samples from milking animals in ~~three~~ 1-3 locations (Ia1 - Ia3) within 5 km distance having the highest dose potential. If there are none, then, one sample from milking animals in each of ~~three~~ 1-3 areas (Ia1 - Ia3) between 5 to 8 km distant where doses are calculated to be greater than 1 mrem per yr.[9]	Semimonthly when animals are on pasture, monthly at other times.	~~Gamma isotopic[5] and~~ I-131 analysis semimonthly when animals are on pasture; monthly at other times. Gamma isotopic monthly(5)
	One sample from milking animals at a control location (Ia4), 15-30 km distant and in the least prevalent wind direction.		
b. Fish and Inverte-brates	One sample ~~of each~~ a commerically and recreationally important species in vicinity of plant discharge area. (Ib1 - Ib2).	Sample in season, or semiannually if they are not seasonal.	Gamma isotopic analysis[5] on edible portions.
	One sample of same species in areas not influenced by plant discharge (Ib10 - Ib11).		
c. Food Products	One sample of each principal class of food products from any area that is irrigated by water in which liquid plant wastes have been discharged (Ic1 - Ic__)13	At time of harvest.[10]	Gamma isotopic analyses[5] on edible portion.

TABLE 3.12-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

EXPOSURE PATHWAY AND/OR SAMPLE	NUMBER OF REPRESENTATIVE SAMPLES AND SAMPLE LOCATIONS[1]	SAMPLING AND COLLECTION FREQUENCY	TYPE AND FREQUENCY OF ANALYSIS
c. Food Products (cont'd)	Samples of three different kinds of broad leaf vegetation grown nearest each of two different offsite locations of highest predicted annual average ground-level D/Q if milk ~~sampling is not performed~~ is being produced but is ~~no~~ not available for sampling (Ic10 - Ic13).	Monthly when available.	Gamma isotopic[5] and I-131 analysis.
	One sample of each of the similar broad leaf vegetation grown 15-30 km distant in the least prevalent wind direction if ~~milk~~ sampling is not performed at Ic10-Ic13 (Ic20 - Ic23).	Monthly when available.	Gamma isotopic[5] and I-131 analysis.

TABLE 3.12-1 (Continued)

TABLE NOTATION

(1) Specific parameters of distance and direction sector from the centerline of one reactor, and additional description where pertinent, shall be provided for each and every sample location in Table 3.12-1 in a table and figure(s) in the ODCM. Refer to NUREG-0133, "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants," October 1978, and to Radiological Assessment Branch Technical Position, Revision 1, November 1979. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to hazardous conditions, seasonal unavailability, malfunction of automatic sampling equipment and other legitimate reasons. If specimens are unobtainable due to sampling equipment malfunction, every effort shall be made to complete corrective ACTION prior to the end of the next sampling period. All deviations from the sampling schedule shall be documented in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.~~11~~ 6. It is recognized that, at times, it may not be possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In these instances suitable alternative media and locations may be chosen for the particular pathway in question and appropriate substitutions made within 30 days in the Radiological Environmental Monitoring Program. In lieu of a Licensee Event Report and pursuant to Specification 6.9.1.~~12~~ 7, identify the cause of the unavailability of samples for that pathway and identify the new location(s) for obtaining replacement samples in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table for the ODCM reflecting the new location(s). X

(2) One or more instruments, such as a pressurized ion chamber, for measuring and recording dose rate continuously may be used in place of, or in addition to, integrating dosimeters. For the purposes of this table, a thermoluminescent dosimeter (TLD) is considered to be one phosphor; two or more phosphors in a packet are considered as two or more dosimeters. Film badges shall not be used as dosimeters for measuring direct radiation. The forty stations is not an absolute number. The number of direct radiation monitoring stations may be reduced according to geographical limitations; e.g., at an ocean site, some sectors will be over water so that the number of dosimeters may be reduced accordingly. The frequency of analysis or readout for TLD systems will depend upon the characteristics of the specific system used and should be selected to obtain optimum dose information with minimal fading.

(3) The purpose of this sample is to obtain background information. If it is not practical to establish control locations in accordance with the distance and wind direction criteria, other sites that provide valid backgound data may be substituted.

TABLE 3.12-1 (Continued)

TABLE NOTATION

(4) Airborne particulate sample filters shall be analyzed for gross beta radioactivity 24 hours or more after sampling to allow for radon and thoron daughter decay. If gross beta activity in air particulate samples is greater than ten times ~~the yearly mean~~ of control samples, gamma isotopic analysis shall be performed on the individual samples.

that of

(5) Gamma isotopic analysis means the identification and quantification of gamma-emitting radionuclides that may be attributable to the effluents from the facility.

(6) The "upstream sample" shall be taken at a distance beyond significant influence of the discharge. The "downstream" sample shall be taken in an area beyond but near the mixing zone. "Upstream" ~~samples in an estuary must be taken far enough upstream to be beyond the plant influence. Salt water shall be sampled only when the receiving water is utilized for recreational activities.~~

Retains Revised statement

not for WBN

(7) A composite sample is one in which the quantity (aliquot) of liquid sampled is proportional to the quantity of flowing liquid and in which the method of sampling employed results in a specimen that is representative of the liquid flow. In this program composite sample aliquots shall be collected at time intervals that are very short (e.g., hourly) relative to the compositing period (e.g., monthly) in order to assure obtaining a representative sample.

(8) Groundwater samples shall be taken when this source is tapped for drinking or irrigation purposes in areas where the hydraulic gradient or recharge properties are suitable for contamination.

(9) The dose shall be calculated for the maximum organ and age group, using the methodology and parameters in the ODCM.

(10) If harvest occurs more than once a year, sampling shall be performed during each discrete harvest. If harvest occurs continuously, sampling shall be monthly. Attention shall be paid to including samples of tuberous and root food products.

Groundwater flow in the area of Watts Bar has been shown to be toward Chickamauga Reservoir. There are no sources tapped for drinking or irrigation purposes between the plant and the reservoir; therefore, sampling of this medium is not required.

11.
12. See attached insert
13.

Insert To Table 3.12-1

11. The nearest water supply that could be affected by plant discharge is approximately 25 miles downstream from the plant. The second water supply is approximately 50 miles downstream; therefore, only the first water supply need be sampled. Iodine analysis by gamma isotopic analysis will be sufficient.

12. The surface water control shall be considered a control for the drinking water sample.

13. Sampling not required when food products not irrigated by water in which liquid plant wastes have been discharged.

TABLE 4.12-1 (Continued)

TABLE NOTATION

(1) This list does not mean that only these nuclides are to be considered. Other peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported to the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.~~11~~ 6

(2) Required detection capabilities for thermoluminescent dosimeters used for environmental measurements are given in Regulatory Guide 4.13.

(3) The LLD is defined, for purposes of these specifications, as the smallest concentration of radioactive material in a sample that will yield a net count, above system background, that will be detected with 95% probability with only 5% probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system, which may include radiochemical separation:

$$LLD = \frac{4.66\ s_b}{E \cdot V \cdot 2.22 \cdot Y \cdot \exp(-gWt)}$$

$-\lambda\Delta t$

Where:

LLD is the "a priori" lower limit of detection as defined above, as picoCuries per unit mass or volume,

s_b is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate, as counts per minute,

E is the counting efficiency, as counts per disintegration,

V is the sample size in units of mass or volume,

2.22 is the number of disintegrations per minute per picoCurie,

Y is the fractional radiochemical yield, when applicable,

g is the radioactive decay constant for the particular radionuclide, and

Wt for environmental samples is the elapsed time between sample collection, or end of the sample collection period, and time of counting.

Typical values of E, V, Y, and Wt should be used in the calculation.

TABLE 4.12-1 (Continued)

TABLE NOTATION

It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as an a posteriori (after the fact) limit for a particular measurement. Analyses shall be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally background fluctuations, unavoidable small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors shall be identified and described in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6.

(4) LLD for drinking water samples. If no drinking water pathway exists, the LLD of gamma isotopic analysis may be used.

within 3 miles downstream from the plant

3/4.12.2 LAND USE CENSUS

LIMITING CONDITION FOR OPERATION

3.12.2 A land use census shall be conducted and shall identify within a distance of 8 km (5 miles) the location in each of the sixteen meteorological sectors of the nearest milk animal, the nearest residence and the nearest garden* of greater than 50 m2 (500 ft2) producing fresh leafy vegetation. (For elevated releases as defined in Regulatory Guide 1.111, Revision 1, July 1977, the land use census shall also identify within a distance of 5 km (3 miles) the locations in each of the sixteen meteorological sectors of all milk animals and all gardens of greater than 50 m2 producing ~~fresh~~ leaf vegetation.)
m^2 broad.

APPLICABILITY: At all times.

ACTION:

a. With a land use census identifying a location(s) that yields a calculated dose or dose commitment greater than the values currently being calculated in Specification 4.11.2.3, in lieu of a Licensee Event Report, identify the new location(s) in the next Semiannual Radioactive Effluent Release Report, pursuant to Specification 6.9.1.7.

b. With a land use census identifying a location(s) that yields a calculated dose or dose commitment (via the same exposure pathway) 20% greater than at a location from which samples are currently being obtained in accordance with Specification 3.12.1, add the new location(s) to the Radiological Environmental Monitoring Program within 30 days. The sampling location(s), excluding the control station location, having the lowest calculated dose or dose commitment(s), via the same exposure pathway, may be deleted from this monitoring program after October 31 of the year in which this land use census was conducted. In lieu of a Licensee Event Report and pursuant to Specification 6.9.1.7, identify the new location(s) in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table for the ODCM reflecting the new location(s).

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

mail, telephone, or

4.12.2 The land use census shall be conducted during the growing season at least once per 12 months using that information that will provide the best results, such as by a door-to-door, ~~survey,~~ aerial survey, or by consulting local agriculture authorities. The results of the land use census shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6.

*Broad leaf vegetation sampling of at least three different kinds of vegetation may be performed at the SITE BOUNDARY in each of two different direction sectors with the highest predicted D/Qs in lieu of the garden census. Specifications for broad leaf vegetation sampling in Table 3.12-1.4c shall be followed, including analysis of control samples.

RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.3 Analyses shall be performed on radioactive materials supplied as part of an Interlaboratory Comparison Program that has been approved by the Commission.

APPLICABILITY: At all times.

ACTION:

a. With analyses not being performed as required above, report the corrective ACTIONS taken to prevent a recurrence to the Commission in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.12.3 ~~The Interlaboratory Comparison Program shall be described in the ODCM.~~ A summary of the results obtained as part of the above required Interlaboratory Comparison Program, shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6.

and in accordance with the methodology and Parameters in the ODCM

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

BASES

3/4.12.1 MONITORING PROGRAM

The Radiological Environmental Monitoring Program required by this specification provides representative measurements of radiation and of radioactive materials in those exposure pathways and for those radionuclides that lead to the highest potential radiation exposures of MEMBERS OF THE PUBLIC resulting from the station operation. This monitoring program implements Section IV.B.2 of Appendix I to 10 CFR Part 50 and thereby supplements the Radiological Effluent Monitoring Program by verifying that the measurable concentrations of radioactive materials and levels of radiation are not higher than expected on the basis of the effluent measurements and modeling of the environmental exposure pathways. Guidance for this monitoring program is provided by the Radiological Assessment Branch Technical Position on Environmental Monitoring. The initially specified monitoring program will be effective for at least the first three years of commercial operation. Following this period, program changes may be initiated based on operational experience.

The required detection capabilities for environmental sample analyses are tabulated in terms of the lower limits of detection (LLDs). The LLDs required by Table 4.12-1 are considered optimum for routine environmental measurements in industrial laboratories. It should be recognized that the LLD is defined as an _a priori_ (before the fact) limit representing the capability of a measurement system and not as _a posteriori_ (after the fact) limit for a particular measurement.

Detailed discussion of the LLD, and other detection limits can be found in HASL Procedures Manual, HASL-300 (revised annually), Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry," Anal. Chem. 40, 586-93 (1968), and Hartwell, J. K., "Detection Limits for Radioanalytical Counting Techniques," Atlantic Richfield Hanford Company Report ARH-SA-215 (June 1975).

In table 3.12-1, Section 4.c, Food Products, broad leaf vegetation sampling is intended as substitute sampling for milk which is not available for sampling, such as milk produced in insufficient quantities to provide a sample or in case of the lack of cooperation by the landowner. If no milk is produced, broad leaf vegetation sampling will not be required.

3/4.12.2 LAND USE CENSUS

mail, telephone or

This specification is provided to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the Radiological Environmental Monitoring Program are made if required by the results of this census. The best information from the door-to-door, ~~survey,~~ ~~from~~ aerial survey or from consulting with local agricultural authorities shall be used. This census satisfies the requirements of Section IV.B.3 of Appendix I to 10 CFR Part 50. Restricting the census to gardens of greater than 50 m^2 provides assurance that significant exposure pathways via leafy vegetables will be identified and monitored since a garden of this size is the minimum required to produce the quantity (26 kg/year) of leafy vegetables assumed in Regulatory Guide 1.109 for consumption by a child. To determine this minimum garden size, the following assumptions were made: (1) 20% of the garden was used for growing broad leaf vegetation (i.e., similar to lettuce and cabbage), and (2) a vegetation yield of 2 kg/m^2.

3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

The requirement for participation in an approved Interlaboratory Comparison Program is provided to ensure that independent checks on the precision and accuracy of the measurements of radioactive material in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring in order to demonstrate that the results are valid for the purposes of Section IV.B.2 of Appendix I to 10 CFR Part 50.

ITEM E1.56

Figure B 3/4 2-1 (Page B 3/4 2-3)

The figure for power distribution limits was provided by TVA's 12/4/81 submittal.

ITEM E1.57

Bases 3/4.4.2 (Page B 3/4 4-2)

The RCS vent bases was provided by TVA's 12/4/81 submittal.

ITEM E1.58

Figures B 3/4.4-1 and B 3/4.4-2 (Page B 3/4 4-11, B 3/4 4-12)

The figure showing the copper shift curve was provided by TVA's submittal of 12/4/81.

ITEM E1.59

Bases 3/4.7.5 (Page B 3/4 7-3)

Remove the reference to 'level' in the attached basis. All other references were removed in a previous submittal. This one was evidently overlooked.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure-induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70°F and 200 psig are based on a steam generator RT_{NDT} of 10°F and are sufficient to prevent brittle fracture.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the component cooling water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident analyses.

3/4.7.4 ESSENTIAL RAW COOLING WATER SYSTEM

The OPERABILITY of the ERCW system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.5 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink ~~level and~~ temperature ensure that sufficient cooling capacity is available either to (1) provide normal cooldown of the facility or (2) mitigate the effects of accident conditions within acceptable limits.

ITEM E1.60

Electrical Equipment Protective Devices Bases 3/4 8.4 (Page B 3/4 8-3)

Please make the attached corrections to the bases to reflect the terminology used in the specification.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Containment electrical penetrations and penetration conductors are protected by either deenergizing circuits not required during reactor operation or by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers or fuses during periodic surveillance in accordance with the recommendations of Regulatory Guide 1.63, Revision 2, July 1978.

The Surveillance Requirements applicable to lower voltage low voltage power circuit breakers and fuses provide assurance of breaker and fuse reliability by testing at least one representative sample of each manufacturer's brand of circuit breaker and/or fuse. Each manufacturer's molded case and ~~metal case~~ circuit breakers and/or fuses are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested and all ~~and/or~~ fuses are ~~tested~~ inspected. If a wide variety exists within any manufacturer's brand of circuit breakers and/or fuses, it is necessary to divide that manufacturer's breakers and/or fuses into groups and treat each group as a separate type of breaker or fuses for surveillance purposes.

The OPERABILITY of the motor-operated valves thermal overload protection and bypass devices ensures that these devices will not prevent safety-related valves from performing their function. The Surveillance Requirements for demonstrating the OPERABILITY of these devices are in accordance with Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor Operated Valves," Revision 1, March 1977.

Circuit breakers actuated by fault currents are used as isolation devices in this plant. The OPERABILITY of these circuit breakers ensures that the IE busses will be protected in the event of faults in nonqualified loads powered by the busses.

ITEM E1.61

Bases 3/4.11.2.3 (Page B 3/4 11-4)

Add a reference to an applicable NUREG (NUREG/CR-1004).

Reactors," Revision 1, July 1977. The ODCM equations provided for determining the air doses at and beyond the SITE BOUNDARY are based upon the historical average atmospheric conditions.

This specification applies to the release of gaseous effluents from each reactor at the site. For units with shared Radwaste Treatment Systems, the gaseous effluents from the shared system are directly proportioned among the units sharing that system. X

3/4.11.2.3 DOSE - IODINE-131 and 133, TRITIUM, AND RADIONUCLIDES IN PARTICULATE FORM

This specification is provided to implement the requirements of Sections II.C, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.C of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive materials in gaseous effluents to UNRESTRICTED AREAS will be kept "as low as is reasonably achievable". The ODCM calculational methods specified in the Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data, such that the actual exposure of a MEMBER OF THE PUBLIC through appropriate pathways is unlikely to be substantially underestimated. The ODCM calculational methodology and parameters for calculating the doses due to the actual release rates of the subject materials are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977, and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Revision 1, July 1977. These equations also provide for determining the actual doses based upon the historical average atmospheric conditions. The release rate specifications for Iodine-131 and 133, tritium, and radionuclides in particulate form with half lives greater than 8 days are dependent upon the existing radionuclide pathways to man, in the areas at and beyond the SITE BOUNDARY. The pathways that were examined in the development of these calculations were: (1) individual inhalation of airborne radionuclides, (2) deposition of radionuclides onto green leafy vegetation with subsequent consumption by man, (3) deposition onto grassy areas where milk animals and meat producing animals graze with consumption of the milk and meat by man, and (4) deposition on the ground with subsequent exposure of man.

This specification applies to the release of gaseous effluents from each reactor at the site. For units with shared Radwaste Treatment Systems, the gaseous effluents from the shared system are directly proportioned among the units sharing that system. X

, NUREG/CR-1004, "A Statistical Analysis of Selected Parameters for Predicting Food Chain Transport and Internal Dose of Radionuclides," October 1979,

ITEM E1.62

Administrative Controls (Pages 6-1, 6-6, 6-11, 6-13, 6-15, 6-16, 6-17, 6-18, 6-27)

The attached revisions should be made to reflect correct organizational titles and to delete reference to the Radiological Assessment Review Committee (RARC).

RARC was invented by TVA to perform a function similar to PORC for work done outside the Office of Power. The reasons behind this decision were twofold. First, the logistics of coordinating review and approval in a timely manner if PORC were the sole review committee created problems. The work would have been interoffice work involving high levels of TVA management in the correspondence chain. Secondly, the Manager of Power and the plant superintendent would have been legally responsible to NRC for the work done by another office within TVA. Because the Office of Power had no line management control over the people performing the initial work, it was judged prudent to make the line organization performing the work responsible to NRC. The recent reorganization of TVA has brought this work within the Office of Power, making the need for RARC disappear. The responsibility now falls to PORC.

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Plant Superintendent shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Chief, Radiological ~~Hygiene Branch~~ Health Staff, shall be responsible for implementing the Radiological Environmental Program and dose calculations and projections as described in the Offsite Dose Calculation Manual (ODCM). These responsibilities include performance of Surveillance Requirements listed in Table 6.1-1.

6.1.3 The Shift Supervisor (or during his absence from the control room, a designated individual) shall be responsible for the control room command function. A management directive to this effect, signed by the ~~General Manager~~ Division Director, shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

OFFSITE

6.2.1.1 The offsite organization for unit management and technical support shall be as shown on Figure 6.2-1.

6.2.1.2 The offsite organization for the Radiological Enviromental Monitoring Program and dose calculations shall be as shown in Figure 6.2-3.

UNIT STAFF

6.2.2 The unit organization shall be as shown on Figure 6.2-2 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-2;

b. At least one licensed Operator shall be in the control room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, 3 or 4, at least one licensed Senior Operator shall be in the control room;

TABLE 6.1-1

SURVEILLANCE REQUIREMENTS PERFORMED BY
RADIOLOGICAL ~~HYGIENE BRANCH~~
Health Staff

1. Liquid Effluents - Specifications 4.11.1.2 and 4.11.1.3.1.

2. Gaseous Effluents - Specifications 4.11.2.1.1 (partial) and 4.11.2.1.2 (partial.

3. Dose-Noble Gases - Specification 4.11.2.2.

4. Dose-Iodine-131 and 133, Tritium, and Radionuclides in Particulate Form - Specification 4.11.2.3.

5. Gaseous Radwaste System - Specification 4.11.2.4. /

6. Monitoring Program - Specification 4.12.1.

7. Land Use Census - Specification 4.12.2.

8. Interlaboratory Comparison Program - Specification 4.12.3.

missing
4.11.4

h. Performance of special reviews, investigations or analyses and reports thereon as requested by the Plant Superintendent or the Nuclear Safety Review Board;

i. Review of the Plant Physical Security Plan and implementing procedures and shall submit recommended changes to the Nuclear Safety Review Board;

j. Review of the Site Radiological Emergency Plan and implementing procedures and shall submit recommended changes to the Nuclear Safety Review Board;

k. Review of any accidental, unplanned or uncontrolled radioactive release including the preparation of reports covering evaluation, recommendations and disposition of the corrective ACTION to prevent recurrence and the forwarding of these reports to the Director, Nuclear Power Division and to the Nuclear Safety Review Board;

l. Review of changes to the PROCESS CONTROL PROGRAM AND THE OFFSITE DOSE CALCULATION MANUAL; and

~~m. Review of meeting minutes of the Radiological Assessment Review Committee (RARC).~~

AUTHORITY

6.5.1.7 The PORC shall:

a. Recommend in writing to the Plant Superintendent approval or disapproval of items considered under Specification 6.5.1.6a. through d. above;

b. Render determinations in writing with regard to whether or not each item considered under Specification 6.5.1.6a. through e. above constitutes an unreviewed safety question; and

c. Provide written notification within 24 hours to the Director, Nuclear Power Division, and the Nuclear Safety Review Board of disagreement between the PORC and the Plant Superintendent; however, the Plant Superintendent shall have responsibility for resolution of such disagreements pursuant to Specification 6.1.1 above.

RECORDS

6.5.1.8 The PORC shall maintain written minutes of each PORC meeting that, at a minimum, document the results of all PORC activities performed under the responsibility and authority provisions of these technical specifications. Copies shall be provided to the Director, Nuclear Power Division, and the Nuclear Safety Review Board.

6.5.2 NUCLEAR SAFETY REVIEW BOARD (NSRB)

FUNCTION

6.5.2.1 The NSRB shall function to provide independent review and audit of designated activities in the areas of:

REVIEW

6.5.2.7 The NSRB shall review:

a. The safety evaluations for: (1) changes to procedures, equipment or systems, and (2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR;

c. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR;

d. Proposed changes to Technical Specifications or this Operating License;

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

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

g. All written reports requiring 24-hour notification to the Commission;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the PORC. ~~and the RARC.~~

AUDITS

6.5.2.8 Audits of unit activities shall be performed under the cognizance of the NSRB. These audits shall encompass:

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

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

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

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10 CFR Part 50, at least once per 24 months;

c. Audit reports encompassed by Specification 6.5.2.8 above, shall be forwarded to the Manager of Power and to the management positions responsible for the areas audited within 30 days after completion of the audit.

6.5.3 RADIOLOGICAL ASSESSMENT REVIEW COMMITTEE (RARC)

FUNCTION

6.5.3.1 The RARC shall function to advise the Chief, Radiological Hygiene Branch, on all matters related to radiological assessments involving dose calculations and projections and environmental monitoring.

Delete

COMPOSITION

6.5.3.2 The RARC shall be composed of the:

Chairman: Radiological Assessment Section Supervisor
Member: Health Physicist, Gaseous, Radiological Hygiene Branch
Member: Health Physicist, Liquid, Radiological Hygiene Branch
Member: Meteorological Engineer, Air Quality Branch
Member: Chemical Unit Supervisor, Engineering Section, WBNP

ALTERNATES

6.5.3.3 All alternate members shall be appointed in writing by the RARC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in RARC activities at any one time.

MEETINGS FREQUENCY

6.5.3.4 The RARC shall meet at least once per 6 months and as convened by the RARC Chairman or his designated alternate.

QUOROM

6.5.3.5 The quorum of the RARC necessary for the performance of the RARC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and three members including alternates.

RESPONSIBILITIES

6.5.3.6 The RARC shall be responsible for:

a. Review of changes to the OFFSITE DOSE CALCULATION MANUAL,

b. Review of all procedures required by Specification 6.8.4 and changes thereto,

c. Review of the results of any audits of the Quality Assurance Program for effluent and environmental monitoring, and

d. ~~Review of proposed changes to the Technical Specifications related to radiological assessments involving dose calculations and projections and environmental monitoring.~~

Delete

~~AUTHORITY~~

~~6.5.3.7 The RARC shall:~~

~~a. Recommend in writing to the Chief, Radiological Hygiene Branch approval or disapproval of items considered under Specification 6.5.3.6 above,~~

~~b. Render determinations in writing with regard to whether or not each item considered under Specification 6.5.3.6 constitutes an unreviewed safety question, and~~

~~c. Provide written notification within 24 hours to the Director, Nuclear Power Division and the Nuclear Safety Review Board of disagreement between the RARC and the Chief, Radiological Hygiene Branch; however, the Chief, Radiological Hygiene Branch shall have responsibility for resolution of such disagreement pursuant to Specification 6.1.2 above.~~

~~RECORDS~~

~~6.5.3.8 The RARC shall maintain written minutes of each RARC meeting that as a minimum, document the results of all RARC activities performed under the responsibility and authority provisions of these technical specifications. Copies shall be provided to the Director, Nuclear Power Division, PORC, and the Nuclear Safety Review Board.~~

6.6 REPORTABLE OCCURRENCE ACTION

6.6.1 The following actions shall be taken for REPORTABLE OCCURRENCES:

a. The Commission shall be notified and/or a report submitted pursuant to the requirements of Specification 6.9, and

b. Each REPORTABLE OCCURRENCE requiring 24 hour notification to the Commission shall be reviewed by the PORC and submitted to the NSRB and the Director, Nuclear Power Division.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. The Director, Nuclear Power Division and the NSRB shall be notified with 24 hours;

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the PORC. This report shall describe: (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective ACTION taken to prevent recurrence;

c. The Safety Limit Violation Report shall be submitted to the Commission, the NSRB and the Director, Nuclear Power Division, within 14 days of the violation; and

d. Critical operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978;

b. ~~The applicable procedures~~ ~~b. Refueling operations~~; required to implement the requirements of NUREG-0737; X

~~c. Surveillance and test activities of safety-related equipment;~~

c ~~d~~. Plant Physical Security Plan implementation;

d ~~e~~. Site Radiological Emergency Plan implementation;

~~f. Fire Protection Program implementation;~~

e ~~g~~. PROCESS CONTROL PROGRAM implementation; delete or qualify as applicable to setpoint implementation and provision of effluent data

f ~~h~~. ~~OFFSITE DOSE CALCULATION MANUAL implementation; and~~

g ~~i~~. Quality Assurance Program for effluent ~~and environmental monitoring~~ ~~using the guidance contained in Regulatory Guide 1.21, Rev. 1, June 1974 and Regulatory Guide 4.1, Rev. 1, April 1975.~~ STET

6.8.2 Each procedure of Specification 6.8.1 above, and changes thereto, shall be reviewed by the PORC and approved by the Plant Superintendent prior to implementation and reviewed periodically as set forth in administrative procedures.

6.8.3 Temporary changes to procedures of Specification 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered,

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Operator license on the unit affected, and

c. The change is documented, reviewed by the PORC and approved by the Plant Superintendent within 14 days of implementation.

6.8.4 Written procedures shall be established, implemented and maintained by the Radiological ~~Hygiene Branch~~ Health Staff covering the activities below:

a. OFFSITE DOSE CALCULATION ~~AL~~ MANUAL implementation, Possible addition: (except as noted in 6.8.1

unless f of 6.8.1 is [illegible]lated

b. Quality Assurance Program for ~~effluent and~~ radiological environmental monitoring, using the guidance contained in Regulatory Guide 4.15, Rev. 1, February 1979, and

c. Surveillance requirements and environmental monitoring requirements shown in Table 6.1-1.

6.8.5 The following programs shall be established, implemented, and maintained:

a. Reactor Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the Safety Injection System, RHR System, Chemical and Volume Control System, Containment Spray System, and RCS Sampling System. The program shall include the following:

1) Preventive maintenance and periodic visual inspection requirements, and

2) Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentrations in vital areas under accident conditions. This program shall include the following:

1) Training of personnel,

2) Procedures for monitoring, and

3) Provisions for maintenance of sampling and analysis equipment.

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

1) Identification of a sampling schedule for the critical variables and control points for these variables,

2) Identification of the procedures used to measure the values of the critical variables,

3) Identification of process sampling points,

6.10.1 (continued)

c. All REPORTABLE OCCURRENCES submitted to the Commission;

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications;

e. Records of changes made to the procedures required by Specifications 6.8.1 and 6.8.4;

f. Records of radioactive shipments;

g. Records of sealed source and fission detector leak tests and results; and

h. Records of annual physical inventory of all sealed source material of record.

6.10.2 The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report;

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories;

c. Records of radiation exposure for all individuals entering radiation control areas;

d. Records of gaseous and liquid radioactive material released to the environs;

e. Records of transient or operational cycles for those unit components identified in Table 5.7-1;

f. Records of reactor tests and experiments;

g. Records of training and qualification for current members of the unit staff;

h. Records of inservice inspections performed pursuant to these Technical Specifications;

i. Records of Quality Assurance activities required by the Operational Quality Assurance Manual;

j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59;

k. Records of meetings of the PORC, ~~RARC,~~ and the NSRB;

l. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed;

ITEM E1.63

Table 6.2-2 (Page 6-7)

Please change the titles for operations personnel to agree with TVA's present naming convention.

TABLE 6.2-2

MINIMUM SHIFT CREW COMPOSITION

~~TWO UNITS WITH A COMMON CONTROL ROOM~~

X

WITH UNIT 2 IN MODE 5 OR 6 OR DEFUELED

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3, or 4	MODE 5 or 6
~~SS~~ SE	1[a]	1[a]
~~LSO~~ SRO	1	None
~~LO~~ RO	2	1
~~AO~~ AVO	2	2[b]
STA	1	None

WITH UNIT 2 IN MODE 1, 2, 3, OR 4

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3, or 4	MODE 5 or 6
~~SS~~ SE	1[a]	1[a]
~~LSO~~ SRO	1[a]	None
~~LO~~ RO	2[b]	1
~~AO~~ AVO	2[b]	1
STA	1[a]	None

a/ Individual may fill the same position on Unit 2.

b/ One of the two required individuals may fill the same position on Unit 2.

~~SS~~ SE - Shift Supervisor with a Senior Operator license on Unit 1
SRO ~~LSO~~ - Individual with a Senior Operator license on Unit 1
RO ~~LO~~ - Individual with a Operator license on Unit 1
AVO ~~AO~~ - Auxiliary Unit Operator
STA - Shift Technical Advisor

Except for the Shift Supervisor, the Shift Crew composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the Shift Crew composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Supervisor from the control room while the unit is in MODE 1, 2, 3, or 4, an individual (other than the Shift Technical Advisor) with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of the Shift Supervisor from the control room while the unit is in MODE 5 or 6, an individual with a valid Senior Operator or Operator license shall be designated to assume the control room command function.

ITEM E1.64

6.5.1 (Pages 6-9 and 6-10)

The changes should be made for consistency and due to revisions to the PORC charter attached.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the appropriate Assistant Plant Superintendent and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix "A" of 10 CFR Part 55 and the supplemental requirements specified in Section A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience identified by the ISEG.

6.5 REVIEW AND AUDIT

6.5.0 The Manager of Power is responsible for the safe operation of all TVA power plants. The functional organization for Review and Audit is shown on Figure 6.2-1.

6.5.1 PLANT OPERATIONS REVIEW COMMITTEE (PORC)

FUNCTION

6.5.1.1 The PORC shall function to advise the Plant Superintendent on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The PORC shall be composed of the:

Chairman:	Plant Superintendent or his Alternate
Member:	Operations Supervisor
Member:	Engineering Supervisor
Member:	Electrical Maintenance ~~Section~~ Supervisor
Member:	Health Physics Supervisor
Member:	Field Quality ~~Assurance Section~~ Supervisor
Member:	Mechanical Maintenance ~~Section~~ Supervisor
Member:	Instrument Maintenance ~~Section~~ Supervisor

(Engineering

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the PORC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PORC activities at any one time. Assistant section supervisors are acceptable as PORC members in the absence of the section supervisors and are not considered alternates.

MEETING FREQUENCY

6.5.1.4 The PORC shall meet at least once per calendar month and as convened by the PORC Chairman or his designated alternate.

QUORUM

6.5.1.5 The minimum quorum of the PORC necessary for the performance of the PORC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and four members including alternates.

RESPONSIBILITIES

6.5.1.6 The PORC shall be responsible for:

a. Review of 1) all procedures required by Specification 6.8.1 and changes thereto, 2) all programs required by Specification 6.8.5, and changes thereto, 3) any other proposed procedures or changes thereto as determined by the Plant Superintendent to affect nuclear safety.

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

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

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

e. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Director, Nuclear Power Division and to the Chairman of the Nuclear Safety Review Board.

f. Review all written reports requiring 24 hour notification to the Commission.

g. Review of unit operations to detect potential nuclear safety hazards.

PLANT OPERATIONS REVIEW COMMITTEE CHARTER

1.0 PURPOSE:

The purpose of this charter is to establish the responsibility, organization, and method of operation of the Plant Operations Review Committee (PORC) at the Watts Bar Nuclear Plant.

2.0 SCOPE:

The organization, responsibilities, and duties of the Plant Operations Review Committee are as described in the plant technical specifications. Additional requirements for the PORC are listed below. (See Punchlist, Item 1.0)

3.0 REFERENCES:

3.1 N-OQAM Part 1 Section 6.2 (See Punchlist, Item 2.0)

3.2 WBNP Technical Specification 6.5.1 (See Punchlist, Item 1.0)

4.0 DUTIES AND RESPONSIBILITIES:

Along with the duties and responsibilities implemented in T/S 6.5.1, the PORC will comply with the following method of operation:

Method of Operation

1. The assistant plant superintendent will serve as chairman in the absence of the plant superintendent.
2. An assistant plant supervisor or a cognizant member of the organization to be represented designated in writing by the chairman may serve as an alternate committee member when his supervisor is absent.
3. A representative of the Field Quality Assurance Staff shall be present at all PORC meetings.
4. A member will be considered present if he is in telephone communication with the committee.
5. A majority vote by the members present is required for the committee to approve recommended action to be taken on agenda matters.
6. In the rare event that committee business must be transacted and a quorum cannot be obtained, the committee chairman may consult with the appropriate central office supervisor (for example, the Chief, Mechanical Branch, may be contacted if plant maintenance supervisors and their alternates are not available) for advice in naming a qualified alternate to handle the anticipated meeting business.

7. PORC shall review proposed changes to instructions/procedures and other items required by the technical specifications in accordance with the requirements of a plant procedure which provides guidance for implementing 10CFR50.59 to determine if an unreviewed safety question (USQ) is involved. (See Punchlist, Item 3.0)

8. The quality assurance representative shall sign the completed minutes attesting to the fact: "The format and content of plant instructions and revisions thereto listed in these minutes are in compliance with plant quality assurance requirements." In addition to the technical specification requirement, a copy of the minutes of each meeting shall be sent to:

   Director, Nuclear Safety Review Staff (See Punchlist, Item 4.0)
   Chief, Radiological ~~Hygiene Branch~~ Health Staff

9. The chairman presiding over the PORC meeting shall sign the minutes authenticating the validity of their contents.

6.1 and 6.2.3.4 (Pages 6-1 and 6-8)

6.1.3

The responsibility of issuing the management directive which was to be issued by the General Manager will be issued by the Division Director due to current TVA organization.

6.2.3.4

Change Manager, Technical Services to Manager, Maintenance and Engineering to reflect the current title.

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Plant Superintendent shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Chief, Radiological Hygiene Branch, shall be responsible for implementing the Radiological Environmental Program and dose calculations and projections as described in the Offsite Dose Calculation Manual (ODCM). These responsibilities include performance of Surveillance Requirements listed in Table 6.1-1.

6.1.3 The Shift Supervisor (or during his absence from the control room, a designated individual) shall be responsible for the control room command function. A management directive to this effect, signed by the ~~General Manager,~~ shall be reissued to all station personnel on an annual basis. Division Director

6.2 ORGANIZATION

OFFSITE

6.2.1.1 The offsite organization for unit management and technical support shall be as shown on Figure 6.2-1.

6.2.1.2 The offsite organization for the Radiological Enviromental Monitoring Program and dose calculations shall be as shown in Figure 6.2-3.

UNIT STAFF

6.2.2 The unit organization shall be as shown on Figure 6.2-2 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-2;

b. At least one licensed Operator shall be in the control room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, 3 or 4, at least one licensed Senior Operator shall be in the control room;

6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine plant operating characteristics, NRC issuances, industry advisories, Licensing Event Reports and other sources of plant design and operating experience information including plants of similar design, which may indicate areas for improving plant safety.

COMPOSITION

6.2.3.2 The ISEG shall be composed of at least five dedicated full-time engineers located onsite. Each shall have a bachelor's degree in engineering or related science and at least two years professional level experience in his field.

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of plant activities to provide independent verification* that these activities are performed correctly and that human errors are reduced as much as practical.

AUTHORITY

6.2.3.4 The ISEG shall make detailed recommendations for revised procedures, equipment modifications, or other means of improving plant safety to the Manager, ~~Technical Services.~~ Maintenance and Engineering

6.2.4 SHIFT TECHNICAL ADVISOR (STA)

6.2.4.1 The STA shall provide technical support to the Shift Supervisor in the areas of thermal hydraulics, reactor engineering and plant analysis with regard to the safe operation of the unit.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions and the supplemental requirements specified in Section A and C of Enclosure 1 of March 28, 1980 NRC letter to all licensees, except for the Health Physicist who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

*Not responsible for sign-off function.

ITEM E1.67

Administrative Controls - 6.9.1.6 (Page 6-21)

The attached revision changes the submittal date from May 1 to May 31 based on the existent requirement to submit two other reports (annual reports for the Browns Ferry and Sequoyah facilities) by May 1 of each year. All sample analyses are usually completed by mid-March of each year; however, a significant amount of time is required to evaluate and verify the data in each report. By delaying the submittal date for the WBN annual report, a more thorough evaluation can be performed on the data set for each report.

The proposed revision to the third paragraph of Section 6.9.1.6 clarifies the intent to make the contents of the WBN report consistent with the contents of the reports submitted for the Browns Ferry and Sequoyah facilities. Submittal of all analytical results, as has been proposed by NRC reviewers, would require the inclusion of an additional 100 to 200 pages of tables in the report.

ANNUAL REPORTS*

6.9.1.4 Annual Reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Reports required on an annual basis shall include a tabulation on an annual basis for the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated manrem exposure according to work and job functions,** e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.6 Routine Radiological Environmental Operating Reports covering the operation of the unit during the previous calendar year shall be submitted prior to May ~~1~~ 31 of each year. The initial report shall be submitted prior to May ~~1~~ 31 of the year following initial criticality.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological environmental surveillance activities for the report period, including a comparison with preoperational studies, with operational controls as appropriate, and with previous environmental surveillance reports, and an assessment of the observed impacts of the plant operation on the environment. The reports shall also include the results of land use censuses required by Specification 3.12.2.

The Annual Radiological Environmental Operating Reports shall include the ~~results of~~ analysis of all radiological environmental samples and of all environmental radiation measurements taken during the report period pursuant to the locations specified in the table and figures in the ODCM, ~~as well as~~ summarized and tabulated results of ~~these analyses and measurements~~ in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted as soon as possible in a supplementary report.

The reports shall also include the following: a summary description of the Radiological Environmental Monitoring Program; at least two legible maps***

*A single submittal may be made for a multiple unit station.

**This tabulation supplements the requirements of 10 CFR Part 20.407.

***One map shall cover stations near the SITE BOUNDARY; a second shall include the more distant stations.

ITEM E1.68

T/S Justification

Please correct all attached typographical errors. (Pages B 2-1, 3/4 3-2, 3/4 3-4, 3/4 3-20, 3/4 3-27, 3/4 3-28, 3/4 3-31, 3/4 3-50, 3/4 3-74, 3/4 3-75, 3/4 3-78, 3/4 3-80, 3/4 4-27, 3/4 5-1, 3/4 6-8, 3/4 6-14, 3/4 6-19, 3/4 6-23, 3/4 7-32, 3/4 8-11, 3/4 8-23, 3/4 11-6, 3/4 11-7, 3/4 11-14, 3/4 11-15, 3/4 11-17, B 3/4 4-6, B 3/4 4-7, B 3/4 7-3, 6-25, 2-8, 2-9)

TABLE 3.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2	1
	2	1	2	3*, 4*, 5*	10
2. Power Range, Neutron Flux - High Setpoint	4	2	3	1, 2	2[#]
Low Setpoint	4	2	3	1[###], 2	2[#]
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2[#]
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	2[#]
5. Intermediate Range, Neutron Flux	2	1	2	1[###], 2	3
6. Source Range, Neutron Flux					
a. Startup	2	1	2	2[##]	4
b. Shutdown	2	1	2	3*, 4*, 5*	10
c. Shutdown	2	0	1	3, 4, and 5	5
7. Overtemperature ΔT					
a. Four Loop Operation	4	2	3	1, ~~2~~ 2	6[#]
b. Three Loop Operation	(**)	(**)	(**)	(**)	(**)
8. Overpower ΔT					
a. Four Loop Operation	4	2	3	1, 2	6[#]
b. Three Loop Operation	(**)	(**)	(**)	(**)	(**)
9. Pressurizer Pressure-Low	4	2	3	1	6[#]
10. Pressurizer Pressure--High	4	2	3	1, 2	6[#]
11. Pressurizer Water Level--High	3	2	2	1	7[#]

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
A. Low Fluid Oil Pressure	3	2	2	1	7#
B. Turbine Stop Valve Closure	4	4	~~*~~ 4	1	11#
19. Safety Injection Input from ESF	2	1	2	1, 2	9
20. General Warning Alarm	2	2	2	1, 2	10
21. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Low Setpoint Power Range Neutron Flux, P-10	4	2	3	1, 2	8
e. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8
f. Power Range Neutron Flux, P-9	4	2	3	1	8

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. Steam Line Isolation (Continued)					
Coincident With Either T_{avg}--Low-Low	1 T_{avg}/loop	1 T_{avg} any two loops	1 T_{avg} any three loops	1, 2, 3	15*
Or					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any two loops	1 pressure any three loops	1, 2, 3	15*
5. Turbine Trip & Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relay	2	1	2	1, 2,	20
b. Steam Generator Water Level--High-High	3/stm. gen.	2/stm. gen. in any operating stm gem.	2/stm. gen. in each operating stm. gen.	1, 2	15*
6. Auxiliary Feedwater					
a. Manual Initiation	2	1	2	1, 2, 3	21
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	20

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. 6.9 kV Shutdown Board		
a. Loss of Power		
1) Start Diesel Generator	0.0 volts with a 1.5 second time delay	0.0 volts with a 1.5 ± 0.5 second time delay
2) Load Shedding	0.0 volts with a 5 second time delay	0.0 volts with 5 ± 1 second time delay
b. Degraded Voltage		
1) Voltage Sensor	_____ volts	_____ volts ± _____ volts
2) Diesel Generator Start and Load Shedding Timer	_____ seconds	_____ seconds ± _____ seconds
3) Safety Injection Degraded Voltage Logic Enable Timer	_____ seconds	_____ seconds ± _____ seconds
9. Engineered Safety Feature Actuation System Interlocks		
a. Pressurizer Pressure, P-11	≤ 1955 psig	≤ 1965 psig
b. Low-Low T_{avg}, P-12, increasing	≤ 550°F	≥ ~~551°F and ≤ 555°F~~ 552°F
decreasing	≤ 550°F	≥ 548°F
c. Reactor Trip, P-4	N.A.	N.A.

TABLE 3.3-11 (Continued)

Zone	Instrument Location	Minimum Instruments Operable Ionization	Photoelectric	Thermal	Infrared
255	125-V Batt. Rm. IV El. 782	1			
256	125-V Batt. Rm. IV El. 782	1			
257	480-V Bd. Rm. 1B El. 782	3			
258	480-V Bd. Rm. 1B El. 782	3			
259	480-V Bd. Rm. 1A El. 782	3			
260	480-V Bd. Rm. 1A El. 782	3			
267	Aux. Instr. Rm. El. 708	7			
268	Aux. Instr. Rm. El. 708			9	
277	ERCW Pumping Sta. El. 704	17			
296	Aux. CR Bds. L-4B, 4D, & 11B El. 755	7			
354	Upr. Compt. Coolers, El. 801		3		
352	Lwr. Compt. Coolers, El. 716		3		
356	RCP 2, El. 716 #			1	
357	RCP 2, El. 716 #				1
360	RCP 1, El. 716 #			1	
361	RCP 1, El. 716 #				1
364	RCP 3, El. 716 #			1	
365	RCP 3, El. 716 #				1
368	RCP 4, El. 716 #			1	
369	RCP 4, El. 716 #				1

The fire detectors located within the containment are not required to be OPERABLE during the performance of Type A containment leak rate test.

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.9 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3-12 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits of Specification 3.11.1.1 are not exceeded. The Alarm/Trip Setpoints of these channels shall be determined in accordance with the OFFSITE DOSE CALCULATION MANUAL (ODCM).

APPLICABILITY: At all times.

ACTION:

a. With a radioactive liquid effluent monitoring instrumentation channel Alarm/Trip Setpoint less conservative than required by the above specification, immediately suspend the release of radioactive liquid effluents monitored by the affected channel or declare the channel inoperable.

b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE take the ACTION shown in Table 3.3-12.

c. The provisions of Specifications 3.0.3, 3.0.4 and 6.9.1.~~7~~11.b. are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.9 Each radioactive liquid effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST operations at the frequencies shown in Table 4.3-8.

TABLE 4.3-8

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release				
a. Waste Disposal System Liquid Effluent Line	D	P	R(3)	Q(1)
b. Steam Generator Blowdown Effluent Line	D	M	R(3)	Q(1)
c. Condensate Demineralizer Regenerant Effluent Line	D	M	R(3)	Q(1)
d. Plant Liquid Discharge Line	D	M	R(3)	Q(1)
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release				
a. Essential Raw Cooling Water Effluent Line	D	M	R(3)	Q(2)
b. Turbine Building Sump Effluent Line	D	M	R(3)	Q(2)
3. Flow Rate Measurement Devices				
a. Waste Disposal System Liquid Effluent Line	D(4)	N.A.	R	Q
b. Steam Generator Blowdown Effluent Line	D(4)	N.A.	R	Q
c. Condensate Demineralizer Regenerant Effluent Line	D(4)	N.A.	R	Q
d. Diffuser Discharge Effluent Line	D(4)	N.A.	R	Q
4. Tank Level Indicating Devices				
a. Condensate Storage Tank	D*	N.A.	R	Q
b. Steam Generator Layup Tank	D*	N.A.	R	N.A.

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.10 The radioactive gaseous effluent monitoring instrumentation channels shown in Table 3.3-13 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits of Specifications 3.11.2.1 and 3.11.2.5 are not exceeded. The Alarm/Trip Setpoints of these channels meeting specification 3.11.2.1 shall be determined in accordance with the ODCM.

APPLICABILITY: As shown in Table 3.3-13

ACTION:

a. With a radioactive gaseous effluent monitoring instrumentation channel Alarm/Trip Setpoint less conservative than required by the above Specification, without delay suspend the release of radioactive gaseous effluents monitored by the affected channel, or declare the channel inoperable.

b. With less than the minimum number of radioactive gaseous effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3-13. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION or, in lieu of a Licensee Event Report, explain in the next Semiannual Radioactive Effluent Release Report why this inoperability was not corrected within the time specified.

c. The provisions of Specifications 3.0.3, 3.0.4, and 6.9.1.~~7~~.b are not applicable. 11

SURVEILLANCE REQUIREMENTS

4.3.3.10 Each radioactive gaseous effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST operations at the frequencies shown in Table 4.3-9.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. Steam Line Isolation (Continued)					
Coincident With Either T_{avg}--Low-Low	1 T_{avg}/loop	1 T_{avg} any two loops	1 T_{avg} any three loops	1, 2, 3	15*
Or					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any two loops	1 pressure any three loops	1, 2, 3	15*
5. Turbine Trip & Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relay	2	1	2	1, 2,	20
b. Steam Generator Water Level--High-High	3/stm. gen.	2/stm. gen. in any operating stm gem.	2/stm. gen. in each operating stm. gen.	1, 2	15*
6. Auxiliary Feedwater					
a. Manual Initiation	2	1	2	1, 2, 3	21
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	20

SPECIFIC ACTIVITY (Continued)

Based upon the above considerations for excluding certain radionuclides from the sample analysis, the allowable time of 2 hours between sample taking and completing the initial analysis is based upon a typical time necessary to perform the sampling, transport the sample, and perform the analysis of about 90 minutes. After 90 minutes the gross count should be made in a reproducible geometroy of sample and counter having reproducible beta or gamma self-shielding properities. The counter should be reset to a reproducible efficiency versus energy. It is not necessary to identify specific nuclides. The determination of the contributors to the $\bar{E}$ result should be based upon those energy peaks identified with a 95% confidence level. The radiochemical determination of nuclides should be based on multiple counting of the sample with typical counting basis following sampling of less than 1 hour, about 2 hours, about 1 day, about 1 week and about 1 month.

Reducing T_{avg} to less than 500°F prevents the release of activity should a steam generator tube rupture since the saturation pressure of the reactor coolant is below the lift pressure of the atmospheric steam relief valves. The Surveillance Requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective ACTION. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G.

The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 and 3.4-3 for the service period specified thereon.

a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation.

REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM VENTS

LIMITING CONDITION FOR OPERATION

3.4.2.3 Two Reactor Coolant System Vent (RCSV) paths shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With only one RCSV path OPERABLE, STARTUP and/or POWER OPERATION may continue provided the inoperable path is maintained closed with power removed from the valve actuators; otherwise be in HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

b. With no RCSV path OPERABLE, within ~~24~~ 72 hours either restore at least one path to OPERABLE status or be in HOT SHUTDOWN.

Based on recent Generic Letter

SURVEILLANCE REQUIREMENTS

4.4.2.3 Each RCSV path shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the upstream manual isolation valve is locked in the opened position,

b. Operating each remotely controlled valve through at least one cycle from the control room, and

c. Verifying flow through the RCSV paths when the vent valves are open.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ACCUMULATORS

COLD LEG INJECTION

LIMITING CONDITION FOR OPERATION

3.5.1.1 Each Cold Leg Injection Accumulator System shall be OPERABLE with:

a. The isolation valve open,

b. A contained borated water volume of between 7617 and 8033 gallons,

c. A boron concentration of between 1900 and 2100 ppm, and

d. A nitrogen cover-pressure of between 399 and 434 psig.

APPLICABILITY: MODES 1, 2, and 3*.

ACTION:

a. With one Cold Leg Injection Accumulator System inoperable, except as a result of a closed isolation valve, restore the inoperable accumulator to OPERABLE status within 1-hour or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one Cold Leg Injection Accumulator System inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in at least HOT STANDBY within 1-hour and in HOT SHUTDOWN within the following 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.1.1.1 Each Cold Leg Injection Accumulator System shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1) Verifying, by the absence of alarms or by measurement of levels and pressures, the contained borated water volume and nitrogen cover-pressure in the tanks, and

2) Verifying that each cold leg injection accumulator isolation valve is open.

*Pressurizer pressure above 1000 psig.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by pressurizing the volume between the door seals to at least ~~50~~ 6.0 psig for at least 30 seconds and verifying the leakage does not exceed 0.01 L_a;

b. By conducting overall air lock leakage tests at not less than P_a, 15 psig, and verifying the overall air lock leakage rate is within its limit:

   1) At least once per 6 months,# and

   2) Prior to establishing CONTAINMENT INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.*

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

#The provisions of Specification 4.0.2 are not applicable.
*This constitutes an exemption to Appendix J of 10 CFR 50.

SURVEILLANCE REQUIREMENTS (Continued)

3) Verifying a system flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

c. After every 720 hours of charcoal adsorber operation, by verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 0.175%;

d. At least once per 18 months, by:

1) Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 8 inches Water Gauge while operating the system at a flow rate of 4000 cfm ± 10%,

2) Verifying that the system starts automatically on a "Phase A" Containment Isolation test signal,

3) Verifying that the filter cooling bypass valves can be opened,

4) Verifying that the air cleanup subsystem maintains the annulus building at a pressure equal to or more negative than minus 0.5 inches water gage relative to the ~~outside atmosphere~~ shutdown board room, and

5) Verifying that the heaters dissipate 20 ± 2.0 kw when tested in accordance with ANSI N510-1975.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks satisfy the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a DOP test aerosol while operating the system at a flow rate of 4000 cfm ± 10%; and

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers satisfy the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 4000 cfm ± 10%.

TABLE 3.6-2

CONTAINMENT ISOLATION VALVES

VALVE NUMBER		FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Phase "A" Isolation			
a.	FCV-1-7*	SG Blow ~~On~~ DN	10
b.	FCV-1-14*	SG Blow ~~On~~ Dn	10
c.	FCV-1-25*	SG Blow ~~On~~ Dn	10
d.	FCV-1-32*	SG Blow ~~On~~ Dn	10
e.	FCV-1-181*	SG Blow ~~On~~ Dn	10
f.	FCV-1-182*	SG Blow ~~On~~ Dn	10
g.	FCV-1-183*	SG Blow ~~On~~ Dn	10
h.	FCV-1-184*	SG Blow ~~On~~ Dn	10
i.	FCV-31C-305	CW-Inst Room Clrs	10
j.	FCV-31C-306	CW-Inst Room Clrs	10
k.	FCV-31C-308	CW-Inst Room Clrs	10
l.	FCV-31C-309	CW-Inst Room Clrs	10
m.	FCV-31C-326	CW-Inst Room Clrs	10
n.	FCV-31C-327	CW-Inst Room Clrs	10
o.	FCV-31C-329	CW-Inst Room Clrs	10
p.	FCV-31C-330	CW-Inst Room Clrs	10
q.	FCV-43-22	Sample RC Outlet Hdrs	10
r.	FCV-43-23	Sample RC Outlet Hdrs	10
s.	FCV-43-~~54D~~ 540	Stm Gen No. 1 Bldn Isol Vlv	10
t.	FCV-43-~~56D~~ 560	Stm Gen No. 2 Bldn Isol Vlv	10
u.	FCV-43-~~59D~~ 590	Stm Gen No. 3 Bldn Isol Vlv	10
v.	FCV-43-~~63D~~ 630	Stm Gen No. 4 Bldn Isol Vlv	10
w.	FCV-43-55	SG Blow Dn Sample Line	10
x.	FCV-43-58	SG Blow Dn Sample Line	10
y.	FCV-43-61	SG Blow Dn Sample Line	10
z.	FCV-43-64	SG Blow Dn Sample Line	10
aa.	FCV-61-96	Gylcol Inlet to Floor Cooler	30
bb.	FCV-61-97	Gylcol Inlet to Floor Cooler	30
cc.	FCV-61-110	Gylcol Outlet to Floor Cooler	30
dd.	FCV-61-122	Gylcol Outlet to Floor Cooler	30
	FCV-30-134	contaimment to annulus ΔP	10
	FCV-30-135	containment to annulus ΔP	10

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to: (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure-induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70°F and 200 psig are based on a steam generator RT_{NDT} of ~~10°F~~ 60°F and are sufficient to prevent brittle fracture.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident analyses.

3/4.7.4 ESSENTIAL ~~EMERGENCY~~ RAW COOLING WATER SYSTEM

The OPERABILITY of the ERCW System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.5 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink ~~level and~~ temperature ensure that sufficient cooling capacity is available either to: (1) provide normal cooldown of the facility, or (2) mitigate the effects of accident conditions within acceptable limits.

PLANT SYSTEMS

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.11.2 The following Spray and/or Sprinkler Systems shall be OPERABLE:

a. Reactor building - RC pump area, Annulus;

b. Auxiliary building - Elev. 692, 713, 729, 737, 757, 772, 782, ~~ABGTS~~ ABGTS Filters, EGTS Filters, Purge Filters, 125 V Battery Rooms;

c. Control building - Elev. 692, Cable spreading room, MCR air filters and Operator living area;

d. Diesel building - Corridor area;

e. Turbine building - Control building wall; and

f. ERCW pumping station (Intake).

APPLICABILITY: Whenever equipment protected by the Spray/Sprinkler System is required to be OPERABLE.

ACTION:

a. With one or more of the above required Spray and/or Sprinkler Systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish a hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11.2 Each of the above required Spray and/or Sprinkler Systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated, or automatic) in the flow path is in its correct position,

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel, and

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below ~~110~~ 105 volts, or battery overcharge with battery terminal voltage above ~~150~~ 140 volts, by verifying that:

   1) The parameters in Table 4.8-2 meet the Category B limits,

   2) There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150×10^{-6} ohms, and

   3) The average electrolyte temperature of 12 of connected cells is above 60°F.

c. At least once per 18 months by verifying that:

   1) The cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration,

   2) The cell-to-cell and terminal connections are clean, tight, and coated with anti-corrosion material,

   3) The resistance of each cell-to-cell and terminal connection is less than or equal to 150×10^{-6} ohms, and

   4) The battery charger will supply at least 150 amperes at 125 volts for at least 4 hours.

d. At least once per 18 months by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test;

e. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. This performance discharge test may be performed in lieu of the battery service test required by Specification 4.8.2.1d.; and

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

TABLE 3.8-2 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION AND/OR BYPASS DEVICES

VALVE NO.	FUNCTION	BYPASS DEVICE
1-FCV-63-177	SIS Pump Inlet to CVCS	Yes
1 2-FCV-63-3	SI Pump Mini-Flow	Yes
1 2-FCV-63-152	ECCS Recirc	Yes
1 2-FCV-63-153	ECCS Recirc	Yes
1 2-FCV-63-22	ECCS Recirc	Yes
1 2-FCV-3-33	Quick Closing Isolation	Yes
1 2-FCV-3-47	Quick Closing Isolation	Yes
1 2-FCV-3-87	Quick Closing Isolation	Yes
1 2-FCV-3-100	Quick Closing Isolation	Yes
1 2-FCV-1-15	Stm Supply to Aux FWP turbine	Yes
1 2-FCV-1-16	Stm Supply to Aux FWP turbine	Yes
1 2-FCV-3-179A	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-179B	ERCW Sys Sypply to Pump	Yes
1 2-FCV-3-136A	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-136B	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-116A	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-116B	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-126A	ERCW Sys Supply to Pump	Yes
1 2-FCV-3-126B	ERCW Sys Supply to Pump	Yes
1 2-FCV-70-133	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-139	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-4	Isolation for Non-Essential Loads	Yes
1 2-FCV-70-143	Isolation for Excess Letdown Ht Xchngr	Yes
1 2-FCV-70-92	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-90	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-87	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-89	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-140	Isolation for RCP Oil Coolers & Therm B	Yes
1 2-FCV-70-134	Isolation for RCP Oil Coolers & Therm B	Yes
1-FCV-67-67	DG Ht Ex	Yes
2-FCV-67-66	DG Ht Ex	Yes
1-FCV-67-66	DG Ht Ex	Yes
2-FCV-67-67	DG Ht Ex	Yes
1-FCV-67-123	CS Ht Ex Supply	Yes
1-FCV-67-125	CS Ht Ex Supply	Yes
1-FCV-67-124	CS Ht Ex Discharge	Yes
1-FCV-67-126	CS Ht Ex Discharge	Yes
0-FCV-67-151*	CCWS Ht Ex Throttling	Yes
0-FCV-67-152*	CCWS Ht Ex Throttling	Yes
1-FCV-67-146	CCWS Ht Ex Throttling	Yes
1-FCV-67-223	Isolation of 1B/2A HDR's	Yes
1-FCV-67-83	Cont. Isol. Lower	Yes
1-FCV-67-88	Cont. Isol. Lower	Yes
1-FCV-67-87	Cont. Isol. Lower	Yes

*Common to Units 1 & 2.

RADIOACTIVE EFFLUENTS

LIQUID WASTE TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.11.1.3 The Liquid Radwaste Treatment System shall be used to reduce the radioactive materials in liquid wastes prior to their discharge when the projected doses due to the liquid effluent, from each unit to UNRESTRICTED AREAS (see Figure 5.1-1) would exceed 0.06 mrem to the total body or 0.2 mrem to any organ in a 31-day period.

APPLICABILITY: At all times.

ACTION:

a. With radioactive liquid waste being discharged without treatment and in excess of the above, limits and any portion of the Liquid Radwaste Treatment System not in operation, in lieu of a Licensee Event Report, prepare and submit to the Commission within 30 days pursuant to Specification 6.9.2, a Special Report which includes the following information:

   1. ~~Evaluation~~ Explanation of ~~early~~ why liquid radwaste was being discharged without treatment, identification of the inoperable equipment or subsystems, and the reason for inoperability;

   2. ACTION(s) taken to restore the inoperable equipment to OPERABLE status; and

   3. Summary description of ACTION(s) taken to prevent a recurrence.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.3.1 Doses due to liquid releases from each unit to UNRESTRICTED AREAS shall be projected at least once per 31 days, in accordance with the methodology and parameter in the ODCM.

4.11.1.3.2 The installed Liquid Radwaste Treatment System, not declared inoperable by a Lincesee Event Report, shall be demonstrated OPERABLE by meeting Specifications 3.11.1.1 and 3.11.1.2.

RADIOACTIVE EFFLUENTS

LIQUID HOLDUP TANKS

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of ~~radioactive material~~ gamma emitting nuclides contained in each of the following tanks shall be limited by the following expression:

$$\sum_i \frac{C_i}{MPC_i} \leq 9200$$

X

Where C_i is the concentration of nuclide i in the tank and MPC_i is the concentration of the nuclide i given in 10 CFR Part 20, Appendix B, Table II, Column 1, in the same measurement units, excluding tritium and dissolved or entrained noble gases.

a. Condensate Storage Tank,
b. Steam Generator Layup Tank, and
c. Outside temporary tanks for radioactive liquid.
d. Chemical Cleaning Iron and Copper Solvent Tanks

APPLICABILITY: At all times.

ACTION:

a. With the quantity of ~~radioactive material~~ gamma emitting nuclides in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank and within 48 hours reduce the tank contents to within the limit.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of gamma emitting nuclides contained in each of the above listed tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank.

RADIOACTIVE EFFLUENTS

GASEOUS RADWASTE TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.11.2.4 The VENTILATION EXHAUST TREATMENT SYSTEM and the WASTE ~~GAP~~ GAS HOLDUP SYSTEM shall be OPERABLE and appropriate portions of these systems shall be used to reduce releases of radioactivity when the projected doses in 31 days due to gaseous effluent releases, from each unit, to areas at and beyond the SITE BOUNDARY (see Figure 5.1-3) would exceed:

a. 0.2 mrad to air from gamma radiation, or

b. 0.4 mrad to air from beta radiation, or

c. 0.3 mrem to any organ of a MEMBER OF THE PUBLIC.

APPLICABILITY: At all times.

ACTION:

a. With radioactive gaseous waste being discharged without treatment and in excess of the above limits, in lieu of a Licensee Event Report, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that includes the following information:

   1. Identification of any inoperable equipment or subsystems, and the reason for the inoperability,

   2. ACTIONS(S) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of ACTION(S) taken to prevent a recurrence.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.4.1 Doses due to gaseous releases from each unit to areas at and beyond the SITE BOUNDARY shall be projected at least once per 31 days in accordance with the methodology and parameters in the ODCM.

4.11.2.4.2 The installed Gaseous Radwaste Treatment System, not declared inoperable by a Licensee Event Report, shall be demonstrated OPERABLE by meeting Specifications 3.11.2.1 and 3.11.2.2 or 3.11.2.3.

RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of oxygen in the WASTE GAS HOLDUP SYSTEM shall be limited to less than or equal to 2% by volume whenever the hydrogen concentration exceeds 4% by volume.

APPLICABILITY: At all times.

ACTION:

a. With the concentration of oxygen in the WASTE GAS HOLDUP SYSTEM greater than 2% by volume but less than or equal to 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

b. With the concentration of oxygen in the WASTE GAS HOLDUP SYSTEM greater than 4% by volume and the hydrogen concentration greater than 4% by volume, immediately suspend all additions of waste gases to the system and reduce the concentration of oxygen to less than or equal to ~~14%~~ 4% by volume immediately, then take ACTION a., above.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5 The concentration of hydrogen and oxygen in the WASTE GAS HOLDUP SYSTEM shall be determined to be within the above limits by continuously monitoring the waste gases in the waste GAS HOLDUP SYSTEM with the hydrogen and oxygen monitors required OPERABLE by Table 3.3-13 of Specification 3.3.3.10.

3/4.11.3 SOLID RADIOACTIVE WASTE

LIMITING CONDITION FOR OPERATION

3.11.3 Radioactive wastes shall be solidified or dewatered in accordance with the PROCESS CONTROL PROGRAM to meet shipping and transportation requirements during transit, and disposal site requirements when received at the disposal site.

APPLICABILITY: At all times.

ACTION:

a. With SOLIDIFICATION or dewatering not meeting disposal site and ship-ping and transportation requirements, suspend shipment of the inadequately processed wastes and corret the PROCESS CONTROL PROGRAM, and procedures and/or the Solid Waste System as ncessary to prevent recurrence.

b. With SOLIDIFICATION or dewatering not performed in accordance with the PROCESS CONTROL PROGRAM: (1) test the improperly processed waste in each container to ensure that it meets burial ground and shipping requirements, and (2) take appropriate administrative action to prevent recurrence.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.3 SOLIDIFICATION of at least one representative test specimen from at least every tenth batch of each type of wet radioactive waste (e.g., filter sludges, spent resins, evaporator bottoms, boric acid solutions, and sodium sulfate solutions) shall be verified in accordance with the PROCESS CONTROL PROGRAM:

a. If any test specimen fails to verify SOLIDIFICATION, the SOLIDIFI_ CATION of the batch under test shall be suspended until such time as additional test specimens can be obtained, alternative SOLIDIFI-CATION parameters can be deteremined in accordance with the PROCESS CONTROL PROGRAM, and a subsequent test verifies SOLIDIFICATION. SOLIDIFI_ CATION of the batch may then be resumed using the alternative SOLIDIFICATION parameters determined by the PROCESS CONTROL PROGRAM;

b. If the initial test specimen from a batch of waste fails to verify SOLIDIFICATION, the PROCESS CONTROL PROGRAM shall provide for the collection and testing of representative test specimens from each consecutive batch of the same type of wet waste until at least three

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB through the W-3 correlation. The W-3 DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, and is indicative of the margin to DNB.

The minimum value of the DNBR during steady-state operation, normal operational transients, and anticipated transients is limited to 1.30. This value corresponds to a 95% probability at a 95% confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The curves ~~of~~ in Figures 2.1-1 and Figure 2.1-2 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than 1.30, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

These curves are based on an enthalpy hot channel factor, $F^N_{\Delta H}$, of 1.55 and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} = 1.55\ [1+ 0.2\ (1-P)]$$

Where P is the fraction of RATED THERMAL POWER.

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion assuming the axial power imbalance is within the limits of the f_1 (delta I) function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature Delta T trips will reduce the Setpoints to provide protection consistent with core Safety Limits.

SPECIFIC ACTIVITY (Continued)

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the reactor coolant's specific activity greater than 1~~0~~ microCurie/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Operation with specific activity levels exceeding 10 microCurie/gram DOSE EQUIVALENT I-131 but within the limits shown on Figure 3.4-1 must be restricted to no more than 800 hours per year (approximately 10% of the unit's yearly operating time) since the activity levels allowed by Figure 3.4-1 increase the 2-hour thyroid dose at the SITE BOUNDARY by a factor of up to 20 following a postulated steam generator tube rupture. The reporting of cumulative operating time over 500 hours in any 6-month consecutive period with greater than 10 microCurie/gram DOSE EQUIVALENT I-131 will allow sufficient time for Commission evaluation of the circumstances prior to reaching the 800-hour limit.

The sample analysis for determining the gross specific activity and Ē can exclude the radioiodines because of the low reactor coolant limit of 1 microCurie/gram DOSE EQUIVALENT I-131, and because, if the limit is ~~excluded~~ exceeded, the radioiodine level is to be determined every 4 hours. If the gross specific activity level and radioiodine level in the reactor coolant were at their limits, the radioiodine contribution would be approximately 10%. In a release of reactor coolant with a typical mixture of radioactivity, the actual radioiodine contribution would probably be about 20%. The exclusion of radionuclides with half-lives less than 10 minutes from these determinations has been made for several reasons. The first consideration is the difficulty to identify short-lived radionuclides in a sample that requires a significant time to collect, transport, and analyze. The second consideration is the predictable delay time between the postulated release of radioactivity from the reactor coolant to its release to the environment and transport to the SITE BOUNDARY, which is relatable to at least 30 minutes decay time. The choice of 10 minutes for the half-life cutoff was made because of the nuclear characteristics of the typical reactor coolant radioactivity. The radionuclides in the typical reactor coolant have half-lives of less than 4 minutes or half-lives of greater than 14 minutes, which allows a distinction between the radionuclides above and below a half-life of 10 minutes. For these reasons the radionuclides that are excluded from consideration are expected to decay to very low levels before they could be transported from the reactor coolant to the SITE BOUNDARY under any accident condition.

h. Errors discovered in the transient or accident analyses or in the methods used for such analyses as described in the Safety Analysis Report or in the bases for the Technical Specifications that have or could have permitted reactor operation in a manner less conservative than assumed in the analyses;

i. Performance of structures, systems, or components that requires remedial ACTION or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the Safety Analysis Report or Technical Specifications bases; or discovery during unit life of conditions not specifically considered in the Safety Analysis Report or Technical Specifications that require remedial ACTION or corrective measures to prevent the existence or development of an unsafe condition;

j. Offsite releases of radioactive materials in liquid and gaseous effluents which exceed the limits of Specification 3.11.1.1 or 3.11.2.1; and

k. Exceeding the limits in Specification 3.11.1.4 or 3.11.2.6 for the storage of radioactive materials in the listed tanks. The written follow-up report shall include a schedule and a description of activities planned and/or taken to reduce the contents to within the specified limits.

THIRTY DAY WRITTEN REPORTS

6.9.1.11 The types of events listed below shall be the subject of written reports to the Regional Administrator of the NRC Regional Office within 30 days of occurrence of the event. The written report shall include, as a minimum, a completed copy of a Licensee Event Report form. Information provided on the Licensee Event Report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

a. Reactor Trip System or Engineered Safety Features Instrument Settings which are found to be less conservative than those established by the Technical Specifications but which do not prevent the fulfillment of the functional requirements of affected systems;

b. Conditions leading to operation in a degraded MODE permitted by a Limiting Condition for Operation or plant shutdown required by a Limiting Condition for Operation;

c. Observed inadequacies in the implementation of Administrative or Procedural Controls which threaten to cause reduction of degree of redundancy provided in Reactor Trip Systems or Engineered Safety Features Systems;

d. Abnormal degradation of systems other than those specified in Specification ~~6.9.1.12.e.~~ 6.9.1.10c above designed to contain radioactive material resulting from the fission process;

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Containment Spray		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High	≤ ~~2.9~~ 2.81 psig	≤ 3.0 psig
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1 above for all Safety Injection Trip Setpoints/ Allowable Values	
b. Phase "B" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Containment Pressure--High-High	≤ 2.9 psig	≤ 3.0 psig

TABLE 3.3-7

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelerographs		
a. 0-XT-52-75A Cont. El. 702	0 - 1.0g	1
b. 0-XT-52-75B Cont. El. 757	0 - 1.0g	1
c. 0-XT-52-75D D/G Bldg. El. 742	0 - 1.0g	1
2. Triaxial Peak Accelerographs		
a. 0-XR-52-76A Rx Bldg. El 725	0 - 5.0 g	1
b. 0-XR-52-76B Rx Bldg. El 730	0 - 5.0 g	1
c. 0-XR-52-76D Control Bldg. El 755	0 - 5.0 g	1
3. Triaxial Seismic Switches		
a. 0-XS-52-80 Cont El 702	0.025 ~~0.25~~ - .25g	1*
4. Triaxial Response-Spectrum Recorders		
a. 0-XR-52-77A	2 - 25.4 Hz	1*
b. 0-XR-52-77B	2 - 25.4 Hz	1
c. 0-XR-52-77D	2 - 25.4 Hz	1
d. 0-XR-~~5277E~~ 52-77E	2 - 25.4 Hz	1

*With reactor control room indication

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

MODES 1, 2, 3, 4, and 5:

a. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 or greater than 100/$\bar{E}$ microCuries per gram of specific activity, perform the sampling and analysis requirements of item 4.a) of Table 4.4-4 until the specific activity of the reactor coolant is restored to within its limits. In lieu of any other report required by Specification 6.9.1, within 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 with a copy to the Director, Nuclear Reactor Regulation, Attention: Chief, Core Performance Branch and Chief, Accident Evaluation Branch, U. S. Nuclear Regulatory Commission, Washington, D. C., 20555. This report shall contain the results of the specific activity analyses together with the following information:

1. Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded,

2. Results of the last isotopic analysis for radioiodines performed prior to exceeding the limit, while limit was exceeded, and one analysis after the radioiodine activity was reduced to less than limit, including for each isotopic analysis, the date and time of sampling and the radioiodine concentrations.

3. Clean-up flow history starting 48 hours prior to the first sample in which the limit was exceeded,

4. History of degassing operations, if any, starting 48 hours prior to the first sample in which the limit was exceeded, and

5. The time duration when the specific activity of the reactor coolant exceeded 1 microcurie per gram DOSE EQUIVALENT I-131.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the reactor coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Isolation (continued)		
c. Containment Ventilation Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1 above for all Safety Injection Trip Setpoints/ Allowable Values	
4. Steam Line Isolation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High	≤ ~~2.9~~ 2.81 psig	≤ 3.0 psig
d. Steam Flow in Two Steam Lines--High	≤ A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load	≤ A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load

TABLE 3.6-2 (Continued)

CONTAINMENT ISOLATION VALVES

VALVE NUMBER		FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
3.	Phase "A" Containment Vent Isolation (Cont.)		
i.	FCV-30-19	Inst Room Purge Air Supply	≤ 4
j.	FCV-30-20	Inst Room Purge Air Supply	≤ 4
k.	FCV-30-37	Lower Compt Pressure Relief	≤ 4
l.	FCV-30-40	Lower Compt Pressure Relief	≤ 4
m.	FCV-30-50	Upper Compt Purge Air Exh	≤ 4
n.	FCV-30-51	Upper Compt Purge Air Exh	≤ 4
o.	FCV-30-52	Upper Compt Purge Air Exh	≤ 4
p.	FCV-30-53	Upper Compt Purge Air Exh	≤ 4
q.	FCV-30-~~66~~ 56	Lower Compt Purge Air Exh	≤ 4
r.	FCV-30-~~67~~ 57	Lower Compt Purge Air Exh	≤ 4
s.	FCV-30-~~68~~ 58	Inst Room Purge Air Exh	≤ 4
t.	FCV-30-~~69~~ 59	Inst Room Purge Air Exh	≤ 4
u.	FCV-90-107	Cntmt Bldg LWR Compt Air Mon	≤ 5
v.	FCV-90-108	Cntmt Bldg LWR Compt Air Mon	≤ 5
w.	FCV-90-109	Cntmt Bldg LWR Compt Air Mon	≤ 5
x.	FCV-90-110	Cntmt Bldg LWR Compt Air Mon	≤ 5
y.	FCV-90-111	Cntmt Bldg LWR Compt Air Mon	≤ 5
z.	FCV-90-113	Cntmt Bldg Up Compt Air Mon	≤ 5
aa.	FCV-90-114	Cntmt Bldg Up Compt Air Mon	≤ 5
bb.	FCV-90-115	Cntmt Bldg Up Compt Air Mon	≤ 5
cc.	FCV-90-116	Cntmt Bldg Up Compt Air Mon	≤ 5
dd.	FCV-90-117	Cntmt Bldg Up Compt Air Mon	≤ 5

*Not subject to Type C leakage tests.

TABLE 3.7-5

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK #
Diesel Generator Building		
	742	0-26-1077
	760	0-26-1082
	760	0-26-1080
Reactor Building		
Reactor Coolant Pumps	702	1-26-1220
Reactor Coolant Pumps	702	1-26-1221
Reactor Coolant Pumps	702	1-26-1222
Reactor Coolant Pumps	702	1-26-1223
Reactor Coolant Pumps	702	1-26-1224
Reactor Coolant Pumps	702	1-26-1225
Standpipe Rx. Bldg. Annulus	Platform 702	1-26-1216
Standpipe Rx. Bldg. Annulus	Platform 702	1-26-1217
Standpipe Rx. Bldg. Annulus	Platform 702	1-26-1218
Standpipe Rx. Bldg. Annulus	Platform 702	1-26-1219
Standpipe Rx. Bldg. Annulus	Platform 724	1-26-1212
Standpipe Rx. Bldg. Annulus	Platform 724	1-26-1213
Standpipe Rx. Bldg. Annulus	Platform 724	1-26-1214
Standpipe Rx. Bldg. Annulus	Platform 724	1-26-1215
Standpipe Rx. Bldg. Annulus	Platform 744	1-26-1208
Standpipe Rx. Bldg. Annulus	Platform 744	1-26-1209
Standpipe Rx. Bldg. Annulus	Platform 744	1-26-1210
Standpipe Rx. Bldg. Annulus	Platform 744	1-26-1211
Standpipe Rx. Bldg. Annulus	Platform 763	1-26-1204
Standpipe Rx. Bldg. Annulus	Platform 763	1-26-1205
Standpipe Rx. Bldg. Annulus	Platform 763	1-26-1206
Standpipe Rx. Bldg. Annulus	Platform 763	1-26-1207
Standpipe Rx. Bldg. Annulus	Platform 782	1-26-1200
Standpipe Rx. Bldg. Annulus	Platform 782	1-26-1201
Standpipe Rx. Bldg. Annulus	Platform 782	1-26-1202
Standpipe Rx. Bldg. Annulus	Platform 782	1-26-1203
Standpipe Rx. Bldg. Annulus	Platform 801	1-26-1196
Standpipe Rx. Bldg. Annulus	Platform 801	1-26-1197
Standpipe Rx. Bldg. Annulus	Platform 801	1-26-1198
Standpipe Rx. Bldg. Annulus	Platform 801	1-26-1199

R.B.
Reactor Building

SPECIFIC ACTIVITY (Continued)

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the reactor coolant's specific activity greater than 10 microCurie/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Operation with specific activity levels exceeding 10 microCurie/gram DOSE EQUIVALENT I-131 but within the limits shown on Figure 3.4-1 must be restricted to no more than 800 hours per year (approximately 10% of the unit's yearly operating time) since the activity levels allowed by Figure 3.4-1 increase the 2-hour thyroid dose at the SITE BOUNDARY by a factor of up to 20 following a postulated steam generator tube rupture. The reporting of cumulative operating time over 500 hours in any 6-month consecutive period with greater than 10 microCurie/gram DOSE EQUIVALENT I-131 will allow sufficient time for Commission evaluation of the circumstances prior to reaching the 800-hour limit. X

The sample analysis for determining the gross specific activity and $\bar{E}$ can exclude the radioiodines because of the low reactor coolant limit of 1 microCurie/gram DOSE EQUIVALENT I-131, and because, if the limit is ~~excluded~~ exceeded, the radioiodine level is to be determined every 4 hours. If the gross specific activity level and radioiodine level in the reactor coolant were at their limits, the radioiodine contribution would be approximately 1[illegible]%. In a release of reactor coolant with a typical mixture of radioactivity, the actual radioiodine contribution would probably be about 20%. The exclusion of radionuclides with half-lives less than 10 minutes from these determinations has been made for several reasons. The first consideration is the difficulty to identify short-lived radionuclides in a sample that requires a significant time to collect, transport, and analyze. The second consideration is the predictable delay time between the postulated release of radioactivity from the reactor coolant to its release to the environment and transport to the SITE BOUNDARY, which is relatable to at least 30 minutes decay time. The choice of 10 minutes for the half-life cutoff was made because of the nuclear characteristics of the typical reactor coolant radioactivity. The radionuclides in the typical reactor coolant have half-lives of less than 4 minutes or half-lives of greater than 14 minutes, which allows a distinction between the radionuclides above and below a half-life of 10 minutes. For these reasons the radionuclides that are excluded from consideration are expected to decay to very low levels before they could be transported from the reactor coolant to the SITE BOUNDARY under any accident condition. X

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS NOTATION

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \left(\frac{1 + \tau_1 S}{1 + \tau_2 S}\right) \left(\frac{1}{1 + \tau_3 S}\right) \leq \Delta T_o \left\{K_1 - K_2 \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \left[T\left(\frac{1}{1 + \tau_6 S}\right) - T'\right] + \cancel{K_2}\, K_3 (P - P') - f_1(\Delta q)\right\}$$

Where: ΔT = Measured ΔT by RTD Manifold Instrumentation,

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = Lead-lag compensator on measured ΔT,

τ_1, τ_2 = Time constants utilized in the lead-lag controller for ΔT, τ_1 = 8 sec., τ_2 = 3 sec,

$\frac{1}{1 + \tau_3 S}$ = Lag compensator on measured ΔT,

τ_3 = Time constant utilized in the lag compensator for ΔT, τ_3 = 2 sec,

ΔT_o = Indicated ΔT at RATED THERMAL POWER,

K_1 = 1.095,

K_2 = 0.013, /°F

$\frac{1 + \tau_4 S}{1 + \tau_5 S}$ = The function generated by the lead-lag controller for T_{avg} dynamic compensation,

τ_4, τ_5 = Time constants utilized in the lead-lag controller for T_{avg}, τ_4 = 33 sec., τ_5 = 4 sec,

T = Average temperature, °F,

$\frac{1}{1 + \tau_6 S}$ = Lag compensator on measured T_{avg},

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS NOTATION

NOTE 1: (continued)

τ_6 = Time constant utilized in the measured T_{avg} lag compensator, τ_6 = 2 sec,

T' $\leq$ 588.2°F (Nominal T_{avg} at RATED THERMAL POWER),

K_3 = 0.000~~605~~647/psi

P = Pressurizer pressure, psig,

P' = 2235 psig (Nominal RCS operating pressure),

S = Laplace transform operator, sec^{-1},

no caps

and $f_1(\Delta q)$ is a function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers; with gains to be selected based on measured instrument response during plant STARTUP tests such that:

(i) for $q_t - q_b$ between -32% and +10% $f_1(\Delta I) = 0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER);

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds -32%, the ΔT Trip Setpoint shall be automatically reduced by 1.34% of its value at RATED THERMAL POWER;

(iii) for each percent that the magnitude of $(q_t - q_b)$ exceeds +10%, the ΔT Trip Setpoint shall be automatically reduced by 1.22% of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 3.1%.

ITEM E1.69

Heat Flux Hot Channel Factor - $F_Q(Z)$ (Page 3/4 2-4)

The peaking factor previously specified by Westinghouse did not consider the impact of the fuel rod model presented in NUREG-630. Considering the impact of NUREG-630, the F_Q limit factor has recently been adjusted to 2.303. (Westinghouse Electric Corporation letter, WAT-D-5494, dated May 17, 1983).

3/4.2.2 HEAT FLUX HOT CHANNEL FACTOR - $F_Q(Z)$

LIMITING CONDITION FOR OPERATION

3.2.2 $F_Q(Z)$ shall be limited by the following relationships:

$$F_Q(Z) \leq \left[\frac{\cancel{2.31}\ 2.303}{P}\right] [K(Z)] \text{ for } P > 0.5, \text{ and}$$

$$F_Q(Z) \leq [\cancel{4.62}\ 4.606] [K(Z)] \text{ for } P \leq 0.5.$$

Where: $P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$

and K(Z) is the function obtained from Figure 3.2-2 for a given core height location.

APPLICABILITY: MODE 1.

ACTION:

With $F_Q(Z)$ exceeding its limit:

a. Reduce THERMAL POWER at least 1% for each 1% $F_Q(Z)$ exceeds the limit within 15 minutes and similarly reduce the Power Range Neutron Flux-High Trip Setpoints within the next 4 hours; POWER OPERATION may proceed for up to a total of 72 hours; subsequent POWER OPERATION may proceed provided the Overpower Delta T Trip Setpoints have been reduced at least 1% for each 1% $F_Q(Z)$ exceeds the limit; and

b. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced limit required by ACTION a., above; THERMAL POWER may then be increased provided $F_Q(Z)$ is demonstrated through incore mapping to be within its limit.

A27 830523 023

ARMS
XC: [illegible]/pwr(2)

Westinghouse Electric Corporation

Water Reactor Divisions

Nuclear Technology Division
Box 355
Pittsburgh Pennsylvania 15230

May 17, 1983

TVA Contract #71C62-54114-1
WAT-D-5494
NS-PL-11571
S.O. WAT/WBT-4705

Mr. L. M. Mills, Manager
Nuclear Regulation and Safety
Tennessee Valley Authority
400 Chestnut Street Tower II
Chattanooga, Tennessee 37401

Ref: L. M. Mills (TVA) to J. L. Tain (W) dated June 24, 1982

Dear Mr. Mills:

TENNESSEE VALLEY AUTHORITY
WATTS BAR NUCLEAR PLANT
UNITS NUMBERS 1 AND 2
Westinghouse Review Comments
on Watts Bar FSAR

The above reference transmitted various draft revisions to the Watts Bar FSAR requesting Westinghouse to review and provide comments where indicated.

Please find attached Westinghouse's comments and various marked-up FSAR pages, table and figures.

If you have any questions, please do not hesitate to contact us.

Very truly yours,

E. A. Novotnak/for

J. L. Tain, Manager
Tennessee Valley Authority Projects

DLC
D. L. Cecchett/bek
Attachment

cc: L. M. Mills, 3L, 3A
J. A. Raulston, 3L, 3A
R. E. Lyman, 1L
S. A. Moser, 1L
B. Wade, 1L

Question #1

	Page	Comment
Westinghouse	Table 4.1-1 Page 4.3-19 Table 4.3-2 Page 4.4-8 Table 4.4-1 Table 15.4-18a Table 15.4-18b	These pages reference the peaking factor limit for Watts Bar. A peaking factor of 2.32 is specified. The revised ECCS report for Watts Bar transmitted to TVA by Westinghouse on April 27, 1982 listed the new peaking factor as 2.32; however, it was noted that this value has not been adjusted for the impact of the fuel rod models presented in NUREG-0630. These sections should be revised to include the new adjusted peaking factor.

Westinghouse Comments:

See attached marked-up WAT FSAR Pages/Tables/Figures

- Table 4.1-1, 4.4-1, 15.4-18a, 15.4.18b
- Table 4.3-2
- Pages 4.3-19, 4.4-8
- Figure 4.3-21

Please note that Westinghouse reviewed the feasibility of changing the F_Q limit (2.32) currently shown in Chapter 4.4 of the WATTS BAR FSAR (page 4.4-8) to the recently determined LOCA F_Q limit value of 2.303. To be consistent with T/H practice to this point, it is recommended that Chapter 4.4 not be changed to reflect the LOCA F_Q limit of 2.303, but to maintain the safety analyses F_Q value of 2.32.

Understandably, this will be inconsistent with the F_Q values shown in other sections of Chapter 4, but is consistent with recent updates of both First Core and Reload FSAR's. The use (or application) of the 2.32 F_Q for safety analyses made in Section 4 representes a more limiting value than does the

LOCA value of 2.303. Also, because there is one FSAR to represent both WATTS BAR units, the use of an F_Q limit of 2.32 in Chapter 4.4 would preclude having a separate section 4 to cover each unit should the LOCA F_Q limit for Unit 2 (WBT) differ from that of Unit 1 (WAT).

Should TVA not want to accept this position, then Westinghouse would defer to TVA's recommendation. However, it is felt that the position outlined above is in the best interest of TVA.

Question #2

Westinghouse	Page 5.2.54a	It appears that there is typographical error in the probability calculations; no exponents are listed.

Westinghouse Comment:

Westinghouse agrees (Typo), should be 5.5×10^{-9}; see attached marked-up page.

Question #3

Westinghouse	Page 6.2.1-25 Table 6.2.1-25 Page 15.3-3 Table 15.4-1 Table 15.4-17a	These pages address the assumptions regarding the initiation of safety injection pump flow for loss-of-coolant accidents. The system response time listed in the draft technical specifications were provided to TVA by Westinghouse on October 1, 1981 (letter number WAT-D-4590). The technical specification value is several seconds longer. Westinghouse should confirm which information is correct and the appropriate changes made.

DNB Parameters - Table 3.2-1 (Page 3/4 2-16)

In order to measure the MTC as required by SR 4.1.1.3.b, the RCS average temperature must be reduced. This causes a corresponding decrease in RCS pressure. It is very difficult to reduce the temperature in a controlled manner in order to get good MTC measurements while also considering RCS pressure.

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS: Four Loops in Operation	LIMITS: ~~Three Loops in Operation~~
Reactor Coolant System T_{avg}	$\leq$ 593°F	~~(**)~~
Pressurizer Pressure	$\geq$ 2220 psia*	~~(**)~~

*Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute, ~~or~~ a THERMAL POWER step in excess of 10% of RATED THERMAL POWER, or performance of SR 4.1.1.3.b.

**~~These values left blank pending NRC approval of three loop operation.~~

Containment Isolation Valves (Page 3/4 6-17)

This addition will allow mode changes as long as an inoperable CIV is closed with power removed (action b) or isolated with a blind flange (action c). The safety function (isolation) is still met.

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 The containment isolation valves specified in Table 3.6-2 shall be OPERABLE with isolation times as shown in Table 3.6-2.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one or more of the isolation valve(s) specified in Table 3.6-2 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange, or

d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

e. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.3.1 The isolation valves specified in Table 3.6-2 shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by performance of a cycling test and verification of isolation time.

ITEM E1.72

Reactor Building Purge Ventilation System (Pages 3/4 9-16, 3/4 9-17, B 3/4 9-3)

The reactor building purge system should be deleted from the technical specification. The method of protection for a fuel handling accident inside containment is through the isolation capability provided by the containment ventilation isolation system listed in the technical specifications.

DELETE

3/4.9.13 REACTOR BUILDING PURGE VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.13 The Reactor Building Purge Ventilation Systems shall be OPREABLE.

APPLICABILITY: During CORE ALTERATIONS or movement of irradiated fuel within the containment.

ACTION:

a. With one Reactor Building Purge Ventilation System inoperable, CORE ALTERATIONS or movement of irradiated fuel within the containment may proceed provided the OPERABLE Reactor Building Purge Ventilation System is capable of being powered from an OPERABLE emergency power source and is in operation and discharging through at least one train of HEPA filters and charcoal adsorbers.

b. With no Reactor Building Purge Ventilation System OPERABLE, suspend all operations involving CORE ALTERATIONS or movement of irradiated fuel within the containment until at least one Reactor Building Purge Ventilation System is restored to OPERABLE status.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.13 The above required Reactor Building Purge Ventilation Systems shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers;

b. At least once per 18 months, or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the system, by:

1) Verifying that the system statisfies the in-place penetration and bypass leakage acceptance criteria of less than 1% and uses the test procedure guidance of Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 14,000 cfm ± 10%;

For Justification see HJG to LMM dated 6/3/83.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 1%; and

3) Verifying a system flow rate of 14,000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

c. After every 720 hours of charcoal adsorber operation, by verifying within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 1%.

d. At least once per 18 months by:

1) Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches Water Gauge while operating the system at a flow rate of 14,000 cfm ± 10%, and

2) Verifying that on a High Radiation test signal, the system automatically starts (unless already operating) and directs its exhaust flow through the HEPA filters and charcoal adsorber banks.

e. After each complete or partial replacement of a HEPA filter bank, by verifying that the HEPA filter banks satisfy the in-place penetration and bypass leakage testing acceptance criteria of less than 1% in accordance with ANSI N510-1975 for a DOP test aerosol while operating the system at a flow rate of 14,000 cfm ± 10%; and

f. After each complete or partial replacement of a charcoal adsorber bank, by verifying that the charcoal adsorbers satisfy the in-place penetration and bypass leakage testing acceptance criteria of less than 1% in accordance with ANSI N510-1975 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 14,000 cfm ± 10%.

DELETE

3/4.9.10 and 3/4.9.11 WATER LEVEL - REACTOR VESSEL and STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.12 AUXILIARY BUILDING GAS TREATMENT SYSTEM

The limitations on the Auxiliary Building Gas Treatment System ensure that all radioactive material released from an irradiated fuel assembly will be filtered through the HEPA filters and charcoal adsorber prior to discharge to the atmosphere. Operation of the system with the heaters ~~on~~ operating for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system and the resulting iodine removal capacity are consistent with the assumptions of the accident analyses.

~~3/4.9.13 REACTOR BUILDING PURGE VENTILATION SYSTEM~~

~~The limitations on the Reactor Building Purge-Ventilation System ensure that all radioactive material released from an irradiated fuel assembly inside containment will be filtered through the HEPA filters and charcoal adsorbers prior to discharge to the atmosphere. The OPERABILITY of this system and the resulting iodine removal capacity are consistent with the assumption of the accident analyses.~~

Delete

ITEM E1.73

Reactor Coolant System Vents (Page 3/4 4-9)

Attached is the BASES for the RCSV specification 3.4.2.3. Also attached is a marked-up version of specification 3.4.2.3 deleting SR c. Verifying flow through the RCSV paths when the vent valves are open is an excessive requirement. Verifying that each remotely controlled valve is operated through one complete cycle of full travel is sufficient to verify operability of the flow path (along with item a). This is consistent with the SR for other such flow paths (see PORV spec 3.4.4, etc).

REACTOR COOLANT SYSTEM VENTS

LIMITING CONDITION FOR OPERATION

3.4.2.3 Two Reactor Coolant System Vent (RCSV) paths shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With only one RCSV path OPERABLE, STARTUP and/or POWER OPERATION may continue provided the inoperable path is maintained closed with power removed from the valve actuators; otherwise be in HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

b. With no RCSV path OPERABLE, within 24 hours either restore at least one path to OPERABLE status or be in HOT SHUTDOWN.

SURVEILLANCE REQUIREMENTS

4.4.2.3 Each RCSV path shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the upstream manual isolation valve is locked in the opened position,

b. Operating each remotely controlled valve through at least one complete cycle of full travel from the control room. ~~and~~

~~c. Verifying flow through the RCSV paths when the vent valves are open.~~

3.4 2.3 REACTOR COOLANT SYSTEM VENTS

The function of the Reactor Coolant System Vents (RCSV) is to remove non-condensables or steam from the reactor vessel head and/or pressurizer. This system is designed to mitigate a possible condition of inadequate core cooling, inadequate natural circulation, or inability to depressurize to Residual Heat Removal System initiation conditions resulting from the accumulation of non-condensable gases in the Reactor Coolant System.

The reactor vessel head vent and the pressurizer vent are each designed with redundant safety grade vent paths. Having either system OPERABLE or having one path in each system from opposite trains OPERABLE is sufficient to meet the provisions of Specification 3.4.23

ITEM E1.75

Fire Suppression Water System (Page 3/4 7-30)

Both the 1980 edition of the ASME Boiler and Pressure Vessel Code, Section XI and National Fire Code no longer recommend monthly testing of electric motor driven pumps. This change is necessary because the fire pumps are not covered by the blanket statement in specification 4.0.5

PLANT SYSTEMS

3/4.7.11 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.11.1 The Fire Suppression Water System shall be OPERABLE with:

a. ~~Two~~ fire suppression pumps, each with a capacity of 1590 gpm at 330 feet of head, with their discharge aligned to the fire suppression header, and

300

b. An OPERABLE flow path capable of taking suction from the forebay and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the standpipe hose valves, and the first valve upstream of the water flow device on each Spray System required to be OPERABLE per Specifications 3.7.11.2 and 3.7.11.4.

APPLICABILITY: At all times.

ACTION:

a. With only one pump OPERABLE, restore at least two pumps to OPERABLE status within 7 days or provide an alternate backup pump or supply. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

b. With the Fire Suppression Water System otherwise inoperable establish a backup Fire Suppression Water System within 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.11.1 The Fire Suppression Water System shall be demonstrated OPERABLE:

a. At least once per ~~31~~ 92 days on a STAGGERED TEST BASIS by starting each pump and operating it for at least 15 minutes on recirculation flow,

b. At least once per 31 days by verifying that each valve (manual, power operated, or automatic) in the flow path is in its correct position,

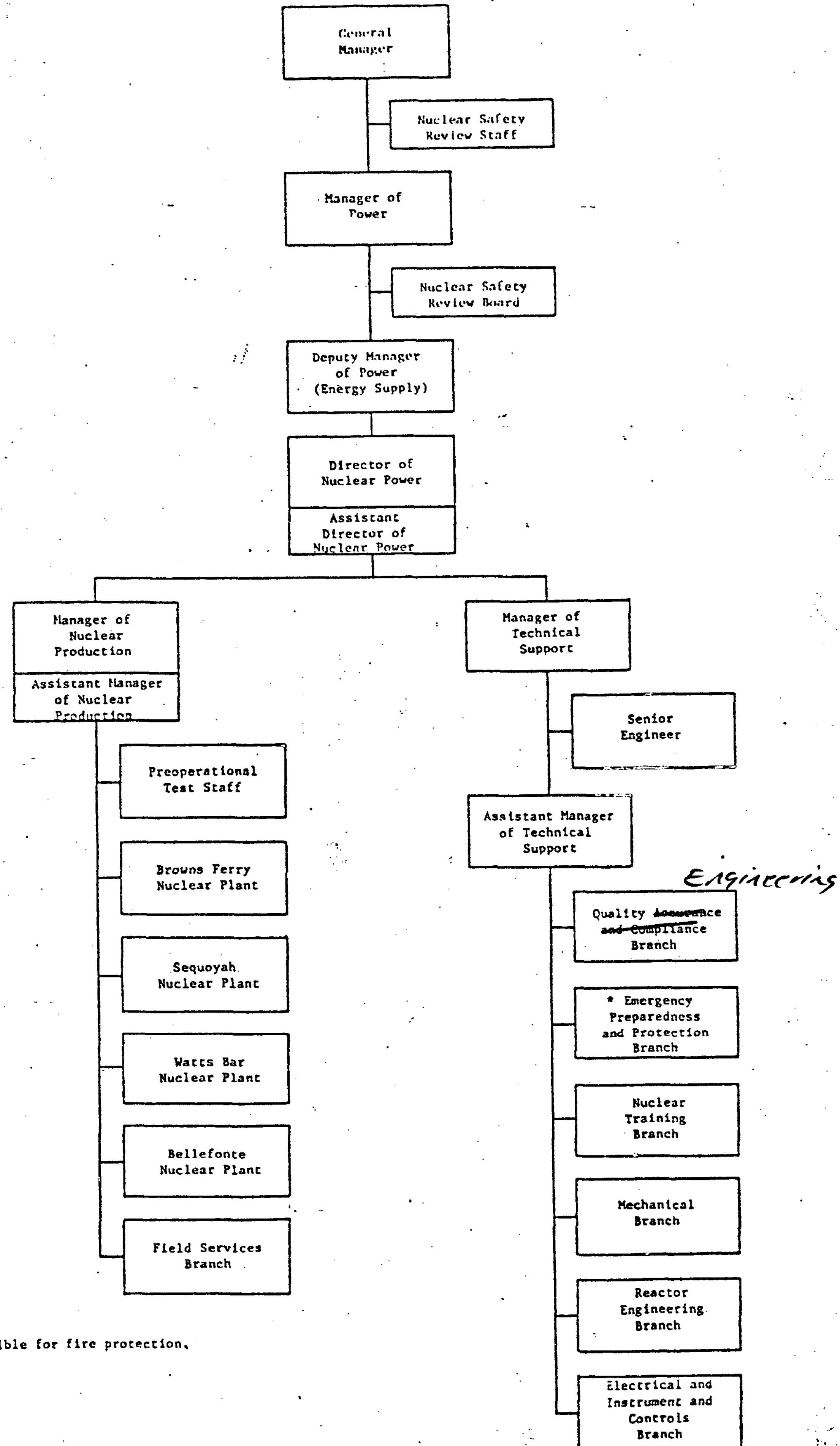
c. At least once per 6 months by performance of a system flush,

d. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel,

ITEM E1.76

Organizational Figures (Pages 6-3, 6-4, and 6-5)

Attached are revised figures 6.2-1, 6.2-2, and 6.2-3.



*Responsible for fire protection.

Figure 6.2-1 Offsite Organization for Facility Management and Technical Support

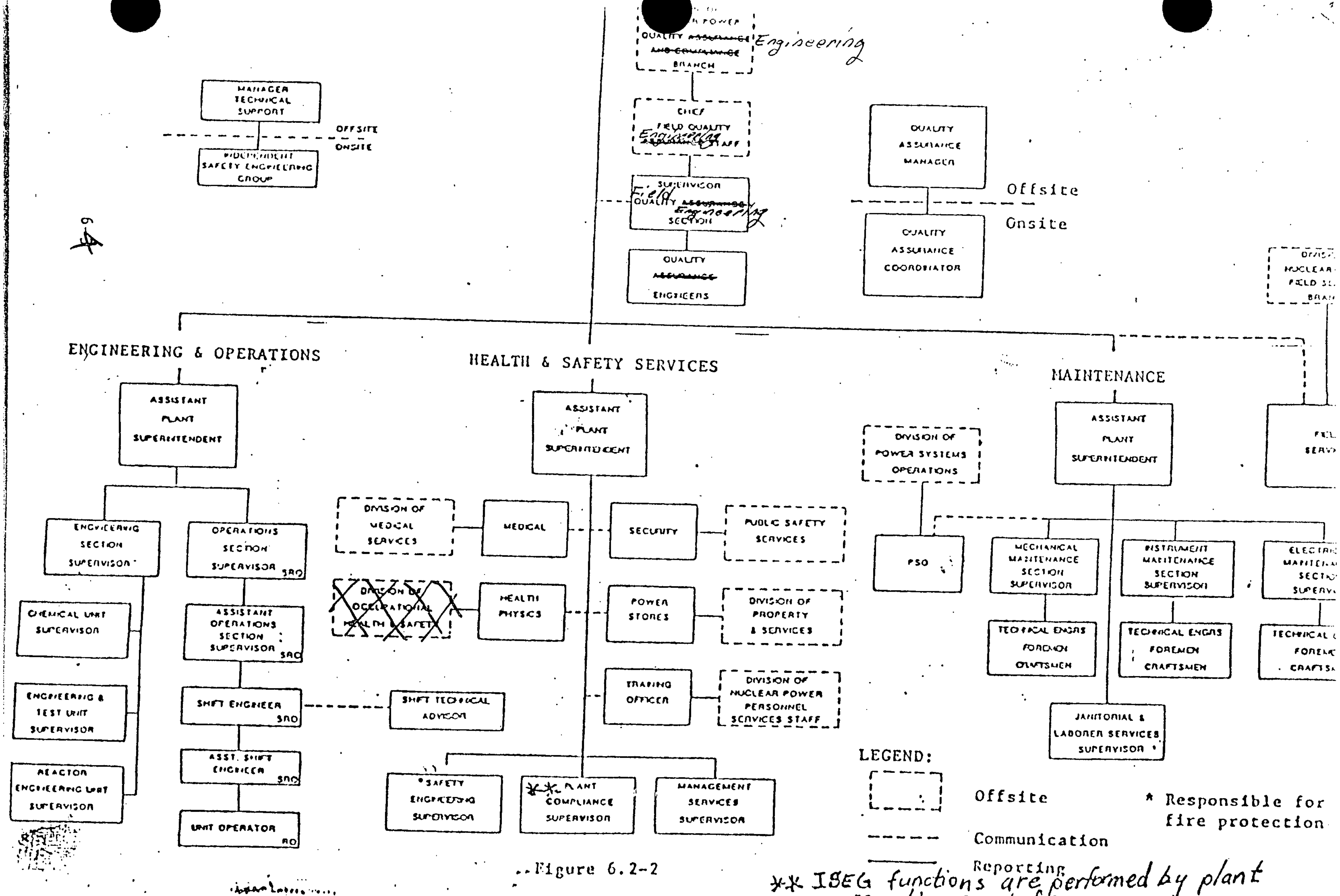


Figure 6.2-2

** ISEG functions are performed by plant compliance staff

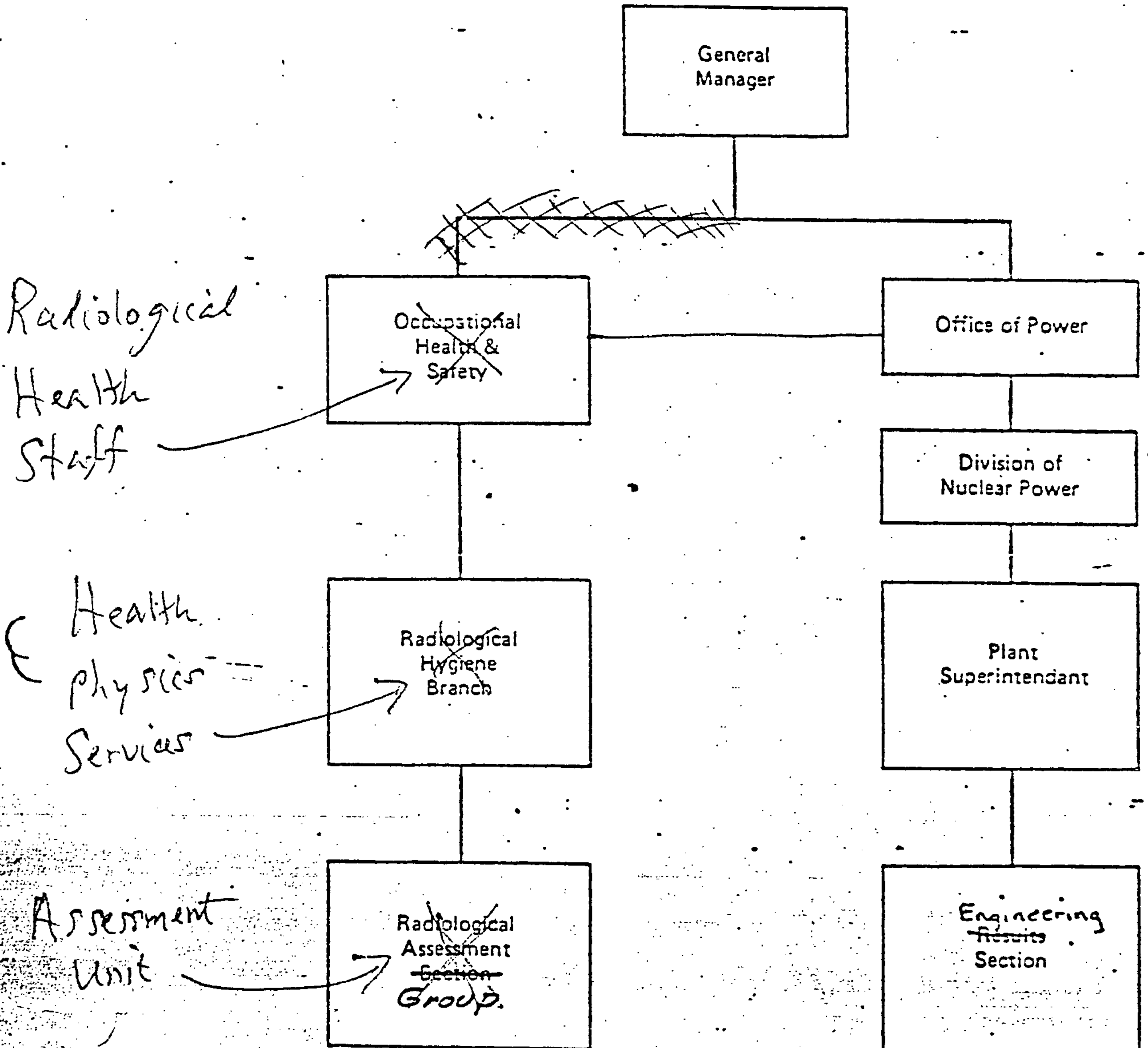


Figure 6.2-3. Offsite Organization for Monitoring Program and Dose Calculations.

ITEM E1.77

Hydrogen Mitigation System (Pages 3/4 6-26, B 3/4 6-4)

The ACTION statement for LCO 3.6.4.3 has been revised to increase the SR interval from 92 days to 7 days during periods of inoperability of one train of igniters. This change has already been accepted for Sequoyah Nuclear Plant.

Also, SR 4.6.4.3(a) has been modified to reflect the addition of 4 igniters to the system.

CONTAINMENT SYSTEMS

HYDROGEN MITIGATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.4.3 Both trains of the Primary Containment Hydrogen Mitigation System shall be operable.

APPLICABILITY: MODES 1 and 2.

ACTION

With one train of the Hydrogen Mitigation System inoperable, restore the inoperable system to OPERABLE status within 7 days ~~or be in at least HOT STANDBY within the next 6 hours~~. or increase the surveillance interval of S.R. 4.6.4.3(a) from 92 days to 7 days on the ~~operable~~ OPERABLE train until the inoperable train is returned to operable status.

SURVEILLANCE REQUIREMENTS

4.6.4.3 Both trains of the Hydrogen Mitigation System shall be demonstrated OPERABLE:

a. At least once per 92 days by energizing the supply breakers and verifying that at least ~~62~~ 66 ignitors are energized, and*

b. At least once per 18 months by verifying the cleanliness of each ignitor by a visual inspection.

*Inoperable ignitors must not be on corresponding redundant circuits which provide coverage for the same region.

3/4.6.3 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 thru 57 of Appendix A to 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions, Either recombiner unit is capable of controlling the expected hydrogen generation associated with: (1) zirconium-water reactions, (2) radiolytic decomposition of water, and (3) corrosion of metals within containment. These Hydrogen Control Systems are consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA", March 1971.

The Hydrogen Mixing Systems are provided to ensure adequate mixing of the containment atmosphere following a LOCA. This mixing action will prevent localized accumulations of hydrogen from exceeding the flammable limit.

The operability of at least ~~31~~ 33 of ~~32~~ 34 ignitors per train (~~62~~ 66 of ~~64~~ 68 for both trains) in the Hydrogen Mitigation System will maintain an effective coverage throughout the containment provided the two inoperable ignitors are not on corresponding redundant circuits which provide coverage for the same region. This system of ignitors will initiate combustion of any significant amount of hydrogen released after a degraded core accident. This system is to ensure burning in a controlled manner as the hydrogen is released instead of allowing it to be ignited at high concentrations by a random ignition source.

WATTS BAR NUCLEAR PLANT
DRAFT TECHNICAL SPECIFICATIONS

ENCLOSURE 2
(Original 9/15/82 Information)

ITEM E2.1

Previously Identified

NRC Questions D.3, D.14
Open Item Nos. 2, 28, 29, 31, 34, 35, 36, 226

T.S. Pages 1-5, 3/4 1-14, 3/4 1-15, 3/4 1-17, 3/4 1-18, 3/4 1-20, 3/4 1-21, B 3/4 1-3

Definition of REFERENCE POSITION - These specifications are being revised to address NRC and plant concerns about the accuracy and usefulness of the analog rod position indicators (ARPI). Our proposal is based on the following:

1. Shutdown banks and control banks A and B positions need to be known accurately in a very limited range near the top and bottom of the core.

2. Control bank C and D positions need to be known accurately at the bottom of the core and from somewhat below the full power insertion limit to the top of the core.

3. Recognition that the ARPI is very temperature sensitive and as such requires that immediate verification of the position after rod movement be shifted from the ARPI to the group step counters with subsequent verification, after temperature equilibration, by the ARPI.

4. Detection of a misaligned rod is primarily limited to control bank C and D and through the use of the REFERENCE POSITION.

REFERENCE POSITION for the shutdown banks and control banks A and B permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these bank positions in these two areas satisfies all accident analysis assumptions concerning their position. REFERENCE POSITION for control banks C and D permits the operator to verify that the control rods in these banks are either fully inserted or above the full power insertion limit, the normal operating modes for these banks. Comparison of the indicated analog rod position to the calibration curve for the in between regions for all rods is sufficient to allow determination that a control rod is indeed misaligned from its bank. Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators, after thermal equilibration after rod motion, is sufficient verification that the control rods are above the insertion limits.

The proposed changes will decrease the number of LERs filed by eliminating those LERs caused by the temperature sensitivity of the ARPIs. It will also remove some problems associated with the system.

W has discussed this approach with M. Dunefeld of the Core Performance Branch (NRC) and found it to be acceptable.

NOTE: The 'typical ARPI vs Group Demand' figure was drawn to maximize the difference between the two readings. The curve was purposely drawn through points (OARPI, 12 GD), (42 ARPI, 30 GD), (162 ARPI, 150 GD), and (216 ARPI, 228 GD).

Reference: Letter from J. C. Miller (W) to H. J. Green dated July 23, 1981. 'Revised Analog Rod Position Indication System Technical Specifications.'

RATED THERMAL POWER

1.25 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3411 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

INSERT attached

REPORTABLE OCCURRENCE

1.~~27~~ 28 A REPORTABLE OCCURRENCE shall be any of those conditions specified in Specifications 6.9.1.12 and 6.9.1.13.

SHIELD BUILDING INTEGRITY

1.~~28~~ 29 SHIELD BUILDING INTEGRITY shall exist when:

a. Each door in each access opening is closed except when the access opening is being used for normal transit entry and exit, then at least one door shall be closed,

b. The emergency gas treatment system is OPERABLE, and

c. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

SHUTDOWN MARGIN

1.~~29~~ 30 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be fully withdrawn.

SLAVE RELAY TEST

1.~~30~~ 31 A SLAVE RELAY TEST shall be the energization of each slave relay and verification of OPERABILITY of each relay. The SLAVE RELAY TEST shall include a continuity check, as a minimum, of associated testable actuation devices.

SOLIDIFICATION

1.~~31~~ 32 SOLIDIFICATION shall be the conversion of radioactive wastes from liquid systems to a uniformly distributed, monolithic, immobilized solid with definite volume and shape, bounded by a stable surface of distinct outline on all sides (free-standing).

etc

INSERT

<u>REFERENCE POSITION</u>

1.27 Analog Rod Position Indication System REFERENCE POSITION is defined as:

a. For all Shutdown Banks, Control Banks A and B, ~~and the Part Length Banks~~; the group demand counter indicated position between 0 and 30 steps withdrawn inclusive and between 200 and 228 steps withdrawn inclusive.

b. For Control Banks C and D; the group demand counter indicated position between 0 and 30 steps withdrawn inclusive and between 150 and 228 steps withdrawn inclusive. For the withdrawal range of 31 to 149 steps inclusive the REFERENCE POSITION shall be the individual rod calibration curve noting indicated analog rod position vs indicated group demand counter position.

REACTIVITY CONTROL SYSTEMS

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

GROUP HEIGHT

LIMITING CONDITION FOR OPERATION

3.1.3.1 All full length (shutdown and control) rods shall be OPERABLE and positioned within ± 12 steps (indicated position) of the REFERENCE POSITION corresponding to their group step counter demand position within 1 hour after rod motion

APPLICABILITY: MODES 1* and 2*.

ACTION:

a. With one or more full length rods inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, ~~determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and~~ be in HOT STANDBY within 6 hours.

b. With more than one full length rod inoperable or misaligned from the REFERENCE POSITION ~~group step counter demand position~~ by more than ± 12 steps (indicated position), be in HOT STANDBY within 6 hours.

c. With one full length rod trippable but inoperable due to causes other than addressed by ACTION a, above, or misaligned from its REFERENCE POSITION ~~group step counter demand height~~ by more than ± 12 steps (indicated position), POWER OPERATION may continue provided that within one hour either:

    1. The rod is restored to OPERABLE status within the above alignment requirements, or

    2. The rod is declared inoperable and the remainder of the rods in the group with the inoperable rod are aligned to within ± 12 steps of the inoperable rod while maintaining the rod sequence and insertion limits of Figure 3.1-1. The THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation, or

    3. The rod is declared inoperable ~~and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied~~. POWER OPERATION may then continue provided that:

        a) A reevaluation of each accident analysis of Table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions.

        b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

*See Special Test Exceptions 3.10.2 and 3.10.3.

ACTION (Continued)

c) A power distribution map is obtained from the movable incore detectors and $F_Q(Z)$ and $F^N_{\Delta H}$ are verified to be within their limits within 72 hours.

d) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within the next hour and within the following 4 hours the high neutron flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

~~4.1.3.1.1 The position of each full length rod shall be determined to be within the group demand limit by verifying the individual rod positions at least once per 12 hours except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.~~

4.1.3.1.2 Each full length rod not fully inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction at least once per 31 days.

4.1.3.1.1 The position of each full ~~[illegible]~~ length rod shall be determined to within ± 12 steps (indicated position) of the REFERENCE POSITION corresponding to the group demand position at least once per 12 hours (allowing for one hour thermal soak after rod motion) except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEMS-OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2 The shutdown and control individual ~~and part length control~~ rod position indication system and the demand position indication system shall be OPERABLE and capable of determining the control rod positions ~~within ± 12 steps~~. actual and demanded respectively, as follows:

See attached insert

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With a maximum of one analog rod position indicator per bank inoperable either:

1. Determine the position of the non-indicating rod(s) indirectly by the movable incore detectors at least once per 8 hours and within one hour after any motion of the non-indicating rod which ~~immediately after any motion of the non-indicating rod which~~ exceeds 24 steps in one direction since the last determination of the rod's position, or

2. Reduce THERMAL POWER TO less than 50% of RATED THERMAL POWER within 8 hours.

b. With a maximum of one group demand position indicator per bank inoperable either:

1. Verify that all rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 12 steps (corrected indicated position) of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2.1 Each analog rod position indicator shall be determined to be OPERABLE by verifying that the demand position indication system and the rod position indication system agree within 12 steps (allowing for one hour thermal soak after rod motion) at least once per 12 hours except during time intervals when the Rod Position Deviation Monitor is inoperable, then compare the demand position indication system and the rod position indication system (by use of the REFERENCE POSITION) at least once per 4 hours.

4.1.3.2.2 Each of the above required rod position indicator(s) shall be determined to be OPERABLE by performance of a ~~CHANNEL FUNCTIONAL~~ ANALOG CHANNEL OPERATIONAL TEST at least once per 18 months.

Analog rod position indicators, within one hour after rod motion (allowance for thermal soak);

All Shutdown Banks - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Banks A and B - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Banks C and D - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 150-228 steps. ± 12 steps of the REFERENCE POSITION for withdrawal range of 31-149 steps.

Group demand counters; ± 2 steps

INSERT ON 3.1.3.2

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEM–SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 ~~The rod~~ The group demand position indicator ~~(excluding demand position indication)~~ shall be OPERABLE and capable of determining ~~the control rod position~~ within ± ~~1~~2 steps the demand position for each shutdown and control ~~or part length~~ rod not fully inserted.

APPLICABILITY: MODES 3*#, 4*# and 5*#.

ACTION:

With less than the above required group demand position indicator(s) OPERABLE, immediately open the reactor trip system breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required ~~rod~~ group demand position indicator(s) shall be determined to be OPERABLE by ~~performance of a CHANNEL FUNCTIONAL TEST at least once per 18 months~~. movement of the associated control rod at least 10 steps in any one direction at least once per 31 days.

*With the reactor trip system breakers in the closed position.
#See Special Test Exception 3.10.5.

REACTIVITY CONTROL SYSTEMS

SHUTDOWN ROD INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown rods shall be fully withdrawn.

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With a maximum of one shutdown rod not fully withdrawn, except for surveillance testing pursuant to Specification 4.1.3.1.2, within 1 hour either:

a. Fully withdraw the rod, or

b. Declare the rod to be inoperable and apply Specification (3.1.3.1).

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown rod shall be determined to be fully withdrawn by use of the group demand counters and verified by the analog rod position indicators within one hour after rod motion

a. Within 15 minutes prior to withdrawal of any rods in control banks A, B, C or D during an approach to reactor criticality, and

b. At least once per 12 hours thereafter.

*See Special Test Exceptions 3.10.2 and 3.10.3.
#With K_{eff} greater than or equal to 1.0.

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control banks shall be limited in physical insertion as shown in Figure 3.1-1.

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification 4.1.3.1.2, either:

a. Restore the control banks to within the limits within 2 hours, or

b. Reduce THERMAL POWER within 2 hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the above figures, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each control bank shall be determined to be within the insertion limits at least once per 12 hours, except during time intervals when the Rod Insertion Limit Monitor is inoperable, then verify the individual rod positions at least once per 4 hours.

by use of the group demand counters and verified by the analog rod position indicators with 1 hour of rod motion,

*See Special Test Exceptions 3.10.2 and 3.10.3.
#With K_{eff} greater than or equal to 1.0.

BORATION SYSTEMS (Continued)

MARGIN from expected operating conditions of 1.6% delta k/k after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires 6542 gallons of 20,000-ppm borated water from the boric acid storage tanks or 75,000 gallons of 2000-ppm borated water from the refueling water storage tank.

With the RCS temperature below 200°F, one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single injection system becomes inoperable.

The limitation for a maximum of one centrifugal charging pump to be OPERABLE and the Surveillance Requirement to verify all charging pumps except the required OPERABLE pump to be inoperable below (275)°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV.

The boron capability required below 200°F is sufficient to provide a SHUTDOWN MARGIN of 1% delta k/k after xenon decay and cooldown from 200°F to 140°F. This condition requires either 835 gallons of 20,000-ppm borated water from the boric acid storage tanks or 9690 gallons of 2000-ppm borated water from the refueling water storage tank.

The contained water volume limits include allowance for water not available because of discharge line location and other physical characteristics.

The limits on contained water volume and boron concentration of the RWST also ensure a pH value of between 8.5 and 11.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

The OPERABILITY of one boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

~~The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) limit the potential effects of rod misalignment on associated accident analyses. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.~~

INSERT Attached

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) limit the potential effects of rod misalignment on associated accident analyses. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. OPERABLE condition for the analog rod position indicators is defined as being capable of indicating rod position to within ± 12 steps of the reference position. For the Shutdown Banks, and Control Banks A and B, ~~and the Part Length Banks~~ the REFERENCE POSITION is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 and 228 steps withdrawn inclusive. This permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these bank positions in these two areas satisfies all accident analysis assumptions concerning their position. For Control Banks C and D the REFERENCE POSITION is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive and between 150 and 228 steps withdrawn inclusive. For the withdrawal range of 31 to 149 steps inclusive the REFERENCE POSITION is defined as the individual rod calibration curve noting indicated analog rod position vs indicated group demand counter position (Figure B 3/4.1-1). Comparison of the indicated analog rod position to the calibration curve is sufficient to allow determination that a control rod is indeed misaligned from its bank. Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the insertion limits.

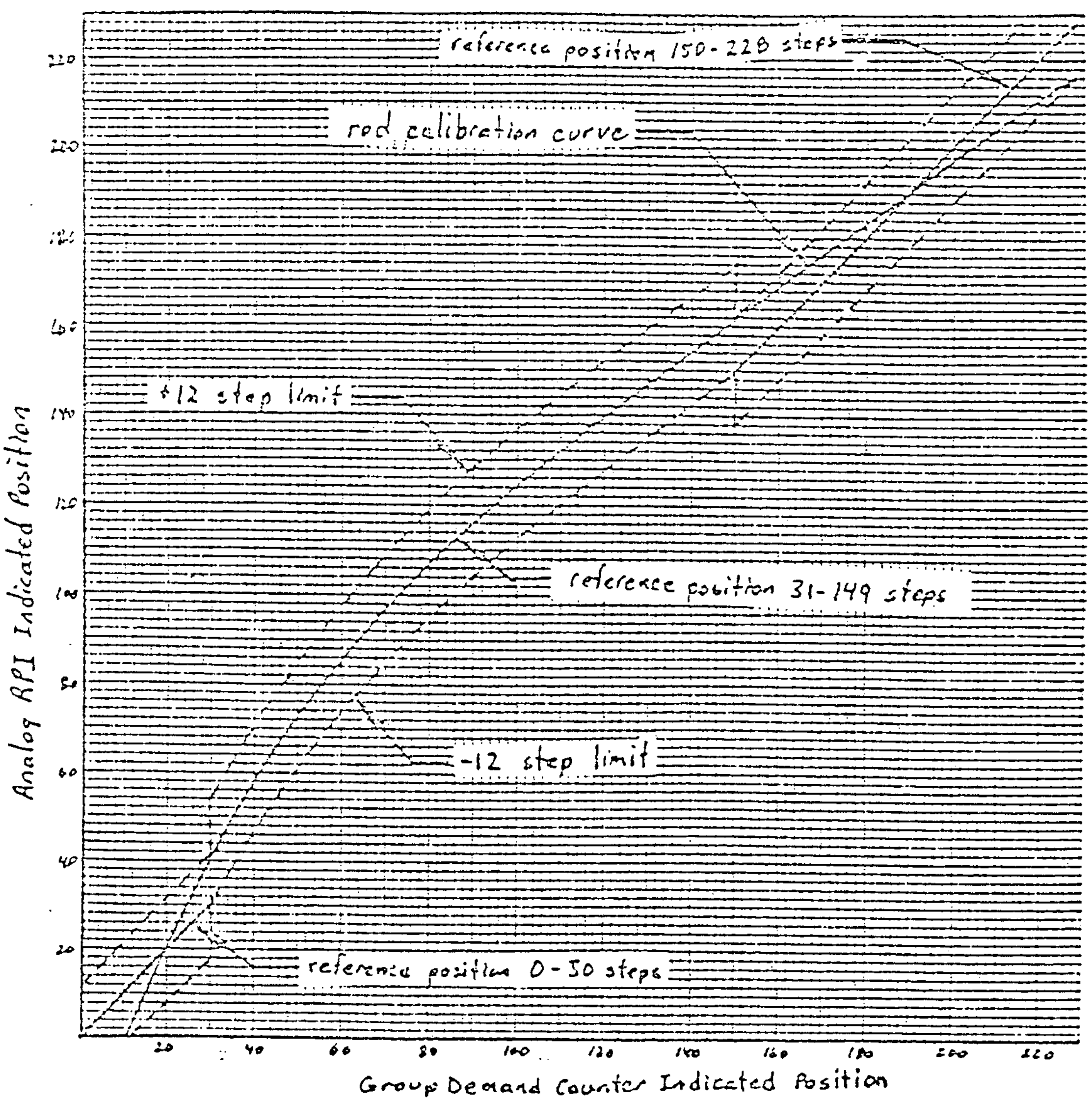


Figure B3/4.1-1 "Typical ARPI vs. Group Demand Counter Indicated Position"

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DIVISION OF NUCLEAR POWER

AUG 3 '81

PRW ✓

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RAS xc 8/3
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ARMS xc 8/3

8/4

L00 810803075

Westinghouse Electric Corporation
Water Reactor Divisions
Nuclear Service Division
Box 2728
Pittsburgh Pennsylvania 15230

July 23, 1981
TVA-81-28

Mr. H. J. Green, Director
of Nuclear Power
Tennessee Valley Authority
1750 Chesnut Street Tower II
Chattanooga, Tennessee 37401

Dear Mr. Green:

Tennessee Valley Authority
Sequoyah Unit 1
REVISED ANALOG ROD POSITION INDICATION SYSTEM TECHNICAL SPECIFICATION

Attached for your information is the Standardized Technical Specifications revised by Westinghouse to allow continued operation by plants with the Analog Rod Position Indication System (ARPI). These specs were revised to address NRC and plant concerns about the accuracy and usefulness of the ARPI. An operating plant has had difficulty in maintaining the ARPI within Tech Spec required minimums. Specifically, work was performed allowing an increase in the inaccuracy of the APRI and an increase in the indicated misalignment allowed. However, this work was very plant and cycle specific and is heavily dependent on the size of the DNBR margin present in the cycle design. Recognizing that this method would not allow a generic solution to the problem of large ARPI inaccuracies, work was performed to determine what changes, if any, could be made to the plant Tech Specs to reflect the real safety requirements of the ARPI. After discussion with the NRC the attached suggested revisions were developed.

Page 1 of the attachment provides a new defined term to be included in the Tech Spec Definitions section. The term defines what will be considered the ARPI's Reference Position. The revised specs are based on the following:

1. Shutdown Banks and Control A and B positions need to be known accurately in a very limited range, near the top and bottom of the core.

2. Control Banks C and D positions need to be accurately known at the bottom of the core and from somewhat below the Full Power insertion Limits (~150 steps) to the top of the core.

3. Recognizing that the ARPI is very temperature sensitive, immediate verification of position after rod movement is shifted from the ARPI to the group step counters with subsequent verification by the ARPI after temperature equilibration.

4. Detection of a misaligned rod is primarily limited to Control Banks C and D and through the use of the Reference Position.

Pages 2, 3 and 4 of the attachment present the revised current NRC spec for a misaligned rod. Westinghouse recommends the use of this spec to assure an adequate response to a misaligned rod, including the evaluation of the transients listed on page 4. Pages 5 and 6 list the revised accuracy and operability requirements for the ARPI and the group demand counters. Page 7 is a revision of the NRC spec on RPI operability when not critical but with the trip breakers closed. The spec has been revised to place reliance on the group step counters. Pages 8 and 9 are revised insertion limit specs noting the use of the group step counters with ARPI verification. Pages 10 and 11 provide revised Bases for the attached Tech Specs revisions. Finally, page 12 provides a typical figure defining the Reference Position for a Control C or D Bank and is referenced in the attached Bases.

The attached have been informally reviewed by M. Duenfeld of the Core Performance Branch of the NRC and have been found to be acceptable. The Tech Specs should be included in the plant specific Tech Specs. It is believed that the attached will decrease the number of LERs filed and remove some of the problems associated with this system. These recommended changes should be made to your plant Tech Specs as soon as reasonably possible. If you have any questions please contact the undersigned.

Very truly yours,

J. C. Miller, Manager
Operating Plant Service
Southern Region

Attachment

cc: R. U. Mathieson

REFERENCE POSITION

Analog Rod Position Indication System REFERENCE POSITION is defined as:

a. For all Shutdown Banks, Control Banks A and B, and the Part Length Banks; the group demand counter indicated position between 0 and 30 steps withdrawn inclusive and between 200 and 228 steps withdrawn inclusive.

b. For Control Banks C and D; the group demand counter indicated position between 0 and 30 steps withdrawn inclusive and between 150 and 228 steps withdrawn inclusive. For the withdrawal range of 31 to 149 steps inclusive the REFERENCE POSITION shall be the individual rod calibration curve noting indicated analog rod position vs indicated group demand counter position.

REACTIVITY CONTROL SYSTEMS

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

GROUP HEIGHT

LIMTING CONDITION FOR OPERATION

3.1.3.1 All full length (shutdown and control) rods, and all part length rods which are inserted in the core, shall be OPERABLE and positioned within ± 12 steps (indicated position) of the REFERENCE POSITION corresponding to the group demand counter position within one hour after rod motion.

APPLICABILITY: MODES 1* and 2*.

ACTION:

a. With one or more full length rods inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in HOT STANDBY within 6 hours.

b. With more than one full or part length rod inoperable or misaligned from the REFERENCE POSITION by more than ± 12 steps (indicated position), be in HOT STANDBY within 6 hours.

c. With one full or part length rod inoperable due to causes other than addressed by ACTION a, above, or misaligned from its REFERENCE POSITION by more than ± 12 steps (indicated position), POWER OPERATION may continue provided that within one hour either:

   1. The rod is restored to OPERABLE status within the above alignment requirements, or

   2. The remainder of the rods in the bank with the inoperable rod are aligned to within ± 12 steps of the inoperable rod while maintaining the rod sequence and insertion limits of Figures (3.1-1) and (3.1-2); the THERMAL POWER level shall be restricted pursuant to Specification (3.1.3.6) during subsequent operation, or

   3. The rod is declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. POWER OPERATION may then continue provided that:

*See Special Test Exceptions 3.10.2 and 3.10.3.

a) A reevaluation of each accident analysis of Table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions.

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

c) A power distribution map is obtained from the movable incore detectors and $F_Q(Z)$ and $F^N_{\Delta H}$ are verified to be within their limits within 72 hours.

d) The THERMAL POWER level is reduced to less than or equal to 75% of RATED THERMAL POWER within one hour and within the next 4 hours the high neutron flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER. THERMAL POWER shall be maintained less than or equal to 75% of RATED THERMAL POWER until compliance with ACTIONS 3.1.3.1.c.3.a and 3.1.3.1.c.3.c above are demonstrated.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full and part length rod shall be determined to be within ± 12 steps (indicated position) of the REFERENCE POSITION corresponding to the group demand position at least once per 12 hours (allowing for one hour thermal soak after rod motion) except during time intervals when the Rod Position Deviation Monitor is inoperable, then verify the group positions at least once per 4 hours.

4.1.3.1.2 Each full length rod not fully inserted and each part length rod which is inserted in the core shall be determined to be OPERABLE by movement of at least 10 steps in any one direction at least once per 31 days.

TABLE 3.1-1

ACCIDENT ANALYSES REQUIRING REEVALUATION IN THE EVENT OF AN INOPERABLE FULL OR PART LENGTH ROD

Rod Cluster Control Assembly Insertion Characteristics

Rod Cluster Control Assembly Misalignment

Loss Of Reactor Coolant From Small Ruptured Pipes Or From Cracks In Large Pipes Which Actuates The Emergency Core Cooling System

Single Rod Cluster Control Assembly Withdrawal At Full Power

Major Reactor Coolant System Pipe Ruptures (Loss Of Coolant Accident)

Major Secondary System Pipe Rupture

Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEMS-OPERATING

LIMITING CONDITION FOR OPERATION

3.1.3.2 The shutdown, control and part length individual rod position indication system and the demand position indication system shall be OPERABLE and capable of determining the actual and demanded control rod positions, respectively, as follows:

Analog rod position indicators, within one hour after rod motion (allowance for thermal soak);

All Shutdown Banks - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Banks A and B - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Control Banks C and D - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 150-228 steps. ± 12 steps of the REFERENCE POSITION for withdrawal range of 31-149 steps.

All Part Length Banks - ± 12 steps of the group demand counters for withdrawal ranges of 0-30 steps and 200-228 steps.

Group demand counters; ± 2 steps

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With a maximum of one analog rod position indicator per bank inoperable either:

1. Determine the position of the non-indicating rod(s) indirectly by the movable incore detectors at least once per 8 hours and within one hour after any motion of the non-indicating rod which exceeds 24 steps in one direction since the last determination of the rod's position, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

b. With a maximum of one group demand position indicator per bank inoperable either:

1. Verify that all rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 12 steps (corrected indicated position) of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.2.1 Each analog rod position indicator shall be determined to be OPERABLE by verifying that the demand position indication system and the rod position indication system (by use of the REFERENCE POSITION) agree within 12 steps (allowing for one hour thermal soak after rod motion) at least once per 12 hours except during time intervals when the Rod Position Deviation Monitor is inoperable, then compare the demand position indication system and the rod position indication system (by use of the REFERENCE POSITION) at least once per 4 hours.

4.1.3.2.2 Each of the above required rod position indicator(s) shall be determined to be OPERABLE by performance of a CHANNEL FUNCTIONAL TEST at least once per 18 months.

REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEM-SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 The group demand position indicator shall be OPERABLE and capable of determining within $\pm$ 2 steps the demand position for each shutdown, control or part length rod not fully inserted.

APPLICABILITY: MODES 3*#, 4*# and 5*#

ACTION:

With less than the above required group demand position indicators(s) OPERABLE, immediately open the reactor trip system breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required group demand position indicator(s) shall be determined to be OPERABLE by movement of the associated control rod at least 10 steps in any one direction at least once per 31 days.

* With the reactor trip system breakers in the closed position.

See Special Test Exception 3.10.5

REACTIVITY CONTROL SYSTEMS

SHUTDOWN ROD INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown rods shall be fully withdrawn.

APPLICABILITY: MODES 1* and 2*#

ACTION:

With a maximum of one shutdown rod not fully withdrawn, except for surveillance testing pursuant to Specification (4.1.3.1.2), within one hour either:

a. Fully withdraw the rod, or

b. Declare the rod to be inoperable and apply Specification (3.1.3.1).

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown rod shall be determined to be fully withdrawn by use of the group demand counters, and verified by the analog rod position indicators within one hour after rod motion.

a. Within 15 minutes prior to withdrawal of any rods in control banks A, B, C or D during an approach to reactor criticality, and

b. At least once per 12 hours thereafter.

*See Special Test Exceptions 3.10.2 and 3.10.3

#With K_{eff} greater than or equal to 1.0

REACTIVITY CONTROL SYSTEMS

CONTROL ROD INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control banks shall be limited in physical insertion as shown in Figures (3.1-1) and(3.1-2).

APPLICABILITY: MODES 1* and 2*#.

ACTION:

With the control banks inserted beyond the above insertion limits, except for surveillance testing pursuant to Specification (4.1.3.1.2), either:

a. Restore the control banks to within the limits within two hours, or

b. Reduce THERMAL POWER within two hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the bank position using the above figures, or

c. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each control bank shall be determined to be within the insertion limits at least once per 12 hours, by use of the group demand counters and verified by the analog rod position indicators within one hour of rod motion, except during time intervals when the Rod Insertion Limit Monitor is inoperable, then verify the individual rod positions at least once per 4 hours.

*See Special Test Exceptions 3.10.2 and 3.10.3
#With K_{eff} greater than or equal to 1.0

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

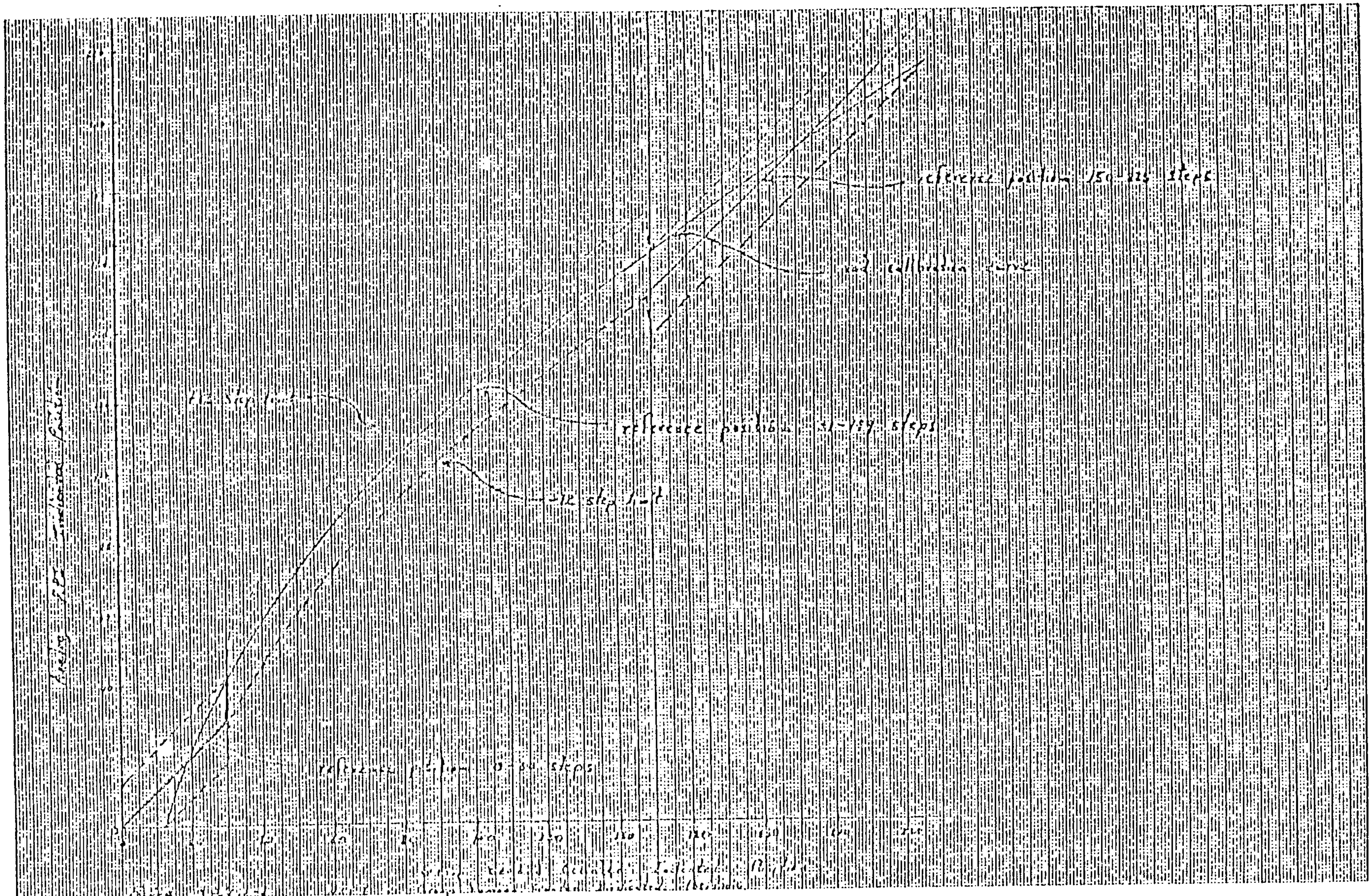
The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) limit the potential effects of rod misalignment on associated accident analyses. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. OPERABLE condition for the analog rod position indicators is defined as being capable of indicating rod position to within ± 12 steps of the reference position. For the Shutdown Banks, Control Banks A and B, and the Part Length Banks the REFERENCE POSITION is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 and 228 steps withdrawn inclusive. This permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these bank positions in these two areas satisfies all accident analysis assumptions concerning their position. For Control Banks C and D the REFERENCE POSITION is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 150 and 228 steps withdrawn inclusive. For the withdrawal range of 31 to 149 steps inclusive the REFERENCE POSITION is defined as the individual rod calibration curve noting indicated analog rod position vs indicated group demand counter position (Figure B 3/4.1-1). Comparison of the indicated analog rod position to the calibration curve is sufficient to allow determination that a control rod is indeed misaligned from its bank. Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the insertion limits.

The ACTION statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met. Misalignment of a rod requires measurement of peaking factors and a restriction in THERMAL POWER. These restrictions provide assurance of fuel rod integrity during continued operation. In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation.

Control rod positions and OPERABILITY of the rod position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCO's are satisfied.

(ALTERNATE)

The restriction prohibiting part length rod insertion ensures that adverse power shapes and rapid local power changes which may affect DNB considerations do not occur as a result of part-length rod insertion during operation.


reference position 150-225 steps
rod calibration curve
reference position 51-149 steps
12 step limit
reference position 0-50 steps

ITEM E2.2

Previously Identified

Open Item Nos. 6, 7, 16

T.S. Page 2-6

RPS - Steam Generator Level Setpoints - The latest version of the Watts Bar Nuclear Plant PLS lists the S.G. level setpoints as 12% between 0 and 30% load. From 30% the setpoints increase linearly to 54.9% at 100% load.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
14. Steam Generator Water Level--Low-Low	≥ 12% of narrow range span between 0 and 30% load, increasing linearly to ≥ 54.9% of narrow range span at 100% of nominal load	≥ 10.6% of narrow range span between 0 and 30% load increasing linearly to ≥ 53.5% of narrow range span at 100% of nominal load
15. Steam Generator Water Level-Low Coincident With Steam/Feedwater Flow Mismatch 12	≤ 40% of full steam flow at RATED THERMAL POWER coincident with steam generator water level ≥ 11% narrow range span between 0 and 30% load, increasing linearly to ≥ 54.9% of narrow range span at 100% of nominal load	≤ 42% of full steam flow at RATED THERMAL POWER coincident with steam generator water level ≥ 10.6% of narrow range span between 0 and 30% load, increasing linearly to 53.5% of narrow range span at 100% of nominal load
	≤ 40% of full steam flow at RATED THERMAL POWER	≤ 42.5% of full steam flow at RATED THERMAL POWER
16. Undervoltage-Reactor Coolant Pumps	≥ 4830 volts-each bus	≥ 4761 volts-each bus
17. Underfrequency-Reactor Coolant Pumps	≥ 56.0 Hz - each bus	≥ 55.9 Hz - each bus
18. Turbine Trip		
a. Low Trip System Pressure	≥ 45 psig	≥ 43 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
19. Safety Injection Input from ESF	N.A.	N.A.

Previously Identified

NRC Question D.9
Open Item No. 11

T.S. Page B 2-3

Bases for Reactor Trip System Instrumentation Setpoints - The statement in question:

> The functional capability at the specified trip settings is required for those anticipatory or diverse reactor trips for which no direct credit was assumed in the accident analysis to enhance the overall reliability of the reactor protection system.

was added to the discussions of source range intermediate range, overpower delta-T, pressurizer water level, and turbine trip reactor signals to provide information important to the operators, STAs, and engineering staff. Full knowledge of accident analysis assumptions is important in evaluation of system failures, USQDs, safety evaluations, etc. In other words, we consider it highly desirable to specify which trips were assumed and which trips were not assumed. Another method of accomplishing the same goal would be to rewrite the generic statement as:

> . . .or diverse reactor trips (source range, intermediate range, overpower delta-T, pressurizer water level, and turbine trip reactor trip signals) for which no . . . .

NOTE: This change is to the Bases, which 'are not part of these Technical Specifications,' therefore, this change should not present a problem to the NRC.

ULTIMATE HEAT SINK (Continued)

The limitations on maximum temperature are based on providing a 30-day cooling water supply to safety related equipment without exceeding their design basis temperature and is consistent with the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," March 1974.

3/4.7.6 FLOOD PROTECTION

The requirements for flood protection ensures that facility protective actions will be taken and operation will be terminated in the event of flood conditions. The elevations of plant features which could be affected by the submergence during floods vary from 714.5 ft mean sea level (MSL) (access to electrical conduits) to 760.5 ft MSL (emergency exits to diesel generator building). Plant grade is elevation 728 ft MSL. A Stage 1 flood warning is issued when the water at the intake pumping station is predicted to exceed 714.5 feet MSL USGS datum during October 1 through April 15, or 726.5 feet MSL USGS datum during April 15 through September 30. A Stage II flood warning is issued when the water at the intake pumping station is predicted to exceed 727 ~~726.5~~ feet MSL USGS datum. A maximum allowed water level of ~~726.5~~ feet MSL 727 USGS datum provides sufficient margin to ensure waves due to high winds cannot disrupt the flood mode preparation. A Stage I or Stage II flood warning requires the implementation of procedures which include plant shutdown. Further, in the event of a loss of communications simultaneous with a critical combination flood, headwaters, and/or seismically induced dam failure the plant will be shutdown and flood protection measures implemented.

3/4.7.7 CONTROL ROOM VENTILATION SYSTEM

The OPERABILITY of the control room ventilation system ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all credible accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR 50.

3/4.7.8 AUXILIARY BUILDING GAS TREATMENT SYSTEM

operating

The OPERABILITY of the auxiliary building gas treatment system ensures that radioactive materials leaking from the ECCS equipment within the pump room following a LOCA are filtered prior to reaching the environment. Operation of the system with the heaters ~~on~~ for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The operation of this system and the resultant effect on offsite dosage calculations was assumed in the accident analyses.

BASES

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor Trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their safety limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Protection System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Protection System which monitors numerous system variables, therefore, providing protection system functional diversity. The functional capability at the specified trip settings is required for those anticipatory or diverse reactor trips for which no direct credit was assumed in the accident analysis to enhance the overall reliability of the reactor protection system.

The Reactor Protection System initiates a turbine trip signal whenever reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive reactor system cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance for all trips including those trips assumed in the safety analyses.

Manual Reactor Trip

The Reactor Protection System includes manual reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a high and low range trip setting. The low setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the high setpoint trip provides protection during power operations to mitigate the consequences of a reactivity excursion from all power levels.

(Source range, intermediate range, over-power ΔT, pressurizer water level, and turbine trip reactor trip signals)

ITEM E2.4

Previously Identified

NRC Question D.9
Open Item No. 17

T.S. Page B 2-8

Basis for P-8 - Input for trip comes from low flow only. The reactor coolant pump breaker signal was deleted from the circuit at NRC's request.

Basis for P-7 - Same as P-8

Reference: TVA Drawing 47 W 611-99-2 R1, FSAR Figure 7.2-1 sheet 4 and 5.

Turbine Trip

A Turbine Trip initiates a Reactor trip. On decreasing power the Turbine trip is automatically blocked by P-9 (a power range channel level of approximately 50% of RATED THERMAL POWER); and on increasing power, reinstated automatically by P-9.

General Warning Alarm

A General Warning Alarm in both Solid State Trip System trains initiates a Reactor trip. The General Warning Alarm is activated in each train of the Solid State Trip System when the train is being tested or is otherwise inoperable. The General Warning Alarm trip provides protection for conditions under which both trains of the Trip System may be rendered inoperable.

Safety Injection Input from ESF

If a Reactor trip has not already been generated by the Reactor Trip System Instrumentation, the ESF automatic actuation logic channels will initiate a Reactor trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Trip System Interlocks

The Reactor Trip System Interlocks perform the following functions:

P-6 On increasing power P-6 allows the manual block of the Source Range Reactor trip and de-energizing of the high voltage to the detectors. On decreasing power, Source Range Level trips are automatically reactivated and high voltage restored.

P-7 On increasing power P-7 automatically enables Reactor trips on low flow in more than one reactor coolant loop, ~~more thn one reactor coolant pump breaker open~~, reactor coolant pump bus undervoltage and underfrequency, pressurizer low pressure and pressurizer high level. On decreasing power the above listed trips are automatically blocked. Fed to delai

P-8 On increasing power P-8 automatically enables Reactor trips on low flow in one or more reactor coolant loops, ~~and one or more reactor coolant pump breakers open~~. On decreasing power the P-8 automatically blocks the above listed trips.

P-9 On increasing power P-9 automatically enables Reactor trip on Turbine trip. On decreasing power P-9 automatically blocks the Reactor trip.

P-10 On increasing power P-10 allows the manual block of the Intermediate Range Reactor trip and the Flow Setpoint Power Range Reactor trip; and automatically blocks the Source Range Reactor trip and de-energizes the Source Range high voltage power. On decreasing power the Intermediate Range Reactor trip and the Low Setpoint Power Range Reactor trip are automatically reactivated. Provides input to P-7.

P-13 Provides input to P-7.

ITEM E2.5

Previously Identified

NRC Question D.13
Open Item Nos. 25.1, 26, 126

T.S. Pages 3/4 1-12, 3/4 1-13, 3/4 5-13

Maximum Water Temperature Surveillance for RWST - The maximum water temperature of 105°F is based on accident analysis for containment spray and it is appropriate to have an LCO for it in specification 3.5.5. However, the water temperature does not affect our shutdown capability required by specification 3.1.2.6. Therefore, the temperature limit in the LCO should be deleted.

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.6 As a minimum, the following borated water source(s) shall be OPERABLE as required by Specification 3.1.2.2:

a. A Boric Acid Storage System and at least one associated Heat Tracing System with:

   1) A minimum contained borated water volume of 6542 gallons,

   2) Between 20,000 and 22,500 ppm of boron, and

   3) A minimum solution temperature of 145°F.

b. The refueling water storage tank with:

   1) A contained borated water volume of between 370,000 and 375,000 gallons,

   2) Between 2000 and 2100 ppm of boron,

   3) A minimum solution temperature of 60°F, and

   ~~4) A maximum solution temperature of 100°F.~~ 105 New.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With the Boric Acid Storage System inoperable and being used as one of the above required borated water sources, restore the inoperable system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% delta k/k at 200°F; restore the Boric Acid Storage System to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the boron concentration in the water,

2) Verifying the contained borated water volume of the water source, and

3) Verifying the Boric Acid Storage System solution temperature when it is the source of borated water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is either less than 60°F or greater than ~~100°F~~.
105

MEW

EMERGENCY CORE COOLING SYSTEMS

3/4.5.5 REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.5 The refueling water storage tank (RWST) shall be OPERABLE with:

a. A contained borated water volume of between 370,000 and 375,000 gallons,

b. A boron concentration of between 2000 and 2100 ppm of boron,

c. A minimum water temperature of 60°F, and

d. A maximum water temperature of ~~100°~~F.
105

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION

With the RWST inoperable, restore the tank to OPERABLE status within 1 hour or be in a least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.5 The RWST shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the contained borated water volume in the tank, and

2) Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is either less than 60°F or greater than ~~100°~~F.
105

ITEM E2.6

Previously Identified

NRC Question D.20
Open Item Nos. 42.1, 42.2, 50.1, 73.1

T.S. Pages 3/4 3-16, 3/4 3-17, 3/4 3-26, 3/4 3-37

Safety Injection Functional Unit - As discussed with Fred Anderson of the STS section, we request the attached minor clarifications be made to the SI functional unit title.

Reference: TVA Drawing FSAR Figure 7.2-1 sheet 8.

TABLE 3.3-3

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (Reactor Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water, Turbine Trip)					
a. Manual Initiation	2	1	2	1, 2, 3, 4	18
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
c. Containment Pressure-High	3	2	2	1, 2, 3	15*
d. Pressurizer Pressure - Low	3	2	2	1, 2, 3#	15*
e. Differential Pressure Between Steam Lines - High	3/steam line	2/steam line any steam line	2/steam line	1, 2, 3##	15*
f. Steam Flow in Two Steam Lines-High	2/steam line	1/steam line any 2 steam lines	1/steam line	1, 2, 3##	15*

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (Reactor Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water, Turbine Trip) (Continued)					
Coincident With Either					
T_{avg}--Low-Low	1 T_{avg}/loop	1 T_{avg} any 2 loops	1 T_{avg} any 3 loops	1, 2, 3##	15*
Or					
Steam Line Pressure-Low	1 pressure/ loop	1 pressure any 2 loops	1 pressure any 3 loops	1, 2, 3##	15*
2. Containment Spray					
a. Manual Initiation	2	1 with 2 coincident switches	2	1, 2, 3, 4	18
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
c. Containment Pressure--High-High	4	2	3	1, 2, 3	16

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Safety Injection (Reactor Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water, Turbine Trip)		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High	≤ 1.54 psig	≤ 1.7 psig
d. Pressurizer Pressure--Low	≥ 1870 psig	≥ 1859 psig
e. Differential Pressure Between Steam Lines--High	≤ 100 psi	≤ 112 psi
f. Steam Flow in Two Steam Lines--High	≤ A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load	≤ A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load
Coincident With		
Either T_{avg}--Low-Low,	≥ 550°F	≥ 548°F
or Steam Line Pressure--Low	≥ ~~575~~ 675 psig	≥ 655 psig

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection (Reactor Trip Feedwater, Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water, Turbine Trip)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
c. Containment Pressure-High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
d. Pressurizer Pressure-Low	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Differential Pressure Between Steam Lines--High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
f. Steam Flow in Two Steam Lines--High Coincident With	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
Either								
1. T_{avg}--Low-Low, or	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
OR								
2. Steam Line Pressure--Low	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2. Containment Spray								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
c. Containment Pressure--High-High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3

Previously Identified

NRC Question D.19
Open Item 48

T.S. Page 3/4 3-22

LOSS OF VOLTAGE/DEGRADED VOLTAGE TECHNICAL SPECIFICATIONS - The action statement for the loss of voltage protection channels should be 18*. A total of only 48 hours is allowed for repair and no more than one channel can be out-of-service at a time. Startup operation should be allowed to proceed parallel with the repair effort. The decision to startup would only be made if the 48 hour limit could be met (note: this statement is true if only economics are considered). We realize that this situation is probably a rather infrequent event but TVA should not suffer an economic penalty when no safety concern is involved. Consideration must be given to the fact that the loss of one hours' generation from a plant like Watts Bar costs TVA an additional $22,000. There is no safety concern because the startup procedure itself, from MODE 3 to power operation, takes an average 24 hours (this limits the time of power with degraded equipment) and the fact that the second level of undervoltage protection (degraded voltage) provides additional protection for the loss of voltage coincident with a safety injection signal event.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
b. RWST Level - Low	4	2	3	1, 2, 3, 4	16
Coincident With					
Containment Sump Level - High	4	2	3	1, 2, 3, 4	16
And					
Safety Injection	See Item 1 above for Safety Injection initiating functions and requirements				
8. 6.9 kV Shutdown Board					
a. Loss of Power					
1) Start Diesel Generator	2/Shutdown Board	1/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18~~*~~
2) Load Shedding	2/Shutdown Board	1/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18~~*~~
b. Degraded Voltage					
1) Voltage Sensor	3/Shutdown Board	2/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18*
2) Diesel Generator Start and Load Shedding Timer	2/Shutdown Board	1/Shutdown Board	1/Shutdown Board	1, 2, 3, 4	18*
3) Safety Injection Degraded Voltage Enable Timer	2/Shutdown Board	1/Shutdown Board	1/Shutdown Board	1, 2, 3, 4	18*

ITEM E2.8

Previously Identified

NRC Question C.13
Open Item Nos. 82, 82.1, 82.2

T.S. Pages 3/4 3-57

Pressurizer Relief Tank Level

The RCS temperature indicated in the auxiliary control room is hot leg not the average temperature as presently shown in table 4.3-6.

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Source Range Nuclear Flux	M	N.A.
2. Reactor Trip Breaker Indication	M	N.A.
3. Reactor Coolant Temperature - ~~Average~~ Hot Leg	M	R
4. Pressurizer Pressure	M	R
5. Pressurizer Level	M	R
6. Steam Generator Pressure	M	R
7. Steam Generator Level	M	R
8. Control Rod Bottom Bistables	M	R
9. RHR Flow Rate	M	R
10. RHR Temperature	M	R
11. Auxiliary Feedwater Flow Rate	M	R
12. Pressurizer Relief Tank Pressure	M	R
13. Containment Pressure	M	R

Feed to take care

Previously Identified

Open Item No. 88

T.S. Pages 3/4 3-64 through 72

Fire detector list

Attached is a revised version of table 3.3-11.

JAN 25 1982

C071

TABLE 3.3-11

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
1	Diesel Gen. Rm. 2B-B, El. 742			5	
2	Diesel Gen. Rm. 2B-B, El. 742			5	
3	Diesel Gen. Rm. 1B-B, El. 742			5	
4	Diesel Gen. Rm. 1B-B, El. 742			5	
5	Diesel Gen. Rm. 2A-A, El. 742			5	
6	Diesel Gen. Rm. 2A-A, El. 742			5	
7	Diesel Gen. Rm. 1A-A, El. 742			5	
8	Diesel Gen. Rm. 1A-A, El. 742			5	
9	Lube Oil Storage Rm. El. 742			1	
10	Lube Oil Storage Rm. El. 742			1	
11	Fuel Oil Transfer Rm. El. 742			1	
12	Fuel Oil Transfer Rm. El. 742			1	
13	Diesel Gen. Corridor, El. 742			6	
14	Air Intake & Exhaust Rm. 2B, El. 760.5			9	
15	Air Intake & Exhaust Rm. 1B, El. 760.5			9	
16	Air Intake & Exhaust Rm. 2A, El. 760.5			9	
17	Air Intake & Exhaust Rm. 1A, El. 760.5			9	
18	Diesel Gen. 2B-B Relay Bd. El. 742	3			
19	Diesel Gen. 1B-B Relay Bd. El. 742	3			
20	Diesel Gen. 2A-A Relay Bd. El. 742	3			
21	Diesel Gen. 1A-A Relay Bd. El. 742	3			
22	Diesel Gen. Board Rm. 2B-B, El. 742	2			
23	Diesel Gen. Board Rm. 2B-B, El. 742			2	
24	Diesel Gen. Board Rm. 1B-B, El. 742	2			
25	Diesel Gen. Board Rm. 1B-B, El. 742			2	
26	Diesel Gen. Board Rm. 2A-A, El. 742	2			
27	Diesel Gen. Board Rm. 2A-A, El. 742			2	

JAN 25 1982

TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
28	Diesel Gen. Board Rm. 1A-A, El. 742	2			
29	Diesel Gen. Board Rm. 1A-A, El. 742			2	
30	Cable Spreading Rm. C7-C11, El. 729	14			
31	Cable Spreading Rm. C7-C11, El. 729	14			
32	Cable Spreading Rm. C7-C11, El. 729	14			
33	Cable Spreading Rm. C7-C11, El. 729	14			
34	Cable Spreading Rm. C3-C7, El. 729	14			
35	Cable Spreading Rm. C3-C7, El. 729	14			
36	Diesel Gen. Bldg Tr A Conduit Entry	1			
37	Diesel Gen. Bldg Tr A Conduit Entry	1			
38	NOT USED				
39	Cont. Spray Pump 1A-A, El. 676	2			
40	Cont. Spray Pump 1B-B, El. 676	2			
41	CONT. SPRAY PUMP 2A-A				
42	CONT. SPRAY PUMP 2B-B				
43	RHR Pump 1A-A, El. 676	2			
44	RHR Pump 1B-B, El. 676	2			
45	RHR PUMP 2A-A				
46	RHR PUMP 2B-B				
47	Aux. Bldg. Corridor, El. 676	10			
48	Corridor, Control Bldg. El. 692	4			
49	Corridor, Control Bldg. El. 692	4			
50	Mech. Equip. Rm. Col. C1, El. 692	2			
51	Mech. Equip. Rm. Col. C1, El. 692			2	
52	Mech. Equip. Rm. Col. 3, El. 692	2			
53	Mech. Equip. Rm. Col. 3, El. 692			2	
54	250-V Batt. Rm. 1, El. 692	3			
55	250-V Batt. Rm. 1, El. 692			3	
56	250-V Batt. Bd. Rm. 1, El. 692	2			
57	250-V Batt. Bd. Rm. 1, El. 692	2			
58	250-V Batt. Bd. Rm. 2, El. 692	2			
59	250-V Batt. Bd. Rm. 2, El. 692	2			
60	250-V Batt. Rm. 2, El. 692	3			
61	250-V Batt. Rm. 2, El. 692			3	

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
62	24-V & 48-V Batt. Rm. El. 692	3			
63	24-V & 48-V Batt. Rm. El. 692			3	
64	24-V & 48-V Batt. Bd. Rm. El. 692	2			
65	24-V & 48-V Batt. Bd. Rm. El. 692	2			
66	Communications Rm. El. 692	4			
67	Communications Rm. El. 692	4			
68	Mech. Equip. Rm. El. 692	2			
69	Mech. Equip. Rm. El. 692			2	
• 70	Aux. Bldg. A5-A11, Col. W-X, El. 692	~~0~~ 5			
• 71	Aux. Bldg. A5-A11, Col. W-X, El. 692	~~0~~ 5			
72	Aux. FW Pump Turbine 1A-S, El. 692	1			
73	Aux. FW Pump Turbine 1A-S, El. 692			1	
74	AUX. FW PUMP TURBINE 2A-S	1			
75	AUX. FW PUMP TURBINE 2A-S			1	
76	S.I. & Charging Pump Rms. El. 692	5			
77	S.I. Pump Rm. 1A, El. 692			1	
78	S.I. Pump Rm. 1B, El. 692			1	
• 79	Charging Pump Rm. 1C, El. 692			1	
• 80	Charging Pump Rm. 1B, El. 692			1	
• 81	Charging Pump Rm. 1A, El. 692			1	
82	UNIT 2 S.I. AND CHGRS PUMP RMS	5			
83	S.I. PMP RM 2A			1	
84	S.I. PMP RM 2B			1	
85	CHARGING PUMP ROOM 2A			1	
86	CHARGING PUMP ROOM 2B			1	
87	CHARGING PUMP ROOM 2C			1	
88	Aux. Bldg. Corridor A1-A8, El. 692	8			
89	Aux. Bldg. Corridor A1-A8, El. 692	8			
90	Aux. Bldg. Corridor A8-A15, El. 692	8			
91	Aux. Bldg. Corridor A8-A15, El. 692	8			
92	Aux. Bldg. Corridor Col. U-W, El. 692	4			
93	Aux. Bldg. Corridor Col. U-W, El. 692	4			
• 94	Valve Galley, El. 692	2			
• 95	Valve Galley, El. 692	2			
96	UNIT 2 PIPE GALLERY EL. 692	2			
97	UNIT 2 PIPE GALLERY EL. 692	2			

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
98	Cntmt Purge Air Fltr., El. 713		2		
99	Cntmt Purge Air Fltr., El. 713		2		
102	Pipe Gallery, El. 713	4			
103	Pipe Gallery, El. 713	4			
104	UNIT 2 PIPE GALLERY EL. 713	4			
105	UNIT 2 PIPE GALLERY EL. 713	4			
106	Aux. Building, El. 713	8			
107	Aux. Building, El. 713	8			
108	Radio Chemical Lab. Area, El. 713	3			
109	Radio Chemical Lab. Area, El. 713	3			
110	Aux. Bldg. A1-A8, Col. Q-U, El. 713	~~10~~ 12			
111	Aux. Bldg. A1-A8, Col. Q-U, El. 713	~~10~~ 13			
112	Aux. Bldg. A8-A15, Col. Q-U, El. 713	9			
113	Aux. Bldg. A8-A15, Col. Q-U, El. 713	9			
114	Waste Packaging Area El. 729	3			
115	Waste Packaging Area El. 729	3			
116	Cask Loading Area El. 729	2			
117	Cask Loading Area El. 729	2			
118	New Fuel Storage Area El. 729	~~2~~ 4			
120	Aux. Bldg. Gas Trtmt. Fltr. El. 729		1		
121	Aux. Bldg. Gas Trtmt. Fltr. El. 729		1		
122	ADDITIONAL EQUIP BLDG UNIT 1 EL 729	6			
123	Volume Cont. Tank Rm. 1A, El 713	1			
124	Additional Equip. Bldg. El.729	6			
125	Volume Cont. Tank Rm. 1A, El 713	1			
126	FUEL TRANSFER Room UNIT 2	2			
127	FUEL TRANSFER Room UNIT 2	2			
128	Fuel Transfer Valve Rm. El.729	2			
129	Fuel Transfer Valve Rm. El.729	2			
130	VENTILATION & PURGE AIR Room UNIT 2	3			
131	VENTILATION & PURGE AIR Room UNIT 2	3			
132	Ventilation & Purge Air Rm. El. 737	3			
133	Ventilation & Purge Air Rm. El.737	3			
134	Aux. Bldg. A5-A11, Col. U-W, El. 737	7			

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable Ionization	Photoelectric	Thermal	Infrared
135	Aux. Bldg. A5-A11, Col. U-W, El. 737	7			
136	Heating & Vent. Rm. El. 737	4			
137	Heating & Vent. Rm. El. 737	4			
~~138~~	~~HEATING & VENT Rm. UNIT 2 EL. 737~~	~~4~~			
139	HEATING & VENT Rm. UNIT 2 EL. 737	4			
140	Hot Instr. Rm. El. 737	1			
141	Hot Instr. Rm. El. 737	1			
142	Aux. Bldg. A1-A8, Col. Q-U, El. 737	12			
143	Aux. Bldg. A1-A8, Col. Q-U, El. 737	12			
144	Aux. Bldg. A8-A15, Col. Q-U, El. 737	9			
145	Aux. Bldg. A8-A15, Col. Q-U, El. 737	9			
146	N_2 Storage Area, El. 729	4			
~~147~~	~~AUX. BLDG. GAS TRTMT FLTR UNIT 2~~	~~1~~			
148	AUX. BLDG. GAS TRTMT FLTR UNIT 2	1			
149	Cable Spreading Rm. C3-C7, El. 729	~~15~~ 14			
150	Cable Spreading Rm. C3-C7, El. 729	~~15~~ 14			
151	VOLUME CONTROL TANK Room 2A	1			
~~152~~	~~VOLUME CONTROL TANK Room 2A~~	~~1~~			
153	Add. Eqpt. Bldg. El. 763.5	4			
154	ADD. EQPT. Bldg. UNIT 1 EL. 763.5	6			
155	Refuel Rm. El. 757	~~19~~ 20			
156	RB Access Rm. El. 757	2			
157	RB Access Rm. El. 757	2			
~~158~~	~~RB Access Rm UNIT 2~~	~~2~~			
159	RB Access Rm UNIT 2	2			
160	SG Blwdn. Rm. El. 757	4			
161	SG Blwdn. Rm. El. 757	4			
162	EGTS Rm. El. 757	~~4~~ 3			
163	EGTS Rm. El. 757	~~4~~ 3			
164	EGTS Fltr. A El. 757		1		
165	EGTS Fltr. A El. 757		1		
166	EGTS Fltr. B El. 757		1		
167	EGTS Fltr. B El. 757		1		
168	RB Eqpt. Hatch El. 757	1			
169	RB Eqpt. Hatch El. 757	1			
170	RB Eqpt. HATCH UNIT 2	1			
~~171~~	~~RB Eqpt HATCH UNIT 2~~	~~1~~			

TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
172	Mech. Eqpt. Rm. El. 757	1			
173	Mech. Eqpt. Rm. El. 757	1			
174	MECH Eqpt Rm UNIT 2	1			
175	MECH Eqpt. Rm UNIT 2	1			
176	480-V Shtdn. Bd. Rm. 1A1 El. 757	2			
177	480-V Shtdn. Bd. Rm. 1A1 El. 757	2			
178	480-V Shtdn. Bd. Rm. 1A2 El. 757	2			
179	480-V Shtdn. Bd. Rm. 1A2 El. 757	2			
180	480-V Shtdn. Bd. Rm. 1B1 El. 757	2			
181	480-V Shtdn. Bd. Rm. 1B1 El. 757	2			
182	480-V Shtdn. Bd. Rm. 1B2 El. 757	~~2~~ 3			
183	480-V Shtdn. Bd. Rm. 1B2 El. 757	~~2~~ 3			
184	6.9-KV Shtdn. Bd. Rm. A El. 757	6			
185	6.9-KV Shtdn. Bd. Rm. A El. 757	6			
186	6.9-KV Shtdn. Bd. Rm. B El. 757	6			
187	6.9-KV Shtdn. Bd. Rm. B El. 757	6			
188	480-V Shtdn. Bd. Rm. 2A1 El. 757	2			
189	480-V Shtdn. Bd. Rm. 2A1 El. 757	2			
190	480-V Shtdn. Bd. Rm. 2A2 El. 757	~~2~~ 3			
191	480-V SHTDN BD Rm 2A2	3			
192	480-V Shtdn. Bd. Rm. 2B1 El. 757	2			
193	480-V Shtdn. Bd. Rm. 2B1 El. 757	2			
194	480-V Shtdn. Bd. Rm. 2B2 El. 757	2			
195	480-V Shtdn. Bd. Rm. 2B2 El. 757	2			
196	125-V Batt. Bd. Rm. I El. 757	2 ~~1~~			
198	125-V Batt. Bd. Rm. II El. 757	~~1~~ 2			
200	125-V Batt. Bd. Rm. III El. 757	~~1~~ 2			
202	125-V Batt. Bd. Rm. IV El. 757	~~1~~ 2			
~~203~~	~~125-V Batt. Bd. Rm. IV El. 757~~ not used	~~1~~			
204	Aux. CR El. 757	2			
205	Aux. CR El. 757	2			
206	Aux. CR Inst. Rm. 1A El. 757	1			

TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
207	Aux. CR Inst. Rm. 1A El. 757	1			
208	Aux. CR Inst. Rm. 1B El. 757	1			
209	Aux. CR Inst. Rm. 1B El. 757	1			
210	Aux. CR Inst. Rm. 2A El. 757	1			
211	Aux. CR Inst. Rm. 2A El. 757	1			
212	Aux. CR Inst. Rm. 2B El. 757	1			
213	Aux. CR Inst. Rm. 2B El. 757	1			
214	Mech. Eqpt. Rm. El. 755	5			
215	Mech. Eqpt. Rm. El. 755	5			
216	CR Fltr. A El. 755	1			
217	CR Fltr. A El. 755	1			
218	CR Fltr. B El. 755	1			
219	CR Fltr. B El. 755	1			
220	Main CR El. 755	25			
221	Rcd. Stor. Vault El. 755	2			
222	Rcd. Stor. Vault El. 755			2	
223	PSO Engr. Shop El. 755	1			
224	PSO Engr. Shop El. 755			1	
225	Relay Bd. Rm. El. 755	~~13~~ ~~12~~ 11			
226	Electric Cont. Bds. El. 755	11 ~~10~~			
227	Oper. Living Area El. 755	7		1	
228	Oper. Living Area El. 755			8	
229	Main Cont. Bds.	~~5~~ 8			
230	Aux. CR Bds. L-4A, 4C, 11A & 10 El. 755	~~4~~ 11			
231	Add. Eqpt. Bldg. El. 786.5	4			
232	Add. Eqpt. Bldg. El. 775.25	4			
233	CONT. ROD DR. Eqpt Rm UNIT 2	4			
234	CONT. ROD DR. Eqpt. Rm UNIT 2	4			
235	Ctrl. Rod Dr. Eqpt. Rm. El. 782	4			
236	Ctrl. Rod Dr. Eqpt. Rm. El. 782	4			
237	Mech. Eqpt. Rm. El. 772	2			
238	Mech. Eqpt. Rm. El. 772	2			
239	~~MECH. Eqpt. Rm. UNIT 2 EL. 772~~	2			
240	MECH. Eqpt. Rm. UNIT 2 EL. 772	2			
241	480-V XFMR Rm. 1A El. 782	3			
242	480-V XFMR Rm. 1A El. 782	3			
243	480-V XFMR Rm. 1B El. 782	3			
244	480-V XFMR Rm. 1B El. 782	3			

TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
245	480V TRANSFORMER Rm 2A	3			
246	480 V TRANSFORMER Rm 2A	3			
247	480V TRANSFORMER Rm 2B	3			
248	480 V TRANSFORMER Rm 2B	3			
249	125-V Batt. Rm. I El. 782	~~1~~ 2			
~~250~~	~~125-V Batt. Rm. I El. 782~~ ~~not used~~	~~1~~			
251	125-V Batt. Rm. II El. 782	~~1~~ 2			
~~252~~	~~125-V Batt. Rm. II El. 782~~ ~~not used~~	~~1~~			
253	125-V Batt. Rm. II El. 782	~~1~~ 2			
~~254~~	~~125-V Batt. Rm. III El. 782~~	~~1~~			
255	125-V Batt. Rm. IV El. 782	~~1~~ 2			
~~256~~	~~125-V Batt. Rm. IV El. 782~~	~~1~~			
257	480-V Bd. Rm. 1B El. 782	4			
258	480-V Bd. Rm. 1B El. 782	4			
259	480-V Bd. Rm. 1A El. 782	4			
260	480-V Bd. Rm. 1A El. 782	4			
261	480-V BD. Rm 2A	4			
262	480-V BD. Rm 2A	4			
263	480-V BD. Rm 2B	4			
264	480-V BD. Rm 2B	4			
265	Lube Oil Purif. Rm. El. 708			1	
266	Lube Oil Purif. Rm. El. 708			1	
267	Aux. Instr. Rm. El. 708	8			
268	Aux. Instr. Rm. El. 708			~~8~~ 9	
269	Computer Rm. El. 708	4			
270	Computer Rm. El. 708			4	
271	AUX. INSTR Rm UNIT 2	8			
272	AUX. INSTR Rm UNIT 2			9	
273	COMPUTER Room CORRIDOR	3			
277	ERCW Pumping Sta. El. ~~704~~ 722	~~21~~ 17			
296	Aux. CR Bds. L-4B, 4D, & 11B El. 755	~~8~~ 8			
297	UNIT 2 MAIN CONT Rm BOARD	8			
298	COMMON MAIN CONTROL Rm BDS & M-15	11			
352	Lwr. Compt. Coolers, El. 716		4		
354	Upr. Compt. Coolers, El. 801		4		

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
356	RCP 2, El. 716			2	
357	RCP 2, El. 716				2
360	RCP 1, El. 716			2	
361	RCP 1, El. 716				2
364	RCP 3, El. 716			2	
365	RCP 3, El. 716				2
368	RCP 4, El. 716			2	
369	RCP 4, El. 716				2
372	Reactor Bldg. Annulus		18		
373	Reactor Bldg. Annulus		18		
384	Turbine Head End, El. 729			5	
386	Auxiliary Boiler El. 755			11	
387	Turbine Cont. Bldg. Wall, El. 729			~~18~~ 22	
388	Main Turbine Oil Tank, El. 729			8	
390	H_2 Seal Oil Unit, El. 729			2	
392	MFPT 1B Oil Tank, El. 729			4	
393	MFPT 1B Oil Tank, El. 729			4	
396	~~Lube Oil Dispensing Rm. El. 729~~ MOTOR DRIVEN FW PUMP UNIT 1			4 ~~2~~	
397	Paint Shop & Storage, El. 729			6A	
398	Paint Shop & Storage, El. 741			5A	
~~405~~	~~INTAKE PUMP STATION EL. 711.0~~	~~5~~			
406	INTAKE PUMP STATION EL. 711.0	5			
412	DUPLEX RELAY BOARDS	4			

Previously Identified

NRC Question D.35
Open Item No. 103

T.S. Page 3/4 4-10

Pressurizer Heater Testing - Surveillance Requirement 4.4.3.3 requires that the heaters be demonstrated OPERABLE once per 18 months by manually transferring power from the normal to the emergency power supply and energizing the heaters. Surveillance Requirement 4.4.3.2 requires verification of heater capacity by current measurement when the heaters are energized. We consider that the requirements imposed by SR 4.4.3.3 are severe from an economic and safety viewpoint. We believe the problem can be resolved once a thorough understanding of our system and test technique are understood.

The normal and emergency power supply for the heaters are one in the same: the 6.9 kV shutdown boards. It is the power supply for the 6.9 kV shutdown boards that changes; offsite power is the preferred source and diesel generators are the emergency source. As part of the 18 month diesel generator testing (SR 4.8.1.1.2.d.7) a blackout coincident with a safety injection signal is simulated. Load shedding and subsequent re-energization of emergency loads are verified. At this time the emergency loads are powered from the emergency power source. However, it is impractical to load the heaters back on the 6.9 kV shutdown board and energize them because this test is typically done during refueling and the pressurizer is empty. The heaters would be damaged if energized in a dry environment. To impose this requirement would limit the flexibility of scheduling the BO/SI test, it could only be scheduled when the pressurizer is full.

We believe verification of the load shed of heaters during this test, with subsequent verification of heater breaker operation before startup (SR 4.4.3.2) satisfies the requirements. The heaters do not 'see' whether the shutdown board is supplied from the normal or emergency power source.

Therefore, the phrase 'and energizing the heaters' should be deleted from SR 4.4.3.3.

References: TVA Drawings: 45W724-1 R6 (FSAR Figure 8.3-16)
45W724-4 R6 (FSAR Figure 8.3-17)
45W760-211-8 (FSAR Figure 8.3-6)
45W760-211-10 (FSAR Figure 8.3-8)
47W611-68-2
45W760-68-4

REACTOR COOLANT SYSTEM

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1656 cubic feet equivalent to an indicated level of less than or equal to 92% on narrow range indication, and at least two groups of pressurizer heaters each having a capacity of at least 150 kW.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one group of pressurizer heaters inoperable, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the Reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by energizing the heaters and measuring circuit current at least once per 92 days.

4.4.3.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by manually transferring power from the normal to the emergency power supply. ~~and energizing the heaters.~~

Previously Identified

Open Item No. 107

T.S. Page 3/4 4-16

Preservice Inspection of Steam Generator Tubes - The standard technical specification for preservice inspection is not consistent with Regulatory Guide 1.83. Regulatory Guide 1.83 defines 'tube inspection' for U-bends as 'entry for the hot leg side with examination from the point of entry completely around the U-bend to the top support of the cold leg' (see footnote 3 on page 1.83-3 of the Regulatory Guide). The Regulatory Guide does not specify when the preservice inspection needs to be performed other than prior to service (R.G. Section C.3.a). TVA has performed the preservice inspection in accordance with Regulatory Guide 1.83. The technical specification must be changed to be consistent with the Regulatory Guide or TVA will be forced to perform a second inspection.

Reference: Regulatory Guide 1.83, Revision 1 (July 1975)

9) Preservice Inspection means a~~n~~ tube inspection of ~~the full length of~~ each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed ~~after the field hydrostatic test and~~ prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit and all tubes containing through-wall cracks) required by Table 4.4-2.

4.4.5.5 Reports

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2;

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission in a Special Report pursuant to Specification 6.9.2 within 12 months following the completion of the inspection. This Special Report shall include:

1) Number and extent of tubes inspected,

2) Location and percent of wall-thickness penetration for each indication of an imperfection, and

3) Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 and require prompt notification of the Commission shall be reported pursuant to Specification 6.9.1 prior to resumption of plant operation. The written followup of this report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
245	480V TRANSFORMER Rm 2A	3			
246	480 V TRANSFORMER Rm 2A	3			
247	480V TRANSFORMER Rm 2B	3			
248	480 V TRANSFORMER Rm 2B	3			
249	125-V Batt. Rm. I El. 782	~~1~~ 2			
~~250~~	~~125-V Batt. Rm. I El. 782~~ not used	~~1~~			
251	125-V Batt. Rm. II El. 782	~~1~~ 2			
~~252~~	~~125-V Batt. Rm. II El. 782~~ not used	~~1~~			
253	125-V Batt. Rm. II El. 782	~~1~~ 2			
~~254~~	~~125-V Batt. Rm. III El. 782~~	~~1~~			
255	125-V Batt. Rm. IV El. 782	~~1~~ 2			
~~256~~	~~125-V Batt. Rm. IV El. 782~~	~~1~~			
257	480-V Bd. Rm. 1B El. 782	4			
258	480-V Bd. Rm. 1B El. 782	4			
259	480-V Bd. Rm. 1A El. 782	4			
260	480-V Bd. Rm. 1A El. 782	4			
261	480-V BD. Rm 2A	4			
262	480-V BD. RM 2A	4			
263	480-V BD. Rm 2B	4			
264	480-V BD. Rm 2B	4			
265	Lube Oil Purif. Rm. El. 708			1	
266	Lube Oil Purif. Rm. El. 708			1	
267	Aux. Instr. Rm. El. 708	8			
268	Aux. Instr. Rm. El. 708			~~8~~ 9	
269	Computer Rm. El. 708	4			
270	Computer Rm. El. 708			4	
271	AUX. INSTR Rm UNIT 2	8			
272	AUX. INSTR Rm UNIT 2			9	
273	COMPUTER Room CORRIDOR	3			
277	ERCW Pumping Sta. El. ~~704~~ 722	~~21~~ 17			
296	Aux. CR Bds. L-4B, 4D, & 11B El. 755	~~8~~ 8			
297	UNIT 2 MAIN CONT Rm BOARD	8			
298	COMMON MAIN CONTROL Rm BDS & M-15	11			
352	Lwr. Compt. Coolers, El. 716		4		
354	Upr. Compt. Coolers, El. 801		4		

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

Fire Zone	Instrument Location	Minimum Instruments Operable: Ionization	Photoelectric	Thermal	Infrared
356	RCP 2, El. 716			2	
357	RCP 2, El. 716				2
360	RCP 1, El. 716			2	
361	RCP 1, El. 716				2
364	RCP 3, El. 716			2	
365	RCP 3, El. 716				2
368	RCP 4, El. 716			2	
369	RCP 4, El. 716				2
372	Reactor Bldg. Annulus		18		
373	Reactor Bldg. Annulus		18		
384	Turbine Head End, El. 729			5	
386	Auxiliary Boiler El. 755			11	
387	Turbine Cont. Bldg. Wall, El. 729			~~18~~ 22	
388	Main Turbine Oil Tank, El. 729			8	
390	H_2 Seal Oil Unit, El. 729			2	
392	MFPT 1B Oil Tank, El. 729			4	
393	MFPT 1B Oil Tank, El. 729			4	
396	MOTOR DRIVEN FW PUMP UNIT 1 ~~Lube Oil Dispensing Rm. El. 729~~			4 ~~2~~	
397	Paint Shop & Storage, El. 729			6	
398	Paint Shop & Storage, El. 741			5	
~~405~~	~~INTAKE PUMP STATION EL. 711.0~~	~~5~~			
406	INTAKE PUMP STATION EL. 711.0	5			
412	DUPLEX RELAY BOARDS	4			

Previously Identified

NRC Question D.35
Open Item No. 103

T.S. Page 3/4 4-10

Pressurizer Heater Testing - Surveillance Requirement 4.4.3.3 requires that the heaters be demonstrated OPERABLE once per 18 months by manually transferring power from the normal to the emergency power supply and energizing the heaters. Surveillance Requirement 4.4.3.2 requires verification of heater capacity by current measurement when the heaters are energized. We consider that the requirements imposed by SR 4.4.3.3 are severe from an economic and safety viewpoint. We believe the problem can be resolved once a thorough understanding of our system and test technique are understood.

The normal and emergency power supply for the heaters are one in the same: the 6.9 kV shutdown boards. It is the power supply for the 6.9 kV shutdown boards that changes; offsite power is the preferred source and diesel generators are the emergency source. As part of the 18 month diesel generator testing (SR 4.8.1.1.2.d.7) a blackout coincident with a safety injection signal is simulated. Load shedding and subsequent re-energization of emergency loads are verified. At this time the emergency loads are powered from the emergency power source. However, it is impractical to load the heaters back on the 6.9 kV shutdown board and energize them because this test is typically done during refueling and the pressurizer is empty. The heaters would be damaged if energized in a dry environment. To impose this requirement would limit the flexibility of scheduling the BO/SI test, it could only be scheduled when the pressurizer is full.

We believe verification of the load shed of heaters during this test, with subsequent verification of heater breaker operation before startup (SR 4.4.3.2) satisfies the requirements. The heaters do not 'see' whether the shutdown board is supplied from the normal or emergency power source.

Therefore, the phrase 'and energizing the heaters' should be deleted from SR 4.4.3.3.

References: TVA Drawings:
45W724-1 R6 (FSAR Figure 8.3-16)
45W724-4 R6 (FSAR Figure 8.3-17)
45W760-211-8 (FSAR Figure 8.3-6)
45W760-211-10 (FSAR Figure 8.3-8)
47W611-68-2
45W760-68-4

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1656 cubic feet equivalent to an indicated level of less than or equal to 92% on narrow range indication, and at least two groups of pressurizer heaters each having a capacity of at least 150 kW.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one group of pressurizer heaters inoperable, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the Reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by energizing the heaters and measuring circuit current at least once per 92 days.

4.4.3.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by manually transferring power from the normal to the emergency power supply. ~~and energizing the heaters.~~

ITEM E2.11

Previously Identified

Open Item No. 107

T.S. Page 3/4 4-16

Preservice Inspection of Steam Generator Tubes - The standard technical specification for preservice inspection is not consistent with Regulatory Guide 1.83. Regulatory Guide 1.83 defines 'tube inspection' for U-bends as 'entry for the hot leg side with examination from the point of entry completely around the U-bend to the top support of the cold leg' (see footnote 3 on page 1.83-3 of the Regulatory Guide). The Regulatory Guide does not specify when the preservice inspection needs to be performed other than prior to service (R.G. Section C.3.a). TVA has performed the preservice inspection in accordance with Regulatory Guide 1.83. The technical specification must be changed to be consistent with the Regulatory Guide or TVA will be forced to perform a second inspection.

Reference: Regulatory Guide 1.83, Revision 1 (July 1975)

SURVEILLANCE REQUIREMENTS (Continued)

9) Preservice Inspection means a~~n~~ tube inspection of ~~the full length of~~ each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed ~~after the field hydrostatic test and~~ prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit and all tubes containing through-wall cracks) required by Table 4.4-2.

4.4.5.5 Reports

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2;

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission in a Special Report pursuant to Specification 6.9.2 within 12 months following the completion of the inspection. This Special Report shall include:

1) Number and extent of tubes inspected,

2) Location and percent of wall-thickness penetration for each indication of an imperfection, and

3) Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 and require prompt notification of the Commission shall be reported pursuant to Specification 6.9.1 prior to resumption of plant operation. The written followup of this report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

C. REGULATORY POSITION

A program for inservice inspection of steam generator tubing should be established and should include the following:

1. Access for Inspection

a. Steam generators of pressurized water reactors should be designed to facilitate inspection of all tubes.

b. Sufficient access should be provided to perform these inspections and to plug tubes as required.

c. Pre-job planning should be undertaken to make provisions for inspections that ensure that personnel radiation exposure is maintained as low as is reasonably achievable.

2. Inspection Equipment and Procedures

a. Inservice inspection should include nondestructive examination by eddy current testing or equivalent techniques. The equipment should be capable of locating and identifying stress corrosion cracks and tube wall thinning by chemical wastage, mechanical damage, or other causes.

b. The inspection equipment should be sensitive enough to detect imperfections 20% or more through the tube wall.

c. A suitable eddy current inspection system could consist of (1) an internal sensing probe, (2) a two-channel eddy current tester, (3) a viewing oscilloscope, (4) a conventional two-channel strip chart recorder, and (5) a magnetic tape data recorder.

d. Examination results and reports should be stored and maintained for the operating life of the facility.

e. Standards consisting of similar as-manufactured steam generator tubing with known imperfections should be used to establish sensitivity and to calibrate the equipment. Where practical, these standards should include reference flaws that simulate the length, depth, and shape of actual imperfections that are characteristic of past experience.

f. The equipment should be capable of examining the entire length of the tubes.[3]

g. The equipment used for eddy current testing should be designed so that operators may be shielded or the equipment may be operated remotely to limit operator exposure to radiation.

h. Personnel engaged in data taking and interpreting the results of the eddy current inspection should be tested and qualified in accordance with American Society for Nondestructive Testing Standard SNT–TC–IA and supplements.[4]

i. The examinations should be performed according to written procedures.

3. Baseline Inspection

a. All tubes in the steam generators should be inspected by eddy current or alternative techniques prior to service to establish a baseline condition of the tubing.

~~b. For operating plants~~ without an initial baseline inspection, the first inservice inspection performed according to regulatory positions C.4 and C.5 will define the baseline condition for subsequent inspections.

c. Operating plants instituting a major change in their secondary water chemistry (e.g., phosphate to volatile treatment) should conduct a baseline inspection before resumption of power operation.

4. Sample Selection and Testing

Selection and testing of steam generator tubes should be made on the following basis:

a. The preservice inspection should include all the tubes in the steam generators.

b. Tubes for the inspection of operating plants should be selected on a random basis except where experience in similar plants with similar secondary water chemistry indicates critical areas to be inspected.

c. At least 3% of the total number of tubes in each steam generator to be inspected should be tested during each inspection (see regulatory positions C.3 and C.6).

d. All of the steam generators in a given plant should be inspected at the first inservice inspection. Subsequent inspections may be limited to one steam generator on a rotating schedule encompassing 3% of the total tubes of the steam generators in the plant if the

[3] For U-bend designs, entry for the hot-leg side with examination from the point of entry completely around the U-bend to the top support of the cold leg is considered sufficient to constitute a tube inspection.

[4] SNT–TC–IA and Supplements, "Recommended Practice for Nondestructive Testing Personnel Qualification and Certification." Copies may be obtained from the American Society for Nondestructive Testing, 914 Chicago Avenue, Evanston, Illinois 60202.

Previously Identified

NRC Question D.37
Open Item No. 110

T.S. Page 3/4 4-20

Intersystem Check Valve Leak Testing - TVA has provided justification for increasing the check valve leakage limit to 9 gpm in response to FSAR Question 112.38. This value is 5% or less of the overpressure protection relief capacity for low pressure systems which would come close to exceeding design safety margins. It is 15% or less of relief capacity for low pressure sytems which can withstand full RCS pressure. The leak rate of 9 gpm will not exceed the capacity of the normal charging system. The permanently installed leakage measurement system range is 1-10 gpm. These points are explained further in FSAR Question 112.38.

References: FSAR Questions Q112.38, Q212.34, Q212.74, Q212.98, and Q413.11 part 10

FSAR Section 5.2.7.4

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

c. 1 gpm total primary-to-secondary leakage through all steam generators and 500 gallons per day through any one steam generator,

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System,

e. 40 gpm CONTROLLED LEAKAGE at a Reactor Coolant System pressure of 2235 ± 20 psig, and

f. 9 ~~1~~ gpm leakage at a Reactor Coolant System pressure of 2235 ± 20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

112.38 Question
(212.74)
(212.13)
(212.18)

As a result of our review of your application regarding inservice inspection of pressure isolation valves, we require the following information:

Provide a list of pressure isolation valves included in your testing program with four (4) sets of piping and instrumentation diagrams which clearly show the reactor coolant system isolation valves. Also, discuss in detail how your leak testing program conforms to the staff position.

Staff Position

There are several safety systems connected to the reactor coolant pressure boundary that have design pressure below the rated reactor coolant system (RCS) pressure. There are also some systems which are rated at full reactor pressure on the discharge side of pumps but have pump suction below RCS pressure. In order to protect these systems from RCS pressure, two or more isolation valves are placed in series to form the interface between the high pressure RCS and the low pressure systems. The leak tight integrity of these valves must be ensured by periodic leak testing to prevent exceeding the design pressure of the low pressure systems thus causing an inter-system LOCA.

Pressure isolation valves are required to be category A or AC per IWV-2000 and to meet the appropriate requirements of IWV-3420 of Section XI of the ASME Code except as discussed below.

Limiting Conditions for Operation (LCO) are required to be added to the technical specifications which will require corrective action i.e., shutdown or system isolation when the final approved leakage limits are not met. Also surveillance requirements, which will state the acceptable leak rate testing frequency, shall be provided in the technical specifications.

Periodic leak testing of each pressure isolation valve is required to be performed at least once per each refueling outage, after valve maintenance prior to return to service, and for systems rated at less than 50% of RCS design pressure each time the valve has moved from its fully closed position unless justification is given. The testing interval should average to be approximately one year. Leak testing should also be performed after all disturbances to the valves are complete, prior to reaching power operation following a refueling outage, maintenance and etc.

The staff's present position on leak rate limiting conditions for operation must be equal to or less than 1 gallon per minute for each valve (GPM) to ensure the integrity of the valve, demonstrate the adequacy of the redundant pressure isolation function and give an indication of valve degradation over a finite period of time. Significant increases over this limiting valve would be an indication of valve degradation from one test to another.

Leak rates higher than 1 GPM will be considered if the leak rate changes are below 1 GPM above the previous test leak rate or system design precludes measuring 1 GPM with sufficient accuracy. These items will be reviewed on a case by case basis.

The Class 1 to Class 2 boundary will be considered the isolation point which must be protected by redundant isolation valves.

In cases where pressure isolation is provided by two valves, both will be independently leak tested. When three or more valves provide isolation, only two of the valves need to be leak tested.

Provide a list of all pressure isolation valves included in your testing program along with four sets of Piping and Instrument Diagrams which describe your reactor coolant system pressure isolation valves. Also discuss in detail how your leak testing program will conform to the above staff position.

Response

Valves which separate high pressure reactor coolant system (RCS) piping from lower pressure piping and components associated with the safety injection (SIS), residual heat removal (RHRS), and upper head injection (UHIS) systems will be tested to assure each valve's leak tightness during each plant startup. The maximum time between tests will not exceed the interval between refueling outages. The permanently installed test systems will normally be used for leak tightness verification.

Technical Specifications

Limiting conditions for operation (LCO), which will specify corrective action when leakage limits are met, and surveillance requirements, which will specify leak rate testing frequency, will be included in the technical specifications.

Test Frequency

Pressure isolation valves (PSIV) shall be tested at a frequency equal to that of containment isolation valves (CIV's) since both types of valves have an identical function (i.e., limiting leakage). The testing frequency specified for CIV's (at each refueling) is reasonable to verify minimal leakage rates and has long been accepted by NRC, even though the valve may change position hundreds of times during the year. The function of CIV's is to limit leakage of radioactive fission products while PSIV's are used to limit the possibility of inter-system LOCA's, etc., which could endanger low-pressure systems. Therefore, it is reasonable to specify the same leakage testing frequency for PSIV's as for CIV's. Watts Bar will test PSIV's for leakage at each refueling and following maintenance which could affect leak tightness with operational checks showing correct valve position after each disturbance of the valve.

Acceptance Criteria

Acceptance for any single check valve wil depend on demonstrating its capability to fully protect its connected, low pressure system from an overpressure transient in the rare event that the valve's redundant counterpart experiences gross leak tightness failure. This will ensure that the normal, primary system charging capability is not challenged by such a failure and the plant can proceed with an orderly shutdown. Small leaks will be corrected at the earliest opportunity.

A leak rate acceptance criteria of 9 gal/min will be employed. This value, as chosen, should not result in undue forced outages, and, it is well within any limits required to ensure plant safety because (1) it is only 5% or less of the overpressure protection relief capacity for the low pressure systems which would come close to exceeding pressure boundary design safety margins if subjected to full RCS pressure, (2) it is 15% or less of relief capacity for low pressure systems which have a high enough design pressure to preclude their gross failure when exposed to full RCS pressure and (3) the leak rate is low enough to have negligible effect on the normal charging system and no effect on a normal shutdown capability, and (4) it is within the permanently installed leak test measurement capability. Further, although a potential leak rate of this magnitude (resulting from gross failure of a redundant check valve) is not desirable, it is not unsafe and would be detected earlier than a small leak, reducing the time of plant operation without the benefit of double check valve protection.

Basis For Categorization

Table Q112.38-1 identifies those valves considered to be pressure isolation valves and includes the appropriate ASME Section XI categorization. The following paragraphs are the basis for this categorization.

1. PSIV - Accumulator Check Valves

   The Safety Injection System (SIS) accumulators are isolated from reactor coolant system pressure by two check valves in series. Only the first check valve in series need be monitored by a seat-leakage test. Leakage past the second check valve will be monitored by observation of the level in the accumulator which is alarmed and has control room monitors. TVA feels that this represents the most reasonable approach to monitoring these valves for pressure isolation. The affected valves are 1-63-622, 1-63-623, 1-63-624, and 1-63-625.

2. PSIV - Hot Safety Injection Leg Check Valves

   These SIS pump discharge lines are isolated from reactor coolant system pressure by two check valves in series and a normally closed motor-operated gate valve. In order to overpressurize the lines in question, failure of all three components is required. While the scenario of leakage past two check valves is possible, although not probable, the scenario of leakage past two check valves and a normally closed gate valve is extremely unlikely. In addition, the relief valves in the SIS are designed to relieve the maximum probable leakage past the two check valves back to the reactor sump. These two points taken together allow Watts Bar to exclude these valves from pressure isolation testing. The affected valves are 63-543, 63-545, 63-547, 63-549, 63-558, and 63-559.

3. PSIV - Safety Injection Cold Leg Check Valves

These SIS pump discharge lines are protected from RCS pressure by two check valves and a pressure relief valve. The relief valves, which drain back to the reactor sump, are sized to relieve the maximum probable leakage through the check valves. The first check valve in each valve train is also a PSIV for the accumulator valve trains and, as such, would be seat leak tested.

Failure of all three valves would be required to overpressurize the pump discharge lines.

TVA feels that adequate safeguards, therefore, exist to ensure against overpressurization of the pump discharge lines. Accordingly, the second check valve in each valve train (63-551, 63-553, 63-555, and 63-557) need not be tested for seat leakage.

4. PSIV - Residual Heat Removal Cold Leg Check Valves

The RHR pump discharge lines are protected from RCS pressure by two check valves and a pressure relief valve. The relief valves, which drain back to the reactor sump, are sized to relieve the maximum probable leakage through the check valves. The first check valve in each valve train is also a PSIV for the accumulator valve trains and, as such, would be seat leak tested.

Failure of all three valves would be required to overpressurize the pump discharge lines.

TVA feels that adequate safeguards, therefore, exist to ensure against overpressurization of the pump discharge lines. Accordingly, the second check valve in each valve train (63-632, 63-633, 63-634, and 63-635) need not be tested for seat leakage.

5. PSIV - Boron Injection Check Valves

The boron injection tank, associated piping, and valves are designed for a pressure of 2,800 psig compared to a RCS design pressure of only 2,580 psig. The valve train from the RCS to the centrifugal charging pumps includes a check valve at each hot leg injection line and a check valve in the manifold line (63-581) followed by two normally closed gate valves in parallel. The BIT (FCV-63-25 and 63-26) has two normally closed gate valves in parallel after the BIT at the centrifugal and reciprocating charging pump discharge lines

(FCV-63-39 and 63-40).

TVA feels that the BIT and associated piping and valves downstream of the charging pump discharge lines isolation valves (FCV-63-39 and 63-40) do not require pressure isolation. Further, the charging pump discharge lines are adequately protected from overpressurization by the normally closed gate valves and check valves in series. Accordingly, check valves 63-581, 63-586, 63-587, 63-588, and 63-589 need not be seat leak tested for pressure isolation function.

6. PSIV - Residual Heat Removal Gate Valves

The original concern involving pressure isolation revolved about the fact that valves can leak due to a lack of positive closure under all system conditions. Gate valves which are verified closed before operation and which do not change position during power operation have extremely low leakage rates. TVA will verify minimal leakage rates on these valves.

7. PSIV - Residual Heat Removal Hot Leg Check Valves

The RHR pump discharge lines in the hot leg recirculation mode are protected from reactor coolant system pressure by two check valves in series and a relief valve designed to pass the maximum probable leakage past the two check valves back to the reactor sump. Failure of all three of these components is required in order to overpressurize the discharge lines. In reviewing these multiple defenses, TVA feels that damage to the discharge piping is an improbable event. Thus, valves 63-640, -641, -643, and -644 will not be tested for pressure isolation function.

8. PSIV - Upper Head Injection Check Valves

Each valve train from the RCS to the upper head injection accumulator is protected from RCS pressure by two check valves in series. Leakage past these check valves would be indicated by an increase of level in the UHI surge tank. TVA feels that the most reasonable approach to monitoring these valves for leakage is to monitor the surge tank level. Accordingly, check valves 87-558, 87-559, 87-560, and 87-561 will be monitored for pressure isolation, and the leakage past 87-562 and 87-563 will be monitored by verifying UHI surge tank level.

Table Q112.38-2 lists safety valve data which shows conservatism in available relief rates for a 9 gal/min leak.

The valves excluded from measured leak rate testing can be tested for closure by observing their ability to maintain an established differential pressure, by leak test, or by any other equally acceptable alternative.

Table Q112.38-1

Pressure Isolation Valve Table

Piping	TVA Valve No.	ASME Section XI Category
Accumulators	63-560	AC
	561	AC
	562	AC
	563	AC
RHR	FCV 74-1	A
	2	A
	8	A
	9	A
UHI	87-558	AC
	559	AC
	560	AC
	561	AC

Added by Amendment 46

Table Q112.38-2

Safety Valve Relief Rate Conservatism

Piping	Safety Valve Setpoint (psig)	Volumetric Relief Capacity (gal/min)	9 gal/min leak rate as a % of Capacity
RHR Pump Discharge	600	820	1.1%
SIS Accumulator	700	235	3.8%
SI Pump Discharge	1750	60	15%
UHI Accumulator	1800	70	13%

Added by Amendment 46

212.34 (6.3) Question

During normal operation, two check valves in series provide pressure and containment isolation for several ECCS lines connected to the primary system. The staff requires that these valves be leak tested periodically in accordance with the ASME Code, Section XI and also continuous leakage monitoring be provided between the high and low pressure systems in accordance with Regulatory Guide 1.45. Provide a description of how these leak testing and monitoring requirements are implemented in the Watts Bar plants. Waterhammer has occurred during periodic leak testing of the valves. Describe design basis for accepting waterhammer in these lines or the provisions for excluding it.

Response

See revised FSAR Section 5.2.7.4.

212.74 (5.2.2) Question

Check valves in the discharge side of the high head safety injection, low head safety injection, RHR, charging, and boron injection systems perform an isolation function in that they protect low pressure systems from full reactor pressure. The staff will require that these check valves be classified ASME IWV-2000 category AC, with the leak testing for this class of valve being performed to code specifications. Each check valve in the systems identified above must be leak tested; it is not satisfactory to just pull a suction on the outer most check valve. This only verifies that one of the series check valves is seated. The necessary frequency of testing will be that specified in the ASME Code, except in cases where only one or two check valves in series separate high to low pressure system. In these cases, leak testing will be performed at each refueling after the valves have been exercised.

Identify the ASME IWV-2000 Section XI category for each valve referred to in the above discussion. Verify that you will meet the required leak testing schedule, and that you have the necessary test lines to leak test each valve. Provide the leak detection criteria that will be used.

Response

Refer to the response to Q112.38. 46

212.98
(6.3)
(212.74)

Question

Your response to Q212.74 regarding leak testing is unacceptable. Tests must assure check valve leak rates of less than 1 gallon per minute. All valves listed in Table Q212.74-1 except those designated "x" (not a high/low pressure boundary interface) must be classified Section XI, Category AC.

Response

The response to Question 212.74 has been revised to classify the check valves listed in Table Q212.74, except those designated "x" as Section XI, Category AC.

canal gate in the prerequisites. Describe the testing to determine operability and leak tightness of these sectionalizing devices.

7. Part a, Item A.12.c. Even though the sampling equipment is purchased as a unit, transportation and installation may have damaged some equipment or invalidated the manufacturer's calibration. Describe the preoperational testing to be conducted to demonstrate that the equipment can perform its function within the required accuracy.

8. Part b(4). Test W3.1 does not include provisions for testing the RWST temperature and level indication. Revise the test description to include this testing. Your response to the question on RWST heater testing is unacceptable. Meeting technical specification limits implies more than an economic necessity. Considering the history of failures of vents, reliefs, and isolation valves in concentrated boric acid systems due to precipitation of boric acid, the ability of the heaters to maintain RWST temperature should be tested.

9. Parts b(5) and (6). Expand test descriptions W6.1 and W6.2 to identify what load tests will be conducted on the bridge and crane.

10. Part b(18). Contrary to your response, the individual test descriptions for CVCS, SIS and auxiliaries, ERCW, and CCW do not contain tests of intersystem leakage. Revise these test abstracts, as necessary, or provide a new description for intersystem leakage detection testing.

Response:

1. Part a, Item A.2.a. Preop test W-2.1, 'CVCS - Charging and Letdown,' calls for the verification of injections and letdown flow paths and flow rates. It also includes a test of the sytem's ability to blend concentrated boric acid for injection during tests of the system in the 'dilute,' 'alternate dilute,' and 'borate' modes. Preop test W-2.2, 'Boric Acid System,' tests the adequacy of heat tracing on concentrated boric acid systems. Sampling concerns are addressed in TVA-23, 'Sampling Systems,' a test which is not the Radwaste Section responsibility.

2. Part a, Item A.3. Sense line response times for the

staff position that a preoperational test is necessary or beneficial in demonstrating functional performance capabilities for laboratory monitoring and analysis equipment. When Radiochemical or Health Physics laboratory equipment is received, it is initially tested in accordance with written plant instructions. These tests provide a functional demonstration that each individual piece of laboratory equipment can perform its intended function within manufacturer's or purchase specification limits. Manufacturer's factory calibration is not used as verification that equipment performance is satisfactory.

Testing is performed using standards traceable to NBS standards and each test is documented. Additional testing of this equipment is performed prior to and periodically after issuance of an operating license to certify that proper calibration is maintained.

We believe that the current identified plant instructions require and document an adequate test of laboratory equipment. For these reasons, a test added to and identified in the preoperational test program would not add any additional measure of assurance that the equipment functions as designed.

8. Part b (4). RWST temperature and level indicators are tested in W-3.1E and W-7.3. W-3.1E demonstrates that the RWST heaters will be energized upon actuation of the proper temperature switches and verifies high range level instrumentation is used to initiate automatic switchover to recirculation mode in W-7.3.

9. Parts b (5) and (6). See revised FSAR table 14.2-1 test objectives for test W-6.2.

10. Part b (18). There are no intersystem leakage problems of practical concern in the CVCS because of the high system design pressure for the interfacing CVCS piping and because the CVCS will generally be at a higher pressure than the RCS to provide the normal charging and seal injection functions. However, under steady state conditions, intersystem leakage from the RCS would be detected by the CVCS as follows:

    At steady state, intersystem leakage from the RCS would cause the pressurizer level to drop which would automatically increase the CVCS charging pump flow rate. A flow element is provided in the common discharge of the three charging pumps with indication in the MCR. The CVCS Volume Control Tank (VCT) level would drop due to increased charging flow rate. When a flow level setpoint was reached, automatic makeup from a primary water makeup pump would be initiated. Indication is provided in the MCR for operation of the makeup pumps. If the level continued to drop, a low level alarm setpoint would be reached. A level sensor is provided on the VCT having both continuous indication and alarm in the MCR. The operator could detect a change in the indication of VCT level corresponding to a loss of approximately 30 gallons. In addition to monitoring the inventory control operations, an RCS inventory balance is performed during steady state operation in accordance with the technical specifications. Another system that interfaces with the CVCS is the component cooling system (CCS). The CCS is provided with radiation monitors downstream of the three CCS heat exchangers which will detect intersystem leakage from any system cooled by the CCS, including the CVCS, during normal plant operation. There is no practical way, however, to test for intersystem leakage from the CVCS into the CCS during preoperational testing.

The Component Cooling System (CCS) serves as an intermediate cooling loop between systems handling radioactive fluids and the Essential Raw Cooling Water (ERCW) system. If outleakage occurs anywhere in the system, detection is accomplished through a falling level in the surge tank, which will actuate a low-level alarm in the control room. Level alarms from the sumps to which this water will drain also serve as leak indicators. Inleakage is detected by a surge tank high-level alarm. The leaking portion of the system is located by visual inspection.

The instrumentation and alarms for the CCS surge tank are checked during the preop test of the CCS. The accuracy of the instrumentation is ± 1/2 percent. The instrumentation and alarms for the sumps are checked in a different test.

Inleakage into the system can be from either the radioactive fluid systems or the ERCW system. Radiation monitors on the discharge of the CCS heat exchangers (HXs) A, B, and C monitor the CCS to determine if any radioactive fluids are leaking into the system. These instruments alarm at a setpoint of 10^{-6} MCI/CC and have a range of 10 to 10^7 counts per minute and are calibrated in a separate test.

The cooling water supply and return lines to the Reactor Coolant Pump Thermal Barriers have a flow differential transmitter to isolate these lines should the Thermal Barrier pressure boundary fail. This instrumentation is accurate to ± 1/2 percent and is calibrated before the CCS preop test.

The Essential Raw Cooling Water (ERCW) system is an open cycle system which supplies cooling to various other systems. There is no specific way to detect inleakage into the system other than through the use of radiation monitors which monitor the ERCW discharge header flow. These instruments have a setpoint of 310 counts per minute and a range of 10 to 10^7 counts per minute and are calibrated in a separate test. If radiation is detected, the header is isolated until the source of the leak into the system is detected.

Outleakage from the system in the powerhouse would be detected if the sump alarms are activated. These alarms are calibrated in a separate test. When the alarm is activated, a visual inspection is required to determine source of a leak. The cooling water supply and return piping to equipment inside the Reactor Buildings have flow elements installed in the piping. If the sump alarms are activated, these flows can be compared to detect any flow difference in the supply and return piping and therefore any outleakage. The coolers in the Reactor Building are air-water coolers, therefore there would be no leakage into the system. These flow elements have an accuracy of ± 1/2 percent.

Leakage from piping located in the yard can only be detected by visual inspection of the ground in which the piping is located. Periodic inservice inspections are required to verify the pressure boundary integrity of the piping in the yard.

Intersystem leakage from the Reactor Coolant system

(RCS) to the Safety Injection system (SIS) would occur through the RCS pressure isolation check valves. The plant technical specifications require that those check valves be periodically tested for leakage. The SIS instrumentation and controls (I&C) includes test lines with flow indicators for measurement of that leakage over the range of 0.1 to 10 gallons per minute. The leak detection I&C are preoperationally tested during the SIS Integrated Check Valve Flow and Integrity Test, W-3.1 test objective 5 in FSAR Table 14.2-1. The preoperational test acceptance criteria allow no more than 0.1 gpm per check valve.

Previously Identified

NRC Question D.41
Open Item Nos. 118, 119

T.S. Page 3/4 5-2

Automatic Actuation of Cold Leg Accumulator Valves - Surveillance requirement 4.5.1.1.1.d should be deleted because no credit is taken in the accident analyses for either the P-11 signal or the safety injection signal. The valves are verified open every 12 hours per surveillance requirement 4.5.1.1.1.b and verification is made every 31 days (when RCS pressure is above 2000 psig) that power to the valves is disconnected. The P-11 nor the safety injection signal would open the valve (if it was inadvertently closed) because power is disconnected. The test in question is unnecessary and not beneficial. It is unnecessary because no credit is taken for the signal and the fact that position verification is made every 12 hours and power disconnect is verified every 31 days. It is not beneficial because the signals cannot open the valves if power is removed.

Reference: 'Motor Control Center Series 5600 Switchgear,' ITE Imperial Corp., Roman Controllers, Contract # 84646.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 2 percent of indicated span (1.6 percent of tank volume) by verifying the boron concentration of the accumulator solution,

c. At least once per 31 days when the RCS pressure is above 2000 psig by verifying that power to the isolation valve operator is disconnected by verifying the breaker is tagged open, and

Fred checking

~~d. At least once per 18 months by verifying that each accumulator isolation valve opens automatically under each of the following conditions:~~

~~1) When an actual or a simulated RCS pressure signal exceeds the P-11 (Pressurizer Pressure Block of Safety Injection) Setpoint, and~~

~~2) Upon receipt of a Safety Injection test signal.~~

4.5.1.2 ~~4.5.1.2.1~~ Each accumulator water level and pressure channel shall be demonstrated OPERABLE:

a. At least once per 31 days by the performance of a ANALOG CHANNEL OPERATIONAL TEST, and

b. At least once per 18 months by the performance of a CHANNEL CALIBRATION.

ITEM E2.14

Previously Identified

NRC Question D.44
Open Item No. 127

T.S. Page 3/4 6-1

Suspected Loss of Containment Integrity - The standard technical specifications do not provide guidance for actions to be taken if a loss of containment integrity is suspected. The only guidance is to declare it lost. We consider this action overly restrictive. Our proposal allows us 24 hours to investigate our suspicion and quantify any leakage to actually determine whether or not containment integrity is lost.

This type of situation has occurred at Browns Ferry and has led to a fine. We are attempting to prevent a similar situation at Watts Bar.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION: a) with a loss of primary containment integrity suspected, verify containment integrity within 24 hours.

b. Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that all penetrations* not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions, except as provided in Table 3.6-2 of Specification 3.6.3.

b. By verifying that each containment air lock is in compliance with the requirements of Specification 3.6.1.3.

c. After each closing of each penetration subject to Type B testing, except the containment air locks, if opened following a Type A or B test, by leak rate testing the seal with gas at P_a, 15 psig, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Specification 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than 0.60 L_a.

INSERT ATTACHED

*Except valves, blind flanges, and deactivated automatic valves which are located inside the annulus and containment and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except that such verification need not be performed more often than once per 92 days.

INSERT $\boxed{A}$

4.6.1.1.d After identifying a leakage path and measuring the leakage, by applicable test methods, verify that the total unit leakage determined pursuant to specification 4.6.1.2.b, when corrected for the identified leakage, is less than 0.60 La.

4.6.1.1.e After identifying leakage from a type B or C leakage path and measuring the leakage, by applicable test methods, verify that the total unit type B and C leakage determined pursuant to specification 4.6.1.2.d, when corrected for the identified leakage is less than 0.60 La for all type B and C leakage paths.

4.6.1.1.f After identifying leakage from a bypass leakage path and measuring the leakage, by applicable test methods, verify that the total unit bypass leakage determined pursuant to specification 4.6.1.3.e, when corrected for the identified leakage is less than 0.25 La for all bypass leakage paths.

Previously Identified

NRC Question D.45
Open Item No. 130

T.S. Page 3/4 6-4

Containment Isolation Valves Sealed with a Fluid from a Seal System - The seal system for valves at Watts Bar consists of piping designed to have a static head on the outboard side of the valves. This method is acceptable and meets the requirements of 10 CFR 50, Appendix J. Our concern with the standard words comes from the following phrase:

> '. . . the combined leakage rate provided the seal system and valves are pressurized to at least 1.10 Pa . . .'

Are the valves in question the containment isolation valves or fluid seal system valves? If they are the latter, TVA does not have any of these types of valves. If it is the former, the standard words are acceptable. In either case, we believe our proposal better reflects the legal requirements.

Reference: 10 CFR 50, Appendix J

SURVEILLANCE REQUIREMENTS (Continued)

g. Air locks shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.3.

h. Type B periodic tests are not required for penetrations continuously monitored by the Containment Isolation Valve and Channel Weld Pressurization Systems, provided the systems are OPERABLE per Surveillance Requirement 4.6.1.4.

i. ~~Leakage from~~ isolation valves ~~that are sealed with fluid from a seal system~~ may be excluded, subject to the provisions of Appendix J, Section III.C.3, ~~when determining the combined leakage rate provided the seal system and valves are pressurized to at least 1.10 P_a, 16.5 psig, and~~ the seal system capacity is adequate to maintain ~~system pressure~~ 1.10 Pa (16.5 psig) for at least 30 days.

j. Type B tests for penetrations employing a continuous leakage monitoring system shall be conducted at P_a, 15 psig, at intervals no greater than once per 3 years.

k. The provisions of Specification 4.0.2 are not applicable.

Type C tests for all isolation valves that are sealed with a fluid from a seal system shall be conducted at 1.10 Pa (16.5 psig) at intervals no greater than 24 months. Leakage from such

(c) Tes[illegible]age rates shall be calculated using absolute values corrected for instrument error.

4. *Preoperational leakage rate tests.* (a) *Test pressure*—(1) *Reduced pressure tests.* (i) An initial test shall be performed at a pressure Pt, not less than 0.50 Pa to measure a leakage rate Ltm.

(ii) A second test shall be performed at pressure Pa to measure a leakage rate Lam.

(iii) The leakage characteristics yielded by measurements Ltm and Lam shall establish the maximum allowable test leakage rate Lt of not more than La (Ltm/Lam). In the event Ltm/Lam is greater than 0.7, Lt shall be specified as equal to La (Pt/Pa).[1]

(2) *Peak pressure tests.* A test shall be performed at pressure Pa to measure the leakage rate Lam.

(b) *Acceptance criteria*—(1) *Reduced pressure tests.* The leakage rate Ltm shall be less than 0.75 Lt.

(2) *Peak pressure tests.* The leakage rate Lam shall be less than 0.75 La and not greater than Ltd.

5. *Periodic leakage rate tests*—(a) *Test pressure.* (1) Reduced pressure tests shall be conducted at Pt.

(2) *Peak pressure tests* shall be conducted at Pa.

(b) *Acceptance criteria*—(1) *Reduced pressure tests.* The leakage rate Ltm shall be less than 0.75 Lt. If local leakage measurements are taken to effect repairs in order to meet the acceptance criteria, these measurements shall be taken at a test pressure Pt.

(2) Peak pressure tests shall be conducted Lam shall be less than 0.75 La. If local leakage measurements are taken to effect repairs in order to meet the acceptance criteria, these measurements shall be taken at a test pressure Pa.

6. *Additional requirements.* (a) If any periodic Type A test fails to meet the applicable acceptance criteria in III.A.5.(b), the test schedule applicable to subsequent Type A tests will be reviewed and approved by the Commission.

(b) If two consecutive periodic Type A tests fail to meet the applicable acceptance criteria in III.A.5(b), notwithstanding the periodic retest schedule of III.D., a Type A test shall be performed at each plant shutdown for refueling or approximately every 18 months, whichever occurs first, until two consecutive Type A tests meet the acceptance criteria in III.A.5(b), after which time the retest schedule specified in III.D. may be resumed.

B. *Type B tests*—1. *Test methods.* Acceptable means of performing preoperation and periodic Type B tests include:

(a) Examination by halide leak-detection method (or by other equivalent test methods such as mass spectrometer) of a test chamber, pressurized with air, nitrogen, or pneumatic fluid specified in the technical specifications or associated bases and constructed as part of individual containment penetrations.

(b) Measurement of the rate of pressure loss of the test chamber of the containment penetration pressurized with air, nitrogen, or pneumatic fluid specified in the technical specifications or associated bases.

(c) Leakage surveillance by means of a permanently installed system with provisions for continuous or intermittent pressurization of individual or groups of containment penetrations and measurement of rate of pressure loss of air, nitrogen, or pneumatic fluid specified in the technical specifications or associated bases through the leak paths.

2. *Test pressure.* All preoperational and periodic Type B tests shall be performed by local pneumatic pressurization of the containment penetrations, either individually or in groups, at a pressure not less than Pa.

3. *Acceptance criteria.* (See also Type C tests.) (a) The combined leakage rate of all penetrations and valves subject to Type B and C tests shall be less than 0.60 La, with the exception of the valves specified in III.C.3.

(b) Leakage measurements obtained through component leakage surveillance systems (e.g., continuous pressurization of individual containment components) that maintains a pressure not less than Pa at individual test chambers of containment penetrations during normal reactor operation, are acceptable in lieu of Type B tests.

C. *Type C tests*—1. *Test method.* Type C tests shall be performed by local pressurization. The pressure shall be applied in the same direction as that when the value would be required to perform its safety function, unless it can be determined that the results from the tests for a pressure applied in a different direction will provide equivalent or more conservative results. The test methods in III.B.1 may be substituted where appropriate. Each valve to be tested shall be closed by normal operation and without any preliminary exercising or adjustments (e.g., no tightening of valve after closure by valve motor).

[1] ANSI N45.4-1972 Leakage Rate Testing of Containment Structures for Nuclear Reactors (dated Mar. 16, 1972). Copies may be obtained from the American Nuclear Society, 244 East Ogden Avenue, Hinsdale, IL 60521. A copy is available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, DC. The incorporation by reference was approved by the Director of the Federal Register on October 20, 1972.

[2] Such inservice inspections are required by § 50.55a.

2. *Test pressure.* (a) Valves, unless pressurized with fluid (e.g., water, nitrogen) from a seal system, shall be pressurized with air or nitrogen at a pressure of Pa.

(b) Valves, which are sealed with fluid from a seal system shall be pressurized with that fluid to a pressure not less than 1.10 Pa.

3. *Acceptance criterion.* The combined leakage rate for all penetrations and valves subject to Type B and C tests shall be less than 0.60 La. Leakage from containment isolation valves that are sealed with fluid from a seal system may be excluded when determining the combined leakage rate: *Provided*, That:

(a) Such valves have been demonstrated to have fluid leakage rates that do not exceed those specified in the technical specifications or associated bases, and

(b) The installed isolation valve seal-water system fluid inventory is sufficient to assure the sealing function for at least 30 days at a pressure of 1.10 Pa.

D. *Periodic retest schedule*—1. *Type A test.* (a) After the preoperational leakage rate tests, a set of three Type A tests shall be performed, at approximately equal intervals during each 10-year service period. The third test of each set shall be conducted when the plant is shutdown for the 10-year plant inservice inspections.[2]

(b) Permissible periods for testing. The performance of Type A tests shall be limited to periods when the plant facility is nonoperational and secured in the shutdown condition under the administrative control and in accordance with the safety procedures defined in the license.

2. *Type B tests.* (a) Type B tests, except tests for air locks, shall be performed during reactor shutdown for refueling, or other convenient intervals, but in no case at intervals greater than 2 years. If opened following a Type A or B test, containment penetrations subject to Type B testing shall be Type B tested prior to returning the reactor to an operating mode requiring containment integrity. For primary reactor containment penetrations employing a continuous leakage monitoring system, Type B tests, except for tests of air locks, may, notwithstanding the test schedule specified under III.D.1., be performed every other reactor shutdown for refueling but in no case at intervals greater than 3 years.

(b)(i) Air locks shall be tested prior to initial fuel loading and at 6-month intervals thereafter at an internal pressure not less than P_a.

(ii) Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than P_a.

(iii) Air locks opened during periods when containment integrity is required by the plant's Technical Specifications shall be tested within 3 days after being opened. For air lock doors opened more frequently than once every 3 days, the air lock shall be tested at least once every 3 days during the period of frequent openings. For air lock doors having testable seals, testing the seals fulfills the 3-day test requirements. In the event that the testing for this 3-day interval cannot be at P_a, the test pressure shall be as stated in the Technical Specifications. Air lock door seal testing shall not be substituted for the 6-month test of the entire air lock at not less than P_a.

(iv) The acceptance criteria for air lock testing shall be stated in the Technical Specifications.

3. *Type C tests.* Type C tests shall be performed during each reactor shutdown for refueling but in no case at intervals greater than 2 years.

IV. Special Testing Requirements

A. *Containment modification.* Any major modification, replacement of a component which is part of the primary reactor containment boundary, or resealing a seal-welded door, performed after the preoperational leakage rate test shall be followed by either a Type A, Type B, or Type C test, as applicable for the area affected by the modification. The measured leakage from this test shall be included in the report to the Commission, required by V.A. The acceptance criteria of III.A.5.(b), III.B.3., or III.C.3., as appropriate, shall be met. Minor modifications, replacements, or resealing of seal-welded doors, performed directly prior to the conduct of a scheduled Type A test do not require a separate test.

B. *Multiple leakage barrier or subatmospheric containments.* The primary reactor containment barrier of a multiple barrier or subatmospheric containment shall be subjected to Type A tests to verify that its leakage rate meets the requirements of this appendix. Other structures of multiple barrier or subatmospheric containments (e.g., secondary containments for boiling water reactors and shield buildings for pressurized water reactors that enclose the entire primary reactor containment or portions thereof) shall be subject to individual tests in accordance with the procedures specified in the technical specifications, or associated bases.

V. Inspection and Reporting of Tests

A. *Containment inspection.* A general inspection of the accessible interior and exterior surfaces of the containment structures

[2] Such inservice inspections are required by § 50.55a.

Previously Identified

NRC Question D.47
Open Item No. 137

T.S. Page 3/4 6-12

Action Statement for Shield Building Structural Integrity - The shield building (inside and outside) is accessible during power operation. The building can be viewed from the outside and entry into the annulus (the region between the shield building and containment structure) is permissible on a limited basis. The present action statement implies that the shield building can only be inspected for damage during shutdown. However, damage can be noticed during power operation. The action statement does not address loss of structural integrity at power. Heatup of the RCS above 200°F is prevented whether the action statement is revised or not because Specification 3.0.4 still applies. It requires compliance with the limiting condition for operation before entering Mode 4 in this case. We consider our proposal to more accurately reflect the Watts Bar design.

Note that the LCO reference to Specification 4.6.1.8 should be 4.6.1.7.

CONTAINMENT SYSTEMS

SHIELD BUILDING STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.7 The structural integrity of the shield building shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.~~8~~. 7

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the structural integrity of the shield building not conforming to the above requirements, restore the structural integrity to within the limits ~~prior to increasing the Reactor Coolant System temperature above 200°F.~~ within 24 hours or be in at least Hot Standby within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The structural integrity of the shield building shall be determined during the shutdown for each Type A containment leakage rate test (Specification 4.6.1.2) by a visual inspection of the exposed accessible interior and exterior surfaces of the shield building and verifying no apparent changes in appearance of the concrete surfaces or other abnormal degradation. Any abnormal degradation of the shield building detected during the above required inspections shall be reported to the Commission pursuant to Specification 6.9.1.

Previously Identified

NRC Question D.48
Open Item No. 150

T.S. Page 3/4 6-29

Ice Bed Temperature Monitoring System Action Statements - The ice bed temperatures are recorded on a multi-point recorder in the main control room. The main control room recorder is not the most reliable piece of equipment. We proposed the additional action statement to cover the situation when the main control room recorder, only, is out-of-service. The temperature can be determined by measuring the thermocouple voltage at the junction box and converting the voltage to a temperature reading. The alternate method would be performed every 12 hours, the same frequency as the CHANNEL CHECK for the main control room recorder. The accuracy of the digital voltmeter is ± 1.5% whereas the accuracy of the recorder is ± 3.0%. We consider the alternate temperature measurement scheme acceptable for use in the event that the main control room recorder is out-of-service. The alternate method can prevent an unnecessary plant shutdown. Consideration must be given to the fact that one hour of generation from a plant like Watts Bar, if lost or delayed, results in an additional cost to TVA of $22,000.

a. With the ice bed temperature [illegible] available in the Main Control Room, determine the ice bed temperature at the local ice condenser temperature monitoring panel every 12 hours

ICE BED TEMPERATURE MONITORING SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.2 The ice bed temperature monitoring system shall be OPERABLE with at least 2 OPERABLE RTD channels in the ice bed at each of 3 basic elevations 10'6", 30'9" and 55' above the floor of the ice condenser for each one-third of the ice condenser.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

b ~~a~~. With the ice bed temperature monitoring system inoperable ~~,~~ and being unable to determine the ice bed temperature at the local panel POWER OPERATION may continue for up to 30 days provided:

1. The ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed;
2. The last recorded mean ice bed temperature was less than or equal to 20°F and steady; and
3. The ice condenser cooling system is OPERABLE with at least:
    a) 21 OPERABLE air handling units,
    b) 2 OPERABLE glycol circulating pumps, and
    c) 3 OPERABLE refrigerant units;

Otherwise, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

c ~~b~~. With the ice bed temperature monitoring system inoperable and being unable to determine the ice bed temperature at the local panel and with the ice condenser cooling system not satisfying the minimum components OPERABILITY requirements of a.3 above, POWER OPERATION may continue for up to 6 days provided the ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed and the last recorded mean ice bed temperature was less than or equal to 15°F and steady; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.2 The ice bed temperature monitoring system shall be determined OPERABLE by performance of a CHANNEL CHECK at least once per 12 hours.

ITEM E2.18

Previously Identified

NRC Question D.49
Open Item Nos. 151, 151.1

T.S. Pages 3/4 6-30, 3/4 6-31

Ice Condenser Doors Surveillance Requirements - This change, replacing fully with initially, has been proposed to accurately reflect the intent and basis for this requirement. The purpose of this surveillance requirement is to verify that the ice condenser system in question is not subject to significant frosting of the doors. The more frequent inspection interval is a one time requirement to verify the system design. Once the design has been verified, the relaxed inspection interval is adequate. The standard statement could be interpreted to imply door surveillance intervals must revert to the more frequent interval each time the ice condenser is reloaded. This is not the intent of the specification and the more frequent interval would lead to more forced outages and lead to a significant increase in operating costs.

Surveillance requirement 4.6.5.3.2.b should be revised to read:

> 'Demonstrated OPERABLE at least once per three months during the first year after the ice bed is initially loaded . . .'

The basis for this change is the same as outlined above.

CONTAINMENT SYSTEMS

ICE CONDENSER DOORS

LIMITING CONDITION FOR OPERATION

3.6.5.3 The ice condenser inlet doors, intermediate deck doors, and top deck doors shall be closed and OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one or more ice condenser doors open or otherwise inoperable, POWER OPERATION may continue for up to 14 days provided the ice bed temperature is monitored at least once per 4 hours and the maximum ice bed temperature is maintained less than or equal to 27°F; otherwise, restore the doors to their closed positions or OPERABLE status (as applicable) within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.3.1 Inlet Doors - Ice condenser inlet doors shall be:

a. Continuously monitored and determined closed by the inlet door position monitoring system, and

b. Demonstrated OPERABLE at least once per 3 months during the first year after the ice bed is INITIALLY fully loaded and at least once per 6 months thereafter by: Fud To add

1) Verifying that the torque required to initially open each door is less than or equal to 675 inch pounds;

2) Verifying that opening of each door is not impaired by ice, frost or debris;

3) Testing a sample of at least 25% of the doors and verifying that the torque required to open each door is less than 195 inch-pounds when the door is 40 degrees open. This torque is defined as the "door opening torque" and is equal to the nominal door torque plus a frictional torque component. The doors selected for determination of the "door opening torque" shall be selected to ensure that all doors are tested at least once during four test intervals;

SURVEILLANCE REQUIREMENTS (Continued)

4) Testing a sample of at least 25% of the doors and verifying that the torque required to keep each door from closing is greater than 78 inch-pounds when the door is 40 degrees open. This torque is defined as the "door closing torque" and is equal to the nominal door torque minus a frictional torque component. The doors selected for determination of the "door closing torque" shall be selected to ensure that all doors are tested at least once during four test intervals; and

5) Calculation of the frictional torque of each door tested in accordance with Specifications 4.6.5.3.1b.3) and 4) above. The calculated frictional torque shall be less than or equal to 40 inch-pounds.

4.6.5.3.2 Intermediate Deck Doors - Each ice condenser intermediate deck door shall be:

a. Verified closed and free of frost accumulation by a visual inspection at least once per 7 days, and

b. Demonstrated OPERABLE at least initially once per 3 months during the first year after the ice bed is ~~fully~~ loaded and at least once per 18 months thereafter by visually verifying no structural deterioration, by verifying free movement of the vent assemblies, and by ascertaining free movement when lifted with the applicable force shown below:

	Door	Lifting Force
1)	0-1, 0-5	$\leq$ 37.4 lbs.
2)	0-2, 0-6	$\leq$ 33.8 lbs.
3)	0-3, 0-7	$\leq$ 31.8 lbs.
4)	0-4, 0-8	$\leq$ 31.0 lbs.

4.6.5.3.3 Top Deck Doors - Each ice condenser top deck door shall be determined closed and OPERABLE at least once per 92 days by visually verifying:

a. That the doors are in place, and

b. That no condensation, frost, or ice has formed on the doors or blankets which would restrict their lifting and opening if required.

ITEM E2.19

Previously Identified

NRC Question D.51
Open Item No. 156

T.S. Page 3/4 6-37

Divider Barrier Seal Inspection - In response to FSAR Question 22.6, TVA has committed to inspect all physically accessible portions of the seal every 18 months. Not all portions are accessible and others are not easily accessible.

Reference: FSAR Question Q22.6

CONTAINMENT SYSTEMS

DIVIDER BARRIER SEAL

LIMITING CONDITION FOR OPERATION

3.6.5.9 The divider barrier seal shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the divider barrier seal inoperable, restore the seal to OPERABLE status prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.5.9 The divider barrier seal shall be determined OPERABLE at least once per 18 months during shutdown by:

a. Removing and pressure testing the divider barrier seal test coupons in accordance with Table 3.6-3,

b. Visually inspecting ~~at least 95 percent~~ all physically accessible portions of the seal~~'s entire length~~ and:

   1. Verifying that the seal and seal mounting bolts are properly installed, and

   2. Verifying that the seal material shows no visual evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or changes in physical appearances.

022.6 Question

Provide the following information regarding the seals between the primary containment wall and the internal containment structures such as the ice condenser floor and refueling canal, the seals between the operating deck and crane wall and the seals for the personnel and equipment hatches through the operating deck:

a. Provide drawings which show the design details of all the seals and their locations within the plant.

b. Specify the design life of the seals at 120°F (lower compartment maximum operating temperature) in their expected radiation environment, and discuss the qualification testing that has been or will be done to assure it.

c. Provide a listing of the minimum values of the seal material properties used in the analysis to determine the ability of the seals to withstand the maximum pressure loadings which could be incurred in the event of a LOCA.

d. Describe the surveillance program which will assure that the equivalent operating deck bypass leakage area remains below the design area of 5 square feet.

Response

a. Figures Q022.6-1 through Q022.6-7 are provided to show the design details and the locations of the seals and gaskets for those required between the ice condenser and containment vessel and for the personnel and equipment hatches through the operating deck.

b. The design life of the seals and gaskets is 8 to 10 years. 45

Actual test results taken from Sequoyah Nuclear Plant - Units 1 and 2 - Testing and Evaluation of Seal and Gasket Materials - TVA Contract 72C33-75424-N2H-15 indicate the seal material EPDM Presray compound E-603 elastomer is acceptable where exposure to combined heat and radiation does not exceed a total radiation dose of 10° rads and 12 hours at 250°F. This elastomer is the sole constituent of those seals and gaskets made into flat, square, rectangular, standard 'o' ring or specially configured shapes. For the seals 45 installed between the ice condenser and containment vessel, the material is a coated fabric (two-ply dacron) with EPDM presray compound E-603 elastomer on both sides and in between to an overall thickness of .090 inches.

An additional testing program was instituted by TVA
under contract 80K73-827716 (N2H-90 and N3H-90) to
prove the coated fabric seals would perform in their
operating environment. All test results were 45
acceptable by demonstrating the seal's ability to
withstand a total radiation dose of 1.3×10^{8} rads
at 250°F for the first hour and 220°F for the next
11 hours without rupture when subjected to more than
three times the expected accident pressure of 18
psi. Supplemental 'grab tests' per ASTM D 751 were
performed on these irradiated specimens and the seal
performance was well above the minimum values
required by the contract specification.

Because no test data are available concerning the
coated fabric deterioration of tensile strength of
the seals between the ice condenser and containment
vessel due to long term exposure from relatively low
radiation levels and 120°F temperatures during
normal operation or the effects of long-term storage
on the seals designated and packaged as spares and 45
replacements, the following procedure for
determining when changeout or replacement of the
seals should be effected.

<u>Specimens</u>

Sample material specimens, 5 inches by 11 inches, from the same batch and calendar run as the ice condenser seals, are to be kept in each package of spares and replacements.

Sample material specimens, 5 inches by 11 inches,
from the same batch and calendar run as the ice
condenser seals, are to be positioned at 90°
intervals around the containment, adjacent to the
operating seals. These specimens will be identified 45
as to azimuth location and so marked.

<u>Tests</u>

The following tests are to be performed on the sample material specimens from each package of spares and replacements and on the sample material specimens at each location adjacent to the operating seals. The initial testing should be conducted after delivery of the seals to the project but before initial plant startup and then at 18-month intervals thereafter on positioned seals and on packaged spares and replacements prior to use.

Pressure testing at 60 lb/in² is to be performed using shop air and the seal contractor's approved test fixture on two of the 5 inches by 11 inches listed in paragraph 2.2 above. If neither specimens ruptures, the seals are not to be replaced.

If a rupture occurs, four additional specimens are to be pressure tested at 30 lb/in². If none of these additional specimens rupture, the seals are not to be replaced.

If any specimen ruptures at 30 lb/in², five specimens are to be returned to the seal contractor for his further testing of the samples after exposure to simulated accident conditions as outlined below. 45

Radiation of 1.3×10^7 rads (total) for a duration of 12 hours, the first hour at 250°F, the next 11 hours at 22°F.

After exposure to the above simulated accident conditions, tests at 15 lb/in² are to be conducted by the seal contractor on the exposed samples. If any sample ruptures, the seals are to be replaced.

Examinations

The following examinations are to be performed on the installed seals and the packaged spares and replacements after delivery and prior to initial plant startup and then at 18-month intervals thereafter.

Visual examination to determine if there is any evidence of cracking which would result in establishing a leak path for air. If any cracking of the seals is observed, the seals are to be replaced.

c. Minimum values of seal material properties are:

1. Seals and gaskets

	ASTM Spec	Before Exposure	After Exposure

Durometer	D2240	50-70	45-75
Min tensile	D412	1800 psi	900 psi
Min elongation	D412	400%	150%
Max compression set	D095	20%	30%

2. Seals between ice condenser and containment vessel. (fabric coated)

	Before Exposure	After Exposure	
Breaking strength warp direction	250 lbs	100 lbs	45
Breaking strength 'fill' direction	250 lbs	100 lbs	

Zero leakage through seal after exposure with 30 psi air pressure applied to one face.

'The after-exposure values of the seal properties were used in the analysis to determine the ability of the seals to withstand the maximum pressure loadings which could be incurred in the event of a LOCA.' 42

d. We are presently developing a surveillance program to assure divider barrier and seal integrity. This surveillance program is being written to satisfy the requirements found in the Watts Bar draft technical specifications. Surveillance instructions are being prepared to correspond to the following surveillance requirements:

4.6.5.5.1 - The personnel access doors and equipment hatches between the containments upper and lower compartments shall be determined closed by a visual inspection before increasing the Reactor Coolant System Taug is above 1/2 200°F.

4.6.5.5.2 - The personnel access doors and equipment hatches between the containments upper and lower compartments shall be determined operable by visually inspecting the seals and sealing surfaces of those penetrations and verifying no detrimental misalignments, cracks, or defects in the sealing surfaces, or apparent deterioration of the seal 42 material:

a. Prior to final closure of the penetration each time it has been opened, and

b. At least once per 10 years for penetrations containing seals fabricated from resilient materials.

4.6.5.9 - The divider barrier seal shall be determined operable at least once per 18 months during shutdown by:

a. Removing two divider barrier seal test coupons and verifying that the physical properties of the test coupons are within the acceptable range. 42

b. Visually inspecting all physically accessible portions of the seal's entire length and:

1. Verifying that the seal and seal mounting bolts are properly installed, and

2. Verifying that the seal material shows no visual evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or changes in physical appearances.

In addition, a maintenance instruction is being prepared for the correct placement of the CRDM missile shield and refueling canal gates.

These procedures will be approved at least three months prior to fuel loading.

ITEM E2.20

Previously Identified

NRC Question A.11
Open Item Nos. 158, 159

T.S. Page 3/4 7-4

Auxiliary Feedwater Pump Pressure Testing - Surveillance requirement 4.7.1.2.a was not revised by NRC as requested by TVA. The auxiliary feedwater pumps fall under the scope of ASME Section XI. Specification 4.0.5 endorses a particular edition of the ASME Code. Currently endorsed codes call for monthly testing although more recent editions endorse quarterly testing. By referencing 4.0.5, a more comprehensive test will be required by technical specifications. In the future, if NRC endorses the ASME Code editions that call for quarterly testing, TVA may be able to go to less frequent tests. However, we consider the trade off (referencing 4.0.5 vs once per 31 days) a net benefit to both TVA and NRC. All other pump test requirements in the current technical specifications just endorse 4.0.5; no other specification identifies a test interval.

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated flow paths shall be OPERABLE with:

a. Two motor-driven auxiliary feedwater pumps, each capable of being powered from separate shutdown boards, and

b. One steam turbine-driven auxiliary feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable, be in at least HOT STANDBY witin 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective ACTION to restore at least one auxiliary feedwater pump to OPERABLE status as soon as possible.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. ~~At least once per 31 days by:~~ Per 4.0.5 by:

1) Verifying that each motor-driven pump develops a differential pressure of greater than or equal to 1599 psid on recirculation flow;

2) Verifying that the steam turbine-driven pump develops a differential pressure of greater than or equal to 1360 psid on recirculation flow when the secondary steam supply pressure is greater than 1000 ~~psig~~ PSIA. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3; and

ITEM E2.21

Previously Identified

NRC Questions C.20, D.57
Open Items Nos. 173, 174

T.S. Page 3/4 7-32

Sprinkler Valve Testing - Surveillance requirement 4.7.11.2.b requires stroking of sprinkler valves every 12 months. We propose that this requirement be limited to those valves that are accessible during plant operation. Valves in high radiation areas, hazardous areas, or inside containment would be exempt. These same valves are tested every 18 months for automatic actuation (including valve stroke) per surveillance requirement 4.7.11.2.c.1.b. TVA considers testing every 18 months adequate for the valves in question. The more frequent testing benefits do not outweigh the risks involved with testing the valves.

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.11.2 The following Spray and/or Sprinkler Systems shall be OPERABLE:

a. Reactor building - RC pump area, Annulus;

b. Auxiliary building - Elev. 692, 713, 729, 737, 757, 772, 782, ABGTS ~~ADGTS~~ Filters, EGTS Filters, Purge Filters, 125 V Battery Rooms;

c. Control building - Elev. 692, Cable spreading room, MCR air filters and Operator living area;

d. Diesel building - Corridor area;

e. Turbine building - Control building wall; and

f. ERCW pumping station (Intake).

APPLICABILITY: Whenever equipment protected by the Spray/Sprinkler System is required to be OPERABLE.

ACTION:

a. With one or more of the above required Spray and/or Sprinkler Systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish a hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11.2 Each of the above required Spray and/or Sprinkler Systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated, or automatic) in the flow path is in its correct position,

b. At least once per 12 months by cycling each testable valve in the flow path that is accessible during plant operation through at least one complete cycle of full travel, and

Previously Identified

Open Item Nos. 181, 181.1

T.S. Page 3/4 8-3, -3a

Diesel Generator Testing - Surveillance requirement 4.8.1.1.2.a.6 requires that the generator be 'synchronized and loaded to greater than or equal to 4400 kW in less than or equal to 60 seconds.' We do not consider this requirement applicable for manual starts because the loading sequence is done manually. Undue concern to the loading time may lead to unsafe operation of the diesel generator unit. We believe the requirement should be written, '. . . to 60 seconds for automatic starts and at the maximum practical rate for manual starts.'

NOTE: Minor word changes were made to SR a.3 and b to reflect the WBN design.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying the fuel level in the 7-day fuel storage tank,

3) Verifying the fuel transfer pump starts and transfers fuel from the 7 day storage ~~system~~ tank to the engine-mounted tank,

~~4) Verifying the lubricating oil inventory in storage,~~

4 ~~5)~~ Verifying the diesel starts from ambient condition and accelerates to at least 900 rpm in less than or equal to 10 seconds. The generator voltage and frequency shall be 6900 ± 690 volts and 60 ± 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual, or

b) Simulated loss-of-offsite power by itself, or

c) Simulated loss-of-offsite power in conjunction with an ESF actuation test signal, or

d) An ESF actuation test signal by itself.

5 ~~6)~~ Verifying the generator is synchronized, loaded to greater than or equal to 4400 kW in less than or equal to 60 seconds for automatic starts and max practical for manual starts, and operates with a load greater than or equal to 4400 kW for at least 60 minutes, and

6 ~~7)~~ Verifying the diesel generator is aligned to provide standby power to the associated shutdown boards.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by removing accumulated water from the engine-mounted fuel tanks;

c. At least once per 92 days and from new fuel prior to addition to the storage tanks, by obtaining a sample of fuel oil in accordance with ASTM-D270~~-1975~~, and by verifying that the sample meets the following minimum requirements and is tested within the specified time limits: X

new

1) As soon as sample is taken (or prior to adding new fuel to the storage tank) verify in accordance with the tests specified in ASTM-D975~~-77~~ that the sample has:

a) A water and sediment content of less than or equal to 0.05 volume percent,

b) A kinematic viscosity @ 40°C of greater than or equal to 1.9 centistokes, but less than or equal to ~~4.1~~ 4.3 centistokes, and

SURVEILLANCE REQUIREMENTS (Continued)

c) A specific gravity as specified by the manufacturers @ 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity @ 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

new

2) Within 7 days ~~1 week~~ after obtaining the sample, verify an impurity level of less than 2 mg of insolubles per 100 ml when tested in accordance with ASTM-D2274~~-70~~; and

3) Within 14 days ~~2 weeks~~ of obtaining the sample verify that the other properties specified in Table 1 of ASTM-D975~~-77~~ and Regulatory Guide 1.137 Position 2.a are met when tested in accordance with ASTM-D975~~-77.~~

d. At least once per 18 months, during shutdown, by:

1) Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service;

Previously Identified

NRC Question A.14
Open Item Nos. 182, 183

T.S. Page 3/4 8-6

Diesel Generator Load Sequencers - The Watts Bar design has individual load sequence timers for each piece of equipment. The nominal setpoint for each load is specified in FSAR table 8.3-3. TVA preoperational tests specify an acceptable operating band for each timer. The acceptable bands are based on equipment operating requirements and diesel generator loading limitations. Percent tolerance is not applicable because of the large variation in nominal timer setpoints (two seconds for charging pumps and 90 seconds for pressurizer heaters).

References: FSAR Section 8.3
Preoperational Test TVA-13B 'Onsite AC Distribution System'

SURVEILLANCE REQUIREMENTS (Continued)

12) Verifying that the fuel transfer pump transfers fuel from each 7 day fuel storage tank to the engine-mounted tanks of each diesel via the installed cross-connection lines;

13) Verifying that the automatic load sequence timers ~~is~~ are OPERABLE and their setpoints are ~~with the interval between each load block~~ within ~~± 10% of its design interval~~; the specified bands.

14) Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

a) Engine overspeed, or

b) 86 GA lockout relay.

not in standard

15) Verifying that with all diesel generator air start receivers pressurized to less than or equal to ___ psig and the compressors secured, the diesel generator starts at least ? 5 times from ambient conditions and accelerates to at least ___ rpm in less than or equal to ___ seconds.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to at least 900 rpm in less than or equal to 10 seconds;

f. At least once per 10 years by:

1) Draining each 7 day fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and

SECTION III is not applicable To WBN

2) ~~Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code at a test pressure equal to 110% of the system design pressure.~~

4.8.1.1.3 The 125-volt D.C. distribution panel, 125-volt D.C. battery bank and associated charger for each diesel generator shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying:

1) Correct breaker alignment, indicated power availability and voltage on the distribution panels greater than or equal to 118 volts,

2) That each battery bank and charger meet the Category A limits in Table 4.8-2, and

3) That the total battery terminal voltage is greater than or equal to 128 volts on float charge.

Previously Identified

Open Item No. 184

T.S. Page 3/4 8-6

Diesel Fuel System Hydro Testing -TVA will comply with the backfit portions of Regulatory Guide 1.137, 'Fuel Oil Systems for Standby Diesel Generators.' The distribution letter from R. B. Monogue dated January 13, 1978 identifies Regulatory Position C.1 as forward-fit only. The hydro testing requirements are listed as Item C.1.e, a forward-fit item. TVA maintains that ASME Section III does not apply to the fuel oil system.

References: Letter from L. M. Mills to Secretary of the Commission (NRC) dated March 21, 1980

Letter from J. E. Gilleland to Secretary of the Commission (NRC) dated April 20, 1978

Letter from R. B. Monogue to Regulatory Guide Distribution List (Division I) dated January 13, 1978

Letter from L. M. Mills to E. Adensam dated March 17, 1982

12) Verifying that the fuel transfer pump transfers fuel from each 7 day fuel storage tank to the engine-mounted tanks of each diesel via the installed cross-connection lines;

13) Verifying that the automatic load sequence timers ~~is~~ are OPERABLE and their setpoint ~~with the interval between each load block~~ within ~~± 10% of~~ its ~~design interval~~; the specified bands.

14) Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

a) Engine overspeed, or

b) 86 GA lockout relay.

not in standard

15) Verifying that with all diesel generator air start receivers pressurized to less than or equal to ___ psig and the compressors secured, the diesel generator starts at least ? 5 times from ambient conditions and accelerates to at least ___ rpm in less than or equal to ___ seconds.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to at least 900 rpm in less than or equal to 10 seconds;

f. At least once per 10 years by:

1) Draining each 7 day fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and

SECTION III is not applicable To WBN

2) Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code at a test pressure equal to 110% of the system design pressure.

4.8.1.1.3 The 125-volt D.C. distribution panel, 125-volt D.C. battery bank and associated charger for each diesel generator shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying:

1) Correct breaker alignment, indicated power availability and voltage on the distribution panels greater than or equal to 118 volts,

2) That each battery bank and charger meet the Category A limits in Table 4.8-2, and

3) That the total battery terminal voltage is greater than or equal to 128 volts on float charge.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

January 13, 1978

REGULATORY GUIDE DISTRIBUTION LIST (DIVISION 1)

Regulatory Guide 1.137, "Fuel-Oil Systems for Standby Diesel Generators," transmitted herewith, describes a method acceptable to the NRC staff for complying with the Commission's regulations regarding fuel-oil systems for standby diesel generators and assurance of adequate fuel-oil quality.

In addition to the provisions of Section D, "Implementation," of the guide, the NRC intends to implement portions of this guide for all nuclear power plants in the following manner:

1. Regulatory Position C.1 will be evaluated, on a case-by-case basis, for application to all construction permit cases under review whose Safety Evaluation Report has not been issued as of the implementation date shown in the published guide.

2. Regulatory Position C.2 will be evaluated, on a case-by-case basis, for application to all operating reactors, operating license reviews, and construction permit cases under review whose Safety Evaluation Reports are completed as of the implementation date shown in the published guide (including Preliminary Design Authorizations).

3. Regulatory Position C.2 will be applied to all construction permit cases under review whose Safety Evaluation Report has not been issued as of the implementation date shown in the published guide.

Robert B. Minogue

Robert B. Minogue, Director
Office of Standards Development

Revision 1
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U.S. NUCLEAR REGULATORY COMMISSION

REGULATORY GUIDE

OFFICE OF STANDARDS DEVELOPMENT

REGULATORY GUIDE 1.137

FUEL-OIL SYSTEMS FOR STANDBY DIESEL GENERATORS

A. INTRODUCTION

General Design Criterion 17, "Electric Power Systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," requires that an onsite electric power system and an offsite electric power system be provided to permit functioning of structures, systems, and components important to safety. In addition, Criterion 17 contains requirements concerning system capacity, capability, independence, redundancy, availability, testability, and reliability. Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 establishes overall quality assurance requirements for the design, construction, and operation of structures, systems, and components important to safety. This regulatory guide describes a method acceptable to the NRC staff for complying with the Commission's regulations regarding fuel-oil systems for standby diesel generators and assurance of adequate fuel-oil quality.* The Advisory Committee on Reactor Safeguards has been consulted concerning this guide and has concurred in the regulatory position.

B. DISCUSSION

Working Group ANS-59.51 of Subcommittee ANS-50, Nuclear Power Plant Systems Engineering, of the American National Standards Committee N18, Nuclear Design Criteria, has prepared a standard that provides design requirements for the fuel-oil systems for standby diesel generators. This standard was approved by the American National Standards Committee N18 and its Secretariat, and it was subsequently approved and designated ANSI N195-1976 by the American National Standards Institute on April 12, 1976.

For proper operation of the standby diesel generators, it is necessary to ensure the proper quality of the fuel oil. Appendix B to ANSI N195-1976 addresses the recommended fuel-oil practices. Although not a mandatory part of the standard, the staff believes Appendix B can serve as an acceptable basis for a program to maintain the quality of fuel oil, as supplemented by regulatory position 2 of this guide.

*Lines indicate substantive changes from previous issue.

C. REGULATORY POSITION

1. The requirements for the design of fuel-oil systems for diesel generators that provide standby electrical power for a nuclear power plant that are included in ANSI N195-1976, "Fuel Oil Systems for Standby Diesel-Generators,"[1] provide a method acceptable to the NRC staff for complying with the pertinent requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50, subject to the following:

a. Throughout ANSI N195-1976, other documents required to be included as part of the standard are either identified at the point of reference or described in Section 7.4, "Applicable Codes, Standards, and Regulations," or in Section 11, "References," of the standard. The specific acceptability of these listed documents has been or will be addressed separately in other regulatory guides or in Commission regulations, where appropriate.

b. Section 1, "Scope," of ANSI N195-1976 states that the standard provides the design requirements for the fuel-oil system for standby diesel generators and that it sets forth other specific design requirements such as safety class, materials, physical arrangement, and applicable codes and regulations. The standard does not specifically address quality assurance, and in this regard ANSI N195-1976 should be used in conjunction with Regulatory Guide 1.28, "Quality Assurance Program Requirements (Design and Construction)," which endorses ANSI N45.2-1977, "Quality Assurance Program Requirements for Nuclear Power Plants," for the design, construction, and maintenance of the fuel-oil system.

c. Section 5.4, "Calculation of Fuel Oil Storage Requirements," of the standard sets forth two methods for the calculation of fuel-oil storage requirements. These two methods are (1) calculations based on the assumption that the diesel generator operates continuously for 7 days at its rated capacity, and (2) calculations based on the time-dependent

[1] Copies may be obtained from the American Nuclear Society, 555 North Kensington Avenue, La Grange Park, Illinois 60525.

loads of the diesel generator. For the time-dependent load method, the maximum required capacity should include the capacity to power the engineered safety features.

d. Section 7.3, "Physical Arrangement," of ANSI N195-1976 states that "the location of day tanks shall be as required by the diesel-engine manufacturer." In addition to this requirement, the physical location of the day tank relative to the engine and design of the engine fuel system should take into account such items as net positive suction head requirements and the potential need for electric fuel pumps powered from a reliable power supply to ensure that the diesel-generator unit can start automatically and attain the required voltage and frequency within acceptable limits and time.

e. Section 7.3 of ANSI N195-1976 states that the arrangement of the fuel-oil system "shall provide for inservice inspection and testing in accordance with ASME Boiler and Pressure Vessel Code, Section XI, 'Rules for Inservice Inspection of Nuclear Power Plant Components.'" For those portions of the fuel-oil systems for standby diesel generators that are designed to Section III, Subsection ND of the Code, an acceptable method of meeting the requirements of Section 7.3 is to ensure that the system arrangement would allow:

(1) Pressure testing of the fuel-oil system to a pressure 1.10 times the system design pressure at 10-year intervals. In the case of storage tanks, recommendations of the tank vendor should be taken into account when establishing the test pressure.

(2) A visual examination to be conducted during the pressure test for evidence of component leakages, structural distress, or corrosion. In the case of buried components, a loss of system pressure during the test constitutes evidence of component leakage.

f. Section 7.3 of ANSI N195-1976 requires that adequate heating be provided for the fuel-oil system. Assurance should be provided that the fuel oil can be supplied and ignited at all times under the most severe environmental conditions expected at the facility. This may be accomplished by use of an oil with a "cloud point" lower than the 3-hour minimum soak temperature[2] expected at the site during the seasonal periods in which the oil is to be used, and/or by maintenance of the onsite fuel oil above the "cloud point" temperature.

NOT REQUIRED

g. Section 7.5, "Other Requirements," of the standard states that "protection against external and internal corrosion shall be provided" for the fuel-oil system. To amplify this requirement for buried supply tanks not located within a vault and other buried portions of the system, a protective coating and an impressed current-type cathodic protection system should be provided in accordance with NACE Standard RP-01-69 (1972 Revision), "Recommended Practice—Control of External Corrosion on Underground or Submerged Metallic Piping Systems."[3] In addition, the impressed current-type cathodic protection system should be designed to prevent the ignition of combustible vapors or fuel oil present in the fuel-oil systems for standby diesel generators.

h. Section 7.5 of the standard includes requirements for fire protection for the diesel-generator fuel-oil system. The requirements of Section 7.5 are not considered a part of this regulatory guide since this subject is addressed separately in more detail in other NRC documents. Thus a commitment to follow this regulatory guide does not imply a commitment to follow the requirements of Section 7.5 concerning fire protection.

2. Appendix B to ANSI N195-1976 should be used as a basis for a program to ensure the initial and continuing quality of fuel oil as supplemented by the following:

a. The oil stored in the fuel-oil supply tank, and the oil to be used for filling or refilling the supply tank, should meet the requirements of Federal Fuel Oil Specification VV-F-800b (April 2, 1975), ASTM D975-77, "Standard Specification for Diesel Fuel Oils," or the requirements of the diesel-generator manufacturer, if they are more restrictive, as well as the fuel-oil total insolubles level specified in Appendix B to the standard. The "cloud point" should be less than or equal to the 3-hour minimum soak temperature[2] or the minimum temperature at which the fuel oil will be maintained during the period of time that it will be stored. If test results for viscosity or for water and sediment for fuel oil contained in the supply tanks exceed the limits specified in the applicable specification, the diesel should be considered inoperable. Fuel oil contained in the supply tank not meeting remaining applicable specification requirements should be replaced in a short period of time (about a week).

CETANE

b. Prior to adding new fuel oil to the supply tanks, onsite samples of the fuel oil should be taken. As a minimum, prior to the addition of new fuel, tests for the following properties should be conducted:

(1) Specific or API gravity
(2) Water and sediment
(3) Viscosity

Test results for the latter two tests should not exceed the limits specified in the applicable specification. Analysis of the other properties of the fuel oil listed in the applicable specification should be completed within 2 weeks of the addition.

c. The periodic sampling procedure for the fuel oil should be in accordance with ASTM D270-1975, "Standard Method of Sampling Petroleum and Petroleum Products."[4]

[2] J.P. Doner, "A Predictive Study for Defining Limiting Temperatures and their Application in Petroleum Product Specifications," U.S. Army, Mobility Equipment Research and Development Center, Coating and Chemical Laboratory, Aberdeen Proving Ground, Maryland, CCL Report No. 316.

[3] Copies may be obtained from the National Association of Corrosion Engineers, 3400 West Loop South, Houston, Texas 77027.

[4] Also designated ANSI Z11.33-1976. Copies may be obtained from the American National Standards Institute, 1430 Broadway, New York, N.Y. 10018.

d. Accumulated condensate should be removed from storage tanks on a quarterly basis or on a monthly basis when it is suspected or known that the groundwater table is equal to or higher than the bottom of buried storage tanks.

e. Day tanks and integral tanks should be checked for water monthly, as a minimum, and after each operation of the diesel where the period of operation was 1 hour or longer. Accumulated water should be removed immediately. If it is suspected that water has entered the suction piping from the day or integral tank, the entire fuel-oil system between the day or integral tank and the injectors should be flushed.

f. As a minimum, the fuel oil stored in the supply tanks should be removed, the accumulated sediment removed, and the tanks cleaned at 10-year intervals. To preclude the introduction of surfactants in the fuel system, this cleaning should be accomplished using sodium hypochlorite solutions or their equivalent rather than soap or detergents.

g. If an event should occur that would require replenishment of fuel oil without the interruption of operation of the diesel generators, the method of adding fuel oil should be such as to minimize the creation of turbulence of the accumulated residual sediment in the bottom of the supply tank since stirring up this sediment during the addition of acceptable new incoming fuel has the potential of causing the overall quality of the fuel oil in the storage tank to become unacceptable.

h. For those facilities having an impressed current-type cathodic protection system, cathodic protection surveillance should be conducted according to the following procedures:

(1) At intervals not exceeding 12 months, tests should be conducted on each underground cathodic protection system to determine whether the protection is adequate.

(2) The test leads required for cathodic protection should be maintained in such a condition that electrical measurements can be obtained to ensure the system is adequately protected.

(3) At intervals not exceeding 2 months, each of the cathodic protection rectifiers should be inspected.

(4) Records of each inspection and test should be maintained over the life of the facility to assist in evaluating the extent of degradation of the corrosion protection systems.

D. IMPLEMENTATION

Except in those cases in which the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the method described herein will be used in the evaluation of all (1) construction permit applications, (2) standard reference system preliminary design applications (PDA) or Type-2 final design applications (FDA-2), and (3) licenses to manufacture that are docketed after November 1, 1979, except those portions of a construction permit application that:

a. Reference an approved standard reference system preliminary or final design (PDA or FDA) or an application for such approval.

b. Reference an approved standard duplicate plant preliminary or final design (PDDA or FDDA).

c. Reference parts of a base plant design qualified and approved for replication.

d. Reference a plant design approved or under review for approval for manufacture under a Manufacturing License, or applications for such approval.

400 Chestnut Street Tower II

March 21, 1980

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IPD
JAR
MNB
NSA
NSR
JRL

Secretary of the Commission
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Attention: Docketing and Service Branch

Dear Sir:

In accordance with provisions for public review and comment indicated in the Federal Register on January 17, 1979, the Tennessee Valley Authority (TVA) is pleased to provide the enclosed comments on the following regulatory guide:

Regulatory Guide 1.137 Revision 1	-	"Fuel-Oil Systems for Standby Diesel Generators"

Since the content and interpretation of regulatory guides have a large impact on TVA's extensive nuclear commitment, we welcome the opportunity for review and comment. TVA comments on additional regulatory guides will be forthcoming as a part of a continuing program.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills, Manager
Nuclear Regulation and Safety

DSK:PJH:CAL
Enclosure
cc (Enclosure):
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Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
1717 H Street, NW
Washington, DC 20555

Mr. Fred Stetson
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7101 Wisconsin Avenue
Washington, DC 20555

MEDS, E4B37 C-K
cc (Enclosure):
ARMS, 640 CST2-C
J. R. Calhoun, 716 EB-C
A. W. Crevasse, 401 UBB-C
~~G. F. Dilworth, W10C126 C-K~~
H. S. Sanger, Jr., E11B33 C-K
F. A. Szczepanski, 417 UBB-C

ENCLOSURE

Regulatory Guide 1.137 - "Fuel-Oil Systems for Standby Diesel Generators"
Revision 1

Part C, Article 2, paragraph b

We disagree that specific or API gravity and viscosity tests should be included in receipt inspection before the adding of new fuel oils to supply tanks.

TVA currently requires that a water and sediment inspection and a flash point test be performed before the adding of new fuel to supply tanks. The subsequent formal analysis of the new fuel oils is obtained from the TVA laboratories within ten working days after fuel receipt which includes a report on API gravity but not viscosity. However, the Federal Fuel Oil Specification VVF-800-B, which the regulatory guide now includes, does not restrict TVA purchased fuels to a fixed range in API gravity nor does it require a viscosity report.

We believe that the flash point test, as conducted by ASTM D270-65 requirements during receipt inspections, is the quickest, most practical, and reliable means of determining whether light oils or gasoline have been mixed with the diesel fuel contained in the commercial carrier. Also, visual inspection for water and sediment content and a slight smelling of the fuel odor are excellent inspection practices for determining whether or not shipments incorrectly contain lighter oils or gasoline.

We believe to impose a viscosity range too stringent for the products normally supplied through conventional refinement will result in fuel supply problems or excessive costs for special refinement. We believe this is the reason a viscosity and API gravity range are not greatly restricted in specification VVF-800-B and that NRC should consider applying the same approach.

We therefore suggest that NRC reconsider its requirements stated in Part C, Article 2, paragraph b of Revision 1 to the regulatory guide and limit its receipt inspection requirements to: (1) water and sediment inspection, and (2) a flash point test using the requirements of ASTM D270-65 as a guide.

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(2)

APR 21 1978
ENGINEERING DESIGN
DIRECTOR'S OFFICE

Secretary of the Commission
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Attention: Docketing and Service Branch

Dear Sir:

In accordance with the provisions for public review and comment indicated in the Federal Register on June 12, 1974, the Tennessee Valley Authority (TVA) is pleased to provide the enclosed comments on Nuclear Regulatory Commission (NRC) Regulatory Guides 1.124, Revision 1, "Design Limits and Loading Combination for Class I Linear-Type Component Supports," and 1.137, "Fuel-Oil System for Standby Diesel Generators."

As the content and interpretation of regulatory guides have a large impact on TVA's extensive nuclear commitment, we welcome the opportunity for review and comment. TVA comments on additional regulatory guides will be forthcoming as part of a continuing program.

Very truly yours,

J. E. Gilleland
Assistant Manager of Power

LMM:DSK:SYO
Enclosure
cc (Enclosure):
Executive Secretary
Advisory Committee on Reactor Safeguards
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Washington, DC 20555

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4-21-78--sd
CC: R. H. Dunham, W11A9 C-K
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J. P. Darling, 403 PRB-C
H. S. Fox, 716 EB-C (Attn: H. J. Green) (Enclosure)
N. B. Hughes, 830 PRB-C
G. H. Kimmons, W12A9 C-K (Enclosure)
H. S. Sanger, E11B33 C-K
F. A. Szczepanski, 417 UBB-C (Enclosure)
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4/21/78 - DEW:MPG
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MEDS, EAB11 C-K
D. R. Patterson, W10C126 C-K

ENCLOSURE

TVA COMMENTS ON REGULATORY GUIDES
1.124, REVISION 1, AND 1.137

A. Regulatory Guide 1.124, Revision 1

In the second paragraph of Section B, we believe Section III of the ASME Boiler and Pressure Vessel Code should not be applied to nonintegral supports and instead nonintegral supports should be designed to AISC standards. Therefore, we recommend the following be substituted for the first sentence of the second paragraph.

> In order to provide uniform requirements for construction, integral component supports should, as a minimum, have the same ASME Boiler and Pressure Vessel Code classifications as those of the supported components. Nonintegral supports should be designed to AISC standards

B. Regulatory Guide 1.137

1. Section C.1.a - Section 7.4 of ANSI N195-1976 primarily requires adherence to ASME Boiler and Pressure Vessel Code, Section II, which is unduly restrictive relative to pressure rating requirements because fuel-oil tanks are not required to withstand elevated pressures. Therefore, Section 7.4 of ANSI N195-1976 should not be made a part of this regulatory guide.

2. Section C.1.e - Since we do not believe that the requirements of the ASME Boiler and Pressure Vessel Code, Section III, are applicable, the associated Section XI requirements are not applicable. Thus the portion of Section 7.3 of ANSI N195-1976 that refer to Section XI should be deleted.

3. Section C.2.a - This section states that stored fuel oil and tank refilling fuel oil should meet the requirements of ASTM D975-74, "Standard Specification for Diesel Fuel Oils." As a Federal agency, TVA purchases and tests fuel oil in accordance with Federal Fuel Oil Specification VV-F-8002 (latest revision), and we recommend that the Federal specification should be included in the regulatory guide to permit additional flexibility as the requirement on the purchase of fuel oil. Therefore, we recommend that the first sentence of Section C.2.a be revised to read as follows:

   > The oil stored in the fuel oil supply tank and the oil to be used for filling and refilling the supply tank should meet one of the following requirements:
   >
   > ASTM D975-74, "Standard Specification for Diesel Fuel Oils"; Federal Fuel Oil Specification VV-F-8002 (latest revision); or the requirements of the diesel-generator manufacturer, if they are more restrictive.

APPENDIX F

WATTS BAR NUCLEAR PLANT

SER SECTION 8.3.2.2
D.C. SYSTEM MONITORING AND ANNUNCIATION
DIESEL GENERATOR BATTERY SYSTEM

To provide further assurance that the surveillance requirements of IEEE 308-1974 criteria for "Independence of Class 1E Equipment and Circuits" for direct-current systems are met, TVA will commit to do the following:

1. To replace the present discharge ammeter with a bidirectional ammeter with zero center position to indicate charging current as well as discharge current.

2. To provide blown fuse indication on the battery main fuses. This will be combined with existing "Diesel Generator Control Power Failure" in the main control room.

3. To check diesel generator battery main breaker position once per eight-hour shift do determine if it is closed, tripped or open.

4. To add an over-voltage relay for alarm purposes, this condition will be combined the existing "Diesel Generator Battery Trouble" alarm in the main control room.

5. To check ground detector once per eight-hour shift to determine if a ground exists.

Nuc PR review

012057.04

Previously Identified

NRC Questions D.77, D.80
Open Items Nos. 244, 250, 253.1

T.S. Pages B 3/4 6-3, B 3/4 7-4, B 3/4 9-3

EGTS and ABGTS Heater Operation - TVA considers running the heaters for 10 cummulative hours per 31 days on the EGTS and ABGTS sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. Also, this '10 continuous hours' requirement is not consistent with the current standard tech specs.

Reference: W STS, Rev. 4

SHIELD BUILDING STRUCTURAL INTEGRITY (Continued)

for the life of the facility. Structural integrity is required to provide 1) protection for the steel vessel from external missiles, 2) radiation shielding in the event of a LOCA, and 3) an annulus surrounding the steel vessel that can be maintained at a negative pressure during accident conditions. A visual inspection is sufficient to demonstrate this capability.

3/4.6.1.9 EMERGENCY GAS TREATMENT SYSTEM

operating

The OPERABILITY of the EGTS ensures that during LOCA conditions, containment vessel leakage into the annulus will be filtered through the HEPA filters and charcoal adsorber trains prior to discharge to the atmosphere. Operation of the system with the heaters ~~on~~ for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. This requirement is necessary to meet the assumptions used in the accident analyses and limit the site boundary radiation doses to within the limits of 10 CFR 100 during LOCA conditions.

3/4.6.1.10 CONTAINMENT VENTILATION SYSTEM

The use of the containment purge lines is restricted to one pair of purge supply and exhaust isolation valves to ensure the site boundary dose guidelines of 10 CFR Part 100 would not be exceeded in the event of an accident during purging operations.

Leakage integrity tests with a maximum allowable leakage rate for purge supply and exhaust isolation valves will provide early indication of resilient material seal degradation and will allow the opportunity for repair before gross leakage failures develop. The 0.60 L_a leakage limit shall not be exceeded when the leakage rates determined by the leakage integrity tests of the valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the containment spray system ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

3/4.9.10 and 3/4.9.11 WATER LEVEL - REACTOR VESSEL and STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.12 AUXILIARY BUILDING GAS TREATMENT SYSTEM

The limitations on the auxiliary building gas treatment system ensure that all radioactive material released from an irradiated fuel assembly will be filtered through the HEPA filters and charcoal adsorber prior to discharge to the atmosphere. Operation of the system with the heaters ~~on~~ operating for at least 10 ~~continuous~~ hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system and the resulting iodine removal capacity are consistent with the assumptions of the accident analyses.

SHIELD BUILDING STRUCTURAL INTEGRITY (Continued)

for the life of the facility. Structural integrity is required to provide 1) protection for the steel vessel from external missiles, 2) radiation shielding in the event of a LOCA, and 3) an annulus surrounding the steel vessel that can be maintained at a negative pressure during accident conditions. A visual inspection is sufficient to demonstrate this capability.

3/4.6.1.9 AIR CLEANUP SYSTEM

The OPERABILITY of the shield building air cleanup system ensures that during LOCA conditions, containment vessel leakage into the annulus will be filtered through the HEPA filters and charcoal adsorber trains prior to discharge to the atmosphere. Cumulative operation of the system with the heaters on for 10 hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. This requirement is necessary to meet the assumptions used in the accident analyses and limit the site boundary radiation doses to within the limits of 10 CFR 100 during LOCA conditions.

3/4.6.1.10 CONTAINMENT VENTILATION SYSTEM

The (42-inch) containment purge supply and exhaust isolation valves are required to be closed during plant operation since these valves have not been demonstrated capable of closing during a LOCA or steam line break accident. Maintaining these valves closed during plant operations ensures that excessive quantities of radioactive materials will not be released via the containment purge system.

The use of the containment purge lines is restricted to the (8-inch) purge supply and exhaust isolation valves to ensure that the site boundary dose guidelines of 10 CFR Part 100 would not be exceeded in the event of a loss-of-coolant accident during purging operations.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the containment spray system ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

(Credit taken for iodine removal)

The containment spray system and the containment cooling system are redundant to each other in providing post accident cooling of the containment atmosphere. However, the containment spray system also provides a mechanism for removing iodine from the containment atmosphere, and therefore the time requirements for restoring an inoperable spray system to OPERABLE status have been maintained consistent with those assigned other inoperable ESF equipment.

ULTIMATE HEAT SINK (Continued)

The limitations on minimum water level and maximum temperature are based on providing a 30-day cooling water supply to safety related equipment without exceeding their design basis temperature and is consistent with the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," March 1974.

3/4.7.6 FLOOD PROTECTION (OPTIONAL)

The limitation on flood protection ensures that facility protective actions will be taken (and operation will be terminated) in the event of flood conditions. The limit of elevation ( ) Mean Sea Level is based on the maximum elevation at which facility flood control measures provide protection to safety-related equipment.

3/4.7.7 CONTROL ROOM EMERGENCY AIR CLEANUP SYSTEM

The OPERABILITY of the control room ventilation system ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all credible accident conditions. Cumulative operation of the system with the heaters on for 10 hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR 50.

3/4.7.8 ECCS PUMP ROOM EXHAUST AIR FILTRATION SYSTEM

The OPERABILITY of the ECCS pump room exhaust air filtration system ensures that radioactive materials leaking from the ECCS equipment within the pump room following a LOCA are filtered prior to reaching the environment. Cumulative operation of the system with the heaters on for 10 hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The operation of this system and the resultant effect on offsite dosage calculations was assumed in the accident analyses.

ITEM E2.26

Previously Identified

NRC Questions A.19, D.81
Open Item Nos. 254, 255, 256

T.S. Page 5-1

Containment - Attached are the correct values for the net free volume.

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The Exclusion Area shall be as shown in Figure 5.1-1.

LOW POPULATION ZONE

5.1.2 The Low Population Zone shall be as shown in Figure 5.1-2.

MAP DEFINING UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

5.1.3 Information regarding radioactive gaseous and liquid effluents, which will allow identification of structures and release points as well as definition of UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC, shall be as shown in Figure ~~5.1-3.~~ STET

The definition of UNRESTRICTED AREA used in implementing the Radiological Effluent Technical Specifications has been expanded over that in 10 CFR 20.3 (a)(17). The UNRESTRICTED AREA boundary may coincide with the Exclusion (fenced) Area boundary, as defined in 10 CFR 100.3(a), but the UNRESTRICTED AREA does not include areas over water bodies. The concept of UNRESTRICTED AREAS, established at or beyond the SITE BOUNDARY, is utilized ~~in the~~ LIMITING CONDITIONS FOR OPERATION to keep levels of radioactive materials in liquid and gaseous effluents as low as is reasonably achievable, pursuant to 10 CFR 50.36a.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The shield building is a reinforced concrete building of cylindrical shape, with a dome roof around a free standing steel containment and having the following design features:

a. Nominal inside diameter = 125 feet,

b. Nominal inside height = 175 feet,

c. Minimum thickness of concrete walls = 3 feet,

d. Minimum thickness of concrete roof = 2 feet,

e. Minimum thickness of concrete floor pad = 9 feet,

f. Minimum thickness of the steel containment liner = 1 3/8 inches for the wall and 13/16 inch for the hemispherical roof, and

g. Net free volume = ~~1.19×10^6~~ 3.75×10^5 cubic feet between the steel containment and the shield building. Containment net free volume = 1.19×10^6 ft^3

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The reactor containment building is designed and shall be maintained for a maximum internal pressure of 15 psig and a temperature of 250°F.

ITEM E2.27

Previously Identified

Open Item Nos. 257, 258

T.S. Pages 5-2, 5-3

Exclusion Boundary and Low Population Zone Figures

Attached are figures 5.1-1 and 5.1-2.

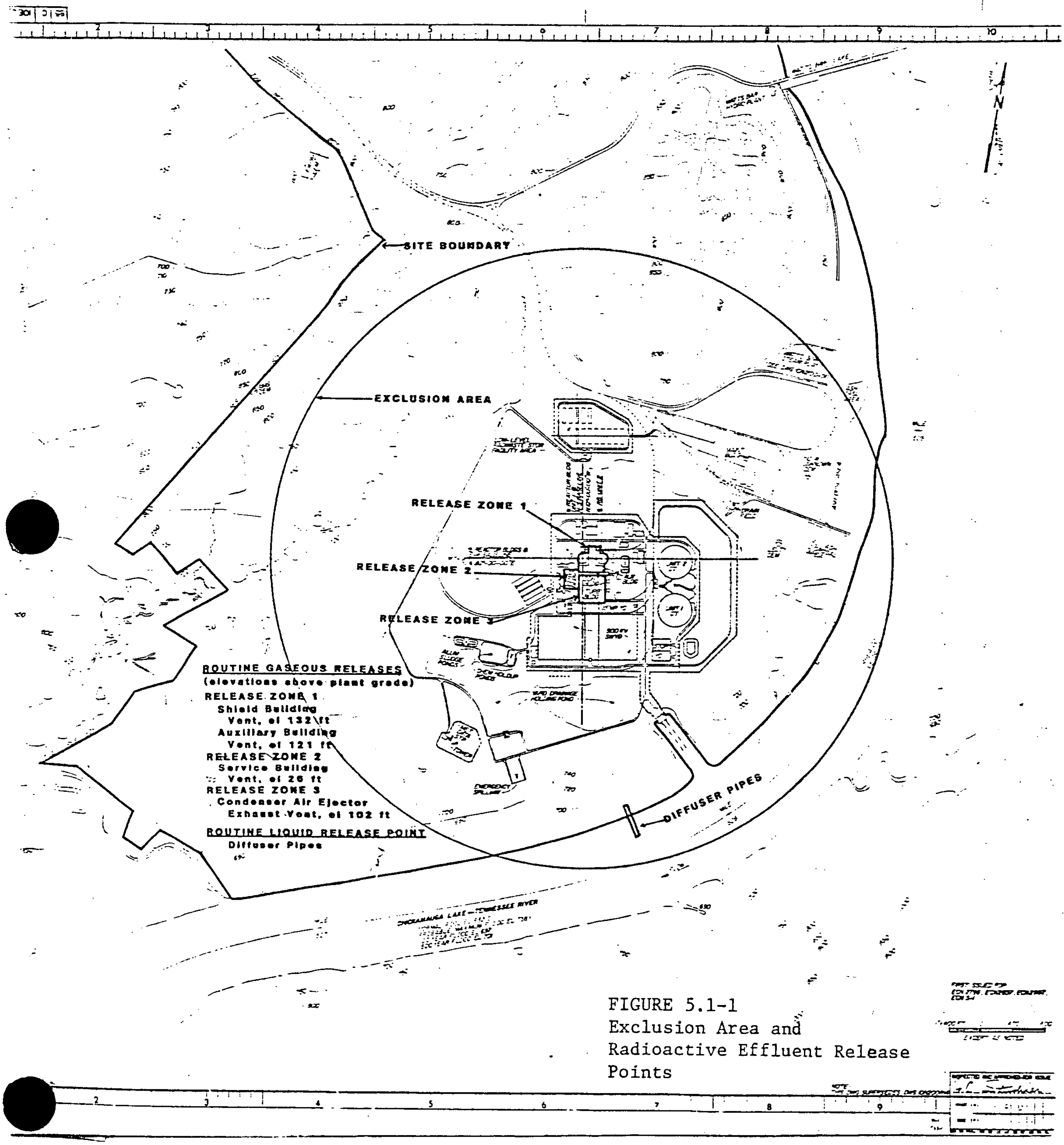

FIGURE 5.1-1
Exclusion Area and
Radioactive Effluent Release
Points

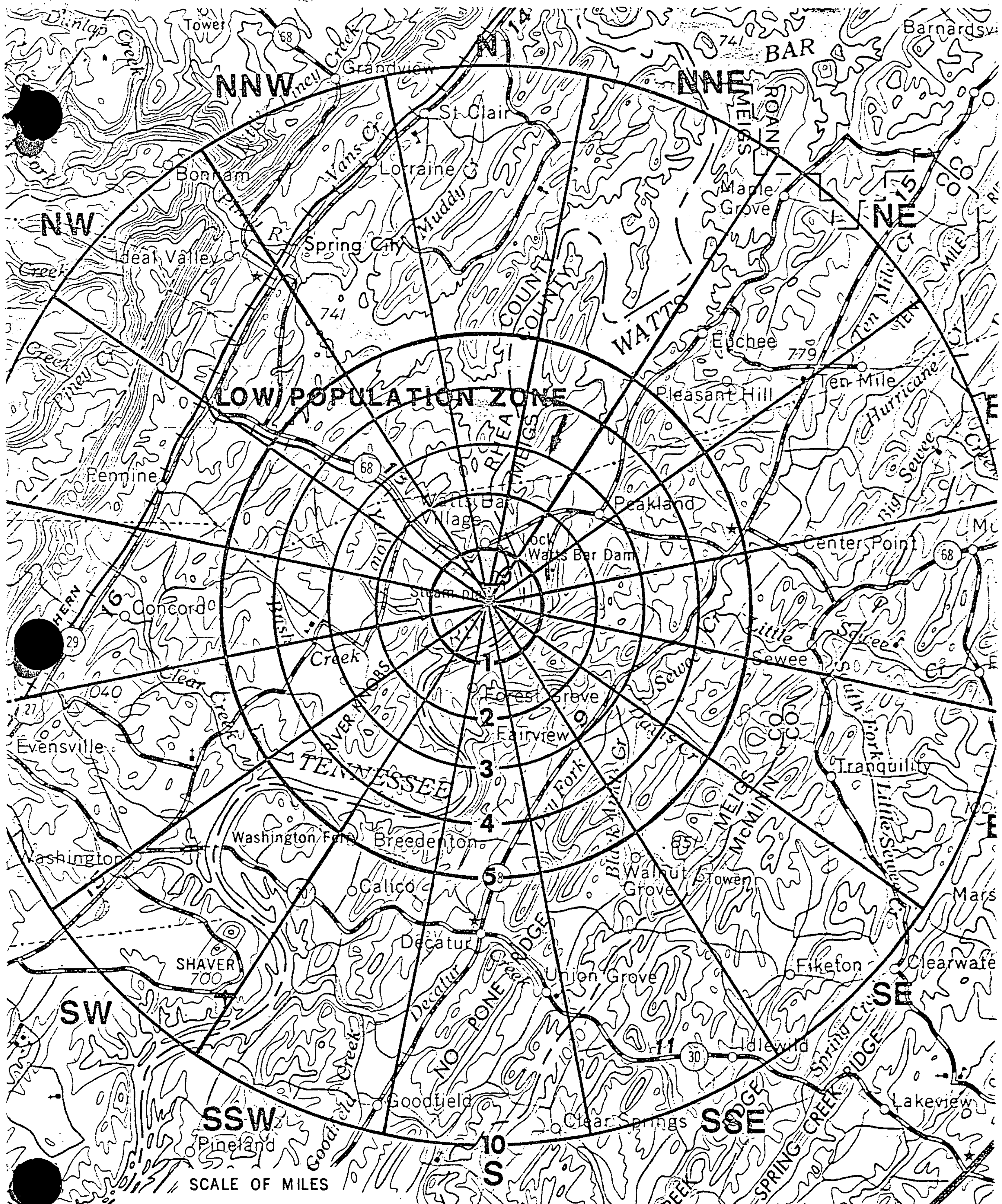

Figure 5.1-2
Low Population Zone