3.16 EMERGENCY POWER SYSTEM

Applicability

Applies to the availability of electrical power for safe operation of the station during an emergency.

Objective

To define those conditions of electrical power availability necessary to shutdown the reactor safely, and provide for the continuing availability of Engineered Safeguards when normal power is not available.

Specification

A. A reactor shall not be made critical nor shall a unit be operated such that the reactor coolant system pressure and temperature exceed 450 psig and 350°F, respectively, without:

1. Two diesel generators (the unit diesel generator and the shared backup diesel generator) OPERABLE with each generator's day tank having at least 290 gallons of fuel and with a minimum on-site supply of 35,000 gal of fuel available.

2. Two 4,160V emergency buses energized.

3. Four 480V emergency buses energized.

4. Two physically independent circuits from the offsite transmission network to energize the 4,160V and 480V emergency buses. One of these sources must be immediately available (i.e. primary source) and the other must be capable of being made available within 8 hours (i.e. dependable alternate source).
5. Two OPERABLE flow paths for providing fuel to each diesel generator.
6. Two station batteries, two chargers, and the DC distribution systems OPERABLE.
7. Emergency diesel generator battery, charger and the DC control circuitry OPERABLE for the unit diesel generator and for the shared back-up diesel generator.

B. During power operation or the return to power from HOT SHUTDOWN, the requirements of specification 3.16-A may be modified by one of the following.

1.a. With either unit's dedicated diesel generator or shared backup diesel generator unavailable or inoperable:

1. Verify the operability of two physically independent offsite AC circuits within one hour and at least once per eight hours thereafter.
2. If the diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the operability of the remaining OPERABLE diesel generator daily. For the purpose of operability testing, the second diesel generator may be inoperable for a total of two hours per test provided the two offsite AC circuits have been verified OPERABLE prior to testing.
3. If this diesel generator is not returned to an OPERABLE status within 7 days, the reactor shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

1.b. One diesel fuel oil flow path may be "inoperable" for 24 hours provided the other flow path is proven OPERABLE. If after 24 hours, the inoperable flow path cannot be returned to service, the diesel shall be considered "inoperable." When the emergency diesel generator battery, charger or DC control circuitry is inoperable, the diesel shall be considered "inoperable."

2. If a primary source is not available, the unit may be operated for seven (7) days provided the dependable alternate source can be OPERABLE within 8 hours. If specification A-4 is not satisfied within seven (7) days, the unit shall be brought to COLD SHUTDOWN.

3. One battery may be inoperable for 24 hours provided the other battery and battery chargers remain OPERABLE with one battery charger carrying the DC load of the failed battery's supply system. If the battery is not returned to OPERABLE status within the 24 hour period, the reactor shall be placed in HOT SHUTDOWN. If the battery is not restored to OPERABLE status within an additional 48 hours, the reactor shall be placed in COLD SHUTDOWN.

C. The continuous running electrical load supplied by an emergency diesel generator shall be limited to 2750 KW.

<u>Basis</u>

The Emergency Power System is an on-site, independent, automatically starting power source. It supplies power to vital unit auxiliaries if a normal power source is not available. The Emergency Power System consists of three diesel generators for two units. One generator is used exclusively for Unit 1, the second generator for Unit 2, and the third generator functions as a backup for either Unit 1 or 2. The diesel generators have a cumulative 2,000 hour rating of 2750 KW. The actual loads using conservative ratings for accident conditions, require approximately 2,320 kw. Each unit has two emergency buses, one bus in each unit is connected to its exclusive diesel generator. The second bus in each unit will be connected to the backup diesel generator as required. Each diesel generator has 100 percent capacity and is connected to independent 4,160 v emergency buses. These emergency buses are normally fed from the reserve station service transformers. The normal station service transformers are fed from the unit isolated phase bus at a point between the generator terminals and the low voltage terminal of the main step-up transformer. The reserve station service transformers are fed from the system reserve transformer in the high voltage switchyard. The circuits which supply power through either system reserve transformer are called "primary source." In the event a system reserve transformer is inoperable, the remaining one may be cross-tied by a 34.5 bus to all three reserve station service transformers. Thus, a primary source is available to both units even if one of the two system reserve transformers is out of service. Verification of primary source operability is performed by confirming that the reserve station service transformers are energized.

In addition to the "primary sources," each unit has an additional off-site power source which is called the "dependable alternate source." This source can be made available in eight (8) hours by removing a unit from service, disconnecting its generator from the isolated phase bus, and feeding offsite power through the main step-up transformer and normal station service transformers to the emergency buses.

The generator can be disconnected from the isolated phase bus within eight (8) hours. A unit can be maintained in a safe condition for eight (8) hours with no off-site power without damaging reactor fuel or the reactor coolant pressure boundary.

Verification of the dependable alternate source operability is accomplished by verifying that the required circuits, transformers, and circuit breakers are available.

The diesel generators function as an on-site back-up system to supply the emergency buses. Each emergency bus provides power to the following operating Engineered Safeguards equipment:

A. One containment spray pump

B. One charging pump

C. One low head safety injection pump

D. One recirculation spray pump inside containment

E. One recirculation spray pump outside containment

F. One containment vacuum pump

G. One motor-driven auxiliary steam generator feedwater pump

H. One motor control center for valves, instruments, control air compressor, fuel oil pumps, etc.

I. Control area air conditioning equipment - four air recirculating units, two water chilling units, one service water pump, and two chilled water circulating pumps

J. One charging pump service water pump

The day tanks are filled by transferring fuel from any one of two buried tornado missile protected fuel oil storage tanks, each of 20,000 gal capacity. Two of 100 percent capacity fuel oil transfer pumps per diesel generator are powered from the emergency buses to assure that an operating diesel generator has a continuous supply of fuel. The buried fuel oil storage tanks contain a seven (7) day supply of fuel, 35,000 gal minimum, for the full load operation of one diesel generator; in addition, there is an above ground fuel oil storage tank on-site with a capacity of 210,000 gal which is used for transferring fuel to the buried tanks.

If a loss of normal power is not accompanied by a loss-of-coolant accident, the safeguards equipment will not be required. Under this condition the following additional auxiliary equipment may be operated from each emergency bus:

A. One component cooling pump

B. One residual heat removal pump

C. One motor-driven auxiliary steam generator feedwater pump

The emergency buses in each unit are capable of being interconnected under strict administrative procedures so that the equipment which would normally be operated by one of the diesels could be operated by the other diesel, if required.

The electrical power requirements and the emergency power testing requirements for the auxiliary feedwater cross-connect are contained in TS 3.6.B.4.c and TS 4.6 respectively.

References

FSAR Section 8.5	Emergency Power System
FSAR Section 9.3	Residual Heat Removal System
FSAR Section 9.4	Component Cooling System
FSAR Section 10.3.2	Auxiliary Steam System
FSAR Section 10.3.5	Condensate and Feedwater System

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3.17 LOOP STOP VALVE OPERATION

Applicability

Applies to the operation of the loop stop valves.

Objective

To specify those limiting conditions for operation of the loop stop valves which must be met to ensure safe reactor operation.

Specifications

1. The loop stop valves shall be maintained open unless the reactor is in COLD SHUTDOWN or REFUELING SHUTDOWN.

2. A hot or cold leg stop valve in a reactor coolant loop may be closed in COLD SHUTDOWN or REFUELING SHUTDOWN for up to 2 hours for valve maintenance or testing. If the stop valve is not opened within 2 hours, the loop shall be isolated.

3. Whenever a reactor coolant loop is isolated, the stop valves of the isolated loop shall have their AC power removed and their breakers locked open.*

4. Whenever an isolated and filled reactor coolant loop is returned to service, the following conditions shall be met:

   a. A source range nuclear instrumentation channel shall be operable and continuously monitored with audible indication in the control room during opening of the hot leg loop stop valve, during relief line flow, and when opening the cold leg stop valve in the isolated loop. Should the count rate increase by more than a factor of two over the initial count rate, the hot and cold leg stop valves shall be re-closed and no attempt made to open the stop valves until the reason for the count rate increase has been determined.

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* Power may be restored to a hot or cold leg loop stop valve in an isolated and filled loop provided the requirements of Specifications 4.b or 4.c are met, respectively. Power may be restored to a loop stop valve in an isolated and drained loop provided the requirements of Specifications 5.a and b are met.

b. Before opening the hot leg loop stop valve.

1) The boron concentration of the isolated loop shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.9, as applicable for the active volume of the Reactor Coolant System. Verification of this condition shall be completed within 1 hour prior to opening the hot leg stop valve in the isolated loop.

c. Before opening the cold leg loop stop valve.

1) The hot leg loop stop valve shall be open with relief line flow established for at least 90 minutes at greater than or equal to 125 gpm.

2) The cold leg temperature of the isolated loop shall be at least 70°F and within 20°F of the highest cold leg temperature of the active loops. Verification of this condition shall be completed within 30 minutes prior to opening the cold leg stop valve in the isolated loop.

3) The boron concentration of the isolated loop shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.9, as applicable for the active volume of the Reactor Coolant System. Verification of this condition shall be completed after relief line flow for at least 90 minutes at greater than or equal to 125 gpm and within 1 hour prior to opening the cold leg stop valve in the isolated loop.

5. Whenever an isolated and drained reactor coolant loop is filled from the active volume of the RCS, the following conditions shall apply:

a. Seal injection may be initiated to the reactor coolant pump in the isolated loop provided that:

1) The isolated loop is drained. Verification of this condition shall be completed within 2 hours prior to initiating seal injection.

2) The boron concentration of the source for reactor coolant pump seal injection shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.9, as applicable for the active volume of the Reactor Coolant System. If using the Volume Control Tank (VCT) as the source for reactor coolant pump seal injection, verification of the boron concentration shall be completed within 1 hour prior to initiating seal injection and every hour thereafter during the loop backfill evolution.

b. The cold leg loop stop valve may be energized and/or opened to backfill the loop from the active volume of the Reactor Coolant System provided that:

1) The isolated loop is drained or reactor coolant pump seal injection has been initiated in accordance with Specification 3.17.5.a above. Verification of the loop being drained shall be completed within 2 hours prior to partially opening the cold leg stop valve in the isolated loop.

2) The Reactor Coolant System level is at least 18 ft.

3) A source range nuclear instrumentation channel is OPERABLE with audible indication in the control room.

c. Backfilling of the isolated loop may continue provided that:

1) The Reactor Coolant System level is maintained at or above 18 ft. If Reactor Coolant System level is not maintained at or above 18 ft. the loop stop valve shall be closed.

2) The boron concentration of the reactor coolant pump seal injection source is greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.9, as applicable for the active volume of the Reactor Coolant System. If the boron concentration is not maintained greater than or equal to the required boron concentration noted above, the loop stop valve on the loop being backfilled shall be closed and either drain the loop or apply Specification 3.17.4.

3) A source range nuclear instrumentation channel is OPERABLE and continuously monitored with audible indication in the control room during the backfill evolution. Should the count rate increase by more than a factor of two over the initial count rate, the cold leg loop stop valve shall be closed and no attempt made to open the cold leg stop valve until the reason for the count rate increase has been determined.

d. When the isolated loop is full, the cold leg loop stop valve can be fully opened and the hot leg loop stop valve opened provided that:

1) The boron concentration of the isolated loop is greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.9, as applicable for the active volume of the Reactor Coolant System. If the VCT was used as the source for reactor coolant pump seal injection, this condition shall be verified within 1 hour prior to fully opening the loop stop valves. If the boron concentration in the isolated loop does not meet the condition above, close the loop stop valve and either drain the loop or apply Specification 3.17.4.

2) The hot and cold leg loop stop valves are opened within 2 hours after the isolated loop is filled. If the loop stop valves are not fully open within 2 hours, close the loop stop valves and either drain the loop or apply Specification 3.17.4.

<u>Basis</u>

The Reactor Coolant System may be operated with isolated loops in COLD SHUTDOWN or REFUELING SHUTDOWN in order to perform maintenance. A loop stop valve in any loop can be closed for up to two hours without restriction for testing or maintenance in these operating conditions. While operating with a loop isolated, AC power is removed from the loop stop valves and their breakers locked opened to prevent inadvertent opening. When the isolated loop is returned to service, the coolant in the isolated loop mixes with the coolant in the active loops. This situation has the potential of causing a positive reactivity addition with a corresponding reduction of shutdown margin if:

a. The temperature in the isolated loop is lower than the temperature in the active loops (cold water accident), or

b. The boron concentration in the isolated loop is insufficient to maintain the required shutdown margin (boron dilution accident).

The return to service of an isolated and filled loop is done in a controlled manner that precludes the possibility of an uncontrolled positive reactivity addition from cold water or boron dilution. A flow path to mix the isolated loop with the active loops is established through the relief line by opening the hot leg stop valve in the isolated loop and starting the reactor coolant pump. The relief line flow is low enough to limit the rate of any reactivity addition due to differences in temperature and boron concentration between the isolated loop and the active loops. In addition, a source range instrument channel is required to be operable and continuously monitored to detect any change in core reactivity.

The limiting conditions for returning an isolated and filled loop to service are as follows:

a. A hot leg loop stop valve may not be opened unless the boron concentration in the isolated loop is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

b. A cold leg loop stop valve can not be opened unless the hot leg loop stop valve is open with relief line flow established for at least 90 minutes at greater than or equal to 125 gpm. In addition, the cold leg temperature of the isolated loop must be at least 70°F and within 20°F of the highest cold leg temperature of the active loops. The boron concentration in the isolated loop must be verified to be greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

c. A source range nuclear instrument channel is required to be monitored to detect any unexpected positive reactivity addition during hot or cold leg stop valve opening and during relief line flow.

If an isolated loop is initially drained, the above requirements are not applicable. An initially isolated and drained loop may be returned to service by partially opening the cold leg loop stop valve and filling the loop in a controlled manner from the Reactor Coolant System. To eliminate numerous reactor coolant pump jogs to completely fill a drained loop, a partial vacuum may be established in the isolated loop prior to commencing filling from the active volume of the Reactor Coolant System. The vacuum-assist loop fill evolution requires initiating seal injection to the reactor coolant pump to permit establishing an adequate vacuum in the isolated loop. A portion of the reactor coolant pump seal injection enters the isolated loop. To preclude the possibility of an uncontrolled positive reactivity addition associated with the water injected into the isolated and drained loop from the seal injection, a water source of known boron concentration is used.

Prior to initiating seal injection to the reactor coolant pump in an isolated loop or partially opening the cold leg loop stop valve, the following measures are required to ensure that no uncontrolled positive reactivity addition or loss of Reactor Coolant System inventory occurs:

a. The isolated loop is verified drained prior to the initial addition of water to return a loop to service, thus preventing the dilution of the Reactor Coolant System boron concentration by liquid present in the loop. Therefore, verification that the loop is drained must occur either prior to initiation of seal injection to the Reactor Coolant Pump if the vacuum-assist backfill method is used or prior to opening the cold leg loop stop valve if the vacuum-assist backfill method is not used.

b. The Reactor Coolant System level is verified to be greater than or equal to the 18 ft. elevation to ensure Reactor Coolant System inventory is maintained for decay heat removal. In addition, the filling evolution is limited to one isolated loop at a time.

c. The water source for the reactor coolant pump seal injection is sampled to ensure the boron concentration is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

d. A source range nuclear instrument channel is monitored to detect any unexpected positive reactivity addition.

During the loop fill evolution, the following measures are implemented to ensure no positive reactivity additions or sudden loss of Reactor Coolant System inventory occur.

a. The Reactor Coolant System is maintained at greater than or equal to the 18 ft. elevation.

b. Makeup to the active portion of the Reactor Coolant System is through a flowpath that will ensure makeup flow is mixed with the reactor coolant in the active portion of the Reactor Coolant System and flows through the core prior to entering the loop being filled.

c. Charging flow from the VCT, if used as the source for reactor coolant pump seal injection, is periodically sampled to ensure the boron concentration is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

d. The source range nuclear instrumentation channel is monitored to provide a secondary indication of any possible positive reactivity addition.

The potential reactivity effects due to Reactor Coolant System cooldown during and following loop backfill are limited to acceptable levels by the small absolute value of the isothermal temperature coefficient of reactivity that exists at cold and refueling shutdown conditions. If steam generator secondary temperature is higher than the active portion of the Reactor Coolant System, a conservative heat transfer analysis demonstrates that 1) the pressurizer insurge rates that could result from heatup are easily accommodated by available relief capacity, and 2) the total integrated insurge due to heatup following backfill is very small, i.e., less than the unmeasured pressurizer volume above the upper level tap.

Reactivity effects due to boron stratification in the backfilled loop are not a concern since stratification is not expected to take place at the normal shutdown boron concentrations (2000-2400 ppm) and temperatures (40°F-200°F) during the time to complete backfill of the loop and open the loop stop valves fully.

After an initially drained loop is filled from the Reactor Coolant System by partially opening the loop stop valves. the loop is no longer considered to be isolated. Thus. the requirements for returning an isolated and filled loop to service are not applicable and the loop stop valves may be fully opened without restriction within two hours of completing the loop fill evolution.

The initial Reactor Coolant System level requirement has been established such that. even if the three cold leg stop valves are suddenly opened and no makeup is available. the Reactor Coolant System water level will not drop below mid-nozzle level. This ensures continued adequate suction conditions for the residual heat removal pumps.

The safety analyses assume a minimum shutdown margin as an initial condition. Violation of these limiting conditions could result in the shutdown margin being reduced to less than that assumed in the safety analyses. In addition, violation of these limiting conditions could also cause a loss of shutdown decay heat removal.

<u>Reference</u>

(1) UFSAR Section 4.2

(2) UFSAR Section 14.2.5

3.18 MOVABLE IN-CORE INSTRUMENTATION

Applicability

Applies to the operability of the movable detector instrumentation system.

Objective

To specify functional requirements on the use of the in-core instrumentation systems, for the recalibration of the excore symmetrical off-set detection system.

Specification

A. A minimum of 16 total accessible thimbles and at least 2 per quadrant, each of which will accept a movable incore-detector, shall be operable during re-calibration of the excore symmetrical off-set detection system.

B. Power shall be limited to 90% of rated power for three loop operation; 54% of rated power for two loop operation with the loop stop valves closed, and 50% of rated power for two loop operation with the loop stop valves open if re-calibration requirements for the excore symmetrical off-set detection system, identified in Table 4.1-1, are not met.

C. The requirements of Specification 3.0.1 are not applicable.

Basis

The Movable In-core Instrumentation System [1] has five drives, five detectors, and 50 thimbles in the core. Each detector can be routed to twenty or more thimbles. Consequently, the full system has a great deal more capability than would be needed for the calibration of the excore detectors.

To calibrate the excore detectors system, it is only necessary that the Movable In-core System be used to determine the gross power distribution in the core as indicated by the power balance between the top and bottom halves of the core.

After the excore system is calibrated initially, recalibration is needed only infrequently to compensate for changes in the core, due for example to fuel depletion, and for changes in the detectors.

If the recalibration is not performed, the mandated power reduction assures safe operation of the reactor since it will compensate for an error of 10% in the excore protection system. Experience at Beznau No. 1 and R. E. Ginna plants has shown that drift due to the core on instrument channels is very slight. Thus limiting the operating levels to 90% of the rated two and three loop powers is very conservative for both operational modes.

Reference

(1) FSAR - Section 7.6

3.19 MAIN CONTROL ROOM BOTTLED AIR SYSTEM

Applicability

Applies to the ability to maintain a positive differential pressure in the main control room.

Objective

To specify functional requirements for the main control room bottled air system

Specification

A. Requirements

Two trains of bottled air shall be OPERABLE and each shall be capable of pressurizing the main control room to a positive differential pressure with respect to adjoining areas of the auxiliary, turbine, and service buildings for one hour. A minimum positive differential pressure of 0.05 inches of water must be maintained when the control room is isolated under accident conditions. This capability shall be demonstrated by the testing requirements delineated in Technical Specification 4.1.

B Remedial Action

1. With one train of the bottled air system inoperable, restore the inoperable train to OPERABLE status within 7 days or both units shall be placed in HOT SHUTDOWN within the next 8 hours
2. With both trains of the bottled air system inoperable, restore one train to OPERABLE status within 8 hours or both units shall be placed in HOT SHUTDOWN within the same 8 hours.
3. With an inoperable control room pressure boundary, restore the boundary to OPERABLE status within 8 hours or both units shall be placed in HOT SHUTDOWN within the same 8 hours. The control room pressure boundary may be intermittently opened under administrative control

If the requirements of Specification 3.19.B.1, 3.19.B.2, or 3.19.B.3 are not met within 48 hours after achieving HOT SHUTDOWN, both units shall be placed in COLD SHUTDOWN within the next 30 hours.

Basis

Following a design basis accident, the containment will be depressurized to 0.5 psig in less than 1 hour and to subatmospheric pressure within 4 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 0.5 psig for the interval from 1 to 4 hours following the Design Basis Accident. Beyond 4 hours, containment pressure is assumed to be less than 0.0 psig, terminating leakage from containment. The main control room is maintained at a positive differential pressure using bottled air during the first hour, when the containment leakrate is greatest.

The main control room is contained in the control room pressure boundary or envelope, which is defined in the Technical Specification 3.23 Basis.

The control room pressure boundary is permitted to be opened intermittently under administrative control without declaring the boundary inoperable. The administrative control must provide the capability to re-establish the control room pressure boundary. For normal ingress into and egress from the pressure boundary, the individual entering or exiting the area has control of the door.

3.20 SHOCK SUPPRESSORS (SNUBBERS)

Applicability

Applies to all shock suppressors (snubbers) which are required to protect the reactor coolant system and other safety-related systems. Snubbers excluded from this inspection program are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effects on any safety-related system.

Objective

To define those limiting conditions for operation that are necessary to ensure that all snubbers required to protect the reactor coolant system, or any other safety-related system or component, are operable during reactor operation.

Specifications

A. During all modes of operation except Cold Shutdown and Refueling, all snubbers required to protect the reactor coolant system and other safety related systems shall be operable except as noted in 3.20.B and 3.20.C below.

B. If any snubber required to protect the reactor coolant system and other safety-related systems is found to be inoperable, it must be repaired and made operable, or otherwise replaced with one which is operable within 72 hours.

C. If the requirements of Specification B cannot be met, an orderly shutdown shall be initiated, and the reactor shall be in the hot shutdown condition within 36 hours.

D. If a snubber is determined to be inoperable while the reactor is in the shutdown or refueling mode, the snubber shall be made operable or replaced prior to reactor startup.

Basis

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all snubbers required to protect the primary coolant system, or any other safety related system or component, be operable during reactor operation.

Because snubber protection is required only during low probability events, a period of 72 hours is allowed for repairs of replacement. In case a shutdown is required, the allowance of 36 hours to reach a hot shutdown condition will permit an orderly shutdown consistent with standard operating procedures. Since plant startup should not commence with knowingly defective safety related equipment, Specification 3.20.D prohibits startup with inoperable snubbers.

3.22 AUXILIARY VENTILATION EXHAUST FILTER TRAINS

Applicability

Applies to the ability of the safety-related system to remove particulate matter and gaseous iodine following a LOCA.

Objective

To specify requirements to ensure the proper function of the system.

Specification

A. Whenever either unit's Reactor Coolant System temperature and pressure is greater than 350°F and 450 psig, respectively, two auxiliary ventilation exhaust filter trains shall be OPERABLE with:

1. Two filter exhaust fans;

2. Two HEPA filter and charcoal adsorber assemblies.

B. With one train of the exhaust filter system inoperable for any reason, return the inoperable train to an operable status within 7 days or be in at least Hot Shutdown within the next 6 hours and in Cold Shutdown within the following 48 hours.

Basis

The purpose of the filter trains located in the auxiliary building is to provide standby capability for removal of particulate and iodine contaminants from the exhaust air of the charging pump cubicles of the auxiliary building, fuel building, decontamination building, containment (during shutdown) and safeguards building adjacent to the containment which discharge through the ventilation vent and could require filtering prior to release. During normal plant operation, the exhaust from any one of these areas can be diverted, if required, through the auxiliary building filter trains remotely from the control room. The safeguards building exhaust and the charging pump cubicle exhaust are automatically diverted through the filter trains in the event of a LOCA (diverted on a safety injection system signal). The fuel building exhaust and purge exhaust are not required to be aligned to pass through the filters during spent fuel handling since the Fuel Handling Accident analysis takes no credit for these filters.

High efficiency particulate air (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment.

3.23 MAIN CONTROL ROOM AND EMERGENCY SWITCHGEAR ROOM VENTILATION AND AIR CONDITIONING SYSTEMS

Applicability

Applies to the Main Control Room (MCR) and Emergency Switchgear Room (ESGR) Air Conditioning System and Emergency Ventilation System.

Objective

To specify requirements to ensure the proper function of the Main Control Room and Emergency Switchgear Room Air Conditioning System and Emergency Ventilation System.

Specification

A. Both trains of the Main Control Room and Emergency Switchgear Room Emergency Ventilation System shall be OPERABLE whenever either unit is above COLD SHUTDOWN.

B. With one train of the Main Control Room and Emergency Switchgear Room Emergency Ventilation System inoperable for any reason, return the inoperable train to an OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 48 hours.

C. The Main Control Room and Emergency Switchgear Room Air Conditioning System shall be OPERABLE as delineated in the following:

*1. Chiller Refrigeration Units

a. Three main control room and emergency switchgear room chillers must be OPERABLE whenever either unit is above COLD SHUTDOWN.

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* This interim specification is necessary until the air conditioning system modifications are completed. Following completion of the permanent modifications, a revised air conditioning system specification will be submitted.

b. The three OPERABLE chillers are required to be powered from three of the four emergency buses with one of those chillers capable of being powered from the fourth emergency bus.

c. If one of the OPERABLE chillers becomes inoperable or is not powered as required by Specification 3.23.C.1.b, return an inoperable chiller to OPERABLE status within seven (7) days or bring both units to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

d. If two of the OPERABLE chillers become inoperable or are not powered as required by Specification 3.23.C.1.b, return an inoperable chiller to OPERABLE status within one (1) hour or bring both units to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

2. Air Handling Units (AHU)

a. Unit 1 air handling units, 1-VS-AC-1, 1-VS-AC-2, 1-VS-AC-6, and 1-VS-AC-7, must be OPERABLE whenever Unit 1 is above COLD SHUTDOWN.

1. If one Unit 1 AHU becomes inoperable, return the inoperable AHU to OPERABLE status within seven (7) days or bring Unit 1 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

b. Unit 2 air handling units, 2-VS-AC-8, 2-VS-AC-9, 2-VS-AC-6, and 2-VS-AC-7 must be OPERABLE whenever Unit 2 is above COLD SHUTDOWN.

1. If one Unit 2 AHU becomes inoperable, return the inoperable AHU to OPERABLE status within seven (7) days or bring Unit 2 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

Basis

When the supply of compressed bottled air is depleted, the Main Control Room and Emergency Switchgear Room Emergency Ventilation System is manually started to continue to maintain the control room pressure at the design positive pressure so that leakage is outleakage. One train of the main control room emergency ventilation consists of one fan powered from an independent emergency power source.

The Main Control Room and Emergency Switchgear Room Emergency Ventilation System is designed to filter the intake air to the control room pressure envelope, which consists of the control room, relay rooms, and emergency switchgear rooms during a loss of coolant accident.

High efficiency particulate air (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radio-iodine to the control room.

If the system is found to be inoperable, there is no immediate threat to the control room, and reactor operation may continue for a limited period of time while repairs are being made. If the system cannot be repaired within the specified time, procedures are initiated to establish conditions for which the filter system is not required.

The Main Control Room and Emergency Switchgear Room Air Conditioning System cools the main control room, the control room annex and the Units 1 and 2 emergency switchgear rooms. The existing air conditioning system includes three chillers (1-VS-E-4A, 4B, and 4C) and eight air handling units (1-VS-AC-1, 2, 6, 7 and 2-VS-AC-6, 7, 8, and 9).

Interim modifications were completed on the Main Control Room and Emergency Switchgear Room Air Conditioning System to address interim failure and increased cooling requirements for the emergency switchgear rooms. Permanent modifications will include replacement of the main control room and emergency switchgear room air handling units (AHU) and installation of additional chiller capacity to restore original design flexibility.

Units 1 and 2 main control room and emergency switchgear room AHUs have been replaced in the initial phases of the permanent modification, restoring redundancy to the AHU portion of the original system design. As a result, the following main control room and emergency switchgear room equipment is required to operate to maintain design temperature under maximum heat load conditions:

- Two chillers
- One Unit 1 MCR AHU and one Unit 1 ESGR AHU
- One Unit 2 MCR AHU and one Unit 2 ESGR AHU

The existing chiller configuration requires that the three chillers in MER-3 (1-VS-E-4A, 4B, and 4C) be OPERABLE so that in the event of a total Loss of Offsite Power to the station and the single failure of an emergency bus or a chiller, two chillers remain available. Installation of the two additional chillers in MER-5 (1-VS-E-4D and 4E) will provide operational flexibility. Any three of the five installed chillers, powered from separate emergency buses with one of those capable of being powered from the fourth emergency bus, will ensure two chillers are available to maintain design temperature under maximum heat load conditions. This operational flexibility is necessary to complete the permanent modification of the existing chillers.

In addition to the equipment restrictions above, a fire watch will be required during this interim period in MER-3 to address Appendix R considerations.

4.0 SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance requirements provide for testing, calibrating, or inspecting those systems or components which are required to assure that operation of the units or the station will be as prescribed in the preceding sections.

4.0.2 Surveillance requirement specified time intervals may be adjusted plus or minus 25 percent to accommodate normal test schedules.

4.0.3 Failure to perform a surveillance requirement within the allowed surveillance interval, defined by Specification 4.0.2, shall constitute noncompliance with the operability requirements for a Limiting Condition for Operation. The time limits of the Action Statement requirements are applicable at the time it is identified that a surveillance requirement has not been performed. The Action Statement requirements may be delayed for up to 24 hours to permit the completion of the surveillance when the allowable outage time limits of the Action Statement requirements are less than 24 hours. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an operational condition shall not be made unless the surveillance requirement(s) associated with a Limiting Condition of Operation has been performed within the stated surveillance interval or as otherwise specified. This provision shall not prevent passage through or to operational conditions as required to comply with Action Statement requirements.

4.0.5 Surveillance requirements for inservice inspection and testing of ASME Code Class 1, 2, and 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

ASME Boiler and Pressure Vessel Code and Applicable Addenda Terminology for Inservice Inspection and Testing Activities	Required Frequencies for Performing Inservice Inspection and Testing Activities
Monthly	At least once per 31 days
Quarterly or Every 3 months	At least once per 92 days
COLD SHUTDOWN	At least once per CSD
REFUELING SHUTDOWN	At least once per RSD

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for pump and valve testing only. Extensions for inservice inspection of components will be to the requirements of Section XI of the ASME Boiler and Pressure Vessel Code.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

BASES

4.0.1 This specification provides that surveillance activities necessary to ensure the Limiting Conditions for Operation are met and will be performed during all operating conditions for which the Limiting Conditions for Operation are applicable.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance value and permits the performance of more frequent surveillance activities.

4.0.3 This specification establishes the failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, as a condition that constitutes a failure to meet the operability requirements for a Limiting Condition for Operation. Under the provisions of this specification, systems and components are assumed to be OPERABLE when surveillance requirements have been satisfactorily performed within the specified time interval. However, nothing in this provision is to be construed as implying that systems or components are OPERABLE when they are found or known to be inoperable although still meeting the surveillance requirements. This specification also clarifies that the Action Statement requirements are applicable when Surveillance Requirements have not been completed within the allowed surveillance interval and that the time limits of the Action Statement requirements apply from the point in time it is identified that a surveillance has not been performed and not at the time that the allowed surveillance interval was exceeded. Completion of the surveillance requirement within the allowable outage time limits of the Action Statement requirements restores compliance with the requirements of Specification 4.0.3. However, this does not negate the fact that the failure to have performed the surveillance within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, was a violation of the operability requirements of a Limiting Condition for Operation. Further, the failure to perform a surveillance within the provisions of Specification 4.0.2 is a violation of a Technical Specification requirement and is, therefore, a reportable event under the requirements of 10 CFR 50.73(a)(2)(i)(B) because it is a condition prohibited by the plant's Technical Specifications.

If the allowable outage time limits of the Action Statement requirements are less than 24 hours or a shutdown is required to comply with Action Statement requirements, e.g., Specification 3.0.1, a 24 hour allowance is provided to permit a delay in implementing the Action Statement requirements. This provides an adequate time limit to complete surveillance requirements that have not been performed. The purpose of this allowance is to permit the completion of a surveillance before a shutdown is required to comply with Action Statement requirements or before other remedial measures would be required that may preclude completion of a surveillance. The basis for this allowance includes consideration for plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. This provision also provides a time limit for the completion of surveillance requirements that become applicable as a consequence of condition changes imposed by Action Statement requirements and for completing surveillance requirements that are applicable when an exception to the requirements of Specification 4.0.4 is allowed. If a surveillance is not completed within the 24 hour allowance, the time limits of the Action Statement requirements are applicable at that time. When a surveillance is performed within the 24 hour allowance and the surveillance requirements are not met, the time limits of the Action Statement requirements are applicable at the time that the surveillance is terminated.

Surveillance requirements do not have to be performed on inoperable equipment because the Action Statement requirements define the remedial measures that apply. However, the surveillance requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

4.0.4 This specification establishes the requirement that all applicable surveillances must be met before entry into an operational condition specified in the applicability statement. The purpose of this specification is to ensure that system and component operability requirements or parameter limits are met before entry into a condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in operational conditions associated with plant shutdown as well as startup.

Under the provisions of this specification, the applicable surveillance requirements must be performed within the specified surveillance interval to ensure that the Limiting Conditions for Operation are met during initial plant startup or following a plant outage.

Exceptions to Specification 4.0.4 allow performance of surveillance requirements associated with a Limiting Condition for Operation after entry into the applicable operational condition.

When a shutdown is required to comply with Action Statement requirements, the provisions of Specification 4.0.4 do not apply because this would delay placing the facility in a lower condition of operation.

4.0.5 This specification ensures that inservice inspection, repairs, and replacements of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves will be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a. Specific relief from portions of the above requirements has been provided in writing by the Commission and is not a part of these Technical Specifications.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout these Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. For example, the Technical Specification definition of OPERABLE does not grant a grace period before a device that is not capable of performing its specified function is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation.

Objective

To specify the minimum frequency and type of surveillance to be applied to unit equipment and conditions.

Specification

A. Calibration, testing, and checking of instrumentation channels and interlocks shall be performed as detailed in Tables 4.1-1, 4.1-A, and 4.1-2.

B. Equipment tests shall be performed as detailed in Table 4.1-2.A and as detailed below.

   1. In addition to the requirements of 4.0.5, each Pressurizer PORV and block valve shall be demonstrated OPERABLE by:

      a. Performing a complete cycle of each PORV with the reactor coolant average temperature >350°F once per 18 months.

      b. Performing a complete cycle of the solenoid air control valve and check valves on the air accumulators in the PORV control system once per 18 months.

      c. Operating each block valve through one complete cycle of travel at least once per 92 days. This surveillance is not required if the block valve is closed in accordance with 3.1.6.a, b, or c.

      d. Verifying that the pressure in the PORV backup air supply is greater than the surveillance limit at least once per 92 days.

      e. Performing functional testing and calibration of the PORV backup air supply instrumentation and alarm setpoints at least once per 18 months.

2. The pressurizer water volume shall be determined to be within its limit as defined in Specification 2.3.A.3.a at least once per 12 hours whenever the reactor is not subcritical by at least 1% $\Delta k/k$.

3. Each Reactor Vessel Head vent path remote operating isolation valve not required to be closed by Specification 3.1.A.7a or 3.1.A.7b shall be demonstrated OPERABLE at each COLD SHUTDOWN but not more often than once per 92 days by operating the valve through one complete cycle of full travel from the control room.

4. Each Reactor Vessel Head vent path shall be demonstrated OPERABLE following each refueling by:

   a. Verifying the manual isolation valves in each vent path are locked in the open position.

   b. Cycling each remote operating isolation valve through at least one complete cycle of full travel from the control room.

   c. Verifying flow through the reactor vessel head vent system vent paths.

C. Sampling tests shall be conducted as detailed in Table 4.1-2B.

D. Whenever containment integrity is not required, only the asterisked items in Table 4.1-1 and 4.1-2A and 4.1-2B are applicable.

E. Flushing of wetted sensitized statinless steel pipe sections as identified in the Basis Section shall be conducted only if the RWST Water Chemistry exceeds 0.15 PPM chlorides and/or florides (CL^- and or F^-). Flushing of sensitized stainless steel pipe sections shall be conducted as detailed in TS Table 4.1-3A and 4.1-3B.

F. Containment Ventilation Purge System isolation valves:

1. The outside Containment Ventilation Purge System isolation valves and the isolation valve in the containment vacuum ejector suction line outside containment shall be determined locked, sealed, or otherwise secured in the closed position at least once per 31 days.

2. The inside Containment Ventilation Purge System isolation valves and the isolation valve in the containment vacuum ejector suction line inside containment shall be verified locked, sealed, or otherwise secured in the closed position each COLD SHUTDOWN, but not required to be verified more than once per 92 days.

G. Verify that each containment penetration not capable of being closed by OPERABLE automatic isolation valves and required to be closed during accident conditions is closed by manual valves, blind flanges, or deactivated automatic valves secured* in the closed position at least once per 31 days. Valves, blind flanges, and deactivated automatic or manual valves located inside containment which are locked, sealed, or otherwise secured in the closed position shall be verified closed during each COLD SHUTDOWN, but not required to be verified more than once per 92 days.

* Non-automatic or deactivated automatic valves may be opened on an intermittent basis under administrative control. The valves identified in TS 3.8.A.2 and TS 3.8.A.3 are excluded from this provision.

H. If the RWST Water Chemistry exceeds 0.15 PPM for Cl^- and/or F^-, flushing of sensitized stainless steel piping as required by 4.1.E will be performed once the RWST Water Chemistry has been brought within specification limit of less than 0.15 PPM chlorides and/or fluorides. Samples will be taken periodically until the sample indicates the Cl^- and/or F^- and levels are below 0.15 PPM.

BASIS

Check

Failures such as blown instrument fuses, defective indicators, and faulted amplifiers which result in "upscale" or "downscale" indication can be easily recognized by simple observation of the functioning of an instrument or system. Furthermore, such failures are, in many cases, revealed by alarm or annunciator action, and a periodic check supplements this type of built-in surveillance.

Calibration

Calibration shall be performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (power level) channels shall be calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process systems instrumentation errors resulting from drift within the individual instruments are normally negligible.

During the interval between periodic channel tests and daily check of each channel, a comparison between redundant channels will reveal any abnormal condition resulting from a calibration shift, due to instrument drift of a single channel.

During the periodic channel test, if it is deemed necessary, the channel may be tuned to compensate for the calibration shift. However, it is not expected that this will be required at any fixed or frequent interval.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (power level) channels, and once per 18 months for the process system channels are considered acceptable.

The OPERABILITY of the Reactor Trip System and ESFAS instrumentation systems and interlocks ensures that 1) the associated ESF action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic and sufficient redundancy are maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the RTS and ESFAS instrumentation, and 3) sufficient system functional capability is available from diverse parameters.

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. Specific 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 TRIP INSTRUMENTATION SYSTEM, and supplements to that report, WCAP-10271 Supplement 2, EVALUATION OF SURVEILLANCE FREQUENCIES AND OUT OF SERVICE TIMES FOR THE ENGINEERED SAFETY FEATURES ACTUATION SYSTEM, and supplements to that report, and WCAP-14333P, PROBABILISTIC RISK ANALYSIS OF THE RPS AND ESF TEST TIMES AND COMPLETION TIMES, as approved by the NRC and documented in SERs dated February 21, 1985, February 22, 1989, the SSER dated April 30, 1990 for WCAP-10271 and July 15, 1998 for WCAP-14333P. For those functional units not included in the generic Westinghouse probabilistic risk analyses discussed above, a plant-specific risk assessment was performed. This risk assessment demonstrates that the effect on core damage frequency and incremental change in core damage probability is negligible for the relaxations associated with the additional functional units.

Surveillance testing of instrument channels is routinely performed with the channel in the tripped condition. Only those instrument channels with hardware permanently installed that permits bypassing without lifting a lead or installing a jumper are routinely tested in the bypass condition. However, an inoperable channel may be bypassed by lifting a lead or installing a jumper to permit surveillance testing of another instrument channel of the same functional unit.

Flushing

During construction of the facility, stress relieving of some of the cold bent stainless steel piping resulted in the piping becoming sensitized to potential stress corrosion cracking under certain conditions, e.g. low pH in conjunction with high chlorides. The subsystems containing the sensitized piping were identified in Stone & Webster Report SW-MER-1A dated July 6, 1971 and further evaluated in Virginia Power Technical Report ME-0009, Rev. 1, dated December 9, 1987. The sensitized piping was either not wetted, reheat treated, or is justified as acceptable because it is in a wetted system with adequate chemistry control i.e., chlorides and/or fluorides (Cl^- and/or F^-) less than 0.15 ppm. These subsystems are as follows:

	Subsystem	Remarks
1)	Recirc. spray inside containment	Not Wetted
2)	Recirc. spray outside containment	Not Wetted
3)	Containment spray inside containment	Not Wetted
4)	Containment spray outside containment	Wetted
5)	Low hd. SI pump discharge	Wetted
6)	Low hd. SI pump to 1st iso. valve	Wetted
7)	High hd. SI inside containment	Wetted
8)	High hd. SI pump discharge	Wetted
9)	RHR	Wetted
10)	Charging and letdown system in containment	Flowing System
11)	Pressurizer relief lines	Reheat Treated Prior to Operation
12)	Pressurizer spray & surge lines	Flowing System

The sensitized piping found in a wetted system is acceptable as long as the fluid in or passing through the piping is less than 0.15 PPM Cl^- and/or F^-. The wetted systems are supplied from the RWST with the exception of the RHR system which communicates directly with the RCS during plant shutdowns. The RHR system does not communicate with the RWST during power operations and therefore, does not require flushing if Cl^- and/or F^- concentration exceeds 0.15 ppm. The acceptance criteria for the piping are based on the RWST Water chemistry staying below 0.15 PPM chlorides and/or fluorides. If the RWST chemistry on chlorides and/or fluorides is out of specification the sensitized piping that is normally supplied by the RWST will be flushed per tables 4.1-3A and 4.1-3B for Units 1 and 2 respectively. Each refueling outage the wetted systems are flow tested, or put in service which will flush the strategic portions of those systems.

The refueling water storage tank is sampled weekly for Cl^- and/or F^- contaminations. Weekly sampling is adequate to detect any inleakage of contaminated water.

Control Room Bottled Air System

The control room bottled air system is required to establish a positive differential pressure in the control room for one hour following a design basis accident. The ability of the system to meet this requirement is verified by: 1) checking air bottle pressurization, 2) demonstrating the capability to pressurize the control room pressure boundary, 3) functionally testing the pressure control valve(s), and 4) functionally testing the manual and automatic actuation capability. The test requirements and frequency are specified in Table 4.1-2A.

Pressurizer PORV, PORV Block Valve, and PORV Backup Air Supply

The safety-related, seismic PORV backup air supply is relied upon for two functions - mitigation of a design basis steam generator tube rupture accident and low temperature overpressure protection (LTOP) of the reactor vessel during startup and shutdown. The surveillance criteria are based upon the more limiting requirements for the backup air supply (i.e. more PORV cycles potentially required to perform the mitigation function), which are associated with the LTOP function.

The PORV backup air supply system is provided with a calibrated alarm for low air pressure. The alarm is located in the control room. Failures such as regulator drift and air leaks which result in low pressure can be easily recognized by alarm or annunciator action. A periodic quarterly verification of air pressure against the surveillance limit supplements this type of built-in surveillance. Based on experience in operation, the minimum checking frequencies set forth are deemed adequate.

TABLE 4.1-1

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
1.	Nuclear Power Range	S	D(1,5) Q(3,5) R(4)	Q(2)	1) Against a heat balance standard, above 15% RATED POWER 2) Signal at ΔT; bistable action (permissive, rod stop, trip) 3) Upper and lower chambers for symmetric offset by means of the movable incore detector system 4) Neutron detectors may be excluded from CHANNEL CALIBRATION 5) The provisions of Specification 4.0.4 are not applicable
2.	Nuclear Intermediate Range (below P-10 setpoint)	*S	R(2,3)	P(1)	1) Log level; bistable action (permissive, rod stop, trip) 2) Neutron detectors may be excluded from CHANNEL CALIBRATION 3) The provisions of Specification 4.0.4 are not applicable
3.	Nuclear Source Range (below P-6 setpoint)	*S	R(2,3)	P(1)	1) Bistable action (alarm, trip) 2) Neutron detectors may be excluded from CHANNEL CALIBRATION 3) The provisions of Specification 4.0.4 are not applicable
4.	Reactor Coolant Temperature	*S	R	Q(1) Q(2)	1) Overtemperature ΔT 2) Overpower ΔT
5.	Reactor Coolant Flow	S	R	Q	
6.	Pressurizer Water Level	S	R	Q	
7.	Pressurizer Pressure (High & Low)	S	R	Q	
8.	4 KV Voltage and Frequency	N.A.	R	Q(1)	1) Setpoint verification not required
9.	Analog Rod Position	*S(1,2) (4)	R	M(3)	1) With step counters 2) Each six inches of rod motion when data logger is out of service 3) Rod bottom bistable action 4) N.A. when reactor is in HOT, INTERMEDIATE OR COLD SHUTDOWN

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
10.	Rod Position Bank Counters	S(1,2) Q(3)	N.A.	N.A.	1) Each six inches of rod motion when data logger is out of service 2) With analog rod position 3) For the control banks, the benchboard indicators shall be checked against the output of the bank overlap unit
11.	Steam Generator Level	S	R	Q	
12.	Deleted				
13.	Deleted				
14.	Deleted				
15.	Recirculation Mode Transfer				
	a. Refueling Water Storage Tank Level-Low	S	R	Q	
	b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	M	
16.	Deleted				
17.	Reactor Containment Pressure-CLS	*D	R	Q(1)	1) Isolation valve signal and spray signal
18.	Deleted				
19.	Deleted				
20.	Deleted				
21.	Deleted				
22.	Steam Line Pressure	S	R	Q	

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
23.	Turbine First Stage Pressure	S	R	Q	
24.	Deleted				
25.	Deleted				
26.	Logic Channel Testing	N.A.	N.A.	M(1)(2)	1) Reactor protection, safety injection and the consequence limiting safeguards system logic are tested monthly per this line item. 2) The master and slave relays are not included in the monthly logic channel test of the safety injection system.
27.	Deleted				
28.	Turbine Trip				Setpoint verification is not applicable
	A. Stop valve closure	N.A.	N.A.	P	
	B. Low fluid oil pressure	N.A.	N.A.	P	
29.	Deleted				
30.	Reactor Trip Breaker	N.A.	N.A.	M	The test shall independently verify operability of the undervoltage and shunt trip attachments
31.	Deleted				

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
32. Auxiliary Feedwater				
a. Steam Generator Water Level Low-Low	S	R	Q(1)	1) The auto start of the turbine driven pump is not included in the monthly test, but is tested within 31 days prior to each startup.
b. RCP Undervoltage	S	R	R(1)(2)	1) The actuation logic and relays are tested within 31 days prior to each startup. 2) Setpoint verification not required.
c. S.I.	(All Safety Injection surveillance requirements)			
d. Station Blackout	N.A.	R	N.A.	
e. Main Feedwater Pump Trip	N.A.	N.A.	R	
33. Loss of Power				
a. 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	N.A.	R	Q(1)	1) Setpoint verification not required.
b. 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	N.A.	R	Q(1)	1) Setpoint verification not required.
34. Deleted				
35. Manual Reactor Trip	N.A.	N.A.	R	The test shall independently verify the operability of the undervoltage and shunt trip attachments for the manual reactor trip function. The test shall also verify the operability of the bypass breaker trip circuit.
36. Reactor Trip Bypass Breaker	N.A.	N.A.	M(1), R(2)	1) Remote manual undervoltage trip immediately after placing the bypass breaker into service, but prior to commencing reactor trip system testing or required maintenance. 2) Automatic undervoltage trip.
37. Safety Injection Input to RPS	N.A	N A	R	
38. Reactor Coolant Pump Breaker Position Trip	N.A.	N A	R	

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
39. Steam/Feedwater Flow and Low S/G Water Level	S	R	Q(1)	1) The provisions of Specification 4.0.4 are not applicable
40. Intake Canal Low (See Footnote 1)	D	R	M(1), Q(2)	1) Logic Test 2) Channel Electronics Test
41. Turbine Trip and Feedwater Isolation				
a. Steam generator water level high	S	R	Q	
b. Automatic actuation logic and actuation relay	N A.	R	M(1)	1) Automatic actuation logic only, actuation relays tested each refueling
42. Reactor Trip System Interlocks				
a. Intermediate range neutron flux, P-6	N.A.	R(1)	R(2)	1) Neutron detectors may be excluded from the calibration 2) The provisions of Specification 4.0.4 are not applicable.
b. Low reactor trips block, P-7	N.A.	R(1)	R(2)	
c. Power range neutron flux, P-8	N.A.	R(1)	R(2)	
d. Power range neutron flux, P-10	N.A.	R(1)	R(2)	
e. Turbine impulse pressure	N.A.	R	R	

Footnote 1:

Check Consists of verifying for an indicated intake canal level greater than 23'-6" that all four low level sensor channel alarms are not in an alarm state.

Calibration Consists of uncovering the level sensor and measuring the time response and voltage signals for the immersed and dry conditions. It also verifies the proper action of instrument channel from sensor to electronics to channel output relays and annunciator. Only the two available sensors on the shutdown unit would be tested.

Tests
1) The logic test verifies the three out of four logic development for each train by using the channel test switches for that train
2) Channel electronics test verifies that electronics module responds properly to a superimposed differential millivolt signal which is equivalent to the sensor detecting a "dry" condition.

TABLE 4.1-1(Continued)
MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
43.	Engineered Safeguards Actuation Interlocks				
	a. Reactor trip, P-4	N.A.	N.A.	R	
	b. Pressurizer pressure, P-11	N.A.	R	R	
	c. Low, low T_{avg}, P-12	N.A.	R	R	

S - Each Shift

D - Daily

N.A. - Not Applicable

Q - Every 92 days

* See Specification 4.1.D

M - 31 days

P - Prior to each startup if not done within the previous 31 days

R - Once per 18 months

TABLE 4.1-A

REACTOR TRIP SYSTEM AND ENGINEERED SAFEGUARDS ACTION INTERLOCKS

DESIGNATION	CONDITION	FUNCTION
Reactor Trip (P-4)	1 of 2 breakers open	Reactor tripped - actuates turbine trip, allows auto closing of main feedwater valves on T_{avg} below setpoint, prevents the opening of the main feedwater valves which were closed by a safety injection or high steam generator water level signal.
Intermediate Range Neutron Flux (P-6)	1 of 2 Intermediate range above setpoint (increasing power level)	Allows manual block of source range reactor trip.
	2 of 2 Intermediate range below setpoint (decreasing power level)	Automatically defeats the block of source range reactor trip.
Power Range Neutron Flux (P-10)	2 of 4 Power range above setpoint (increasing power level)	Allows manual block of power range (low setpoint) and intermediate range reactor trips and intermediate range rod stop. Automatically blocks source range reactor trip.
	3 of 4 Power range below setpoint (decreasing power level)	Automatically defeats the block of power range (low setpoint) and intermediate range reactor trips and intermediate range rod stop.
		Input to P-7.
Low Power Reactor Trip Block (P-7)	2 of 4 Power range above setpoint or 1 of 2 Turbine Impulse chamber above setpoint (Power level increasing)	Allows reactor trip on: Low flow or reactor coolant pump breakers open in more than one loop, Undervoltage (RCP busses), Underfrequency (RCP busses), Turbine Trip, Pressurizer low pressure, and Pressurizer high level.
	3 of 4 Power range below setpoint and 2 of 2 Turbine Impulse chamber pressure below setpoint (Power level decreasing)	Prevents reactor trip on: Low flow or reactor coolant pump breakers open in more than one loop, Undervoltage (RCP busses), Underfrequency (RCP busses), Turbine Trip, Pressurizer low pressure, and Pressurizer high level.

TABLE 4.1-A (continued)

REACTOR TRIP SYSTEM AND ENGINEERED SAFEGUARDS ACTION INTERLOCKS

DESIGNATION	CONDITION	FUNCTION
Power Range Neutron Flux (P-8)	2 of 4 Power range above setpoint (Power level increasing)	Permit reactor trip on low flow or reactor coolant pump breaker open in a single loop.
	3 of 4 Power range below setpoint (Power level decreasing)	Blocks reactor trip on low flow or reactor coolant pump breaker open in a single loop.
Pressurizer Pressure (P-11)	2 of 3 Pressurizer pressure above setpoint (increasing pressure)	On increasing pressurizer pressure, P-11 automatically reinstates safety injection actuation on low pressurizer pressure.
	2 of 3 Pressurizer pressure below setpoint (decreasing pressure)	On decreasing pressure, P-11 allows the manual block of safety injection actuation on low pressurizer pressure.
Low, Low T_{avg} (P-12)	2 of 3 T_{avg} above setpoint (temperature increasing)	On increasing primary coolant loop temperature, P-12 automatically reinstates safety injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure, and provides an arming signal to the steam dump system.
	2 of 3 T_{avg} below setpoint (temperature decreasing)	On decreasing primary coolant loop temperature, P-12 allows the manual block of safety injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure and automatically removes the arming signal from the steam dump system.

TABLE 4.1-1A

EXPLOSIVE GAS MONITORING INSTRUMENTATION REQUIREMENTS

CHANNEL DESCRIPTION	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Waste Gas Holdup System Explosive Gas Monitoring System Oxygen Monitor	D	Q(1)	M

(1) The channel calibration shall include the use of standard gas samples containing a nominal:
1. one volume percent oxygen, balance nitrogen, and
2. four volume percent oxygen, balance nitrogen

D - Daily
M - Monthly
Q - Quarterly

TABLE 4.1-2
ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Auxiliary Feedwater Flow Rate	P		R
2. Inadequate Core Cooling Monitor	M		R
3. PORV Position Indicator (Primary Detector)	M		R
4. PORV Position Indicator (Backup Detector)	M		R
5. PORV Block Valve Position Indicator	M		R
6. Safety Valve Position Indicator	M		R
7. Safety Valve Position Indicator (Backup Detector)	M		R
8. Containment Pressure	M		R
9. Containment Water Level (Narrow Range)	M		R
10. Containment Water Level (Wide Range)	M		R
11. Containment High Range Radiation Monitor	M	Q	R
12. Process Vent High Range Effluent Monitor	M	Q	R
13. Ventilation Vent High Range Effluent Monitor	M	Q	R
14. Main Steam High Range Radiation Monitor	M	Q	R
15. Auxiliary Feedwater Pump Turbine Exhaust Radiation Monitor	M	Q	R
16. Recirculation Spray Heat Exchanger Service Water Outlet Radiation Monitors	M	Q(1)	R

(1) Channel Functional testing shall include the associated sample pump.

M - Monthly

P - Prior to each startup if not done within the previous week

Q - Quarterly

R - Once per 18 months

TABLE 4.1-2A
MINIMUM FREQUENCY FOR EQUIPMENT TESTS

DESCRIPTION	TEST	FREQUENCY	FSAR SECTION REFERENCE
1. Control Rod Assemblies	Rod drop times of all full length rods at hot conditions	Prior to reactor criticality: a. For all rods following each removal of the reactor vessel head b. For specially 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. Once per 18 months	7
2. Control Rod Assemblies	Partial movement of all rods	Quarterly	7
3. Refueling Water Chemical Addition Tank	Functional	Once per 18 months	6
4. Pressurizer Safety Valves	Setpoint	Per TS 4.0.5	4
5. Main Steam Safety Valves	Setpoint	Per TS 4.0.5	10
6. Containment Isolation Trip	* Functional	Once per 18 months	5
7. Refueling System Interlocks	* Functional	Prior to refueling	9.12
8. Service Water System	* Functional	Once per 18 months	9.9
9. Fire Protection Pump and Power Supply	Functional	Monthly	9.10
10. Primary System Leakage	* Evaluate	Daily	4
11. Diesel Fuel Supply	* Fuel Inventory	5 days/week	8.5
12. Deleted			
13. Main Steam Line Trip Valves	Functional (Full Closure)	Before each startup (TS 4.7) The provisions of Specification 4.0.4. are not applicable.	10

TABLE 4.1-2A (CONTINUED)
MINIMUM FREQUENCY FOR EQUIPMENT TESTS

	DESCRIPTION	TEST	FREQUENCY	FSAR SECTION REFERENCE
14a.	Service Water System Valves in Line Supplying Recirculation Spray Heat Exchangers	Functional	Once per 18 months	9.9
b.	Service Water System Valves Isolating Flow to Non-essential loads on Intake Canal Low Level Isolation	Functional	Once per 18 months	9.9
15.	Control Room Bottled Air System			
a.	Air Bottle Pressure	* Verify each bank pressurized to a minimum of 2350 psig	Monthly	9.13
b.	Positive Differential Pressure Capability	* Demonstrate ability to maintain positive differential pressure as required by Technical Specification 3.19 by pressurizing the boundary using either one of the ventilation system fans with orificed flow (simulating discharge of one train of bottled air) or by discharging one train of the bottled air system	Once per 18 months	9.13
c.	Pressure Control Valve(s) Functionality	* Demonstrate ability to pressurize the boundary to 0.05 inches of water for 1 hour as required by Technical Specification 3.19 by discharging each train of the bottled air system	Once per 18 months	9.13
d.	Manual Actuation Capability	* Functional	Once per 18 months	9.13
e.	Automatic Actuation Capability	* Functional	Once per 18 months	9.13
16.	Reactor Vessel Overpressure Mitigating System (except backup air supply)	Functional & Setpoint	Prior to decreasing RCS temperature below 350°F and monthly while the RCS is < 350°F and the Reactor Vessel Head is bolted	4.3
		CHANNEL CALIBRATION	Once per 18 months	
17.	Reactor Vessel Overpressure Mitigating System Backup Air Supply	Setpoint	Once per 18 months	4.3
18.	Power-Operated Relief Valve Control System	Functional, excluding valve actuation	Monthly	4.3
		CHANNEL CALIBRATION	Once per 18 months	

TABLE 4.1-2A(CONTINUED)
MINIMUM FREQUENCY FOR EQUIPMENT TESTS

	DESCRIPTION	TEST	FREQUENCY	UFSAR SECTION REFERENCE
19.	Primary Coolant System	Functional	1. Periodic leakage testing(a)(b) on each valve listed in Specification 3.1.C.7a shall be accomplished prior to entering POWER OPERATION after every time the plant is placed in COLD SHUTDOWN for refueling, after each time the plant is placed in COLD SHUTDOWN for 72 hours if testing has not been accomplished in the preceding 9 months, and prior to returning the valve to service after maintenance, repair or replacement work is performed.	
20.	Containment Purge MOV Leakage	Functional	Semi-Annual (Unit at power or shutdown) if purge valves are operated during interval(c)	
21.	Containment Hydrogen Analyzers	a. CHANNEL FUNCTIONAL TEST b. CHANNEL CALIBRATION 1. Sample gas used: One volume percent (±0.25%) hydrogen, balance nitrogen Four volume percent (±0.25%) hydrogen, balance nitrogen 2. CHANNEL CALIBRATION will include startup and operation of the Heat Tracing System	Once per 92 days Once per 18 months	
22.	RCS Flow	Flow ≥ 273,000 gpm	Once per 18 months	14
23.	Delete			

(a) To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.
(b) Minimum differential test pressure shall not be below 150 psid.
(c) Refer to Section 4.4 for acceptance criteria.
* See Specification 4.1.D.

TABLE 4.1-2B
MINIMUM FRFOUENCIES FOR SAMPLING TESTS

	DESCRIPTION	TEST	FREQUENCY	UFSAR SECTION REFERENCE
1.	Reactor Coolant Liquid Samples	Radio-Chemical Analysis(1)	Monthly(5)	
		Gross Activity(2)	5 days/week(5)	9.1
		Tritium Activity	Weekly (5)	9.1
		* Chemistry (CL, F & O_2)	5 days/week(9)	4
		* Boron Concentration	Twice/week	9.1
		$\bar{E}$ Determination	Semiannually(3)	
		DOSE EQUIVALENT I-131	Once/2 weeks(5)	
		Radio-iodine Analysis (including I-131, I-133 & I-135)	Once/4 hours(6) and (7) below	
2.	Refueling Water Storage	Chemistry (Cl & F)	Weekly	6
3.	Boric Acid Tanks	* Boron Concentration	Twice/Week	9.1
4.	Chemical Additive Tank	NaOH Concentration	Monthly	6
5.	Spent Fuel Pit	* Boron Concentration	Monthly	9.5
6.	Secondary Coolant	Fifteen minute degassed beta and gamma activity	Once/72 hours	
		DOSE EQUIVALENT I-131	Monthly(4) Semiannually(8)	
7.	Stack Gas Iodine and Particulate Samples	* I-131 and particulate radioactive releases	Weekly	

* See Specification 4.1.D

(1) A radiochemical analysis will be made to evaluate the following corrosion products: Cr-51, Fe-59, Mn-54, Co-58, and Co-60

(2) A gross beta-gamma degassed activity analysis shall consist of the quantitative measurement of the total radioactivity of the primary coolant in units of μCi/cc.

(3) $\bar{E}$ determination will be started when the gross gamma degassed activity of radionuclides with half-lives greater than 15 minutes analysis indicates ≥ 10 μCi/cc. Routine sample(s) for $\bar{E}$ analyses shall only 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.

(4) If the fifteen minute degassed beta and gamma activity is 10% or more of the limit given in Specification 3.6.E, a DOSE EQUIVALENT I-131 analysis will be performed.

(5) When reactor is critical and average primary coolant temperature ≥350°F.

(6) Whenever the specific activity exceeds 1.0 μCi/cc DOSE EQUIVALENT I-131 or $100/\bar{E}$ μCi/cc and until the specific activity of the Reactor Coolant System is restored within its limits.

(7) One sample between 2 & 6 hours following a THERMAL POWER change exceeding 15 percent of RATED POWER within a one hour period provided the average primary coolant temperature ≥350°F.

(8) When the fifteen minute degassed beta and gamma activity is less than 10% of the limit given in Specification 3.6.E.

(9) Sampling for chloride and fluoride concentrations is not required when fuel is removed from the reactor vessel and the reactor coolant inventory is drained below the reactor vessel flange, whether the upper internal and/or the vessel head are in place or not. Sampling for oxygen concentration is not required when the reactor coolant temperature is below 250 degrees F.

TABLE 4.1-3A

UNIT 1

MINIMUM FREQUENCY FOR FLUSHING SENSITIZED PIPE

Flush Flow Path General Description	Flush Duration	Frequency
1) Containment Spray Pump Discharge	Note 1	Note 2
2) Low Hd SI Pump Discharge	Note 1	Note 2
3) Low Hd SI Pump up to 1st Iso. Valve	Note 1	Note 2
4) High Hd SI Pump Inside Containment	Note 1	Note 2
5) High Hd SI Pump Discharge	Note 1	Note 2

Note 1: Flush until sample is below 0.15 PPM Cl^- and/or F^-

Note 2: When RWST Chemistry has exceeded 0.15 PPM Cl^- and/or F^- (only after restoring the RWST Chemistry to spec for Cl^- and/or F^-)

TABLE 4.1-3B

UNIT 2

MINIMUM FREQUENCY FOR FLUSHING SENSITIZED PIPE

Flush Flow Path General Description (Ref. SW Report SW-MER-1A)	Flush Duration	Frequency
1) Containment Spray Pump Discharge	Note 1	Note 2
2) Low Hd SI Pump Discharge	Note 1	Note 2
3) Low Hd SI Pump up to 1st Iso. Valve	Note 1	Note 2
4) High Hd SI Pump Inside Containment	Note 1	Note 2
5) High Hd SI Pump Discharge	Note 1	Note 2

Note 1: Flush until sample is below 0.15 PPM Cl^- and/or F^-

Note 2: When RWST Chemistry has exceeded 0.15 PPM Cl^- and/or F^- (only after restoring the RWST Chemistry to spec for Cl^- and/or F^-)

4.2 AUGMENTED INSPECTIONS

Applicability

Applies to inservice inspections which augment those required by ASME Section XI.

Objective

To provide the additional assurance necessary for the continued integrity of important components involved in safety and plant operation.

Specifications

A. Inspections shall be performed as specified in TS. Table 4.2-1. Nondestructive examination techniques and acceptance criteria shall be in compliance with the requirements of TS 4.0.5.

B. The normal inspection interval is 10 years.

C. Detailed records of each inspection shall be maintained to allow a continuing evaluation and comparison with future inspections.

Bases

The inspection program for ASME Section XI of the ASME Boiler and Pressure Vessel Code limits its inspection to ASME Code Class 1, 2, and 3 components and supports. Certain components, under Miscellaneous Inspections in this section, were added because of no corresponding code requirement. This added requirement provides the inspection necessary to insure the continued integrity of these components.

Item 1.4

The low pressure turbine rotor blades are normally inspected concurrent with the disk and hub inspections. The disk and hub inspection frequency is based on existing crack size, crack growth rate, and system operating conditions. ASME Section XI does not provide specific examination requirements or acceptance criteria for turbine rotor inspections. Procedures and acceptance criteria for turbine rotor inspections are consistent with general industry practices.

Sensitized stainless steel augmented inspections were added to assure piping integrity of this classification.

Item 2.1

The examinations required by this item utilize the periodically updated ASME Section XI Boiler and Pressure Vessel Code referenced in Technical Specification 4.0.5 in this augmented examination. The surface and volumetric examinations required by this item will be conducted at three times the frequency required by the Code in an interval. In addition to the Code required pressure testing, visual examinations will be conducted, while the piping is pressurized by the procedures defined in Tables 4.1-3A & B of Technical Specification 4.1, concerning flushing of sensitized stainless steel piping. Weld selection criteria are modified from the Code for Class 1 welds, since stress level information as correlated to weld location is unavailable for Surry.

Item 2.2

The sensitized stainless steel located in the containment and recirculation spray rings in the overhead of containment are classified ASME Class 2 components. These components are currently exempted by ASME Section XI from surface and volumetric examination requirements. As such, an augmented program will remain in place requiring visual (VT-1) examination of these components for evidence of cracking. Additionally, sections of the piping will be examined by liquid penetrant inspection when the piping is visually inspected.

TABLE 4.2-1

SECTION A. MISCELLANEOUS INSPECTIONS

Item No.	Required Examination Area	Required Examination Methods	10-Year Interval Inspection	Remarks
1.1	Deleted			
1.2	Low Head SIS piping located in valve pit	Visual	Non-applicable	This pipe shall be visually inspected once per 18 months.
1.3	Primary Pump Flywheel	See remarks	See remarks	Inspect once every 10 years by a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius or a surface examination (MT and/or PT) of exposed surfaces defined by the volume of the disassembled flywheels.
1.4	Low Pressure Turbine Rotor	Visual and Magnetic Particle or Dye Penetrant	See remarks	100% of blades every six operating years. Inspections are normally performed concurrent with LP turbine rotor disk and hub inspections.

TABLE 4.2-1(continued)

SECTION B. SENSITIZED STAINLESS STEEL

Item No.	Required Examination Area	Required Examination Methods	10-Year Interval Inspection	Remarks
2.1.1	Class 1 circumferential, longitudinal, branch pipe connection, and socket welds	As required by T.S. 4.0.5	The welds examined by volumetric or surface techniques shall be conducted at three times the frequency required by T.S. 4.0.5	A minimum of 5% of the welds shall be examined once per 18 months. At least 75% of the total population of welds shall be examined each interval. The same welds may be selected in subsequent intervals for examination. See Note 1.
2.1.2	Class 2 circumferential, longitudinal, branch pipe connection, and socket welds	As required by T.S. 4.0.5	The welds examined by volumetric or surface techniques shall be conducted at three times the frequency required by T.S. 4.0.5	A minimum of 2.5% of the welds shall be examined once per 18 months. At least 22.5% of the total population of welds shall be examined each interval. The same welds may be selected in subsequent intervals for examination. See Note 1.
2.1.3	Class 1 and Class 2 sensitized stainless steel pieces	Visual (VT-2) as required by T.S. 4.0.5	As required by T.S. 4.0.5	In addition to the Code required examinations the affected piping shall be visually (VT-2) examined during the flushing requirements of T.S. Tables 4.1-3A and 4.1-3B.

TABLE 4.2-1 (continued)

SECTION B. SENSITIZED STAINLESS STEEL

Item No.	Required Examination Area	Required Examination Methods	10-Year Interval Inspection	Remarks
2.2.1	Containment and Recirculation Spray Piping	Visual (VT-1) and surface examination	(See remarks)	At least 25% of the examinations shall have been completed by the expiration of one-third of the inspection interval and at least 50% shall have been completed by the expiration of two-thirds of the inspection interval. The remaining required examinations shall be completed by the end of the inspection interval. Surface examinations will include 6 patches (each 9 inches square) evenly distributed around each spray ring.

Note 1: a) The examinations shall be distributed among the systems prorated, to the degree practicable, on the number of sensitized stainless steel welds in each system (i e , if a system contains 30% of the welds, then 30% of the required examinations shall be performed on that system).

b) Within a system terminal ends (e g., branch connections, pipe to pump, pipe to valve) shall be selected. The remainder of the selection shall select structural discontinuities (pipe fittings) prorated to the degree practicable to the number of discontinuities in that system. Other selections may be necessary to meet the total weld selection criteria.

c) Within each system, examinations shall be distributed between line sizes prorated to the degree practicable.

4.3 ASME CODE CLASS 1, 2, AND 3 SYSTEM PRESSURE TESTS

Applicability

Applies to requirement for ASME Code Class 1, 2, and 3 System Pressure Tests. In this context, closed is defined as the state of system integrity which permits pressurization and subsequent normal operation after the system has been opened.

Objective

To specify requirements for ASME Code Class 1, 2, and 3 System Pressure Tests following normal operation, modification, or repair. The pressure-temperature limits for Reactor Coolant System tests will be in accordance with Figure 3.1-1.

Specification

A. Inservice inspection, which includes system pressure testing, of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the NRC pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

BASIS

System pressure testing is performed in order to insure integrity of the system. For normal opening the integrity of the system, in terms of strength, is unchanged. The testing is based on 10 CFR 50.55a and performed pursuant to Section XI of the ASME Code for inservice inspection of Class 1, 2, and 3 components.

4.4 CONTAINMENT TESTS

Applicability

Applies to containment leakage testing.

Objective

To assure that leakage of the primary reactor containment and associated systems is held within allowable leakage rate limits; and to assure that periodic surveillance is performed to assure proper maintenance and leak repair during the service life of the containment.

Specification

A. Periodic and post-operational integrated leakage rate tests of the containment shall be performed in accordance with the requirements of 10 CFR 50, Appendix J, "Reactor Containment Leakage Testing for Water Cooled Power Reactors."

B. Containment Leakage Rate Testing Requirements

1. The containment and containment penetrations leakage rate shall be demonstrated by performing leakage rate testing as required by 10 CFR 50 Appendix J, Option B, as modified by approved exemptions, and in accordance with the guidelines contained in Regulatory Guide 1.163, dated September, 1995. Leakage rate acceptance criteria are as follows:

   a. An overall integrated leakage rate of less than or equal to La, 0.1 percent by weight of containment air per 24 hours, at calculated peak pressure (Pa).

   b. A combined leakage rate of less than or equal to 0.60 La for all penetrations and valves subject to Type B and C testing when pressurized to Pa.

   Prior to entering an operating condition where containment integrity is required the as-left Type A leakage rate shall not exceed 0.75 La and the combined leakage rate of all penetrations subject to Type B and C testing shall not exceed 0.6 La.

2. The provisions of Specification 4.0.2 are not applicable.

Basis

The leak tightness testing of all liner welds was performed during construction by welding a structural steel test channel over each weld seam and performing soap bubble and halogen leak tests.

The containment is designed for a maximum pressure of 45 psig. The containment is maintained at a subatmospheric air partial pressure consistent with TS Figure 3.8-1 depending upon the cooldown capability of the Engineered Safeguards and will not rise above 45 psig for any postulated loss-of-coolant accident.

The initial test pressure for the Type A test is 47.0 psig to allow for containment expansion and equalization. A review was performed to determine the effects of pressurizing containment above its design pressure of 45.0 psig. This review was based on the original containment test at 52 psig. During that test, the calculated stresses were found to be well within the allowable yield strength of the structural reinforcing bars, therefore performance of the Type A test at 47 psig will have no detrimental effect on the containment structure.

All loss-of-coolant accident evaluations have been based on an integrated containment leakage rate not to exceed 0.1% of containment volume per 24 hr.

The above specification satisfies the conditions of 10 CFR 50.54(o) which stated that primary reactor containments shall meet the containment leakage test requirements set forth in Appendix J.

The limitations on closure and leak rate for the containment airlocks are required to meet the restrictions on containment integrity and containment leak rate. Surveillance testing of the airlock seals provides assurance that the overall airlock leakage will not become excessive due to seal damage during the intervals between airlock leakage tests.

References

UFSAR Section 5.4	Design Evaluation of Containment Tests and Inspections of Containment
UFSAR Section 7.5.1	Design Bases of Engineered Safeguards Instrumentation
UFSAR Section 14.5	Loss of Coolant Accident
10 CFR 50 Appendix J	"Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors"

4.5 SPRAY SYSTEMS TESTS

Applicability

Applies to the testing of the Spray Systems.

Objective

To verify that the Spray Systems will respond promptly and perform their design function, if required.

Specification

A. Each containment spray subsystem shall be demonstrated OPERABLE:

1. By verifying, that on recirculation flow, each containment spray pump performs satisfactorily when tested in accordance with Specification 4.0.5.

2. By verifying that each motor-operated valve in the containment spray flow path performs satisfactorily when tested in accordance with Specification 4.0.5.

3. By verifying each spray nozzle is unobstructed following maintenance which could cause nozzle blockage.

4. Coincident with the containment spray pump test described in Specification 4.5.A.1, by verifying that no particulate material clogs the test spray nozzles in the refueling water storage tank.

B. Each recirculation spray subsystem shall be demonstrated OPERABLE:

1. By verifying each recirculation spray pump performs satisfactorily when tested in accordance with Specification 4.0.5.

2. By verifying that each motor-operated valve in the recirculation spray flow paths performs satisfactorily when tested in accordance with Specification 4.0.5.

3. By verifying each spray nozzle is unobstructed following maintenance which could cause nozzle blockage.

C. Each weight-loaded check valve in the containment spray and outside containment recirculation spray subsystems shall be demonstrated OPERABLE once per 18 months by cycling the valve one complete cycle of full travel and verifying that each valve opens when the discharge line of the pump is pressurized with air and seats when a vacuum is applied.

D. A visual inspection of the containment sump and the inside containment recirculation spray pump wells and the engineered safeguards suction inlets shall be performed once per 18 months and/or after major maintenance activities in the containment. The inspection should verify that the containment sump and pump wells are free of debris that could degrade system operation and that the sump components (i.e., trash racks, screens) are properly installed and show no sign of structural distress or excessive corrosion.

Basis

The flow testing of each containment spray pump is performed by opening the normally closed valve in the containment spray pump recirculation line returning water to the refueling water storage tank. The containment spray pump is operated and a quantity of water recirculated to the refueling water storage tank. The discharge to the tank is divided into two fractions; one for the major portion of the recirculation flow and the other to pass a small quantity of water through test nozzles which are identical with those used in the containment spray headers.

The purpose of the recirculation through the test nozzles is to assure that there are no particulate material in the refueling water storage tank small enough to pass through pump suction strainers and large enough to clog spray nozzles.

Due to the physical arrangement of the recirculation spray pumps inside the containment, it is impractical to flow-test them other than during a unit outage. Flow testing of these pumps requires the physical modification of the pump discharge piping and the erection of a temporary dike to contain recirculated water. The length of time required to setup for the test, perform the test, and then reconfigure the system for normal operation is prohibitive to performing the flow-test on even the cold shutdown frequency. Therefore, the flow-test of the inside containment recirculation spray pumps will be performed once per 18 months during a unit outage.

The inside containment recirculation spray pumps are capable of being operated dry for approximately 60 seconds without significantly overheating and/or degrading the pump bearings. During this dry pump check, it can be determined that the pump shafts are turning by rotation sensors which indicate in the Main Control Room. In addition, motor current will be compared with an established reference value to ascertain that no degradation of pump operation has occurred.

The recirculation spray pumps outside the containment have the capability of being dry-run and flow tested. The test of an outside recirculation spray pump is performed by closing the containment sump suction line valve and the isolation valve between the pump discharge and the containment penetration. This allows the pump casing to be filled with water and the pump to recirculate water through a test line from the pump discharge to the pump casing.

With a system flush conducted to remove particulate matter prior to the installation of spray nozzles and with corrosion resistant nozzles and piping, it is not considered credible that a significant number of nozzles would plug during the life of the unit to reduce the effectiveness of the subsystems. Therefore, an inspection or air or smoke test of the nozzles following maintenance which could cause nozzle blockage is sufficient to indicate that plugging of the nozzles has not occurred.

The spray nozzles in the refueling water storage tank provide means to ensure that there is no particulate matter in the refueling water storage tank and the containment spray subsystems which could plug or cause deterioration of the spray nozzles. The nozzles in the tank are identical to those used on the containment spray headers. The flow test of the containment spray pumps and recirculation to the refueling water storage will indicate any plugging of the nozzles by a reduction of flow through the nozzles.

Performing the containment sump and pump well inspections will reduce the potential for system degradation due to sump debris associated with refueling activities or major maintenance activities as well as reduce wear on the inside containment recirculation spray pumps during dry testing. Ensuring proper installation and structural integrity of the trash racks and sump screens will prevent ingress of debris generated during the DBA and will allow long term containment cooling and recirculation mode cooling of the core.

<u>References</u>

FSAR Section 6.3.1, Containment Spray Pumps

FSAR Section 6.3.1, Recirculation Spray Pumps

4.6 EMERGENCY POWER SYSTEM PERIODIC TESTING

Applicability

Applies to periodic testing and surveillance requirements of the Emergency Power System.

Objective

To verify that the Emergency Power System will respond promptly and properly when required.

Specification

The following tests and surveillance shall be performed as stated:

A. Diesel Generators

1. Tests and Frequencies

   a. Manually initiated start of the diesel generator, followed by manual synchronization with other power sources and assumption of load by the diesel generator up to 2750 Kw. This test will be conducted monthly on each diesel generator for a duration of 30 minutes. Normal station operation will not be affected by this test.

b. Automatic start of each diesel generator, load shedding, and restoration to operation of particular vital equipment, initiated by a simulated loss of off-site power together with a simulated safety injection signal. Testing will demonstrate load shedding and load sequencing initiated by a simulated loss of off-site power following a simulated engineered safety features signal. Testing will also demonstrate that the loss of voltage and degraded voltage protection is defeated whenever the emergency diesel is the sole source of power to an emergency bus and that this protection is automatically reinstated when the diesel output breaker is opened. This test will be conducted during reactor shutdown for refueling to assure that the diesel generator will start and accept load in less than or equal to 10 seconds after the engine starting signal.

c. Availability of the fuel oil transfer system shall be verified by operating the system in conjunction with the monthly test.

d. Each diesel generator shall be given a thorough inspection once per 18 months utilizing the manufacturer's recommendations for this class of stand-by service.

2. Acceptance Criteria

The above tests will be considered satisfactory if all applicable equipment operates as designed.

B. <u>Fuel Oil Storage Tanks for Diesel Generators</u>

1. A minimum fuel oil storage of 35,000 gal shall be maintained on-site to assure full power operation of one diesel generator for seven days.

C. Station Batteries

1. Tests and Frequencies

a. The specific gravity, electrolytic temperature, cell voltage of the pilot cell in each battery, and the D.C. bus voltage of each battery shall be measured and recorded weekly.

b. Each month the voltage of each battery cell in each battery shall be measured to the nearest 0.01 volts and recorded.

c. Every 3 months the specific gravity of each battery cell, the temperature reading of every fifth cell, the height of electrolyte of each cell, and the amount of water added to any cell shall be measured and recorded.

d. Twice a year, during normal operation, the battery charger shall be turned off for approximately 5 min and the battery voltage and current shall be recorded at the beginning and end of the test.

e. During the normal refueling shutdown each battery shall be subjected to a simulated load test without battery charger. The battery voltage and current as a function of time shall be monitored.

f. Once per 18 months connections shall be checked for tightness and anti-corrosion coating shall be applied to the interconnections.

2. Acceptance Criteria

a. Each test shall be considered satisfactory if the new data when compared to the old data indicate no signs of abuse or deterioration.

b. The load test in (d) and (e) above shall be considered satisfactory if the batteries perform within acceptable limits as established by the manufacturers discharge characteristic curves.

D. EMERGENCY DIESEL GENERATOR BATTERIES

1. Tests and Frequencies

a. The specific gravity, electrolytic temperature, cell voltage of the pilot cell in each battery and the D.C. bus voltage of each battery shall be measured and recorded weekly.

b. Each month the voltage of each battery cell in each battery shall be measured to the nearest 0.01 volts and recorded.

c. Every 3 months the specific gravity of each battery cell, the temperature reading of every fifth cell, the height of electrolyte of each cell, and the amount of water added to any cell shall be measured and recorded.

d. Once per 18 months, each battery shall be subjected to a normal load or simulated load test without battery charger. The battery voltage and current as a function of time shall be monitored.

e. Once per 18 months, connections shall be checked for tightness and anti-corrosion coating shall be applied to interconnections.

2. Acceptance Criteria

a. Each test shall be considered satisfactory if the new data when compared to the old data indicate no signs of abuse or deterioration.

b. The load test in (d) above shall be considered satisfactory if the batteries perform within acceptable limits as established by the manufacturers discharge characteristic curves.

Basis

The tests specified are designed to demonstrate that the diesel generators will provide power for operation of essential safeguards equipment. They also assure that the emergency diesel generator system controls and the control systems for the safeguards equipment will function automatically in the event of a loss of normal station service power.

The testing frequency specified will be often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The fuel supply and starting circuits and controls are continuously monitored and any faults are alarm indicated. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

Station batteries may deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated by experience to provide an indication of a cell becoming unserviceable long before it fails. In addition alarms have been provided to indicate low battery voltage and low current from the inverters which would make it extremely unlikely that deterioration would go unnoticed.

Emergency diesel generator batteries may deteriorate with time but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated by experience to provide an indication of a cell becoming unserviceable long before it fails.

The equalizing charge, as recommended by the manufacturer, is vital to maintaining the ampere-hour capability of the battery. As a check upon the effectiveness of the equalizing charge, the battery shall be loaded rather heavily and the voltage monitored as a function of time. If a cell has deteriorated or if a connection is loose, the voltage under load will drop excessively indicating the need for replacement or maintenance. FSAR Section 8.5 provides further amplification of the basis.

References

FSAR Section 8.5 Emergency Power System

4.7 MAIN STEAM LINE TRIP VALVES

Applicability

Applies to periodic testing of the main steam line trip valves.

Objective

To verify the ability of the main steam line trip valves to close upon signal.

Specification

A. Tests and Frequencies

1. Each main steam line trip valve shall be tested for full closure before each startup, unless a satisfactory test has been conducted within the previous 24 hours. The provisions of Specification 4.0.4 are not applicable.

B. Acceptance Criteria

1. A full closure test of a main steam line trip valve shall be considered satisfactory if the following criteria are met:

    a. T1 less than or equal to 4.0 seconds and
    b. T2 less than or equal to 5.0 seconds

    where

T1 = measured elapsed time from manual initiation of steam line isolation to initiation of main steam trip valve motion, seconds

T2 = measured elapsed main steam trip valve stroke time (full open to full closed), seconds

Basis

The main steam trip valves serve to limit an excessive Reactor Coolant System cooldown rate and resultant reactivity insertion following a main steam line break accident. Their ability to close fully within the maximum allowable time specified shall be verified prior to reactor startup.

The acceptance criteria reflect the assumptions made in the safety analysis of a main steam line break accident. The analysis assumes a 5 second delay from the time the system process variables reach the design setpoints to initiation of valve motion, followed by a 5 second linear ramp closure of the valve.

The acceptance criteria are established to ensure this safety analysis assumption is maintained. Thus the criteria may be written as follows:

a. I + B less than or equal to 5 seconds and

b. S less than or equal to 5 seconds

where

I = Instrument response time (delay from the time the process variable reaches the setpoint to initiation of bleedoff of instrument air from the main steam trip valve air cylinders), seconds.

B = Time delay from initiation of bleedoff of instrument air from the main steam trip valve air cylinders to initiation of valve motion, seconds.

S = Valve stroke time (full open to full closed), seconds.

The instrument response time I is represented by a value of 1.0 seconds based on a conservative evaluation of the actual response time. The bleedoff time B is equivalent to the measured interval T1 as defined in the Acceptance Criteria section of the Specification. The stroke time S is conservatively approximated by the measured interval T2 as defined in the Specification. Under actual steam line break conditions it is expected that S will be much less than T2, since valve closure is flow assisted. Thus the acceptance criterion may be rewritten as shown in Section 4.7.B.1.

4.8 AUXILIARY FEEDWATER SYSTEM

Applicability

Applies to the periodic testing requirements of the Auxiliary Feedwater System.

Objective

To verify the operability of the auxiliary feedwater pumps.

Specification

A. Tests and Frequencies

1. At least once per 31 days:

   a. Verify that the Auxiliary Feedwater System manual, power operated, and automatic valves in each flow path are in the correct position. This verification includes valves that are not locked, sealed, or otherwise secured in position, valves in the the cross-connect from the opposite unit and valves in the steam supply paths to the turbine driven auxiliary feedwater pump.

2. At least once per 92 days:

   a. Verify that each motor-operated valve in the auxiliary feedwater flow paths, including the cross-connect from the opposite unit, performs satisfactorily when tested in accordance with Specifications 4.0.5.

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

   a. Verify that the auxiliary feedwater pumps perform satisfactorily when tested in accordance with Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable for the turbine driven pump.

4a. Within 72 hours prior to Reactor Coolant System temperature and pressure exceeding 350°F and 450 psig, respectively, the motor driven auxiliary feedwater pumps shall be flow tested from the 110,000 gallon above ground Emergency Condensate Storage Tank to the steam generators .

4b. Wthin 72 hours after achieving reactor criticality, the steam turbine driven auxiliary feedwater pump shall be flow tested from the 110,000 gallon above ground Emergency Condensate Storage Tank to the steam generators. The provisions of Specification 4.0.4 are not applicable.

5. During periods of reactor shutdown with the opposite unit's Reactor Coolant System temperature and pressure greater than 350° F and 450 psig, respectively:

   a. Continue to verify that the motor driven auxiliary feedwater pumps perform satisfactorily when tested at the frequency defined in Specification 4.8.A.3.

   b. Verify that each motor-operated valve in the auxiliary feedwater cross-connect flow path for the opposite unit performs satisfactorily when tested in accordance with Specifications 4.0.5.

B. <u>Acceptance Criteria</u>

The pump and valve tests, except the system flow test, shall be considered satisfactory if they meet the ASME Section XI Inservice Testing Program acceptance criteria.

The system flow tests during unit startup from COLD SHUTDOWN or REFUELING SHUTDOWN shall be considered satisfactory if the control board indication demonstrates that flow paths exist to each steam generator.

Basis

The correct alignment for manual, power operated, and automatic valves in the Auxiliary Feedwater System steam and water flow paths, including the cross-connect flow path, will provide assurance that the proper flow paths exist for system operation. This position check does not include: 1) valves that are locked, sealed or otherwise secured in position since they are verified to be in their correct position prior to locking, sealing or otherwise securing; 2) vent, drain or relief valves on those flow paths; and, 3) those valves that cannot be inadvertently misaligned such as check valves. This surveillance does not require any testing or valve manipulation. It involves verification that those valves capable of being mispositioned are in the correct position.

The auxiliary feedwater pump will be tested periodically in accordance with ASME Section XI to demonstrate operability. The pumps are flow tested on recirculation to the 110,000 gallon Emergency Condensate Storage Tank. Valves in the flow path to the steam generators and cross-connect flow path are tested periodically in accordance with ASME Section XI.

The auxiliary feedwater pumps are capable of supplying feedwater to the opposite units steam generators. For a main steam line break or fire event in the Main Steam Valve House, one of the opposite units auxiliary feedwater pumps is required to supply feedwater to mitigate the consequences of those accidents. Therefore, when considering a single failure, both motor driven auxiliary feedwater pumps are required to be OPERABLE* during shutdown to support the opposite unit if the Reactor Coolant System temperature or pressure of the opposite unit is greater than 350°F and 450 psig, respectively. Thus, to establish operability* the motor driven auxiliary feedwater pumps will continue to be tested quarterly on the same STAGGERED TEST BASIS when the unit is shutdown to support the opposite unit. The turbine driven pump is not required to be OPERABLE when the unit is shutdown and therefore, is not tested during periods of shutdown.

* excluding automatic initiation instrumentation

The capacity of the Emergency Condensate Storage Tank and the flow rate of any one of the three auxiliary feedwater pumps in conjunction with the water inventory of the steam generators is capable of maintaining the plant in a safe condition and sufficient to cool the unit down.

Proper functioning of the steam turbine admission valve and the ability of the auxiliary feedwater pumps to start will demonstrate the integrity of the system. Verification of correct operation can be made both from instrumentation within the Main Control Room and direct visual observation of the pumps.

References

UFSAR Section 10.3.1 Main Steam System
UFSAR Section 10.3.2 Auxiliary Steam System

4.9 RADIOACTIVE GAS STORAGE MONITORING SYSTEM

Applicability

Applies to the periodic monitoring of radioactive gas storage.

Objective

To ascertain that waste gas is stored in accordance with Specification 3.11.

Specification

A. The concentration of oxygen in the waste gas holdup system shall be determined to be within the limits of Specification 3.11.A by continuously monitoring the waste gases in the waste gas holdup system with the oxygen monitor required to be OPERABLE by Table 3.7-5(a) of Specification 3.7.E.

B. The quantity of radioactive material contained in each gas storage tank shall be determined to be within the limits of Specification 3.11.B at least once per month when the specific activity of the primary reactor coolant is $\leq$ 2200 μCi/gm dose equivalent Xe-133. Under the conditions which result in a specific activity > 2200 μCi/gm dose equivalent Xe-133, the waste gas decay tanks shall be sampled once per day.

4.10 REACTIVITY ANOMALIES

Applicability

Applies to potential reactivity anomalies.

Objective

To require evaluation of applicable reactivity anomalies within the reactor.

Specification

A. Following a normalization of the computed boron concentration as a function of burnup, the actual boron concentration of the coolant shall be compared monthly with the predicted value. If the difference between the observed and predicted steady-state concentrations reaches the equivalent of one percent in reactivity, an evaluation as to the cause of the discrepancy shall be made and reported to the Nuclear Regulatory Commission per Section 6.6 of these Specifications. The provisions of Specification 4.0.4 are not applicable.

B. During periods of POWER OPERATION at greater than 10% of RATED POWER, the hot channel factors identified in Section 3.12 shall be determined during each effective full power month of operation using data from limited core maps. If these factors exceed their limits, an evaluation as to the cause of the anomaly shall be made. The provisions of Specification 4.0.4 are not applicable.

DELETED

Basis

BORON CONCENTRATION

To eliminate possible errors in the calculations of the initial reactivity of the core and the reactivity depletion rate, the predicted relation between fuel burnup and the boron concentration necessary to maintain adequate control characteristics must be adjusted (normalized) to accurately reflect actual core conditions. When full power is reached initially, and with the control rod assembly groups in the desired positions, the boron concentration is measured and the predicted curve is adjusted to this point. As power operation proceeds, the measured boron concentration is compared with the predicted concentration, and the slope of the curve relating burnup and reactivity is compared with that predicted. This process of normalization should be completed after about 10% of the total core burnup. Thereafter, actual boron concentration can be compared with prediction, and the reactivity status of the core can be continuously evaluated. Any reactivity anomaly greater than 1% would be unexpected, and its occurrence would be thoroughly investigated and evaluated.

The value of 1% is considered a safe limit since a shutdown margin of at least 1% with the most reactive control rod assembly in the fully withdrawn position is always maintained.

PEAKING FACTORS

A thermal criterion in the reactor core design specified that "no fuel melting during any anticipated normal operating condition" should occur. To meet the above criterion during a thermal overpower of 118% with additional margin for design uncertainties, a steady state maximum linear power is selected. This then is an upper linear power limit determined by the maximum central temperature of the hot pellet.

The peaking factor is a ratio taken between the maximum allowed linear power density in the reactor to the average value over the whole reactor. It is of course the average value that determines the operating power level. The peaking factor is a constraint which must be met to assure that the peak linear power density does not exceed the maximum allowed value.

During normal reactor operation, measured peaking factors should be significantly lower than design limits. As core burnup progresses, measured designed peaking factors typically decrease. A determination of these peaking factors during each effective full power month of operation is adequate to ensure that core reactivity changes with burnup have not significantly altered peaking factors in an adverse direction.

4.11 SAFETY INJECTION SYSTEM TESTS

Applicability

Applies to the operational testing of the Safety Injection System.

Objective

To verify that the Safety Injection System will respond promptly and perform its design functions, if required.

Specifications

A. The refueling water storage tank (RWST) shall be demonstrated OPERABLE:

   1. At least once per day by verifying the RWST solution temperature.

   2. At least once per week by:

      a. Verifying the RWST contained borated water volume, and

      b. Verifying the RWST boron concentration.

B. Each safety injection accumulator shall be demonstrated OPERABLE:

   1. At least once per 12 hours by:

      a. Verifying the contained borated water volume is within specified limits, and

      b. Verifying the nitrogen cover-pressure is within specified limits.

2. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the accumulator solution.

   a. This surveillance is not required when the volume increase makeup source is the RWST.

C. Each Safety Injection Subsystem shall be demonstrated OPERABLE:

1. By verifying, that on recirculation flow, each low head safety injection pump performs satisfactorily when tested in accordance with Specification 4.0.5.

2. By verifying that each charging pump performs satisfactorily when tested in accordance with Specification 4.0.5.

3. By verifying that each motor-operated valve in the safety injection flow path performs satisfactorily when tested in accordance with Specification 4.0.5.

4. Prior to POWER OPERATION by:

   a. Verifying that the following motor operated valves are blocked open by de-energizing AC power to the valves motor operator and tagging the breaker in the off position:

Unit 1	Unit 2
MOV-1890C	MOV-2890C

   b. Verifying that the following motor operated valves are blocked closed by de-energizing AC power to the valves motor operator and the breaker is locked, sealed or otherwise secured in the off position:

Unit 1	Unit 2
MOV-1869A	MOV-2869A
MOV-1869B	MOV-2869B
MOV-1890A	MOV-2890A
MOV-1890B	MOV-2890B

c. Power may be restored to any valve or breaker referenced in Specifications 4.11.C.4.a and 4.11.C.4.b for the purpose of testing or maintenance provided that not more than one valve has power restored at one time, and the testing and maintenance is completed and power removed within 24 hours.

5. Once per 18 months by:

a. Verifying that each automatic valve capable of receiving a safety injection signal, actuates to its correct position upon receipt of a safety injection test signal. The charging and low head safety injection pumps may be immobilized for this test.

b. Verifying that each charging pump and safety injection pump circuit breaker actuates to its correct position upon receipt of a safety injection test signal. The charging and low head safety injection pumps may be immobilized for this test.

c. Verifying, by visual inspection, that each low head safety injection pump suction inlet from the containment sump is free of debris that could degrade system operation. Perform each refueling outage and/or after major maintenance activities in the containment.

Basis

Complete system tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation. The method of assuring operability of these systems is therefore to combine system tests to be performed during unit outages, with more frequent component tests, which can be performed during reactor operation.

The system tests demonstrate proper automatic operation of the Safety Injection System. A test signal is applied to initiate automatic operation action and verification is made that the components receive the safety injection signal in the proper sequence. The test may be performed with the pumps blocked from starting. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

During reactor operation, the instrumentation which is depended on to initiate safety injection is checked periodically, and the initiating circuits are tested in accordance with Specification 4.1. In addition, the active components (pumps and valves) are to be periodically tested to check the operation of the starting circuits and to verify that the pumps are in satisfactory running order. The test interval is determined in accordance with ASME Section XI. The accumulators are a passive safeguard.

References

UFSAR Section 6.2, Safety Injection System

4.12 AUXILIARY VENTILATION EXHAUST FILTER TRAINS

Applicability

Applies to the testing of safety-related air filtration systems.

Objective

To verify that leakage efficiency and iodine removal efficiency are within acceptable limits.

Specifications

A. Tests and Frequency

1. Each redundant filter train circuit shall be operated every month if it has not already been in operation.

2. Once per 18 months, the operability of the entire safety-related portion of the auxiliary ventilation system shall be demonstrated.

3. Auxiliary ventilation system exhaust fan flow rate through each filter train in the LOCA mode of operation shall be determined initially, after any structural maintenance on the HEPA filter or charcoal adsorber housings, once per 18 months, or after partial or complete replacement of the HEPA filters or charcoal adsorbers.

   The procedure for determining the air flow rate shall be in accordance with Section 9 of the ACGIH Industrial Ventilation document and Section 8 of ANSI N510-1975.

4. A visual inspection of the filter train and associated components shall be conducted before each in-place air flow distribution test, DOP test, or activated charcoal adsorber leak test in accordance with the intent of Section 5 of ANSI N510-1975.

5. An air distribution test across the prefilter bank shall be performed initially and after any major modification, major repair, or maintenance of the air cleaning system affecting the filter bank flow distribution. The air distribution test shall be performed with an anemometer located at the downstream side and at the center of each carbon filter.

6. In-place cold DOP tests for HEPA filter banks shall be performed:

   a. Initially;

   b. Once per 18 months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of the HEPA filter cells; and

   e. After any structural maintenance on the filter housing.

   The procedure for in-place cold DOP tests shall be in accordance with ANSI N510-1975, Section 10.5 or 11.4. The flow rate during the in-place cold DOP tests shall be 36,000 CFM ±10 percent. The flow rate shall be determined by recording the flow meter reading in the control room.

7. In-place halogenated hydrocarbon leakage tests for the charcoal adsorber bank shall be performed:

   a. Initially;

   b. Once per 18 months;

c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

d. After each complete or partial replacement of charcoal adsorber trays; and

e. After any structural maintenance of the filter housing.

The procedure for in-place halogenated hydrocarbon leakage tests shall be in accordance with ANSI N510-1975, Section 12.5. The flow rate during the in-place halogenated hydrocarbon leakage tests shall be 36,000 CFM ±10 percent. The flow rate shall be determined by recording the flow meter reading in the control room.

8. Laboratory analysis of each charcoal train shall be performed:

   a. Initially, whenever a new batch of charcoal is used to fill adsorbers trays; and

   b. After 720 hours of train operation; and

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation; and

   d. After any structural maintenance on the HEPA filter or charcoal adsorber housings that could affect operation of the charcoal adsorber; and

   e. At least once per eighteen months, if not otherwise performed per condition 8.b, 8.c, or 8.d within the last eighteen months.

   The procedure for iodine removal efficiency tests shall follow ASTM D3803. The test conditions shall be in accordance with those listed in Specification 4.12.B.7.

9. The pressure drop across the HEPA filter and adsorber banks shall be checked:

   a. Initially;

   b. Once per 18 months thereafter for systems maintained in a standby status and after 720 hours of system operation; and

   c. After each complete or partial replacement of filters or adsorbers.

B. Acceptance Criteria

1. The minimum period of air flow through the filters shall be 15 minutes per month.

2. The system operability test of Specification 4.12.A.2 shall demonstrate automatic start-up, shutdown and flow path alignment.

3. The air flow rate determined in Specification 4.12.A.3 shall be:

   a. 36,000 cfm ±10 percent with system in the LOCA mode of operation.

   b. The ventilation system shall be adjusted until the above limit is met.

4. Air distribution test across the prefilter-bank shall show uniformity of air velocity within ± 20 percent of average velocity. The ventilation system shall be adjusted until the limit is met.

5. In-place cold DOP test on HEPA filters shall show greater than or equal to 99.5 percent DOP removal. Leakage sources shall be identified, repaired, and retested. Any HEPA filters found defective shall be replaced.

6. In-place halogenated hydrocarbon leakage tests on charcoal adsorber banks shall show greater than or equal to 99 percent halogenated hydrocarbon removal. Leakage sources shall be identified, repaired, and retested.

7. Laboratory analysis on charcoal samples of the in-place charcoal adsorber, or new adsorbent, when obtained as described in Regulatory Guide 1.52, Revision 2, shall show:

   Methyl iodide penetration less than or equal to 14 percent, when tested in accordance with ASTM D3803-1989 (with the exception of face velocity which is to be at 24.4 M/min), with the relative humidity equal to 95 percent, and the temperature equal to 30°C (86°F).

   a. Laboratory analysis of charcoal adsorbers shall be available within 31 days of sampling.

   b. If the test results are unacceptable for the in-place charcoal adsorber, all the adsorbent in the affected filter shall be replaced with new qualified adsorbent.

8. The pressure drop across filter cells and adsorbers shall not exceed 7.0 inches W.G. If this condition cannot be met, new filter cells shall be installed.

Basis

Ventilation system filter components are not subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. The tests outlined above provide assurance of filter reliability and will ensure timely detection of conditions which could cause filter degradation.

A pressure drop across the combined HEPA filters and charcoal adsorbers of less than 7 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Operation of the filtration system for a minimum of 15 minutes a month prevents moisture buildup in the filters and adsorbers.

The frequency of tests and sample analysis of the degradable components of the system, i.e., the HEPA filter and charcoal adsorbers, is based on actual hours of operation to ensure that they perform as evaluated. System flow rates and air distribution do not change unless the ventilation system is radically altered.

If painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemical, or foreign material, the same tests and sample analysis are performed as required for operational use.

The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99.5 percent removal of DOP particulates. The heat release from operating ECCS equipment limits the relative humidity of the exhaust air to less than 80 percent even when outdoor air is assumed to be 100 percent relative humidity and all ECCS leakage evaporates into the exhaust air stream. Methyl iodide testing to a penetration less than or equal to 14 percent (applying a safety factor of 2) demonstrates the assumed accident analysis efficiencies of 70 percent for methyl iodide and 90 percent for elemental iodine. This conclusion is supported by a July 10, 2000 letter from NCS Corporation that stated "Nuclear grade activated carbon, when tested in accordance with ASTM D3803-1989 (methyl iodide...) to a penetration of 15%, is more conservative than testing the same carbon in accordance with ASTM D3803-1979 (elemental iodine...) to a penetration of 5%. ...As a general rule, you may expect the radioiodine penetration through nuclear grade activated carbon to increase from 20 to 100 times when switching from elemental iodine to methyl iodide testing." Therefore, the efficiencies of the HEPA filters and charcoal adsorbers are demonstrated to be as specified, at flow rates, temperatures, velocities, and relative humidities which are less than the design values of the system, the resulting doses will be less than 10 CFR 100 guidelines for the accidents analyzed. The demonstration of bypass 1% and demonstration of 86 percent methyl iodide removal efficiency will assure the required capability of the adsorbers is met or exceeded.

AUGMENTED INSERVICE INSPECTION PROGRAM FOR HIGH ENERGY LINES OUTSIDE OF CONTAINMENT

Applicability

Applies to welds in piping systems or portions of systems located outside of containment where protection from the consequences of postulated ruptures is not provided by a system of pipe whip restraints, jet impingement barriers, protective enclosures and/or other measures designed specifically to cope with such ruptures.

For Surry Units 1 and 2, this specification applies to welds in the main steam and main feedwater lines in the main steam valve house of each unit.

Objective

To provide assurance of the continued integrity of the piping systems over their service lifetime.

Specifications

A. For the 20 welds identified in TS Figure 4.15:

1. At the first refueling outage period a volumetric examination shall be performed with 100 percent inspection of welds in accordance with the requirement of ASME Section XI Code, Inservice Inspection of Nuclear Power Plant Components, to

establish system integrity and baseline data.

2. The inservice inspection at each weld shall be performed in accordance with the requirements of ASME Section XI Code, Inservice Inspection of Nuclear Power Plant Components, with the following schedule: (The inspection intervals identified below sequentially follow the baseline examination of TS 4.15.A.1 above):

First 10 Year Inspection Program Intervals	
a. First 3-1/3 years (or nearest refueling outage)	100% volumetric inspection of all welds
b. Second 3-1/3 years (or nearest refueling outage)	100% volumetric inspection of all welds
c. Third 3-1/3 years (or nearest refueling outage)	100% volumetric inspection of all welds.
Successive Inspection Intervals	
Every 10 years thereafter (or nearest refueling outage)	Volumetric inspection of 1/3 of the welds at the expiration of each 1/3 of the inspection interval with a cumulative 100% coverage of all welds

Note - The welds selected during each inspection period shall be distributed among the total number to be examined to provide a representative sampling of the conditions of the welds.

3. Examinations that reveal unacceptable structural defects in a weld during an inspection under TS 4.15.A.2 shall be extended to require an additional inspection of another 1/3 of the welds. If further unacceptable defects are detected in the second sampling, the remainder of the welds shall be inspected.

4. In the event repairs of any welds are required following any examination during successive inspection intervals, the inspection schedule for the repaired welds will revert back to the first 10 year inspection program.

B. For all welds other than those identified in TS Figure 4.15:

1. Welds in the main steam lines including the safety valve headers and in the feedwater lines in the main steam valve house shall be examined in accordance with the requirements of subsection IWC of the ASME Section XI Code.

C. For all welds in the main steam valve house:

1. A visual inspection of the surface of the insulation at all weld locations shall be performed on a weekly basis for detection of leaks. Any detected leaks shall be investigated and evaluated. If the leakage is caused by a through-wall flaw, either the plant shall be shutdown, or the leaking piping isolated. Repairs shall be performed prior to return of this line to service.

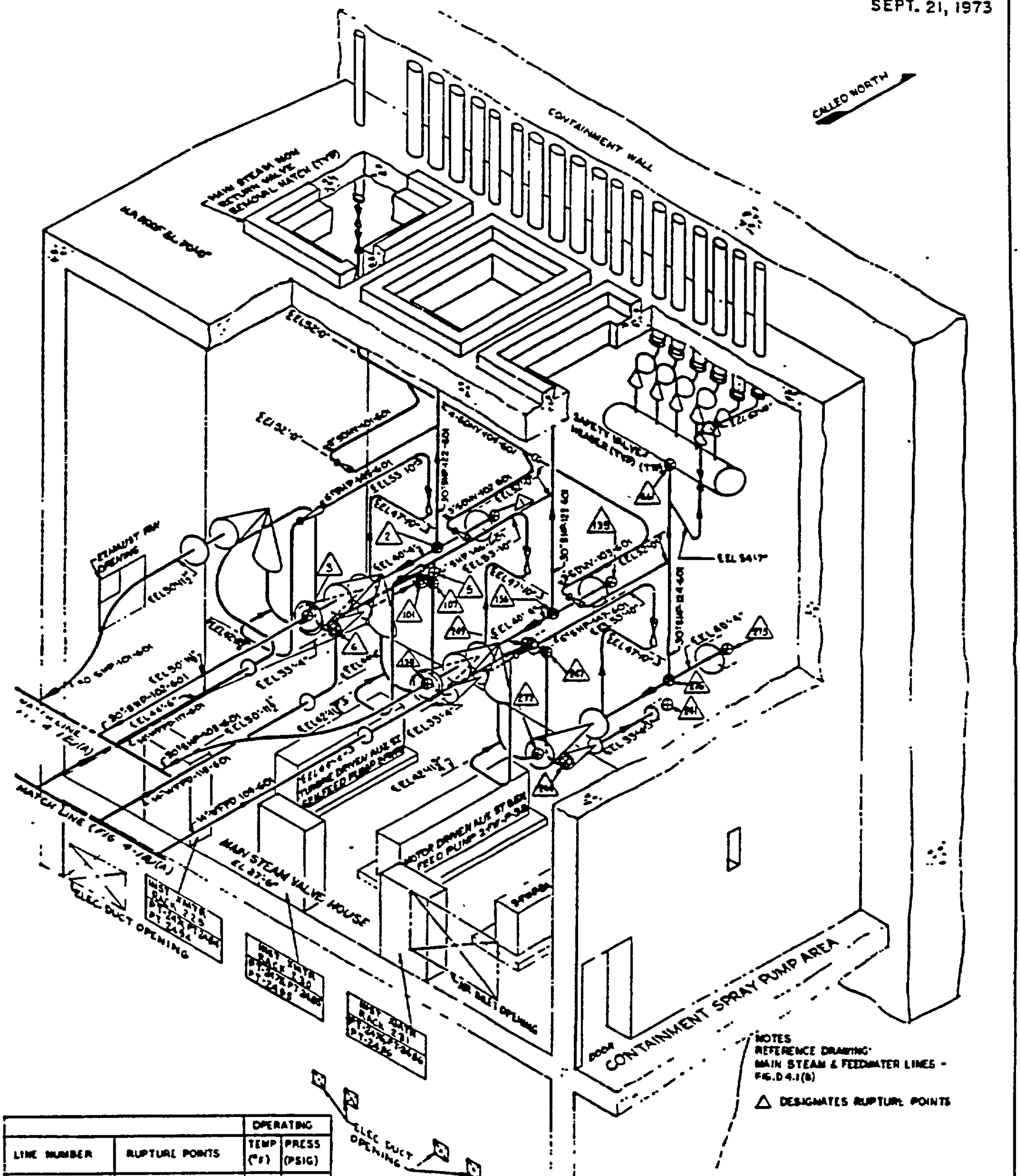
2. Repairs, reexamination and piping pressure tests shall be conducted in accordance with the rules of ASME Section XI Code.

Basis

Under normal plant operating conditions, the piping materials operate under ductile conditions and within the stress limits considerably below the ultimate strength properties of the materials. Flaws which could grow under such conditions are generally associated with cyclic loads that fatique the metal, and lead to leakage cracks. The inservice examination and the frequency of inspection will provide a means for timely detection even before the flaw penetrates the wall of the piping.

CHANGE No. 13 TS FIG. 4.15

SEPT. 21, 1973



NOTES

REFERENCE DRAWING: MAIN STEAM & FEEDWATER LINES - FIG. D 4.1(B)

△ DESIGNATES RUPTURE POINTS

LINE NUMBER	RUPTURE POINTS	OPERATING TEMP (°F)	OPERATING PRESS (PSIG)
14" WFPD 109-601	241, 244, 247 & 249	450	1032
14"-WFPD-113-601	101 & 107	450	1032
14"-WFPD-117-601	5 & 6	450	1032
30"-SHP-103-601	275, 276 & 277	547	1005
30"-SHP-102-601	135, 136 & 138	547	1005
30" SHP-101-601	1, 2, 3	547	1005
30"-SHP 124-601	461 (TYP FOR 3 SAFETY VALVE HEADERS)	547	1005

MAIN STEAM AND FEEDWATER LINES - UNIT 2

SURRY POWER STATION UNITS 1 AND 2

4.16 LEAKAGE TESTING OF MISCELLANEOUS RADIOACTIVE MATERIALS SOURCES

Applicability

Applies to miscellaneous radioactive materials sealed sources not subject to core flux and that are not stored and out of use.

Objective

To maintain doses due to ingestion or inhalation within the limits of 10 CFR 20.

Specifications

A. Source Leakage Test

Radioactive sources shall be leak tested for contamination. The leakage test shall be capable of detecting the presence of 0.005 microcurie of radioactive material on the test sample. If the test reveals the presence of 0.005 microcurie or more of removable contamination, it shall immediately be withdrawn from use, decontaminated, and repaired or be disposed of in accordance with Commission regulations.

Those quantities of byproduct material that exceed that quantities listed in 10 CFR 30.71 Schedule B are to be leak tested in accordance with the schedule shown in Surveillance Requirements. All other sources (including alpha emitters) containing greater than 0.1 microcurie are also to be leak tested in accordance with the Surveillance Requirements.

Commission or an agreement State as follows:

a. Each sealed source, except startup sources subject to core flux, containing radioactive material other than Hydrogen 3 with a half-life greater than thirty days and in any form other than gas shall be tested for leakage and/or contamination at intervals not to exceed six months.

b. The periodic leak test required does not apply to sealed sources that are stored and not being used. The sources excepted from this test shall be tested for leakage prior to any use or transfer to another user unless they have been leak tested within six months prior to the date of use or transfer. In the absence of a certificate from a transferor indicating that a test has been made within six months prior to the transfer, sealed sources shall not be put into use until tested.

c. Startup sources shall be leak tested prior to and following any repair or maintenance and before being subjected to core flux.

2. A complete inventory of radioactive materials in possession shall be maintained current at all times.

Basis

Ingestion or inhalation of source material may give rise to total body or organ irradiation. This specification assures that leakage from radioactive materials sources does not exceed allowable limits. The limits for all other sources (including alpha emitters) are based upon 10 CFR 70.39(c) limits for plutonium.

4.17 SHOCK SUPPRESSORS (SNUBBERS)

Applicability

Applies to all hydraulic and mechanical shock suppressors (snubbers) which are required to protect the Reactor Coolant System and other safety-related systems. Snubbers excluded from this inspection are those installed on non-safety-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.

Objective

To specify the minimum frequency and type of surveillance to be applied to the hydraulic and mechanical snubbers required to protect the Reactor Coolant System and other safety-related systems.

Specification

Each snubber shall be demonstrated OPERABLE by performing the following augmented inservice inspection program and the requirements of Specification 4.0.5. As used in this specification, "type of snubber" shall mean snubbers of the same design and manufacturer, irrespective of capacity.

A. Visual Inspections

1. Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 4.17-1. The visual inspection interval of each category of snubber shall be determined based upon the criteria provided in Table 4.17-1.

B. Visual Inspection Acceptance Criteria

1. Visual inspections shall verify that:

   a. the snubber has no visible indications of damage or impaired operability,

   b. attachments to the foundation or supporting structure are functional,

   c. fasteners for the attachment of the snubber to the component and to the snubber anchorage are functional, and

   d. in those locations where snubber movement can be manually induced without disconnecting the snubber, that the snubber has freedom of movement and is not frozen up.

2. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that:

   a. the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type that may be generically susceptible, and

   b. the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Specification 4.17.D or E.

   When hydraulic snubbers which have uncovered fluid ports are tested for operability, the test shall be performed by starting with the piston at the as-found setting and extending the piston rod in the tension mode direction.

3. All snubbers found connected to an inoperable common hydraulic fluid reservoir shall be counted as unacceptable for determining the next inspection interval.

4. A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the action requirements of Specification 3.20 shall be met.

C. Functional Tests

1. Once per 18 months, a representative sample of 10% of the total of each type snubber used in the plant shall be functionally tested using either an in-place test machine or a bench test.

2. The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. This representative sample shall not, to the extent practicable, include those snubbers tested in a previous representative sample.

3. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

   a. the first snubber away from each reactor vessel nozzle,

   b. snubbers within 5 feet of heavy equipment (valve, pump, turbine, motor, etc), and

   c. snubbers within 10 feet of the discharge from a safety relief valve.

4. Snubbers identified as "Especially Difficult to Remove" or in "High Radiation Zone During Shutdown" shall also be included in the representative sample.*

5. In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber (if it is repaired and installed in another position) and the spare snubber shall be retested. Test results of these snubbers may not be included for the resampling.

6. For each snubber that does not meet the functional acceptance criteria of Specification 4.17.D or 4.17.E, an additional 10% of that type of snubber shall be functionally tested.

7. For snubbers of 50 kips and above that are extremely difficult to remove or in high radiation zones that fail the functional testing, an engineering evaluation is required to determine the failure mode. If the failure is determined to be non-generic, an additional 10% of that type will be tested during the next functional test period.

8. 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 design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

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* Permanent or other exemptions from functional testing for individual snubbers in these categories may be granted by the Commission only if a justifiable basis for exemption is presented and/or snubber life destructive testing was performed to qualify snubber operability for all design conditions at either the completion of their fabrication or at a subsequent date.

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

D. Hydraulic Snubbers Functional Test Acceptance Criteria

1. The hydraulic snubber functional test shall verify that:

   a. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

   b. Snubber bleed, or release rate, where required, is within the specified range in compression and tension. For snubbers specifically required to not displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

E. Mechanical Snubbers Functional Test Acceptance Criteria

1. The mechanical snubbers functional test shall verify that:

   a. The drag force of the snubber in both tension and compression is less than the specified maximum drag force.

   b. Activation (restraining action) is achieved within the specified range of velocity in both tension and compression.

c. Snubber release rate, where required, is within the specified range in compression and tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

F. Snubber Service Life Monitoring

1. A record of the service life of each snubber, the date at which the designated service life commences, and the installation and maintenance records on which the designated service life is based shall be maintained as required by the Virginia Electric and Power Company Operational Quality Assurance Program Topical Report.

2. Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records.

Bases

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

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, or are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested once per 18 months. Functional testing is to be in accordance with the ASME Section XI Inservice Inspection program approved by the NRC. Observed failures of these sample snubbers shall require functional testing of additional units.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs.

The service life of a snubber is evaluated 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.

TABLE 4.17-1
SNUBBER VISUAL INSPECTION INTERVAL

Population or Category (Notes 1 and 2)	NUMBER OF UNACCEPTABLE SNUBBERS		
	Column A Extend Interval (Notes 3 and 6)	Column B Repeat Interval (Notes 4 and 6)	Column C Reduce Interval (Notes 5 and 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers are categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, the licensee must make and document that decision before any inspection and shall use that decision as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B, but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C, but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

All table pages are deleted 4.17-10 through 4.17-52.

4.19 STEAM GENERATOR INSERVICE INSPECTION

Applicability

Applies to the periodic inservice inspection of the steam generators.

Objective

To provide assurance of the continued integrity of the steam generator pressure boundaries.

Specifications

A. Each steam generator shall be demonstrated operable pursuant to Specification 3.1.A.2 by performance of the following augmented inservice inspection program and the requirement of Specification 4.2.A.

B. Steam Generator Sample Selection and Inspection - Each steam generator shall be determined operable during shutdown by selecting and inspection at least the minimum number of steam generators specified in Table 4.19-1.

C. Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in

Table 4.19-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.19.D and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.19.E. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations > 20%.

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 4.19.E.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an

adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 4.19-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.

C-3 More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (>10%) further wall penetrations to be included in the above percentage calculations.

D. Inspection Frequencies - The above inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.19-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.19.D.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.19-2 during the shutdown subsequent to any of the following conditions:

1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.1.C.6.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A major main steam line or feedwater line break.

E. Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube containing imperfections $\geq$20% of the nominal wall thickness caused be degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service because it may become unserviceable prior to the next inspection and is equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect is structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.19.D.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

9. Preservice Inspection means an 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 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 4.19-2.

F. Reports

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days.

b. The complete results of the steam generator tube inservice inspection shall be reported on an annual basis for the period in which the inspection was completed. This report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

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 by special report prior to resumption of plant operation. The report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

BASIS

The surveillance requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The unit is expected to be operated in a manner such that the secondary coolant will be maintained within those parameter limits found to result in negligible corrosion of the steam generator tubes.If the secondary coolant chemistry is not maintained within these parameter limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitatin of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage of 500 gallons per day per steam generator). Cracks having a primary-to-secondary leakage less than this limit during operatin will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 500 gallons per day per steam generator can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Wastage-type defects are unlikely with the all volatile treatment (AVT) of secondary coolant. However, even if a defect of similar type should develop inservice, it will be found during scheduled inservice steam generator tube examination. Plugging will be required of all tubes with imperfections exceeding the plugging limit which, by the definition of Specification 4.19.E.a, if 40% of the tube nominal wall thickness. Steam generator tube inspections of operating plants have demonstrated the capability of reliably detecting degradation that has penetrated 20% of the original tube wall thickness.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be reported to the Commission by special report prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations tests, additional eddy current inspection, and revision of the Technical Specification, if necessary.

TABLE 4.19-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE

INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No			Yes			
No. of Steam Generators	Two	Three		Two	Three		
First Inservice Inspection	All			One	Two		
Second & Subsequent Inservice Inspections	One[1]			One[1]	One[2]		

Table Notation:

1. The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

2. The other steam generator not inspected during the first inservice inspection shall be inspected. The third and subsequent inspections should follow the instructions described in 1 above.

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TABLE 4.19-2

STEAM GENERATOR TUBE INSPECTION

	1st SAMPLE INSPECTION		2nd SAMPLE INSPECTION		3rd SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect addit- 4S tubes in this S.G.	C-1	None
					C-2	Plug defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., plug defective tubes & inspect 2S tubes in each other S.G. Special Report	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug defective tubes Special Report	N/A	N/A

$S=3\frac{N}{n}\%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection

4.20 CONTROL ROOM AIR FILTRATION SYSTEM

Applicability

Applies to the testing of safety-related air filtration systems of the control room and relay room.

Objective

To verify that leakage efficiency and iodine removal efficiency are within acceptable limits.

Specification

A. Tests and Frequency

1. The control room air filtration system flow rate test shall be performed:

   a. Initially;

   b. Once per 18 months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of the HEPA filter or charcoal adsorbers; and

   e. After any structural maintenance the HEPA filter or charcoal adsorber housings; and

   f. After any major modification or repair of the air cleaning system.

2. The procedure for determining the air flow rate shall be in accordance with Section 9 of the ACGIH Industrial Ventilation document and Section 8 of ANSI N510-1975. A visual inspection of the filter train and its associated components shall be conducted before each in-place airflow distribution test, DOP test, or activated charcoal adsorber leak test in accordance with the intent of Section 5 of ANSI N510-1975.

3. In-place cold DOP tests for HEPA filter banks shall be performed:

    a. Initially;

    b. Once per 18 months;

    c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

    d. After each complete or partial replacement of the HEPA filter cells; and

    e. After any structural maintenance of the filter housing.

4. The procedure for in-place cold DOP tests shall be in accordance with ANSI N510-1975, Section 10.5 or 11.4. The flow rate during this test shall be that value determined under Specification 4. 20. A. 1 and shall be within the range specified in Specification 4. 20. B. 1.

5. In-place halogenated hydrocarbon leakage tests for the charcoal adsorber bank shall be performed:

   a. Initially;

   b. Once per eighteen months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of charcoal adsorber trays; and

   e. After any structural maintenance on the filter housing.

6. The procedure for in-place halogenated hydrocarbon leakage tests shall be in accordance with ANSI N510-1975 Section 12.5. The flow rate during this test shall be that value determined under Specification 4.20.A.1 and shall be within the range specified in Specification 4.20.B.1.

7. Charcoal Adsorber shall be replaced:

   a. After 720 hours of train operation; and

   b. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation; and

   c. After any structural maintenance on the HEPA filter or charcoal adsorber housing that could affect the operation of the charcoal adsorber; and

   d. At least once per eighteen months, if not otherwise replaced per condition 7.a, 7.b, or 7.c within the last eighteen months.

Upon meeting any of these conditions, the affected charcoal bank shall be removed from service and the charcoal replaced with new charcoal meeting the specifications in 4.20.B.4.

8. The procedure for iodine removal efficiency tests shall follow ASTM D3803. The test conditions shall be in accordance with those listed in Specification 4. 20. B. 4.

9. The pressure drop across the HEPA filter and adsorber banks shall be checked:

   a. Initially;

   b. Once per 18 months; and

   c. After each complete or partial replacement of filters or adsorbers.

10. Each filter train circuit shall be operated every month. Filter Train Operation shall be initiated manually from the control room.

B. <u>Acceptance Criteria</u>

1. Fan flow tube test shall show a flow rate through any single filter train of 1000 ± 10 percent cfm.

2. In-place cold DOP tests on HEPA filters shall show greater than or equal to 99.5 percent DOP removal. Leaking sources shall be identified, repaired and retested. Any HEPA filter found defective shall be replaced.

3. In-place halogenated hydrocarbon leakage tests on charcoal adsorber banks shall show greater than or equal to 99 percent halogenated hydrocarbon removal. Leakage sources shall be identified, repaired and retested.

4. Laboratory analysis on new charcoal adsorbent shall show the methyl iodide penetration less than or equal to 14 percent, when tested in accordance with ASTM D3803-1989 (with the exception of face velocity which is to be at 24.4 M/min), with the relative humidity equal to 95 percent, and the temperature equal to 30°C (86°F).

5. The pressure drop across filter cells and adsorbers shall not exceed 5.0 inches W.G. at design flow rate. If this condition cannot be met, new filter cells shall be installed.

6. The minimum period of air flow through the filter shall be 15 minutes per month.

Basis

Ventilation system filter components are not subject to rapid deterioration, having lifetimes of many years. The tests outlined above provide assurance of filter reliability and will ensure timely detection of conditions which could cause filter degradation.

A pressure drop across the combined HEPA filters and charcoal adsorbers of less than 5 inches of water will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Operation of the filtration system for a minimum of 15 minutes a month prevents moisture buildup in the filters and adsorbers.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated.

If painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from fumes, chemicals, or foreign material, the HEPA filters are tested and the charcoal adsorbers are replaced to ensure the operational requirements are met.

The in-place test results should indicate a system leaktightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99.5 percent removal of DOP particulates. Methyl iodide testing to a penetration less than or equal to 14 percent (applying a safety factor of 2) demonstrates the assumed accident analysis efficiencies of 70 percent for methyl iodide and 90 percent for elemental iodine. This conclusion is supported by a July 10, 2000 letter from NCS Corporation that stated "Nuclear grade activated carbon, when tested in accordance with ASTM D3803-1989 (methyl iodide...) to a penetration of 15%, is more conservative than testing the same carbon in accordance with ASTM D3803-1979 (elemental iodine...) to a penetration of 5%. ...As a general rule, you may expect the radioiodine penetration through nuclear grade activated carbon to increase from 20 to 100 times when switching from elemental iodine to methyl iodide testing." Therefore, if the efficiencies of the HEPA filters and charcoal adsorbers are as specified, at the temperatures, flow rates and velocities within the design values of the system, the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR Part 50.

The charcoal in the Control Room Filtration System is replaced with new charcoal rather than tested for continued use because the charcoal bed design does not include a provision for taking in-place charcoal samples.

5.0 DESIGN FEATURES

5.1 SITE

Applicability

Applies to the location and boundaries of the site for the Surry Power Station.

Objective

To define those aspects of the site which will affect the overall safety of the installation.

Specification

The Surry Power Station is located in Surry County, Virginia, on property owned by Virginia Electric and Power Company on a point of land called Gravel Neck which juts into the James River. It is approximately 46 miles SE of Richmond, Virginia, 17 miles NW of Newport News, Virginia, and 25 miles NW of Norfolk, Virginia. The minimum distance from a reactor centerline to the site exclusion boundary as defined in 10CFR100 is 1,650 ft. This is the distance for Unit 1, which is controlling. A map of the site is shown in TS Figure 5.1-1.

References

FSAR section 2.0 Site

FSAR Section 2.1 General Description

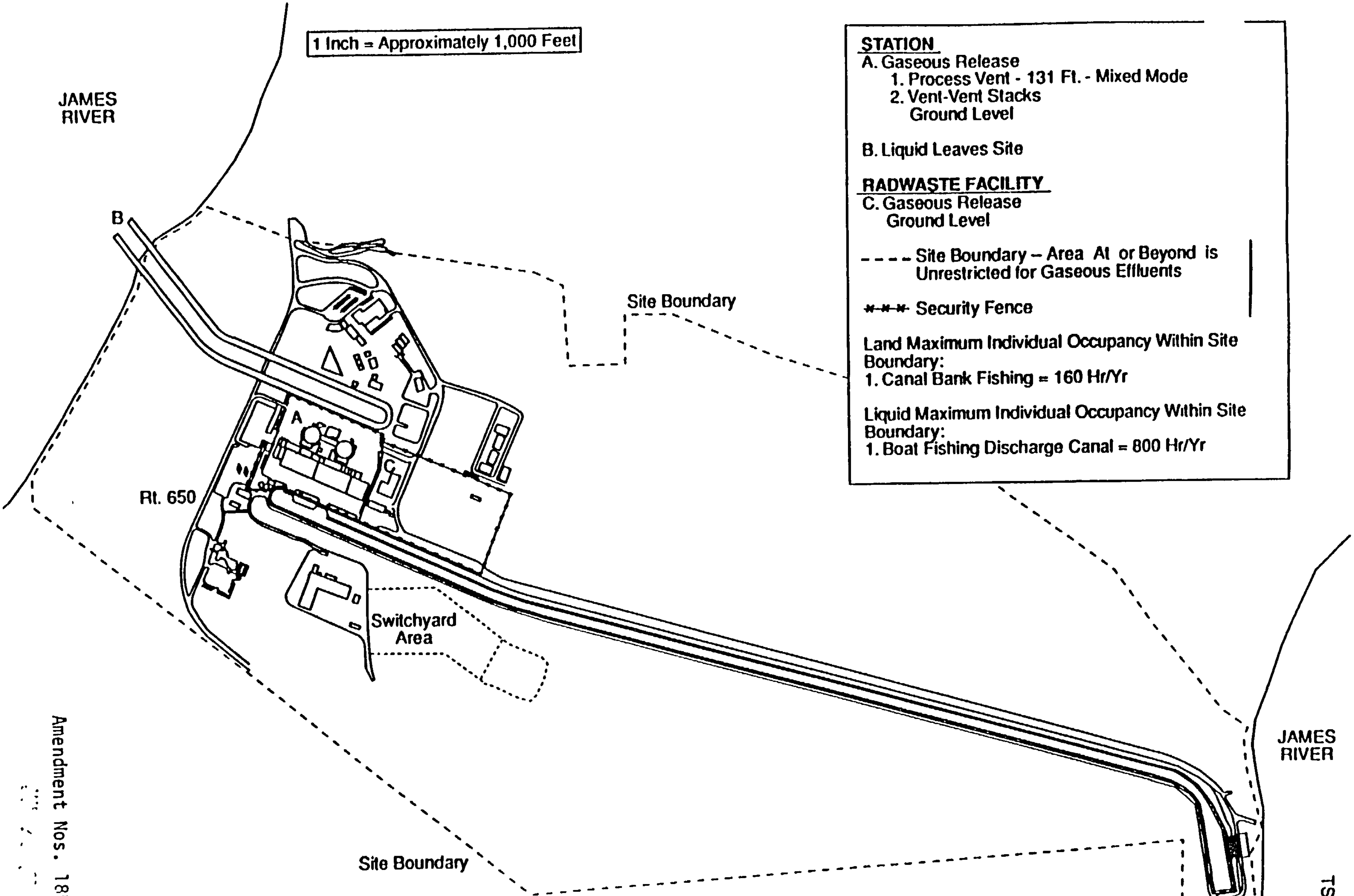

FIGURE 5.1-1
MAP DEFINING UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS

Amendment Nos. 185 and 185

TS Figure 5.1-1

5.2 CONTAINMENT

Applicability

Applies to those design features of the reactor containment structures and containment systems relating to operational and public safety.

Objective

To define ths significant design features of the reactor containment structures and containment systems.

Specifications

A. Structure

1. A containment structure completely encloses each reactor and Reactor Coolant System and assures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even if gross failure of a Reactor Coolant System occurs. Each structure provides biological shielding for both normal operation and accident situations. Each containment structure is designed for an internal subatmospheric pressure of 8 psia.

2. Each containment structure is designed for a reactor operating at the ultimate rated thermal power of 2546 MWt.

3. Each containment structure is designed to withstand an internal design pressure of 45 psig acting simultaneously with: (1) loads resulting from an Operational Basis Earthquake having a horizontal ground acceleration of 0.07 g at zero period with an assumed structural damping factor of 5 percent, or (2) loads resulting from a Design Basis Earthquake having a horizontal ground acceleration of 0.15 g at zero period with an assumed structural damping factor of 10 percent.

B <u>Containment Penetrations</u>

1. All penetrations through the containment structure for pipe, electrical conductors, ducts, and access hatches are of the double barrier type.

2. The automatically actuated isolation valves are designed to close as outlined below. The actuation system is designed such that no single component failure will prevent containment isolation if required. Refer to Table 3.7-4 in the Technical Specifications for set point values of the signals.

   a. A safety injection signal closes all trip valves which are located in normally open lines connecting the reactor coolant loops and penetrating the containment.

b. A high containment pressure isolation signal closes the automatic trip valves in all normally open lines penetrating the containment which are not required to be open to control containment pressure to perform an orderly reactor shut down without actuation of the consequence limiting safeguards in case of a small Reactor Coolant System leak.

c. A further rise in containment pressure, indicating a major loss-of-coolant accident, produces a containment high-high pressure isolation signal which closes all normally open lines which penetrate the containment which have not been closed by 2-b above.

d. Isolation can be accomplished manually from the control in the Main Control Room if any of the automatic signals fail to actuate the above valves.

C. <u>Containment Systems</u>

1. Following a loss-of-coolant accident, the Containment Spray Subsystems distribute at least 2,600 gpm borated water spray containing sodium hydroxide for iodine removal within the containment atmosphere. The Recirculation Spray Subsystems recirculate at least 3,000 gpm of water from the containment sump.

2. No part of the Containment Ventilation System is designed for continued operation during a total loss-of-coolant accident. It may, however, continue to operate with small Reactor Coolant System leaks until the Containment Spray System is initiated.

<u>References</u>

FSAR Section 5.2	Containment Isolation
FSAR Section 5.3	Containment Systems
FSAR Section 5.4	Design Evaluation
FSAR Section 7.2.2	Safeguards Initiation and Containment Isolation
FSAR Section 15.2.4	Seismic Design
FSAR Section 15.5.1	Containment Structure
Technical Specification	Section 3.3 Safety Injection System

5.3 REACTOR

Applicability

Applies to the reactor core, Reactor Coolant System, and Safety Injection System.

Objective

To define those design features which are essential in providing for safe system operations.

Specifications

A. Reactor Core

1. The reactor core contains approximately 176,200 lbs of uranium dioxide in the form of slightly enriched uranium dioxide pellets. The pellets are encapsulated in Zircaloy-4 or ZIRLO tubing to form fuel rods. All fuel rods are pressurized with helium during fabrication. The reactor core is made up of 157 fuel assemblies. Each fuel assembly contains 204 fuel rods except for fuel assemblies which may be reconstituted to replace leaking fuel rods with non-fueled rods (e.g. zircaloy or stainless steel).

2. The average enrichment of the initial core is 2.51 weight percent of U-235. Three fuel enrichments are used in the initial core. The highest enrichment is 3.12 weight percent of U-235.

3. Reload fuel will be similar in design to the initial core. The enrichment of reload fuel will not exceed 4.3 weight percent of U-235.

4. Burnable poison rods are incorporated in the initial core. There are 816 poison rods in the form of 12 rod clusters, which are located in vacant control rod assembly guide thimbles. The burnable poison rods consist of pyrex clad with stainless steel.

5. There are 48 full-length control rod assemblies in the reactor core. The full-length control rod assemblies contain a 144-inch length of silver-indium-cadmium alloy clad with stainless steel.

6. Surry Unit 1, Cycle 4, Surry Unit 2, Cycle 3, and subsequent cores will meet the following criteria at all times during the operation lifetime.

   a. Hot channel factor limits as specified in Section 3.12 shall be met.

b. The moderator temperature coefficient in the power operating range is less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT. The maximum upper limit for the moderator temperature coefficient shall be:

1) + 6 pcm/°F at less than 50% of RATED POWER, or

2) + 6 pcm/°F at 50% of RATED POWER and linearly decreasing to 0 pcm/°F at RATED POWER.

c. Capable of being made subcritical in accordance with Specification 3.12.A.3.C.

B. Reactor Coolant System

1. The design of the Reactor Coolant System complies with the code requirements specified in Section 4 of the UFSAR.

2. All piping, components, and supporting structures of the Reactor Coolant System are designed to Class 1 seismic requirements, and have been designed to withstand:

a. Primary operating stresses combined with the Operational seismic stresses resulting from a horizontal ground acceleration of 0.07g and a simultaneous vertical ground acceleration of 2/3 the horizontal, with the stresses maintained within code allowable working stresses.

b. Primary operating stresses when combined with the Design Basis Earthquake seismic stresses resulting from a horizontal ground acceleration of 0.15g and a simultaneous vertical ground acceleration of 2/3 of the horizonal, with the stresses such that the function of the component or system shall not be impaired as to prevent a safe and orderly shutdown of the unit.

3. The total liquid volume of the Reactor Coolant System, at rated operating conditions, is approximately 9300 cubic feet.

5.4 FUEL STORAGE

Applicability

Applies to the design of the new and spent fuel storage areas.

Objective

To define those aspects of fuel storage relating to prevention of criticality in fuel storage areas; to prevention of dilution of the borated water in the reactor; and to prevention of inadvertent draining of water from the spent fuel storage area.

Specification

A. The reinforced concrete structure and steel superstructure of the Fuel Building and spent fuel storage racks are designed to withstand Design Basis Earthquake loadings as Class 1 structures. The spent fuel pit has a stainless steel liner to ensure against loss of water.

B. The new and spent fuel storage racks are designed so that it is impossible to insert assemblies in other than the prescribed locations. New fuel is stored vertically in an array with a distance of 21 inches between assemblies to assure $k_{eff} \leq 0.98$ with fuel of the highest anticipated enrichment in place assuming optimum moderation.* Spent fuel is stored vertically in an array with a distance of 14 inches between

*E.G., an aqueous foam envelopment as the result of fire fighting.

assemblies to ensure $k_{eff} \leq 0.95$, even if unborated water were used to fill the spent fuel storage pit. The spent fuel pool is divided into a two-region storage pool. Region 1 comprises the first three rows of fuel racks (324 storage locations) adjacent to the Fuel Building Trolley Load Block. Region 2 comprises the remainder of the fuel racks in the fuel pool. During spent fuel cask handling, Region 1 is limited to storage of spent fuel assemblies which have decayed at least 150 days after discharge and shall be restricted to those assemblies in the "acceptable" domain of Figure 5.4-1. Administrative controls with written procedures will be employed in the selection and placement of these assemblies. The enrichment of the fuel stored in the spent fuel racks shall not exceed 4.3 weight percent of U-235.

C. Whenever there is spent fuel in the spent fuel pit, the pit shall be filled with borated water at a boron concentration not less than 2300* ppm to match that used in the reactor cavity and refueling canal during refueling operations.

D. The only drain which can be connected to the spent fuel storage area is that in the reactor cavity. The strict step-by-step procedures used during refueling ensure that the gate valve on the fuel transfer tube which connects the spent fuel storage area with the reactor cavity is closed before draining of the cavity commences. In addition, the procedures require placing the bolted blank flange on the fuel transfer tube as soon as the reactor cavity is drained.

* This limit takes effect at the time the Unit 2 reactor cavity is flooded following the end of Operating Cycle 10.

<u>References</u>

FSAR Section 9.5 Fuel Pit Cooling System

FSAR Section 9.12 Fuel Handling System

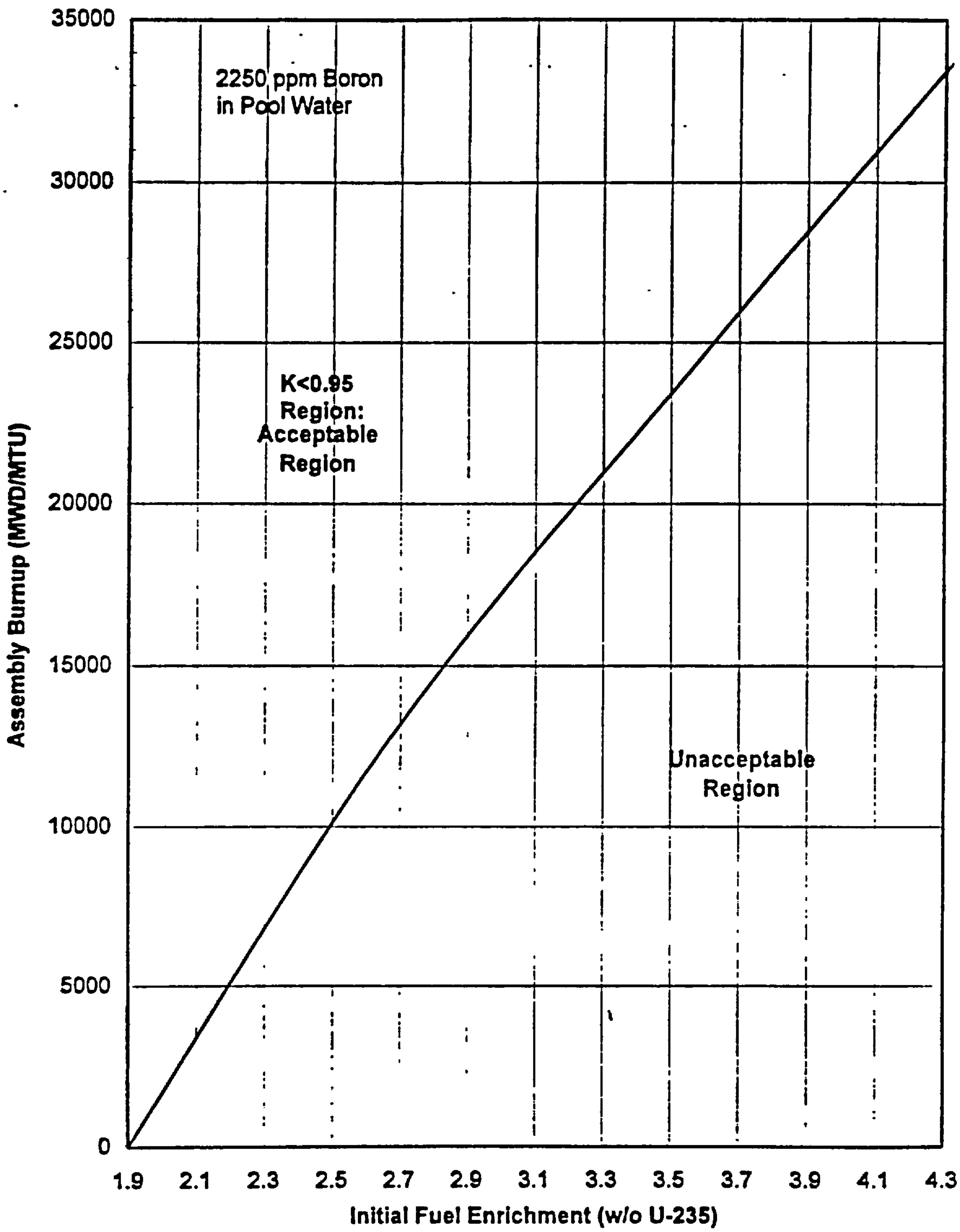

FIGURE 5.4-1

MINIMUM FUEL EXPOSURE VERSUS INITIAL ENRICHMENT
TO PREVENT CRITICALITY IN DAMAGED RACKS

6.0 ADMINISTRATIVE CONTROLS

6.1 Organization, Safety and Operation Review

Specification

A. The Site Vice President shall be responsible for the overall operation of the facility. In his absence, the Manager - Station Operations and Maintenance shall be responsible for the safe operation of the facility. During the absence of both, the Site Vice President will delegate in writing the succession to this responsibility.

An onsite and an offsite organization shall be established for facility operation and corporate management. The onsite and offsite organization shall include the positions for activities affecting the safety of the nuclear power plant.

1. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the UFSAR.

2. The Site Vice President shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

3. The Vice President - Nuclear Operations shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining and providing technical support to the plant to ensure nuclear safety.

4. The management position responsible for training of the operating staff and the position responsible for the quality assurance functions shall have sufficient organizational freedom including sufficient independence from cost and schedule when opposed to safety considerations.

5. The management position responsible for health physics shall have direct access to that onsite individual having responsibility for overall facility management. Health physics personnel shall have the authority to cease any work activity when worker safety is jeopardized or in the event of unnecessary personnel radiation exposures.

B. The facility organization shall conform to the following requirements:

1. Each member of the facility staff shall meet or exceed the minimum qualifications of ANS 3.1 (12/79 Draft)* for comparable positions, except for:

   a. The Superintendent - Radiological Protection shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

   b. The Superintendent Operations shall hold (or have previously held) a Senior Reactor Operator License for Surry Power Station or a similar design Pressurized Water Reactor plant.

   c. The Supervisor Shift Operations shall hold an active Senior Reactor Operator License for Surry Power Station.

2. Incumbents in the positions of Shift Supervisor, Assistant Shift Supervisor (SRO), Control Room Operator - Nuclear (RO), and Shift Technical Advisor, shall meet or exceed the requirements of 10 CFR 55.59(c) and 55.31(a)(4).

3. The Manager - Nuclear Training is responsible for ensuring that retraining and replacement training programs for the licensed facility staff meet or exceed the requirements of 10 CFR 55.59(c) and 55.31(a)(4). Also, a retraining and replacement training program for non-licensed facility staff shall meet or exceed the recommendations of Section 5 of ANS 3.1 (12/79 Draft)*.

4. Each on-duty shift shall be composed of at least the minimum shift crew composition for each unit as shown in Table 6.1-1.

5. A health physics technician shall be on site when fuel is in the reactor.

6. All core alterations shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator limited to fuel handling who has no other concurrent responsibilities during this operation.

* Exceptions to this requirement are specified in VEPCO's QA Topical Report, VEP-1, "Quality Assurance Program, Operational Phase."

7. Deleted.

8. Deleted.

9. The health physics technician requirement of Specification 6.1.B.5 may not be met for a period of time not to exceed 2 hours in order to accommodate an unexpected absence provided immediate action is taken to fill the required position.

10. Procedures will be established to insure that NRC policy statement guidelines regarding working hours established for employees are followed. In addition, procedures will provide for documentation of authorized deviations from those guidelines and that the documentation is available for NRC review.

TABLE 6.1-1

MINIMUM SHIFT CREW COMPOSITION

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION		
	ONE UNIT OPERATING	TWO UNITS OPERATING	TWO UNITS IN COLD SHUTDOWN OR REFUELING
SS	1	1	1
SRO	1	1	None
RO	3	3	2
AO	4	4	4
STA	1	1	None

TABLE 6.1-1 (Continued)

SS - Shift Supervisor with a Senior Reactor Operators License.
SRO - Individual with a Senior Reactor Operators License.
RO - Individual with a Reactor Operators License.
AO - Auxiliary Operator
STA - Shift Technical Advisor

Except for the Shift Supervisor, the Shift Crew Composition may be one less than the minimum requirements of Table 6.1-1 for a period of time not to exceed 2 hours in order to accomodate 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 6.1-1. 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 operation, an individual (other than the Shift Technical Advisor) with a valid SRO 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 shutdown or refueling, an individual with a valid RO license (other than the Shift Technical Advisor) shall be designated to assume the Control Room command functions.

C. Organization units to provide a continuing review of the operational and safety aspects of the nuclear facility shall be constituted and have the authority and responsibilities outlined below:

1. Station Nuclear Safety and Operating Committee (SNSOC)

a. Function

The SNSOC shall function to advise the Site Vice President on all matters related to nuclear safety.

b. Composition

The SNSOC shall be composed of the:

Chairman:	Manager - Station Safety and Licensing
Vice Chairman and Member:	Manager - Station Operations and Maintenance
Member:	Superintendent - Operations
Member:	Superintendent - Maintenance
Member:	Superintendent - Radiological Protection
Member:	Superintendent - Engineering

c. Alternates

All alternate members shall be appointed in writing however, no more than two alternates shall participate as voting members in SNSOC activities at any one time.

d. Meeting Frequency

The SNSOC shall meet at least once per calendar month and as convened by the SNSOC Chairman or his designated alternate.

e. Quorum

A quorum of the SNSOC shall consist of the Chairman or Vice Chairman and two members including alternates.

f. Responsibilities

The SNSOC shall be responsible for:

1. Review of a) all new normal, abnormal, and emergency operating procedures and all new maintenance procedures, b) all procedure changes that require a safety evaluation, and c) any other procedures or changes thereto as determined by the Site Vice President which affect nuclear safety.

2. Review of all new test and experiment procedures that affect nuclear safety.

3. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

4. Review of proposed changes to Technical Specifications and shall submit recommended changes to the Site Vice President.

5. Investigation of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Vice President - Nuclear Operations and to the Management Safety Review Committee.

6. Review of all Reportable Events and special reports submitted to the NRC.

7. Review of facility operations to detect potential nuclear safety hazards.

8. Performance of special reviews, investigations or analyses and report thereon as requested by the Chairman of the SNSOC or Site Vice President.

9. Deleted.

10. Deleted.

11. Review of every unplanned onsite release of radioactive material to the environs exceeding the limits of Specification 3.11, 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 Vice President - Nuclear Operations and to the Management Safety Review Committee.

12. Review of changes to the Process Control Program and the Offsite Dose Calculation Manual.

13. Review of the Fire Protection Program and implementing procedures and shall submit recommended Program changes to the designated offsite management responsible for reviewing changes that pertain to Fire Protection.

g. Authority

The SNSOC shall:

1. Provide written approval or disapproval of items considered under (1) through (3) above. SNSOC approval shall be certified in writing by either the Manager - Station Operations and Maintenance or the Manager - Station Safety and Licensing.

2. Render determinations in writing with regard to whether or not each item considered under (1) through (5) above constitutes an unreviewed safety question.

3. Provide written notification within 24 hours to the Vice President - Nuclear Operations and to the Management Safety Review Committee of disagreement between SNSOC and the Site Vice President; however, the Site Vice President shall have responsibility for resolution of such disagreements pursuant to 6.1.A above.

h. Records

The SNSOC shall maintain written minutes of each meeting and copies shall be provided to the Vice President - Nuclear Operations and to the Management Safety Review Committee.

2. MANAGEMENT SAFETY REVIEW COMMITTEE (MSRC)

a. Function

The Management Safety Review Committee shall function to provide independent review and audit of designated activities in the areas of:

1. Station Operations
2. Maintenance
3. Reactivity Management
4. Engineering
5. Chemistry and Radiochemistry
6. Radiological Safety
7. Quality Assurance Practices
8. Emergency Preparedness

b. Composition

The MSRC shall be composed of the MSRC Chairman and a minimum of four MSRC members. The Chairman and all members of the MSRC shall have qualifications that meet the requirements of Section 4.7 of ANS 3.1-(12/1979 Draft)

c. Alternates

All alternate members shall be appointed in writing by the MSRC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in MSRC activities at any one time.

d. Consultants

Consultants should be utilized as determined by the MSRC Chairman to provide expert advice to the MSRC.

e. Meeting Frequency

The MSRC shall meet at least once per calendar quarter.

f. Quorum

The minimum quorum of the MSRC necessary for the performance of the MSRC review and audit functions of these Technical Specifications shall consist of the Chairman or his designated alternate and at least 50% of the MSRC members including alternates. No more than a minority of the quorum shall have line responsibility for operation of the unit.

g. Review

The MSRC shall be responsible for the review of:

1. Safety evaluations as programmatically discussed in the Updated Final Safety Analysis Report for 1) changes to procedures, equipment or systems and 2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to assess the effectiveness of the safety evaluation program and to verify that the reviewed actions did not constitute an unreviewed safety question.

2. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

3. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

4. Proposed changes to Technical Specifications or the Operating Licenses.

5. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

6. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety.

7. Events requiring written notification to the Commission.

8. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety.

9. A representative sample of reports and meeting minutes of the SNSOC.

h. Audits

Audits of facility activities shall be performed under the cognizance of the MSRC. These audits shall encompass:

1. The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions.

2. The performance, training and qualifications of the entire facility staff.

3. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems or method of operation that affect nuclear safety.

4. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix "B", 10 CFR 50.

5. Any other area of facility operation considered appropriate by the MSRC or the Vice President - Nuclear Operations.

6. The Fire Protection Program and implementing procedures.

7. An independent fire protection and loss prevention inspection and audit shall be performed utilizing an outside qualified fire consultant.

8. The radiological environmental monitoring program.

9. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures.

10. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive waste.

i. Authority

The MSRC shall report to and advise the Senior Vice President - Nuclear on those areas of responsibility specified in Sections 6.1.c.2.g and 6.1.c.2.h.

j. Records

Records of MSRC activities shall be prepared, approved and distributed as indicated below:

1. Minutes of each MSRC meeting shall be prepared, approved and forwarded to the Senior Vice President - Nuclear within 14 days of each meeting.

2. Reports of reviews with safety significant findings encompassed by Section 6.1.c.2.g above, shall be prepared, approved and forwarded to the Senior Vice President - Nuclear within 14 days following completion of the review.

3. Audit reports encompassed by Section 6.1.c.2.h above, shall be forwarded to the Senior Vice President - Nuclear and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization.

6.2 GENERAL NOTIFICATION AND REPORTING REQUIREMENTS

Specification

A. The following actions shall be taken for Reportable Events:

1. A report shall be submitted pursuant to the requirements of Section 50.73 to 10 CFR, and

2. Each Reportable Event shall be reviewed by the SNSOC. The Vice President - Nuclear Operations and the MSRC shall be notified of the results of this review.

B. Immediate notifications shall be made in accordance with Section 50.72 to 10 CFR.

C. CORE OPERATING LIMITS REPORT

Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle. Parameter limits for the following Technical Specifications are defined in the CORE OPERATING LIMITS REPORT:

1. TS 3.1.E and TS 5.3.A.6.b - Moderator Temperature Coefficient

2. TS 3.12.A.2 and TS 3.12.A.3 - Control Bank Insertion Limits

3. TS 3.12.B.1 and TS 3.12.B.2 - Power Distribution Limits

The analytical methods used to determine the core operating limits identified above shall be those previously reviewed and approved by the NRC, and identified below. The core operating limits shall be determined so that applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided for information for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REFERENCES

1. VEP-FRD-42, Rev. 1-A, "Reload Nuclear Design Methodology," September 1986

   (Methodology for TS 3.1.E and TS 5.3.A.6.b - Moderator Temperature Coefficient; TS 3.12.A.2 and 3.12.A.3 - Control Bank Insertion Limit; TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor and Nuclear Enthalpy Rise Hot Channel Factor)

2a. WCAP-9220-P-A, Rev. 1, "Westinghouse ECCS Evaluation Model - 1981 Version," February 1982 (W Proprietary)

   (Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

2b. WCAP-9561-P-A, ADD. 3, Rev. 1, "BART A-1: A Computer Code for the Best Estimate Analysis of Reflood Transients-Special Report: Thimble Modeling in W ECCS Evaluation Model," July 1986 (W Proprietary)

   (Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

2c. WCAP-10266-P-A, Rev. 2, "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," March 1987 (W Proprietary)

   (Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

2d. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985 (W Proprietary)

(Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

2e. WCAP-10079-P-A, "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985 (W Proprietary)

(Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

2f. WCAP-12610, "VANTAGE+ Fuel Assembly Report," June 1990 (Westinghouse Proprietary).

(Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Heat Flux Hot Channel Factor)

3a. VEP-NE-2-A, "Statistical DNBR Evaluation Methodology," June 1987

(Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Nuclear Enthalpy Rise Hot Channel Factor)

3b. VEP-NE-3-A, "Qualification of the WRB-1 CHF Correlation in the Virginia Power COBRA Code," July 1990

(Methodology for TS 3.12.B.1 and TS 3.12.B.2 - Nuclear Enthalpy Rise Hot Channel Factor)

6.3 ACTION TO BE TAKEN IF A SAFETY LIMIT IS EXCEEDED

Specification

A. The following actions shall be taken in the event a Safety Limit is violated:

1. The facility shall be placed in at least hot shutdown within 1 hour.

2. The Safety Limit violation shall be reported to the Commission, the Vice President - Nuclear Operations, and the MSRC within 24 hours.

3. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the SNSOC. 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.

4. The Safety Limit Violation Report shall be submitted to the Commission, the Vice President - Nuclear Operations, and the MSRC within 14 days of the violation.

6.4 UNIT OPERATING PROCEDURES

Specification

A. Detailed written procedures with appropriate check-off lists and instructions shall be provided for the following conditions:

1. Normal startup, operation, and shutdown of a unit, and of all systems and components involving nuclear safety of the station.

2. Calibration and testing of instruments, components, and systems involving nuclear safety of the station.

3. Actions to be taken for specific and foreseen malfunctions of systems or components including alarms, primary system leaks and abnormal reactivity changes.

4. Release of radioactive effluents.

5. Emergency conditions involving potential or actual release of radioactivity.

6. Emergency conditions involving violation of industrial security.

7. Preventive or corrective maintenance operations which would have an effect on the safety of the reactor.

8. Refueling operations.

B. Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

1. In lieu of the "control device" or "alarm signal" required by paragraph 20.1601 of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP)*. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

   a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

   b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

   c. An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by Health Physics in the RWP.

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* Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they comply with approved plant radiation protection procedures for entry into high radiation areas.

2. The requirements of 6.4.B.1 above, shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr, but less than 500 rads/hr at one meter from a radiation source or any surface through which radiation penetrates. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the Shift Supervisor on duty and/or the senior station individual assigned the responsibility for health physics and radiation protection.

3. Written procedures shall be established, implemented, and maintained covering the activities referenced below:

   a. Process Control Program implementation.

   b. Offsite Dose Calculation Manual implementation.

C. All procedures described in 6.4.A and 6.4.B shall be reviewed and approved by the Station Nuclear Safety and Operating Committee (SNSOC) prior to implementation. Subsequent procedure changes that require a safety evaluation shall also be reviewed and approved by SNSOC prior to implementation. All other changes shall be independently reviewed and approved as discussed in the Updated Final Safety Analysis Report.

D. All procedures described in Specifications 6.4.A and 6.4.B shall be followed.

E. The facility Fire Protection Program and implementing procedures which have been established for the station shall be implemented and maintained.

F. Deleted

G. In cases of emergency, operations personnel shall be authorized to depart from approved procedures where necessary to prevent injury to personnel or damage to the facility. Such changes shall be documented, reviewed and approved by the Station Nuclear Safety and Operating Committee.

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H. Practice of site evacuation exercises shall be conducted annually, following emergency procedures and including a check of communications with off-site report groups.

I. Deleted.

J. Deleted.

K. <u>Systems Integrity</u>

The licensee shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

L. Iodine Monitoring

The licensee shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital area under accident conditions. This program shall include the following:

1. Training of personnel,
2. Procedures for monitoring, and
2. Provisions for maintenance of sampling and analysis equipment.

M. Deleted

N. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to ten times 10 CFR 20, Appendix B, Table 2, Column 2,

3) Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

4) Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5) Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days,

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31-day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas at or beyond the SITE BOUNDARY shall be limited to the following:

a) For noble gases: Less than or equal to a dose rate of 500 mrem/yr to the total body and less than or equal to a dose rate of 3000 mrem/yr to the skin, and

b) For Iodine-131, Iodine-133, Tritium, and all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to a dose rate of 1500 mrem/yr to any organ.

8) Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, Tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

O. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM.

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

P. Secondary Water Chemistry Monitoring Program

A secondary water chemistry monitoring program shall be provided to inhibit steam generator tube degradation. This program shall include the following:

1) Identification of a sampling schedule for the critical parameters and control points for these parameters.

2) Identification of the procedures used to quantify parameters that are critical to control points.

3) Identification of process sampling points.

4) Procedure for the recording and management of data.

5) Procedures defining corrective actions for off control point chemistry conditions, and

6) A procedure for identifying the authority responsible for the interpretation of the data, and the sequence and timing of administrative events required to initiate corrective action.

Section 6.5, "Station Operating Records," has been relocated to the Operational Quality Assurance Program, and Pages TS 6.5-2 and TS 6.5-3 have been deleted in their entirety.

6.6 STATION REPORTING REQUIREMENTS

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following identified reports shall be submitted to the Administrator of the appropriate NRC Regional Office unless otherwise noted.

A. Routine Reports

1. Startup Report

A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the tests identified in the FSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any addditional specific details required in license conditions based on other commitments shall be included in this report.

Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operations), supplementary reports shall be submitted at least every 3 months until all three events have been completed.

2. Annual Reports[1]

a. A tabulation on an annual basis of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man-rem exposure according to work and job functions[2], 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 totaling 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.

Note: Footnotes 1 and 2 are located on page TS 6.6-12.

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.1.D.4. In addition, the information itemized in Specification 3.1.D.4 shall be included in this report.

3. Monthly Operating Report

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the Reactor Coolant System PORV's or safety valves, shall be submitted on a monthly basis to the Director, Office of Management and Program Analysis, U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, with a copy to the Regional Office of Inspection and Enforcement, no later than the 15th of each month following the calendar month covered by the report.

Pages 6.6-4 through 6.6-9 have been deleted.

B. Unique Reporting Requirements

1. Inservice Inspection Evaluation

Special summary technical report shall be submitted to the Director of Reactor Licensing, Office of Nuclear Reactor Regulation, NRC, Washington, D.C. 20555, after 5 years of operation. This report shall include an evaluation of the results of the inservice inspection program and will be reviewed in light of the technology available at that time.

2. Annual Radiological Environment Operating Report[1]

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The report shall include summaries, interpretations, and analysis of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR Part 50.

3. Annual Radioactive Effluent Release Report[3]

The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

C. Special Reports

In the event that the Reactor Vessel Overpressure Mitigating System is used to mitigate a RCS pressure transient, submit a Special Report to the Commission within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or the administrative controls on the transient and any corrective action necessary to prevent recurrence.

FOOTNOTES

1. A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2. This tabulation supplements the requirements of Section 20.2206 of 10 CFR Part 20.

3. A single submittal may be made for a multi-unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

6.7 Environmental Qualifications

A. By no later than June 30, 1982 all. safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines); or, NUREG-0588 "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979. Copies of these documents are attached to Order for Modification of License Nos. DPR-32 and DPR-37 dated October 24, 1980.

B. By no later than December 1, 1980, complete and auditible records must be available and maintained at a central location which describe the environmental qualification method used for all safety-related electrical equipment in sufficient details to document the degree of compliance with the DOR Guidelines or NUREG-0588. Thereafter, such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.8 PROCESS CONTROL PROGRAM AND OFFSITE DOSE CALCULATION MANUAL

A. Process Control Program (PCP)

Changes to the PCP:

1. Shall be documented and records of reviews performed shall be retained as required by Specification 6.5.B.12. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   b. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall require review and acceptance by the SNSOC and the approval of the Site Vice President prior to implementation.

B. Offsite Dose Calculation Manual (ODCM)

Changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained as required by Specification 6.5.B.12. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

b. A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

2. Shall require review and acceptance by the SNSOC and the approval of the Site Vice President prior to implementation.

3. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.